U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-219/88-14

Docket No. 50-219

License No. DPR-16 Priority - Category C

Licensee: GPU Nuclear Corporation
P. O. Box 388
Forked River, New Jersey 08731

Facility Name: Oyster Creek Nuclear Generating Station

Inspection At: Forked River, New Jersey

Inspection Conducted: May 16-20, 1988

Inspectors: CJA for C. Woodard — 6/27/88
C. Woodard, Reactor Engineer — date

CJA for D. Ward — 6/27/88
D. Ward, Reactor Engineer — date

Approved by: CJ Anderson — 6/27/88
C. J. Anderson, Chief, Plant Systems — date

Inspection Summary: Inspection 50-219/88-14 on May 16-20, 1988

Areas Inspected: Routine unannounced inspection of selected areas of the Fire Protection and Electric Power Systems. The Fire Protection inspection included plant tours and inspection of equipment; reviews of administrative control and surveillance procedures; review of fire brigade procedures, training and witnessing a fire brigade drill; review of audits; and licensee actions taken to resolve previously identified items. The electrical inspection included plant tours and inspection of equipment; verification of power feeder transformer tap settings; investigation of a ground fault indication; and licensee actions taken to resolve previously identified items including SIMS Item MPA-B-62 Engineered Safety Features (ESF) Reset Controls.

Results: Inspection conclusions were generally favorable. However, there was one Severity Level V violation (which was resolved during the inspection) and a deviation identified in the Fire Protection System. Four previously identified items were resolved and the licensee's actions taken on SIMS Item MPA-B-62 were considered acceptable.

DETAILS

1.0 Persons Contacted (30703)

GPU Nuclear Corporation

*E. Fitzpatrick, Director of Oyster Creek
*J. Barton, Deputy Director of Oyster Creek
*J. Sullivan, Director of Plant Operations
*G. Bush, Licensing
*J. Rogers, Licensing Engineer
D. Jones, Senior Electrical Engineer
*J. Deblasio, Manager, Support Engineering
R. Fitts, Quality Assurance Auditor
R. Barrett, Manager, Plant Materials
P. Fischer, Supervisor, Electrical Maintenance
A. Dickenson, Senior Electrical Engineer
*E. Scheyder, Director, MCF
*D. Ranft, Plant Engineering Manager
*J. Kowalski, Licensing Manager
*T. Gaffney, Supervisor, I&C
*J. Ventossa, Fire Protection Engineer
*T. Prosser, Fire Protection Instructor
*P. Thompson, Auditor

United States Nuclear Regulatory Commission

*J. Wechselberger, Senior Resident Inspector
*E. Collins, Resident Inspector

*Indicates those present at the exit meeting May 20, 1988.

2.0 Licensee's Actions on Previous Findings (92701)

2.1 (Update) Unresolved Item 87-21-01 - Containment Water Level Monitor

The Containment Water Level Monitoring System is a dual channel system with separate instrumentation, wiring, cable and power supplies in order to meet the single failure acceptance criteria.

During inspection 87-21, the inspector noted that the water level impulse signal to both channels of instrumentation is from a single upturned water collecting tube in the bottom of the torus which splits outside the torus to provide each instrument with a level signal (approved by NRC June 19, 1985 letter). Scrap, debris, etc., could collect in this upturned sensing signal tube and go unnoticed

during calibrations and operation of these instruments since the torus water level is generally a static level. Obstructions in the sensing line could impair the dynamic response of these instruments in the event of an accident. Each of the dual channel level instrument detectors located outside the containment has capped stub lines which could be backflushed to assure that the sensing line is open.

Inspection revealed that the licensee has revised Station Procedure 604.3.017 - Wide Range Torus Level Calibration (Revision 5, October 19, 1987) to include backflushing the instrument sensing lines. Since the Technical Specification Section 4.13 requires calibration of this instrument at least once each six months, the instrument lines will be flushed at these times. These actions overcome one of the sources of single failure for these instruments. However, further NRC evaluation is needed to assure the acceptability of this design.

2.2 (Closed) Unresolved Item 50-219/86-11-01 - Insufficient Fire Drill Participation

Plant procedures did not require fire brigade members to participate in periodic fire drills. This resulted in several firefighters not attending a sufficient number of drills to meet NRC guidelines.

Procedure 6232-PGD-2684, Oyster Creek Fire Protection Training Program, Revision 0, has been issued and requires fire drills to be conducted on a quarterly basis for each operating shift. In addition, the procedure stipulates that any brigade member not participating in at least one drill annually will be removed from the active fire brigade roster.

