U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-454/88007(DRP); 50-455/88007(DRP)

Docket Nos. 50-454; 50-455 License Nos. NPF-37; NPF-66

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

Facility Name: Byron Station, Units 1 and 2

Inspection At: Byron Station, Byron, Illinois

Inspection Conducted: April 1 - May 16, 1988

Inspectors: P. G. Brochman
N. V. Gilles
B. A. Azab
L. R. Greger
W. W. Ogg
R. M. Lerch
R. B. Landsman
T. M. Tongue
P. R. Sunderland

Approved By: R. M. Lerch for
J. M. Hinds, Jr., Chief
Reactor Projects Section 1A

6-1-88
Date

Inspection Summary

Inspection from April 1 through May 16, 1988 (Report Nos. 50-454/88007(DRP); 50-455/88007(DRP))
Areas Inspected: Routine, unannounced safety inspection by the resident inspectors and region based inspectors of licensee action on previous inspection findings; licensee event reports; bulletins; operations summary; engineering and technical support; quality assurance programs; training; containment integrity; surveillance; maintenance; operational safety and engineered safety features system walkdowns; radiation protection; event followup; licensee actions in response to suspected drug use; allegations; and management meetings.
Results: Of the 14 areas inspected, no violations or deviations were identified in 11 areas; 3 violations were identified in the following areas: failure to incorporate design requirements into plant operations and failure to translate a design change into plant operations - paragraph 6; failure of a post-modification test procedure to incorporate recommended testing and failure to write the test procedure to assure that check valves were properly

tested - paragraph 6; failure to ensure that combustible rags were not stored next to safety-related cables - paragraph 12. Additionally, 1 violation was identified in the remaining area: failure to maintain a diesel generator operable - paragraph 3; however, in accordance with 10 CFR 2, Appendix C, Section V.G.1, a Notice of Violation was not issued. The first 2 violations were of more than minor safety significance and indicative of weaknesses in the licensee's modification program.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

R. Pleniewicz, Station Manager
T. Joyce, Production Superintendent
*R. Ward, Services Superintendent
*W. Burkamper, Quality Assurance Superintendent
T. Tulon, Assistant Superintendent, Operating
*G. Schwartz, Assistant Superintendent, Maintenance
*L. Sues, Assistant Superintendent, Technical Services
*D. St. Clair, Assistant Superintendent, Work Planning
*T. Higgins, Operating Engineer, Unit 0
J. Schrock, Operating Engineer, Unit 1
D. Brindle, Operating Engineer, Unit 2
T. Didier, Operating Engineer, Rad-Waste
*M. Snow, Regulatory Assurance Supervisor
R. Flahive, Technical Staff Supervisor
*S. Barret, Radiation/Chemistry Supervisor
P. O'Neil, Quality Control Supervisor
*G. Staufer, Assistant Regulatory Assurance Supervisor
*W. Kouba, Assistant Technical Staff Supervisor
*J. Ewald, Technical Staff
*S. Sober, Health Physicist
*W. Carl, Health Physicist
*L. Bushman, ALARA Coordinator
*D. Robinson, Nuclear Safety Group, Onsite
*R. Linboom, Station Fire Marshal
W. Pirnat, Regulatory Assurance Staff
*E. Zittle, Regulatory Assurance Staff

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

* Denotes those present during the exit interview on May 16, 1988.

2. Action on Previous Inspection Findings (92701 & 92702)

   a. (Closed) Unresolved Item (454/86018-01(DRP)): Licensee policy on the control of critical drawings. The inspector reviewed the licensee's program as described in the Commonwealth Edison Quality Assurance Manual, Quality Procedure 6-52, and verified that it is being implemented as stated. The inspector interviewed personnel responsible for implementing these requirements to verify their understanding. Based on these reviews, this item is considered closed.

   b. (Closed) Violation (454/87026-01(DRS)): The licensee failed to respond to the low level Spent Fuel Pit (SFP) alarm, which annunciated continuously during refueling activities, by not adhering to the Byron Annunciator Response procedure, BAR 1-1-C1, "Spent Fuel Pit Level High Low." The SFP water level was intentionally lowered below the low level alarm setpoint to keep the fuel handling tools from being submerged when stored in their racks and to prevent fuel handling personnel from working with their hands in the water. The basis for the SFP low level alarm setpoint of 424'2" is a recommendation in the FSAR, Section 9.1.4.3.4. The FSAR states that during all phases of fuel handling transfer the gamma dose rate at the surface of the water should be 2.5 mR/hr or less, which is accomplished by maintaining a minimum of 10 feet of water above the top of the fuel assembly during fuel handling operations. The low level alarm setpoint of 424'2" corresponds to 10 feet of water above the top of the fuel assembly at its highest point, when it is being moved by the SFP bridge crane.

The licensee has committed to modify the fuel handling tool racks such that the tool handles will remain above the water level. The fuel tool handling racks are mounted in various locations on the SFP wall at differing depths. The licensee plans to design and fabricate extensions which will be bolted to the top of the racks, thereby raising the tool handles above the 424'2" water level when they are stored in their racks. The licensee is tracking this corrective action via Action Item Record (AIR) 87-0301. Completion is required before commencement of the Unit 1 refueling outage in September 1988.

The licensee also revised procedure BAR 1-1-C1 to give further guidance for operator actions if the SFP level goes below the 424'2" setpoint. The procedure allows fuel movement to continue only if the following two conditions are satisfied: (1) level is above the minimum Technical Specification level, and (2) dose rates during all phases of fuel transfer are deemed to be acceptable.

The second condition is designed to meet the intent of the FSAR recommendation of 10 feet of water above the top of the fuel, which is based on maintaining acceptable dose levels. Procedure BAR 1-1-C1 was revised to ensure that the dose rate is measured and evaluated when the fuel being moved is at its highest point. Based on this review, the inspector's concerns have been addressed, and this violation is considered closed.

