U. S. NUCLEAR REGULATORY COMMISSION
REGION 1

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

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

Location: Shippingport, Pennsylvania

Dates: June 23 - July 27, 1990

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Approved by: Francis Young — August 28 1990
Francis I. Young, Acting Chief — Date
Reactor Projects Section No. 4B

Inspection Summary

This inspection report documents routine and reactive inspections during day and backshift hours of station activities including: plant operations; radiological protection; surveillance and maintenance; emergency preparedness; security; engineering and technical support; and safety assessment/quality verification.

Results

Overall, the facility was operated safely. No violations were identified. Licensee activities associated with a Unit 2 reactor trip were reviewed. No deficiencies were identified (Detail 2.3.1). A good safety perspective was demonstrated on the decision to enter into a Unit 1 maintenance outage (Detail 2.3.2). The Unit 1 maintenance outage was well planned and controlled (Detail 4.2). Two inadvertent Unit 1 chemical and volume control systems letdown isolations during surveillance testing were reviewed. No deficiencies were identified (Detail 4.4). Three previous open NRC items were reviewed and two were closed. The review of one open item indicated weakness in questioning attitude by members of the licensee's staff (Detail 8.2).

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DETAILS

1. Summary of Facility Activities

At the beginning of the period, Unit 1 was at approximately 81 percent power and Unit 2 was operating at approximately 87 percent power. On June 25, Unit 1 power was raised to 100 percent and Unit 1 continued at full power until July 13, when the unit was shut down for a maintenance outage. On July 17, Unit 1 entered Cold Shutdown (Mode 5) to apply a freeze seal for a valve repair. Unit 1 returned to power operation on July 25 and at the end of the period was holding power at 30 percent for steam generator chemistry.

Unit 2 power was reduced to approximately 47 percent during the first two weekends of the period as part of a core extension schedule. On July 2, Unit 2 tripped from 90 percent power (see Detail 2.3) following a main generator trip. Unit 2 returned to power operations on July 7 and operated at full power for the remainder of the period.

2. Plant Operations

2.1 Operational Safety Verification

The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted in the following plant areas:

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

During the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. The inspector verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspector comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with Technical Specification (TS) requirements. Operability of engineered safety features, other safety related systems and onsite and offsite power sources were verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TS and implementation of appropriate action statements for equipment out of service was inspected. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted lead book. The inspector also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspector conducted detailed walkdowns of accessible areas of both Unit 1 and Unit 2. Housekeeping at both units was generally good. During a tour of the Unit 1 containment, the inspector observed small quantities of oil on the containment floor. The oil was from a small leak of lubricating oil from a reactor coolant pump. The floor was subsequently cleaned.

2.2 Engineered Safety Features System Walkdown

The operability of selected engineered safety feature systems was verified by performing detailed walkdowns of the accessible portions of the systems. The inspectors confirmed that system components were in the required alignments, instrumentation was valved-in with appropriate calibration dates, as-built prints reflected the as-installed systems and the overall conditions observed were satisfactory. The Unit 1 and 2 systems inspected during this period included the Emergency Diesel Generators, Safety Injection Auxiliary Feed and Recirculation Spray systems. No concerns were identified.

2.3 Followup of Events Occurring During the Inspection Period

The inspectors provided onsite coverage and followup of unplanned events. Plant parameters, performance of safety systems, and licensee actions were reviewed. The inspectors confirmed that the required notifications were made to NRC. The following events were reviewed:

2.3.1 Unit 2 Reactor Trip

On July 2, 1990, while operating at 90 percent power, a Unit 2 reactor trip occurred due to a main generator turbine trip. Control room operators responded to the event in accordance with procedure and stabilized the plant in Hot Standby (Mode 3). All systems performed as designed except as noted below. The main generator tripped due to the opening of the main generator 345 KV output breakers. The output breakers tripped open due to inadvertent activation of a primary 345 KV leads protection relay. Technicians from the licensee's off-site Substation Department working in the Unit 2 switchyard mistakenly opened a 4-pole current transformer shorting switch, isolating current to the above relay. Unit 2 control room operators were not aware that the Substation Department personnel were working in the switchyard. However, the work had been authorized by the offsite System Operator.

