U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.: 50-334/88-11 License Nos.: DPR-66
50-412/88-07 NPF-73

Licensee: Duquesne Light Company
One Oxford Center
301 Grant Street
Pittsburgh, PA 15279

Facility Name: Beaver Valley Power Station, Units 1 and 2

Location: Shippingport, Pennsylvania

Dates: Unit 1 and Unit 2: February 16, 1988 - March 31, 1988

Inspectors: J. E. Beall, Senior Resident Inspector
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Approved By: David F. Lipinski 4/28/88
for Lowell E. Tripp, Chief Date
Reactor Projects Section No. 3A, DRP

Inspection Summary: Combined Inspection Report No. 50-334/88-11 and 50-412/88-07 - February 16, 1988 through March 31, 1988.

Areas Inspected: Routine inspections by the resident inspectors (247 hours) of licensee actions on previous inspection findings, plant operations, physical security, radiological controls, plant housekeeping and fire protection, natural circulation cooldown, review of periodic and special reports, review of licensee event reports and maintenance and surveillance testing.

Results: No violations were identified. One NRC open item was closed during this inspection. Two unresolved items were opened regarding Unit 1 and Unit 2 labeling of plant components (Section 4.2.5) and resolution of Unit 1 fire protection/separation deficiencies (Section 4.5.3). Licensee weaknesses identified during the inspection included Unit 1 housekeeping (Section 4.5) and recently submitted licensee event reports (Section 8).

TABLE OF CONTENTS

DETAILS

1. Persons Contacted

During the report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activities.

2. Summary of Facility Activities

At the beginning of the inspection period, Unit 1 was in Mode 5 (Cold Shutdown) following the Cycle 6 refueling outage and Unit 2 was at 100% power. During the period, Unit 1 completed outage recovery and was placed on the grid on March 2, 1988. On March 3, 1988, the licensee identified that Unit 1 had operated in apparent violation of the Technical Specifications for about eight days in that two of four high-high containment pressure channels had been rendered inoperable by placing their associated bistables in the bypass condition (see Section 4.2.4). A Special Inspection (50-334/88-12) was conducted during March 3 - 8, 1988, and an Enforcement Conference was held with the licensee on March 24, 1988, at the Region I offices in King of Prussia, Pennsylvania. Both Unit 1 and Unit 2 were at 100% power at the close of the inspection period.

3. Followup on Outstanding Items

The NRC Outstanding Items (OI) List was reviewed with cognizant licensee personnel. Items selected by the inspector were subsequently reviewed through discussions with licensee personnel, documentation reviews and field inspection to determine whether licensee actions specified in the OIs had been satisfactorily completed. The overall status of previously identified inspection findings was reviewed, and planned/completed licensee actions were discussed for the item reported below:

(Closed) Unresolved Item (50-334/86-15-04): Evaluate/resolve whether QA Procedure OP-4, Design Change Control, should be revised to require a 10 CFR 50.59 review prior to design change package implementation. The licensee revised OP-4 (Revision 1, effective 2/26/88) to require that the safety evaluation be completed prior to physically modifying an existing safety-related system described in the FSAR. The inspector reviewed the procedure revisions and no concerns were identified. This item is closed.

4. Plant Operations

4.1 General

Inspection tours of the following accessible plant areas were conducted during both day and night shifts with respect to Technical Specification (TS) compliance, housekeeping and cleanliness, fire protection, radiation control, physical security/plant protection and operational/maintenance administrative controls.

-- Control Room	-- Safeguard Areas
-- Auxiliary Building	-- Service Building
-- Switchgear Area	-- Diesel Generator Buildings
-- Access Control Points	-- Containment Penetration Areas
-- Protected Area Fence Line	-- Yard Area
-- Turbine Building	-- Intake Structure

The operability of selected Engineered Safety Features (ESF) Systems were verified by performing walkdowns of the accessible portions of the systems. The inspectors confirmed that system components were in the required alignments, instrumentation sensors were valved in with appropriate calibration dates, prints reflected the as-built systems and the overall conditions observed were satisfactory. Systems inspected during this period include the Auxiliary Feedwater, Emergency Diesel Generator and Low Head Safety Injection Systems.

No concerns were identified.

