U. S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-454/95007(DRP); 50-455/95007(DRP)

FACILITY

Byron Nuclear Plant, Units 1 & 2

License No. NPF-37; NPF-66

LICENSEE

Commonwealth Edison Company
Opus West III
1400 Opus Place
Downers Grove, IL 60515

DATES

June 23, 1995 through August 3, 1995

INSPECTORS

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APPROVED BY

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9/26/95
Date

AREAS INSPECTED

A routine, unannounced inspection of operations, maintenance, engineering, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Regional Security specialist inspection was performed during the time period of June 12-21, 1995, the results of this inspection was documented in this report.

RESULTS

Assessment of Performance

Performance within the area of OPERATIONS was considered satisfactory. The licensee continued to be self-critical, identifying problems and bringing them to the attention of station management through the problem identification form (PIF) program. The licensee identified a condition where a safety related system (Main Turbine Trip Protection Circuit) was missing control fuses. The licensee was aggressively involved in the root cause determination. This was considered an unresolved item (paragraph 1.1.1). NRC inspectors raised some concern with the licensee's awareness of the importance of auxiliary building floor drain system. Minor flooding, due to a floor drain being clogged in the Containment Spray pump room, was identified by the licensee. The licensee appeared to satisfactorily investigate the cause of the minor flooding, but was slow to recognize the safety significance of clogged floor drains. This item was considered an inspection follow up item (paragraph 1.1.2). Overall, the inspectors determined that the licensee effectively carried out its responsibility to oversee and direct safe plant operations.

Performance within the area of MAINTENANCE was considered satisfactory. The licensee's involvement and coordination of routine surveillance and minor maintenance activities were reviewed by the inspectors, and no major concerns were noted. However, one violation, pertaining to inadequate procedure adherence in erecting a seismic scaffold near safety related equipment, the 2A diesel generator, was identified (paragraph 2.1).

Performance within the area of ENGINEERING was mixed. Overall safety responsibility with regard to engineering support was satisfactory. The licensee's investigation and corrective action regarding failed secondary neutron sources appeared good. However, the inspectors noted an apparent lack of timeliness and thoroughness of operability assessment on several other issues. Specifically, issues involving equipment qualification, and diesel generator expansion limiter bolts were identified (paragraphs 3.1, 3.2, 3.3, and 3.4). A total of four unresolved items were identified. A Site Quality Verification audit of the engineering group was reviewed. The audit was considered good, and reflected similar inspector concerns. Finally, the overall engineering involvement associated with the inadequate seismic scaffold on the 2A Emergency Diesel Generator was considered weak.

Performance within the area of PLANT SUPPORT was good. The licensee's radiological protection (RP) organization continues to be very active in reducing contaminated areas throughout the plant. A special inspection of licensee activities associated with security and safeguards was conducted. Two non-cited violations and one inspection follow-up item concerning licensee's security practices were identified (paragraphs 4.2.2 and 4.4.1). However, the licensee's overall security organization continues to satisfactorily perform its plant security responsibilities.

SUMMARY OF OPEN ITEMS

Violation: identified in Section 2.1

Unresolved Items: identified in Sections 1.1.1, 3.1, 3.2, 3.3, and 3.4

Inspection Follow-up Items: identified in Sections 1.1.2 and 4.2.2

Non-cited Violations: identified in Section 4.2.2 and 4.4.1

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in the performance of an inspection of ongoing plant operations. One unresolved item and one inspection follow-up item were identified (paragraphs 1.1.1, and 1.1.2).

1.1 Performance of Operations at Power Performance in plant operations was satisfactory. During this inspection period, certain items identified by the licensee indicated some performance problems in the area of fuse control. Also, NRC inspectors raised some concerns with the licensee's awareness of the importance of auxiliary building floor drain system. Overall, the inspectors determined that the licensee effectively carried out its responsibility to oversee and direct safe plant operations.

1.1.1 Main Turbine Trip Protection Circuit Fuse Block Found Not Installed

On July 6, 1995, during the performance of Unit 2 Engineering Safety Feature Actuation System (ESFAS) Instrumentation Slave Relay (K640) surveillance for the train B turbine trip, the indication for the turbine trip permissive was not received. Upon further investigation, the licensee identified that the fuse block associated with the train B turbine trip circuit was not installed. The K640 relay of B train solid state protection system (SSPS) was closed, it energizes the turbine trip circuit through the fuse block. The licensee determined that the ESFAS relay K640 was always operable; however, without the fuses installed, its output to open the solenoid valve 20-2/AST to trip the turbine would not have occurred. Solenoid valve 20-2/AST was one of three turbine overspeed trip protection circuits. The effects of this event appeared to be similar to the results of the 1994 event associated with the 20/ET solenoid valve inoperable due to a buildup of varnish on the moveable valve (inspection report 94009).