Two systems did not function as required following the reactor trip. The turbine driven auxiliary feedwater pump (TDAFW) tripped (overspeed device) following an auto start signal. In addition, excessive leakage from the TDAFW steam drain lines filled the room (which contained other safety related equipment) with steam. One of the two source range nuclear instruments failed to track flux levels following the trip.

The inspector reviewed the licensee's root cause analysis of the event and corrective actions. The event was attributed to human error in that the Substation Department technicians mistakenly actuated the wrong switch while performing a calibration test in the Unit 2 Switchyard. Other contributing factors identified were a lack of communication, human factors considerations, and inadequate supervision of the job. Some of the licensee's short term corrective actions included posting of warning labels on all the 4-pole shorting switches and additional training for substation relay technicians. For the long term, the licensee plans to schedule the testing switchyard relay during outages and to improve communications between the Substation Department and the site.

The licensee found that the TDAFW pump trip was caused by a combination of misaligned linkages in the trip throttle valve and a worn washer. This resulted in an incomplete resetting of the overspeed trip device. Subsequently, the linkages were adjusted and the washer was replaced. The inspector witnessed the satisfactory post maintenance testing of the TDAFW pump and the overspeed trip device.

The licensee determined that the excessive steam from the TDAFW steam drains was caused by two drain line throttle valves being excessively cracked open. Procedurally, the valves were required to be throttled open 1/4 to 1/2 a turn. The drain line valves were found to be cracked open 1/2 turn. Shutting the valves a quarter turn stopped the excessive steam leakage into the room. The inspector questioned whether the other safety related equipment in the room was environmentally qualified for 100 percent humidity. The licensee provided documentation which indicated that all the equipment was adequately qualified.

The cause of the source range nuclear instrument failure was determined to be a failed detector which was subsequently replaced and satisfactorily tested.

The inspector found that licensee review of the event and follow on corrective actions to be detailed and comprehensive. The inspector had no further questions.

2.3.2 Unit 1 Shutdown

On July 13, 1990, Unit 1 performed a controlled shutdown to repair a failed control rod position indicator. The licensee had postulated that one of the possible causes of the failed indicator was a leaking instrument penetration on the reactor vessel head. The licensee had developed contingency plans if the repair required the unit to be brought to cold shutdown (Mode 5) to enter into a maintenance outage to perform inspections and repairs to the main generator and a moisture separator reheater.

Once the unit was shutdown, licensee personnel entered the containment to inspect the reactor vessel head. No reactor coolant leakage was found. The cause of the failed control rod position indicator was found to be a loose connector and was subsequently repaired.

Another problem was identified during a containment walkdown by the nuclear shift supervisor (NSS) that required the unit to be cooled down to Mode 5. The NSS observed a small body-to-bonnet leak on the normal charging line isolation motor operated valve (MOV-CH-310). While attempting to torque the valve's bonnet bolts to stop the leak, two of the bolts failed. Further visual examination revealed indications of boric acid induced corrosion of the bonnet bolts. The licensee determined that a freeze seal would be required to safely replace all the bonnet bolting. The licensee started to cool down to Mode 5 on July 15 and implemented the maintenance outage contingency plans. See Detail 4.2 for a discussion of outage activities.

The licensee demonstrated a strong safety perspective in the decision made to shut down the unit to investigate the cause for the failed rod position indicator even though there was no requirement to shut down. The careful non-required walkdown of the containment by the NSS identified a degrading material condition which, if not repaired, could have been a location for significant Reactor Coolant System leakage.

3. 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.

There were no notable observations.

4. Maintenance and Surveillance

4.1. Maintenance Observation

The inspector reviewed selected maintenance activities to assure that:

-- The activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable;

-- required approvals and releases had been obtained prior to commencing work;

-- procedures used for the task were adequate and work was within the skills of the trade;

-- activities were accomplished by qualified personnel;

-- where necessary, radiological and fire preventive controls were adequate and implemented;

-- QC hold points were established where required and observed;

-- equipment was properly tested and returned to service.