This item is resolved.

2.3 (Closed) Inspector Followup Item 50-219/86-24-05 - Review Corrective Action Associated with Flooding of Cable Spreading Room

The inadvertent operation of the deluge sprinkler system in the Cable Spreading Room resulted in loss of rod position indication due to moisture intrusion into the ER2 cabinets.

In response to this incident, the licensee evaluated various protection methods for the ER2 cabinets to prevent reoccurrence. The licensee elected to modify the deluge system in the area by replacing the open head sprinklers with closed head sprinklers in the area of the cabinets. This effectively eliminated the possibility of inadvertently spraying the cabinets since such an occurrence would require a dual failure of the deluge valve operating and the closed head opening. This modification was accomplished under Maintenance and Construction Short Form 36386. The modification was verified to have been completed by field inspection by the inspector.

In addition, the licensee evaluated the potential for damage to plant equipment under Technical Data Report 864, Revision 0. This report evaluated the need for additional protective measures for equipment in all plant areas and established an ongoing method to evaluate the need for additional protective measures due to future plant modifications.

This item is resolved.

2.4 (Closed) SIMS Item MPA-B-62, IE Bulletin 80-06 - Engineered Safety Feature Reset Controls (92703)

Bulletin 80-06 dated March 13, 1980 cited potential design deficiencies in the Engineered Safety Features (ESF) reset controls based upon reported instances where safety activation signals were either manually overridden or bypassed (blocked) during normal plant operations. In addition, a related design deficiency with regards to the resetting of ESF actuation signals was reported where upon the reset of an ESF signal certain safety-related equipment would return to its non-safety mode.

Operating licensees were required to take the following actions in response to Bulletin 80-06:

1. Review the drawings for all systems serving safety-related functions at the schematic level to determine whether or not upon the reset of an ESF actuation signal, all associated safety-related equipment remains in its emergency mode.

2. Verify the actual installed instrumentation and controls at the facility are consistent with the schematics reviewed in Item 1 above by conducting a test to demonstrate that all equipment remains in its emergency mode upon removal of the actuating signal and/or manual resetting of the various isolating or actuation signals. Provide a schedule for the performance of the testing in the response to this Bulletin.

3. If any safety-related equipment does not remain in its emergency mode upon reset of an ESF signal at your facility, describe proposed system modification, design change, or other corrective action planned to resolve the problem.

4. Report in writing within 90 days, the results of your review and include a list of all devices which respond as discussed in item 3 above, actions taken or planned to assure adequate equipment control, and a schedule for implementation of corrective action.

Accordingly, the licensee responded to Bulletin 80-06 by letter dated June 19, 1980 as follows:

Item 1 - The licensee conducted drawing reviews which identified components in the following systems that would not remain in their emergency mode following reset of the ESF actuation signal.

1) Drywell Isolation (DI)
2) Main Steam Isolation (MSI)
3) Core Spray System (CSS)
4) Standby Gas Treatment System (SGTS)
5) Auto Depressurization System (ADS)
6) Isolation Condenser System (ICS)

Item 2 - The licensee verified that the installed instrumentation and controls were consistent with the Item 1 schematics by demonstration tests except for the MSI, CSS and ICS. These were committed for test after startup from the 1980 outage with NRC to be advised of any discrepancies.

Item 3 - The licensee committed to design modifications for the DI, MSI and CSS systems; operating procedures revisions for the SGTS, and justifications in lieu of corrective actions for the ADS and IDS.

The licensee's responses were evaluated by NRR and reported by letter dated June 21, 1982 (including the Safety Evaluation Report). This evaluation concluded that the licensee's Bulletin 80-06 response/ actions were considered to be in compliance with NRC criteria subject to inspection confirmation of the following:

- Successful installation of the modifications

- Successful completion of demonstration tests which verify that all associated equipment operates properly to achieve the proper ESF reset control functions.

The modifications required included the replacement of two position isolation valve control switches with three position spring return switches in the following circuits:

- Main Steam Line Valves

- Clean-Up Steam Line Isolation Valves

- Shutdown Cooling Isolation Valves

- Drywell Floor Sump Isolation Valves

- Equipment Sump Isolation Valves
- Drywell Ventilation Isolation Valves
- Drywell Purge Isolation Valves
- Drywell N_2 Purge Inlet Valves
- Torus N_2 Purge Inlet Valves
- Recirc Loop Sample Valves
- Torus Vent Valves
- Instrument Air Valves
- Isolation Condenser Vent Valves
- Torus/Drywell Atmosphere Control Valves
- TIP Ball Valves

The detailed modification description including the valve and circuit identifications is in Oyster Creek Modification Proposal 528.80-3, Containment Isolation Switch Replacement.

