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

REGION III

Report No. 50-346/78-30

Docket No. 50-346 License No. NPF-3

Licensee: Toledo Edison Company
Edison Plaza
300 Madison Avenue
Toledo, OH 43652

Facility Name: Davis-Besse Nuclear Power Station, Unit 1

Inspection At: Davis-Besse Site, Oak Harbor, OH

Inspection Conducted: October 31 - November 2, December 20-22, 1978, and January 12-15, 1979

Inspectors: J. S. Creswell (above dates) 1/31/79

J. F. Streeter (December 21-22, 1978) 2/5/79

J. D. Smith (January 12-15, 1979) 2/5/79

Approved By: J. F. Streeter, Chief 1/31/79
Nuclear Support Section 1

Inspection Summary

Inspection on October 31 - November 2, December 20-22, 1978, and January 12-15, 1979 (Report No. 50-346/78-30)

Areas Inspected: Routine, unannounced inspection of power ascension testing and unresolved items. The inspection involved 101 inspector-hours onsite by three NRC inspectors.

Results: No items of noncompliance were identified.

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DETAILS

1. Persons Contacted

*T. Murray, Station Superintendent
*C. Domeck, Project Engineer
*B. Beyer, Assistant Superintendent
*S. Quennos, Technical Engineer
*D. Lee, Test Program Manager
F. Miller, Power Engineering Engineer
*W. Green, Administrative Assistant

The inspector also interviewed other licensee employees, including members of the technical and operations staff.

*Denotes those attending the exit interviews.

2. Licensee Actions on Previous Inspection Findings

(Open) Unresolved Item (346/78-12), IE Inspection Report No. 50-346/78-27 - During the exit interview on November 2, 1978, the inspector again requested to review the licensee's evaluation concerning high pressure injection (HPI) delay which would demonstrate the HPI flow experienced during the September 24, 1977, event was conservative when compared to accident analysis assumptions. The inspector was informed that the analysis was not available for review. During the entrance interview on December 20, 1978, the inspector again requested the analysis and again it was not available for review. During the exit interview on December 22, 1978, the inspector informed the licensee that, prior to returning to power operation, the licensee should assure that the flow delay did not indicate the HPI system was inoperable. The inspector reiterated that the licensee's evaluation should address a comparison of flow versus RCS pressure as assumed in the small break analysis versus the flow versus RCS pressure experienced during the event. The Plant Superintendent stated that Power Engineering personnel had made this comparison. During the January 12-14, 1979, inspection, the inspector received the analysis and informed the licensee that the report would be reviewed in the office.

(Open) Unresolved Item (346/78-13), IE Inspection Report No. 50-346/78-27 - During the October 31 - November 2, 1978, inspection, the inspector was given a copy of BWT-1707 which addressed the effect the net makeup flow on pressurizer level analysis for the November 27, 1977, event. The report was then examined in the Region III office. During the inoffice review the inspector also received a copy of BWT-1698 dated September 1, 1978, which the project inspector had received from the licensee. This report was entitled, "Pressurizer Performance During Reactor Trips." BWT-1698 concluded that if main steam pressure was maintained above 980 psig the pressurizer would not void under full power conditions with or without reactor coolant pumps running. During subsequent telephone conversations the licensee was again asked if there were any conditions under which the pressurizer could void. The licensee stated that he had an analysis which indicated that following a reactor trip from 15% power with six feet of auxiliary feedwater in the steam generators and with the reactor coolant pumps continuing to run, the pressurizer would be nearing the voiding condition. In addition, the licensee stated that with the RCPs running and auxiliary feedwater at five feet in the steam generators following a reactor trip from 100% power, near voiding of the pressurizer would result. (Note: The auxiliary feedwater level is automatically controlled at ten feet to conform to small break analysis assumptions).

Since this information indicated a potential unreviewed safety question, the licensee was requested to further analyze the consequences of pressurizer voiding. The analysis was provided to the inspectors on site on December 22, 1978. This information was simultaneously conveyed to Region III and NRR. A subsequent telephone conversation resulted on December 23, 1978, between the licensee, IE, and NRR and is discussed in paragraph 4. NRR concluded at that time that an unreviewed safety question did not exist.

