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REGION I

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Inspectors:	D. Kern, Senior Resident Inspector F. Lyon, Resident Inspector G. Dentel, Resident Inspector S. Pindale, Resident Inspector B. Welling, Project Engineer
Approved by:	P. Eselgroth, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/97-01 & 50-412/97-01

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 5-week period of resident inspection.

Operations

- The inspectors had several negative observations associated with the standby service water pump surveillance performed on February 25, 1997. The maintenance foreman failed to attend the evolution prebrief and therefore failed to get permission for a related post maintenance test. Operators subsequently performed the post maintenance test without getting permission from the shift foreman. Vibration monitoring locations were not clearly marked for effective pump performance trend analysis. Valve manipulation beyond that prebriefed with the planned evolution was contrary to management expectation and was a challenge to configuration control. This represents an additional example of configuration control issues which were the subject of an escalated notice of violation (NOV), previously issued on March 24, 1997. The February 25 issue is encompassed by the March 24 NOV and occurred before the licensee's corrective actions were fully implemented. (Section O1.2)

- On March 13, 1997, operations supervisors failed to recognize the service water system was inoperable for about 20 hours. The operators performed a valve stoke surveillance test to confirm its operability before the technical specification (TS) action statement period was exceeded. Therefore, no violation of regulatory requirements occurred. Failure to identify the valve as inoperable was a weakness. The inspectors also noted weaknesses in operations turnovers and the effectiveness of system engineering involvement, which were contributing factors. (Section O1.3)

- Unit 2 operators responded appropriately and in a controlled manner to a secondary process rack power supply failure. Operators reacted quickly and effectively to the inadvertent opening of the atmospheric steam dump valves during troubleshooting, which reduced the transient effect on the plant. Operations management's thorough questioning resulted in additional controls during the second troubleshooting attempt on the process rack. (Section O1.4)

- An inadequate chemistry sample for degasifier boron concentration resulted in an unexpected boration of the RCS when the Unit 2 degasifier was placed in service. Operator response was appropriate; however, the lack of an effective pre-job briefing presented a challenge to operators since contingency actions had not been discussed. The root cause analysis and corrective actions were comprehensive. (Section O1.5)

- During routine tours, inspectors observed that station-wide standards for material condition, work area cleanliness including maintenance work shops, plant housekeeping, and problem identification were good. This was a noted improvement over the poor plant housekeeping and work area conditions observed in late 1996. Minor unidentified material deficiencies and unnecessary contaminated areas continue to exist, which indicates that continued attention to detail during routine tours and work activities is warranted. Deficiencies identified by the inspectors were promptly corrected. (Section O2.2)

- Overtime controls were effectively implemented during refueling outage 1R11. QA surveillance reports were thorough and representative of station activities. Findings were promptly identified and corrected. The potential programmatic concern related to inadequate guidance for shift turnover time was a particularly noteworthy finding, which was promptly and effectively corrected. (Section O6.1)

- Operators showed good attention to detail and questioning attitude in noticing and following up discrepancies. Examples included an incorrect setpoint on a safety injection pump cubicle temperature switch, a hydraulic fluid leak on the Unit 1 main turbine overspeed trip block, and small cracks in safety-related ductwork for the Supplementary Leak Collection and Release System. DLC corrective actions were appropriate and displayed reasonable engineering judgement. (Section O8.1)

- Five previously unresolved items were closed. Four were associated with escalated enforcement actions previously issued in NRC letters dated March 10 and March 24, 1997. (Sections O8.2 to O8.6)

- The Nuclear Shift Supervisor's identification of deficiencies in the electrical checks done after hydrogen recombiner testing indicated a good questioning attitude. (Section M7.1)

Maintenance

- Insufficient planning and system knowledge during troubleshooting on a Unit 2 secondary process rack resulted in opening two atmospheric steam dump valves. The valves failing open was a challenge to operators and to the plant. Initial troubleshooting efforts were not properly documented. Failure to initially submit a condition report to evaluate troubleshooting problems through the formal corrective action program is a weakness. Additional troubleshooting efforts and replacement of the power supply were appropriately performed. (Section M1.3)

- The Fix-It-Now (FIN) team was effective in correcting minor deficiencies before they developed into larger problems. With one isolated exception, FIN team work was properly performed. Recent revisions to address repeat component work were appropriate. The FIN team manager indicated that the maintenance organization intends to expand FIN Team work scope significantly in the near future. Additional controls and management review of the FIN program are necessary prior to expanding the work scope further to include emergent work such as control room deficiencies. (Section M1.4)

- Collectively, failure to take EDG kilowatt meter instrument inaccuracy into account, improper sequencing of RCS pressure isolation valve leak testing, and improper sequencing of hydrogen recombiner electrical checks indicated potential weaknesses in the scheduling and procedures that implement the surveillance testing program. These deficiencies in the surveillance testing program are unresolved pending DLC's determination of corrective actions and subsequent NRC review. (Section M7.1)

- DLC continues to be challenged at being able to reduce the control non-outage maintenance backlog. In the short-term, additional staff has been hired to bring down the backlog. In the long-term, DLC is establishing a new work control center (scheduled to begin implementation in April 1997) and is developing improvements to the work control process (such as re-characterizing the backlog and making the 12-week schedule process more efficient) with the goal of reducing backlog from approximately 1550 (February 1997) to 1000 by the end of 1997. Some administrative discrepancies were noted in the backlog lists, but the backlog appeared to be properly prioritized. (Section M1.5)

Engineering

- Deficiency card signatures on various equipment in the auxiliary buildings indicated that system engineers had recently begun to spend more time in plant areas walking down their systems. This was a positive trend with regard to station personnel actively monitoring equipment to identify minor problems before they become severe. (Section O2.2)

- Actions taken following the failure of main steam trip bypass valve MOV-MS-101A and subsequent discovery that it was not listed in the Containment Isolation Table were conservative in treating it as a containment isolation valve. Licensing engineers effectively reviewed the function of the valve and determined that MOV-MS-101A/B/C should be listed as containment isolation valves. Appropriate action was initiated to update the Containment Isolation Table. (Section E2.1)

- System engineering identification of the EDG kilowatt meter inaccuracy issue through industry operating experience review and evaluation of its applicability to Beaver Valley were excellent. Identification and follow-up of the issue indicated a good questioning attitude from system engineering staff. (Section M7.1)

- The Updated Final Safety Analysis Report (UFSAR) Verification Project was a significant licensee commitment to verify that the station is operated as designed and licensed. The inspectors noted that the independent verification and QSU audit functions were well conceived as methods to verify quality assessment and resolution of identified UFSAR discrepancies. Follow-up of the UFSAR Verification Project is an unresolved issue pending completion of DLC activities and subsequent NRC review. (Section E8.1)

Plant Support

- DLC's immediate corrective actions for the loss of power to the Emergency Response Facility (ERF) were appropriate; however, the event indicated potential weaknesses in operating procedures for the ERF building, delegation of responsibility among site organizations for the ERF, and follow-up of corrective actions for previous similar events. DLC management had not reviewed the Event Response Team evaluation and long term corrective action recommendations at the end of the period. Deficiencies associated with the loss of power to the ERF are an unresolved item pending completion of DLC evaluation and subsequent NRC review. (Section P2.1)

Safety Assessment and Quality Verification

- Quality Services Unit (QSU) identification of deficiencies in the sequencing of RCS pressure isolation valve leak testing and hydrogen recombiner testing was good. Identification and follow-up of the issues indicated good attention to detail during audits by the QSU staff. (Section M7.1)

- QSU inspectors have been more proactive over the past six months in identifying and reporting problems. Important station wide processes and work activities were selected and audited. The recent TS surveillance audit findings and resultant audit scope expansion were of particular significance. The condition report system has been effectively used to communicate QSU identified deficiencies to station management and clearly assign responsibility for issue resolution. The QSU provided valuable independent oversight for station activities during this inspection period. (Section E7.1)

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Report Details

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power. On February 19, DLC initiated a plant shutdown required by Technical Specifications after declaring both emergency diesel generators inoperable. DLC concluded that the 18 month loading capability had not been demonstrated during surveillance testing because the inaccuracies in the monitoring system had not been taken into account fully. The shutdown was terminated when one of the EDGs was successfully tested and returned to service (section M7.1). On February 26, DLC entered Technical Specification 3.0.3 after discovering deficiencies in the surveillance testing of the hydrogen recombiners. The recombiners were tested and returned to service before a unit shutdown was required (section M7.1). The unit operated without significant incident for the remainder of the period.

Unit 2 operated at 100 percent power without significant incident throughout the period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)[1]

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

O1.2 Standby Service Water Pump Surveillance

a. Inspection Scope (61726, 71707)

The inspectors attended the prebrief, observed the pump surveillance run, independently verified procedural adherence, and interviewed operations and maintenance personnel to evaluate the standby service water pump quarterly surveillance and associated post maintenance testing.

b. Observations and Findings

On February 25, 1997, operators conducted 2OST-30.1A "Standby Service Water Pump [2SWE-P21A] Test," Revision 5. The assistant nuclear shift supervisor (ANSS) held a thorough prebrief, stressing the importance of attention to any abnormal pump operation. The inspectors noted that maintenance personnel were

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

not present at the prebrief. The inspectors observed that operators performed a detailed walkdown of the auxiliary intake structure in preparation for the surveillance.

The operators identified problems with taking vibration readings on the pump. The vibration tags, identifying the location to take readings, were missing for several points. In addition, several of the locations were above floor level without a suitable avenue to access the physical location to take the readings. Operators contacted the vibration engineer for assistance to obtain the reading. Through interviews with operators and the engineer, the inspectors identified that the operators relied on the tags to know the correct location to take vibration readings, while the engineer relied on operator knowledge to take readings in the correct location. This misunderstanding could result in inconsistent location of readings and invalidate trending data. The engineer obtained the readings by climbing on the piping and an electrical box. The inspectors determined that this was a personnel safety hazard and improper use of equipment. The inspectors noted several locations in the alternate intake structure where insulation was damaged, which appeared to be a result of personnel stepping on the piping. The inspectors discussed these issues with operations management and vibration analysis engineers who stated that they would resolve the issues.

