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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-334/84-15

Docket No. 50-334 License No. DPR-66

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

Facility Name: Beaver Valley Power Station, Unit 1

Inspection At: Shippingport, Pennsylvania

Inspection Conducted: June 2 - July 6, 1984

Inspectors: Wm. Troskoski 7-11-84
W. M. Troskoski, Senior Resident Inspector date signed

D M Johnson 7-11-84
D. M. Johnson, Resident Inspector date signed

Approved by: S. W. Meyer 7-16-84
for L. E. Tripp, Chief, Reactor Projects date signed
Section No. 3A, Reactor Projects
Branch 3

Inspection Summary: Inspection No. 50-334/84-15 on June 2 - July 6, 1984.

Areas Inspected: Routine inspections by the resident inspector (134 hours) of licensee actions on previous inspection findings, plant operations, housekeeping, fire protection, radiological controls, physical security, surveillance program, maintenance activities, engineered safety features verification, annual emergency preparedness drill, licensee event reports and containment emergency airlock modifications.

Results: Three potential safety issues were identified (inadequate control of station battery tests - detail 3.b.1, violation of station equipment clearance procedures - detail 6, and missed surveillances - detail 8).

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DETAILS

1. Persons Contacted

J. Carey, Vice President, Nuclear Group
M. Coppula, Superintendent of Technical Services
K. Grada, Superintendent of Licensing and Compliance
T. Jones, Manager, Nuclear Operations
W. Lacey, Station Superintendent
J. Sieber, Manager, Nuclear Safety and Licensing
N. Tonet, Manager, Nuclear Engineering

The inspector also contacted other licensee employees and contractors during this inspection.

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

(Closed) Unresolved Item (84-04-05): Revise breaker PMPs to inspect auxiliary relay mechanical linkage. PMP 1-36SS-BKR-1E, ITE 5KV Air Circuit Breaker Inspection, was revised to include a visual inspection of cubicle linkages and interlocks. Additional checks for signs of physical defects or deformation, contact fitting, wear and tightness of bolts and screws were also added. This item is closed.

(Closed) Unresolved Item (84-04-02): Correct Control Room prints to reflect containment sump pump discharge lines as-built condition and other temporary modifications. The inspectors reviewed the Control Room prints and verified that OM Figure 9-3 now reflects the as-built condition. Additionally, the licensee performed a review of other Control Room drawings and verified that the other temporary modifications were identified on the Control Room prints. This item is closed.

(Closed) Unresolved Item (84-09-01): Verify that emergency operating procedures contain appropriate flags to direct operators to the reactor vent system procedures when needed. The inspector reviewed the Control Room copy of OM Chapter 53, Emergency Operating Procedures, Rev. 15, and verified that references to the reactor vent procedures were added at appropriate steps. This item is closed.

(Open) Unresolved Item (84-12-05): Review the component cooling water (CCR) heat exchanger corrective actions. The inspectors reviewed the Nuclear Engineering and Construction Units report dated June 25, 1984, on the CCR heat exchanger tube degradation problem. This report indicated that the tube degradation mechanism is limited to crevice corrosion caused by manganese deposits from the river water.

Because of the mechanism involved, the licensee does not believe that the failure process could lead to tube fracture and that a limited leakage through wall pit formation is the most severe failure expected. Additionally, the heat exchanger system has been analyzed for thermal performance and it was determined that with 75 tubes plugged in each heat exchanger, the ability to bring the plant to cold shutdown condition within the specified time limit is still satisfied. The report was forwarded to the Regional office for review by a metallurgy specialist. This item remains open pending tube bundle replacement scheduled for the fourth refueling outage or other disposition as justified by DLC engineering.