4.2 Operations

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. During plant tours, logs and records were reviewed to determine if entries were properly made and that equipment status/deficiencies were identified and communicated. These records included operating logs, turnover sheets, tagout and jumper logs, process computer printouts, unit off-normal and draft incident reports. The inspector verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. In general, inspector comments or questions resulting from these reviews were resolved by licensee personnel. Inspections conducted during backshifts and weekends verified that plant operators were alert and displayed no signs of fatigue or inattention to duty.

4.2.1 Inadvertent Reactor Trip Signal

On February 19, 1988, while in Mode 5 (Cold Shutdown) a reactor trip signal was generated on Unit 1. Plant operators had begun a draining and refilling evolution on the steam generators (SGs) to improve SG secondary side chemistry for plant startup. During the midnight shift, the reactor trip breakers were closed to support solid state protection system (SSPS) testing (Maintenance Surveillance Test). Following completion of the SSPS testing, the breakers were left in the closed position. During the day shift, plant operators began draining the "B" SG; however, when the SG water level drained to below the low-low level reactor trip setpoint, the trip signal was generated. The reactor trip breakers opened as designed upon receipt of the signal. All shutdown and control rods were already fully inserted and there were no positive reactivity additions in progress at the time of the event. Simulated water level signals were subsequently inserted into the SG level circuitry to prevent additional actuations as the draining and refilling evolutions continued. The licensee notified the NRC of the event via ENS in accordance with 10 CFR 50.72 reporting requirements.

The licensee determined that the cause for the event was personnel error in that the individuals involved failed to take additional actions needed to prevent the reactor trip signal during the filling and draining evolutions. The inspector noted that Operating Manual Chapter No. 24, Procedure T, Draining and Refilling the Steam Generators, was not consulted for the above evolution. The licensee stated that during certain activities that are routine and within the knowledge of plant operators, plant procedures are not used as directed by a senior operator. OM 24.T, however, included steps which insert "dummy" normal SG water level signals to prevent a reactor trip signal during these evolutions. The licensee counseled the individuals involved in the event concerning maintaining proper awareness of plant status at all times and the use of available and appropriate plant procedures during routine evolutions. Additionally, this event was reviewed by all operations shift personnel at shift briefings.

During the review of this event, the inspector noted that the Maintenance Surveillance Procedure (MSP) failed to instruct the technicians to return the reactor trip breakers to the as-found (in this case, open) condition. The licensee stated that the MSP is written assuming that the test is to be performed while at power (reactor trip breakers are closed). The inspector noted that this event is similar to the March 3, 1988, identification of equipment out of service in that both resulted from MSPs which did not return equipment to the as-found condition. Specifically, two out of four high-high containment pressure channels were defeated by technicians for a period of eight days (see Section 4.2.4 and also Inspection Report 50-334/88-12). The licensee stated that CM 24.T contains steps which specifically direct the operators to assess scram breaker position and take the required actions. The licensee agreed to review the MSP for possible revisions.

4.2.2 Refueling Water Storage Tank Instrumentation Line Freezing

On February 21, 1988, the control room bistable status light for the "C" refueling water storage tank (RWST) level transmitter illuminated indicating that the low-low level setpoint for that channel had been reached. Plant operators immediately verified that the remaining three RWST level channels were indicating normal RWST levels, and confirmed that "C" channel had failed low. Licensee investigation determined that the affected instrumentation line had frozen. Ambient temperature was about 12° F. A temporary kerosene heater was subsequently placed in the RWST cubicle area. Additionally, a tent was erected to increase the effectiveness of the kerosene heater. After about 2½ hours, the affected transmitter sensing lines thawed and the transmitter was returned to service.

About five hours later, the "C" transmitter bistable status light again illuminated. Licensee investigation found that the instrumentation line had frozen again causing the transmitter to fail low. Further investigation found that the heat tracing for both the "A" and "C" level transmitter sensing lines had been de-energized. The local temperature inside the tent had apparently reached the setpoint at which the associated thermostats de-energized the heat tracing circuits. The licensee therefore increased the trip setpoints for the thermostats. Before the heat tracing could thaw the "C" transmitter sensing lines, the same lines associated with the "A" level transmitter had also frozen causing that transmitter to fail low. Technical Specification action statement 3.0.3 was entered, and the licensee bypassed the bistable associated with the "C" level transmitter. Therefore, a one-out-of-two coincident was required for the remaining two operable transmitters to satisfy the two-out-of-four logic which automatically initiates the recirculation cooling mode of the safety injection system following a safety injection actuation.