This item remains unresolved pending RIII review of additional information to be submitted by the licensee to NRR in mid February 1979.

(Open) Unresolved Item (346/78-14), IE Inspection Report No. 50-346/78-27 - During the inspection on October 31 - November 2, 1978, the inspector requested to review procedure revisions associated with operator actions subsequent to a LOCA as addressed during a previous inspection.[1/] The inspector was informed these revisions were in process and were not available for review since they were not approved by the Safety Review Board. During the December 20-22, 1978, inspection, those procedures were reviewed by the inspectors. Emergency Procedure EP 1202.06, "Loss of Reactor Coolant and Reactor Coolant Pressure," was noted to contain as an immediate operator action the requirement (Section 2.3.6) that when RCS pressure falls below 1600 psig, verify that SFAS levels 1 and 2 are actuated and then "Block" and reopen the RC Normal Makeup Isolation Valve, MU 33, if available. The inspectors

1/ IE Inspection Report No. 50-346/78-27.

noted that the Technical Specifications require automatic closing of valve MU 33 on SFAS Incident Level 2 and that opening the valve manually prior to incident level 3 would be contrary to Technical Specifications. The Plant Superintendent could not recall the reason for opening the valve but was certain that the makeup pumps were not required to satisfy emergency core cooling needs for a LOCA. A representative from Power Engineering referred to a possible need for makeup flow to increase pressurizer level after SFAS initiation. When asked why MU 33 and the seal injection valves were not analyzed in the FSAR to remain open on SFAS incident level 2 instead of level 3, the representative stated it was an error. The licensee was informed that if the subject valves were to be opened at SFAS level 2, a Technical Specification change would be required to support that mode of operation.

The inspectors also reviewed the subject procedure for instructions to the operators in light of the September 24, 1977 event. During the review it was determined that if a break occurred upstream of the power operated relief valve or safety valves an immediate indication of the leak would not be sensed by temperature elements or level instruments on the pressurizer quench tank. Because of the time delay in identifying the leak, immediate operator actions regarding stopping of the high pressure injection pumps when pressurizer level is "re-established" are negated. The licensee will review this item further and the issue will be addressed during a future inspection.

During the inoffice review of System Procedure SP 1104.07, "High Pressure Injection System Procedure," the inspector noted the following statement: "As RCS pressure drops, HPI flow will increase. As the flow increases to 450 gpm per line, the HPI high flow alarms will occur. (See Attachment 6). Here it becomes necessary for the Control Room Operator to block the SFAS signal and throttle the discharge of the HPI pumps using the motor operated globe valves HP2A and HP2B (HP2C and HP2D) until flow through each HPI line is restored to 450 gpm (see AP 3003.41). This process of throttling will have to be repeated for the entire time the HPI pumps continue to run. The HPI pumps should be throttled only enough to limit each pump to 900 gpm."

Since this statement indicated operator action was required during a LOCA and pump(s) runout might occur and damage the pump(s), the matter was discussed with the Chief, Nuclear Support Section 1, Region III. Subsequent telephone discussions between the licensee and the Chief, Nuclear Support Section 1, on January 10-12, 1979, resulted in the determination that the reactor vendor had reviewed the matter and that operator action was not required to prevent HPI pump runout during a LOCA. During the January 12-14, 1979, inspection, the inspector noted that a temporary modification regarding the removal of the procedure requirement had been issued. The inspector has no further questions about this matter at this time.

