U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report No. 79-13

Docket No. 50-334

License No. DPR66 Priority: -- Category: C

Licensee: Duquesne Light Company

Facility Name: Beaver Valley Power Station Unit 1

Inspection at: Shippingport, Pennsylvania

Inspection conducted: May 29 - June 1 and June 11-13, 1979

Inspectors: D. A. Beckman — 8-27-79
D. Beckman, Reactor Inspector — date signed

D. A. Beckman for — 8-27-79
T. McNatt, Reactor Inspector — date signed

A. P. Finkel — 8-31-79
A. Finkel, Reactor Inspector — date signed

Approved by: for H. B. Kister — 9/11/79
R. R. Keimig, Reactor Projects Section No. 1, RO&NS Branch — date signed

Inspection Summary:

Inspection on May 29 - June 1 and June 11-13, 1979 (Report No. 50-334/79-13)
Areas Inspected: Routine, unannounced inspection of licensee action on previous inspection findings, followup on an NRC Headquarters request, and followup on a licensee event. The inspection involved 69 inspector hours onsite by three regional based NRC Inspectors.
Results: Of the three areas inspected, one item of noncompliance was identified in one area (Infraction - inadequate implementation of design control measures).

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DETAILS

1. Persons Contacted

*W. Glidden, QA Engineer
*K. Grada, Nuclear Shift Supervisor
*L. Hutchinson, Station QA
*F. Lipchick, Station QA
*R. Prokopovitch, Reactor Engineer
*L. Schad
D. Schulz, Nuclear Shift Supervisor
J. Turner, Nuclear Shift Supervisor
J. Werling, Superintendent
*D. Williams, Results Engineer
*H. Williams, Chief Engineer
R. Woodling, Senior Engineer
J. Zagorski, Outage Coordinator

*Denotes those present at the exit meetings.

The inspector also interviewed other licensee and licensee contractor personnel during the inspection including members of the operations, maintenance, engineering, and general office staffs.

2. Licensee Action on Previous Inspection Findings

(Open) Unresolved Item (78-24-05): Corrective Actions for Diesel Generator Breaker Closure Failures in Manual Exercise Mode. As reported in Licensee Event Reports 78-50 and 78-51, failures of the No. 1 Diesel Generator Output Breaker to close while in the manual exercise mode have occurred on several occasions. The failures have occurred while in the manual exercise mode when the control room operator attempted to close the breaker using the bench board control switch. The failures have not been consistently repetitive or reproducible in that after an initial closure failure, subsequent attempts to close the breaker manually have been successful.

After the initial failures, the licensee performed Temporary Operating Procedure (TOP) 78-33 to demonstrate that the equipment's capability to start and sequentially load the emergency bus was not affected. The licensee maintains the position that the output breaker closure failures occur only in the manual exercise mode and the Diesel's ability to auto-load the emergency bus is not affected.

The inspector, in discussions with the licensee, determined that the problem has not been resolved and the licensee is still investigating the problem.

This matter continues to be unresolved pending further review of licensee actions.

(Open) Unresolved Item (78-24-01): No. 2 Diesel Generator Field Flash Failure. The licensee identified the field flash cut out relay (FFCO) as, a Westinghouse Type SV1 relay, which sticks intermittently as the apparent cause of these failures.

During bench testing of the FFCO replay, the licensee determined that the relay stuck intermittently in the "pick-up" position, i.e., in the conditions that inhibits application of the battery voltage to the generator field.

The licensee's Engineering Department has been requested to provide a recommended replacement for the SV1 relay. Westinghouse has issued a report on Type SV and SV-1 Relays dated October 2, 1973 (Letter #73-29) identifying failures of the SV relays to re-set when the operating signal is removed.