Maintenance activities reviewed included:

MWR 905203	Trouble Shooting and Repair of Unit 2 Turbine Driven Auxiliary Feed Pump Overspeed Trip Mechanism
MSP 6.20.I	Delta Tave Protection Channel I Test T-RC 412

MWR 901024 Disassemble and Repair Unit 1 "C" Main Feedwater Regulating Valve

MWR 901063 Investigate and Repair Ground on Unit 1 DC Bus No. 1

There were no notable observations.

4.2 Unit 1 Maintenance Outage Activities

On July 15, 1990, after identifying a repair (see Detail 2.3.2) that required Unit 1 to cool down to Cold Shutdown (Mode 5), the licensee implemented contingency plans to conduct a short maintenance outage. Some of the major outage activities are discussed below.

The repair which required the cooldown was the replacement of the bonnet bolting on the normal charging line motor operated isolation valve (MOV-CH-310). Boric acid from a slight body-to-bonnet leak had resulted in material degradation of the carbon steel bonnet bolts. Two bolts had failed during a previous attempt to retorque the bolts. A freeze seal upstream of the valve had to be used to provide satisfactory isolation for the repair. Evaluation of the bolting indicated that 9 of the 12 (including the two failed bolts), exhibited significant degradation due to boric acid induced corrosion. The valve was subsequently satisfactorily repaired.

The licensee conducted a detailed containment inspection to identify other valves which exhibited boric acid crystal buildup. Several valves were identified to have slight packing leaks. These valves were cleaned and then an evaluation was performed to determine if any material degradation of the valves had occurred. No significant degradation was found.

The Unit 1 main generator was inspected. Vibration detectors in the generator had indicated excessive vibration and possible damage to the generator windings. The inspection found no winding degradation. Shims were added to reduce vibration.

A licensee evaluation of the performance of the 1B Moisture Separator Reheater (MSR) indicated a drop in efficiency. Inspection of the MSR found several leaking tubes which were subsequently plugged.

The inspector found that outage activities were well planned and controlled. The inspector observed the active involvement of Quality Control inspectors for safety related work. Cleanliness controls at work sites were fully implemented.

4.3 Surveillance Observation

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, Technical Specifications were satisfied, testing was performed by qualified personnel and test results satisfied acceptance criteria or were properly dispositioned. The following surveillance testing activities were reviewed:

OST	1.36.20	Diesel Generator No. 2 Startup (Twice)
OST	1.21.5	Main Steam Trip Valve (TV-1MS-101B) Full Closure Test
OST	1.21.6	Main Steam Trip Valve (TV-1MS-101C) Full Closure Test
OST	2.13.1	Quench Spray Pump (2QSS*P21A) Test
OST	2.36.1	Emergency Diesel Generator (2EGS*EG2-1) Monthly Test

There were no notable observations.

4.4 <u>Inadvertent Letdown Isolations During Surveillance Testing</u>

On July 14, 1990, while Unit 1 was in Hot Standby (Mode 3), two Chemical and Volume Control System (CVCS) letdown line automatic isolations occurred during main steam trip valve full stroke surveillance testing. Both isolations were the result of low pressurizer level caused by slight overcooling of the Reactor Coolant System. Letdown automatically isolates either due to a safety injection signal (an Engineered Safety Feature) or low pressurizer level (control feature).

The first isolation occurred while attempting to reopen the "A" main steam trip valve (MSTV) following the stroke test. The valve had a 5 psid interlock which had to be satisfied before the valve could be reopened. To satisfy the interlock, control room operators throttled open the "A" Steam Generator (SG) atmospheric steam dump. When the differential pressure equalized, the "A" MSTV stroked open. The combination of steam flow from the steam dump valve and the "A" MSTV resulted in a RCS cooldown of approximately 14°F which in turn caused the pressurizer level to drop below 13 percent and the subsequent automatic isolation of the letdown line.

The second isolation occurred approximately five minutes after the "B" MSTV was reopened following its stroke test while restoring SG water level. RCS temperature had previously dropped approximately 5°F during the reopening of the "B" MSTV. This, in combination with the cooldown caused by feeding the steam generator, resulted in a decrease in pressurizer level below 13 percent and subsequent letdown isolation.

Control room operators responded promptly to both events. Pressurizer level and letdown flow were restored. The licensee reported both events in accordance with the requirements of 10 CFR 50.72(b)(2).

