U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-456/88019(DRP); 50-457/88019(DRP)

Docket Nos. 50-456; 50-457 License Nos. NPF-72; NPF-77

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: Braidwood Station, Units 1 and 2

Inspection At: Braidwood Site, Braidwood, Illinois

Inspection Conducted: May 29 through July 9, 1988

Inspectors: T. M. Tongue
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S. P. Sands
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Reactor Projects Section 1A

07.19.88
Date

Inspection Summary

Inspection from May 29 through July 9, 1988 (Report Nos. 50-456/88019(DRP); 50-457/88019(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident inspectors, region-based inspectors, and NRR project manager of licensee action on previously identified items; emergency preparedness; headquarters request; regional request; followup on Three Mile Island (TMI) action items; events; Unit 2 coolant piping flaw evaluation; startup test observation; operational safety verification; radiological protection; engineered safety feature systems; physical security; monthly maintenance observation; monthly surveillance observation; alcohol and drug awareness program; training effectiveness; report review; and meetings and other activities.

Results: Of the eighteen areas inspected, no violations were identified in seventeen. In the remaining area, two violations were identified regarding initiation of an unusual event (Paragraph 3.a) and 10 CFR 50.72 reporting requirements (Paragraph 3.b).

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*T. J. Maiman, Vice President
*K. L. Graesser, General Manager Power Operations
*S. Hunsader, Nuclear Licensing Administrator
*R. E. Querio, Station Manager
W. E. Vahle, Construction Superintendent
*D. E. O'Brien, Station Services Superintendent
K. Kofron, Production Superintendent
L. E. Davis, Assistant Superintendent - Technical Services
B. Byers, Assistant Construction Superintendent
M. Lohman, Project Startup Superintendent
P. Cretens, Station Startup Assistant Superintendent
*T. Joyce, Byron Production Superintendent
*B. M. Saunders, Nuclear Security Administrator
*F. Willaford, Security Administrator
*S. C. Roth, Assistant Security Administrator
*M. A. Melnicoff, Assistant Technical Staff Supervisor
D. E. Paquette, Maintenance Assistant Superintendent
G. R. Masters, Operations Assistant Superintendent
E. L. Martin, Quality Assurance Superintendent
*P. L. Barnes, Regulatory Assurance Supervisor
M. Takaki, Regulatory Assurance
J. Gosnell, Quality Control Supervisor
*R. E. Aker, Radiation/Chemistry Supervisor
J. Jasnoz, Technical Staff AR/PR Coordinator
R. Lemke, Technical Staff Supervisor
*G. E. Groth, Startup/Testing Supervisor
E. R. Netzel, Quality Assurance Supervisor
*F. G. Lentine, Licensing Supervisor
G. M. Orlov, Staff Assistant to Project Manager
P. G. Holland, Regulatory Assurance
R. C. Bedford, Regulatory Assurance
R. D. Kyrouac, Quality Assurance Supervisor
L. Kline, Regulatory Assurance Industry Group
L. W. Raney, Nuclear Safety
*R. J. Ungeran, Operating Engineer - Unit 1
*R. Yungk, Operating Engineer - Unit 2
B. McCue, Operating Engineer - Unit 0
R. J. Legner, Lead Operating Engineer
T. O'Brien, Tech Staff
S. Hedden, Master, Instrument Maintenance
R. Hoffman, Master, Mechanical Maintenance
J. Smith, Master, Electrical Maintenance
W. McGee, Training Supervisor
B. Tanouye, Project Construction Department
A. J. D'Antonio, Quality Control

D. H. Schavey, Training
*E. Carroll, Regulatory Assurance
*S. H. Stapp, Quality Assurance
*F. D. Bevington, Quality Assurance
*J. B. Cronin, Chemistry
*B. James, Chemistry
*T. M. Bandura, Quality Assurance Inspector

Burns Security

*H. Walker, Assistant Security Force NCR

NRC - RIII

*A. B. Davis, Regional Administrator
*C. J. Paperiello, Deputy Regional Administrator
*E. G. Greenman, Director, Division of Reactor Projects
*W. D. Schafer, Chief, Emergency Preparedness and Radiological Protection Branch
*J. N. Hinds, Chief, Reactor Projects, Section 1A
*S. Sands, Licensing Project Manager, Braidwood
*T. Tongue, Senior Resident Inspector, Braidwood
*R. M. Lerch, Reactor Inspector, Branch 1
*G. A. VanSickle, Project Engineer, Section 1A

*Denotes those attending the exit interview conducted on July 7, 1988, and/or the Management Meeting on June 30, 1988.