3. <u>Licensee Event Report (LER) Followup</u> (92700)

(Closed) LERs (455/88002-LL; 455/88003-LL): Through direct observation, discussions with licensee personnel, and review of records, the following LERs were reviewed to determine that the reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence was accomplished in accordance with Technical Specifications.

LER No.	Title
455/88002	Component cooling water surge tank level instrumentation installed incorrectly due to a design error.
455/88003	2B diesel generator inoperable due to a drawing error.

With regard to LER 455/88002, this LER describes an incorrect design identified during a Safety System Functional Inspection (SSFI) performed by the licensee. Consequently, in accordance with NRC policy, no enforcement action will be taken.

On March 29, 1988, based on notification from the Braidwood Station Technical Staff and subsequent investigation, the Byron Station Technical Staff concluded that instrumentation discrepancies existed on the Byron Unit 2 Component Cooling (CC) Surge Tank. A design change had been executed which reversed the trains of the power supplies and labels for the 2A CC pump and the 2B CC pump. However, this change did not reverse the power supplies or labels of the A & B surge tank level transmitters. Because there is a baffle plate that divides the surge tank up to the 40% level, level transmitter A indicated the tank level associated with pump B, and vice versa. At the same time, CC surge tank low level pump trip switches were also reversed when installed. The licensee's investigation determined the root cause to be errors by the design organization, Sargent and Lundy (the architect/engineer).

The safety concerns regarding these errors are considered minor. The Component Cooling System's safety-related function would be affected only if the CC system experienced a line break in combination with a Reactor Coolant System loss-of-coolant accident. As corrective action, the licensee has re-labeled the level transmitter gages to indicate correctly, temporarily disabled the surge tank low level pump trip switches, and initiated modifications to permanently correct the labels and electrical cabling. The architect/engineer has reviewed all other safety-related systems and found no other systems serving both trains from one tank. Based on these actions, this LER is considered closed.

With regard to LER 455/88003, this LER describes an event from 10:36 p.m. on March 29 to 8:15 a.m. on March 31, 1988, during which time the 2B diesel generator was rendered inoperable. This event was the result of isolating both trains of the starting air system due to errors on the Piping and Instrumentation Drawing for the diesel generator. The cause of the drawing errors is not known.

There was minimal impact on safety as the 2A diesel generator was available during that time. The other three diesel generators were reviewed for this problem, and the 2A diesel also had the drawing error. As corrective actions, drawing revision requests have been submitted, improved control switch labels will be installed with temporary ones already in place, caution cards explaining the drawing discrepancy were hung and increased surveillance of the diesel local control panels was implemented.

The failure to maintain both diesel generators operable while in Mode 1 without performing the appropriate Technical Specification (TS) action statements is a violation of TS 3.8.1.1 (455/88007-01(DRP)). However, this violation meets the tests of 10 CFR 2, Appendix C, Section V.G.1; consequently, no Notice of Violation will be issued, and this matter is considered closed.

The inspector discussed this event with licensee management and expressed concern over the length of time it took the equipment operators to notice the local control panel light which indicated that the diesel generator was not available for service. The inspector recommended that the licensee review the equipment operator log sheet for the diesel generators to verify that it contains all necessary information.

4. NRC Compliance Bulletin Followup (92701)

   a. (Open) Bulletin (454/88001-BB; 455/88001-BB): Defects in Westinghouse circuit breakers. The inspector reviewed the licensee's response, provided in a letter from W. E. Morgan to A. B. Davis, dated April 8, 1988, and verified that it was submitted within the required time interval. A review of the technical adequacy of the licensee's response will be accomplished by the Office of Nuclear Reactor Regulation (NRR). This bulletin will remain open pending completion of this review.

   b. (Open) Bulletin (454/88002-BB): Rapidly propagating cracks in steam generator (SG) U-tubes. The inspector reviewed the licensee's response, provided in a letter from W. E. Morgan to A. B. Davis, dated April 8, 1988, and verified that it was submitted within the required time interval. A review of the technical adequacy of the licensee's response will be accomplished by NRR. This bulletin will remain open pending completion of this review.

   c. (Closed) Bulletin (455/88002-BB): Rapidly propagating cracks in SG U-tubes. The inspector reviewed the licensee's response, provided in a letter from W. E. Morgan to A. B. Davis, dated April 8, 1988, which stated that the bulletin was not applicable to Byron Unit 2. The inspector verified that the Unit 2 SGs have stainless steel instead of carbon steel support plates, and that the SGs are model D-5. Consequently, the Unit 2 SGs are not within the purview of this bulletin. Based on this review, this bulletin is considered closed.

5. Summary of Operations

Unit 1 began a shutdown from 98% power at 9:50 p.m. on April 2, 1988, due to a tube leak in the 1D steam generator (see paragraph 14.a). Prior to the shutdown Unit 1 was online for 233 days, a new record for Byron Station. Following repairs the unit was taken critical at 8:28 a.m. on April 15 and synchronized to the grid at 3:28 p.m. on the same day. The unit operated at power levels up to 98% until 9:20 p.m. on April 18 when a reactor trip due to a dropped control rod occurred (see paragraph 14.b). The unit was taken critical at 12:10 p.m. on April 21, synchronized to the grid at 2:35 p.m. on the same day, and operated at power levels up to 98% for the rest of the report period.

Unit 2 operated at power levels up to 94% until 12:16 p.m. on May 6 when the unit was manually tripped due to decreasing level in the 2C steam generator following a trip of the 2C main feed pump (see paragraph 14.c). The unit was taken critical at 12:13 a.m. on May 7, synchronized to the grid at 4:50 a.m. the same day, and operated at power levels up to 94% for the rest of the report period.