(Open) Noncompliance (346/78-15), IE Inspection Report No. 50-346/78-17, Infraction 2.c - The inspector reviewed the September 22, 1978, CNRB minutes which addressed the following test results:

ST 5013.02 - Control Rod Assembly Insertion Time Test
ST 5013.03 - Post Refueling Physics Testing
TP 800.01 - Shield Survey
TP 800.03 - Site and Station Radiation Survey
TP 800.11 - Core Power Distribution Test
TP 800.05 - Reactivity Coefficients at Power
TP 800.18 - Power Imbalance Detector Correlation
TP 800.24 - Incore Detector Testing
TP 200.11 - Reactor Coolant Pump Flow Test
TP 800.22 - NSSS Heat Balance
TP 800.20 - Rod Reactivity Worth
TP 800.29 - Dropped Control Rod Test
TP 800.31 - Vibration and Loose Parts Monitoring
TP 800.12 - Unit Load Steady State Test
TP 800.14 - Turbine/Reactor Trip Test

The minutes note that further results would be reviewed upon completion of 100% testing. The inspector also noted the following comments:

RE: TP 800.18 - The calibration would be redone after operating at 100% power.

RE: TP 200.11 - Results will again be checked at 100% power.

RE: TP 800.20 - The CNRB requested that Power Engineering review the "agree favorably" aspect of the procedure and report back to the CNRB only if a problem arises.

RE: TP 800.29 - TECo has stated that the calculations performed by the on-line computer are adequate and that there is sufficient overall conservatism in the calculation.

RE: TP 800.31 and TP 800.12 - Deficiencies noted.

RE: TP 800.14 - Reactor has tripped twice during testing - ICS will require additional tuning.

The inspector will review further actions taken in regard to comments noted and subsequent reviews during future inspections.

(Open) Noncompliance (346/78-16), IE Inspection Report No. 50-346/78-27, Infraction 2.b - During the inspection on October 31 - November 2, 1978, the inspector examined the licensee's corrective action associated with commitments and found the corrective action to be unacceptable. This information was conveyed to the licensee during the exit interview. During the inspection on December 20-22, 1978, the inspector noted that the corrective action was again not taken and told the licensee that if the corrective actions were not implemented, further enforcement action would be considered.

During the January 13-15, 1979, inspection the inspector noted that improved criteria for determining incore detector failure had been implemented by temporary procedure change but that administrative controls to provide guidance to assure that conservative values for failed incore detectors in high power assemblies or other critical assemblies used for test data was not fully implemented. The inspector discussed the matter with the project inspector and they concluded that acceptable corrective action would be for the licensee to include a statement in procedure ST 5033.01, "Incore Detector Surveillance," to the effect that a previous history of detector performance was developed and conservative correlations made based upon conservative predicted detector performance. The project inspector has informed the licensee of this requirement and a commitment has been obtained.

3. Review of 75% Turbine Trip Data

During the review of test data associated with this test the inspector noted data had been taken concerning relief valve operation on one of the steam generators during the testing. He further noted that some of the safety valves had lifted out of sequence. This information was discussed with the licensee and communicated to the project inspector for resolution. The inspector noted that the same computer alarm was experienced during the transfer of power to offsite power as an alarm experienced during "throwover" testing performed in December of 1977 when a subsequent drop of two safety groups of control rods[2/] into the core resulted. The licensee could not explain

2/ IE Inspection Report No. 50-346/78-06.

the cause of the alarm but it appears to the inspector that some sort of disturbance caused by the electrical transfers is affecting the rod control system. Since conformance with General Design Criterion 17 has forced operation on the startup transformers at all times, transfers from the auxiliary transformers to the startup transformers will not occur. However, future operation on the auxiliary transformer should necessitate a further review of the matter to determine if the electrical transfers will cause dropped rod conditions which are contrary to the Technical Specifications. The inspector has no further questions about this matter at this time.

4. Review of Loss of Offsite Power Test Commitments

The inspector gave the licensee procedure comments related to commitments[3/] that had been made concerning the conduct of the loss of offsite power test. Acceptance criteria for the test were requested as soon as they were ready. During subsequent telephone conversations, the licensee stated that the operators would be given detailed instructions as to when to intervene and assume control of equipment if hazardous conditions developed.