The inspectors also talked with and interviewed several other licensee employees, including members of the technical and engineering staffs, startup engineers, reactor and auxiliary operators, shift engineers and foremen, and electrical, mechanical and instrument maintenance personnel, as well as contract security personnel.

2. Licensee Action on Previously Identified Items

a. Open Items

(Closed) 456/86016-02(DRP); 457/86014-01(DRP): Documentation of the 10 CFR 50.59 Safety Review for temporary procedures and changes gave the impression of a questionable review. It was confirmed that these procedures were not subject to the requirements of 10 CFR 50.59 reviews. The licensee issued Revision 3 to Procedure BwAP 1205-6, "Conduct of Safety Evaluations, and 10 CFR 50.59 Review," on October 16, 1987. This revision provides an additional review procedure so that procedures and procedure changes that do not require a full review can be identified and documented. This procedure will prevent the previously existing situation, in which reviewers had to answer 10 CFR 50.59 review questions that did not apply to the procedures under review. This item is closed.

(Closed) 456/87004-01: Failure of diesel generator rocker arms. Multiple failures of the diesel rocker arms are discussed in NRC Inspection Reports No. 456/87004; No. 457/87003 and No. 456/87015; 457/87015. Two failure modes are postulated to have initiated the cracking. Failure of the 1R and 3R rocker arms on the 2A diesel on February 4, 1987, was attributed to momentary seizure of the crossheads in the guides. To prevent recurrence of this problem, the licensee increased the crosshead-to-guide clearance to the maximum recommended by the manufacturer. Failure of the 5R rocker arm on the 2A diesel on February 13, 1987, and the 5R rocker arm on the 2B diesel on March 28, 1987, has been attributed to rocker arm castings made of low strength material. To alleviate this problem, all rocker arms with tensile strengths of less than 30 Ksi have been replaced. This replacement of low strength rocker arms was also effected at the CECo Byron facility.

To add additional confidence in the diesel generator reliability, 100-hour test runs were performed on both Unit 1 and Unit 2 machines.

b. Unresolved Items

(Closed) 456/86065-03(DRP): Inadequacies in valve locks identified during plant tours. In response, the licensee corrected the valve deficiencies that were identified. In addition, the licensee developed an operating guideline which included a section on valve locking devices, and the operating shift personnel were trained in valve locking in tailgate sessions. With regard to other valves, walkdowns were performed by the station operations and Fire Marshall staffs. Additional locking deficiencies were identified. Work requests were written on the fire protection valves, and 29 others were reported to the technical staff for correction. In discussions between the technical staff and the inspector, it was established that the 29 valves had been evaluated, and appropriate corrections taken. The work requests on the fire protection valves were also reported completed on February 3, 1987. All identified deficiencies have been corrected by procedure; fire protection valve positions are visually confirmed on a monthly basis, and locked valves in accordance with an 18-month surveillance procedure. This item is closed.

(Closed) Item 456/87044-01(DRP); 457/87045-04(DRP): Containment Recirculation Sump Screen - evaluation. The licensee submitted a letter, dated December 28, 1987, with answers to a number of questions and how they affect Braidwood and Byron. The licensee verified that under loss of coolant accident (LOCA) conditions the sump screens are covered with water, that the sump screens have a solid top, and that the sump screens are close to identical for all four units. The licensee also provided the areas of each of the sump screens and an analysis to show that although the flow velocity through the screens may exceed the guideline of 0.2 feet per second (fps), the 0.2 fps is attained at about one inch in front of the screens.

This issue was discussed with members of NRR in NRC Headquarters via telephone on June 29, 1988, and it was agreed that the initial determination of the sump screen area is an example of poor engineering on the part of the Architect Engineer. However, the later analysis showing that the flow velocity at about one inch in front of the screens meets the criteria of 0.2 fps is acceptable. This item is closed.

c. Violations

(Closed) 456/87007-02(DRP): Failure to meet the required time limits of the Technical Specification 3.7.11 Action Statement for fire watches. Three examples were given. The licensee responded that in each of the occurrences, the responsible individuals were counselled on the event. For one event, this included counselling all operating shift crews on the importance of response to control room annunciators. A review of Deviation Reports (DVRs) found that October 1987 to May 1988, five additional events in which fire watches did not comply with the station Fire Protection Program (DVRs 20-1-87-260, 20-1-87-396, 20-1-88-110, 20-1-88-140, and 20-2-88-85) occurred. In each case appropriate administrative actions were reported taken with the individuals involved and to comply with the program. The primary causes of these events were personnel errors. The licensee's disciplinary actions regarding personnel errors should make clear to employees the seriousness with which it views fire watch commitments. As these events were licensee identified and corrected, there are no concerns with the program performance at this time. This item is closed.