3. Plant Operations

a. General

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

-- Control Room
-- Primary Auxiliary Building
-- Turbine Building
-- Service Building
-- Main Intake Structure
-- Main Steam Valve Room
-- Purge Duct Room
-- East/West Cable Vaults
-- Emergency Diesel Generator Rooms
-- Containment Building
-- Penetration Areas
-- Safeguards Areas
-- Various Switchgear Rooms/Cable Spreading Room
-- Protected Areas

Acceptance criteria for the above areas include the following:

-- BVPS FSAR
-- Technical Specifications (TS)
-- BVPS Operating Manual (OM), Chapter 48, Conduct of Operations
-- OM 1.48.5, Section D, Jumpers and Lifted Leads
-- OM 1.48.6, Clearance Procedures
-- OM 1.48.8, Records
-- OM 1.48.9, Rules of Practice
-- OM Chapter 55A, Periodic Checks - Operating Surveillance Tests
-- BVPS Maintenance Manual (MM), Chapter 1, Conduct of Maintenance
-- BVPS Radcon Manual (RCM)
-- 10 CFR 50.54(k), Control Room Manning Requirements
-- BVPS Site/Station Administrative Procedures (SAP)
-- BVPS Physical Security Plan (PSP)
-- Inspector Judgement

b. Operations

The inspectors toured the Control Room regularly to verify compliance with NRC requirements and facility technical specifications (TS). Direct observations of instrumentation, recorder traces and control panels were made for items important to safety. Included in the reviews were the rod position indicators, nuclear instrumentation systems, radiation monitors, containment pressure and temperature parameters, onsite/offsite emergency power sources, availability of reactor protection systems, and proper alignment of engineered safety feature systems. Where an abnormal condition existed (such as out-of-service equipment), adherence to appropriate TS action statements was independently verified. Also, various operation logs and records, including completed surveillance tests, equipment clearance permits in progress, status board maintenance and temporary operating procedures were reviewed on a sampling basis for compliance with technical specifications and those administrative controls listed in paragraph 3a.

During the course of the inspection, discussions were conducted with operators concerning reasons for selected annunciators and knowledge of recent changes to procedures, facility configuration and plant conditions. The inspectors verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. Except where noted below, inspector comments or questions resulting from these daily reviews were acceptably resolved by licensee personnel.

1. While comparing surveillance tests used at BVPS Unit 1 with those being developed for Unit 2, the licensee determined that the service test did not meet the intent of Technical Specification 4.8.2.3.2d for station batteries. Surveillance test BVT 1.1-1.39.1 (.2), No. 1 (No. 2) Battery and Charger Load Test, performed on an 18 month frequency during shutdown, subjects station batteries to a two hour flat rate load test at 90 amps. The intent of the technical specification is that battery capacity be demonstrated to be adequate to supply and maintain in operable status, all of the actual or simulated emergency loads for a two hour design duty cycle of the DC system. IEEE Standard 450-1980, IEEE Recommended Practice for Maintenance, Testing and Replacement of Large Lead Storage Batteries, referenced in the TS bases to Amendment 54 and its Safety Evaluation Report, requires the service test to be performed to an actual load profile expected to occur on the DC system during a design bases accident. Resident inspector discussions with cognizant licensee personnel on June 21, 1984, indicated that such a testing profile had not been developed by the station and consequently was not included in the FSAR.

From a review of the original acceptance test data, the inspector determined that the batteries were subjected to a 924 amp discharge rate for one minute followed by a sustained flat rate of 374 amps for the duration of the two hour test. Additionally, the 8 hour 225 amp capacity test performed under TS 4.8.2.3.2.e during 1981 and 1982 for battery banks 1 and 2 respectively, showed a maximum degradation of less than 5% of the manufacturer's rating on each bank, well within the 80% of original capacity acceptance limit. Additionally, original purchase specifications referenced in the FSAR indicated that a 49% safety factor was built into the battery bank capacity. This item was addressed during a conference call with representatives from NRR (including the Power Systems Branch) and DLC's Superintendent of Licensing and Compliance. During this discussion, it was determined that the station batteries could perform their intended safety function as born out by past test results.

The licensee has proposed a TS change, reviewed & approved by the Onsite Safety Committee and Offsite Review Committee, that would allow continued operation until the fourth refueling outage scheduled for October, 1984, when the following course of action will be taken:

- Develop the design bases load scheme for each station battery.

- Obtain new test equipment capable of performing the specified load tests.

- Develop specific battery service test procedures to be performed on the installed station batteries prior to startup from the fourth refueling outage.

This course of action was determined to be acceptable by both NRR and Region I management.