On December 11, 1978, the licensee submitted an analysis to NRR regarding continued operation with dual level setpoint control of the steam generators. The request was based on maintaining pressurizer level indication during transients to satisfy General Design Criterion 13. During a subsequent telephone conversation on December 23, 1978, NRR stated that the licensee's administrative control of auxiliary feedwater level at 35 inches was acceptable. However, a request was made that TECo and B&W give a rationale why a revised break analysis was not required to be documented to remain in compliance with 10 CFR 50.46(k). On December 28, 1978, the licensee informed NRR[4/] of a commitment to provide a detailed engineering design of auxiliary feedwater level control changes by February 21, 1978. This memo did not address the determination that a small scale break reanalysis was not required. The licensee has informed NRR he will address this matter by mid February 1979 This matter is an Unresolved Item (346/78-30-01) pending further review of the licensee's determination.

5. Review of Natural Circulation Test

During the inspection on October 31 - November 2, 1978, the licensee was preparing for the natural circulation test. A difficulty was being experienced with high oxygen levels in the condensate storage

3/ Memo, Roe to Stolz, dated August 23, 1978.
4/ Memo, Roe to R. Reid, dated December 28, 1978.

tank which would result in exceeding chemistry limits for the steam generators if the auxiliary feed pumps injected condensate storage tank water into the steam generators. The licensee proposed using a supply of water from the deareator in lieu of the condensate storage tank. The inspector requested guidance from Region III regarding the acceptability of this method. The region stated that this was acceptable providing that the licensee perform certain surveillance testing on the alternate service water system supply. During the licensee's process of performing this testing, it was discovered that the auxiliary feed pump turbine (AFPT) steam generator level control system and the AFPT speed switch and pressure interlocks were not being tested as required by the Technical Specifications.5/

While reviewing the natural circulation test data during the subsequent inspection, the inspector noted that the primary coolant flow versus steam generator level relationship was essentially constant for the 65-inch and 35-inch levels. It appears the flow should have increased with level since higher heat transfer would be expected to produce more natural circulation flow. This matter is an Unresolved Item (346/78-30-02) and will be reviewed further in a future inspection.

While reviewing the chronological log associated with the natural circulation test the inspector noticed the following entry at 0256 hours on November 4, 1978:

> Aux Blr Tripped (-) low voltage on essential bus due to RCP start (-) EDG started.

Further investigation and discussions with the Plant Superintendent revealed that, during reactor coolant pump and circulating water pump starts, undervoltage relays are disabled to prevent the tripping of essential buses. The Plant Superintendent stated that during the November 4, 1978, event the wrong relays were disabled and when the reactor coolant pump was started the voltage drop caused the tripping of the essential bus associated with the power supply to that pump. This resulted in the start of the diesel generator to supply essential bus power. The inspectors informed the licensee that bypassing of the undervoltage protection was contrary to the Technical Specifications when the plant is in Modes 1 through 4. The licensee agreed to cease bypassing the undervoltage protection until he requested and was issued a technical specification change to allow the bypassing. The licensee agreed to expeditiously pursue his request for a technical specification change.

5/ LER No. NP-33-78-126.

As an interim measure, the licensee proposed to voluntarily enter Technical Specification Action Statement 4.8.2.1 and supply both 4160 VAC essential buses from the same 13.8 KV to 4.16 KV bus tie transformer when starting a RCP or CWP on the other 13.8 KV bus when in Modes 1 through 4. The Chief, Nuclear Support Section 1, stated that was an acceptable interim measure providing the licensee expeditiously pursued the Technical Specification change mentioned above.

This is an Unresolved Item (346/78-30-03) pending further review by RIII.

6. Minimum Temperature for Starting Reactor Coolant Pumps

The inspectors reviewed the licensee's temperature restrictions on starting the fourth reactor coolant pump. The licensee's RCP starting procedure is based upon a Babcock and Wilcox recommendation that the fourth RCP not be started below 500° F to avoid potential core lifting at the lower RCS densities. The licensee has installed an electrical interlock to prohibit starting the fourth RCP below 500° F.

