U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/89026(DRP); 50-249/89025(DRP)

Docket Nos. 50-237; 50-249 License Nos. DPR-19; DPR-25

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: Dresden Nuclear Power Station, Units 2 and 3

Inspection At: Dresden Site, Morris, IL

Inspection Conducted: December 2, 1989 through January 5, and January 18, 1990

Inspectors: S. G. Du Pont
D. E. Hills

Approved By: J. M. Hinds, Chief
Reactor Projects Section 1B

JAN 18 1990
Date

Inspection Summary

Inspection during the period of December 2, 1989 through January 5, and January 18, 1990 (Report Nos. 50-237/89026(DRP); 50-249/89025(DRP)). Areas Inspected: Routine unannounced resident inspection of previously identified inspection items, licensee event reports, plant operations, maintenance and surveillances, safety assessment/quality verification and report review.

Results:

- No violations or deviations were identified during the inspection period.
- Numerous maintenance, modification and surveillance activities were observed in conjunction with a refueling outage and a dual unit outage as indicated in paragraphs 3.b.1, 4.b.1 and 4.b.2 with no notable problems identified.
- The licensee discovered grease on the internals of two primary containment isolation valves as described in Paragraph 4.b.2 although none appeared on the valve seats themselves. Repeat of a local leak rate test (LLRT) on one of the valves following removal of the grease showed a substantial increase in the measured leak rate. The licensee is continuing activities in regard to this issue.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
*L. Gerner, Technical Superintendent
E. Mantel, Services Director
*J. Kotowski, Production Superintendent
D. Van Pelt, Assistant Superintendent - Maintenance
J. Achterberg, Assistant Superintendent - Work Planning
G. Smith, Assistant Superintendent-Operations
*K. Peterman, Regulatory Assurance Supervisor
C. Allen, Administrative Service Superintendent
W. Pietryga, Operating Engineer
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
J. Williams, Operating Engineer
M. Strait, Technical Staff Supervisor
L. Johnson, Q.C. Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
*K. Kociuba, Quality Assurance Superintendent
*R. Falbo, Regulatory Assurance Assistant
*R. Janecek, Nuclear Safety-Senior Participant
*K. Yates, OnSite Nuclear Safety

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

*Denotes those attending one or more exit interviews conducted informally and formally at various times throughout the inspection period.

2. Licensee Event Reports Followup (93702)

Through direct observations, discussions with licensee personnel, and review of records, the following event report was reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications.

(Closed) LER 249/89010: Improper Stationing of Fire Inspections Due to Personnel Error. This event and corresponding licensee actions were described in inspection report 50-237/89022; 50-249/89021.

No violations or deviations were identified in this area.

3. Plant Operations (60705, 60710, 71707, 71714 and 93702)

a. Operational Activities

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during this period. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of Units 2 and 3 reactor buildings and turbine 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, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan. This included verification that the appropriate number of security personnel were on site; access control barriers were operational; protected areas were well maintained; and vital area barriers were well maintained.

The inspectors verified that the licensees' radiological protection program was implemented in accordance with facility policies and programs and was in compliance with regulatory requirements.

The inspectors reviewed new procedures and changes to procedures that were implemented during the inspection period. The review consisted of a verification for accuracy, correctness, and compliance with regulatory requirements.

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

The inspectors verified that the licensee was implementing protective measures for extreme cold weather. These measures included inspection of areas and equipment susceptible to freezing, including corrective actions for any identified problems. Various problems were encountered such as the main transformer low oil flow condition which resulted from extreme cold during the Unit 2 startup

on December 21, 1989, and the loss of canal level indication in the control room due to freezing of local indication on December 22, 1989. Corrective measures were established for each. Particular attention was paid to cold conditions in normally warm areas of the plant during the dual unit shutdown.