(Closed) 456/87007-06(DRP): Administrative requirements of the station lubrication program were not performed; there were no procedures for authorization of lubrication activities, and no provisions for post-lubrication functional checks. The licensee revised the procedure, reassigning program responsibility to the fuel handlers, providing for lubrication status and record retention, and requiring a post-lubrication operability run for safety-related equipment that is taken out of service. The station Quality Assurance (QA) department has resumed audits of the lubrication program and has verified that lubrication of safety-related equipment is current. Due to subsequent difficulties in establishing a working program, primarily with the non-safety-related equipment, QA has performed follow-up reviews on roughly a monthly basis and is maintaining an open finding. The lubrication program was also impacted by the issue concerning the environmental qualification of valve lubricants, which has been resolved. Based on the QA audit finding of up-to-date safety-related equipment lubrication records, the continued QA follow-up, and the procedure changes that have been made, this item is closed.

(Closed) 456/87023-03(DRP): Failure to enter a Technical Specification (TS) action statement when the inoperable 1B main steam isolation valve (MSIV) opened with the unit in Mode 2. MSIV 1B was inoperable for maintenance work and gagged shut when

workers bled off the pneumatic system pressure. This subjected the stem to system pressure, causing the gagging device to fail and the valve to open. Technical Specifications require an inoperable MSIV to be maintained in a closed position. Unit operators failed to follow up on a plant indication (a cleared alarm) to determine that the valve had opened and that entry into a TS action statement was required.

This event was reported in LERs 456/87025 and 456/87025, Revision 1, and was reviewed in Inspection Reports 456/87014 and 456/87023. The review in Inspection Report 456/87023 closes the LER and Revision 1. The licensee initiated corrective actions through the Deviation Report (DVR) procedure and documented its commitments in LER 456/87025 and in the response to the violation, a letter from L. D. Butterfield to A. Bert Davis, dated September 24, 1987. The corrective actions included: (1) a review of the event with mechanical maintenance personnel, which included a discussion on MSIV operation theory; (2) a review of the event with all operating shifts emphasizing the need to thoroughly investigate and resolve all alarms; and (3) revision of the maintenance procedure for depressurizing the MSIV actuator and blocking the valve closed. In addition, in response to an NRC concern with personnel performance during this event, transmitted in the inspection report cover letter, the licensee sent each operating shift to a one-day program on Professionalism in Operations. These corrective actions have been completed, as verified by the revised procedure and signed off action item forms for each of the training commitments. There are no further concerns. This item is closed.

(Closed) 457/88007-01(DRS): Failure to initiate a Deviation Report for a plugged boric acid recirculation line. By letter, dated June 17, 1988, from G. C. Wright to Cordell Reed, the NRC withdrew this violation. Withdrawal was based on a DVR which was issued for the lack of flow from the Unit 0 boric acid pump due to a valve in the recirculation path being closed. This item is withdrawn and closed.

d. 10 CFR 50.55(e) Report

(Closed) 457/87001-EE: Failure of 2A diesel generator rocker arms. See Open Item 456/87004-01.

No violations or deviations were identified.

3. Emergency Preparedness

On June 7, 1988, at 6:00 p.m., the licensee discovered that the motor operator for containment isolation valve No. 2SI8809B (cold leg injection isolation valve for reactor coolant system [RCS] loops C and B from the B train of the residual heat removal [RHR] system) was not certified as meeting the environmental qualification (EQ) requirements. Valve 2SI8809B

was declared inoperable and the Limiting Condition for Operation Action Requirement (LCOAR) of Technical Specification (TS) 3.6.3 was entered. TS 3.6.3 states that for an inoperable containment isolation valve, within four hours restore the inoperable valve to operable status or isolate the affected penetration, otherwise be in at least hot standby within the next six hours and in cold shutdown within the following 30 hours. Valve 2SI8809B was left open because closing the valve would reduce cold leg injection capabilities to two loops, which would be an unanalyzed condition. After evaluating the possibilities for returning the valve to an operable status, a licensee management decision was made to commence a reactor shutdown. Locating the missing required EQ documentation or replacing the motor operator would have exceeded the four hours allowed by the LOCAR.