6. Engineering and Technical Support (37700)

On January 11, 1988, the inspector identified a concern relating to missiles generated by fans 0VW03CA and 0VW03CB affecting two essential service water (SX) system pipes which provide cooling to both Unit 2 emergency diesel generators (DG). The SX pipes, 2SX26AA10 and 2SX26AB10, each provide cooling water to one of the Unit 2 DGs and are both approximately eight feet away and in line-of-sight from the VW fans. The inspector asked if an analysis had been performed which evaluated the susceptibility of both trains of SX piping to damage from missiles generated by the failure of either fan 0VW03CA or 0VW03CB. The licensee's architect/engineer was able to produce an analysis, which showed that any missiles generated by the failure of these centrifugal fans would not penetrate the fan housing. Additionally, the wall thickness of the SX pipes is greater than that of the fan housings. Consequently, the licensee believes that these two fans can not generate a credible missile threat to penetrate SX pipes 2SX26AA10 and 2SX26AB10. Based on this information, this concern is considered closed.

The inspector performed an independent inspection of a modification to the instrument air (IA) system on Unit 1. On April 13, 1988, the inspector identified several concerns on a modification which had been performed on the Unit 1 pressurizer power-operated relief valves (PORVs). Modification M6-1-85-0049 had changed the source of operating fluid (motive force) for the PORVs from high pressure nitrogen to low pressure IA. A post-modification test was performed on the new components and the modification was placed in operation on May 8, 1987.

During a review of the system piping and instrumentation drawing (P&ID) M-60, sheet 8, revision V, the inspector noted that valves 1RY087A and 1RY087B were indicated as locked open; however, the inspector verified the valves were in fact not locked and were not included in the licensee's locked equipment program. Byron Administrative Procedure BAP 330-3, "Locked Equipment Program," defines the licensee's program for locking equipment. BAP 330-A1, "Safety Related Locked Valves," lists all valves which are required to be locked. Byron Operating Procedure BOP RY-M1, Revision 5, "Reactor Coolant Pressurizer (RY) System Valve Lineup" defines the normal position of valves in the RY system. BOP RY-M1 specified the normal positions of valves 1RY087A and 1RY087B as open instead of locked open.

A review of the modification package identified a letter from Sargent & Lundy (Architect/Engineer for Byron) to R. E. Querio, dated June 17, 1986, which forwarded a revision to the modification's design, contained in Post Fuel Load Engineering Change Notice (PECN) P-155-1. PECN P-155-1 changed the position of valves 1RY087A and 1RY087B from open to locked open.

10 CFR 50, Appendix B, Criterion III, as implemented by Commonwealth Edison Company's Quality Assurance Manual, Quality Requirement 3.0, requires that measures shall be established to assure that the applicable design basis is correctly translated into specifications, drawings, procedures and instructions. Quality Procedure QP 3-51, paragraph C.28.d, requires that all procedures necessary for system operation are completed prior to placing the equipment in operation, following its modification. The failure to translate the design change, described in PECN P-155-1, into procedures BAP 330-A1 and BOP RY-M1 is a violation of 10 CFR 50, Appendix B, Criterion III (454/88007-01a(DRP)).

Valves 1RY087A & B are located between the RY accumulators and the PORVs. The accumulators provide a safety-related reservoir of air to operate the PORVs should there be a loss of the non-safety-related IA system. Valves 1RY087A & B are required to be locked open for two reasons: (1) shutting the valves isolates the PORVs from the accumulators, and (2) shutting the valves isolates the accumulators (pressure vessels) from their respective code safety valves 1RY087A and 1RY087B. After identification of this problem in Unit 1, the licensee determined that the same condition existed in Unit 2. However, the change from nitrogen to IA in Unit 2 was accomplished as part of the construction process, before issuance of the Unit 2 operating license on November 6, 1986.

10 CFR 50.55a(a)(2) requires that systems and components of pressurized water-cooled nuclear power reactors must be constructed in accordance with the applicable edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code) as described in 10 CFR 50.55a(b).

The accumulators and safety valves are designated as ASME Code Class 3. 10 CFR 50.55a(g)(4) requires that throughout the service life of a pressurized water-cooled nuclear power facility, components which are classified as ASME Code Class 3 shall meet the requirements set forth in Section XI of the ASME Code and its addenda that are effective as described in 10 CFR 50.55a(g)(3).

The licensee has committed to the 1980 Edition, Winter 1981 addenda, of the ASME Code. Section XI, Division I, Article IWA-7210, paragraph a requires that replacements shall meet the requirements of the Construction Code to which the original component was built. The Construction Code applicable to this replacement was the 1974 Edition, Summer 1975 Addenda. Section III, Division I, Article ND-7100 requires that Class 3 components be protected from the consequences of overpressure conditions which are in excess of the system's design. Article ND-7153 requires that no stop valves (isolation valves) be located between the safety valve (overpressure protection device) and the system it is to protect, unless such stop valves are constructed and installed with positive controls and interlocks so that the relieving capacity of the safety valve is met under all conditions of operation. Measures shall be provided to verify the operability of controls and interlocks by testing.

The licensee believes that due to the location of valves 1RY087A, 1RY087B, 2RY087A, and 2RY087B inside the Unit 1 and 2 containments, respectively, periodic surveillance testing of the PORVs is adequate to verify that valves 1RY087A and 1RY087B are open. The inspector believes that the position of the valves can be inferred as a result of the surveillance; however, the design requirements for both units mandates the use of positive control and interlocks. Article ND-7153 requires positive controls and interlocks in addition to testing to verify that the positive controls and interlocks are properly functioning. The safety valves are required to protect the accumulators and piping at all times, even though the PORVs could be inoperable, and consequently no surveillance test would be performed. The licensee's surveillance testing has only verified that the valves have not been inadvertently closed and has not demonstrated that positive controls and interlocks are functioning.