b. Refueling Activities

Unit 3 was shutdown for refueling on December 3, 1989, and removal of the reactor fuel commenced on December 8, 1989. The inspectors verified the technical adequacy of approved procedures and establishment of administrative controls for refueling activities by review of Dresden Fuel Procedure (DFP) 800-1, Master Refueling Procedure, and other associated refueling and operating surveillance procedures. The inspector also verified implementation of these administrative controls prior to and during fuel movements by review of appropriate completed checklists, logs and surveillances, direct observation, personnel interviews, and verification that technical specification requirements for refueling were met. Observation of new fuel receipt and licensee inspection was documented in inspection report 50-237/89019; 50-249/89018. Activities prior to fuel movement were also observed including reactor shutdown and various aspects of removal of the shielding blocks, drywell head, reactor vessel head and dryer/separator. The inspectors verified that key personnel possessed an adequate understanding of their individual responsibilities and administrative requirements through direct observation and personal interviews. Adequate staffing for refueling activities and adequate plant cleanliness conditions were also verified by the inspectors. Appropriate radiation protection controls were verified to have been implemented in conjunction with these activities. The inspectors also verified that steps were being taken for the fuel handling foremen to activate their senior reactor operator licenses in accordance with 10 CFR 55.53(f)(2). Discussions with the fuel handlers indicated that they were aware of the recent fuel handling event which occurred at the Quad Cities plant. The inspectors regarded this as an example of sharing of information with other facilities and remaining cognizant of relevant issues at other facilities and their possible effect upon Dresden.

No violations or deviations were identified in this area.

4. <u>Maintenance and Surveillances (62703, 61720, 61726 and 93702)</u>

a. Maintenance Activities

Station maintenance activities of 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.

The following items were considered during this review:

The limiting conditions for operation (LCO) were met while components or systems were removed from 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 status of outstanding jobs and to assure that priority was assigned to safety related equipment maintenance which may affect system performance.

Portions of the following maintenance items were observed during the inspection period:

Unit 3 Main Turbine/Generator Overhaul
Swing Diesel Generator Lube Oil System Modification Work
Control Rod Drive Pump 3B Internals Inspection and Repair
Unit 3 Control Rod Guide Tube Vacuuming
4 Kv Breaker Inspection and Overhaul
Unit 3 Detailed Control Room Design Review Modification Work
Disassembly, Inspection and Cleaning of Recirculation Pump Motor-Generator Sets 3A and B Generators

The inspectors also witnessed or reviewed various aspects of the following occurrences:

(1) On December 1, 1989, while touring the Unit 2 west low pressure coolant injection (LPCI)/core spray corner room, the inspectors found a conduit body with attached environmental qualification (EQ) tag 661 to be missing it's cover plate. A taped splice was protruding about two inches out of the conduit body through the opening. The conduit continued in three directions to a junction box on LPCI/containment spray instrument rack 2202-19B, a junction box on HPCI instrument rack 2202-29 and through the wall into the torus area. Upon identification to the licensee, the missing cover was replaced. Further review indicated that it was left in the found condition following previous licensee inspections for collection, documentation and submittal of field verification data on junction boxes, pull boxes, conduit bodies and pulling sleeves which were installed on conduit systems associated with EQ equipment items. The need for these licensee EQ inspections was described in inspection report 50-237/89010; 590-249/89009 and were instituted due to the discovery of unqualified terminal blocks and missing weep holes in electrical EQ enclosures.

These inspections had been ongoing since July 10, 1989, under work request 85410. This document contained general instructions for cover removal, inspection in accordance with an attached engineering procedure, conduct of corrective

actions such as drilling of weep holes, cover replacement, and independent verification of cover replacement. The engineering procedure contained specific data forms to be completed for each electrical enclosure. However, the work request was ambiguous as to whether the work request instructions had to be separately signed off as complete for each individual inspected enclosure. The licensee indicated that the intent was for these instructions to outline the scope of work only and that any required signatures would be included in the data forms. Review of the data forms indicated that they contained no instructions or signoffs for replacement of the covers. As a result of the inspector's concerns, the licensee revised the data sheets to provide for reinstallation of the covers, verification thereof and appropriate sign-offs for both.