Between 7:47 and 7:58 p.m., with the Unit 2 power level at 247 megawatts electric (MWe), a 3 MWe/minute reactor shutdown to 175 MWe was initiated due to the inoperability of 2SI8809B, in order to meet the requirements of TS 3.6.3.

a. Failure to Properly Declare Initiation of an Unusual Event

At 9:40 p.m. an unusual event was declared after Unit 2 entered Mode 3 (hot standby). At 9:55 p.m. an Emergency Notification System (ENS) notification was made to NRC Headquarters to communicate details of the 2SI8809B inoperability and to both declare and terminate a General Station Emergency Plan (GSEP) unusual event. NUREG-0654 guidelines call for the declaration of an unusual event when plant conditions require a plant shutdown under TS requirements. NUREG-0654 guidelines are implemented by licensee procedure BwZP 200-1, "Braidwood Emergency Action Levels." BwZP 200-1, Emergency Action Level 14, requires the declaration of an unusual event when "Equipment described in the TS is degraded such that a Limiting Condition for Operation requires a shutdown."

Through discussions between the Braidwood Resident Inspector, NRC Region III emergency preparedness personnel, and licensee emergency preparedness personnel, it has been determined that the initiation of the unusual event should have been declared upon initiating the reactor shutdown between 7:47 and 7:58 p.m. The failure to declare the unusual event between 7:47 and 7:58 p.m. on June 7, 1988, is considered contrary to NUREG-0654 and BwZP 200-1 requirements and is therefore a violation of 10 CFR 50, Appendix B, Criterion V (457/88019-01(DRP)).

The termination of the unusual event was determined to be acceptable at Mode 3. However, a more prudent and conservative manner of operation would have been to terminate the event upon reaching Mode 5, at a point where the TS no longer applied, or subsequent to declaring the affected valve operable.

b. Failure to Report an Event in Accordance with 10 CFR 50.72

Between 7:47 and 7:58 p.m. on June 7, 1988, a Unit 2 shutdown was initiated in accordance with TS 3.6.3, as noted in the Shift Engineer's (SE's) 7:47 p.m. log entry, which stated, "Commenced S/D on U-2 due to 2SI8809B. . . ," and in his 7:58 p.m. entry, which stated, "commenced ramping U-2 to 175 MW @ 3 MW/min." The details of this event were discussed with NRC Region III, NRR, and the Braidwood Station resident inspectors. The NRC's conclusion was that at 7:58 p.m., with the commencement of the power reduction due to 2SI8809B inoperability, the initiation of the reactor shutdown was started in accordance with TS 3.6.3. 10 CFR 50.72(b)(i)(A) requires that within one hour of initiation of a reactor shutdown an ENS notification is required. However, ENS notification, which informed NRC Headquarters of the GSEP declaration/termination, the inoperable condition of 2SI8809B, and subsequent entrance into TS 3.6.3 requiring a plant shutdown completed at 9:39, was not made until 9:55 p.m. The event notification should have been made within one hour (by 8:58 p.m.) of the shutdown initiation. This failure to properly notify NRC within one hour of initiation of a reactor shutdown is considered a violation of 10 CFR 50.72(b)(1)(A) reporting requirements (457/88019-02(DRP)).

Based on reviews of associated documentation and interviews with shift and site emergency preparedness personnel, it seems that the shift personnel were cognizant of the GSEP and reporting requirements. It appears that higher management made last minute policy changes that resulted in these violations. This issue should be addressed by the licensee in its response to the violations.

4. Headquarters Request

Misinterpretation of Valve Operability

By memos dated April 25, 1988 and April 21, 1988, NRR requested a review of each plant to determine if a problem exists in the interpretation of Technical Specification 3/4.6.4.5, "Containment Isolation Valves." It appears that a licensee interpreted this Technical Specification to mean, "If the valve is closed, then the valve is operable." NRR concern was expressed in that an inoperable closed isolation valve could inadvertently open, then fail to close on an isolation signal. An additional NRR concern was whether licensees acknowledge entry into the applicable Technical Specification Limiting Conditions for Operation (LCOs) and/or Action Statements for shut dual function valves (valves in safety system flow paths which also provide containment isolation).

The inspector polled SEs, Shift Control Room Engineers (SCREs), and Operating Engineers (OEs) at Braidwood and found unanimous concurrence that the more conservative action would be taken. If a dual function valve is affected and it is left open, then the plant would enter the TS LCO and/or Action Statement as appropriate for the isolation capability.

If the valve is inoperable and shut, then the plant would enter the appropriate LCO and/or Action Statement for the loss of system capability.

This response was discussed with Region III; Region III concurred with this practice and with the determination that if an isolation valve is shut, then the valve may be considered inoperable; however, the system containing the valve may still be considered operable provided that it is not required by another TS.

This information was passed on to Mr. T. Ross of NRR via telecon on June 28, 1988, and it was agreed that the interpretation of this TS is not a problem at Braidwood at this time.