The replacement of these switches was verified by physically inspecting each of the switches in its control panel location. No discrepancies were observed.

The inspector confirmed that the licensee has verified that the actual installed equipment and controls were consistent with the schematic drawings by conducting tests to demonstrate that all equipment remains in its emergency mode upon removal of the actuating signal and/or manual resetting of the various isolating or actuation signals. These tests were performed utilizing routine station surveillance, test, calibration procedures as follows:

- 602.3.005 Automatic Depressurization Actuation Circuit Test and Calibration
- 607.3.002 Containment Spray System Automatic Actuation Test*
- 609.3.002 Isolation Condenser Isolation Test and Calibration*
- 610.3.105 Core Spray System I Instrument Channel Calibration and Test

- 610.3.205 Core Spray System II Instrument Channel Calibration and Test
- 619.3.003 High Drywell Pressure Isolation Functional Test*
- 619.3.004 Reactor Lo-Lo Water Level Functional Test*
- 619.3.005 High Flow in Main Steam Line Test and Calibration
- 619.3.007 Low Pressure Main Steam Line Functional Calibration and Test While Shutdown
- 619.3.008 Low Pressure Main Steam Line Functional and Calibration Test While Operational
- 619.3.009 Main Steam Line Tunnel High Temperature Sensor Calibration
- 619.3.010 Main Steam Line Tunnel High Temperature Sensor Functional Test
- 621.3.003 Main Steam Line Radiation Monitor Test and Calibration
- 621.3.005 High Radiation Monitor (Rx Build Isolation) Calibration
- 651.4.001 Standby Gas Treatment System Test

*These procedures required temporary changes to verify equipment response.

A sample review was made of the current revisions of the above surveillance procedures to verify that they demonstrate that equipment remains in its emergency mode upon removal of the actuating signal and/or manual resetting of the various isolating or actuation signals. The following procedures were reviewed:

- 610.3.105 - Core Spray System Instrument Calibration and Test, Revision 11, February 4, 1988
- 651.4.001 - Standby Gas Treatment System, Revision 26, March 16, 1988

No discrepancies were observed. This item is closed.

2.5 (Closed) Unresolved Item 87-33-01 - "C" Main Station Battery Disconnected

2.5.1 Description of the Event

On October 30, 1987, the licensee discovered that the "C" main station battery, which supplies 125 volt DC control power to emergency diesel generator (EDG) No. 1 logic and other vital loads was disconnected from its bus while EDG No. 2 was out of service for maintenance. As a consequence, the redundant trains of safety-related equipment required to be operable would not have functioned as designed during a loss of offsite power event. The event was considered reportable in accordance with the requirements of the Code of Federal Regulations 10 CFR 50.73(a)(2)(v) and was properly reported by the licensee on the day of its discovery (October 30, 1987).

2.5.2 Background and Conditions of the Plant Leading to the Event

The plant was in cold shutdown for a maintenance outage with the reactor coolant temperature less than 212°F. During the outage, plans were made to perform the 18-month inspection of both emergency diesel generators (EDGs). Inspection of EDG No. 1 was begun on September 30, 1987 and completed on October 10, 1987. The "C" main station battery discharge test was begun on October 10, 1987. The 125 volt direct current (DC) distribution center normally supplied by the "C" battery was supplied by the "C" battery charger during the discharge test. After discharge of the "C" battery, charging operations were begun the same day. Due to difficulties associated with charging the battery, however, the battery was not returned to service until October 30, 1987. In the meantime, EDG #2 was removed from service on October 13, 1987 for its 18-month inspection and returned to service on October 19, 1987. When the "C" battery was returned to service on October 30, 1987, personnel discovered that for the six-day period that EDG #2 was being inspected with "C" battery being charged, neither EDG would have automatically initiated on a loss of offsite power.

2.5.3 Licensee Analysis of the Cause of the Event

When the "C" battery was removed from service, the temporary variation was not logged on the Temporary Variation Summary Sheet, as required by Plant Procedure 108, "Equipment Control." Personnel also neglected to log the outage on the control room turnover sheets. In addition, the turnover sheets do not specifically address "C" battery operability status. Thus, the operators who removed EDG No. 2 from service were not aware that the "C" battery was out of service.