About 20 minutes after both lines had frozen, the lines thawed and both transmitters were returned to normal operation. The licensee is in the process of developing a permanent fix for this problem. A similar situation occurred on January 1, 1988. Adequate resolution of this problem will be reviewed during a subsequent inspection.

4.2.3 Outage Recovery

A separate NRC inspection (50-334/88-10) was conducted on February 22-26, 1988, to observe outage recovery activities. The resident inspectors also monitored portions of these activities. The attitude of plant operators was noted to be positive. Access to the control board was limited as described in station procedures. The inspectors noted that the drawings in the control room were not always kept current to reflect actual system alignment, however, significant deficiencies were not identified. While a considerable amount of required surveillance time was spent in verifying that all prerequisites and testing were completed prior to mode changes, the system assumes that several plant systems/components are not changed by the various station groups (also see NRC Inspection Report No. 50-334/88-12). Portions of the approach to criticality and grid synchronization were observed by the inspector.

4.2.4 Auxiliary Feedwater System Actuation

On February 25, 1988, while in Mode 3 (Hot Standby), a Unit 1 automatic auxiliary feedwater system initiation occurred. A monthly operations surveillance test (OST 1.24.4) was being performed on the steam driven auxiliary feedwater (AFW) pump which incorporated the yearly requirement to manipulate the steam driven AFW pump supply valves from the emergency shutdown panel (SDP). The flowpath for the steam supply to the AFW pump turbine is through two parallel trip valves (105A and 105B) and then through a common trip throttle valve. The sequence of events, as directed by OST 1.24.4 is as follows.

-- Steam driven AFW pump started from Control Room using 105A.

-- Control for 105B transferred to SDP.

-- 105B opened from SDP - 105A closed from Control Room.

-- Control for 105A transferred to SDP

-- 105A opened from SDP.

-- Both 105A and 105B verified open from SDP.

-- Steam driven AFW pump shut down by closing 105A and 105B.

-- Transferred control for 105A and 105B back to control room.

Upon control transfer of the closed steam supply valves back to the control room, a momentary de-energization of the solenoid valves, which vent air pressure from the steam supply valves to open them, occurred. This de-energization resulted in a start demand signal for the steam driven AFW pump. However, when the pump was stopped by closing 105A and 105B at the SDP, the turbine trip throttle valve (located downstream of the steam supply valves in the common steam supply line) automatically closed as per design. The trip throttle valve automatically closes when either a low bearing oil pressure or mechanical overspeed occurs and the valve must be manually relatched to open it. When the steam driven AFW pump was stopped by closing 105A and 105B, a low bearing oil pressure condition occurred, and therefore, the trip throttle valve automatically closed, and was not yet relatched and reopened. Since the trip throttle valve was closed, the steam driven AFW pump did not start. The AFW system design is such that the motor driven AFW pumps (2) automatically start whenever the steam driven AFW pump does not develop a specified discharge pressure within a pre-determined time following a start demand. The above conditions resulted in generating automatic start signals for both motor driven AFW pumps.

The B motor driven AFW pump automatically started as designed, however, the A motor driven pump did not start. Each motor driven pump uses a separate pressure switch to sense the discharge pressure of the steam driven pump to determine when an automatic start signal is required. The licensee concluded that the failure of the A motor driven pump to start was due to a momentary misoperation of its associated pressure switch (PS-FW-157) in that it apparently "hung up" and did not respond to the low discharge pressure. The licensee subsequently tested the switch several times, and it functioned properly each time, initiating an automatic start signal for the A motor driven pump. The initial actuation of the AFW system resulted due to a procedural deficiency in that the procedure allowed the transfer of closed valves in a circuit that incorporates break-before-make contacts for the associated solenoid valves after the steam driven pump was shut down. The procedure was revised to require that control for 105A and 105B be transferred back to the control room prior to shutting down the steam driven pump. The inspector verified that this change was implemented.