To assure that the SV-1 relay has reset after running the diesel generator, the licensee has designed and installed a test circuit in the diesel start circuitry to allow monitoring of the FFCO relay contact status to ensure the relay is not left in the "pick-up" position after a diesel run. To ensure that the SV-1 relay is in the proper position for automatic generator operation, Operating Surveillance Test, OST 1.36.1 (and 2) Diesel Generator No. 1 (and 2) Monthly Test, has been revised to confirm relay position.

The inspector examined the relay test circuits that were incorporated in the Diesel Generator Panels Nos. PNL-DIGEN-1 and -2 and the work package (Engineering Memorandum No. 20121) dated October 26, 1978. During the inspection the inspector was not able to determine the material used to mount the electronic parts nor whether or not the test circuit mounting had been seismically reviewed. In reviewing this work package, the inspector was informed by the licensee that the installation was a temporary modification and therefore did not receive in-depth review that a permanent design change receives under the Quality Assurance Procedure OP-4 Revision 5 dated April 29, 1977. The Onsite Safety Committee Meeting of November 9, 10, 1978 (item 51-1, EM 20121) authorized the temporary local monitoring circuit for the SV-1 relay until it is replaced.

It appears that the temporarily installed test circuit did not receive the detailed evaluation a circuit is required to undergo when interfacing with safety related equipment.

The licensee was informed that this was contrary to the requirements of Quality Assurance Procedure, OP-4, Revision 5, and Appendix B, Criterion 111 of 10 CFR 50 and is an item of noncompliance at the infraction level (334/79-13-01).

3. Followup on LER 79-05, Inadvertant Safety Injection Actuation

a. Review of Transient

The inspector conducted a detailed review of this event in response to a request for information from the Commission's Advisory Committee on Reactor Safeguards This review involved an in depth inspection of the causes of the event, actual system operation versus expected system operation, and corrective action taken to preclude recurrence. The inspector also considered the following during this review:

-- The reporting requirements of Technical Specifications and applicable Station Administrative Directives has been met.

-- Corrective action has been or is being taken and is appropriate to correct the cause of the event.

-- The event has been reviewed by the licensee as required by Technical Specifications and Station Administrative Directive No. 21.

-- The event did not involve operation of the facility in a manner which constituted an unreviewed safety question pursuant to 10CFR50.59.

-- The event was reviewed to identify generic implications or recurrence of a previous event.

-- The report was clearly and accurately prepared.

The review of this event included inspector interviews of operating personnel on shift during the occurrence, review of facility records including computer logs, main control board recorder charts, operator logs, and discussions with licensee vendors and facility management. The event was initiated by the trip of a heater drain pump on heater drain tank low level. The valid low level condition was caused by the heater drain tank high

level dump valve failing to close on demand and thereby diverting excessive drain flow directly to the condenser. The resultant low tank level caused the heater drain pump to trip as designed. The heater drain pump contributes approximately 30% of the total condensate flow to the main feed pumps' common suction line at rated conditions. Loss of this flow contribution results in a main feed pump low suction pressure alarm which, if uncorrected, will progress to a main feed pump low suction pressure trip of one or both pumps.

At approximately 2201 hours on January 18, 1979 and while at approximately 92% power, the 1B Heater Drain Pump tripped and the main feed pump low suction pressure alarm was annunciated. The BVPS Operating Manual, Chapter 24, Section P, Correcting Safety Related Alarm Conditions - Steam Generator Feed Pump Suction Pressure Low, requires reduction of turbine load if the plant is operating above 65% power. This procedure recommends that the load be reduced at a rate of 5%/minute or higher as long as steam dump operation may be avoided. Inspector review of preoperational and startup test data indicates that the plant has responded to a 20% load rejection at 200%/minute with negligible operation of the condenser steam dump valves.

Upon receipt of the above alarms, the operator began a 100 MWe load reduction to approximately 80% power at a rate of 200%/minute. This is within the designed step load rejection capability of the plant (approximately 11.7% vs. 15% Design). During this time period, control rod motion was attempting to restore/maintain T-ave to the program value and key plant parameters were stabilizing.

