U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Reports No. 50-454/84-79(DRP); 50-455/84-53(DRP)

Docket Nos. 50-454; 50-455 Licenses No. NPF-23; No. CPPR-131

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

Facility Name: Byron Station, Units 1 and 2

Inspection At: Byron Station, Byron, IL

Inspection Conducted: November 4 through December 31, 1984

Inspectors: J. M. Hinds

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Approved By: J. F. Streeter, Director
Byron Project Division

1/30/85
Date

Inspection Summary

Inspection on November 4 through December 31, 1984 (Reports No. 50-454/84-79(DRP); 50-455/84-53(DRP))

Areas Inspected: Routine, unannounced safety inspection of licensee action on SER items; previous inspection findings; Part 21 reports; main steamline safety valve blowdown adjustment; administrative controls for incore instrumentation seal table maintenance; termination lug crimp inspections on safety related battery chargers manufactured by Power Conversion Products; Byron Unit 1 fuel

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loading operations; operational safety; startup test performance; surveillance test program implementation; Licensee Event Reports and other activities. NRC Chairman Palladino and Commissioner Bernthal toured the facility during this report period. Meetings between NRC and licensee management personnel were held on December 6 and 19, 1984, to discuss Unit 1 facility status and licensee corrective actions for nonroutine events. The inspection consisted of 407 inspector-hours onsite by six NRC inspectors including 104 inspector-hours during off-shifts.

Results: One item of noncompliance was identified (failure to perform pump inservice tests in accordance with Technical Specifications - Paragraph 11.d.)

DETAILS

1. Persons Contacted

Commonwealth Edison Company

#°*R. Querio, Station Superintendent
#° R. Tuetken, Startup Coordinator
#° R. Ward, Assistant Superintendent, Administrative & Support Services
#°*R. Pleniewicz, Assistant Superintendent, Operating
L. Sues, Assistant Superintendent, Maintenance
M. Loehman, Project Construction Assistant Superintendent
#° V. I. Schlosser, Project Manager
#° T. Tulon, Operating Engineer
T. Higgins, Training Supervisor
°* R. Poche, Technical Staff
#°*D. St. Clair, Technical Staff Supervisor
*W. Burkamper, QA Supervisor (Operating)
S. Barrett, Station Chemist
G. Stauffer, Station Nuclear Engineer
S. Dresser, Technical Staff
P. Anthony, Technical Staff
#° T. Maiman, Manager of Projects

The inspectors also contacted and interviewed other licensee and contractor personnel during the course of this inspection.

#Denotes those present during the management meeting on December 6, 1984.
°Denotes those present during the management meeting on December 19, 1984.
*Denotes those present during the exit interview on December 31, 1984.

2. Byron Safety Evaluation Report (SER) Items

(Closed) SER Item (454/83-00-15): Electrical power distribution system voltage verification. Review of applicable preoperational test procedures and inspector witnessing of selected portions of tests was documented in NRC Inspection Report (454/84-47(DRS)). By letters dated January 5, 1984 and September 6, 1984, the licensee documented evaluations of results for Preoperational Test 2.5.1i, "Bus Loading and Independency". The evaluations compared measured ESF bus voltages with ESF bus voltages predicted by a computer-based analytical model. Acceptance criteria were met in that measured bus voltages fell within ± 3% of predicted values.

3. Action on Previous Inspection Findings

a. (Closed) Noncompliance (454/84-55-01(DRP); 455/84-38-38-(DRP)): Failure to account for inaccuracies in remote valve position indication in Engineered Safety Feature (ESF) response time measurements. By letter dated December 13, 1984, from D. Farrar to J. G. Keppler the licensee described corrective actions taken to measure and account for any remote position indication inaccuracies in time response measurements. As discussed in NRC Inspection Reports No. 454/84-55(DRP); 455/84-38(DRP), preoperational test data for Unit 1 was re-evaluated and found to be acceptable. Applicable surveillance test procedures have been appropriately revised to account for remote valve position indication inaccuracies in future ESF time response measurements.