The inspectors observed that the vibration readings obtained were taken in the correct locations and were within the acceptance criteria. The standby service pump passed the surveillance test. During the pump run, the operator at the pump, under guidance of a maintenance supervisor, performed post-maintenance testing of several valves associated with Unit 1 filtered water to the Unit 2 seal water for the standby service water pump. The operator manipulated several valves without procedural guidance and without operations supervisor knowledge. Maintenance supervision expected that the post-maintenance tests would be performed during this surveillance. Inadequate communications between the maintenance foreman and the ANSS resulted in conflicting views on what was expected in the field. The lack of maintenance presence in the prebrief was a contributing cause.

Manipulation of valves without station procedures was contrary to management expectations. The licensee had identified previous problems with configuration control of seal water valves. On January 31, 1997, two Unit 2 seal water valves for the standby service water system were found out of their normal system alignment (NSA) position. The licensee was unable to determine an exact cause for the mispositioned valves. Configuration control is being addressed as part of the escalated enforcement action (EA 97-076). A notice of violation (NOV) (EA 97-076) was issued on March 24, 1997 for various configuration control deficiencies. The inspectors determined that the February 25 issue was encompassed by the subsequently issued NOV and that corrective actions discussed at the March 7 predecisional enforcement conference were appropriate to address the standby service water configuration deficiencies.

The operators double verified the valves were in the NSA position and operations management was informed of the issue. Condition report 970418 was initiated to address the issue. The inspectors independently verified the valves were in the correct positions.

c. Conclusions

The inspectors had several negative observations associated with the standby service water pump surveillance performed on February 25, 1997. The vibration engineer obtained proper pump readings; however, the potential existed for inconsistent readings due missing vibration location tags and reliance on operator knowledge. The use of piping and electrical boxes to climb to obtain vibration readings was a personnel safety hazard as well as an equipment degradation issue. The maintenance foreman failed to attend the evolution prebrief and therefore failed to get permission for a related post maintenance test. Operators subsequently performed the post maintenance test without getting permission from the shift foreman. Vibration monitoring locations were not clearly marked for effective pump performance trend analysis. Valve manipulation beyond that prebriefed with the planned evolution was contrary to management expectation and was a challenge to configuration control. This represents an additional example of configuration control issues which were the subject of an escalated notice of violation (NOV), previously issued on March 24, 1997. The February 25 issue is encompassed by the March 24 NOV and occurred before the licensee's corrective actions were fully implemented.

O1.3 Service Water System Seal Water Supply

a. Inspection Scope (71707)

The inspectors performed daily control room tours, observed operator turnover, and reviewed operator logs. In addition, the inspectors discussed with operations personnel the status of equipment, technical specifications, and upcoming testing. On March 14, 1997, the inspectors noted that the service water system emergency seal water supply was inoperable and the applicable technical specification was not entered. The inspectors interviewed operations supervisors, system engineers, and maintenance personnel as part of the investigation.

b. Observations and Findings

On March 8, while performing procedure 2OM-30.4.B, the emergency seal water supply valve (2SWS-SOV-130A) failed to open. Operators mechanically agitated the valve open and proper seal pressure was established to the service water pump. The suspected cause of the valve's failure-to-close was excessive debris due to the high river level. On March 10, the inspectors questioned the nuclear shift supervisor (NSS) on the basis for operability of the valve. The valve was considered operable based on the valve being in the required open position allowing emergency flow to the service water pumps. The inspectors determined that the valve would perform its emergency function; however, operation supervisors did not

appropriately track the failure of the valve to stroke. Operators wrote a maintenance work request (MWR) to address the problem.

On March 13, the 2SWS-130A valve was shut and normal filtered water began supplying flow to the service water pump seals. At this point, the service water system was considered operable by the operations staff, even though the valve had not been repaired and was not in its required open emergency position. After reviewing operator logs on March 14, the inspectors questioned the operability of the service water system to the assistant NSS. During the morning, the plant manager also questioned the operability of the service water system. At 8:54 a.m., the operators completed the OST for the seal water system and successfully stroked open the 2SWS-130A valve. Based on the plant manager input, the 2SWS-130A valve will remain in the open position pending further analysis of the failure modes.

Through discussions with system engineers, maintenance management, and operation supervisors and a review of work documents, the inspectors determined that the valve was not repaired or stroked from March 8 to March 14. On March 13, the valve was returned to service without the required actions to verify operability. Therefore, the service water system should have been declared inoperable at 12:20 pm, on March 13, and Technical Specification (TS) 3.7.4.1 entered. After 8:54 am, on March 14, the TS would have been exited.

Based on the discussion with the operations supervisors, the inspectors determined that failure to properly identify the 2SWS-130A valve as inoperable resulted in the valve being returned to service without proper testing. A contributing cause was inadequate operator turnover of the service water system information and a lack of system engineering involvement in the failures.

c. Conclusions

Operations supervisors failed to recognize the service water system was inoperable for about 20 hours. The operators performed a valve stoke surveillance test to confirm its operability before the TS action statement period was exceeded. Therefore, no violation of regulatory requirements occurred. Failure to identify the valve as inoperable was a weakness. The inspectors also noted weaknesses in operations turnovers and the effectiveness of system engineering involvement, which were contributing factors.

O1.4 Process Rack Power Supply Failure

a. Inspection Scope (71707)

On February 3, 1997, Unit 2 lost power to the 'A' Secondary Process Rack (RK'2SEC-PROC-A). This resulted in a loss of some control room indications and functions. The inspectors reviewed operator response to the initial loss of power and to the effects of reenergizing the process rack. The inspectors also evaluated the compensatory actions taken to mitigate the loss of the instrumentation.

b. Observations and Findings

On February 3 at 3:30 am, the operators received a process rack power supply failure alarm. Within 10 minutes, the upstream breaker (PNL-VITBUS2-1A, breaker 1A-11) tripped. The control room indications and process controllers that were lost included: (1) diesel generator 2-1 building ventilation controller; (2) component cooling water flow indication to the 'A' reactor cooling pump (RCP) which caused isolation of flow to the RCP 21A thermal barrier; (3) service water pressure indicator failed low, which caused an auto start of the standby service water (SWE) pump; (4) atmospheric steam dump valves (ADVs) 'A' and 'C'; (5) primary component cooling water surge tank level transmitter; and (6) various other instrumentation. Operations management added additional operators to monitor the control room and notified Instrumentation and Controls (I&C) staff of the failure. Operations personnel also reviewed emergency operating procedures to identify any additional concerns the loss of instrumentation would cause if needed in an emergency. Operations supervisors developed contingencies to address the loss of the diesel generator ventilation control.

Initial troubleshooting of the secondary process rack by I&C (Section M1.3) resulted in the opening of atmospheric steam dump valves 'A' and 'C'. The reactor operator, noting the change in Tave, placed the controller in manual and closed the atmospheric steam dump valves. The operator's quick and decisive response prevented a major transient on the reactor. The nuclear shift supervisor's and the General Manager of Nuclear Operation's thorough questioning of further I&C troubleshooting resulted in additional measures to prevent impact on station equipment.

c. Conclusions

Operators responded appropriately and in a controlled manner to the initial loss of the process rack. Operators reacted quickly and effectively to the inadvertent opening of the atmospheric steam dump valves, which reduced the transient effect on the plant. Operations management's thorough questioning resulted in additional controls during the second troubleshooting attempt on the process rack. Operator performance and shift supervision compensatory actions effectively reduced the impact of the secondary process rack failure and the ADV opening during the initial troubleshooting effort.

O1.5 Unexpected Reactor Coolant System Boration

a. Inspection Scope (61726, 71707)

On February 23, 1997, operators placed the Unit 2 degasifier in service per 2OM-7.4T "Continuous Degasification," Rev. 1. Differences in expected boron concentration and actual boron concentration in the degasifier resulted in an unexpected boration of the Reactor Coolant System (RCS). The inspectors reviewed the condition report (CR 970362), evaluated corrective actions, and discussed management expectation of operator response.

b. Observations and Findings

The Unit 2 degasifier was sampled prior to placing it in service. The chemistry technician determined that the degasifier had a slightly higher boron concentration than the RCS (1186 ppm vs. 1172 ppm). As prebriefed, operators planned to dilute the RCS with 80 gallons of water to maintain constant RCS average temperature (Tave). After adding the planned 80 gallons dilution, operators observed that Tave continued to lower, which was not expected. Operators added an additional 500 gallons of water over a one hour period to maintain Tave within 2 degrees of programmed RCS temperature (Tref). The water was added to the RCS to stabilize Tave and was conducted based on the monthly reactivity plan.

The licensee identified root cause was that chemistry technicians analyzed a non-representative sample of the degasifier fluid. The operations procedure (2OM-7.4.T) and the chemistry sampling procedure (CM 2-3.2 "Sampling and Testing Degasifier System," Rev. 3) did not establish or verify process flow at the sample point. In addition, the degasifier is constantly in recirculation mode even when the system is not part of the RCS. This method of operation increases the boron concentration in the degasifier. The licensee root cause analysis effectively identified these issues and corrective actions were appropriate.

The licensee analysis also identified that the operations crew failed to discuss contingency plans during the pre-job briefing. The licensee review concluded that operator actions taken during this event were timely, proper, and within the requirements of the operations standards. The inspectors concluded that actions taken were appropriate; however, the lack of an effective pre-job briefing presented a challenge to operators.

c. Conclusions

An inadequate chemistry sample for degasifier boron concentration resulted in an unexpected boration of the RCS when the Unit 2 degasifier was placed in service. Operator response was appropriate; however, the lack of an effective pre-job briefing presented a challenge to operators since contingency actions had not been discussed. The root cause analysis and corrective actions were effective in addressing the issue.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns

a. Inspection Scope (71707)

The inspectors performed a detailed walkdown and review of the Unit 2 high head safety injection system to assess operability and material condition.

b. Observations and Findings

The inspectors walked down the accessible portions of the Unit 2 high head safety injection system. The system piping and instrumentation diagrams and system alignment checklists were verified with the actual system configuration. No lineup discrepancies were observed.