The rapid rate of generator load reduction appears to have resulted in a sufficient rate of change in turbine first stage (impulse) pressure to have provided an arming signal to the condenser steam dump valves. The impulse pressure channel (T-reference) is equipped with a rate sensitive anticipatory circuit which apparently provided the arming signal to the steam dump controls by sensing a rate of change in impulse pressure corresponding to a load rejection of greater than 15%. With the condenser steam dump controls armed by this signal, the first two banks of 9 dump valves (total) are available for a "modulate open" signal generated by the T-ave/T-reference error circuitry. The T-ave signal used to generate this error signal is also rate sensitive.

Available strip chart and computer data does not appear to substantiate the presence of a sufficient actual temperature error to have actuated the dump valves, but, due to the manner in which the T-ave and T-reference signals are actually displayed

and recorded for the operator as discussed below, the rate-induced error cannot be seen:

-- T-ave Displayed from the averaging circuit prior to lead/lag signal conditioning

-- T-ref The actual controlling channel is not recorder displayed although an identically conditioned channel is. The display includes a 1.8 second lag function but is further conditioned by a 12 second lag after the recorder but before the controller output, effectively desensitizing the signal for rate changes.

The maximum displayed temperature mismatch between T-ave and T-ref appears to be approximately 1° F which is within the 5° deadband of the steam dump controller. Based on the above discussion, the steam dump control signal was apparently affected by the undisplayed rate of T-ave change resulting in actuation of the steam dump valves. Sequence of events computer data, recorder charts, and operator interviews indicate the following:

-- The steam dump valves appear to have operated through one complete cycle followed by a second cycle about 15 seconds later. Both cycles occurred after the initial step change load decrease had been completed and power levelled at approximately 81% for two to four minutes.

-- On the second cycle, the steam dump valves remained open until or after the time of the trip.

-- Non-annunciated steam dump valve status light indications in the control room were not specifically observed by the operator. Direct records of steam dump valve position are not otherwise available.

-- The steam dump valve actuation appears to have resulted in an increase in steam flow of about 1.96 million lbm/hr (about 22% increase over the post load reject steam flow) which is sufficient to cause a high steam flow signal input to the ECCS trip logic.

-- Apparent steam dump flow is equivalent to approximately 17% of total steam dump capacity. Based upon a controller gain of 5% valve opening/°F error, the rate adjusted error signal appears, by calculation, to have been equivalent to an 8.5°F T-ave/T-ref mismatch.

Control Room data indicates an approximate 2-4 minute lag between completion of the load reduction and the first indication of steam dump actuation (via steam flow indication). Steam dump control circuit response characteristics and indicated plant parameters do not account for this lag. It appears that the rod control circuitry features or mechanical and environmental problems with the steam dump controllers may have resulted in this lag.

The rod control circuitry appears to have responded to the initial decrease in steam demand as expected. As the initial nuclear power/steam power mismatch was reduced, the rate sensitive power mismatch anticipatory circuits may have provided a signal which overrode a developing T-ave error signal, allowing actual T-ave to increase without correspondent rod motion. This phenomenon has been previously observed at this facility. If actual T-ave increased at a sufficient rate, steam dump actuation could have been demanded. The circuit time constants, however, do not appear to be large enough to allow this to occur over the 2-4 minute lag time evident from the recorder data.

Another potential cause of the lag is a delayed steam dump actuation caused by failed capacitors in the control circuits or the below freezing temperatures in the turbine building at the time of the trip. Failed capacitors were replaced during subsequent maintenance on the system. The below freezing temperatures, to be discussed below, may have resulted in delayed actuation but a specific failure mechanism has not been identified.

Steam dump actuation, as previously indicated, provided steam flows high enough to satisfy the high steam flow portion of the safety injection and Containment Isolation-Phase A logic. Safety injection and the Containment Isolation-Phase A were initiated by the momentary receipt of the Channel B and C low steam line pressure signals, also a result of steam dump actuation. This signal was present for approximately 20 milliseconds (as determined from computer sequence of events data) which was sufficient to result in a latched-in trip signal.