In response to the inspectors' questions, the licensee determined that the conduit body was not required to be EQ although it was tagged as such. The licensee EQ inspections were conducted by selecting known EQ equipment as starting points and walking down connected conduits. Therefore, some connected conduits were included in the inspections and associated enclosures were tagged as such although it was not known whether they actually contained EQ cables. This specific conduit body contained cables that provided power from a lighting cabinet in the torus area to electrical outlets contained in the two junction boxes mentioned above. The inspectors verified this on the electrical drawings. Thus, there was no safety significance to the example identified by the inspectors.

Another example of a missing conduit body cover plate (EQ tag 819) was discovered by the inspectors in the Unit 2 east LPCI/Core Spray pump room. However, the licensee provided documentation that this had been identified during the EQ inspection and was one of three such examples where parts had been ordered to replace the missing cover plate. Several other missing covers had been discovered during the EQ inspection and had been replaced. The three conduit bodies still awaiting arrival of new cover plates, although containing EQ cables, did not contain splices and thus were not of a safety concern in the interim. Due to the absence of any safety concern in the identified examples and the prompt corrective action taken by the licensee, the inspectors had no remaining concerns regarding this issue.

(2) On December 18, 1989, following completion of lube oil modification work on the 2/3 diesel generator, the diesel generator tripped on high crankcase pressure during a test run. The pressure switch was removed, successfully tested and re-installed. A manometer was also installed on a crankcase tap to determine if a high crankcase pressure actually existed. The diesel generator again tripped on the same signal during the subsequent test although the manometer indicated expected

crankcase pressures demonstrating that the pressure switch was faulty as opposed to an actual high crankcase pressure condition. The pressure switch was bypassed and the diesel generator successfully retested and declared operable to allow commencement of the Unit 2 startup on December 20, 1989. Bypassing of this trip function did not affect the safety function of the diesel generator since this trip was designed to be automatically bypassed on an automatic start. The licensee also planned to observe the manometer which was left in place whenever the diesel generator was operated. The diesel generator was left in this condition until a new pressure switch was procured and installed.

(3) On December 22, 1989, Unit 2 was taken off-line due to discovery of excessive oil in the main generator. This was first noted when a Liquid Detector Full alarm was received in the control room. The licensee drained oil from the hydrogen seal oil drain enlargement and the generator casing. Power was reduced to 30 percent rated thermal power at which time the generator was taken off-line. Reactor power was further reduced to achieve a condition with three to four main turbine bypass valves open while the licensee attempted to determine the source of the oil. The licensee inspected the hydrogen seal oil float trap, seal oil pressure regulator and the generator bushings following purging of the main generator.

The licensee determined that the float trap had become stuck in the closed position such that oil backed up into the hydrogen drain enlargement and overflowed into the inlet pipe to the liquid detector. The float trap assembly was cleaned such that it worked correctly and the licensee confirmed that the high oil level had not damaged the generator including the bushings. The main generator was placed back on line on December 25, 1989.

b. Surveillance Activities

The inspectors observed surveillance testing, including required Technical Specification surveillance testing, and verified for actual activities observed that testing was performed in accordance with adequate procedures. The inspectors also verified that test instrumentation was calibrated, that Limiting Conditions for Operation were met, that removal and restoration of the affected components were accomplished and that test results conformed with Technical Specification and procedure requirements. Additionally, the inspectors ensured that the test results were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed or reviewed portions of the following test activities:

Quarterly Oil Simulated HPCI Overspeed Trip Test
HPCI System Operability Verification

Unit 3 Bypass Valve Oscillation Special Test
Refueling Interlock Check
Intermediate Range Monitor (IRM) Detector Rod Block Functional Test
IRM Downscale Rod Block Functional Test
Source Range Monitor (SRM) Response During Refueling
SRM Functional Test Prior to Core Alteration
SRM Detector Position Rod Block Functional Test
SRM Mode Switch Not in Operate Rod Block Functional Test
Control Rod Blade Inspection