The licensee stated that this issue was generic to all B&W plants. The inspectors stated that they would review this matter further to determine if it had been generically dispositioned by NRR. However, the inspectors stated that even if it has been generically dispositioned by NRR, it is not clear if the potential for core lifting (1) was reviewed in light of the burnable poison rod assembly removal last summer or, (2) is consistent with an FSAR statement in Section 4.4.2.7 that a net downward holddown force exist during normal plant operations. The licensee stated he would provide information to clarify these two issues by February 1, 1979.

This is an Unresolved Item (346/78-30-04) pending the licensee providing the above mentioned information and further review by RIII.

7. Load Rejection Testing

The inspectors witnessed the 100% load rejection test on January 13, 1979. Preliminary evaluation indicates the test was successful. Final acceptance of the test by RIII will be contingent on a final evaluation.

Onsite power during the test was supplied from Startup Transformer 01. Power Engineering requested data on bus voltages during the test. The inspectors noted that essential bus voltages prior to

...ts. During the test it was
...curred on buses C1 and D1.
... bus voltages before and after the test.
...e reviewed in a subsequent inspection.

...d that since the onsite power supply was not
...e auxiliary transformer, the capability to runback
...-generator and reactor to supply onsite power has not
...ven and further testing may be required to demonstrate
...rmance to FSAR commitments.

Shutdown Outside of Control Room Testing

On January 14, 1979, the licensee performed the subject test. During the test the following information was conveyed by control room personnel to the personnel outside the control room:

a. Makeup tank level
b. Instructions to shut off a makeup pump
c. Tave

During the initial phase of the test, pressure control on the secondary side was by activation of the safety-relief valves. Since operation on the safety valves resulted in a decrease in Tave, an operator was dispatched to manually control the atmospheric dump valves.

The response to question 7.4.2 of the FSAR states in part (e):

The integrated control system will maintain hot shutdown condition steam pressure and temperature by modulating the quantities of steam passing through the condenser, via the turbine bypass valves.

The above referenced actions appear to be contrary to the safety analysis response. However, if emergency procedures are modified to include the actions taken there appears to be no impact on the acceptability of the test.

The reason for monitoring makeup tank level from the control room is that it is not available at the auxiliary shutdown panel. An early action required is to switch suction for the makeup pumps from the makeup tank to the borated water storage tank. In addition, if letdown flow to the makeup tank is not isolated with the tank discharge isolated the tank will fill and relieve to the reactor coolant drain tank.

Based on the requirement tha the reactor can be shutdown and maintained in hot standby outside the control room and that there was communication from the control room regarding the makeup tank level the test results were unacceptable. Further review by the Project Inspector is proceeding to determine if the test is acceptable. Computer logs and data associated with the test are under further review.

9. Loss of Offsit Power Test

The inspectors witnessed the loss of offsite power test on January 15, 1979. After the first 15 minutes of the test, the inspector was approached by the test engineer and Plant Superintendent concerning the performance of the second 15-minute phase of the test. They stated they did not want to transfer to the second diesel because of interruption of seal flow to the reactor coolant pumps and that anticipated high control rod drive stator temperatures were not occurring. The inspector pointed out that the procedure addressed certain commitments made by the licensee and that their concerns for the RCP seals were considered in the development of the commitments. The inspector stated that the decision to depart from the procedure should be based on the safe operation of the plant. The procedure was then performed as written.

While synchronizing the second diesel in the asynchronous mode, a low frequency alarm occurred. Since the diesel generator would synchronize on a "dead" bus normally and a subsequent synchronous transfer did occur, there was no effect on the results of the test. The subsequent transfer occurred when the operator started a RCP during test recovery and the voltage dip caused undervoltage relays to trip the essential bus. The associated diesel did start and power the essential bus.

Based on a preliminary re iew, the test was successful but final acceptance of the test will be contingent on a final evaluation.

While reviewing the latest revision to the test procedure, the inspector noticed that provisions had been made to supplant the essential air supply with a diesel powered compressor. Because of weather conditions, the compressor would not start. Since the licensee evidenced concern about the essential air supply, the inspector requested him to formalize an action point at which the test would be terminated and recovery initiated. This was done by means of a temporary procedure change. Minimum air pressure experienced during the test was 83 psi which was above the action point. The sizing of the essential air compressor appears to be marginal.