The failure to establish positive controls and interlocks over the positions of valves 1RY087A, 1RY087B, 2RY087A and 2RY087B utilizing instructions, procedures and drawings is a violation of 10 CFR 50, Appendix B, Criterion III, 10 CFR 50.55a, and the ASME Code, Section III, Division I, Article ND-7153 (454/88007-01b(DRP); 455/88007-02(DRP)).

The licensee locked open valves 1RY087A and 1RY087B on April 13, 1988. Valves 2RY087A and 2RY087B can not be locked without modifying the valve handwheels, but have been verified open. The licensee has committed to locking these valves at the first available outage.

The inspector next reviewed the post-modification test and identified two concerns. First, valves 1RY092A and 1RY092B were added by PECN 155-2 and, in a letter from the project engineering department (PED) to the station (letter from D. Elias to R. E. Querio, dated December 23, 1986), PED stated that the accumulators should be verified to pressurize with needle valves 1RY092A and 1RY092B fully open; or else the valves should be throttled as required to allow the accumulators to pressurize, and then the valves should be secured in place. The post-modification test did not specifically position these two valves, require that a valve lineup be performed, or directly verify that the accumulators would pressurize as required. The licensee stated that the valves were lined up per the PECN and the engineer who performed the test "recalls" that the valves were fully open.

Secondly, the inspector questioned whether check valves 1RY082A, 1RY082B, 1RY083A and 1RY083B had been adequately tested. These check valves are upstream of the accumulators and are at the code break and safety-related/non-safety-related boundary. Sections 9.5 and 9.6 of the test procedure performed a pressure decay test and required that the upstream isolation valves for each accumulator 1RY083A and 1RY083B, respectively, be shut and the pressure then monitored in the accumulator for 24 hours. The test procedure does not specify that the piping upstream of the check valves be vented off, such as via 1RY092A & B. With the upstream piping not vented it is not possible to verify that the check valves will perform their intended function. There was a previous instance at Byron where the safety-related/non-safety-related boundary in an IA system was not properly verified to function (failure of the main steam isolation valves to close during a startup test) as a result of inadequate testing of an IA boundary. The licensee believes that the piping was vented off via 1RY092A & B.

10 CFR 50, Appendix B, Criterion XI, as implemented by Commonwealth Edison Company's Quality Assurance Manual, Quality Requirement 11.0, requires that a test program be established to assure that all testing required to demonstrate that systems and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The post-modification test was less than rigorous in specifying the position of these two needle valves. The failure of test procedure to incorporate the recommendations of the Elias letter to verify that valves 1RY092A & B do not have to be throttled and the failure of the procedure to positively ensure that the upstream side of check valves 1RY082A & B and 1RY083A & B was vented during their test is a violation of 10 CFR 50, Appendix B, Criterion XI (454/88007-02(DRP)).

7. Quality Assurance Programs (40702)

The inspectors performed an independent inspection of the licensee's quality assurance (QA) department's followup of previously identified audit findings, observations, and open items. The inspectors reviewed approximately 65 QA audits performed since 1986. The licensee's program requires that each finding, observation, and open item be reviewed monthly until corrective action, which is acceptable to the QA department, has been completed. Subsequent followups are performed quarterly for one year, to verify that there is no repetition of the audit findings. The inspectors did not identify any instances in which followup audits had not been completed within the required time interval. During the review, the inspectors noted continued improvement in the QA department's documentation of audit followup activities.

The inspectors also reviewed the licensee's computerized schedule to verify that future audits were scheduled within the required time interval. One deficiency was identified: QA audit 06-87-25, finding #1 specified that followup occur at a frequency greater than the normal (quarterly); the computer schedule did not reflect this new frequency. The licensee corrected this error when it was identified.

No violations or deviations were identified.

8. Training (41400 & 41701)

The effectiveness of training programs for licensed and nonlicensed personnel was reviewed by the inspectors during witnessing of the licensee's performance of routine surveillance, maintenance, and operational activities and during review of the licensee's response to events which occurred during April and May 1988. Personnel appeared to be knowledgeable of the tasks being performed, and nothing was observed which indicated ineffective training.

No violations or deviations were identified.

9. Containment Integrity Verification (61715)

The inspector performed a verification of the integrity of the Unit 1 containment after it was established by the licensee, following the forced outage. The inspector verified through direct observation that a random sample of 15 containment mechanical and electrical penetrations were intact and in their proper positions. The inspector walked down a system designed to mitigate the release of radioactive material from containment following a LOCA (loss-of-coolant accident) to verify that it was operable.

No violations or deviations were identified.

10. Monthly Surveillance Observation (61726)

Station surveillance activities of the safety-related systems and components listed below were observed or reviewed to ascertain that they were conducted in accordance with approved procedures and in conformance with Technical Specifications.

Unit 1 Moderator Temperature Coefficient Measurement
Functional Test for Steam Generator 2A Pressure Channel 516
Functional Test for Steam Generator 2A Level Channel 517
Functional Test for Delta T/Tave Channel 441

The following items were considered during this review: the limiting conditions for operation were met while affected components or systems were removed from and restored to service; approvals were obtained prior to initiating the testing; testing was accomplished in accordance with approved procedures; test instrumentation was within its calibration interval; testing was accomplished by qualified personnel; test results conformed with Technical Specifications and procedural requirements and were reviewed by personnel other than the individual directing the test; and any deficiencies identified during the testing were properly documented, reviewed, and resolved by appropriate management personnel.

No violations or deviations were identified.

11. Monthly Maintenance Observation (62703)

Station maintenance activities of the safety-related systems and components listed below were observed or 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.