b. (Closed) Open Item (454/84-61-01(DRP); 455/84-42-01(DRP)): Failure to complete training as required by station procedures. The licensee completed a review of the training matrices required by Byron Training Procedure (BTP) 500-5, Revision 0, dated October 16, 1984. Personnel delinquent in specific training for individual job positions were identified. The licensee developed a computer based data management system to maintain the training matrices up to date and completed the balance of the required training. The inspector reviewed the new computer matrix system and verified that all training required by BTP 500-5 matrices has been completed.

c. (Open) Unresolved Item (454/84-62-01(DRP)): FSAR Figure 6.3-2 incorrectly indicates that valves 1RH 610-1 and 1 RH 611-2 are motor-operated globe valves. By letter dated October 17, 1984 from T. Tramm to J. G. Keppler the licensee submitted an advance copy of revised FSAR Figure 6.3-2 which reflected the fact that in early 1984 the subject valves were respecified as motor-operated gate valves. The licensee stated in the letter that a general update of FSAR P&IDs reflecting a number of other minor changes was scheduled to be submitted in December 1984. Based upon discussions with licensee personnel the inspector determined that the referenced changes will be part of FSAR Amendment No. 46 which is scheduled for submittal in the near future. This item will remain open pending inspector review of FSAR Amendment No. 46.

4. <u>10 CFR Part 21 Reports</u>

a. (Open) Part 21 Report (454/84-01-PP; 455/84-01-PP): Environmental qualification of viton seals used in post-LOCA Hydrogen recombiners manufactured by Rockwell International. The licensee has received the qualified replacement seals specified by the vendor. Installation of the seals will commence after receipt of all required certification documents. The licensee anticipates that installation will be accomplished prior to Unit 1 entry into Mode 2.

b. (Open) Part 21 Report (454/84-05-PP; 455/84-05-PP): Failure of Ruskin fire dampers installed in ventilation ducts to close under rated airflow conditions. The licensee identified all 51 units supplied by the vendor and determined that 36 of the units were installed in ductwork and therefore potentially affected. The licensee reviewed the potentially affected units and concluded that no additional actions were warranted. Inspector review of the licensee's evaluation will be performed during a future inspection.

5. Main Steamline Safety Valve Blowdown Adjustment (License Condition E.1.b of Attachment 1 to Operating License No. NPF-23)

(Closed) Vendor Program Branch (VPB) Generic Issue (454/84-03-PP(DRP)): forwarded issue from VPB Inspection Report 99900054/84-01. The licensee issued Nuclear Work Request B12758 to require adjustment of blowdown rings on all 20 main steamline safety valves per instructions provided by the vendor, Dresser Industries. The specified adjustments were based upon the results of a vendor test program which empirically determined safety valve blowdown over a range of set pressures and as a function of blowdown ring adjustment. The specified adjustment will provide a blowdown of 6%, ± 3% for any set pressure. The licensee completed the work on December 7, 1984, while in Mode 5. Completion of this effort prior to Mode 2 satisfied License Condition E.1.b of Attachment 1 to Operating License No. NPF-23.

6. Administrative Controls for Incore Instrumentation Seal Table Maintenance

Problems have been experienced at Sequoyah and D. C. Cook facilities related to outward movement and ejection of thimble tubes during seal table maintenance at pressure. In response to the inspector's request, the licensee provided the following as to whether or not seal table maintenance activities at pressure are specifically prohibited at Byron Station:

- Based on NRC Information Notice 84-55, Byron Letter 84-1201 dated September 29, 1984, was issued stating that no maintenance will be performed at the seal table at elevated temperature and pressure.
- Maintenance Directive 84-02 dated December 19, 1984, was issued to further clarify the licensee's position.
- BMP 3300-16, "Incore Thimble Cleaning", requires system depressurization as a prerequisite.
- BMP 3118-1 and BMP 3118-12, "Inserting and Retracting the Incore Instrumentation Thimbles", both require the system to be at refueling shutdown conditions as a prerequisite.

From a review of the above, it appears that the licensee has adequate administrative controls in place to prevent seal table maintenance at pressure.