The inspector reviewed the surveillance procedures and noted some weakness in the guidance and precautions provided. In addition, pressurizer level could have been slightly raised at the start of each test to provide sufficient margin to prevent an inadvertent isolation. At the close of the inspection, the licensee was revising the procedure to prevent recurrence. The inspector concluded that the events had minor safety significance and had no further questions.

5. Emergency Preparedness

The resident inspectors had no noteworthy observations in this area during this inspection.

6. Security

The inspectors observed implementation of the Physical Security Plan as follows:

-- 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.

There were no noteworthy observations.

7. Engineering and Technical Support

7.1 Electrical Cable Submergence in Water

In September 1987, rainwater entered a Unit 1 annunciator panel from outside the plant via an underground cable run resulting in a number of control room alarms. The affected conduit contained safety related cabling. During the licensee's investigation of the event, several manholes were found partially filled with rainwater.

The licensee's corrective actions were previously reviewed in Inspection Report 50-334/90-02; 50-412/90-02. In that review, the inspector found that the licensee's corrective actions were adequate with the exception that no testing had been performed to demonstrate that no insulation degradation of low energy safety related control and instrumentation cabling insulation had not been tested after the event.

Further investigation by the licensee determined that no safety related instrument cabling had been routed in the affected ducts. The licensee also received additional test data from the manufacturer of the safety related control cabling (Okonite Co.) installed in the affected ducts. This data indicated that the cabling could withstand submergence in rainwater for a three years without cable insulation degradation. To date, there have been no reported failures of any of the affected control cables. The inspector had no further questions.

7.2 Auxiliary Feedwater Engineering Recommendations

In May 1988, an inspector found that maintenance engineers' decisions not to incorporate technical manual and Engineering Department recommendations into maintenance procedures were not being documented. Specifically, three of the licensee's Nuclear Engineering Department authorized vendor recommendations for the Unit 1 turbine driven auxiliary feed pump were not incorporated into the licensee's surveillance and maintenance procedures. No documented justification for not incorporating the recommendations was found. The recommendations not incorporated were as follows:

a. Flushing the oil system for four hours.
b. Oil Preheat to 110°F - 120°F.
c. Weekly testing of the overspeed trip.

The inspector reviewed the above item and found that the flushing of the oil system for four hours was only required for new installations. The overspeed trip testing was already being routinely tested in Operations Department's Operation Surveillance Tests. Justification for not preheating the oil had been previously documented in Engineering Memorandum (EM) 62106 dated February 13, 1987.

The inspector found that although the licensee had no centralized location for documenting maintenance engineers' decisions concerning vendor and Engineering Department recommendations, maintenance engineers' decisions were routinely being documented in several ways such as procedure change requests, Preventive Maintenance (PM), Task Addition/Rescheduling and Deletion Forms, PM Critique Forms, formal letters, and EMs. The inspector had no further questions.

8. Safety Assessment and Quality Verification

8.1 Review of Written Reports

The inspector reviewed LERs and other written reports submitted to the NRC Region I Office to verify that the details of the events 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 90-009-00 Operation Prohibited by Technical Specifications

Unit 2:

LER 87-030-02 Manual Reactor Trip from Control Room Due to Fire at No. 2 Turbine Bearing

LER 90-006-00 Operation in a Condition Prohibited by Technical Specifications

LER 90-007-00 Operation with Refueling Cavity Drain Installed.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LERs were found to be of high quality with good documentation of event analyses, root cause determinations, and corrective actions. The inspector noted that the title of two of the LERs (90-009 on Unit 1 and 90-006 on Unit 2) did not contain the information requested by NUREG 1022, Supplement No. 2. The titles should have contained a root cause, a result and link between them. The licensee acknowledged the inspectors concerns and agreed to review this matter.

The inspector had no other notable observations.

8.2 Unit 1 Auxiliary Feedwater Pump Performance

The inspector reviewed the licensee's evaluations and actions concerning an NRC Unresolved Item (50-334/87-07-02). In May 1987, surveillance testing indicated that the total developed head (TDH) for the motor driven Auxiliary Feedwater (AFW) pump 3A, while satisfying the Updated Final Safety Analysis Report (UFSAR) design requirements, was above the upper limit values per ASME Section XI. The TDH data was obtained using installed instrumentation.