The licensee verified technical specification requirements for limiting condition for operation (LCO) applicability. Technical specification 3.3.4, "Turbine Overspeed Protection," was determined by the licensee to be the only applicable LCO. The specification requires at least one turbine overspeed protection system be operable. The licensee determined that two other overspeed protection systems (train A 20/ET trip circuit and mechanical overspeed circuit) were operable. Based on the availability of the two circuits, the licensee determined that no technical specification LCO was exceeded.

The licensee also reviewed the possibility of being outside design basis with two trains of turbine trip circuitry (train A 20/ET and train B 20-2/AST) inoperable. The two trains would have been inoperable for up to 2 hours during actuation logic and relay testing on the opposite train (train A) of SSPS. Following review of the Updated Final Safety Analysis Report (UFSAR) and accident analysis, the licensee determined that the plant was never outside its design basis. Based on the above conclusions, the licensee determined that the event was not reportable.

The inspectors determined that the licensee's actions appeared adequate. However, the inspectors noted a concern with the fuse control program. The program required the documentation of who, why, and when a fuse was removed; however, the program appeared not to require documentation of re-installing the fuse. This was considered an unresolved item pending licensee's root cause determination and further NRC review (50-454/455-95007-01(DRP)).

1.1.2 <u>Containment Spray Pump Room 1A Contaminated Due To Floor Drain Plugging</u>

On July 31, 1995, during the replacement of a leaking vent valve on the 1A containment spray (CS) pump, water drained unexpectedly from the CS system. The floor drains in the CS pump room failed to drain the water, resulting in a minor flood condition with approximately 1 inch of water across the floor. Approximately, 500 ft^2 of floor space was contaminated. The licensee used a portable pump to pump out the water and subsequently decontaminated the room. The licensee determined that the problem was due to a plugged leak detection sump drain line, and a work request was initiated to unplug the drain line.

The inspectors questioned the licensee on the operability of safety related equipment in the Emergency Core Cooling System (ECCS) rooms with an inoperable floor drain system. The inspectors identified that in the UFSAR credit was taken for the floor drain system to mitigate the consequences of a flood. Therefore, the floor drains are support equipment and ensure operability of the CS and the residual heat removal (RHR) pumps. The licensee had not addressed the operability of safety related equipment for inadequate flood mitigation due to inoperable floor drains. The licensee responded to the inspector's concern by expediting repair of the floor drain system. Also, the licensee performed an engineering evaluation to determine operability of the affected equipment.

The licensee found that only one of two floor drains in the CS pump room was clogged. Other floor drains in the CS and RHR pump rooms were identified to be operational. Based on this configuration, the licensee estimated that during a design basis flooding accident, the flood level would be about five inches below the CS and RHR pumps. The analysis assumed the flood duration of only thirty minutes in accordance with the UFSAR. Based on this information, the licensee determined that the pumps were operable.

The inspectors also asked the licensee about the existence of any plant surveillance or preventive maintenance for the auxiliary building floor drain system. A semi-annual administrative surveillance 0BOS WF-SA1, "Auxiliary Building Floor Drain Screen Inspection," was identified. The inspectors reviewed this surveillance and determined that it was not all inclusive. The surveillance did not include the inspection of the ECCS floor drains. The surveillance only required the inspection of screens installed in the drains. Apparently, there was no requirement to fully test the drains with water flow to identify any plugged pipes. The licensee's planned corrective actions included testing of all leak detection sump alarms and drains. Also, the additions to the preventive maintenance program or functional tests of sumps were to be reviewed for implementation by the licensee. Estimated completion date was September 8, 1995.

The inspectors concluded that the flooding was caused by inadequate preparation and draining of the portion of the CS system being released for maintenance. The licensee satisfactorily investigated the cause of the minor flooding, but was slow to recognize the safety significance of clogged floor drains. This was considered an inspection follow-up item pending the licensee's long term corrective actions to address the weakness in the auxiliary floor drain surveillance and further NRC review (50-454/455-95007-02(DRP)).

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726 were used to perform an inspection of maintenance and surveillance activities. Several maintenance and surveillance activities were reviewed. Overall, these activities were satisfactorily performed; however, one violation pertaining to inadequate procedure adherence in erecting seismic scaffold near a safety related equipment, the 2A diesel generator, was identified (paragraph 2.1).

Maintenance support for routine surveillance and corrective maintenance activities were considered satisfactory. Errors still occur on an intermittent basis, all activities were not error free. In this end, the licensee continued to work in improving overall maintenance performance.