Test control criteria contained in both 10 CFR 50, Appendix B, and the licensee's Quality Assurance Program requires that testing conducted to demonstrate that systems will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the acceptance limits contained in applicable design documents. IEEE Standard 450-1980, referenced in TS 3/4.8.2 bases, provides guidance for performing service tests to meet the design requirements (battery duty cycle) of the DC system such that the discharge rate and test length correspond as closely as practical to those requirements. The failure to identify and incorporate those requirements into the acceptance criteria of BVT 1.1-1.39.1 (-.2), No. 1 (No. 2) Battery and Charger Load Test is a Violation (84-15-01).

2. During a plant tour on June 28, 1984, the inspector noted that a charging pump switch was red danger tagged on the remote shutdown panel (SDP), located in the switchgear room. However, other out of service ESF equipment controls (river water pump) were not so tagged as part of their equipment clearance. Discussions with licensee personnel indicated that the charging pump had been removed from service per OM Chapter 1.7.4 A.M., Removing a Charging Pump From Service for Mechanical Maintenance, a detailed procedure for clearing this specific ESF component that apparently does not have a counterpart for other components. While not required to be flagged on the SDP controls, the inspector stated that other ESF components should also be so identified as the SDP would become an extension of the Control Room, should it have to be evacuated. Those comments were acknowledged by the licensee.

   While reviewing the technical specification associated with the SDP, the inspector noted that the only existing test requirements related to the panels instrumentation. There are no requirements to demonstrate actual operability of the various ESF component controls. Discussions with NRR indicated that a standard technical specification addressing 10 CFR 50, Appendix R, Fire Protection Program for Nuclear Facilities, requirements was currently being developed that would include surveillance testing requirements in this area, probably on a refueling outage frequency. This was brought to the licensee's attention. The inspector had no further concerns.

3. The reactor was shut down at 1:18 a.m. on July 5, 1984, due to the loss of chilled water to the containment air recirculation cooling coils and instrument air compressor aftercooler. This occurred as a result of valve TV-CC-110D (containment recirculation cooling coil outlet containment isolation valve) failing in the shut position. Containment air temperature subsequently increased above 105 F to a maximum of about 112 F. This resulted in the licensee entering two separate technical specification action statements, each of which would ultimately require the plant to be placed in cold shutdown. The first involved limiting primary containment average air temperature to less than 105 F when in Modes 1 thru 4 per TS 3.6.1.5, and the second action statement, TS 3.6.1.4, indirectly related to the first, limits primary containment internal air partial pressure to a region defined in TS Figure 3.6-1, which is valid for a temperature range of 75 F to 105 F. Additionally, because of the loss of cooling to the containment instrument air compressor aftercoolers, manual containment isolation valve IA-90, the cross-connect valve from station instrument air to containment instrument air, was opened to prevent further equipment damage. This resulted in entry into the primary containment integrity action statement (TS 3.6.1.1). The station maintained a dedicated operator at IA-90, while the reactor was above Mode 5 conditions.

As a result of the above action statements, the plant was placed in Mode 5 (cold shutdown) by 11:30 a.m. on July 6, 1984. The licensee's actions were acceptable.

The diaphram to TV-CC-110D was replaced. The licensee determined that this particular item had recently been replaced during the last refueling outage and an investigation into the failure determined that the probable cause was a pressure spike from the valve actuator.

c. Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in the areas listed in paragraph 3a above with regard to the following:

-- Protected area barriers were not degraded;

-- Isolation zones were clear;

-- Persons and packages were checked prior to allowing entry into the Protected Area;

-- Vehicles were properly searched and vehicle access to the Protected Area was in accordance with approved procedures;

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

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

-- Adequate lighting maintained.

1. While touring the protected area on June 20, 1984, the inspector observed a visitor in the I&C Engineer's office without an escort. This was brought to the attention of an I&C engineer, who unsuccessfully attempted to page the individual's escort for several minutes. The I&C engineer accepted escort responsibility for the visitor.

   Discussions with the I&C Supervisor revealed that the visitor had been properly brought onsite by two engineers. Apparently, one of the individuals left the office on an errand without telling the second individual, who was not aware of his escort responsibilities, and subsequently left the visitor unescorted. The inspector reviewed the security procedures for bringing visitors on site, and deemed them to be adequate. Because this appears to be an isolated case involving an error in judgement, no violation will be issued at this time.