Repeated tests failed to repeat the malfunction of the pressure switch, however, a maintenance work request (MWR) was generated to re-verify the operability of the pressure switch during the next scheduled performance of OST 1.24.4. This was performed on March 21, 1988. MWR 882569 requested that a recorder be connected to TS-FW-157 to monitor the output status of the pressure switch during the running of OST 1.24.4. The inspector reviewed the MWR and its associated recorder trace. The trace was inconclusive as to whether the pressure switch properly reset and when the pressure switch operated as related to the starting and stopping of the steam driven pump. Pressure switch operation could not be confirmed from the trace following completion of the OST and MWR. The MWR instructions were apparently unclear as to what was to be compared to pressure switch operation (i.e., pump operation), and therefore, pump starts and stops were not noted on the trace. The inspector questioned whether the pressure actually did reset since it could not be confirmed from the test or MWR results. The licensee subsequently obtained voltage and resistance readings across the pressure switch contacts. The readings confirmed that the associated pressure switch had functioned properly and had reset. Due to the intermittent nature of the pressure switch misoperation, the licensee committed to recheck the proper functioning of both pressure switches (one per motor driven pump) during the next two OST performances. The results of these checks will be reviewed during routine inspections. No additional concerns were identified.

4.2.5. <u>ESF Actuation</u>

On February 19, while at 84% power, the Unit 2 operators attempted to place the startup feedwater pump in service. Unit 1 was in Mode 5 (Cold Shutdown) at the time. Upon placing the control switch in the start position, an electrical transient occurred such that an overcurrent protection relay was actuated for the emergency response facility (ERF) 3B transformer. The overcurrent condition resulted in the actuation of auxiliary relays which isolated the 3B transformer. During de-energization and transfer of affected electrical buses, the momentary voltage loss actuated a supplementary leak collection and release (SLCR) radiation monitor (2RMR-RQI301). The loss of power to 2RMR-RQI301 simulated a high radiation signal, which initiated the SLCR system realignment to its ESF (filtered) flowpath. The opening of the supply breaker for the 3B transformer also resulted in a loss of power to the Unit 1 "1B" station service transformer and its associated two normal 4 KV buses (1C and 1D) in the 4 KV emergency bus (DF). The associated No. 2 emergency diesel generator did not automatically start as designed because it was out of service for repairs, (since Unit 1 was in Mode 5, only one train of 4 KV emergency power was required to be operable). The "A" train had been the priority train at the time of the event and all associated equipment was operable. This event was reported to the NRC via ENS in accordance with 10 CFR 50.72 reporting requirements.

The three phase overcurrent relays for the ERF 3B transformer were subsequently tested and found to be operating satisfactorily. The licensee elected to replace the relay which was sent to an off-site vendor for further analysis.

The transformer overcurrent protection provides the second level of protection for the circuit. Overcurrent relays downstream of the 3B transformer on an associated 4 KV bus feeder breaker constitute the first level of protection. The licensee found that the 125 volt DC control power for the overcurrent relays had been de-energized. The control power circuit breaker located in the ERF substation was left open because it was not labeled and was mistakenly thought to be an unused spare. This breaker was also omitted from the ERF operating manual power supply switch list. The power supply switch list has since been revised to include this breaker and plans were made to place a label on the breaker.

The licensee plans to initiate a review of the entire ERF substation to identify and resolve any similar problems. Similar concerns have previously been identified (NRC Inspection Report No. 50-334/87-11) with respect to labeling components in the plant. The previous concern identified that many plant components were labeled with marking pens or other types of uncontrolled markers. The licensee initiated corrective actions to assure that appropriate plant equipment is correctly identified in a controlled manner through an improved identification system. The concern identified during this inspection (inadequate and/or lack of labeling) should also be included in the licensee's evaluation. A followup inspection was performed on Unit 2, during which similar problems with respect to labeling also existed. Resolution of this concern for both units will be followed via Unresolved Item Nos. 50-334/88-11-01 and 50-412/88-07-01.

4.2.6 High-High Containment Pressure Channels Defeated

On March 3, 1988, with Unit 1 at 30% power, the licensee identified that two out of the four high-high containment pressure (HHCP) bistables were bypassed (defeated). The bistables were promptly restored but the two channels were found to have been defeated for about eight days. This event and the licensee's initial corrective actions were reviewed during NRC Special Inspection 50-334/88-12 and discussed during the March 24, 1988, Enforcement Conference. One root cause of this violation was that certain licensee Maintenance Surveillance Procedures (MSPs) did not require restoration of switches to the as-found position. The HHCP bistables involved had been placed in the operating position as part of a Startup Checklist, then placed in the bypass position for a MSP, and left bypassed after the MSP's were performed on February 22, 1988.