2.1 Seismically Inadequate Scaffold Over Safety Related Equipment

On July 10, 1995, the inspectors questioned the purpose of the scaffolding installation over the 2A diesel generator (DG). The licensee indicated that the scaffolding was to allow inspection and modification planning for Darmatt fireproofing and cable re-route which was scheduled for the next Unit 2 refueling outage. The inspectors understood that per licensee procedures scaffolding over safety related and operable equipment was allowed if seismically installed. Byron Administrative Procedure (BAP) 499-3, "Requirements for Erecting Scaffolding and Ladders," provides criteria for building pre-qualified seismic scaffolding such that if the criteria was met, the scaffolding would be seismically qualified. The 2A DG room scaffolding was approved by the licensee to be installed per the pre-qualified seismic procedure on June 26, 1995.

On July 13, 1995, the licensee's Operations department reviewed the scaffolding for potential interference with plant operation or equipment and concluded that the scaffolding did not meet the seismic requirements for clearance from safety related components, lack of bracing to prevent tipping, lack of bay spacing, and lack of internal bracing.

After review, the licensee determined that the scaffolding contained discrepancies from the pre-approved procedure, BAP 499-3; however, according to the licensee's engineering evaluation, the deficiencies in the configuration and construction of the scaffolding was deemed acceptable. The licensee determined that there was no significant deficiencies relating to bay spacing and internal bracing; however, additional safety margin could be provided by installing tie-offs and stand-backs. The other discrepancies were also resolved by installing tie-offs. Engineering (engineering judgement) and safety evaluations (10 CFR 50.59) were subsequently performed. On July 14, the licensee certified the 2A diesel generator room scaffolding as seismic.

On July 24, 1995, the inspectors re-examined the scaffolding in the 2A diesel generator room. The inspectors noted some discrepancies with the seismic requirements of cross and diagonal bracing required per BAP 499-3. In accordance with licensee procedures, seismically qualified scaffolds require longitudinal cross ("X") bracing on one side and at least one longitudinal brace on the other side. On scaffolding with more than one bay, longitudinal cross bracing was required on same side. Also, width cross bracing was required to be installed on both ends of each bay. A bay was an area enclosed by four scaffold posts. The procedure, however, allows an exception if cross bracing cannot be installed due to congestion. The procedure requires "K" bracing to be installed in its place. No allowance for tie-offs or stand-backs as an acceptable substitute. The inspectors identified that tnis seismic requirement was apparently not met, although engineering and 10 CFR 50.59 evaluations were previously performed.

A review of BAP 499-3 by the inspectors identified some programmatic and procedural weaknesses. The inspectors noted that there were no requirements for periodic inspection by a supervisor or engineer during scaffolding construction to ensure procedure adherence. The paragraph providing guidance for when engineering evaluation was required was not clear. There were no requirements for engineering to perform a review prior to, during, or after scaffolding construction unless a procedural deviation was identified. However, if a deviation was not identified prior to construction it potentially renders the equipment inoperable during scaffold construction.

Some procedural requirements or statements may be considered unclear; however, the procedure clearly stated that scaffolding requiring seismic qualification shall be installed per the requirements for pre-qualified seismic scaffolding. Additionally, if scaffolding cannot be built as pre-qualified seismic scaffolding according to the procedure, then an engineering review and a 10 CFR 50.59 safety review was to be completed prior to constructing the scaffold.

In this particular incident, the engineering seismic evaluation should have been performed prior to construction of the scaffolding. This programmatic issue of seismic design concerns on scaffolding was initially identified by the inspectors in a previous inspection report, IR 93013.

The inspectors concluded that the scaffolding over the 2A DG was not constructed in accordance with the pre-approved seismic procedure, BAP 499-3, and therefore not considered seismically qualified during construction. The inspectors determined that the licensee had allowed a potentially non-seismically qualified scaffolding around and over safety related equipment (2A DG) for approximately two weeks with no safety evaluation to determine the DG operability. Engineering and the 10 CFR 50.59 evaluations were performed and was determined by the licensee that the scaffold was adequate; however, the evaluation was made after the scaffolding discrepancies were identified. Furthermore, the inspectors determined that the evaluations appeared weak. No engineering calculations were performed to support the engineering judgement to deviate from the approved seismic procedure. The safety evaluation was performed assuming the scaffolding was seismic subsequent to licensee's corrective actions. The evaluation did not consider that the scaffold was erected unsatisfactory against approved procedures and was allowed to stand over safety related equipment for approximately two weeks. The failure to follow procedures to erect a seismically qualified scaffolding over safety related operable equipment or perform engineering and safety evaluations prior to construction were considered a violation of station procedures, 10 CFR 50 Appendix B, and technical specifications (50-455-95007-03(DRP)).