2. On June 28, 1984, the inspector was informed by the licensee that at 10:05 a.m., it was discovered that an individual had entered the protected area through the access control point without first obtaining and displaying a security picture badge, in accordance with 10 CFR 73.55(d)(5) and the BVPS Security Plan requirements. This individual, who is authorized access to the protected area and most vital areas, had been onsite for about one and a half hours before a routine security patrol noted that he was not displaying a picture badge. Investigation revealed that after approaching the badge issue station, the individual was distracted by a station page and failed to pick up his picture badge before going thru the access check point. Upon personal recognition, the access guard allowed him entry, failing to verify displayment of the picture badge, in violation of post orders. The individual had received annual general employee retraining, which includes BVPS Unit 1 security requirements in November, 1983, and has been employed at the site since 1976.

   After discussions with the resident inspector, the licensee reported the event via the ENS line to NRC Headquarters on June 29, 1984, within 24 hours, followed by a written report in accordance with 10 CFR 73.71(C), as a moderate loss of security effectiveness. Planned corrective actions, which included review of the event with security and contractor personnel, modification of security procedures and proposed hardware changes scheduled to be implemented with the installation of the consolidated Unit 1/2 automated security system, were discussed with Regional management and found to be acceptable. A review of the BVPS enforcement history indicated that no similar violation has occurred for more than two years. Because this event meets the criteria specified in 10 CFR 2, Appendix C, no NRC violation will be issued.

d. <u>Radiation Controls</u>

   Radiation controls, including posting of radiation areas, the conditions of step-off pads, disposal of protective clothing, completion of Radiation Work Permits, compliance with Radiation Work Permits, personnel monitoring devices being worn, cleanliness of work areas, radiation control job coverage, area monitor operability (portable and permanent), area monitor calibration, and personnel frisking procedures were observed on a sampling basis.

On June 4, 1984, the licensee notified the inspector of a violation of 10 CFR 20.408, Reports of Personnel Monitoring On Termination of Employment or Work. Through a record review of radiation exposure reports, it was determined that an individual who was employed by a contractor at BVPS Unit 1 from July 5 through August 10, 1983, terminated employment, and the licensee failed to furnish the report of his exposure to the Director of Management and Program Analysis within 90 days. The inspector reviewed the individual's external exposure information and noted that no exposure had been recorded for the whole body. The licensee informed the inspector that a review of past RWPs and security access control points related to radiation control areas indicated that the individual apparently had no job assignment in a radiation control area. The problem of licensee contractors failing to notify the Radcon office when rad workers terminate employment has been previously discussed in NRC Inspection Report 50-334/83-30. In December, 1983, the licensee changed their program in response to this to ensure prompt submittal of termination notification so that an individual's exposure could be forwarded to the NRC in a timely manner. This particular item was not identified at that time because the individual's termination occurred prior to December, 1983. Both DLC and contractor records were cross checked to verify that no other individuals have been omitted from the reporting requirements. Because this is licensee identified and adequate corrective action has been taken, no violation will be issued as in accordance with 10 CFR 2, Appendix C.

e. Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control of material to prevent fire hazards were observed in areas listed in paragraph 3a. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas was also observed. No inadequacies were noted.

4. Engineered Safety Features (ESF) Verification

The operability of the following systems was verified by performing a walkdown of accessible portions that included the following as appropriate:

(1) System lineup procedures match plant drawings and the as-built configuration.

(2) Equipment conditions were observed for items which might degrade performance. Hangers and supports are operable.

(3) The interior of breakers, electrical and instrumentation cabinets were inspected for debris, loose material, jumpers, etc.

(5) Valves were verified to be in the proper position with power available. Valve locking mechanisms were checked, where required.

(6) Technical specification required surveillance testing was current.

-- Electrical Power Systems, DC Distribution, June 22, 1984.

-- Chemical Addition System, June 20, 1984.

-- Low Head Safety Injection System, June 8, 1984.

-- Auxiliary Feedwater System, June 8, 1984.

No deficiencies were noted.

5. Surveillance Activities

To ascertain that surveillance of safety-related systems or components is being conducted in accordance with license requirements, the inspector observed portions of selected tests to verify that:

a. The surveillance test procedure conforms to technical specification requirements.

b. Required administrative approvals and tagouts are obtained before initiating the test.

c. Testing is being accomplished by qualified personnel in accordance with an approved test procedure.

d. Required test instrumentation is calibrated.

e. LCOs are met.

f. The test data are accurate and complete. Selected test result data was independently reviewed to verify accuracy.

g. Independently verify the system was properly returned to service.

h. Test results meet technical specification requirements and test discrepancies are rectified.

i. The surveillance test was completed at the required frequency.