The main station battery discharge test procedure (Plant Procedure 634.2.001) does not specify the safety functions and equipment rendered inoperable with removal of the battery from service (upon a loss of offsite power) nor does it provide procedural controls to ensure that EDG No. 2 is not removed from service while the "C" battery is out of service. It should be noted that the procedure deficiencies resulted from a failure of the procedure preparer and reviewer to recognize the implications of removing a station battery from its bus concurrent with a loss of offsite power.

2.5.4 Licensee Safety Assessment Analysis of the Event

When the plant is in the cold shutdown condition, the safety systems required to be operable are the core spray system (EIIS Code BM) and standby gas treatment system (SGTS)(EIIS Code BH). Core spray is required to assure that a makeup source to the reactor vessel is available in the unlikely event of a large leak in the reactor primary system. The SGTS is required in the event of a release of radioactive material to the reactor building to provide a filtered elevated release pathway. If an accident had occurred concurrent with a loss of offsite power, neither diesel generator would have automatically actuated to supply power to safety systems. Although the inoperability of safety systems is significant, the consequences of this occurrence are minimized by three factors.

First, there are two diesel operated fire water system (EIIS Code KP) pumps which can be manually aligned to supply water directly to the reactor to provide makeup for leakage up to the delivered capacity (2000 gallons per minute each) of the fire suppression pumps. Emergency operating procedures provide direction to accomplish this evolution.

Second, this condition would not have occurred during power operation since the plant is always shut down for diesel generator inspections and station battery discharge tests. Under these conditions, the probability is low for a condition to develop which threatens adequate core cooling. For such a condition, all of the following events must occur simultaneously: "C" battery disconnected from its bus; EDG #2 out of service; both fire water pumps out of service; complete loss of offsite power; and a leak in the primary system sufficient to uncover the fuel.

Third, in the event that Core Spray or SGTS would have been required, Station Procedure 2000-OPS-3024.10c, "Electrical Distribution-125VDC Diagnostic and Restoration Actions," provides guidance for diagnosis and correction of a loss of station DC power. Even at the end of a discharge test, the minimum battery voltage is 105 volts DC for the 60-cell battery. Therefore, sufficient energy is present to provide breaker switching functions and undervoltage load sensing to permit EDG No. 1 to start and assume load. It should be noted that when station battery "B" is discharged, its load can be cross-tied to another battery ("A"). The "A" battery is capable of providing required DC with the exception that it is not seismically mounted. Thus, the situation where EDG No. 1 is removed from service while the "B" battery is discharged is not a major concern.

2.5.5 Licensee Corrective Actions

The licensee took immediate corrective actions to restore all safety-related 4160VAC and 125VDC to an operable status. In order to preclude recurrence, station operating procedures 340.1, 340.3 and 341 and control room turnover sheets were revised to provide additional administrative control and specific indication of operability status for the 125VDC battery systems and for the emergency diesel generators. The licensee also indicated plans to revise the 18-month battery surveillance procedure 634.2.001 prior to the next outage to explicitly require that all necessary safety systems supplied from the in-service battery are operable when the other division battery is out of service.

2.5.6 Conclusions

The NRC inspector concurs with the licensee's analysis of the event including the circumstances which led up to it and the corrective actions taken to prevent recurrence. The root causes of the event as described in paragraph 2.5.2 of this report and in LER No. 87-044 dated November 1987 were inadequate procedures which led to personnel errors. The procedural deficiencies were attributed to the failure of the preparers and reviewers to recognize the safety implications of removing a station battery from its bus concurrent with a loss of offsite power.

As such, this event is a violation of the licensee's technical specification section 6.5.1.1 which requires that procedures important to safety be prepared by persons knowledgeable in the areas affected and that the procedures shall be reviewed for adequacy by others.

However, due to the fact that the circumstances which led to this event had a very low probability of occurring, the safety significance was minimal, and it was licensee identified, reported and appropriate corrective actions taken to prevent recurrence no notice of violation will be used. Technical Specification 3.7C Paragraph 3 requires that if both diesel generators become inoperable, the reactor shall be placed in cold shutdown condition. Since the plant was already in cold shutdown, the inspector concluded that this event was not a violation of a Limiting Condition of Operation.

This item is closed.