4.3 Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in various plant areas with regard to the following:

-- Protected Area and Vital Area barriers were well maintained and not compromised;

-- Isolation zones were clear;

-- Personnel and vehicles entering and packages being delivered to the Protected Area were properly searched and access control was in accordance with approved licensee procedures;

-- Persons granted access to the site were badged to indicate whether they have unescorted access or escorted authorization;

-- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were properly authorized.

-- Security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and

-- Adequate illumination was maintained.

No concerns were identified.

4.4 Radiological Controls

Posting and control of radiation and high radiation areas were inspected. Radiation Work Permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent) and personnel frisking were observed on a sampling basis.

Significant concerns were not identified during this inspection in the area of radiological controls. Housekeeping in radiologically controlled areas, however, was found to exhibit weakness (see Section 4.5.2).

4.5 Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control and storage of flammable material and other potential safety hazards were observed in various areas during plant tours. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed. The inspector conducted detailed walkdowns of the accessible areas of both Unit 1 and Unit 2.

4.5.1 Unit 2 Areas

During the previous inspection, the inspector expressed the concern that items such as improperly secured gas bottles, unsecured gas bottles and wheeled devices were still being found near safety-related equipment. In addition, a temporary laydown area of boards, ladders and scaffolding material was found by the inspector to be stacked around and against a Unit 2 containment isolation valve during plant startup. The inspector concluded that this area exhibited weakness during the previous inspection period. During the current inspection period, the inspector noted a marked improvement in Unit 2 housekeeping including the removal of gas bottles and securing of equipment. At the end of this period, Unit 2 had attained a very good level of housekeeping.

4.5.2 Unit 1 Radiologically Controlled Locked Areas

During the current period, Unit 1 completed the sixth refueling outage and was placed on the grid on March 2, 1988. Housekeeping was found generally to be adequate during the eleven week outage although the general radiological housekeeping and posting practices were found in one inspection (see Inspection Report 50-334/88-03; 50-412/88-02) to be poor compared to other utilities. The licensee attributed the decline in radiological housekeeping to the large volume of outage activities.

At the end of the period, approximately one month after outage completion, the inspector conducted a detailed walkdown of the accessible Unit 1 radiation areas including those normally locked to limit access. Notable improvements were observed in that some areas which had been contaminated, like the fuel pool cooling pumps, were now accessible. Other areas, such as the boron recovery pump cubicles, were also nearly complete in decontamination. Aggressive efforts to reduce the area of floor space marked as contaminated were evident. In some cases, the residual taped areas appeared to be too small in that insufficient taped area was provided around a contaminated component to provide working access. In the waste pump cubicles, one pump had a very small oil drippage but the oil was found to have pooled off the pump platform within the contaminated area, across the boundary tape, and into the "clean" area. In another waste pump cubicle a coiled extension cord was found straddling the taped boundary, half inside the contaminated zone and half outside on the "clean" floor. These examples are considered isolated cases, but they do indicate a need for caution in the control and reduction of contaminated areas.

Housekeeping in the Unit 1 radiologically controlled areas still exhibited weakness one month after conclusion of the sixth refueling outage. Many areas were found littered with tools (such as wrenches, knives, crowbars and flashlights), parts (such as gaskets, pipe caps, screws and fittings) and debris (such as used gloves, cotton glove liners, paper swipes and empty bags). Some cubicles not marked as contaminated were visibly dirty and one area had clearly experienced a spill of chromate-contaminated fluid.

4.5.3 Unit 1 - Non-Radiological Housekeeping

Unit 1 general housekeeping improved after the outage although examples of unsecured gas bottles and open cable junction boxes were identified by the inspector and reported to the licensee. Two potentially serious deficiencies were identified by the inspector in the cable spreading room. Cable junction boxes designed to provide ESF train separation were found open and cable tray covers were found missing, damaged and improperly installed. The inspector brought these deficiencies to the licensee's attention and corrective actions were in process shortly after the completion of the inspection. This item is Unresolved (50-334/88-11-02). The inspector will review the licensee's corrective actions including root cause evaluation and actions taken to prevent recurrence in a future inspection.