The following surveillance activities were observed:

- OST 1.21.4 (-.5, -.6), Main Steam Valve Full Closure Test, June 9, 1984.
- MSP 2.05, Power Range Neutron Flux Channel N-NI43 Quality Calibration, June 13, 1984.
- OST 1.13.1, Quench Spray Pump Functional Test, June 20, 1984.
- BVT 1.1-1.2.1, Moderator Temperature Coefficient Determination, July 3, 1984.

Following difficulties encountered during the previous full closure tests of the main steam trip valves (detail 5 of NRC Inspection Report 50-334/84-12), the licensee opted to perform a retest to Technical Specification 3.7.1.5 surveillance requirements on June 9, 1984, during a weekend maintenance outage. OST 1.21.4, .5, .6, demonstrates that each valve will travel to the full closed position within five seconds from any closure actuation signal while in hot standby with T-average greater than or equal to 515 F during each reactor shutdown, if not previously tested in the past 92 days. Review of past data indicated that the valve closure time had always been close to the TS limit. During performance of the OSTs, witnessed by the inspector, all three valves exceeded the 5 second limit and were declared inoperable; the maximum time was 6.2 seconds.

Through subsequent troubleshooting, the problem with the main steam trip isolation valves was identified as coming from the time delay necessary to bleed the air cylinder pressure down through the SOV before the disc begins travel. The valve recorder trace data indicated that the time from when the disc begins travel to the time it fully closes was consistent among all three (about 2.5 seconds). To reduce the closure time from the TS threashold, two additional 3/4" ASCO SOVs were installed parallel to the existing two. The inspector attended the OSC meeting on June 10, 1984, which discussed and approved the design changes to the instrument air system. This was effective in correcting the problem, as review of subsequent valve retests under no steam flow conditions, indicated that the closure time was reduced to the range of 4.5 to 4.7 seconds. The inspector had no further concern on this item.

6. Maintenance Activities

The inspector observed portions of selected maintenance activities on safety-related systems and components to verify that those activities were being conducted in accordance with approved procedures, technical specifications and appropriate industrial codes and standards. The inspector conducted record reviews and direct observations to determine that:

- Those activities did not violate a limiting condition for operation.

- Redundant components were operable.

- Required administrative approvals and tagouts had been obtained prior to initiating work.

- Approved procedures were used or the activity was within the "skills of the trade."

- The work was performed by qualified personnel.

- The procedures used were adequate to control the activity.

- Replacement parts and materials were properly certified.

- Radiological controls were properly implemented when necessary.

- Ignition/fire prevention controls were appropriate for the activity.

- QC hold points were established where required and observed.

- Equipment was properly tested before being returned to service.

- An independent verification was conducted to verify that the equipment was properly returned to service.

Activities inspected were:

- Troubleshooting MOV-SI-864A breaker, June 7, 1984.

- Repair of Quench Spray Pump 1B breaker, June 11, 1984.

- Preventive maintenance on River Water Pump 1C Motor, June 20, 1984.

1. During performance of OST 1.11.6, ECCS Flowpath and Valve Position Check (LHSI Loop A), on June 6, 1984, MOV-SI-864A, the 1A lowhead safety injection to reactor coolant cold leg isolation valve, tripped its line starter at the motor control center when the operator went to the open position on the control switch. The breaker was reset and the valve opened satisfactorily. Recycling of the valve verified that the opening time was within specifications (140 seconds). The inspector observed subsequent troubleshooting which determined that the problem was with the line starter in the West Cable Vault Room, and not the valve motor. A loose screw was found on an overload block which was tightened and the valve retested satisfactorily.

Through discussions with cognizant licensee personnel and document review, it was determined that this particular linestarter last received preventive maintenance on July 27, 1983, per MWR 837357. This work was performed on all safety related linestarters during the third refueling outage because of 17 failures that were experienced during the previous year. From a review of the MWR data, it was apparent that most linestarters were found to have at least one loose part, including contacts, overloads, terminal blocks, contactors and leads. A review of PMP No. 1-37-Linestarter-1E, Revision 0, which the Senior Electrical Maintenance Engineer stated would form the basis for a revised program, indicated that a work frequency of 36/48 months was planned. A bases justifying this extended frequency, along with development of a formal PM schedule for safety related linestarters is Unresolved Item (84-15-02).