The inspectors also witnessed or reviewed various aspects of the following occurrences:

(1) On December 2, 1989, the licensee declared the Unit 3 HPCI system inoperable in order to decouple the HPCI turbine from the pump for testing purposes. Dresden Operating Surveillance (DOS) 2300-2, HPCI Overspeed Test, and that portion of DOS 2300-3, HPCI System Operability Verification, dealing with the quarterly oil simulated overspeed trip test, were conducted. These surveillances passed their acceptance criteria and, upon completion, the system was further tagged out of service for detailed control room design review (DCRDR) modification work during the refueling outage. The HPCI system was not required to be returned to service since shutdown for the refueling outage was completed prior to expiration of the corresponding technical specification LCO.

(2) On December 5, 1989, with the Unit 3 in the refueling mode, the reactor building to torus check valve 3-1601-31B failed its LLRT. Two vacuum breakers were designed to relieve pressure from the reactor building to the torus if pressure differential exceeded 0.5 psid. Each of the vacuum breaker lines had one of these check valves for primary containment isolation. These were swing check valves manufactured by Crane. Upon removal of a nearby access port and visual observation of the check valve internals the licensee discovered grease on the valve internals. Prior to an NRC investigation in 1983, it was standard practice to apply grease to valve seats to assist in valve maintenance practices. The application of grease to valve seating surfaces could lead to erroneous local leak rate test valves which might not be applicable to accident conditions. This could cause valves to leak during accidents at an excessive rate.

The licensee immediately formed an investigation committee and informed the inspector. The inspector visually inspected the valve internals and noted grease on the outer edges of the valve disk and on the valve body on each side of the seating surface. However, no grease was evident on the valve seat or seating surface itself. The licensee also removed the access port for reactor building to torus check valve 3-1601-31A so that the inspector could also inspect that valve. Grease was

also found on that A valve in the same configuration as the previous valve. While the grease was dirty on both valves possibly indicating that it was there for some time, the grease on the A valve was of a much thicker consistency. The licensee was still awaiting completion of an analysis conducted on samples of the grease at the end of the inspection period.

A shaft cover over the B check valve operating arm access was also found to be installed backwards, which the licensee believed may have been the cause of the failed LLRT. The A valve flange was installed correctly and it had passed its LLRT. A review of operator logs and work histories regarding these valves did not find any valve disc leakage repairs to have been performed since 1975. Additionally, no LLRT failure attributable to valve disc leakage on these valves had occurred since 1980. Thus, the licensee believed the grease was applied prior to the 1983 corrective actions to prevent such occurrences. The 1983 corrective actions included visual inspections of three selected valves. This inspection was witnessed by NRC inspectors and no other examples of greased seats were discovered. Neither of these recently discovered valves were part of the 1983 sample group. The incorrectly installed flange was most likely accomplished during the last completion of DOS 1600-13, Quarterly Suppression Chamber to Reactor Building Vacuum Breaker Full Stroke Exercise Test for 2(3)-1601-31A and B on October 4, 1989. This surveillance involved removal of the shaft cover and a check to ensure that the disk could be freely rotated to the fully open position.

Instructions were included to re-install the shaft cover but no instructions were given as to its correct orientation.

The licensee correctly installed the shaft cover on the B valve and repeated the LLRT. The measured leak rate was 32 standard cubic feet per hour (scfh) compared to a leak rate of 159 scfh during the first LLRT. A leak rate of 30.8 scfh was considered passing. An internal flange where the spool piece connected to the valve body was identified to be leaking slightly. After further repair, a repeat LLRT obtained a 26 scfh leak rate which the licensee believed was still attributable to the internal flange. The LLRT was again repeated after the grease was cleaned from the valve internals and indicated a 225 scfh leak rate. As the licensee believed that grit may have been introduced on the valve seat during the first cleaning, the seats were cleaned and the LLRT was repeated another time indicating a 325 scfh leak rate. The licensee believed that the worsening leak rate was not due to removal of the grease but instead to wearing on the bottom of the pins holding the valve disk which may have caused the valve to seat incorrectly. The licensee planned to rotate the pins 180 degrees and repeat the LLRT on the B valve. Following removal of the grease on the A valve an LLRT indicated a leak rate of 16 scfh compared to an initial measured leak rate of 12 scfh prior to grease

removal. The licensee also planned to review the adequacy of commitments made to the NRC following the 1983 event, to review the practice of removing the shaft covers for operability testing and to present the issue in a station tailgate session. Licensee inspection of the corresponding Unit 2 valves did not find any grease on their internals.