3.0 Electrical Systems and Components (51053)

3.1 Ground Fault Detection Improper Actuation

During a routine operations surveillance start of the "A" Core Spray Pump on May 13, 1988, the ground fault detection relay indicating target flag indicated a ground. However, the pump started and operated satisfactorily without a trip from the ground fault detection relay. Investigation by the licensee revealed that the ground fault relay had not tripped sufficiently to close its contacts in the trip coil circuit of the core spray pump circuit breaker to cause the breaker to trip which would stop the pump. The indicating flag was reset and subsequent restarts of the pump did not cause the ground fault detection flag to indicate or the relay to trip the pump. The licensee concluded that a ground did not exist and that the flag indication was a random, improper, erroneous indication of ground.

The inspector determined that the ground relay is a General Electric Model PJC with energized to pick-up coil tap adjustment settings from 0.5 to 2.0 amperes. The core spray pump relay was set on the 0.5 ampere tap. With this tap setting, the relay has an instantaneous pick-up time of approximately .006 seconds. The circuit design in applying this relay is such that its coil responds to unbalanced three phase currents to the core spray pump which are derived from a single window-type current transformer through which all three (power cables) phases pass. Normal pump starting and running currents should be balanced and should not actuate this relay. Whereas unbalanced currents such as those which could be caused by a ground would actuate this relay. The design of the relay is such that the current transformer secondary currents directly activate the relay coil to move the relay armature. When the relay armature moves sufficiently, the target flag moves and mechanically latches into a ground-indicating position. However, it appears that the relay armature may travel sufficiently to cause the flag to latch but at the same time, may not travel sufficiently either in length of travel or time duration (or both) to actuate the relay contacts to trip the core spray pump. (This same type of relay is used in numerous other similar safety-related applications.)

The licensee reported that minor movement of the relay armature due to minor unbalances in phase currents during the instantaneous motor starting transient could be expected. However, that both the extremely short magnitude and duration of these transients should be such that erroneous and improper tripping of the flag or the pump are not expected. It was the opinion of the licensee that a defective flag mechanical release/latch for the "A" core spray pump ground relay may be the cause of the problem experienced. In order to complete this evaluation, the licensee plans (at the next appropriate outage) to examine the relay mechanism to determine if there are either electrical or mechanical problems with it. In addition, an order of magnitude evaluation of the amount of relay armature travel expected during normal starting transients will be compared to that travel required to close the relay contacts and trip the pump. This item is unresolved pending completion of the licensee's evaluation, completion of any necessary corrective actions and NRC review. (Unresolved Item 88-14-01)

3.2 Degraded Grid Voltage Protection System

The Technical Specification changes required to implement the Oyster Creek Degraded Grid Voltage Protection System for Class 1E Power Systems were authorized by NRC letter dated February 11, 1985. These changes are included in Amendment No. 80 to the Technical Specification. Licensee supporting documentation for the changes in the technical specification include requirements that each of the adjustable power feeder transformers to the Class 1E systems be set on a specific tap position in order to provide the required voltages. The 34,500/4160 volt Startup Transformers and Auxiliary Transformers are required to be set on Taps 4 and 5 respectively. The 4160/480 volt unit substation transformers 1A3 and 1B3 are required to be set on Tap position 2; 1A2 and 1B2 are required to be set on Tap 3; and 480-208/120 volt transformer 1T3 is required to be set on the 456 volt tap. These tap settings were confirmed by visual inspection except for 1T3 which was confirmed by verifying the licensee change on Work Request 2113A3 which was completed on August 12, 1980. No deficiencies were identified.

4.0 Fire Protection/Prevention Program (64704)

4.1 Fire Prevention/Administrative Control Procedures

The inspector reviewed the following Fire Prevention/Administrative Procedures:

Procedure No./Revision	Title
101.2/Rev. 11	Fire Protection Organization and Responsibility
119/Rev. 7	Housekeeping
120/Rev. 12	Fire Hazards
120.1/Rev. 9	Welding, Burning and Grinding Administrative Procedure
120.2/Rev. 1	Continuous Fire Watch Instructions
120.4/Rev. 4	Fires
333/Rev. 22	Plant Fire Protection Systems

Within the scope of this review, it was determined that programs administered by the above procedures meet the NRC guidelines of the document entitled "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls, and Quality Assurance" dated June 1977, except the procedures associated with Ignition Source Work.