Although recorder chart data shows that indicated steam line pressure did not reach the actuation setpoint pressure, this circuit also includes a rate sensitive anticipatory signal which provided an equivalent signal on the step change decrease in pressure. Pressure appears to have decreased in this step change from 840 psig to 800 psig resulting in a rate adjusted signal of less than the 500 psig setpoint.

Available data indicates that ECCS and containment isolation equipment functioned properly. The sequence of events computer

printout confirms operation of all ECCS pumps, select Containment Isolation-Phase A signals, select ECCS valve alignment shifts, and Feedwater System isolation. Log reviews indicate that the Emergency Diesel Generators started as required.

Main steam line (MSL) isolation, however, did not occur. The MSL isolation signal is generated by the same "high steam flow coincident with low steam pressure" signal which initiated the reactor trip and safety injection. As previously noted, this signal was present for only 20 milliseconds.

The MSL trip valves are held in the open position by instrument air via normally deenergized solenoid trip valves. On an MSL isolation signal, the solenoids energize to vent the instrument air pressure, allowing the swing gate of the trip valves to drop shut assisted by steam flow. Recent experience at the plant and discussion with the licensee's contractors indicates that the isolation signal, which does not latch in, must be present for on the order of 200-500 milliseconds. This provides sufficient time for venting air from the operator to allow the valve to droop approximately 5° into the flow stream where steam flow will complete valve closure even if the air operator is repressurized by loss of the isolation signal. The FSAR, Section 14.2.5.1.1, stipulates that the MSL trip valve actuation equipment provides MSL break protection by valve closure within the first five seconds of an actual line break (for which a continuous signal should be present).

Following the reactor trip and safety injection (SI), the operators appear to have responded properly. Immediately following the trip the operators manually shut the MSL trip valves based on failure of the valves to automatically close and the as yet unknown cause of the momentary high steam flows. This action isolated the steam dump valves,placing secondary plant pressure control on the steam generator pilot operated atmospheric relief valves.

The SI and Containment Isolation-Phase A signals were reset at approximately 3 minutes after the reactor trip. Low Head Safety Injection Pumps were also secured at this time. The operators secured one High Head Safety Injection Pump (of the two operating) and one Motor Driven Auxiliary Feedwater Pump (of the two operating) at 5-7 minutes after the trip as pressurizer pressure and level and steam generator levels had recovered from the trip. The HHSI pump above appears to have been secured as pressure neared the Pressurizer Power Operated Relief Valve setpoint of 2235 psig. Pressurizer Relief Tank level data indicates that the valve(s) may have lifted, relieving approximately 200 gallons to the PRT at about the same time the HHSI pump was secured. There is no indication of PORV malfunction and the valve(s) apparently

reseated properly. Pressurizer water level and pressure were subsequently maintained in their respective scale midranges. The maximum pressurizer pressure recorded by the computer was 2317 psig.

At approximately 10 minutes post-trip, Reactor Coolant System temperatures and Steam Generator pressures were increasing due, in part, to Reactor Coolant Pump heat input. The 1B Reactor Coolant Pump was secured at this time to minimize plant heatup, actually resulting in a slight cooldown and temperature stabilization. One to two minute intermittent actuations of the steam atmospheric relief valves appear to have occurred during the time of peak RCS temperatures and SG pressures. During the hour following the trip, the plant systems appear to have been returned to a normal Hot Standby lineup with no apparent abnormalities or malfunctions.

The licensee has attributed the apparent malfunction or sluggishness of the steam dump valves to a combination of high moisture content in the instrument air used to operate the valves and below freezing temperatures existing in the turbine building at the time of the vent. The turbine building ventilation system utilizes a large bank of dampers to privide fresh air supply to the building. These dampers, making up a large portion of the turbine building wall approximately 20 feet from the steam dump pneumatic equipment, are individually opened as individual building exhaust fans are started. A number of exhaust fans were in operation at the time of the event, resulting in a number of dampers being open and introducing subfreezing outside air directly to the steam dump pneumatics.