The inspectors regarded licensee identification and investigation of this issue to be thorough and to demonstrate a strong regard for possible NRC concerns.

(3) On December 8, 1989, the licensee informed the inspectors of a deficiency discovered in the LLRT program. Specifically, certain containment isolation valves in the service air, clean demineralized water and drywell air sampling systems were not included in the program. This was discovered by comparing the results of a corporate assessment at the Quad Cities plant to see if the findings also applied to Dresden. The containment isolation valves of concern in the service air and clean demineralized water systems were manual valves and remained closed during normal operation. The drywell air sampling valves of concern were manual valves and were only opened during normal operation to take samples. The licensee planned to incorporate these valves into the LLRT program and completed the LLRTs on the applicable Unit 3 valves prior to the end of the December 1989 Unit 3 refueling outage. The licensee completed LLRTs on the applicable Unit 2 valves during the Unit 2 maintenance outage in December 1989 which all passed the acceptance criteria. The inspectors considered licensee identification of this deficiency to be an example of remaining cognizant of issues at other facilities and applying those findings to Dresden.

(4) While Unit 2 was shutting down on December 10, 1989, for a planned maintenance outage, an unusual event was declared when the drywell personnel interlock inner door failed to pass an LLRT. Technical Specifications required a test pressure of 10 psig and the interlock passed at that pressure. However, 10 CFR 50 Appendix J requirements were inconsistent with Technical Specifications, requiring a much higher test pressure of 48 psig. The interlock could not pass the LLRT at the higher pressure. The leak rate at the higher pressure caused the Technical Specification combined type B and C LLRT limits to be exceeded. The licensee had been evaluating changes to Technical Specifications to conform with Appendix J in this regard but had not yet submitted the proposed changes to the NRC. However, the licensee took a conservative approach and applied higher pressure LLRT results to the appropriate Technical Specification action statements resulting in a required plant shutdown. The unusual event was declared due to implementation of a Technical Specification required shutdown, although the unit was already in the process of shutting down at the time. The unusual event was terminated when reactor

temperature was below 212 degrees F at which time primary containment integrity was not required. The licensee's determination as to the cause of the failure was that it was due to a leaking conduit which contained wiring for a light and the telephone in the interlock. The conduit was cut and capped and the LLRT was successfully repeated. The inspectors considered the licensee actions to be conservative in nature and to exhibit a strong regard for safety concerns beyond compliance with regulations.

(5) On December 7, 1989, the combined leakage rate for the type B and C LLRTs conducted thus far during the Unit 3 refueling outage exceeded the Technical Specification limit of 0.60 La (488.452 scfh). La is the maximum allowable leakage rate at Pa while Pa is the calculated peak containment internal pressure related to the design basis accident. The major contributors to the failure at that time included feedwater check valve 3-0220-58A (1062.82 scfh), reactor building to torus vacuum breaker check valve 3-1601-31B (159.08 scfh) and HPCI steam exhaust to torus check valve 3-2301-45 (100.5 scfh). The licensee planned to determine the cause of the excessive leakage and to complete repairs prior to the Unit 3 startup. As of January 8, 1990, 130 of the planned 163 LLRTs for the Unit 3 refueling outage had been completed with a total of 11 failures.