5. Natural Circulation Cooldown

Unit 1:

The inspector reviewed the licensee's action taken to implement Generic Letter (GL) No. 81-21, Natural Circulation Cooldown. The NRC has tracked this issue as multi-plant action No. B-66 and SIMS No. MTA-B-66. The GL, issued on May 5, 1981, requested that within six months of receipt of the generic letter, licensees furnish an assessment of their facility's procedure and training program with respect to reactor vessel voiding during natural circulation cooldown. The assessment was to include (1) a demonstration that controlled natural circulation cooldown from operating conditions to cold shutdown conditions, conducted in accordance with plant procedures, should not result in reactor vessel voiding, (2) verification that supplies of condensate-grade auxiliary feedwater are sufficient to support the cooldown method, and (3) a description of the training program and the provisions of the procedures that deal with prevention or mitigation of reactor vessel voiding.

The licensee responded to GL 81-21 for Unit 1 by letter dated November 1, 1981. By letter August 2, 1983, the NRC issued a safety evaluation report which concluded that the licensee had adequately demonstrated the capability to reach cold shutdown using natural circulation without upper head void formation. Additionally, the safety evaluation report concluded that the plant had sufficient condensate supplies for an extensive cooldown. The safety evaluation report did not review operating procedures; however, the letter documented that the operator procedures will be adequate for performance of a safe natural circulation cooldown upon acceptable implementation of the NRC-approved Westinghouse Owner's Group Emergency Response Guidelines. This was subsequently achieved on November 15, 1985.

The inspector reviewed the licensee's training program and confirmed that natural circulation cooldown is adequately addressed for both classroom and simulator coverage. Discussions were held with selected operators, which indicated that the individuals were knowledgeable on the natural circulation cooldown process. Plant specific emergency operating procedures also adequately address natural circulation cooldown in accordance with the licensee's response to Generic Letter 81-21. No concerns were identified. This issue is closed.

Unit 2:

Natural Circulation cooldown was addressed in the NRC Safety Evaluation Report (SER), NUREG-1057, related to the operation of BVPS, Unit 2. The issue of natural circulation testing was previous tracked by NRC Licensing as Confirmatory Issues No. 22, Natural Circulation Tests. The licensee was to perform a comparison study of BV-2 with North Anna Unit 2 to verify the adequacy of the mixing of borated water added to the reactor coolant system under natural circulation and the ability to cool down the plant with natural circulation. However, the only natural circulation tests were performed at a Westinghouse plant to meet the requirements of Branch Technical Position RSB 5-1 were at the Diablo Canyon Plant. Diablo Canyon is a four-loop plant and there was the concern that other significant differences may exist between the two plants such as upper vessel head temperature. The SER noted that, with respect to natural circulation testing, the licensee can demonstrate that the Diablo Canyon test is applicable to BV-2 with comparison of thermal and hydraulic similarities in the core, upper vessel head and loops. By letter dated May 11, 1987, the licensee submitted a report which documents the applicability of Diablo Canyon boron mixing results to BV-2. Based on the above, the NRC concluded that there was reasonable assurance that BV-2 could operate for one cycle until this issue was resolved since (1) natural circulation has been demonstrated for other Westinghouse plants, (2) operator training will be provided on a simulator which adequately represents BV-2 performance with regard to natural circulation, (3) systems required for natural circulation cooldown (e.g., auxiliary feedwater) are safety grade, and (4) there is an ample auxiliary feedwater supply from seismic Category I sources. Therefore, a license condition was not imposed on BV-2 with respect to natural circulation testing. The NRC closed Confirmatory Issue No. 22 in SER, Supplement No. 5, and resolution of the natural circulation testing issue will be tracked via licensing action No. TAC 62905.

The licensee's training program for BV-2 is similar to BV-1. Natural circulation cooldown is adequately covered in the operator training program as confirmed through discussions with plant operators who were demonstrated to be knowledgeable on the issue. The plant specific emergency operating procedures also adequately address natural circulation cooldown concerns. With the exception of natural circulation testing, which will be tracked separately, this issue is closed.