Attachment 4 to the NRC document referenced above includes guidance for an acceptable program for controlling work involving the use of ignition sources. Included in the guidance is the requirement that fire watches for ignition source work be trained and equipped to prevent and combat fires. In addition, Attachment 4 also references the National Fire Protection Association (NFPA) Standard 51B, Cutting and Welding Processes, for additional guidance. Section 3-3 of NFPA 51B requires that fire watches for ignition source work have fire extinguishing equipment readily available and be trained in its use, including practice on test fires.

By letters dated April 7, 1978 and September 22, 1978, GPU committed to meet the requirements of Attachment 4 in developing their ignition source control program. This commitment was approved in Supplement 3 to Oyster Creek's Fire Protection Safety Evaluation dated August 25, 1980.

During the week of the inspection, two jobs involving ignition sources were observed. In both cases, the fire watch assigned to the job was not performing their duties in accordance with plant procedures and were not fully aware of their duties as a fire

watch. The site training program does not include specialized training for these fire watches which meets the requirements of the NRC guidance and NFPA 51B. Therefore, the licensee has failed to satisfy their commitment to provide such a training program. This is identified as Deviation Item 88-14-03, Failure to Provide Training for Ignition Source Fire Watches.

The licensee acknowledged th failure to satisfy the commitment to provide training for ignition source fire watches in the exit meeting held May 20, 1988 and committed to be in compliance with their commitment within 90 days.

4.2 Fire Protection Surveillance Procedures

The inspector reviewed the following Fire Protection System Surveillance Procedures:

Procedure No./Revision	Title
645.4.001/Rev. 3	Fire Pump Operability Test (Monthly)
645.6.004/Rev. 10	Fire Suppression Water System Valve Lineup (Monthly)
645.6.015/Rev. 3	CO_2 Storage Tank Weekly Check (Weekly)
645.6.017/Rev. 3	Fire Barrier Penetration Surveillance (18 Month)
645.6.023/Rev. 1	Fire Suppression Water System Underground Flush Test (3 Year)
645.6.026/Rev. 2	Fire Damper Functional Test (18 Month)
645.6.028/Rev. 0	Thermo-Lag Envelope System Fire Barrier Surveillance (18 Month)

The above surveillance procedures were reviewed to determine if the various test outlines and inspection instructions adequately implement the surveillance requirements of the plant's Fire Protection Technical Specifications. In addition, these procedures were reviewed to determine if the inspection and test instructions followed general industry fire protection practices, NRC fire

protection program guidelines and the guidelines of the National Fire Protection Association (NFPA) Fire Codes. Within the scope of this review, it was determined that the above procedures are satisfactory.

4.3 Fire Protection System Surveillance Inspections and Tests

The inspector reviewed the following surveillance inspection and test records for the dates indicated:

Procedure No.	Results Reviewed
645.4.001	1/6/88, 1/12/88, 2/13/88 and 3/4/88
645.6.004	5/13/87 through 2/17/88
645.6.015	1/28/87 through 2/29/88
645.6.017	2/2/88
645.6.023	8/11/83 and 4/30/87
645.6.026	2/19/85, 2/19/86 and 2/26/88

The surveillance test record data and testing frequency associated with the above fire protection system surveillance test/inspections were found to be satisfactory with regard to meeting the requirements of the plant's Fire Protection Technical Specifications.

4.4 Fire Protection Audit

The most recent audit reports of the Oyster Creek Fire Protection Program were reviewed. These audits were:

Audit No.	Date Conducted
0-OC-87-04	6/22 - 7/2/87
0-OC-86-06	6/16 - 7/15/86

These audits identified several fire protection program discrepancies and unresolved items, and recommended several program improvements. The licensee has evaluated these items and, where warranted has either

implemented the corrective actions associated with these audit findings or a scheduled date for completion of the corrective actions had been established. It was concluded that the licensee was taking the appropriate corrective actions on these audit findings.

4.5 Fire Brigade

(1) Organization

The total station fire brigade is composed of approximately 80 personnel from the Operations, Maintenance and I&C staff. The on duty shift fire brigade leader is normally one of the licensed operators. The inspector reviewed the shift coverage logs for the following dates and verified that sufficient qualified fire brigade personnel were on duty to meet the provisions of the plant's Technical Specification:

January	1988
February	1988
March	1988

These shift coverage logs had previously been reviewed by the site QA department which identified 11 occasions where unqualified personnel were assigned brigade duty. These discrepancies are identified in Quality Assurance Monitoring Report serial number 8823007 and corrective action was taken. The inspector did not identify any additional discrepancies.