7. Termination Lug Crimp Inspections on Battery Chargers Supplied by Power Conversion Products

On October 17, 1984, Illinois Power Company informed the NRC Region III Office, pursuant to 10 CFR 50.55(e), that defective termination lug crimp connections had been identified on safety-related battery chargers supplied to the Clinton Nuclear Power Plant by Power Conversion Products (PCP). In response to the reported condition, reinspections of the following Class 1E battery chargers manufactured by PCP and installed at Byron Units 1 and 2 were performed on December 17, 1984:

125v Battery Charger 111
125v Battery Charger 112
125v Battery Charger 211
125v Battery Charger 212

The inspections did not disclose any problems with termination lug crimp connections.

8. Byron Unit 1 Fuel Loading Operations

The licensee entered Mode 6 and began initial core loading of Byron Unit 1 on November 2, 1984. NRC inspectors provided 24 hour-a-day coverage until November 5, 1984. From November 6, 1984, until completion of fuel loading on November 27, 1984, NRC inspectors provided routine coverage.

The inspectors identified all technical specification requirements and license conditions applicable for Mode 6 and verified conformance with these requirements on a sampling basis. The inspectors verified that: startup test procedures were available and in use; prerequisites and initial conditions required by Byron Startup Test Procedures 2.52.35B, "Nuclear Instrumentation System - Source Range Detectors", 2.52.31B, "Temporary Core Loading Instrumentation System During Core Load", and 2.32.32, "Initial Core Load", were satisfied prior to execution; nuclear instruments were properly calibrated and operating with a measurable count rate during core alterations; shift crew requirements specified in the startup test procedures and technical specifications were satisfied; adequate communications were in place and; inverse multiplication plots were being maintained in accordance with procedural requirements.

The inspectors performed daily reviews of operating logs, witnessed several shift turnovers, verified primary coolant system boron concentration complied with technical specification shutdown margin requirements, witnessed several reactor coolant boron concentration determinations (sample analyses), reviewed implementation of personnel access and cleanliness controls in place on the refueling floor, verified the use of refueling status boards throughout coreload, and interviewed licensee personnel to determine if they understood their specific responsibilities.

No items of noncompliance or deviations were identified.

9. Operational Safety Verification

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the months of November and December. The inspector verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of containment, auxiliary building and turbine building were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

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.

No items of noncompliance or deviations were identified.

10. Startup Test Witnessing and Observation

The inspectors witnessed performance of portions of startup test Procedures 2.59.30, "PI System Checkout", and 2.64.31, "CRDM Operational Test", in order to verify that testing was conducted in accordance with the operating license and all procedural requirements, test results were acceptable, and the performance of licensee personnel conducting the tests demonstrated an understanding of assigned duties and responsibilities.

During performance of 2.59.30 the inspector noted that the procedure used the Architect Engineer's numbering system for annunciator alarm window identification rather than the system described in the Byron Annunciator Response (BAR) procedures. The inspector discussed this matter with the licensee's staff and the licensee agreed to include a check to verify that the correct annunciator window numbers are used and to correct any identified discrepancies in startup test procedure reviews.

During performance of startup test 2.64.31 the inspector observed that, when a control rod was moved, one of the pens on a strip-chart recorder used to monitor control rod drive mechanism operation did not respond properly. The test engineer discovered that the strip-chart recorder leads had been connected to the wrong test points. The leads were shifted to the correct test points and the test section reperformed with satisfactory results. The root cause of this deficiency was a problem with the verbal test point connection directions given to test personnel. The resolution of this problem was to provide a copy of the tables detailing the test connection points to the personnel making these connections. Based on discussions with the startup test coordinator and corrective actions taken, the inspector has no further concerns.

No items of noncompliance or deviations were identified.