5. Regional Request

As requested, the inspector performed a review of the licensee's responses to I.E. Bulletin (IEB) 85-01, "Steam Binding of Auxiliary Feedwater Pumps," and Generic Letter (GL) 88-03, "Resolution of Generic Safety Issue 93, Steam Binding of Auxiliary Feedwater Pumps." The purpose of this review was to evaluate the licensee's response and to verify implementation of activities relative to GL 88-03 and IEB 85-01. The inspectors' review identified that the licensee has implemented the items identified in previous NRC Inspection Reports 456/86065 and 457/87049. The identified activities included a documented shiftly check of AFW discharge piping temperature and the preparation of abnormal operating procedures stating actions to be taken for AFW discharge piping temperatures greater than 130°F. GL 88-03 was not issued at the time of the previous inspections. GL 88-03 stated that the temporary actions required by IEB 85-01 are now permanently required activities.

6. Follow-up on TMI Action Items

I.C.4 Control Room Access

NUREG-0737 requirements for control room access as delineated in NUREG-0578, Section 2.2.2(a) are:

a. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access.

b. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current Senior Reactor Operator's license.

The inspector has reviewed licensee procedures BwAP 900-10, "Control Room Access," and BwAP 300, "Conduct of Operations," and has determined them to be adequate in scope and content to address the above requirements. These procedures were implemented prior to Unit 1 initial fuel load. This item is considered closed for Units 1 and 2.

Status of TMI Items

During previous inspection periods, certain TMI items were closed with an ending statement, "This item is considered closed." The statement did not make it clear as to the units affected. This paragraph documents that the following TMI items are considered closed for Units 1 and 2:

1.C.5.1	2.F.1.2.D
2.B.1.2	2.F.1.2.E
2.B.1.3	2.K.3.5.B
2.E.3.1.1	2.K.3.9
2.E.4.2.1-4	2.K.3.10
2.E.4.2.5.B	2.K.3.12.B
2.E.4.2.6	2.K.3.25
2.3.4.2.7	2.K.3.25.B

No violations or deviations were identified.

7. Events (93702)

GSEP ALERT Declared for Inoperable Containment Spray

On July 2, 1988, the licensee declared an ALERT under the GSEP upon discovery that both the A and B Trains of Containment Spray (CS) for Unit 1 were inoperable. The inoperable trains were determined through a review of the INPO Nuclear Network News, in which the South Texas Project had identified a similar problem. The CS system has two timers (15 and 40 seconds) for sequencing pump starts during the accident scenario. The licensee found that both 40-second timers were last tested on Unit 1 in May 1986 during preoperational testing and had not been included in the routine 18-month surveillance procedure.

The 18-month surveillance was due in November 1987, with a critical date of March 1988. The 15-second timers had been tested satisfactorily during the 18-month surveillance outage started on January 1, 1988.

Upon identification, the licensee declared the ALERT per GSEP Emergency Action level "EAL 14 A," which states "Equipment described in Technical Specification is degraded beyond the limiting condition for operation that requires a shutdown . . . ." Declaration of this action level was necessary because the CS timers had not been demonstrated operable in accordance with Technical Specification 3.3.2, "Engineered Safety Features Activation System (ESFAS), Instrumentation," which requires that instrumentation channels and interlocks in Table 3.3-3 shall be shown operable by showing that their trip setpoints and response times are as stated in Tables 3.3.4 and 3.3.5 respectively. Table 3.3-3, Item 2.b, "Containment Spray - Automatic Actuation Logic and Actuation Relays," requires that two channels be operable in Modes 1, 2, 3, and 4. In addition, with less than the required number of channels operable, it requires that the reactor be in hot standby within six hours, and in cold shutdown within the following 30 hours.

When both channels were declared inoperable, making the CS system inoperable, the licensee entered Technical Specification 3.0.3 and commenced an orderly shutdown at 0.1 megawatt per minute. In addition, upon declaration of the GSEP ALERT, the licensee manned the Technical Support Center (TSC) and the Operational Support Center (OSC) at the site; however, shift of control was not completed due to the shortness of the ALERT, low urgency, and minimal interference with the corrective actions.

The licensee wrote, reviewed, approved, and performed a surveillance procedure on the affected timers. Channel A required minor adjustment; however, the as-found condition would not have degraded an accident condition. Channel B was found to be acceptable.

The alert was declared at 2:10 p.m. and cleared at 5:05 p.m.

The licensee notified the NRC in accordance with 10 CFR 50.72 and maintained open communications throughout the ALERT.