In addition, the inspector verified that sufficient personnel were assigned to each shift to meet the minimum operating and fire brigade staff requirements of the Technical Specifications. Therefore, based on the review of the duty rosters associated with the above dates, it was determined that there was sufficient manpower on duty to meet both the operational and the fire brigade requirements of the plant's Technical Specifications.

(2) Training

The inspector reviewed the training and drill records for 7 brigade leaders and 12 brigade members for 1987 and 1988. The records reviewed indicated that each of these leaders and members had attended the required training and participated in the required number of drills. The inspector also verified that a fire brigade drill had been conducted quarterly for each shift. The fire brigade training records which were inspected were found satisfactory, and met the licensee's commitments for fire brigade training.

The inspector reviewed the licensee's initial fire brigade training program to verify that the following training topics are being covered:

- Indoctrination of the plant fire fighting plan with specific identifications of each individual's responsibilities.

- Identification of the type and location of fire hazards and associated types of fires that could occur in the plant.

- The toxic and corrosive characteristics of expected products of combustion.

- Identification of the location of fire fighting equipment for each fire area and familiarization with the layout of the plant, including access and egress routes to each area.

- The proper use of available fire fighting equipment and the correct method of fighting each type of fire. The types of fires should include fires in energized electrical equipment, fires in cables and cable trays, hydrogen fires, fires involving flammable and combustible liquids or hazardous process chemicals, fire resulting from construction or modifications (welding), and record file fires.

- The proper use of communication, lighting, ventilation and emergency breathing equipment.

- The proper method for fighting fires inside buildings and confined spaces.

- The direction and coordination of the fire fighting activities (fire brigade leaders only).

Based on this review, it was determined that the licensee's initial fire brigade training program covers the above required training topics. In addition, it appears that the licensee's fire brigade training program repeats the basic fire fighting skills of the initial program to qualify fire brigade members every two years.

(3) Fire Brigade Drill

During this inspection, the inspector witnessed an unannounced fire brigade drill. The drill fire scenario was a fire in a flammable liquids locker in the basement of the Turbine Building.

Five fire brigade members responded to the pending fire emergency. The brigade assembled at the mezzanine level of the Turbine Building in full protective firefighting turnout clothing and two brigade members in self-contained breathing apparatus. An initial size-up of the fire condition was made by the fire brigade leader and two 1½ inch fire attack hose lines, one utilizing firefighting foam, were advanced into the basement. The fire attack hose lines were placed in service on the fire and the fire was placed under control in twenty minutes. In addition, the fire brigade initiated fire victim search and rescue.

The fire brigade utilized proper manual firefighting methods and reacted to the fire drill scenario in an effective and efficient manner.

One problem was noted during the drill. The brigade leader dispatched a runner to bring firefighting foam to the fire scene; however, due to a modification in the area where the foam was stored, the foam was inaccessible. The inspector emphasized the need for emergency firefighting equipment to be available at all times during his exit interview with plant management.

4.6 Plant Tour and Inspection of Fire Protection Equipment

(1) Inspection of Fire Brigade Manual Fire Fighting Equipment

The inspector performed an inspection of the fire brigade equipment stored at the fire brigade equipment lockers located in the Turbine Building Mezzanine and Monitor and Change Areas.

A total of five sets of turnout gear (coats, boots, helmets, etc.), five sets of self-contained breathing apparatus, and sixteen spare air cylinders are stored in each area. Based on this inspection, the designated fire brigade equipment was found to be properly maintained and stored in a ready condition.

(2) Outside Fire Protection Inspection

The inspector verified that the fire pond and redundant water tank contained sufficient water to meet the requirements of plant Technical Specifications. The three fire pumps were inspected and found to be in service. The diesel fuel tanks for the normal diesel driven fire pumps were approximately 3/4 full of fuel which met the requirements of the Technical Specifications.

The following sectional control valves in the outside fire protection water supply system were inspected and verified to be properly aligned and locked in position:

V-9-4	Fire Pump 1-1 Discharge
V-9-5	Fire Pump 1-2 Discharge
V-9-8	Loop Post Indicating Valve
V-9-16	A.O.G. Building Isolation Valve
V-9-33	Loop Post Indicating Valve

The following fire hydrant equipment houses were inspected:

#1	North of Turbine Building
#2	By Intake Structure
#4	North of Radwaste
#5	By Acid and Caustic Tank

The equipment houses contained the minimum equipment required by plant procedures and were adequately maintained.