2. During performance of OST 1.13.2 1B Quench Spray Pump Flow Test (QS-P-1B), on June 11, 1984, the pump breaker tripped. The breaker was racked to the test position and reclosed at which time arcing was noticed. The breaker was then racked onto the bus and successfully closed for performance of the OST. After the pump was run for the required 30 minutes, breaker operability was again rechecked at which time it again tripped and was declared inoperable. Maintenance personnel troubleshooting noted a white residue and no grease on the DC contacts. The breaker was replaced with a spare and a PM was performed. The last preventive maintenance performed on QS-P-1B breaker was conducted on June 14, 1983, per PMP 1-37SS-9P5-1E. This is performed on a 24 month frequency for all GE AK-3A-25 480 volt switchgear. Discussions with cognizant licensee personnel indicated that these generic preventive maintenance procedures would be updated to also provide inspection of the DC relays.

3. The inspector determined through discussions with electrical maintenance personnel, that preventive maintenance was planned for the river water pump 1C (WR-P-1C) motor and two 4KV breakers (WR-P-1C is a "swing pump" that can be powered from either 4KV emergency bus) on June 20, 1984. After touring the Control Room, it was noted that neither the control board, control room prints, nor equipment status board indicated that WR-P-1C was out of service for maintenance. Discussions with Operations personnel indicated that they were not aware of any work in progress, only that a breaker PMP was planned for sometime later in the shift. Inspection of the pump breakers in the switchgear room found that both breakers were red danger tagged per Clearance Permit 495226. After going to the WR-P-1C cubicle in the river water intake structure, the inspector found that work to change out the motor lube oil under PMP1-75-Motor-1E, Pump Motor Inspection, Lubrication and Linestarter Inspection, had begun at 6:00 a.m., that morning. Clearance Permit 495226 specified only that preventive maintenance was planned for the breakers. The inspector could not determine whether there was a change in scope of planned activities after the clearance permit was issued, or if the problem resulted from poor communications on what activities the permit was issued for. However, the clearance points were adequate for all activities performed and no ESF train was inoperable.

Station Administrative Procedures, Chapter 4, Operations, and OM Chapter 1.48.6, Clearances, specify the rules governing control measures that must be taken to identify the clearance boundary points and scope of planned maintenance activities to ensure that (1) equipment is safe to work on for personnel safety reasons, and (2) the Nuclear Shift Supervisor is aware of the status of all systems and equipment and of all intended operations. These rules (SAP-4, VI) strictly forbid performing work on adjoining components or apparatus, unless listed on the clearance permit, nor making changes, additions, or deletions to a clearance permit after it is issued. They further require that the Control Room prints and Status Boards be updated when performing a Switching Order (a form used by the operator to direct each clearance).

Contrary to these rules, the scope of the river water pump 1C 4KV breaker work was expanded to include a motor lube oil changeout, after the issuance of Clearance Permit 495226. Additionally, the only indication available to Operations personnel in the Control Room that WR-P-1C is unavailable, was that both control switches were in the pull-to-lock position, though not tagged. This is a violation (84-15-03) of station equipment clearance procedures required by Technical Specification 6.8.1 and Regulatory Guide 1.33.

7. Containment Emergency Airlock Modification

Under 10 CFR 50.59, Changes, Tests, and Experiments, the licensee is allowed to make changes to the facility as described in the Safety Analysis Report (SAR) without prior Commission approval unless the change involved an unreviewed safety question. Specifically, it must be determined that the modification will not increase the probability of an accident previously evaluated in the SAR nor introduce the possibility of a different type than has been evaluated. The inspector reviewed the licensee's 10 CFR 50.59 evaluation performed for DCP 210, Containment Emergency Airlock, to verify that such a determination had been made.