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an onsite inspection of the engineering function. The licensee was faced with several challenges during this inspection period. Engineering interface with operations, maintenance, and other site organization continued to be satisfactory. Licensee's investigation and corrective action regarding failed secondary neutron sources appeared good. However, the inspectors noted an apparent lack of timeliness and thoroughness of operability assessment on several other issues identified during this inspection period, as discussed below. Additionally, the overall engineering involvement associated with the inadequate seismic scaffold on the 2A Emergency Diesel Generator was weak. Four unresolved items were identified. Overall performance in engineering was mixed.

3.1 Main Steam Tunnel Environmental Qualification (EQ) Concern

On July 25, 1995, the inspector was briefed by the licensee of an apparent issue on Equipment Qualification (EQ) of safety systems and components (SSC) located in the main steam tunnels. The licensee had revisited an old issue from an NRC Information Notice (IN) 84-90, and was addressing concerns regarding the analysis for a Main Steam Line Break (MSLB) Outside Containment and Superheat Condition Evaluation. Licensee's corporate organization, Nuclear Fuel Services (NFS), determined through recent calculations that the original MSLB analysis was apparently incomplete. NFS analysis indicated that the peak temperatures in the steam tunnel, subsequent to a MSLB accident, could reach as high as 561 degrees F. The level of qualification for SSC in the steam tunnel was originally evaluated to be 419 degrees F. The apparent higher qualification temperature would render the SSC in the steam tunnel inoperable. The components potentially affected are the main steam isolation valves (MSIV) and certain Regulatory Guide 1.97 post accident monitoring instrumentation.

The inspector's immediate concern was the apparent inoperability of MSIVs to be able to adequately close and terminate a steam break outside containment. The inspector identified that the licensee had not performed a preliminary operability assessment on the EQ issue affecting the MSIV operation. Further evaluation to answer the concern regarding the potential inoperability of the steam tunnel SSC (e.g., MSIVs) was subsequently addressed by the licensee. A problem identification form (PIF) was written on July 27, 1995. The PIF included a preliminary evaluation where the licensee determined, through engineering judgement and vender/industry information, the equipment in the steam tunnel were functional. The inspector's immediate concern for MSIV operability was adequately addressed, based on the original licensee information on the accident analysis for MSIV isolation occurring prior to 419 degrees F. However, the licensee was retrieving additional data and evaluating this issue for final resolution.

The licensee appeared to have identified the problem concerning the EQ question on a Braidwood PIF dated July 12, 1995. The licensee also held a meeting between Byron, Braidwood, and NFS on July 14, 1995, to discuss the MSLB EQ issue. The licensee indicated that this issue came up as part of the design reviews supporting the transition to Vantage 5 fuel, and noted that the original analysis may be incomplete. However, the inspector noted to the licensee that the transition to Vantage 5 fuel had occurred several cycles ago.

The inspector questioned the licensee on the time frame of their initial understanding and assessment of the EQ question. The inspector received additional information noting several past evaluations on the subject of steam tunnel temperature results following a MSLB outside containment. This document was a summary of steam tunnel temperature results, dated November 8, 1994. The document dealt with the MSLB temperature evaluation, and noted three reference correspondences dating back to 1986, 1988, and 1993. The document also specified the highest peak temperature of 561.8 degrees F, and notes the question of an official reanalysis to the EQ group.

Based on the above information, the inspector had concerns regarding the licensee's timeliness in addressing and resolving the EQ operability issue. At the conclusion of the inspection period, the licensee's estimated time line was to resolve the overall EQ issue by the end of the year, with no firm date established. Furthermore, the licensee had not addressed the MSIV operability issue until questioned by the inspector. Also, the timeliness for informing the inspector of the issue could have been improved.

The inspector concluded that the EQ temperature issue was not a recently identified concern, rather an apparent old item potentially dating back as early as 1988. The original concern of equipment qualification (environmental effects) for a MSLB outside containment was noted in the IN 84-90, and subsequent NRC questions in the safety evaluation report (SER) on the same subject. The licensee responded to the NRC SER and IN letters dated July 22 and September 10, 1986. The NRC's response was noted in SER (NUREG-0876 Supplement No. 7) dated November 1986 (Section 3.11). The NRC accepted the licensee's evaluation for EQ temperatures as indicated in the 1986 SER.

The inspector had performed a preliminary investigation and gathered licensee's documentation on this subject. Based on this preliminary review, the inspector noted that the licensee may not have adequately addressed EQ and Regulatory Guide 1.97 requirements for the peak steam tunnel temperatures. This issue was considered an unresolved item pending licensee's final analysis and further NRC evaluation (50-454/455-95007-04(DRP)).

3.2 <u>Operability Concern Of Certain Barton Transmitters Located In Containment</u>

On July 24, 1995, the licensee identified that the sensing elements on a replacement Barton transmitter obtained from stores was filled with the incorrect fluid. The transmitter was required to be filled with silicon oil; however, it was found filled with demineralized water. Silicon oil was required in accordance with environmental qualification (EQ) for severe containment atmosphere temperatures during post loss of coolant accident conditions. The licensee intended to use the transmitter to replace an apparently bad transmitter on one of two containment floor level indications.