A tour of the exterior of the plant indicated that sufficient clearance was provided between permanent safety-related buildings and structures and temporary buildings, trailers, and other transient combustible materials. The general housekeeping of the areas adjacent to the permanent plant structures was satisfactory.

(3) Permanent Plant Fire Protection Features

A plant tour was made by the inspector. During the plant tour, the following safe shutdown related plant areas and their related fire protection features were inspected:

Fire Zone	Location
2B-FZ-1F1 and 1F4	Reactor Building - 19'6" Elev.
RB-FZ-1C	Reactor Building - 75'3" Elev.
RB-FZ-1B	Reactor Building - 95'3" Elev.
TB-FZ-11A	Turbine Building - 46'6" Elev.
OB-FZ-4	Turbine Building - 23'6" Elev.

The fire/smoke detection systems, manual fire fighting equipment (i.e., portable extinguishers, hose stations, etc.) and the fire area boundary walls, floors and ceiling associated for the above plant areas were inspected and verified to be in service or functional.

In addition, the following sprinkler systems were inspected:

System Number	Area Protected
2	Condenser Bay (Riser Only)
3	Turbine Building Mezzanine
9	Turbine Building Basement
15	New Cable Spreading Room
16	Cable Tunnel

The sprinkler systems were found to be in service; however, the inspector noted that the isolation valve to the pressure switch associated with Sprinkler System Number 15 (Fire Zone OB-FZ-22A) was closed. This pressure switch is required to be operable

per plant Technical Specification 3.12.A.1. With the isolation valve closed to the switch, the switch is inoperable since it cannot perform its intended function. This is identified as Violation Item 88-14-02, Inoperable Technical Specification Pressure Switch.

The safety significance of this switch being isolated is minor. In a fire situation, the sprinkler system would have operated as designed regardless of the position of the pressure switch isolation valve. Since the area protected by sprinkler system also has a smoke detection system installed, the loss of the pressure switch as an alarm is insignificant. The inspector was concerned that had the system inadvertently actuated, the lack of the water flow alarm provided by the switch would have resulted in water damage. The licensee had already evaluated such an inadvertent operation and has waterproof sealed the floor of the New Cable Spreading Room.

In response to the inspector's finding, the licensee initiated the following corrective actions:

- The pressure switch was immediately tested and verified operable.

- All isolation valves to pressure switches on all plant sprinkler systems were inspected and verified to be in the correct position.

- The isolation valves to pressure switches required to be operable per plant Technical Specifications were locked in the open position.

The licensee's corrective action resolved the inspector's finding.

Based on this inspection, it appears that the fire protection features associated with the above plant areas are satisfactorily maintained.

The plant tour also verified the licensee's implementation of the fire prevention administrative procedures. The control of combustibles and flammable materials, liquids and gases, and the general housekeeping were found to be satisfactory in the areas inspected.

(4) Appendix R Fire Protection Features

The inspector visually inspected the fire rated raceway fire barriers required for compliance with Appendix R, Section III.G.2 in the following plant areas:

Fire Zone	Location
RB-FZ-1D	Reactor Building 61' Elev.
RB-FZ-1E	Reactor Building 23' Elev.
TB-FZ-11D	Turbine Building Basement

Based on the inspector's observations of the above raceway fire barrier enclosures, it appears that the one hour fire barrier integrity associated with the above fire barrier assemblies was being properly maintained in a satisfactory condition.

The following eight-hour emergency lighting units were inspected:

Unit No.	Location
15	RB-FZ-1F1
16	RB-FZ-1F1
22	RB-FZ-1D
25	RB-FZ-1E
26	RB-FZ-1E
47	RB-FZ-1F4

These units were in service, lamps properly aligned and appeared to be properly maintained.

Except as noted above, within the areas inspected, no additional violations or deviations were identified.

5.0 Unresolved Items (92701 and 92703)

Unresolved items are matters about which more information is needed to determine whether they are acceptable or a violation. Unresolved items are discussed in sections 2, 3 and 4 of this report.

6.0 Exit Interview (30703)

On May 20, 1988 at the conclusion of this inspection, the inspectors met with those NRC and licensee representatives identified in paragraph 1.0 of this report. The scope of the inspection and the inspection findings were reviewed and summarized. Based upon the review and discussions with the licensee, it was determined that this report does not contain information subject to 10 CFR 2 restrictions (proprietary information.)

During this inspection, the inspectors did not provide any written material to the licensee.