The overall material condition of the system was good. Minor housekeeping discrepancies were brought to the attention of the system engineer and operations department personnel, as appropriate. The inspectors discussed minor oil leaks observed on the charging pumps with the system engineer, who indicated that he was evaluating possible design changes for some of the oil system pipe fittings.

The results of selected of recent surveillance test reports were also reviewed. The inspectors found that acceptance criteria for the tests were met, and the surveillance tests satisfied the technical specifications requirements.

The inspectors reviewed planned corrective maintenance items associated with the high head safety injection system. These items were determined to be appropriately prioritized for resolution.

c. Conclusions

The inspectors concluded that Unit 2 high head safety injection system was properly aligned for system operability. The overall material condition of the system was assessed as good.

O2.2 Plant Area Tours and Housekeeping

a. Inspection Scope (71707, 71750)

Previous observations during plant tours in late 1996 indicated low standards station-wide with regard to control of transient material, tools and construction materials left unattended for long periods of time with no work in progress, and instances where radiological contaminated area barriers were not properly maintained. The inspectors conducted plant tours within the protected area to assess the general material condition of equipment and work spaces.

b. Observations and Findings

The inspectors conducted frequent tours of both units process buildings, maintenance work shops, and outside areas within the protected area perimeter. Outside areas were maintained very well. Loose material and staged equipment which would have the potential to damage transformers and other outside equipment had been properly removed or stored. Maintenance personnel conducted a month long effort to upgrade the maintenance work shops. Stray equipment was removed, the shops were cleaned and painted, and work areas generally improved

to better support quality maintenance activities. Efforts to improve shop storage of on-hand parts continued at the end of the period.

Equipment operators were familiar with equipment condition in the Unit 1 auxiliary building, and the Unit 2 auxiliary and turbine buildings when questioned by the inspectors. The inspectors noted several minor discrepancies including loose tools, extraneous scaffolding, outdated room area radiological postings, a heat trace panel deficiency which was over two years old, and roof leaks. Steam leaks, oil leaks, and other more significant material problems had been properly identified and reported by licensee personnel. Deficiency card signatures indicated that system engineers had recently begun to spend more time in the plant areas walking down their systems. The inspectors noted this was a positive trend with regard to station personnel actively monitoring equipment to identify minor problems before they become severe.

The inspectors observed that although contaminated areas were properly posted, several areas which did not have active radiological leaks continued to be posted as contaminated areas without being cleaned up. Such areas included the degasifier rooms, containment hatch rooms, and areas surrounding various equipment which was previously abandoned in place. This adversely limited operator access to these areas during plant tours. The inspectors discussed their tour findings with operations management personnel who promptly initiated appropriate action to correct the identified discrepancies.

c. Conclusions

The inspectors concluded that station-wide standards for material condition, work area cleanliness including maintenance work shops, plant housekeeping, and problem identification observed during routine tours were good. This was a noted improvement over the poor plant housekeeping and work area conditions observed in late 1996. System engineers have begun to spend more time in plant areas identifying minor equipment problems before they become more severe. Minor unidentified material deficiencies and unnecessary contaminated areas continue to exist, which indicates that continued attention to detail during routine tours and work activities is warranted. Deficiencies identified by the inspectors were promptly corrected.

O6 Operations Organization and Administration

O6 1 Licensee Assessment of Use of Overtime for Licensee and Contractor Personnel

a. Inspection Scope (40500, 71707)

The inspectors reviewed the licensee's control of overtime for licensee and contractor employees. In particular, the inspectors reviewed administrative procedures, interviewed personnel, reviewed overtime records for engineering and operations personnel, and reviewed surveillances performed by the Quality Services Unit (QSU) regarding use and control of overtime.

b. Observations and Findings

The Unit 1 and Unit 2 Technical Specifications (TS) delineate the requirements for use of overtime for personnel performing safety related functions. The TS requirements are further implemented via Nuclear Power Division Administrative Manual - Directive (NPDAD) 1.2.8, Use of Overtime, Rev. 4.

The inspectors reviewed QSU surveillance reports 1-MIS-47-96 and 1-MIS-48-96 for use and control of overtime for licensee and contractor personnel, respectively. The inspectors discussed the methodology and procedures used with the surveillant. The time period that was reviewed for both surveillance reports was March 15, 1996, through May 15, 1996 (1R11 refueling outage). The completed reports identified several minor discrepancies which were identified, evaluated, corrected, and documented in Qualify Assurance Deficiency Reports (QADRs).

The surveillant also identified a potential programmatic weakness. The overtime requirements specify limits for hours of work for certain time periods (e.g. no more than 16 hours in any 24 hour period). However, shift turnover time is excluded from the hours of work period. The surveillant identified that there were no restrictions on the length of turnover time that can be charged. For example, one turnover consisted of about three hours. In response to this concern, Deficiency Report QSAS-96-0092 was initiated on July 2, 1996. The licensee subsequently implemented program and procedure changes to define shift turnover time as a maximum of two hours total, one hour on each side of the shift. The inspectors verified that the procedure changes were implemented.

The inspectors independently reviewed records for various time frames to confirm that overtime requirements were satisfied, particularly for operators. No deficiencies were identified.

c. Conclusions

The inspectors determined that overtime controls were effectively implemented during refueling outage 1R11. QA surveillance reports were thorough and representative of station activities. Findings were promptly identified and corrected. The potential programmatic concern related to inadequate guidance for shift turnover time was a particularly noteworthy finding, which was promptly and effectively corrected.

O8 Miscellaneous Operations Issues (71707)

O8.1 Operator Attention to Detail

a. Inspection Scope (71707)

Inspectors monitored resolution of selected issues raised by operators in the course of routine tours and evolutions.

b. Observations and Observations

Safety Injection Pump Cubicle Temperature Switch

During a routine engineered safety features train verification for a tagout, operators noted that TS-1VS-4-13 (temperature switch for the B low head safety injection pump (SI-P-1B) cubicle) was set at 160 degrees F instead of the expected 145 F. The temperature switch actuates an annunciator (Recirc Spray and Safety Inj PP Compartment Temp High-Low, Window A11-56) in the control room, but has no other function. Ventilation system protective features (such as damper re-positioning) are actuated by a different temperature switch set at 105 F. The rheostat-type switch is physically located above the entrance to the cubicle. The issue was documented on Condition Report 970381.

Following evaluation by licensee staff and management, the switch was reset to 145 F. No deficiencies were found in the settings for the other cubicle temperature switches.

Inspectors discussed the issue with operations and system engineering staff. There was no maintenance history on the switch and neither it nor the low temperature switch (set at 40 F) were in the calibration program. It was last verified as functional in May 1995, but its setpoint was not checked as part of the functional verification test. The system engineer could not identify an existing need for the switch.

The temperature switch was originally installed for monitoring during a high energy line break (HELB) accident. Since there are no high energy lines in the area, however, DLC re-analyzed the area and removed the requirement for the temperature switch. Analysis showed that temperatures in the pump cubicle area are not expected to exceed 120 F during a HELB. Inspectors reviewed Engineering Memorandum 109626 for Beaver Valley Test 1-2.16.8, "Safeguards Cubicles Ventilation Test, "Calculation 11700-US(B)-251 Rev. 2 dated January 31, 1991, "Steam Generator Blowdown Line Break Analysis," and Engineering Standard ES-M-012, which provided the engineering basis for eliminating the temperature switch from the calibration and test program.

Operators showed good attention to detail and questioning attitude in noticing and following up the discrepancy. Inspectors questioned management as to their assessment of the usefulness of the temperature switch since it apparently provides no safety function and is set above the design temperature of the cubicle. It provides an input to a control room annunciator, but it is not in the calibration program. Engineering staff were still evaluating whether to maintain or remove the switch at the end of the period.

Operator Walkdowns

Operators posting a routine tagout noted about six small cracks (1 inch to 6 inch) in the ductwork downstream of Supplementary Leak Collection and Release System

(SLCRS) damper VS-D-4-8B. SLCRS fan VS-F-4B was declared inoperable and Unit 1 entered TS 3.7.8.1 (allows 7 days to return the system to service or shutdown the unit). Engineering staff responded to the issue promptly and determined the root cause to be fatigue failure due to vibration. No additional deficiencies were noted during follow-up inspection of the other trains. As immediate corrective action, DLC did a weld repair and added additional stiffeners to the duct to return it to service. The ductwork is scheduled to be replaced during the next refueling outage.

Operators on routine tour noted electro-hydraulic control (EHC) fluid below the Unit 1 main turbine and traced it to a leak on the turbine overspeed trip block. The leak appeared to be from an O-ring on an EHC connection on the bottom of the block. It was about 8 ml/min. DLC contained the leak with a catchment and tube running back to the EHC reservoir. Following discussion with the vendor and consideration of the available repair options, DLC decided to wait for an outage opportunity to repair it. Operators continued to monitor the leakage on a periodic basis for signs of a degrading condition.

c. Conclusions

Operators showed good attention to detail and questioning attitude in noticing and following up the discrepancies. DLC corrective actions were appropriate and displayed reasonable engineering judgement.

O8.2 (Closed) URI 50-412/95080-02: No problem report issued to address inadequate clearance and subsequent flooding of the B & D recirculation spray (RS) pump cubicals.