Repair of oil leak on the 2A auxiliary feedwater pump
Installation of temporary alteration in the 2A containment spray pump control circuit
Troubleshooting on 2C steam generator PORV control circuit

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.

No violations or deviations were identified.

12. Operational Safety Verification and Engineered Safety Features System Walkdown (71707, 71709, 71710, & 71881)

The inspectors observed control room operation, reviewed applicable logs and conducted discussions with control room operators during April and May 1988. During these discussions and observations, the inspectors ascertained that the operators were alert, cognizant of plant conditions, and attentive to changes in those conditions, and that they took prompt action when appropriate. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified the proper return to service of affected components. Tours of the auxiliary, fuel-handling, rad-waste, turbine and Unit 1 containment buildings 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.

The inspectors verified by observation and direct interviews that the physical security plan was being implemented in accordance with the station security plan.

The inspectors also witnessed portions of the radioactive waste system controls associated with rad-waste shipments and barreling. During April and May 1988, the inspectors walked down portions of the high head, intermediate head, and low head emergency core cooling systems inside the Unit 1 containment to verify their operability.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. On April 21, 1988, during a tour of the auxiliary building at location L-15 on the 383' elevation, the inspector observed an apparent fire hazard. Painting contractors were storing combustible material next to safety-related equipment, cable riser 1R254 C1E and auxiliary feedwater pump 1B. Cans of volatile epoxy paint were not sealed, but only covered with flame retardant cloth. Used floor covering paper was stuffed in a corner next to the cable risers. Sealed cans of paint were not stored in combustible material lockers. 10 CFR 50, Appendix B, Criterion V, as implemented by Commonwealth Edison Company's Quality Assurance Manual, Quality Requirement 5.0, requires that activities affecting quality shall be prescribed and accomplished in accordance with documented instructions and procedures. Byron Administrative Procedure BAP 1100-9, "Control of Combustible and Flammable Liquids," defines the licensee's program for controlling combustible liquids. Paragraph C.3 requires that combustible liquids shall not be stored adjacent to safety-related systems. Paragraph C.9 requires that cleaning rags and absorbers shall be properly disposed of in waste cans with self-closing lids. Paragraph C.1 requires that combustible liquids shall be stored in closed containers as required by the National Fire Protection AET 30 Flammable Liquids Code.

On April 27, 1988, the inspector revisited the area and observed that all the painting materials had been removed. Upon climbing up a temporary ladder, the inspector observed several piles of cotton rags under and in safety-related cable tray 1684B C1E. There was no one in the area. BAP 1100-7, "Fire Prevention for Use of Lumber and other Combustibles," paragraph C.8, requires that in safety-related areas excess combustible material be removed at the end of a shift. Additionally, excess material may remain in an area provided the area is not left unattended.

In subsequent discussions with operating department supervisors, the inspector was informed that painters were using the material, but had left the area for their morning break period when the inspector visited the area. The licensee cleaned up the area, removed excess painting materials, procured additional flammable material lockers for the auxiliary building, and modified painting procedures to require that paint be stored in the flammable material lockers when it is not being immediately used. The combustible rags were removed from the area, and the licensee's housekeeping committee has increased efforts in inspecting relatively inaccessible areas for evidence of accumulation of combustible material.

The failure of licensee management to ensure that combustible rags were stored in accordance with BAP 1100-7 is a violation of 10 CFR 50, Appendix B, Criterion V (454/88007-03(DRP)). Based on the corrective actions initiated by the licensee, the inspector has no further concerns regarding this event and this violation is considered closed; consequently, no reply to this violation is required.

13. Radiation Protection (93702)

During the Unit 1 outage to identify and repair tube leaks in the "D" steam generator, an incident occurred which resulted in airborne iodine-131 being released from the "D" steam generator into the Unit 1 containment as a result of several licensee weaknesses. A number of workers received minor iodine-131 intakes; however, no regulatory requirements appear to have been violated.

The iodine-131 was inadvertently released into the containment atmosphere when a temporary ventilation system being used to ventilate the steam generator for the tube plugging operations was breached. The temporary ventilation system, installed by station health physics personnel the previous day (April 5), consisted of a combined HEPA filter and fan unit, a charcoal unit, and connecting metal-reinforced vinyl "elephant trunk" ducting. Because of difficulty encountered in locating HEPA prefilters for the charcoal unit, the charcoal unit was installed downstream of the combined HEPA and fan unit in order to provide particulate filtration for the charcoal. This arrangement presented a weakness, however, in that the elephant trunk between the combined HEPA and fan unit and the charcoal unit was pressurized; therefore, any leakage in the elephant trunk would result in the release of iodine-contaminated air to the containment, which is what occurred when the elephant trunk subsequently became disconnected from the charcoal unit upstream connection piece. The back pressure presented by the charcoal unit apparently was enough, with the fan running at full speed, to cause the taped connection fastening the elephant trunk to the charcoal unit to come loose. The disconnected elephant trunk was apparently discovered and reconnected on two occasions by a station technical staff engineer who was working in containment on an unrelated job. The technical staff engineer, however, failed to notify health physics personnel of the problem, nor did health physics personnel inspect the system after it was started up or when increasing iodine levels were first identified. The problem was finally discovered by health physics personnel approximately eight hours after the steam generator was opened (eleven hours after the portable ventilation unit was started up).