The licensee's action was to return the part to the vender and acquire a new part. The inspector questioned the safety significance and operability of these transmitters, and if similar transmitters in the plant were water filled instead of oil filled. Following the inspector's inquires, the licensee indicated that the part was transferred to Byron stores from construction following plant completion. The licensee also determined that these transmitters were shipped water filled and required Barton to refill the sensing elements with oil during installation. The inspector requested construction documentation to assure that the Barton transmitters installed in the plant were correctly filled with silicon oil.

The licensee was actively searching for construction documentation to verify that the transmitters were oil filled. No definitive documentation was found; however, the licensee was given verbal information from the vender that pertinent information would be searched and mailed to the station. The licensee determined that 12 instruments were potentially affected, two transmitters per unit associated with containment sump level, containment wide range pressure, and containment floor level. These transmitters were Barton model 764 with model 351 isolation bellows attached.

At the conclusion of this inspection period, the licensee was still involved in obtaining documentation to answer the inspector's concern. The licensee's response to the transmitter discrepancy was mixed. The identification of the transmitter difference from stores was good; however, the inquiry into the safety significance and potential inoperability of post accident instrumentation was slow. This item was considered an unresolved item pending licensee's verification of transmitter fluid content and further NRC review (50-454/455-95007-05(DRP)).

3.3 Diesel Generator Lube Oil System Expansion Joint Limiter Rods Found Missing

On July 27, 1995, the inspectors were informed by the Braidwood Resident inspectors of a potential issue concerning the emergency diesel generators (DG). The DG lube oil system has an expansion joint bellows downstream of the main shaft driven lube oil pump. This expansion joint was designed to allow some flex in the piping caused by the pressure thrust during engine start-up. To limit the flex on the bellows, the assembly was designed with four expansion joint limiter rods. At Braidwood, the inspector identified that one of the DG did not have the limiter rods installed. The inspectors reviewed the condition of the Byron DGs. The inspectors identified that all four Dgs did not have the limiter rods installed. The inspectors informed the licensee, and found that the system engineer was previously notified of the potential concern by the Braidwood system engineer.

The licensee immediately initiated an operability assessment for the Dgs. The DG vendor informed the licensee that these rods were installed during the initial qualification of the engine skid and should be installed on the diesel. The licensee's site engineering group made a preliminary assessment that the Dgs were operable. This was based on the licensee's determination that even with the missing expansion limiter rods, the piping stress values were within the ASME Section III Appendix F allowable. The inspectors verified that the NRC Generic Letter 91-18, "Technical Guidance for Resolution of Degraded and Nonconforming Conditions," allowed the use of ASME Section III Appendix F criteria in evaluating operability of piping subsystems. However, Generic Letter 91-18 only allowed the margin of piping stress until the next available outage. Where the system was then required to be repaired to its original stress design.

The licensee's preliminary operability evaluation appeared satisfactory. The licensee was working on the final operability assessment and documentation. The licensee manufactured the required limiter rods, which were installed the following day. The length of time the condition existed and the cause of the discrepancy was still under investigation. This was considered an unresolved item pending completion of licensee investigation and NRC review (50-454/455-95007-06(DRP)).

3.4 Error In Calculation Of Shutdown Margin

On July 14, 1995, the licensee's corporate organization, Nuclear Fuel Services, generated a PIF informing Byron, Braidwood, and Zion stations of an apparent error in the shutdown margin (SDM) methodology for calculating control rod worth. Apparently, this error was originally identified by Westinghouse during a 1993 reload analysis for control rod worth. The error involved the calculation of SDM during a post reactor trip uncontrolled cooldown condition below 550 degrees F. The calculation was performed down to 525 degrees F, but the values for 557 degrees F were assumed. This error was evaluated in 1993 to make a difference in reactivity of 20 pcm or 2 ppm in boron concentration. The Westinghouse staff considered this value to be insignificant. However, the licensee recently discovered that the impact was 120 to 150 pcm and that this difference in the SDM calculation was no longer conservative. The minimum SDM requirement of 1300 pcm could not be supported for a post-trip cooldown from 557 to 525 degrees F at the end of cycle.

The licensee performed calculations using corrected control rod worth to determine how the current operating cycles would be affected. The licensee determined that sufficient SDM existed until the Units reach 12,000 MWD/MTU. The burnup conditions were approximately 9,300 and 4,500 MWD/MTU for the Byron Units 1 and 2 respectively. Preliminary operability was performed and the licensee determined that there was no immediate concern until the units reached 12,000 MWD/MTU. Apparently, the Byron units have at least six weeks until it reaches 12,000 MWD/MTU.