On May 1, 1995, the B & D RS pump cubicals were inadvertently partially flooded with river water due to an inadequate clearance posting. The issues of the inadequate clearance and partial cubical flooding were identified by the licensee during follow-up review of the event several days later. The inspectors observed that the licensee did not document the event in a problem report for corrective action resolution, and assigned this URI pending determination of whether there was a programmatic breakdown in identifying and documenting problems.

The inspectors verified that a problem report was subsequently written to document the clearance/flooding issue. In addition, as documented in NRC IR No. 50-334(412)/96-10, the licensee has demonstrated a low threshold for identifying and reporting problems in the new condition report program. Configuration control issues are promptly reported to security and operations personnel and documented in condition reports for resolution. Current inspector observations indicate this has not continued to be a programmatic problem. This item is closed.

O8.3 (Closed) URI 50-412/95080-01: Inadequate independent verification of valve position for service water valve 2SWS-82

This URI was closed to VIOs EA 97-076 01023 and EA 97-076 01033 issued by NRC letter dated March 24, 1997.

O8.4 (Closed) URI 50-334(412)/95080-04: Mispositioning of 2SWS-82 and two instrument valves.

This URI was closed to VIOs EA 97-076 01013 and EA 97-076 01033 issued by NRC letter dated March 24, 1997.

O8.5 (Closed) URI 50-334/96007-01: Unit 1 pressurizer power operated relief block valve configuration contrary to UFSAR.

This URI was closed to VIO EA 96-462 02013, issued by NRC letter dated March 10, 1997.

O8.6 (Closed) URI 50-412/96009-02: Inadequate 2RCS-64 Leak Injection Repair.

This URI was closed to VIOs EA 96-540 01013, EA 96-540 01023, EA 96-540 01033, and EA 96-540 01043 issued by NRC letter dated March 10, 1997.

O8.7 (Closed) Licensee Event Report (LER) 50-334/96003-01: Engineered Safety Feature (ESF) Actuation Due to Steam Generator Water Level Transient.

This event was discussed in NRC inspection report 50-334(412)/96-003. The inspection report noted that the sequence of testing as directed by operations management contributed significantly to difficulties experienced by the operators in maintaining proper reactor coolant system temperature, ultimately leading to a turbine trip and feedwater isolation. The report also indicated that a root cause analysis was under development by the licensee.

The inspectors reviewed the root cause analysis and considered it to be thorough. This analysis was used to develop corrective actions for the event, as described in supplement 1 to the LER. The analysis identified a number of notable weaknesses in the operations area including: poor procedural guidance for low power operations, training weaknesses in controlling reactor coolant temperature at low power levels and in following up on related industry reactivity control events, and weaknesses in shift communications and command and control.

The inspectors also reviewed completed corrective actions and verified that progress was being made on longer term actions to prevent recurrence. Several procedural upgrades were made to startup, shutdown, and low power operations procedures. A number of other operator training enhancements and operations policy revisions were also initiated. The inspectors concluded that the corrective actions adequately addressed the issues identified in the root cause analysis for the event. The LER thoroughly documented the event and corrective actions. The inspectors identified no additional issues.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Routine Maintenance Observations (62707)

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

- •MWR 061501 Conduct Continuity and Megger Checks on Hydrogen Recombiner 1B; MSP-46.01B-E

The activities observed and reviewed were performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the work depending on its priority and difficulty.

M1.2 Routine Surveillance Observations (61726)

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

2OST 36.2 "Emergency Diesel Generator [2EGS*EG2-2] Monthly Test," Rev. 20
2OST-30.1A "Standby Service Water Pump [2SWE-P21A] Test," Rev. 5
2OST 7.5 "Centrifugal Charging Pump [2CHS*P21B]," Rev. 11
1OST-13.2, "Quench Spray Pump [QS-P-1B] Test," Rev. 11
1OST-24.2, "Motor Driven Auxiliary Feed Pump Test [1FW-P-3A]," Rev. 11
1OST-46.4, "Six Month Hydrogen Recombiner-1B Test," Rev. 3
1OST-36.2, "Diesel Generator No. 2 Monthly Test," Rev. 16
1OST-7.5, "Centrifugal Charging Pump Test [1CH-P-1B]," Rev.10

Surveillance testing was generally performed safely and in accordance with proper procedures. Additional observations regarding surveillance testing are discussed in Section O1.2 and the following sections. The inspectors noted that an appropriate level of supervisory attention was given to the testing, depending on its sensitivity.

M1.3 Process Rack Power Supply Failure

a. Inspection Scope (62707)

On February 3, 1997, Unit 2 lost power to the 'A' Secondary Process Rack (RK*2SEC-PROC-A). This resulted in a loss of some control room indications and functions. The inspectors observed troubleshooting efforts and subsequent replacement of the secondary power supply. The inspectors interviewed system engineers and I&C personnel on the troubleshooting efforts and subsequent problems. The follow documents were reviewed:

- CR 97-203 "Process Rack Power Failure"
- CR 97-206 "Drawing/OM Procedure Errors for 2CCP-LT100A Loss of Power"
- MWR 60774 "Breaker 1A-11 on PNLVITBS2-1A Tripped, all Power Lost to Secondary Process Cabinet A"

b. <u>Observations and Findings</u>

On February 3, breaker 1A-11 tripped resulting in a loss of power to the 'A' Secondary Process Rack. Instrumentation and Control personnel developed plans for troubleshooting the breaker and two parallel power supplies. The initial troubleshooting effort involved a series of steps to reenergize the breaker and power supplies while monitoring voltages. When power was restored to the process rack, atmospheric steam dumps valves 'A' and 'C' opened. Operators quickly took manual control and reclosed the valves (Section O1.1).

Maintenance engineering reviewed the atmospheric steam dump controllers circuitry and identified the cause of the inadvertent opening. The atmospheric steam dump controllers have their opening setpoint drop to zero and then the control returns to automatic upon being reenergized. Before original Unit 2 startup a design change modified the atmospheric steam dump control circuitry. This change resulted in the above stated vulnerability in the system which was not recognized prior to the current event.

The inspectors identified insufficient planning as a contributing cause to the atmospheric steam dumps opening. Instrumentation and control (I&C) personnel failed to take adequate precautions to limit the effect on downstream parameters prior to reenergization of the power supply. In addition, the I&C personnel did not effectively monitor system parameters to determine the cause of the breaker trip; therefore, a second troubleshooting attempt was needed.

The inspectors noted that the work package to perform the original troubleshooting was not retained. The inspectors requested the work package on the day the troubleshooting was performed. Interviews with numerous I&C personnel indicated that a work package was used and then later revised for the second troubleshooting effort. The failure to retain the original work package is contrary to TS 6.10.1(b) which requires that records of principal maintenance activities of equipment related to nuclear safety be retained for at least five years. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy **(NCV 50-412/97001-01)**.

The inadequate planning combined with insufficient knowledge of the atmospheric steam dumps controls resulted in the atmospheric steam dump valves opening and challenging operators. The initial troubleshooting also tested the vital bus by causing the breaker to open again.

The full evaluation and corrective actions to the atmospheric steam dumps opening have not been fully completed. Immediate corrective actions to change procedures has begun. Operations, maintenance, and system engineers failed to address the issue in the station formal corrective action program. This contributed to a delay in completing the corrective actions. Upon further questioning by the inspectors, condition report 970589 was initiated to address the process rack failure.

The second troubleshooting effort was better controlled with excellent input by operations. With the use of additional monitoring equipment, the problem was quickly narrowed to a power supply. The replacement of the power supply was performed safely and effectively.

c. Conclusions

Insufficient planning and system knowledge during troubleshooting on a Unit 2 secondary process rack resulted in opening two atmospheric steam dump valves. The valves failing open was a challenge to operators and to the plant. Failure to properly document the troubleshooting efforts was a non-cited violation. The inspectors considered the failure to initially submit a condition report to evaluate troubleshooting problems through the formal corrective action program a weakness. Additional troubleshooting efforts and replacement of the power supply were appropriately performed.

M1.4 Fix-it-Now Maintenance Program and Implementation Review

a. Inspection Scope (62707, 71707)

The Fix-It-Now (FIN) maintenance program was established to provide controls for performing minor skill-of-the-craft maintenance work without requiring a detailed work document. During this inspection, the inspectors reviewed the controlling FIN program procedure, interviewed responsible personnel, observed work in progress and reviewed completed FIN work orders.

b. Observations and Findings

The FIN maintenance program is implemented by a group of maintenance personnel (FIN Team), currently consisting of seven craft personnel, one planner, one supervisor/planner. FIN team members are fully qualified craft personnel who routinely perform regular maintenance work orders (MWRs) when not performing FIN work. The Director of Building Maintenance is responsible for the overall program. Maintenance Programs Unit Administrative Manual (MPUAM), 4.11, Fix-It-Now Maintenance Program, Rev. 1, establishes the administrative controls for the FIN maintenance program. The FIN program began around June 1996.

The inspectors observed portions of ongoing activities, discussed the FIN maintenance program concept and implementation with FIN Team personnel, and reviewed approximately 100 pending and completed FIN work orders. The inspectors found the personnel to be technically competent and generally knowledgeable of FIN maintenance program requirements and guidelines. Although the majority of FIN work orders were determined to be complete and satisfactory, several required further review to determine whether the work activities were within the FIN maintenance program scope.

MPUAM 4.11 defines FIN maintenance as maintenance that requires no initiating work documents and is performed on the spot by skill-of-the-craft. Limitations specified in the definition include 1) tasks that do not affect the safety related function of the component and 2) tasks that do not affect the Appendix R/Fire Protection function of the component. The inspectors determined that the FIN team work scope was typically appropriate. Two specific exceptions are discussed below.