The Chief, Section 1A, Division of Reactor Projects, monitored the ALERT from the Region III office and maintained a heightened state of awareness for possible activation of the Incident Response Center (IRC) if necessary. The Senior Resident Inspector reported to the site to monitor the activities and the licensee evaluation.

The final evaluation of this ev will be completed upon submittal of the Licensee Event Report.

No violations or deviations were identified.

8. Review of Unit 2 Coolant Piping Flaw Evaluation

As discussed in NRC Inspection Report No. 50-456/88003; 50-457/88003, the ASME Section XI, pre-service ultrasonic inspection detected an unacceptable circumferential indication near reactor coolant piping weld 2RC-01-04. This is an elbow-to-valve weld with a wall thickness of 2.55 inches. The area of concern corresponds with an indication detected on the field weld radiograph.

The NRC inspector reviewed the field weld radiographs and noted two axially orientated indications approximately 1/2 inch each in length and separated by 1/2 inch. The inspector requested that the vendor radiographs for the cast elbow be retrieved. Upon retrieval the vendor radiographs of the elbow weld end prep were reviewed. The area of concern was located with reasonable assurance and evaluated. Indications resembling the flaw in question had been noted by the vendor and evaluated as acceptable inclusions per ASTM E-186, Severity Level 2. It should be noted that the film type and gamma source utilized for the vendor radiographs did not yield a flaw definition quite as good as that of the field weld radiographs.

In summary, the flaw was evaluated by the vendor and properly accepted per the Code criterion for castings; however, the flaw as detected during

the Section XI pre-service examination does not meet the IWB-3500 acceptance standards. The licensee has submitted to the NRC a Relief Request, allowing the use of ASME Section XI, Paragraph IWB-3640, flaw evaluation procedures.

Westinghouse prepared report No. MT-SME-200, "Evaluation of an Indication in the Braidwood, Unit 2, Loop 1, Elbow to Valve Weld Region," in an effort to address the Code flaw evaluation requirements. This evaluation was location - specific and considered the effects of thermal expansion (normal and upset), pressure, deadweight, and seismic (OBE and SSE) loadings. Upon identification of the governing stress loadings, a fracture mechanics approach was applied to determine the allowable flaw size and fatigue crack growth rates. For this evaluation, stress corrosion cracking was not considered a credible mechanism for piping failure.

For the fatigue crack growth analysis, residual welding stresses were also considered along with the loadings mentioned above. All design transients contained in the equipment specification were considered, except the faulted conditions, since their frequency of occurrence is too low to affect fatigue crack growth. Utilizing the appropriate crack growth equation published by the ASME (PUP-99, December 1985) a circumferential crack with a depth of .53 inches and an axial crack with a depth of .57 inches is conservatively calculated after a period of ten years of service. This determination is based on an initial circumferential flaw with a length of 1.5 inches and a depth of .5 inches and an initial axial flaw with a length of .8 inches and a depth of .5 inches. From Section XI, Paragraph IWB-3641, the maximum allowable depth for both circumferential and axial flaws in the elbow material is 1.9 inches. For the shielded metal arc welding (SMAW) weld material, the maximum allowable circumferential flaw depth is 1.55 inches.

The NRC inspector reviewed the above referenced report and found the evaluation methodology to be acceptable and in accordance with Code provisions. From this evaluation, it was demonstrated that the flaw, as characterized, is acceptable and that ample margin exists. Additionally, the licensee will perform augmented inspection of the flaw area in accordance with Section XI, Paragraph IWB-2420.

No violations or deviations were identified.

9. Startup Test Observation (72302)

The inspectors witnessed performance of portions of the following Unit 2 startup test procedures in order to verify that testing was conducted in accordance with the operating license and procedural requirements, that test data was properly recorded, and that performance of licensee personnel conducting the tests demonstrated an understanding of assigned duties and responsibilities:

IT-71 - Power Coefficient Determination

10. Operational Safety Verification (71707)

The inspectors conducted routine plant tours during the inspection period to make an independent assessment of equipment conditions, plant conditions, construction activities, security, fire protection, general personnel safety, housekeeping, and adherence to applicable regulatory requirements. During the tours, the inspectors reviewed various logs and daily orders, interviewed personnel, attended shift briefings and plan of the day meetings, witnessed various construction work activities, and independently determined equipment status. During the shift changes, the inspectors observed operator, shift control room engineer, and shift engineer turnovers and panel walkdowns.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

Model Spaces Program

During routine tours of the turbine building and auxiliary building, it became apparent that housekeeping quality has declined in finished areas. Although there is an ongoing effort to continue painting toward completion of the model spaces, the turbine building showed evidence of an accumulation of dust and dirt and numerous stains on the control room carpet. It was later found that the number of members of the cleaning force had been reduced. Favorable comments by senior NRC management and by Commissioners during visits and in Headquarters during the Unit 2 full power briefing had identified Braidwood as an example of excellence both to the utility and to the entire industry. It is disappointing that this indication of a declining trend has appeared shortly after the licensing of Unit 2. Through discussions with the station management, the inspectors pointed out that although no violation had been identified, the licensee must make the choice on what resources will be applied to maintaining the plant appearance somewhere between marginally acceptable and excellent. Hopefully, this declining trend will reverse itself in the near future.