Byron Emergency Procedure BEP ES-0.1, "Reactor Trip Response," required emergency boration of the reactor coolant system (RCS) if primary temperature decreased to less than 525 degrees F after a reactor trip to maintain an adequate shutdown margin. The licensee determined that with the present rod worth condition a conservative approach was to start boration at 545 degrees F on a post-trip uncontrolled cooldown. At the conclusion of this inspection period, the licensee had initiated actions to upgrade its procedures to reflect the requirement to start boration at a temperature of 545 degrees F. However, the licensee determined that further evaluation was required for long term resolution of this issue.

The licensee's preliminary actions to mitigate the SDM error appeared adequate. The action to upgrade the emergency procedures to initiate early boration at 545 degrees F appeared satisfactory; however, the basis was unclear. The inspectors had additional questions concerning the time of identification, on the cause of the error, and the overall licensee's response. An NRC regional specialist was requested to monitor and assess the licensee's corrective actions. This was considered an unresolved item pending licensee's long-term solution and further NRC regional specialist evaluation (50-454/455-95007-07(DRP)).

3.5 Failed Secondary Neutron Source

During the fall 1994 refueling outage, Unit 1 secondary neutron sources (Antimony (Sb)/Beryllium (Be)) were identified as having a cladding failure (inspection reports IR 94022 and 94023). These secondary sources were encapsulated in a single clad four pin arrangement that was attached to a modified thimble tube plug. The two fuel assemblies with the secondary sources were removed from the reactor and stored in the spent fuel pool on September 26, 1994. The Unit 1 sources were replaced with a double clad design.

The licensee was concerned with the long term affects of the sources left in the spent fuel pool. The activated antimony added to the overall radiation level in the reactor coolant system for Unit 1, and continued exposure of the failed source in the spent fuel pool would potentially lead to further clad degradation. Thimble guide tube design allows a small flow of water through the guide tube, therefore the failed source would allow antimony out into the coolant stream. The isotope of concern was antimony-124, which has a 60 day half-life.

To preclude further consequences from the failed secondary source, the licensee designed a permanent storage container to isolate the source from the water in the spent fuel pool. On June 30, 1995, the licensee initiated actions to specifically identify the failed source and to remove both secondary sources from the spent fuel assemblies. One failed pin in one secondary source was identified. The two secondary source assemblies from Unit 1 were successfully removed and transferred to the permanent storage container. A portion of the failed pin was left in the spent fuel assembly thimble tube. The licensee with Westinghouse was initiating plans to plug the thimble tube to preclude any further antimony leakage into the spent fuel pool.

The failure history in the industry showed that the single clad secondary sources should be replaced with double clad sources. The Unit 2 secondary sources were replaced with double clad design during the Spring 1995 refueling outage as a precaution against a cladding failure. The licensee has made plans to relocate the Unit 2 secondary source assemblies into permanent storage containers during the second quarter of 1996.

Overall, the coordination and planning between operations, engineering, and radiological protection groups were considered good. The execution of source removal was well planned including contingency actions for any radioactive gas release from the failed source. No radioactive gas release was observed during the evolution. The licensee appeared to have addressed all questions associated with the design of the permanent storage containers. The storage containers were manufactured and designed with Westinghouse support. The licensee was investigating different methods of removal of antimony from the spent fuel pool water, none have proved effective in reducing the antimony concentration in the spent fuel pool. At the end of the inspection period, no major problems were noted in the increase in radiation level in the spent fuel pool from the antimony; however, the licensee was continuing its efforts to attempt to remove the antimony from the water.

3.6 Engineering Support on Seismic Scaffolding

During this inspection period, the inspectors identified an apparent lack of licensee's control of erecting seismically qualified scaffolding. This issue was not a new concern, but was originally brought to the licensee's attention in inspection report IR 93013. The licensee was to address the seismic and general concerns on its overall scaffolding process. During the time frame of July 10-24, 1995, an incident of inadequate seismic scaffold was identified in the 2A Emergency Diesel Generator room. Concerns regarding procedure adherence, and adequacy of procedures and engineering evaluation was noted by the inspectors. Specific information of the event was detailed in paragraph 2.1 of this report.

3.7 Self-Assessment and Quality Verification - Engineering

NRC Inspection Procedure 40500 was used to perform a review of station SAQV functions. Byron Site Quality Verification (SQV) continues to be very self-critical and offers great benefit to station self-assessment. Particular items of note included the added attention to operator performance, engineering, and industrial safety. The inspectors have reviewed some SQV audits for content and scope. Engineering issues were of particular interest by the inspectors. The audits were noted to be very self-critical and readily identified problems and concern areas. The inspectors reviewed the results of a recent engineering audit for any potential or immediate safety concerns. The audit report indicated no immediate safety issues or violations; however, some potential issues relating to engineering practices were noted. These items included recommendations for improvement in temporary alteration, application of industry experience, and operability assessment programs. The licensee's response and actions on these items will be monitored along with the inspector's recently identified concerns in timeliness and thoroughness of operability assessment noted in above paragraphs 3.1 through 3.4.