10. Review of January 12, 1979, Event Regarding Loss of 120 VAC Essential Bus Y2

The following information was obtained from the Plant Superintendent on January 13, 1979:

While performing surveillance testing on a hydrogen analyzer a ground strap shorted out input terminals on a module. This action resulted in the tripping of inverter YV2 and the loss of power on bus Y2. Reactor Protection System Channel 3 was being tested and was bypassed because of surveillance testing. A reactor trip occurred on Flux/Delta Flux/Flow because with RPS Channel 3 bypassed and Channel 2 losing power the following events occurred:

a. An ICS flow signal was lost.

b. With 1 RPS channel in bypass the ICS received an auctioned power signal from the combination of flux 1 + flux 3 or flux 2 and flux 4.

c. With flux 3 bypassed the ICS automatically selected flux 2 and flux 4.

d. Since flux 2 was input as zero the sum of the fluxes (power) was 0% + 100% which was 50% power.

e. The ICS then initiated a signal to the rod control system to pull rods.

f. The ICS which had experienced a loss of flow signal also initiated a signal to the rod control system to runback power. (Three of four flow inputs to the RPS were "good").

g. The resulting action from items e and f was that rods were withdrawn and power increased.

h. Maximum power read from the reactimeter at the time of the trip was 103%. (Note: This data is sampled every three seconds and is a product of the average power times 2). The Plant Superintendent did not know what the maximum power was from the control room strip charts.

i. Delta flux during the event was approximately -2 to -3%.

j. An SFRCS trip occurred approximately one minute after the reactor trip.

k. The loss of flow signal to the ICS caused excessive BTU limits on both steam generators. This resulted in low steam generator level actuation of the SFRCS system.

l. Power was restored to Y2 bus by manual transfer to power supply YBR.

m. Recovery and stabilization were initiated.

n. A maintenance work order was issued and implemented to replace blown fuses in inverter YV2.

During the event there was a loss of control room indication from instruments supplied by the Y2 bus.

The Plant Superintendent stated the Technical Section was writing a report regarding the event. The inspector requested that the following information be addressed in the report:

a. Did the steam generators go "dry" per the vendor's criteria of nine inches?

b. What control room indications were lost during the event?

c. What was the minimum steam generator pressure?

The Plant Superintendent stated there were no problems with thermal stresses in the primary system.

The project inspector will review this event further. This is an Unresolved Item (346/78-30-05) pending his review.

11. <u>Event Regarding Flow From BWST to Emergency Sump on January 5, 1979</u>

During the inspection the inspector talked to an operator who had recently conducted a walk-through of the containment. The operator commented there was a lot of water in the containment. The operator stated that the water resulted from surveillance testing being conducted on January 5, 1979, on the SFAS channels associated with BWST level instrumentation. There was a faulty relay in one of the channels and when testing was performed on the complimentary channel, the 2 out of 4 logic circuitry tripped which resulted in valve DH9 opening and the closing of DH7 valve. This resulted in a direct flow path from the BWST to the emergency sump allowing some 6300 gallons of borated water to flow into the sump. During the event the operator noticed a red light on the emergency sump and blocked the SFAS and closed DH9.

The operator stated that the water splashed upward about 30 feet but that it did not affect safety-related equipment. He also stated that borated water storage tank levels as required by the Technical Specifications were maintained. Because of high airborne activity levels in containment, full face respirators were required for the walk-through.

During the walk-through the operator measured RCP seal leakage and noted leakage from the incore detector penetrations. He also noted that the pressurizer relief and safety valves were leaking but that the leakage was within specified limits.

The project inspector will review this event further and this is an Unresolved Item (346/78-30-06) pending his review.

12. Results of Auxiliary Building Tour

The inspectors accompanied a member of the shutdown outside control room test group on a tour of areas which would be occupied during the test to determine the individual's familiarity with the procedure and to determine if communication equipment was available and operable.