No violations or deviations were identified.

11. Radiological Protection (71709)

The inspectors selected portions of the licensee's radiological program to verify conformance with facility policies, procedures, and regulatory requirements. Observed aspects included the health physics managers' awareness of any unusual conditions or challenges, the implementation of the ALARA program, the use of Radiological Work Permits (RWPs), the control and monitoring of radiation exposures, including work in high radiation areas if applicable, and the control of radioactive material.

Chemistry Monitoring

During a recent inspection by a Region III specialist for confirmatory measurement analysis, the presence of Argon 41 in the Unit 1 reactor coolant system was identified through the NRC van analysis (see

Inspection Report No. 50-456/88017(DRS); 50-457/88017(DRS)). The Senior Resident Inspector (SRI) pointed out that this was evidence of air intrusion into the RCS and that the associated dissolved oxygen (DO) could aggravate corrosion. This concern was acknowledged by CECo station chemistry personnel, and they noted that their analytical chemistry analysis had identified the presence of DO and that there was an ongoing search for the source of air. At the request of the SRI, the station provided a later follow-up that indicated that the apparent sources of air in-leakage were leaks in the seal bladders on the primary water storage tanks (PWSTs). This was promptly corrected.

After further consideration, the SRI found that response acceptable. However, the SRI inquired as to whether the detection of Argon 41 in the RCS would trigger searches for air intrusion even if DO is not detected. Additional discussion with Radiation Chemistry personnel revealed that the normal abundance of dissolved hydrogen in the RCS and ongoing recombination process of hydrogen and oxygen would reduce DO in the RCS to where it is essentially not a corrosion problem. In addition, since the Braidwood design includes neoprene bladders on the PWSTs, previous experience indicates that some evidence of air intrusion in the RCS and the associated presence of some Argon 41 is normal. Since the licensee has set up plans for monitoring and trending Argon 41 routinely, and the effect of the hydrogen, it does not seem appropriate to use the presence of Argon 41 as formal mechanism to initiate a search for air intrusion at this time.

No violations or deviations were identified.

12. Engineered Safety Feature (ESF) Systems (71710)

During the inspection, the inspectors selected accessible portions of several ESF systems to verify their status. Consideration was given to the plant mode, applicable Technical Specifications, Limiting Conditions for Operating Action Requirements (LCOARs), and other applicable requirements.

Various observations, where applicable, were made of hangers and supports; housekeeping; whether freeze protection, if required, was installed and operational; valve positions and conditions; potential ignition sources; major component labeling, lubrication, cooling, etc.; interior conditions of electrical breakers and control panels; whether instrumentation was properly installed and functioning and significant process parameter values were consistent with expected values; whether instrumentation was calibrated; whether necessary support systems were operational; and whether locally and remotely indicated breaker and valve positions agreed.

During the inspection, the following ESF components were walked down:

Unit 0

0A Hydrogen Recombiner
0B Hydrogen Recombiner

Unit 1

1A Auxiliary Feedwater Pump
1B Auxiliary Feedwater Pump

Unit 2

2A Auxiliary Feedwater Pump
2B Auxiliary Feedwater Pump

No violations or deviations were identified.

13. Physical Security (71881)

At various times throughout the inspection period, the inspectors monitored compliance with the Physical Security Plan (PSP). Observations were made of selections of manning levels and collateral duties of assigned personnel; access control equipment and processes, such as x-ray machines, metal detectors, explosive detectors, and other search mechanisms; whether protected area (PA) and vital area (VA) barriers were properly maintained; whether procedures were properly followed; whether compensatory measures were appropriately used when required; whether persons in the PA and VA were properly badged and escorted if required; whether various detection/assessment aids, such as fences and illumination of the PA, were operable; and whether TV monitors had sufficient clarity and resolution.

While performing a routine tour of the turbine and auxiliary building spaces, the Resident Inspector identified a potential security violation. Region III security personnel have reviewed the event and a special security report has been issued.