11. Surveillance Test Program Implementation

a. Monthly Surveillance Observation

The inspector observed technical specifications required surveillance testing on the Digital Rod Position Indication System BOS 10.5-1 and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that test 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.

b. Inservice Tests for Pumps

On December 12, 1984, while in Mode 5 both Unit 1 Residual Heat Removal (RHR) pumps were declared inoperable after failing surveillance (inservice) tests performed to satisfy Byron Unit 1 Technical Specification 4.0.5. Based upon discussions with licensee personnel, the inspector determined that the pumps were considered operable for entry into Modes 6 and 5 though entry into these operational modes occurred well after the surveillance interval for the pumps had expired. The pumps were first successfully inservice tested on June 30, 1984. The licensee entered Mode 6 on November 7, 1984, and entered Mode 5 on November 30, 1984. The licensee did not understand that RHR loop operability required by Technical Specifications 3.9.8.2 (Mode 6), 3.4.1.4 and 3.4.1.4.2 (Mode 5), was contingent upon completion of inservice pump tests pursuant to Technical Specification 4.0.5 within the required surveillance interval. Failure to perform inservice tests of the Unit 1 RHR pumps within the required surveillance interval to establish operability is an example of an item of noncompliance (454/84-79-01a(DRP))

Licensee corrective actions following the RHR pump inservice test failures on December 11, 1984, included changing the test procedure to utilize more suitable test instrumentation for pump suction and discharge pressure measurements and to require component cooling water flow to the RHR heat exchangers. Component cooling water was required to remove heat added by the RHR pump and thus preclude pressurization of the RHR test flowpath during test performance. The RHR pumps were successfully retested and declared operable on December 12, 1984. Based upon a review of licensee actions concerning the RHR pumps, the inspector found no evidence that RHR pump performance had ever actually degraded to an unacceptable level between the first successful inservice test run on June 30, 1984 and the subsequent successful tests conducted on December 12, 1984.

Upon learning that RHR pump suction pressure instruments used for inservice tests prior to December 12, 1984, exceeded the maximum allowable range requirements of the licensee's inservice test program, the inspector requested that the licensee re-review all instrumentation used for pump inservice testing against the allowable range and accuracy requirements of the program. The licensee's re-review disclosed that the following instrumentation had been used for required pump inservice tests and exceeded the maximum allowable range requirements of the licensee's inservice test program:

PUMP	INSTRUMENT
1CV01PA Centrifugal Charging Pump	1PI-187 (Suction Pressure)
1CV01PB Centrifugal Charging Pump	1PI-188 (Suction Pressure)
1D001PA Diesel Oil Transfer Pump	1PI-D0066 (Suction Pressure)
1D001PB Diesel Oil Transfer Pump	1PI-D0067 (Suction Pressure)
1D001PC Diesel Oil Transfer Pump	1PI-D0068 (Suction Pressure)
1D001PD Diesel Oil Transfer Pump	1PI-D0069 (Suction Pressure)
1RH01PA Residual Heat Removal Pump	1PI-RH (Suction Pressure)
1RH01PB Residual Heat Removal Pump	1PI-RH (Suction Pressure)
1W001PA Control Room Chilled Water Pump	1PI-W0001 (Suction Pressure)
1W001PB Control Room Chilled Water Pump	1PI-W0002 (Suction Pressure)

Inservice testing of the above pumps to establish pump and/or system operability using inadequate instrumentation is an example of noncompliance (454/84-79-01b(DRP)).

12. NRC Commissioners' Inspection Tours

a. Commissioner Bernthal - November 9, 1984

Representatives of local intervenor groups were in attendance at a briefing of the Commissioner by CECo managers. Following the CECo briefing, NRC, licensee, and intervenor personnel toured selected areas of the Byron facility including portions of the auxiliary building, Unit 1 containment, turbine building, and service building.

b. Chairman Palladino - November 30, 1984

Representatives of local intervenor groups were in attendance at a briefing of the Commissioner by CECo managers. Following the CECo briefing, NRC, licensee, and intervenor personnel toured selected areas of the Byron facility including portions of the service building, turbine building, auxiliary building, fuel handling building, and Unit 1 containment building. Following the plant tour the Commissioner addressed members of the public and local news media in a press conference held at the Byron site.

13. Licensee Event Reports (LERs) Followup

a. (Closed) LERs (454/84-01-LL; 454/84-02-LL; 454/84-04-LL; 454/84-05-LL; 454/85-06-LL; 454/85-08-LL): Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished. Licensee actions for these LERs were acceptable.