The inspectors questioned completed FIN work orders that adjusted fire door closure mechanisms (FIN work orders 391 through 395). The licensee stated that adjusting the fire door mechanism was within the scope of the FIN maintenance program as long as the mechanism was not replaced. The inspectors found, however, that the "cause of failure" block for the five fire door adjustments documented that the ventilation system changes resulted in the door closure problems. The completed FIN work order may have resolved only symptoms of potentially broader problems (caused by ventilation system changes). The inspectors expressed concern that the current FIN team process could mask early signs of component degradation and lead to more significant equipment problems if not properly communicated to engineering personnel. Based on the inspectors observations the FIN tracking program was revised to ensure that repeat work items were automatically flagged in the system upon their third occurrence. This flag now requires the problem to be resolved by a maintenance work request (MWR) which requires further planning and evaluation than a FIN work item. In addition the Director of Building Maintenance informed the inspectors that the issue of masking larger problems would be considered in an upcoming revision to the FIN procedure. The inspectors determined that this action was appropriate and that adjustment of fire door closure mechanisms was within the intended FIN program scope.

The second questionable work activity involved adjusted valve packing for steam generator blowdown trip valve TV-BD-107C (FIN work order 210). The valve is a non-safety related valve that isolates on a high level on the steam generator blowdown tank. It is not a containment isolation valve. Attachment 2 to MPUAM 4.11 provides examples of mechanical maintenance FIN activities. Although the list is not intended to be all-inclusive, the only category for valve packing adjustments is for manual valves that are not subject to testing. Mechanics torqued TV-BD-107C packing to 95 inch-pounds as per the work order instructions, but the leak still persisted. Then, per additional engineering guidance, the packing was torqued to 144 inch-pounds; however, the packing leak continued.

The inspectors noted that the completed work order did not indicate that the valve had been stroked as a post maintenance test (PMT) which was specified in the FIN work order instructions. Maintenance personnel subsequently informed the inspectors that the valve was not stroked after the maintenance. Operations personnel would not permit mechanics to stroke the valve without a procedure or formal work instructions. The FIN team failed to follow-up and ensure the PMT was completed. The inspectors expressed concern that given the expanded engineering involvement and controls needed for the PMT, the FIN team should have reevaluated this work item to be completed as a MWR. After discussions with the inspectors, operations personnel caution tagged TV-BD-107C to identify the need to stroke it for PMT. The Director of Building Maintenance, informed the inspectors that additional automatic actuating valve packing adjustments will not be performed using FIN work orders until the FIN program is revised. Training was held with FIN team members regarding the improper PMT sign-off. The inspectors determined that failure to complete the PMT on TV-BD-107C was an isolated performance weakness and that corrective actions taken were adequate.

Maintenance records indicate that the FIN team completes about 45 work orders and 10 MWRs per week. The FIN work order backlog is about 50 work orders. The inspectors determined that the FIN team had been effective in correcting minor deficiencies before they developed into larger problems and with one isolated exception had properly performed the work. The Director of Building Maintenance informed the inspectors that the FIN program was going to be significantly expanded in the near future to include emergent work such as control room deficiency resolution. The inspectors noted that while the FIN team had been successfully employed to correct minor problems before equipment degraded substantially, the existing program did not have sufficient controls for the planned work scope expansion. The General Manager of Maintenance informed the inspectors that the program instructions would be revised and approved by station management prior to expanding the FIN team work scope. The inspectors will continue to evaluate the FIN program during routine maintenance inspections.

c. Conclusions

The inspectors determined that the FIN team had been effective in correcting minor deficiencies before they developed into larger problems and with one isolated exception had properly performed the work. Recent revisions to address repeat component work were appropriate. Additional controls and management review of the FIN program are necessary prior to expanding the work scope further to include emergent work such as control room deficiencies.

M1.5 Review of Maintenance Backlog

a. Inspection Scope (62707)

Inspectors reviewed the non-outage corrective maintenance backlog to broadly assess the licensee's work control effort and prioritization of pending work.

b. Observations and Observations

Total Non-Outage Corrective Maintenance Backlog fell from 2160 in September to 1357 in December of 1996, but then climbed back to 1597 in the beginning of February. DLC used contractor support and overtime to get the backlog down in December, but ended the additional contractor support in January and began an overtime reduction effort. DLC is currently hiring additional workers (9 planners, 3 schedulers, and about 15 construction personnel) to help reduce maintenance backlog again.

In the long-term, DLC plans modifications to their work control process intended to strengthen the 12-week schedule. Following completion of the senior reactor operator (SRO) class in March (3 new SROs), DLC intends to establish a new work control center. Part of this plan is to eventually (within the next year) re-arrange the control room, moving the Shift Supervisors closer to the operators while reducing their current work control administrative burden. The new work control center is to be staffed with one SRO and two plant operators per unit.

Inspectors reviewed the lists of Unit 1 "open non-outage work requests greater than one year old (159 total items)" and "open non-outage category 1 (safety-related) work requests (164 total items)" and discussed them with the Director of Work Planning. Generally, the work appeared to be properly prioritized. Some administrative discrepancies were noted (work requests were no longer applicable because the system was retired, work was completed but work request was still open, work required special conditions not noted in the remarks, remarks requested work be done by a specific date or concurrent with other work that was already past). The director stated that the backlog needed to be re-characterized to more accurately reflect the actual state of the plant by separating repair activities from support activities. DLC's goal was to reduce backlog to 1000 by the end of 1997.

c. Conclusions

DLC continues to be challenged at being able to reduce non-outage maintenance backlog. In the short-term, additional staff has been hired to bring down the backlog. In the long-term, DLC is establishing a new work control center (scheduled to be implemented in April) and is developing improvements to the work control process (such as re-characterizing the backlog and making the 12-week schedule process more efficient) with the goal of reducing backlog to 1000 by the end of 1997. Some administrative discrepancies were noted in the backlog lists, but the backlog appeared to be properly prioritized.

M3 Maintenance Procedures and Documentation

M3.1 Review of Quadrant Power Tilt Ratio Alarm Surveillance Test

a. Inspection Scope (61726)

The inspectors reviewed the Unit 2 operating surveillance test procedure, 2OST-2.4 "Quadrant Power Tilt Ratio Alarm Check," Rev. 8, which verifies the functionality of the Quadrant Power Tilt Ratio (QPTR) alarm.

b. Observations and Findings

The inspectors reviewed the purpose and acceptance criteria for operating surveillance test 2OST-2.4. This test is performed monthly to verify the functionality of the QPTR alarm, which serves to alert operators of an asymmetric reactor flux distribution.

The inspectors noted that the licensee utilized the test as a verification that the alarm setpoint has not drifted excessively. The alarm is calibrated to the setpoint of 1.02, as defined in TS 2.4, on an 18 month frequency by Maintenance Surveillance Procedure (MSP) 2.02, "QPTR Alarm Calibration Procedure," Rev. 1.

The acceptance criteria for the surveillance test allowed a range of 1.005 to 1.035. The inspectors questioned the technical basis of this acceptance band. Specifically, the inspectors noted that this acceptance band was based on the sum of the manufacturers' tolerances of the instrumentation used, which was inconsistent with the commonly accepted practice of using the square root of the sum of the squares of the tolerance values. The inspectors also questioned apparent discrepancies between wording in the purpose and acceptance criteria sections of the procedure.

These issues were discussed with operations and instrumentation and controls (I&C) supervisors. The inspectors also independently reviewed recorded test data for a recently performed test. Based on this information, the inspectors determined that the actual value of acceptance band value was appropriate. The I&C supervisor, though, acknowledged that the technical basis of the acceptance band documented in the procedure was incorrect. He indicated that procedure changes would be initiated to clarify both the basis and purpose discussions in the acceptance criteria section of the procedure.

c. Conclusions

The inspectors concluded that QPTR alarm surveillance test satisfied its intended purpose of checking the functionality of the alarm. An appropriate procedure revision was initiated to correct a minor discrepancy in the technical basis for the procedure's acceptance criteria.

M7 Quality Assurance in Maintenance Activities

M7.1 Surveillance Testing Deficiencies

a. Inspection Scope (61726, 71707)

Inspectors reviewed licensee evaluation and corrective actions surrounding three events involving deficiencies in surveillance testing. The events involved the hydrogen recombiners on both units, reactor coolant system pressure isolation valves on both units, and the load meters on the Unit 1 emergency diesel generators (EDGs).

b. Observations and Observations

EDG Load Testing

During a review of industry operating events, system engineering staff discovered a potential EDG surveillance test deficiency due to failure to fully account for the instrument inaccuracies in the kilowatt (KW) meters used to measure EDG load. Unit 1 Technical Specification (TS) 4.8.1.1.2.b.5 requires that each EDG be demonstrated operable at least every 18 months by verifying it operates for at least 60 minutes while loaded to at least 2750 KW. The Unit 2 TS requirement is at least 4238 KW (the different load requirement between units is due to different diesel manufacturers and sizes). DLC discovered that the surveillance tests used to verify compliance with the TS did not take the KW meter instrument accuracies, for either unit, into account.

DLC evaluated the KW meter instrument loop inaccuracies in conjunction with the latest calibration data for the meters to determine the test values needed to ensure compliance with the TS limits. These were compared to the values actually measured during the last 18-month surveillance testing on the EDGs. For Unit 2, the actual test values were sufficient to meet the TS requirements while considering the existing KW meter loop inaccuracies. EDG 2-1 was last tested at 4300 KW (meter inaccuracy of 60 KW) and EDG 2-2 was tested at 4390 KW (meter inaccuracy of 97 KW).

For Unit 1, neither EDG test value provided sufficient margin to account for the meter inaccuracies. EDG 1-1 had been tested at 2850 KW and EDG 1-2 at 2800 KW (last tested on 4/20/96 and 4/11/96, respectively). Nuclear Engineering staff calculated that the EDGs needed to be tested to at least 2875 KW to account for meter inaccuracies. As a result, DLC declared both Unit 1 EDGs inoperable and entered TS 3.8.1.1.E, which required that one EDG be restored to service within two hours or a plant shutdown be initiated. DLC was unable to complete the revised test on EDG 1-1 before the two hour limit expired and began a unit shutdown at 10:40 p.m. on February 19. The test was completed satisfactorily at 10:46 p.m., EDG 1-1 was restored to operability, and the shutdown was terminated (after only a 10 MW power reduction). EDG 1-2 was also tested satisfactorily later

that night. The initiation of the plant shutdown was reported to the NRC as required by 10 CFR 50.72.