Subsequent to this event, disassembly and inspection of the Instrument/Pneumatic (I/P) Converters for the dump valves revealed a high moisture content which could have affected the operation of the units due to ice buildup, causing the valves to remain open longer or open further than desired. Subsequent to this and another trip on February 5, 1979, additional troubleshooting was conducted on the entire steam dump control system. Problems resulting in repair or replacement were found in air regulators and filters on the I/P converters, a bellows assembly in one dump valve operator, a diaphragm on a second dump valve operator, and direct current electrolytic capacitors in several of the associated electronics modules. Several of the above individual problems could have, of themselves, caused the dumps to react sluggishly. Since the dates of the above trips, the licensee has attempted to improve the normal response time of the steam dump control circuit by increasing the gain of the temperature error controller by approximately 33% from 5%/°F to approximately 7%/°F.

A complete overhaul and recalibration of the steam dump controller was accomplished during the current outage. Additionally administrative controls have been imposed to ensure that the turbine building equipment is not unduly exposed to harsh environmental conditions by administratively controlling ventilation system operation through the safety tagging system and providing a locked control enclosure for TG building fans.

Inspector review of the available transient data was unable to establish the presence of a specific steam dump valve or controller malfunction or failure mode. This is due, in part, to the lack of reliable data on steam dump controller input and output signals during the event and the lack of clarity of strip chart data which would indicate such a malfunction.

The instrument and control air supply quality appears to be a significant contributor to the event. Instrument and control air for the station, except containment, is provided from the station service air system via an absorber tower dryer and separate air receiver. The station has experienced a history of air system problems including water and particulate contamination of the instrument air supply, system capacity problems due to compressor outages, and routine system/equipment malfunctions affecting system reliability. None of the station's air systems are required for Engineered Safety Features actuation or safe shutdown.

The instrument air dryer is of the twin tower absorber type which results in one absorber tower being on-line for air drying while the other is being regenerated by electrical resistance heaters. Various dryer malfunctions including heater failures have resulted in considerable dryer outage time which has contributed to the moisture related air system problems. New type dryers have been installed and are in the process of being evaluated.

Over the last 1-2 years the station has utilized a portable compressor located on the turbine deck to provide backup capability for compressor outages. This unit was piped into the service air supply header. A new, permanent third compressor is in the process of installation to eliminate the need for the temporary connection.

This event was initiated by a malfunction of the heater drain tank high level dump valve. The licensee has established that the actuator for this valve is undersized for its application and is unable to reliably close the valve at high flows and differential pressures. In order to prevent undesirable transients until permanent corrective action is taken, the licensee has disabled the controller for this valve and now requires operator action to correct heater drain tank high level conditions. This appears to

provide sufficient time for operator action to correct the malfunction prior to its effect reaching the NSSS. A new actuator is being sought for installation during the upcoming refueling outage. The licensee has additionally limited operating power levels to values low enough to permit avoidance of a plant trip or ECSS actuation which might be caused by feedwater system upsets. The corrective action taken and planned by the licensee will be followed during future inspections.

b. Findings

No items of noncompliance were identified. Except as noted below, the inspector had no further questions.

(1) Inspector review of BVPS Operating Manual Chapter 24, Section 1.24.P, Correcting Safety Related Alarm Conditions - Steam Generator Feed Pump Suction Pressure Low Alarm, resulted in the following inspector comments:

-- The procedure, as written, is potentially misleading to the operator. The procedure does not reflect the rate sensitivity of the steam dump controller's response to load rejection transients. This may have contributed to the above event in that the procedure only specifies a T-average deviation of greater than 5°F as a criteria for steam dump actuation. The maximum deviation indicated to the operator was approximately 1°F.