4.0 PLANT SUPPORT

NRC Inspection Procedure 71750 was used to perform an inspection of the Plant Support Activities. Specific inspection of licensee activities associated with Security and Safeguards was conducted using NRC Inspection Procedure 83750. Two non-cited violation and one inspection follow up items concerning licensee's security practices were identified (paragraphs 4.2.2 and 4.4.1). However, the licensee's overall security organization continues to satisfactorily perform its plant security responsibilities. The licensee's radiological protection (RP) organization continues to be very active in reducing contaminated areas throughout the plant. Overall, the licensee's performance in plant support was considered good.

4.1 Radiological Controls

During this inspection period, the licensee's RP organization continued to aggressively reduce overall contaminated areas throughout the plant. Presently, the percentage of station contaminated area was less than 1.3%. In conjunction with contaminated area reduction, source term reduction was also targeted. The licensee has initiated special procedures and enhanced other procedures regarding system flushing and tank cleaning. The system flushing improvements resulted in reduction of long term hot spots in several areas. The containment spray isolation valve, 1CS009A, hot spot radiation was reduced from 1.5 Rem to 80 mrem, and the 2A charging system demineralizer outlet line radiation was reduced from 2.9 Rem to 80 mrem. The licensee was involved in developing new radiation protection procedures to outline further RP responsibilities during resin transfers to prevent formation of hot spots. In addition, the station RP organization was teaming with Braidwood station to gain experience during Braidwood's reactor coolant system modification scheduled for the Fall 1995 outage. In conclusion, the licensee continued to maintain an overall good radiological controls program.

4.2 Security and Safeguards

During June 12-21, 1995, a security and safeguards inspection was conducted by regional security specialist. Security force performance pertaining to search drill results during audits required aggressive oversight by security management. Several instances were also noted whereby the security staff was unaware of some procedure requirements and therefore did not comply with the requirements. The noncompliance was of low safety significance, and was identified as a non-cited violation. However, a need to be more aware of security procedural requirements was identified and an inspection followup item was assigned for this item. Overall, the observed performance of the security force was very good and in compliance with security procedures. Self assessment efforts continued to be good and varied. Significant improvement has been made in reducing door ajar alarm concerns. Drills pertaining to certain search functions have identified a level of performance that security management has not fully corrected and warranted continued emphasis by security and Site Quality Verification (SQV) (See paragraph 4.3.4 for related information).

4.2.2 Security Procedures

In reference to the need for more awareness of security procedural requirements, there were four instances noted where security procedure requirements were unknown by the security staff and therefore not complied with. The four procedural items were: (1) occasions when security badges were issued and activated prior to granting of approval by the Station Security Administrator contrary to Section 2.b of Byron Administrative Procedure (BAP) 900-3, (2) access to safeguards information was given to newly hired security officers during initial training classes before fingerprint cards were submitted to the NRC contrary to Section 3.c of procedure BAP 900-7, (3) at least two security procedures pertaining to weekly testing of alarm systems were published as guidance documents rather than as Byron Security Procedures (BSP) as required by Section 1.6 of procedure BAP 900-12, and (4) a critical task (physical examination) was not entered on the individual qualification record as required by Section 2.2.4 of the Security Training and Qualification Plan.

None of the above procedural non-compliance had significant safety concern for a variety of reasons and were considered a violation of minor significance. In accordance with the new NRC Enforcement Policy, this item was treated as a non-cited violation. The licensee's deviation from the procedures does highlight the need for the security staff to be more aware of applicable procedure requirements, comply with them, or revise the procedures to reflect existing practices. This item will be reviewed further during the next inspection by the security specialist and was considered an inspection follow up item (50-454/455-95007-08(DRSS).

4.2.3 Security Self Assessment

Self assessment was varied and well-documented. Since the previous security inspection, two program audits were conducted by the contract security organization and by the SQV organization. Both audits were very good. Additionally, SQV conducted 27 surveillances of security activities within the past year and the contract security organization quality assurance group conducted nine self-assessment surveillances during the past year. Audit and surveillance items were effectively tracked and monitored by the security staff.

4.2.4 Security Events - Security Door Ajars

Several performance trends were monitored by the security organization. An adverse trend was noted during the February and March 1995 time frame, particularly in reference to loggable security events. The trends have significantly improved for the past two months. A very significant improvement was noted during June 1995 regarding door ajar alarms. As of June 20, 1995, only one door ajar incident had to be logged, compared to 18 in May and 63 in March 1995. The licensee's security organization has undertaken an aggressive approach in monitoring and following up on door ajar incidents. The security actions included added plant awareness and accountability of responsible groups causing the door ajar alarms, and support from the maintenance organization to expedite repairs of security doors.