Inspectors monitored DLC corrective actions, discussed the issue with operations and engineering staff and management, and reviewed Engineering Memorandum (EM) 113990, which documented the DLC engineering calculations and recommendations. System engineering identification of the issue and review of its applicability to Beaver Valley were excellent. Engineers also ensured that EDG design limits were not exceeded by their recommendations for testing (though this was not documented in the EM). Other tests that used the KW meters were also evaluated for potential impact. No additional adverse consequences were noted. DLC's short-term corrective actions were satisfactory.

DLC documented the issues on Condition Reports 970313 and 970314. As long-term corrective action, DLC is considering replacing the existing KW meters with more accurate instruments or using more accurate methods of measuring EDG loading (such as the kilowatt-hour meter, current transformer measurement, or direct voltage and current outputs of the KW meter).

Pressure Isolation Valve Testing

During a Quality Services Unit (QSU) audit of TS requirements, auditors discovered that some reactor coolant system (RCS) pressure isolation valve (PIV) leak testing was performed out of the sequence required by TSs. Unit 1 and Unit 2 TS 4.4.6.3.1 requires that leakage testing of RCS PIVs in Table 4.4-3 be accomplished prior to entering Mode 2 (startup) *after* every time the plant is placed in the cold shutdown condition (Mode 5) for refueling and prior to returning the valve to service after each maintenance, repair or replacement work is performed. Auditors noted that Operating Surveillance Test (OST)-1.10.5, "Leak Test [MOV-1RH-700 and 701]," had been performed on March 23, 1996, with Unit 1 in Mode 4 (hot shutdown) *prior* to entering Mode 5 for the refueling outage. MOV-1RH-700 and 701 are the residual heat removal (RHR) system inlet isolation valves. DLC found that the Unit 2 RHR system inlet isolation valves (2RHS-MOV-701A/B and 702A/B) had also been tested prior to entering Mode 5 for the last refueling outage. The issue was documented on Condition Report 970338.

As immediate corrective actions, DLC declared the valves inoperable and verified that they were shut and de-energized in order to comply with the action of TS 3.4.6.3. These valves are shut and de-energized by procedure when the plant is starting up from cold shutdown to power operation in order to protect the RHR system from full reactor coolant system pressure. DLC also reviewed the leak testing done on the other PIVs in Table 4.4-3 to verify that it was done in the proper sequence. No other deficiencies were found. QSU documented the issue on Condition Report 970338. Both units will remain in the action statement for TS 3.4.6.3 until leak testing can be done at the next time they are taken to cold shutdown.

Inspectors reviewed the OSTs performed on the RHR system valves (1OST-10.5 and 2OST-10.5). The OSTs included a note on the front page stating, "leak testing of each valve listed above shall be accomplished prior to entering Mode 2 after every time the plant is placed in COLD SHUTDOWN condition for refueling and prior to returning the valve to service after each maintenance, repair or replacement work is performed." The requirement was not stated in the body of the procedure, such as the precautions and limitations or the initial conditions. Apparently, outage planners scheduling the OSTs and operators performing the OSTs failed to note the required sequencing. As long-term corrective actions, DLC intends to revise the surveillance test procedures to clarify and re-enforce when they are to be performed.

Hydrogen Recombiner Testing

During a QSU audit of TS requirements, auditors discovered that electrical inspections to verify the integrity of heater circuits in the hydrogen recombiners were not being performed as required by the TSs. Unit 1 and Unit 2 TS 4.6.4.2.b.4 requires verifying the integrity of all heater electrical circuits by performing a continuity and resistance to ground test *immediately following* the 18-month functional test. The 18-month functional test requirement is met by OST-46.1 and 46.2 ("Post DBA Hydrogen Control System A and B, respectively). The heater electrical circuit checks should then be performed using maintenance surveillance test (MSP)-46.01A-E and B-E. On Unit 1, auditors found that the functional tests for both recombiners had been performed on March 24, 1996, but the MSPs had been performed on March 18 and February 6, 1996, for recombiners 1A and 1B, respectively. Unit 2 had similar discrepancies in the sequencing of the OSTs and MSPs.

As a result, operators declared the two hydrogen recombiners on each unit inoperable. Both units entered TS 3.0.3 at noon on February 26, which requires that a plant shutdown be initiated within one hour; however, TS 4.0.3 was invoked to allow 24 hours to complete the required surveillances. Auditors documented the issue on Condition Report 970390.

The initial electrical inspections were completed early in the morning of February 27; however, the Unit 1 Nuclear Shift Supervisor found during his review that electricians had done only the resistance checks and not the continuity checks. Following discussion between operations, maintenance, and plant management, the electrical inspections were redone. As a result, the entire 24 hour allowance of TS 4.0.3 was used. The required electrical inspections were completed on the morning of February 27 for one hydrogen recombiner per unit, which allowed the units to exit TS 3.0.3 and avoid shutdown. The remaining two recombiners were returned to service the following day.

Inspectors monitored the recombiner testing and subsequent electrical checks. The testing was done using a revised six month OST, which used outside air through the recombiner, instead of the 18 month OST, which uses containment air. Inspectors discussed the issue with DLC licensing staff and reviewed the

engineering evaluation that concluded that performing the electrical checks after the six month OST was equivalent to performing them after the 18 month OST. Inspectors determined that the technical justification was adequate.

c. Conclusions

System engineering identification of the EDG kilowatt meter inaccuracy issue through industry operating experience review and evaluation of its applicability to Beaver Valley were excellent. DLC immediate corrective actions were appropriate.

QSU identification of deficiencies in the sequencing of RCS PIV leak testing and hydrogen recombiner testing was good. The issues identified deficiencies in surveillance scheduling. DLC immediate corrective actions were adequate.

Identification and follow-up of these issues indicated a good questioning attitude from system engineering staff and good attention to detail during audits by the QSU staff. Collectively, the issues indicated potential weaknesses in the scheduling and procedures that imple: ent the surveillance testing program.

Root cause analysis and consideration of generic implications and long-term corrective actions were still under evaluation by DLC at the end of the period. These deficiencies in the surveillance testing program are unresolved pending DLC's determination of corrective actions and subsequent NRC review **(URI 50-334(412)/97001-02)**.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Main Steam Trip Bypass Valve Failure During Surveillance Testing

a. Inspection Scope (37551, 71707)

The inspectors reviewed the circumstances and component history related to problems identified with Unit 1 main steam trip bypass valve MOV-MS-101A. The inspectors interviewed operations and engineering personnel; reviewed operator logs, maintenance work requests, and an engineering summary of valve issues; and reviewed documentation such as technical specifications, the UFSAR, the Inservice Testing (IST) program, and surveillance procedures.

b. Observations and Findings

Each of the three main steam line trip valves is equipped with a motor-operated bypass valve, whose function is to allow pressure equalization across the trip valve disc and warming of the main steam lines when the trip valves are closed. On December 9, 1996, while performing maintenance work request (MWR) 54025 (clean limit switch and torque switch contacts and measure continuity across torque

switch contacts) for MOV-MS-101A, maintenance workers found the bolt holding a contact for the torque switch was loose and stripped, and two limit switch wires were frayed. Problem Report 1-96-963 was initiated to document and evaluate the deficiencies. It was determined that the torque switch must be replaced to address the stripped bolt, which in turn, would require manipulating the inoperable valve and performing MOVATS testing.

The licensee reviewed the list of containment penetrations and associated isolation valves, to determine whether any action was required per TS 3.6.3, "Containment Isolation Valves." The three main steam trip bypass valves are not listed. Conservatively, as of December 10, 1996, operators treated the inoperable MOV-MS-101A as a containment isolation valve, and administratively controlled the valve shut with the operator de-energized. Licensing engineers promptly initiated a review to determine whether the three main steam trip bypass valves should be added to the list of containment isolation valves.

The inspectors met with engineering personnel and determined that MWR 54025 for MOV-MS-101A was previously planned due to prior problems with the other two main steam trip bypass valves. Those problems included dual valve indication for MOV-MS-101B and MOV-MS-101C, and the failure of MOV-MS-101B to close on two occasions upon demand during surveillance testing (on June 22, 1996, and on August 22, 1995). Problem Reports and/or MWRs were initiated for the above problems, which were believed to be the result of an accumulation of a slight oily film or slight oxidation buildup on the valve operators' torque and limit switch contacts. Several actions were taken or planned at the time of the problems, including 1) inspecting and cleaning the MOV-MS-101A limit and torque switch contacts (December 1996), 2) replacing limit and torque switch O-rings to prevent oil leakage, and 3) submitting change requests to revise preventive maintenance instructions and changing the PM interval from 36 months to 18 months.

The inspectors noted that MOV-MS-101A/B/C appear to function as reactor containment closed system isolation valves as described in 10 CFR 50, Appendix A, Criterion 57. The main steam trip bypass valves, although normally closed during power operation, receive a steam line isolation signal (phase B) to automatically close. They are included in the licensee's inservice testing program, which requires a quarterly timed stroke test. In addition, the main steam trip bypass valves on Unit 2 are identified as containment isolation valves. The inspectors informed licensing engineers that although not listed in the containment penetration table, MOV-MS-101A/B/C appear to be containment isolation valves. Licensing engineers informed the inspectors that MOV-MS-101A would be controlled (per TS 3.6.3) as a containment isolation valve pending completion of an engineering review to determine whether the main steam trip bypass valves should be listed as containment isolation valves. Licensing engineers completed their review at the end of the inspection period and informed the inspectors that MOV-MS-101A/B/C would be added to the Containment Isolation Table by the end of April 1997. The inspectors determined that this action was appropriate.

c. Conclusions

The inspectors determined that the licensee's actions following the failure of MOV-MS-101A and subsequent discovery that it was not listed in the Containment Isolation Table were conservative in treating it as a containment isolation valve. Licensing engineers effectively reviewed the function of the valve and determined that MOV-MS-101A/B/C should be listed as containment isolation valves. Appropriate action was initiated to update the Containment Isolation Table.