Unit 1 LER No.	Title
454/84-01	Failure of Security to Patrol Fire Watch for Penetration Seals
454/84-02	Failure to Complete the Entry of Data on a Shift Surveillance of the Residual Heat Removal System
454/84-04	Core Alterations with Inoperable Control Room Ventilation System
454/84-05	Failure to Maintain Positive Pressure in the Control Room Area
454/84-06	Momentary Loss of Positive Pressure in Main Control Room While Loading Fuel
454/84-08	Diesel Oil Storage System Out of Service Without a Fire Watch

b. (Open) LERs (454/84-03; 454/84-10; 454/84-19; and 454/84-20): Source range channel spiking. These reports document approximately 41 occasions between November 7, 1984 and December 2, 1984, on which either one or both source range channels responded to electrical noise generated from within or electromagnetically induced on to the system. Byron Unit 1 initial core loading was in progress when the source range "spiking" began. Though it was clear that the detector spiking was not reflective of actual core behavior, in each instance licensee personnel complied with administrative controls requiring containment evacuation and radiological surveys prior to containment re-entry and resumption of fuel load. Core loading was suspended for over a week while the licensee took extensive diagnostic and remedial actions to correct the electrical noise problem. The source range channels were finally declared operable and core loading was completed.

A supplemental report describing corrective actions taken and their effectiveness, along with planned corrective actions to further reduce source range channel susceptibility to electrical noise will be issued by the licensee in the near future.

Byron Station utilizes the source range nuclear instrumentation system via the Solid State Protection System (SSPS) for automatic actuation of equipment to mitigate the consequences of a boron dilution accident. If the source range nuclear instrumentation channels detect that neutron flux has doubled in ten minutes or less, valves are automatically repositioned to provide a flowpath from the Refueling Water Storage Tank (RWST) to the charging pump suction and to isolate the Volume Control Tank (VCT) from the charging pump suction. This design feature is referred to as the Boron Dilution Prevention System (BDPS).

The licensee has classified BDPS actuations associated with the source range spiking as non-emergency events requiring 4 hour NRC notification via the ENS phone in accordance with 10 CFR 50.72(b)(2)(ii) and a thirty-day written report in accordance with 10 CFR 50.73(a)(2)(iv). Both of these regulations require a reporting of manual or automatic actuation of Engineered Safety Features (ESFs), including the Reactor Protection System (RPS) that is not part of a pre-planned sequence during plant operation or testing.

The Byron FSAR does not consider the BDPS as an ESF or as part of the reactor trip subsystem traditionally referred to as the RPS. The NRC Region III Office will review the reportability of BDPS actuations.

These LERs will remain open pending receipt and review of the licensee's supplemental report on the source range instrumentation noise problem and a determination that licensee corrective actions have resulted in acceptable source range instrumentation performance.

14. Management Meetings

On December 6 and December 19, 1984, Mr. J. F. Streeter, Director, Byron Project Division, and NRC resident inspector office personnel met with licensee management and supervisory personnel denoted in Paragraph 1 of the report. These meetings were held to assess overall facility status, readiness of Unit 1 for criticality (Mode 2) and operation above 5% of rated thermal power, and to discuss Reportable Events which had occurred since issuance of the Byron Unit 1 operating license.

NRC personnel expressed concern over the number of Reportable Events which had already occurred and the apparent repetitive nature of certain event types, including those discussed in Paragraph 13b of this report. Licensee personnel stated that they understood the NRC concerns and had initiated additional corrective actions aimed at reducing the number of events attributable to personnel error, procedural inadequacy, and equipment malfunctions. Specifically, the licensee stated that initial event evaluations, specification of corrective actions, and dissemination of information to responsible personnel would be required to be completed in a more timely manner. Cognizant personnel were reinstructed to consider any generic ramifications of events and place emphasis on preventing recurrence when specifying corrective actions. NRC personnel acknowledged the licensee's statements and indicated that the effectiveness of those additional licensee actions as well as overall licensee performance would be reassessed and discussed in a future management meeting.

15. Exit Interview

The inspector met with licensee representatives denoted in Paragraph 1 at the conclusion of the inspection on December 31, 1984. The inspector summarized the purpose and the scope of the inspection and the findings.