During the seventh refueling outage, flow testing of the AFW pump 3A performed using both installed and test instrumentation again indicated that the pump TDH was above the limits of ASME Section XI while satisfying the UFSAR design requirements for TDH. However, the evaluation of the data from the test instrumentation indicated that the pumps TDH was below the lower ASME alert limit and the USFAR design TDH. Both the installed and the test instrumentation were bench tested and found to be properly calibrated. The licensee concluded, based on the pump's motor current measured during the test and then compared to the current measurements taken during the pump's initial testing in 1975, that the installed instrumentation was indicating closer to the actual TDH. As permitted by ASME XI, the licensee raised the upper allowable limits for pump performance.

The inspector asked the licensee (see IR 50-334/90-02; 50-412/90-02) why no evaluation had been performed to determine why the more accurate test instruments were indicating approximately 40 psig lower than the installed instruments. The licensee subsequently determined that the installed discharge pressure gauge for the 3A AFW pump used in determining TDH was indicating 40 psig above actual pressure for the pressure ranges under consideration.

The licensee found that the physical installation (gauge support plate) of the discharge pressure gauge was applying a torque or strain on the gauge's bourdon tubes which caused an approximately 40 psi zero shift. This condition had gone previously unnoticed because of the licensee's routine practice of bench testing pressure gauges vice performing calibrations in place. As a corrective action, the introduced strain was eased and the gauge was satisfactorily calibrated in place. The licensee examined a large sample of similar installed pressure gauges and found no other similar problems.

In 1988, as part of a Safety System Functional Evaluation, the licensee conservatively calculated that the minimum allowable TDH required to assure the AFW flow rate of 350 gpm used in accident analyses was 2660 feet. Based on this calculation, the 3A AFW pump minimum acceptance criteria pump head curve was lowered. The new minimum acceptance criteria pump head curve was within 2 percent of the pump manufacturer curve. Testing was conducted on July 17, 1990, which indicated that total developed head was above the minimum calculated TDH at rated flow.

The only section of the UFSAR that explicitly describes the rated TDH for the 3A AFW pump is Section 10.3.5.1.2 which states that the rated TDH is 2,696 feet. The inspector asked whether a 10 CFR 50.59 safety evaluation had been performed to determine whether an unreviewed Safety Question was involved. The licensee stated that the rated TDH given in the UFSAR was derived from the pump's purchase specification and was not the TDH value used in the UFSAR accident analyses. When asked to provide the TDH value used in the UFSAR analyses, the licensee could not readily provide the number.

Some of the activities associated with the above AFW concerns indicated a weakness in questioning attitude in assessing the inconsistencies in test data. That is, there was an apparent willingness to accept the test data from the installed test instruments without evaluating why there was a significant difference from the more accurate test instrumentation. At the end of the period, the TDH value used in the UFSAR had not been determined and this item will remain open pending the evaluation of the USFAR accident analyses.

9. Status of Previous Inspection Findings

The NRC Outstanding Items 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 items reported below.

9.1 (Open) Unresolved Item 50-334/87-07-02: Licensee to resolve Auxiliary Feedwater Pump 3A performance characteristics. The inspector reviewed recent licensee evaluations concerning the above item. The review of this item is discussed in Detail 8.2.

9.2 (Closed) Unresolved Item (50-334/87-13-01): Licensee to address cable qualification and corrective actions for annunciator panel flood event. The inspector's review of this item is discussed in Detail 7.1.

9.3 (Closed) Unresolved Item (50-334/88-08-03): Lack of documentation for maintenance engineers' decisions not to incorporate technical manual recommendations into procedures. The inspector's review of this item is discussed in Detail 7.2.

10. Exit Meeting

10.1 Preliminary Inspection Findings Exit

Periodic meetings were held with senior facility management 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 August 3, 1990.

10.2 Attendance at Exit Meetings Conducted by Region-Based Inspectors

Dates	Subject	Inspection Report No.	Reporting Inspector
7/9-19/90	Unit 1 Requal Exams	50-334/90-14	Hughes
7/16-20/90	Physical Security	50-334/90-17; 50-412/90-17	Smith