4.3 Follow-up on Previously Opened Items NRC Inspection Procedures 83750 and 92904 were used to perform follow-up inspection of the following items:

4.3.1 (Closed) Unresolved Item (50-454/94017-01; 50-455/94017-01): This was an unresolved item pertaining to the need for a revision to the Security Force Training and Qualification Plan (SFT&QP) to clarify the job conditions and standards for the position of watchperson, and determine if the form used to record completion of training (IQR) met the criteria of the SFT&Q Plan. The SFT&Q Plan revision review had not been formally completed during the inspection period. The review results will be addressed by separate letter. Therefore, this item was considered closed.

4.3.2 <u>(Closed) Inspection Item (50-454/94017-02; 50-455/94017-02):</u> This item pertained to the need to receive the Station Security Administrator's (SSA) approval prior to rebooting the primary security computer system when going from the backup to the primary system. This authorization was considered appropriate to prevent a possible security/safety conflict, because manual loading of security badge data may be necessary when the system transfer occurs. Also, such actions may be more safely performed during shift periods when there are minimum personnel on site.

Necessary guidance for this matter has been provided to the alarm station operators. Also, personnel interviewed during the inspection were aware of the requirement to obtain the necessary approval prior to rebooting the primary security computer system. This item was considered closed.

4.3.3 <u>(Closed) Inspection Item (50-454/94017-03; 50-455/94017-03):</u> This item pertained to monitoring the timeliness of mechanical maintenance support for security equipment. The inspectors noted that almost half of the mechanical maintenance work requests (5 of 11) had been pending from 263 to 425 days; that security compensatory measure hours for security related doors had doubled between May and June 1994; and that the SQV audit noted that the level of mechanical maintenance support did not appear to be as timely as the level of support provided by the electrical and instrument maintenance departments.

The initial trends noted above and the mechanical maintenance support has improved. Such support will be routinely monitored during future inspections. This item was considered closed.

4.3.4 <u>(Open) Inspection Item (50-454/94017-04; 50-455/94017-04):</u> This item was addressed in a Safeguards Information attachment to inspection report 94017 and pertained to search of hand carried items. Details of the issue was considered Safeguards Information and exempt from public disclosure in accordance with 10 CFR 73.21. The inspection report also noted that the Site Vice President stated that recent performance in this area did not meet security supervision's expectations and the situation would be analyzed.

Until recently, performance in this area was excellent. However, during a recent audit, the security force performance was worse than the level of performance noted during the previous inspection and was the basis for the issue becoming an inspection followup item. This item will remain open for review during subsequent inspections.

4.4 Follow-up on Non-Routine Events NRC Inspection Procedures 83750, 90712 and 92700 were used to perform a review of written reports and non-routine events. The following item was closed.

4.4.1 (Closed) Security Licensee Event Report (SLER No.95-001): A SLER was submitted on February 28, 1995 to describe the circumstances pertaining to non-compliance with station security plan requirements during equipment configuration changes due to personnel errors. A hatch was not protected to the level required by the security plan and compensatory measures were not implemented in a timely manner when the deficiency was noted. However, the hatch always had some level of security protection. The security plan has been revised (revision 42) to describe the level of protection currently provided for the hatch and the revision was approved by the NRC by letter dated June 22, 1995. The security weakness meets the criteria of a licensee identified non-cited violation as allowed by the NRC Enforcement Policy. This item was considered closed.

5.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection on August 3, 1995, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities, and discussed the likely content of the report. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

K. Graesser, Site Vice President
*K. Kofron, Station Manager
*D. Wozniak, Site Engineering Manager
T. Gierich, Operations Manager
*P. Johnson, Technical Service Superintendent
*E. Campbell, Maintenance Superintendent
*M. Snow, Work Control Superintendent
*D. Brindle, Regulatory Assurance Supervisor
A. Javorik, Technical Staff Supervisor
*T. Higgins, Support Services Director
E. Zittle, Security Administrator
*K. Passmore, Station Support & Engineering Supervisor
P. Donavin, Site Engineering Mod Design Supervisor
*T. Schuster, Site Quality Verification Director
*R. Colglazier, NRC Coordinator
*W. Kouba, Long Range Work Control Superintendent
J. Bauer, Executive Assistant
*A. Bonnell, Shift Engineer
*J. Feimster, SSE Mechanical Lead
*R. Linboom, Senior Inspector - SQV
*R. Wegner, Shift Operations Supervisor
B. Gossman, Chemistry Supervisor

D. Kruger, Environmental Qualification Coordinator
S. Gackstetter, Thermal Group Leader