-- The procedure does not directly specify a rate or magnitude of load reduction to be implemented by the plant operator. In conjunction with the comment above, this can result in a too small or too large a load reduction to adequately respond to the alarm condition.

-- The procedure provides no criteria for terminating plant operation by a reactor trip should alarm response corrective actions be ineffective. Plant experience appears to indicate that a loss of Steam Generator Feedwater Pump(s) condition can quickly proceed to the actuation of automatic plant trips and safety injections. Operator action should be incorporated into the procedure which will preclude unncessary challenges to the ESF systems due to such secondary plant upsets.

The licensee informed the inspector that the above comments would be reviewed and that appropriate procedure revisions would be implemented prior to startup from the current outage. This matter will be unresolved pending completion of this licensee action and review of the procedure revisions by NRC:RI (79-13-02)

(2) During review of control room recorder strip charts associated with this event, the inspector noted that several problems with data recording contributed to complexity of event analysis. These included:

-- Periodic annotation of time and date on individual strip charts was not consistently accomplished making it difficult to clearly identify the time of a recorded event.

-- Recorder pens frequently failed to ink properly on charts resulting in data being either illegible or unrecorded.

-- Specific transient pen indications were not annotated as to their cause, resulting in apparently aberrant indications being unexplainable. In several cases the aberrant indications could be attributed to routine instrument channel changes, etc.

-- The licensee has encountered problems in procuring chart paper which is printed with the specific, custom made scales for certain recorders. While generically scaled (0-100%, etc.) paper can be interpreted from available scaling factors when used on the subject recorder, charts using such generic paper were not consistently identified as requiring referral to correct scales.

The BVPS Operating Manual, Chapter 48 provides recommended practices for the above problems but implementation of these guidelines is not consistent. The licensee acknowledged the inspector's comments and stated that these items would be addressed prior to startup from the current outage to ensure that the chart records will be properly maintained. This item will remain unresolved pending NRC:RI review of the licensee's actions. (79-13-03)

4. Review of Seismic Piping Supports

During the late construction phase of the facility, piping supports associated with the main steam lines were temporarily removed to

allow installation of pipe whip restraints. In response to a request from NRC headquarters, the inspectors reviewed the status of selected supports which were disturbed to accomplish that work. Pipe snubbers H206 and H208 were apparently removed to support the installation above. The inspectors reviewed Isometric Drawings Numbers 11700-6.24.1, Sheet 1, Revision 1, dated February 17, 1970 and 11700-6.24.2, Sheet 1, Revision A, dated February 18, 1970 in order to determine the location of these snubbers. The revision history of the subject drawings were also reviewed as were records of surveillance testing in accordance with the facilitity's Technical Specifications. The inspectors determined that the H207 and H208 snubbers had apparently been reinstalled at their original locations following installation of pipe whip restraints and that the snubbers are being tested under the licensee's surveillance program. The facility has recently completed a reanalysis of safety related piping as a result of the NRC Show Cause Order issued on March 13, 1979. This reanalysis included the main steam lines and specifically the 32 inch main steam line of interest (line number SHP-57-601-02).

The inspectors were further requested to determine whether restraints numbered H107 and H108 were associated with the main steam lines in the area affected by the construction work above and whether they had been involved in the work required to install the pipe whip restraints. The inspectors confirmed that these supports are not associated with the main steam in the areas of interest and are not included on the isometric drawings for those areas. The inspectors were unable to determine whether restraints with the designations H107 and H108 may be associated with other, non-safety related balance of plant piping in the main steam system.

No items of noncompliance were identified.

5. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable, items of noncompliance or deviations. Unresolved items addressed during this inspection are discussed in paragraphs 2 and 3 of this report.

6. Exit Interview

Meetings with facility management were conducted during the morning and afternoon of June 13, 1979. Attendees are denoted in paragraph 1. The inspectors presented the scope and findings of this inspection as discussed in this report.