(6) The licensee issued revision 8 to Dresden Administrative Procedure (DAP) 7-5 Operating Logs and Records to prescribe usage of a control rod drive accumulator high water/low pressure alarm log. This was to be used to identify recurring accumulator failure alarms such that appropriate corrective maintenance could be instituted. This was in response to a General Electric (GE) service information letter regarding accumulator piston maintenance.

(7) On December 15-16, 1989, the scheduled inspection of Unit 3 control rod blades utilizing a high resolution color video camera, revealed indications of defects (minor cracks) on the blade surfaces of three control blades. These were among eight ASEA-ATOM control blades that were installed at the beginning of cycle 9 as part of an Electric Power Research Institute (EPRI) sponsored demonstration. No defects were found on the other five which were also examined. All eight passed a gauge test showing no significant deformation of the blade wings. An additional twelve ASEA-ATOM control blades of a similar but enhanced design were installed at the beginning of cycle 11 which was just completed. After evaluation of the significance of the defects, the licensee re-installed one of the control blades and permanently discharged the other two. The decision to re-install the blade was based upon an ASEA-ATOM analysis relying upon previous experience with usage of cracked blades in Swedish and Finnish reactors.

(8) On December 16, 1989, a Unit 3 group III primary containment isolation occurred during surveillance testing. While performing the surveillance on the standby gas treatment system automatic autuation circuitry, specific fuses were removed to cause the standby gas treatment system to automatically start and a reactor building ventilation system isolation in accordance with the procedure. However, the shutdown cooling system and the reactor water cleanup system also isolated, although jumpers had been previously installed to prevent these two actions from occurring. The licensee determined that work request and surveillance procedure instructions prescribing the jumper installation were correct but that inadequate labeling had caused the jumpers to be installed on the wrong terminal block. The inspector verified that two terminal blocks were located one directly above the other in a control room panel. Only one label indicating terminal block DD was located above the upper terminal block. Since the instructions prescribed installing the jumpers on terminal block DD locations, the instrument technicians used the upper terminal block. However, subsequent review determined the upper terminal block to actually be terminal block DDA while the lower was the intended terminal block DD. The licensee correctly re-labeled the terminal blocks.

No violations or deviations were identified in this area.

5. Safety Assessment/Quality Verification (40500)

The inspectors observed the monthly performance review meeting conducted on December 14, 1989. Plant management reviewed items of interest which occurred since the last meeting including engineered safety feature actuations, specific technical specification limiting conditions for operation entered, continuous or occurring control room alarms, degraded or out of service equipment and potentially significant events. In addition, the status of the top technical issues was discussed. In order to facilitate greater sharing of information with similar facilities, a representative (Shift Engineer) from the Quad Cities plant was also present. In addition, the meeting was attended by a licensed plant operator and a station laborer. The inspectors considered attendance by these individuals to be beneficial toward maintaining management awareness and involvement in relevant issues both internal and external to the plant. Attendance by the plant operator also tended to promote greater professionalism and a sense of responsibility among that group.

The inspectors observed the onsite review committee meeting conducted on December 15, 1989, for the Unit 2 startup that was subsequently conducted on December 20, 1989. This was one of several such meetings on the same subject. The inspectors noted a similar format to the onsite review meeting conducted for the HPCI system alternate lineup which the inspectors observed on October 27, 1989. The details of this issue were described in inspection report 50-237/89023; 50-249/89022. The inspectors noted that the meetings were conducted in accordance with DAP 10-1, On-site Review and Investigative Function, and DAP 10-9, Selection

of On-site Review Participants, as well as Technical Specification 6.1.G.2. The inspectors regarded these meetings as thorough in that they adequately addressed the relevant issues and indicated good knowledge and a safety oriented aggressive attitude toward issues.

The inspectors also reviewed the monthly status report for the month of November. The inspectors found this to be an excellent management tool for remaining cognizant and identifying trends in various departmental indicators.

No violations or deviations were identified in this area.

6. Report Review

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for November, 1989. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16.

No violations or deviations were identified in this area.

7. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on January 5, and January 18, 1990, and informally throughout the inspection period, and summarized the scope and findings of the inspection activities.

The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.