During the tour the inspectors noted conditions regarding the pressurizer heater breakers, (auxiliary cooling), heat tracing, (two circuits out of six operating) for pressurizer valves and tubing to valve MU9 (quality of workmanship) that have been relayed to the project inspector for his further review.

13. Possible Operation at Power on Auxiliary Feedwater System

During the entrance interview on December 20, 1978, the inspector conveyed to the Plant Superintendent a concern regarding the possible operation of the reactor on the auxiliary feedwater system due to spurious actuation of the SFRCS system at powers on the order of 15% (The September 24, 1977, event occurred at approximately 9% power). The scenario proposed was that with a spurious SFRCS actuation, RCS pressure and temperature would begin to rise due to mismatch between power produced by the reactor and power removed by the auxiliary feedwater system and safety valves. With the increase of pressure the power operated relief valve (normal operation) would activate and relieve pressure and prevent a high pressure reactor trip. In addition, at a certain power level or range of power levels it appears pressure would not decrease to the low pressure trip setpoint such that no automatic trip action would take place. The inspector requested that the licensee evaluate this condition to determine what automatic protection is provided to terminate the event. Other concerns are:

a. What is the effect of prolonged power operated relief valve operation? Would the rupture disc on the pressurizer quench tank relieve and steam adversely affect containment components? (Note: The licensee states that after the September 24, 1977, event a deflector was installed to prevent steam from impacting on the steam generators, electrical cables, and containment instrumentation).

b. Would RCS temperatures increase to the point where water would be relieved from the power operated relief valve.

c. Would fuel damage occur e.g. DNB.

The licensee committed to provide this information by February 15, 1979. This is an Unresolved Item (346/78-30-07) pending review of the licensee information.

14. Unresolved Items

Unresolved items are matters about which more information is required to ascertain whether they are acceptable items, items of noncompliance, or deviations. Unresolved items disclosed during the inspection are discussed in paragraphs 4, 5, 6, 10, 11 and 13.

15. Exit Interviews

The inspectors met with licensee representatives (denoted in Paragraph 1) at the conclusion of each phase of the inspections. The inspectors summarized the purpose and scope of the inspection and the findings.

a. On November 2, 1978, the inspector met with Mr. Beyer and other members of the staff. The following items were discussed:

(1) Effect of makeup flow on pressurizer level calculations.

(2) Request for acceptance criteria for loss of offsite power test.

(3) High pressure injection operability during September 24, 1977, event.

(4) Emergency procedure modifications regarding HPI operation.

(5) Incore detector operability criteria.

(6) Main steam safety valve operation during the 75% turbine trip.

b. On December 22, 1978, the Chief, Nuclear Support Section 1 and reactor inspector met with Mr. Murray and members of his staff to discuss the following items:

(1) HPI performance during the September 24, 1977, event.

(2) Emergency Procedure EP 1202.06.1.

(3) CNRB review of power ascension testing.

(4) Incore detector operability criteria.

(5) Possible unreviewed safety question regarding the loss of pressurizer level.

(6) Natural circulation test-tripping of essential bus issue.

(7) Core lift issue.

(8) Operation at Power on auxiliary feedwater system.

Regarding the core lift issue, the licensee committed to provide the information requested in Paragraph 6 by February 1, 1979.

Regarding the issues concerning possible operation at power on auxiliary feedwater system described in Paragraph 13, the licensee committed to provide the information by February 1, 1979.

c. On January 15, 1979, the licensee met with Mr. Murray and members of his staff and discussed the following issues:

(1) Load rejection test.

(2) Loss of offsite power test.

(3) Shutdown outside control room test.

(4) Results of the auxiliary building tour.

(5) Reporting of the events described in Paragraphs 10 and 11.

(6) CRD trip breaker maintenance. The licensee stated they were following B&W's recommendation.

The licensee committed to review and revise emergency procedures associated with the testing performed based on their detailed evaluation by February 15, 1979.

Regarding the acceptability of the Shutdown Outside the Control Room Test, the licensee stated that he believed the test was acceptable. The issue is presently being discussed with the licensee by the project inspector.