It appears that for a significant portion of the period that the portable ventilation unit was operated the exhaust air was being released directly into containment without charcoal filtration. Fortunately, iodine-131 levels in the steam generator were relatively low (approximately 4 MPC as measured by licensee grab sample), and the containment airborne levels consequently only reached approximately one MPC. A containment mini-purge (3000 cfm) was in progress at the time of this incident. Due to the relatively low airborne iodine-131 concentrations in containment, the mini-purge was continued to ensure that the airborne activity would not migrate into other plant buildings. The mini-purge exhausts through a HEPA filter to stack 1. Although the mini-purge has no charcoal filtration, a dilution factor of about 60 is provided by other ventilation flow out the stack, and the stack release point is approximately 200 feet above grade, thereby providing additional dilution. Consequently, the iodine-131 release from the station (approximately 1/2 millicurie) was insignificant when compared to the releases authorized by the technical specifications.

Initial indications of a problem were received around 7:30 a.m. on April 6 (about 4½ hours after the steam generator was opened and 7½ hours after the portable ventilation system was started up) when the containment iodine monitor reached the ALERT setpoint (½ MPC). At approximately 10:30 a.m., two workers alarmed the whole body contamination monitors upon exiting containment; they were whole body counted when initial decontamination efforts were unsuccessful; iodine-131 was identified by the whole body counting. At approximately the same time that iodine-131 was identified from the whole body counts of the two workers, a radiation protection technician (RCT) performing routine surveillance of the portable ventilation system discovered the elephant trunk disconnected from the charcoal unit and reported the problem to the RCT foreman.

The containment was subsequently evacuated, and all personnel were whole body counted. A total of 60 workers had been in containment sometime between 7:30 a.m. and noon. Based on whole body count results, approximately ten workers exceeded 10 MPC-hours intake (the weekly intake threshold requiring inclusion in the assessment of individual intakes of radioactive material per 10 CFR 20.103). These workers were whole body counted on repeated occasions to monitor their iodine burdens. As noted below maximum intakes were calculated to be less than 20 MPC-hours. Seventeen additional workers were in containment between midnight and 7:30 a.m.; selected workers were counted; no significant intakes were identified.

Even though the maximum personal airborne intakes resulting from this incident were below the 40 MPC-hour investigation level specified in 10 CFR 20.103, the licensee conducted station and corporate investigations in an attempt to better understand the causal factors for the incident and to identify corrective actions. The corporate report of this incident was not released in time to be reviewed; it will be reviewed during a subsequent inspection by regional NRC radiation specialists. (Open Item 50-454/88007-04)

Several licensee weaknesses were evidenced by this incident. The licensee has a procedure, BAP 700-5, "Utilization of Portable Air Filtration/Ventilation Equipment," which addresses use of portable ventilation in situations similar to this. However, the procedure should be revised to incorporate additional precautions and to strengthen existing recommendations. For instance, the procedure does not contain a precaution to arrange the portable ventilation system components such that the unfiltered portions of the system are under negative pressure or to specify use of mechanical clamps instead of tape on connections, nor does the procedure require inspection (walkdown) of the system shortly after startup to check for leaks, etc., or require monitoring of the system exhaust flow or connection of the system exhaust directly to the plant filtered ventilation system. The other general weakness highlighted by this incident was the inappropriate personnel responses to off-normal situations, which may be indicative of training inadequacies. For instance, when appropriate HEPA filters for the charcoal filter unit could not be located, the charcoal unit was switched to the pressurized side of the portable ventilation fan, thereby setting up a potential for unfiltered release if system leakage occurred, without any compensatory measures such as more frequent visual inspections, better connectors, use of local monitoring equipment, etc; when the initial elevated containment iodine levels were reported as a result of the alarm (ALERT) on the containment monitor, no attempt was made to verify the operability of the portable ventilation system; and when the station technical staff engineer discovered the disconnected elephant trunk (two occasions), he reconnected the elephant trunk (even though he was not completely knowledgeable of the system function), but did not inform health physics or operations personnel. Licensee actions regarding these weaknesses will be reviewed during future inspections. (Open Item 50-454/88007-05)

It should be noted that the persistence of licensee personnel in following up on the two contaminated workers, even though surveys using an HP-210 "frisker" probe did not show contamination, was indicative of good performance and contributed to the eventual identification of the iodine-131 release to containment. Good licensee performance was also exhibited by the aggressive investigation of this incident by plant and corporate personnel.

An additional concern emanating from this incident is with the licensee's procedure (LRP-1340-10) for correlating whole body count data to MPC-hours exposure, which is the basis for conformance to the NRC regulatory limit. The licensee's procedure is based primarily on ICRP-2 methodology, and consequently attempts to apply models derived for chronic intake situations to actual acute intake incidents. The use of ICRP-30 methodology would be more appropriate in most nuclear power plant intake incidents. (It is noted that the NRC has been slow to officially acknowledge the acceptability of ICRP-30 methodology, and therefore has contributed to this concern.) While the licensee predicted a maximum individual exposure of approximately 7½ MPC-hours, based on an initial whole body count taken several hours after the suspected intakes, ICRP-30 methodology would predict approximately 10 or 15 MPC-hours depending on whether or not bodily excretion is assumed to have occurred. These differences are not significant in this case because of the small intakes experienced, but they could assume considerably more regulatory significance for larger intakes. Also, both ICRP-2 and ICRP-30 methodology predict maximum exposures of approximately 15 to 20 MPC-hours based on the whole body counts taken several days after the intake. The latter data is more dependent upon modeling consistencies but less dependent upon time accuracies. It appears judicious to quantify the maximum intake in this incident as being between 10 and 20 MPC-hours; customary conservativeness utilized when evaluating personnel radiological exposures would dictate the desirability of assigning the 20 MPC-hour value to the individual. This intake is still only a fraction, approximately 3%, of the NRC quarterly regulatory limit for intakes of airborne radioactive material. The licensee's procedure for correlating whole body count results to airborne intakes (MPC-hours) will be reviewed further during a future inspection. (Open Item 50-454/88007-06)