6. Calibration Program

The licensee's calibration program uses red foil-type stickers to identify those components required by TS to be calibrated within a specific period. Certain components which are used to measure the performance of other TS required equipment are also given red foil-type stickers. In a previous inspection (50-334/88-01; 50-412/88-01), the inspector noted that certain of these stickers had been identified to the licensee as being beyond the required calibration due date.

The licensee provided a response near the end of the inspection period which indicated that most of the inspector-identified stickers were erroneously labelled. In some cases, the stickers were marked incorrectly and in others the wrong type sticker had been used. The inspector provided the licensee additional examples of potentially deficient stickers and will continue to review this area during the next inspection period.

7. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted pursuant to Technical Specification 6.9 (Reporting Requirements) were reviewed. The review assessed whether the reported information was valid, included the NRC required data and whether results and supporting information were consistent with design predictions and performance specifications. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

BV2 - Monthly Operating Report for Plant Operations from January 1-31, 1988 (Revised).

BV1/BV2 - Monthly Operating Report for Plant Operations from February 1-29, 1988.

BV1/BV2 - Monthly Operating Report dated March 10, 1988.

BV1 - Reactor Containment Building Integrated Leak Rate Test Results.

BV1/BV2 - Annual Report of all Challenges to the Pressurizer Power Operated Relief Valves (PORVs) or Pressurizer Safety Valves.

No concerns were identified.

8. Inoffice Review of Licensee Event Reports (LERs)

The inspector reviewed LERs submitted to the NRC Region I office to verify that the details of the event were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LERs were reviewed:

Unit 1

LER 88-01-00: Steam Generator Tube Plugging.

LER 88-02-00: Reactor Trips on Low-Low Steam Generator Level Due to Personnel Error.

LER 88-03-00: Inadvertent Start of Auxiliary Feedwater Pumps Due to Procedural Deficiency.

Unit 2

LER 87-33-01: Failure to Perform Surveillance Test within Required Frequency.

LER 88-02-00: Reactor Trip and Control Room Emergency Bottled Air Pressurization System Actuation.

LER 88-03-00: Improper Clearance Results in ESF Actuation.

LER 88-04-00: Diesel Generator Actuation due to Spurious Overcurrent Signal.

LER 88-05-00: Overcurrent Relay Trip Leads to ESF Actuation.

LER 88-06-00: 2/4 Refueling Water Storage Tank Level Channels Inoperable.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Previous inspection reports have noted that while most LERs provided good documentation of event analyses, root cause determination and corrective actions, some LERs were weak in that they contained event inaccuracies and safety evaluation omissions. Most of the above LERs were good but two, LER 88-03 on Unit 1 and LER 88-06 on Unit 2, were not as strong. LER 88-03 misidentifies which motor driven AFW pump started and which one failed to start (see Section 4.2.4 for details of this event). The LER correctly states that there was no safety implication to the inadvertent auto-start of a motor driven AFW pump, but did not address the potentially more significant safety implication inherent in one pump failing to auto start on demand.

LER 88-06 concludes that there were no safety implications due to the inoperability of two out of four RWST level channels because the other two channels were operable and "fully capable of initiating" automatic switchover to the Containment sump. This is not wholly accurate in that the two failed-low channels would, without operator action, have immediately upon receipt of an SI signal initiated switchover to the dry containment sump thus defeating the ECCS. This potential safety significance was also discussed in Inspection Report 50-334/88-01; 50-412/88-01. The concern was addressed by leaving one low-low signal in and bypassing the other failed channel. This allowed the automatic switchover feature to be actuated from either one of the two operable channels (one out of two logic). These actions are not presented in the LER.

9. Maintenance and Surveillance Testing

Corrective and preventive maintenance and routine surveillance testing activities during this inspection period were reviewed as part of the Unit 1 NRC Probabilistic Risk Analysis Based Team Inspection. Specific activities and programmatic reviews are documented in NRC Inspection Report 50-334/88-08. Other maintenance and surveillance activities were reviewed during NRC Special Inspection Report 50-334/88-12.

10. Exit Interview

Meetings were held with senior facility management periodically during the course of this inspection to discuss the inspection scope and findings. A summary of inspection findings was further discussed with the licensee at the conclusion of the report period on April 4, 1988.