14. Monthly Maintenance Observation (62703)

Station maintenance activities affecting the safety-related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with Technical Specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from and restored to service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented. Work requests were reviewed to determine the status of outstanding jobs and to assure that priority is assigned to safety-related equipment maintenance which may affect system performance.

Maintenance activities on the following equipment were observed and reviewed:

Unit 1

1A Auxiliary Feedwater Pump - Orifice and Gasket Replacement.
Moveable Incore Detector Thimble Tube Obstruction Removal.

Unit 2

2A Emergency Diesel Generator.
Solid State Protection System Printed Circuit Board Replacement.

The obstructed thimble tubes for moveable incore detectors (MIDs) were discussed in detail in Inspection Report 456/88013; 457/88014. The obstructed tubes had reduced the number of available detectors to less than the 75% required for surveillances involving the MIDs. From June 11 to 13, 1988, Westinghouse contractors cleared 13 tubes with a manually driven gun brush. Sufficient detectors were then available for the performance of an overdue incore-excore calibration of the power range high neutron flux trip setpoint, which was completed later in the inspection period. The licensee intends to run the MIDs into the core periodically in an attempt to keep the thimble tubes clear.

No violations or deviations were identified.

15. Monthly Surveillance Observation (61725)

The inspectors observed surveillance testing required by Technical Specifications during the inspection period and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, that results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors also witnessed portions of the following test activities:

Unit 1

SR N31 BwIS 3.1.1-222 High Flux at Shutdown.
Quarterly Moveable Incore Detection System Calibration.
Monthly Moveable Incore Detection System Functional Check.

One inspector concern identified during the inspection period was the frequent performance of surveillances shortly before their critical dates (dates when Technical Specification required surveillance intervals, with allowable extensions, expire). Scheduled due dates for surveillances were frequently missed, resulting in the challenges to the critical dates. This state of affairs indicates a lack of management emphasis on performance of surveillance activities in accordance with published schedules.

No violations or deviations were identified.

16. Alcohol and Drug Awareness Program (ADA)

During the inspection, the Senior Resident Inspector was interviewed by Richard M. Bucher, Ph.D, Senior Associate of Bensinger, DuPont, and Associates as part of the licensee's ADA program. The discussion involved providing information to the NRC related to ADA issues at the site, upcoming NRC rule changes, the sampling program, and the NRC perspective on this issue.

No violations or deviations were identified.

17. Training Effectiveness (41400 - 41701)

The effectiveness of training programs for licensed and non-licensed personnel was reviewed by the inspectors during the witnessing of the licensee's performance of routine surveillance, maintenance, and operational activities and during the review of the licensee's response to events which occurred during the inspection period. Personnel appeared to be knowledgeable of the tasks being performed, and nothing was observed which indicated any ineffectiveness of training.

No violations or deviations were identified.

18. Report Review

During the inspection period, the inspector reviewed the licensee's Monthly Operating Report for May 1988. The inspector confirmed that the information provided met the requirements of Technical Specification 6.9.1.8 and Regulatory Guide 1.16.

The inspector also reviewed the licensee's Monthly Plant Status Report for May 1988.

No violations or deviations were identified.

19. Meetings and Other Activities (30702)

Management Meeting - Unit 2 Ascension to Greater Than 50% Power

A management meeting was held in Region III on June 30, 1988, between members of the Region III staff and Commonwealth Edison, to discuss present issues and the licensee's preparation for taking Unit 2 above 50% power.

This was similar to the meeting held for Unit 1 on October 5, 1987, during which a commitment was made for this meeting.

With respect to Braidwood Unit 2, the subjects discussed were: startup testing and performance; control room annunciators and alarms; maintenance backlog status; Deviation Reports and LERs; reactor trips, including recent trips; trip reduction committee; personnel error evaluation program; and overall performance summary.

A summary provided by the Regional Administrator (RA) advocated conservatism in plant activities and concluded that operation of Unit 2 above 50% power was acceptable. With respect to recent findings related to moveable incore detectors and associated surveillances on Unit 1, the RA urged the licensee to bring issues to the NRC if they involve stopping or delaying Technical Specification surveillances prior to exceeding their critical dates.

A commitment was made to hold monthly meetings at least during the remainder of the startup/power ascension period.

Other subjects discussed during the meeting were the recent secondary chemical excursion at Byron, auxiliary feedwater check valve leakage at Zion, and the counterfeit fastener problem within the industry.

20. Exit Interview (30703)

The inspectors met with the licensee and contractor representatives denoted in paragraph 1 during the inspection period and at the conclusion of the inspection on July 7, 1988. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.