14. Onsite Followup of Events at Operating Reactors (93702)

The inspectors performed onsite followup activities for events which occurred during April and May 1988. This followup included reviews of operating logs, procedures, Deviation Reports, Licensee Event Reports (where available), and interviews with licensee personnel. For each event, the inspector developed a chronology, reviewed the functioning of safety systems required by plant conditions, and reviewed licensee actions to verify consistency with procedures, license conditions, and the nature of the event. Additionally, the inspector verified that the licensee's investigation had identified the root causes of equipment malfunctions and/or personnel errors and that the licensee had taken appropriate corrective actions prior to restarting the unit. Details of the events and the licensee's corrective actions developed through inspector followup are provided in paragraphs a through c below:

a. Unit 1 - Excessive Tube Leakage in the 1D Steam Generator

On March 11, 1988, the licensee identified a tube leak in the 1D steam generator with a calculated leak rate of 0.71 gallons per day (gpd) (previously discussed in Inspection Report 454/88006). The licensee monitored the leakage rate closely, which began to increase exponentially, and by April 2, 1988, had increased to 330 gpd. At 9:50 p.m. the licensee commenced a normal shutdown, which was completed at 9:03 a.m. on April 3. The licensee timed the shutdown to avoid exceeding the limit of Technical Specification 3.4.6.2 of 500 gpd for SG tube leakage, while still allowing the leak to be large enough to allow for easy detection.

The secondary side of the SG and main condenser is not a closed system and noncondensible gasses such as Xe-133 and Xe-135 are stripped from the condensing steam in the main condenser and are exhausted directly to the environment. Consequently, releases to the environment of radioactive gasses did occur during this event. The licensee's monitoring of these releases indicated that they were never greater than the minimum threshold of detectability of 0.9 micro curies/sec. The licensee's monitoring indicated that no gaseous iodine isotopes were released.

The licensee performed eddy current inspections of the first two rows of tubes in the 1D SG. The leak was located on the top side of the apex of a row 1 tube. The affected tube was plugged and an additional five tubes were plugged, based on the eddy current examinations. The U-tubes in the Unit 1 SGs were not heat treated (stress relieved) prior to the SGs being installed. The high residual stresses in the short radius U-bends of the row 1 and 2 tubes makes them susceptible to stress corrosion cracking. The licensee performed shot peening of the roll transition region of the U-tubes during the last refueling outage to reduce the residual stresses in that area. The licensee has determined that there is no need to perform additional stress relieving on the U-tubes, specifically in the apex area.

In addition to plugging the leaking SG tube the licensee completed inspections on 672 snubbers located inside Unit 1 containment and also completed various "inservice" inspections required upon entry into cold shutdown. The unit was taken critical at 8:28 a.m. on April 15 and synchronized to the grid at 3:28 p.m. on the same day.

b. Unit 1 - Reactor Trip Due to Dropped Control Rod

At 9:20 p.m. on April 18, 1988, with reactor power at 98%, a reactor trip occurred on high negative flux rate in the power range nuclear instruments. The negative flux rate trip was caused by a control rod dropping into the reactor core. An uncontrolled cooldown occurred following the reactor trip resulting in a loss of pressurizer level and isolation of letdown; pressurizer level remained on scale during the transient. The uncontrolled cooldown was due to the Moisture Separator Reheater (MSR) control valves being in manual for maintenance. Consequently, they continued to drain off steam, thereby cooling down the reactor, until they were identified to still be open. Tave dropped to 540 degrees F. Normal Tave is 557 degrees F. Reactor operators identified that a cooldown was in progress and in accordance with the station emergency operating procedures began isolating steam loads. During this process the MSR control valves were discovered to be in manual, the valves were shut, the cooldown was terminated, and the unit was stabilized in Mode 3.

The licensee initiated an investigation but could not determine the root cause of the dropped rod. The licensee's corrective actions included attaching recorders to various points in the 2BD rod drive power cabinet and other cabinets to monitor the rod drive system. A surveillance test was performed to insert and withdraw rods while taking data at key points. The licensee replaced the moveable and lift thyristors when some of the data indicated that the thyristors could be malfunctioning intermittently. A thorough search of each rod drive cabinet was made. All loose and frayed connections were identified and repaired. The 2BD cabinet card frame connectors were cleaned and tightened. The licensee then performed 1BVS XPT-2, "Checkout of the Bank Overlap Unit," to ensure satisfactory operation of the rod drive system prior to startup.

Unit 1 was taken critical at 12:10 p.m. on April 21, 1988, and was synchronized to the grid at 2:35 p.m. the same day.

c. Unit 2 - Manual Reactor Trip Due To Decreasing Level in the 2C Steam Generator

At 12:16 p.m. on May 6, 1988, the Unit 2 reactor was manually tripped from 94% power when the level in the 2C steam generator (SG) decreased to approximately 20%, following a trip of the 2C main feed pump. The cause of the trip of the 2C feed pump was the loss of hydraulic fluid to the high pressure governor valve, which was controlling the supply of steam to the feed pump turbine at the time.

The feed pump turbines are normally controlled using the low pressure governor valves during power operations. However, the 2C low pressure governor valve was out of service due to problems which had been experienced with the valve in early April. In order to clear some paperwork (a temporary lift), the Unit 2 Nuclear Station Operator (NSO) had decided to re-isolate the hydraulic fluid to the low pressure governor valve in accordance with the out of service (OOS). He did not realize that this action would also isolate hydraulic fluid to the high pressure governor valve as well. When the isolation was accomplished, the high pressure governor valve closed and tripped the feed pump. When the NSO saw the decreasing level in the 2C SG, he attempted to run back the main turbine generator using automatic control. However, the loss of the steam supply to the 2C feed pump (supplied directly from main steam) caused a momentary increase in the speed of the main turbine generator, leading the NSO to believe that the runback did not take affect. He immediately switched to manual control of the turbine but could not run it back in time and manually tripped the reactor on order from the Station Control Room Engineer (SCRE) and Shift Foreman before reaching the SG low level trip setpoint of 17% level. Indications from the licensee's post-trip investigation, including discussions with Westinghouse, were that the automatic turbine controls had, in fact, started to run back the turbine before the operator switched to manual control.