From a walkdown of the modification, it was noted that two potential escape paths are available from containment: (1) through the original equipment hatch seal, and (2) through the new emergency airlock flange seal. Because the emergency airlock is a 5' diameter tube approximately 13' long that penetrates the containment equipment hatch, it appears that the dynamic effects of a seismic event on this member could compromise containment integrity at both of the above sealing surfaces. This was discussed with the primary sponsoring engineer who informed the inspector that this consideration had not been addressed in the original 10 CFR 50.59 review. The airlock had already been conditionally accepted during September, 1983, but is not considered operational as it is tagged out of service until a technical specification change to incorporate airlock surveillance testing requirements can be completed. The licensee contacted their architect-engineer who provided the assumptions used in analyzing the equipment hatch modification. The AE felt that the sealing capacity of the cover to barrel seals during a seismic event is adequate since the bolted gasket connection is designed in accordance with ASME III NE-3326.

As the original 10 CFR 50.59 review of DCP 210 appears inadequate, the licensee committed to performing an engineering review to verify that containment integrity is maintained at both sealing surfaces through a design based seismic event. This is Unresolved Item (84-15-04).

8. Inoffice Review of Licensee Event Reports (LERs)

The inspector reviewed LERs submitted to the NRC:RI office to verify that the details of the event were clearly reported, including the 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 follow-up. The following LERs were reviewed:

-- LER 84-04* Reactor Trip Due to Generator/Turbine Trip

-- LER 84-05 Missed Surveillances

LER 84-05 identified two missed technical specification surveillance requirements. TS 4.6.1.1.A.1, Primary Containment Integrity, requires that all penetrations not capable of being closed by an operable automatic isolation valve and are required to be closed during accident conditions, are verified to be closed by a manual valve, blank flange or deactivated automatic valve at least once per 31 days. Contrary to this, the licensee identified that the containment vacuum breaker outside isolation damper, VS-D-5-6, had not been included in OST 1.47.2, Containment Integrity Verification, which is performed to meet the 31 day surveillance requirement. At no time was VS-D-5-6 open during reactor operation in Modes 1 thru 4. OM Chapter 1.50.3, Startup Checklist B, verifies that all containment isolation penetration valves are in their normal alignment prior to leaving Mode 5. VS-D-5-6 is included in Table 47-1, referred to by Startup Checklist B. The inspector verified that VS-D-5-6 was added to OST 1.47.2 by OMCN 84-92 dated April 23, 1984.

The second item involved the failure to functionally test the manual switches used to transfer from safety injection to recirculation mode, as required by TS 4.3.2.1.1 and Table 4.3-2, during each refueling outage. The automatic transfer, triggered by a low level in the RWST, was tested per BVT 1.3-1.11.1, S.I. Auto Switchover to Recirculation Operability Test. This BVT has since been revised to perform this functional test, and is scheduled to be run during the next refueling outage. It should be noted that the operators also have the option of performing the realignment by use of individual valve controls.

Because each of the above items has minimum safety significance due to plant design features and each was identified by the licensee during a quality check of their surveillance program in accordance with NRC commitments and adequate corrective action has been taken, no violation will be issued in accordance with the guidelines of 10 CFR 2, Appendix C.

*Discussed in detail 3 of NRC Inspection Report 50-334/84-12.

9. Emergency Preparedness Drill

On June 27, 1984, DLC conducted their annual full scale EP exercise. The states of Ohio, West Virginia, and the Commonwealth of Pennsylvania participated along with all local communities within the 10 mile emergency planning zone. Their performance was evaluated by the Federal Emergency Management Agency (FEMA). The NRC observed the licensee's response both onsite and offsite. The findings of the NRC Emergency Preparedness Team are discussed in Inspection Report 50-334/84-16.

The licensee activated the new Emergency Response Facility (ERF) for the conduct of this drill. The inspectors observed licensee's actions from the Control Room and the new Technical Support Center (TSC). The licensee's transfer of functions to the new ERF facility were accomplished without any major problems. The inspectors observed that normal plant operations in the Control Room were not adversely affected by the drill. Personnel participating in the drill, both in the Control Room and TSC, conducted their actions in accordance with the BVPS Emergency Preparedness Plan and Implementing Procedures. Accurate identification of Emergency Action Levels (EALs), notification of offsite agencies, use of proper procedures, control of operations, and good communications were observed. The drill was actively observed and critiqued by the designated licensee personnel. Within the scope of this inspection, the licensee demonstrated an adequate operational capability to deal with an onsite emergency.

10. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable, items of noncompliance or deviations. Two new unresolved items were identified and are discussed in details 6 and 7. Followup on several previous unresolved items is discussed in Section 2.

11. 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.