E7 Quality Assurance in Engineering Activities

E7.1 Recent Quality Services Unit (QSU) Activities and Findings

a. Inspection Scope (37551, 71707)

The Quality Services Unit (QSU) performs independent oversight and audit of station activities to determine whether station activities are being performed consistent with the requirements of the station Operations Quality Assurance Program. The inspectors reviewed recent QSU records, station condition reports, and interviewed personnel to evaluate the effectiveness of recent QSU oversight activities.

b. Observations and Findings

The inspectors recently noted an increased number of QSU identified deficiencies reported and discussed at the daily plant status meeting. In October 1996, the QSU began documenting identified deficiencies using the station-wide problem report system (condition reports starting January 1997) instead of relying on the QSU deficiency report system. All condition reports are discussed by the station management team at the daily plant status meeting. The inspectors determined that this change has resulted in more effective communication of QSU identified deficiencies to station management and more visible assignment of responsibility for issue resolution.

The inspectors met with the QSU manager to discuss recent findings as well as deficiency trends. The most recent QSU Biennial Report indicated that the number of QSU identified deficiencies increased by 23% from 1995 to 1996. The severity of issues identified increased as well. Significant issues included corrective action programmatic weaknesses, deviations from the UFSAR, and large maintenance work backlogs. On several occasions QSU staff stopped work activities in the field pending resolution of observed deficiencies. Notable findings during the last five months included:

- Untimely maintenance rule disposition of Residual Heat Removal pump seal issues
- Excessive senior reactor operator burden during the January 14, 1997 reactor startup

- Independent QSU walkdown of system alignments assisted in quantifying the extent of configuration control problems
- Various procedure discrepancies affecting configuration control.
- Missed technical specification (TS) required surveillances (i.e containment hydrogen recombiners, RHS isolation valve)
- Nineteen deficiencies identified during Engineering Audit BV-C-96-12, included delays processing vendor technical information, untimely controlled drawing updates, and work priority issues
- Stopped field installation of two MWRs (comparator module and copper tubing to SOV-VS-110) for which material substitutions had not been validated for equivalency
- Untimely resolution of 21 of 55 on-site safety committee open items

The QSU expanded the TS surveillance audit scope based on identifying two missed TS surveillances in February 1997 (see Section M7.1). Team membership expanded to six people to review 100% of all event driven and sequence dependent TS surveillances (approximately 100 per unit). The team intends to complete the review by the end of March 1997. QSU findings were clearly communicated to station management and affected department managers at the morning plant status meetings. The inspectors determined that QSU inspectors were aggressive in identifying deficiencies and had selected important processes and work activities to audit. Previous QSU knowledge deficiencies regarding leak injection repair techniques were corrected as demonstrated by QSU coverage for a secondary plant leak injection repair completed this report period.

c. Conclusions

The inspectors determined that QSU inspectors have been more proactive over the past six months in identifying and reporting problems. Important station wide processes and work activities were selected and audited. The recent TS surveillance audit findings and scope expansion were of particular significance. The condition report system has been effectively used to communicate QSU identified deficiencies to station management and clearly assign responsibility for issue resolution. The QSU provided valuable independent oversight for station activities during this inspection period.

E8 Miscellaneous Engineering Issues

E8.1 UFSAR Verification Project

a. Inspection Scope (37551, 71707)

As a result of increased regulatory attention to licensee adherence to operate nuclear power plants as described in the UFSAR, both the industry and the NRC have identified numerous failures to conform to the UFSAR. Based on recent NRC findings at Beaver Valley and based on the results of a UFSAR sampling review performed in late 1996, the licensee decided to perform a 100% line-by-line UFSAR

verification. This commitment was documented in a letter from Duquesne Light Company to the NRC dated December 26, 1996.

The NRC encouraged such licensee initiatives and authorized enforcement discretion to be granted for certain UFSAR deficiencies discovered during the UFSAR verification period. Enforcement discretion may be granted for up to severity level II violations which are identified and properly addressed through comprehensive corrective actions by October 18, 1998. The purpose of this section is to document the current intended scope and schedule for the licensee voluntary UFSAR Verification Project initiative for consideration in future enforcement assessments regarding UFSAR deviations.

b. Observations and Findings

The inspectors met with the Director of Safety & Licensing and the UFSAR Verification Project manager and discussed the intended project scope and schedule. The project began in late 1996 when approximately a dozen senior reactor operator (SRO) candidates, many previously licensed at other utilities, performed an operations procedures validation against the UFSAR. This review identified approximately 60 discrepancies which were submitted for further evaluation and corrective action. A team of contractors with industry experience was formed for the first level evaluation. Disposition of this initial discrepancy list was completed in March 1996. The review team determined that the discrepancies were minor, mostly administrative in nature, and did not constitute unreviewed safety questions. The inspectors discussed a small sample of the discrepancies with the team and agreed with the team's conclusions.

The detailed line-by-line UFSAR review is scheduled to begin in March 1997 and be complete by December 31, 1998. The inspectors reviewed the background of several contractors selected for the project and determined that the individuals possessed appropriate experience and qualifications to perform this project. The overall project team will be comprised of three components; the Design Review Team which identifies potential design related discrepancies, the Plant Verification Team which performs actual plant walkdowns and procedure validation, and an Independent Verification Team. The Design Review Team and Plant Verification Team will identify potential UFSAR discrepancies and forward the issues to an appropriate department (i.e. operations, engineering) for resolution. SRO candidates will be heavily involved in plant verification walk downs during the in plant portion of their training program. This is intended to enable station personnel to retain knowledge and experience gained from the UFSAR Verification Project rather than losing this knowledge when contractors leave at the end of the project. The Independent Verification Team will conduct independent reviews of selected UFSAR sections based on guidelines established in NEI 96-05, UFSAR Review Sampling Guidance. In addition, the UFSAR project manager will oversee an independent validation of issue resolutions and recommended corrective actions returned by the assigned station departments. The inspectors determined that independent verification was very important to the success of this project given that station causal evaluation to problem reports in 1996 were often incomplete.

The project team intends to review processes and documents that directly affect the UFSAR and those which don't directly affect the UFSAR but may identify further action which may lead to UFSAR changes. Programmatic processes and documents identified for review include:

- Quality Assurance, Security, & Emergency Plans per 10 CFR 50.54
- Licensing amendments per 10 CFR 50.90
- Design changes per 10 CFR 50.59
- Procedure changes per 10 CFR 50.59
- UFSAR updates per 10 CFR 50.71e
- Regulatory commitment changes
- Degraded or non-conforming conditions
- Configuration management changes (e.g. operator work arounds, TS interpretations)
- Procedure changes not subject to 10 CFR 50.59
- Design changes not subject to 10 CFR 50.59
- Safety evaluations per 10 CFR 50.59
- Docketed correspondence to/from the NRC
- Temporary modifications
- Maintenance work requests

As identified UFSAR discrepancies are resolved, the UFSAR will be updated continuously on-site (e.g. a living UFSAR) rather than updates awaiting the completion of the program. The UFSAR submittal to the NRC will continue to be issued annually. Based on the rate of recent UFSAR revision processing, the inspectors questioned whether the licensee would be able to update the UFSAR in a timely manner. The Director of Safety & Licensing informed the inspectors that additional resources would be provided as necessary to incorporate UFSAR revisions in a timely manner. In addition, the UFSAR Verification Project manager plans to request the QSU to perform a self audit of the project prior to completion.

c. <u>Conclusions</u>

The inspectors determined that the UFSAR Verification Project was a significant licensee commitment to verify the station is operated as designed and licensed. The inspectors noted that the independent verification and QSU audit functions were well conceived as methods to verify quality assessment and resolution of identified UFSAR discrepancies. Follow-up of the UFSAR Verification Project is an unresolved issue pending completion of DLC activities and subsequent NRC review **(URI 50-334(412)/97001-03)**.

IV. Plant Support

P2 Status of EP Facilities, Equipment, and Resources

P2.1 Loss of Power to the Emergency Response Facility

a. Inspection Scope (37551, 71707)

Inspectors reviewed DLC's response to a loss of power to the site emergency response facility (ERF) and monitored their root cause analysis and corrective actions.

b. Observations and Observations

At 4:53 a.m. on February 14, power was lost to the site ERF due to a spurious signal from a programmable logic controller (PLC) at the ERF substation. The ERF houses the Technical Support Center (TSC) and Emergency Operations Facility (EOF). Power was restored to the ERF at 12:05 p.m. During the time that power was unavailable, the licensee considered the ERF to be inoperable due to loss of required ventilation capability. Redundant backup facilities were available in accordance with the Emergency Preparedness Plan. DLC concluded that the event did not meet the reporting criteria of 10 CFR 50.72; however, they made a voluntary notification to the NRC. DLC established an Event Review Team (ERT) to investigate the event and documented it on Condition Report 970292.

Power to the ERF is supplied from the ERF substation, which is located on site. The substation normal power supply is from two 138kV/4160V transformers located in the switchyard. These transformers take power from the switchyard 138kV buses and deliver it to ERF substation 4kV buses 1G and 1H, which are connected by a normally open tie breaker. Buses 1G and 1H supply ERF 4kV buses 1K and 1J, respectively. ERF 4kV buses 1K and 1J supply the ERF 480V buses 2 and 1 (PNL-AC-2A and PNL-AC-1A), respectively, through two 4160V/480V transformers. The 4kV buses can be lined up to supply either or both of the 480V buses.