The licensee determined that the cause of the reactor trip was inadequate planning on the part of the NSO who had restored the isolation on the LP governor valve. The NSO did not consult plant drawings before sending an equipment operator (EO) to isolate the valve, and even when the equipment operator expressed some reservations about closing the valve due to the tag on the valve which said it was the EH supply valve, the NSO told him that it was the correct valve and to proceed with closing the valve.

All systems functioned normally following the trip, with the exception of the 2C SG PORV, which went full open with 0% demand on the valve. The operator took manual control, placed the PORV control switch to close, and received indication that the PORV was closed. The PORV was then placed back in automatic control and remained closed. The licensee's investigation into the abnormal behavior could not determine a cause.

The licensee's corrective actions included completing a new OOS request to allow clearing of the previous OOS on the low pressure governor valves in order to allow the 2C feed pump to be run on high pressure steam without the requirement for a temporary lift. This event will be reviewed by the licensee's Personnel Error Review Board, and any required changes to the temporary lift program will be followed by the board. Discussions were held with the SCRE, Shift Engineer, Shift Foreman, NSO, and EO involved, and will be held again in conjunction with the Personnel Error Review Board.

The unit was taken critical at 12:13 a.m. on May 7, 1988, and was synchronized to the grid at 4:50 a.m. the same day.

No violations or deviations were identified.

15. Followup of Licensee Actions in Response to Suspected Drug Use (99024)

On March 15, 1988, the inspector was notified by licensee management that an anonymous allegation had been substantiated as to the use of controlled substances offsite, by an individual with unrestricted access to Byron station (previously discussed in Inspection Reports 454/88006(DRP); 455/88006(DRP)). The individual in question performed non-licensed, non-supervisory, safety-related duties. The individual's security access was suspended in accordance with the licensee's program. On April 13, 1988, the inspector was informed by licensee management that following a medical evaluation the individual's security access would be restored. The individual is continuing in the licensee's employee assistance program (rehabilitation program) and the individual's performance will be monitored by licensee supervisors and the resident inspectors.

16. Allegation Followup (99024)

(Closed) RIII-87-A-0135: The NRC received a concern from a former contractor employee at Byron involving soil borings being done for the Preliminary Safety Analysis Report (PSAR). While drilling the borings, contractor personnel encountered cavernous limestone which would make the site unsuitable if not corrected. The alleger felt that to fill the caverns would be a tremendous grouting job due to the ground water heard moving in the cavern. However, he felt that if the grouting could be done, no problems would exist. The alleger departed the site prior to the start of any remedial work.

Findings: Starting in 1972, a series of explorations was conducted to identify the geologic, groundwater, and foundation characteristics of the Byron site. These investigations included test borings, test pits, and surface seismic and borehole geophysical surveys. About 154 borings, ranging in depth from 5 to 317 ft., were drilled at the site. The borings determined that soil thickness at the plant site varied from a few feet to about 40 ft. Directly beneath the soil, the uppermost bedrock is a dolomite with a thickness of about 200 ft. Directly underlying this formation is competent bed rock.

The uppermost bedrock, because of the carbonate content, solutioned (eroded) along joints, at joint intersections, and along bedding planes. Solutioning at joint intersections has resulted in a few oval depressions at the surface about 50 ft. in diameter. One has been found to be larger, almost 150 ft. in diameter. Borings and excavations have not uncovered large voids or caves capable of causing collapse. The dolomites are extensively fractured near the top, but become dense at depth.

Due to the condition of the uppermost rock unit, it was decided to pressure grout the entire subsurface upper rock unit under the power block to stabilize the foundation. The grouting program would improve the rock mass by solidifying solutioned areas.

Approximately, 1400 grouting holes, for a total of 300,000 linear feet, were drilled into the underlying rock with approximately 200,000 cubic feet of solids (cement and sand) injected into the underlying voids. In addition, over excavated rock surface areas were filled in with concrete to level the rock surfaces.

Nineteen verification borings were drilled within the grouted plant foundation to determine the effectiveness of the grouting operations. These borings were drilled after grouting was completed in an area. These borings were taken in the largest grout take areas. This verification operation demonstrated that the grouting program has adequately filled voids, sealed off solution channels, and solidified the rock mass.

Conclusions: The concern was substantiated; however, the grouting program was successful, and all significant solution features below the plant foundation level have been filled with cement grout. No violations or deviations were identified. This allegation is considered closed.

17. Management Meeting

On May 6, 1988, Mr. N. J. Chrissotimos, Deputy Director, Division of Reactor Safety in Region III, met with licensee executives, managers, and staff members who recently passed NRC operator licensing examinations to present license certificates to the newly licensed operators.

18. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in paragraph 13.

19. Violations for which A "Notice of Violation" Will Not Be Issued

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of 10 CFR 2, Appendix C, Section V.G.1. These tests are: (1) the violation was identified by the licensee; (2) the violation would be categorized as Severity Level IV or V; (3) the violation was reported to the NRC, if required; (4) the violation will be corrected, including measures to prevent recurrence, within a reasonable time period; and (5) it was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation.

A violation of regulatory requirements identified during the inspection for which a Notice of Violation will not be issued is discussed in paragraph 3.

20. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the inspection on May 16, 1988. The inspectors summarized the purpose and scope of the inspection and the findings. The inspectors also discussed the likely informational content of the inspection report, with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.