Two Modicon 484 PLCs are used to provide certain control functions at the ERF substation, such as the ERF substation diesel generator load sequencer and local bus transfer schemes. The PLCs are designated A and B. One PLC is normally in service, with the other serving as a backup.

After investigation, the ERT concluded that a spurious output from one of the input/output modules (I/O module #9) on inservice controller B had initiated the event. The controller then executed the programmed bus transfer scheme, beginning by opening 4kV bus 1G supply breaker ACB-1G3.

Loads supplied from 4kV bus 1G were stripped off and re-energized from the 1H bus by automatic tie breaker action in accordance with the PLC program. At the ERF, however, both 480V buses were lined up to the 1K bus (which receives power from 1G), and the automatic transfer feature between the 1K and 1J (which

receives power from 1H) buses was not in service. As a result, when bus 1K lost power, there was no transfer, and the ERF lost all power.

The ERT concluded that a contributing causal factor to the extended loss of power to the ERF for about seven hours was that procedures for the alignment of the building's 480V distribution system had not been developed. The lack of procedures also contributed to the ERF 480V distribution system not being in a redundant lineup at the time of the event. If the ERF electrical distribution had been in its normal configuration, only one ERF 480V bus would have been de-energized for about 10 seconds.

As corrective actions, the ERF was restored to its normal 480V electrical configuration and procedures were issued to support the immediate operation and recovery of the ERF, including a procedure to setup the ERF 480V auto-transfer scheme. Additional procedure development is being tracked under the Condition Report system. DLC replaced the PLC output module associated with the event and added surge suppression on the power supply inputs to both PLCs prior to returning them to service to make them less susceptible to spurious electrical transients. In addition, the ERT determined that the implementation of coincidence logic would significantly reduce the probability of future events. Coincidence logic would require two separate output modules to activate to initiate the trip of a critical load. The addition of coincidence logic to both PLCs is under evaluation by the DLC engineering staff (TER 10984).

Several deficiencies were noted during review of the event. While the most probable initiator of the event was a spurious output from the B controller, the cause of loss of power to the ERF was lack of redundancy in the electrical lineup. If power had been supplied to the ERF from the redundant 4kV 1G and 1H sides, total loss of power to the facility would not have occurred, and the impact of the event would have been minimal. DLC found that procedures were insufficient to support operation of the ERF, including lack of a procedure to setup the ERF 480V distribution system auto-transfer scheme. In addition, there was not a clear delegation of responsibility for the ERF building between Operations and Maintenance staff.

In addition, inspectors noted that the two uninterruptable power sources (UPS) shut down at about 11:50 a.m. due to low voltage on the UPS batteries. At the end of the period, DLC had not yet determined whether the battery response was expected for this event. DLC had experienced at least seven previous unexplained openings of ERF 4kV bus supply breakers where it was determined that the cause of the breakers tripping originated from a PLC output when no valid inputs to the PLC could be confirmed. These included a loss of power to the ERF substation on August 18, 1993 (LER 2-93-008). Inspectors noted that the corrective actions recommended by ISEG for the loss of the ERF substation in 1993 (ISEG ltr NDISEG:0852 dated June 29, 1994) had not been completed. DLC had not evaluated those corrective actions to determine whether they would have prevented the current event.

Inspectors monitored the ERF recovery and subsequent component testing and discussed the event with engineering staff. Inspectors reviewed the Emergency Preparedness Plan, UFSAR, and TSs to verify that the ERF satisfied licensee commitments.

c. Conclusions

The alternate emergency facilities were available throughout the event in accordance with the Emergency Preparedness Plan, so there were no safety consequences to the loss of the ERF. DLC's immediate corrective actions for the loss of power to the ERF were appropriate; however, the event indicated potential weaknesses in operating procedures for the ERF building, delegation of responsibility among site organizations for the ERF, and follow-up of corrective actions for previous similar events. DLC management had not reviewed the Event Response Team evaluation and long term corrective action recommendations at the end of the period. Deficiencies associated with the loss of power to the ERF are an unresolved item pending completion of DLC evaluation and subsequent NRC review **(URI 50-334(412)/97001-04)**.

L1 Review of FSAR 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 compared plant practices, procedures and/or parameters to the UFSAR description.

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

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 March 27, 1997. The licensee acknowledged the findings presented.

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

X2 Pre-Decisional Enforcement Conference Summary

On March 7, 1997, a predecisional enforcement conference was held at the NRC Region I offices in King of Prussia, Pennsylvania. The meeting was held to discuss plant configuration control issues related to component mispositionings. The senior representatives present were Mr. H. Miller, Regional Administrator, NRC Region I, and Mr. J. Cross, President, Generation Group, Duquesne Light Company.

X3 Management Meetings and other NRC Activities

On February 26 - 27, 1997, Mr. Peter Eselgroth, NRC Region I, Branch Chief, Division of Reactor Projects (DRP), Projects Branch 7, met with the resident inspector staff, toured the station, and met with licensee management to discuss current licensee performance.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

DLC

J. Cross, President, Generation Group
R. LeGrand, Vice President, Nuclear Operations/Plant Manager
**S. Jain, Vice President, Nuclear Services
B. Tuite, General Manager, Nuclear Operations
C. Hawley, General Manager, Maintenance Programs Unit
K. Beatty, General Manager, Nuclear Support Unit
J. Arias, Director, Licensing
K. Ostrowski, Manager, Quality Services
R. Vento, Manager, Health Physics
D. Orndorf, Manager, Chemistry
L. Freeland, Manager, Nuclear Engineering Department
F. Curl, Manager, Nuclear Construction
A. Dulick, Manager, Operations Experience
J. Matsko, Manager, Outage Management Department
A. Brunner, Manager, Procedure Upgrade Project
C. Custer, Acting Manager, System and Performance Engineering
M. Perger, Director, Quality Services Unit
R. Hart, Senior Licensing Supervisor, Compliance
A. Mizia, Supervisor, Quality Services Unit
T. Porter, Supervisor, Quality Services Unit
B. Sepelak, Senior Engineer

NRC

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

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92901:	Follow-up, Operations
IP 92902:	Follow-up, Engineering
IP 92903:	Follow-up, Maintenance
IP 92904:	Follow-up, Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED AND DISCUSSED

Opened

EA 50-334(412)/97076 01013	VIO	Failure to Implement Procedures as Written-Configuration Control Problems (Section O8.3)
EA 50-334/97076 01023	VIO	Failure to Monitor Oxygen Concentration During WGDT Filling Operation (Section O8.3)
EA 50-334(412)/97076 01033	VIO	Inadequate Corrective Action-Failure to Identify and Correct Configuration Control Problems (Section O8.3)
EA 50-334/96462 02013	VIO	Failure to Identify and Correct Longstanding PZR PORV Block Valve Configuration Discrepancy from UFSAR (Section O8.5)
EA 50-412/96540 01013	VIO	Failure to Provide Adequate QA Oversight of Reactor Head Vent System Leak Repair Activities (Section O8.6)
EA 50-412/96540 01023	VIO	Failure to Provide Adequate Measures to Select Leak Sealant Material (Section O8.6)
EA 50-412/96540 01033	VIO	Failure to Assure Leak Repair Activities were Performed in Accordance with Proper Procedures (Section O8.6)
EA 50-412/96540 01043	VIO	Failure to obtain OSC review and General Manager, Nuclear Operations, Approval of Leak Repair Procedures (Section O8.6)
URI 50-334(412)/97001-02	URI	Deficiencies in the Surveillance Testing Program (Section M7.1)
URI 50-334(412)/97001-03	URI	UFSAR Verification Project Follow-up (Section E8.1)
URI 50-334(412)/97001-04	URI	Deficiencies Noted During ERF Loss of Power Follow-up (Section P2.1)

Closed

50-412/95080-02	URI	No problem report issued to address inadequate clearance and subsequent flooding of the B & D recirculation spray (RS) pump cubicals (Section O8.2)
50-412/95080-01	URI	Inadequate independent verification of valve position for service water valve 2SWS-82 (Section O8.3)
50-334(412)/95080-04	URI	Mispositioning of 2SWS-82 and Two Instrument Valves (Section O8.4)
50-334/96007-01	URI	Unit 1 pressurizer power operated relief block valve configuration contrary to UFSAR (Section O8.5)
50-412/96009-02	URI	Inadequate 2RCS-64 Leak Injection Repair (Section O8.6)
50-334/96003-01	LER	Engineered Safety Feature (ESF) Actuation Due to Steam Generator Water Level Transient (Section O8.7)
50-412/97001-01	NCV	Failure to Retain Maintenance Work Documents (Section M1.3)

LIST OF ACRONYMS USED

ANSS	Assistant Nuclear Shift Supervisor
BVPS	Beaver Valley Power Station
DLC	Duquesne Light Company
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
EHC	Electro Hydraulic Control
EM	Engineering Memorandum
EOF	Emergency Operations Facility
ERF	Emergency Response Facility
FIN	Fix it Now
HELB	High Energy Line Area
I&C	Instrumentation and Control
IST	Inservice Testing
LER	Licensee Event Report
MPUAM	Maintenance Programs Unit Administrative Manual
MSP	Maintenance Surveillance Procedure
MWR	Maintenance Work Request
NSA	Normal System Alignment
NPDAP	Nuclear Power Division Administrative Procedure
NSS	Nuclear Shift Supervisor
ODCM	Offsite Dose Calculation Manual
OST	Operational Surveillance Test
PDR	Public Document Room
PIV	Pressure Isolation Valve
PLC	Programmable Logic Controller
PMT	Post Maintenance Testing
QADR	Qualify Assurance Deficiency Report
QPTR	Quadrant Power Tilt Ratio
QSU	Quality Services Unit
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RP&C	Radiological Protection and Chemistry
RS	Recirculation Spray
SG	Steam Generator
SLCRS	Supplementary Leak Collection & Release System
SRO	Senior Reactor Operator
SWS	Service Water System
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item