U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-277/85-29 & 50-278/85-33

Docket No. 50-277 & 50-278

License No. DPR-44 & DPR-56

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Peach Bottom Atomic Power Station Units 2 and 3

Inspection at: Delta, Pennsylvania

Inspection conducted: September 14 - October 25, 1985

Inspectors: T. P. Johnson, Senior Resident Inspector
J. H. Williams, Resident Inspector
J. P. Rogers, Reactor Engineer

Reviewed by: J E Beall 12/18/85
J. E. Beall, Project Engineer date

Approved by: Robert M Gallo 12/18/85
Robert M. Gallo, Chief date
Reactor Projection Section 2A

Inspection Summary: Routine, on-site regular and backshift resident inspection (157 hours Unit 2; 140 hours Unit 3) of accessible portions of Unit 2 and 3, operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, refueling and outage activities, maintenance, and outstanding items.

Results: Licensee management continued their involvement in Unit 2 and 3 operations. Personnel generally implemented station procedures except for the following areas: administrative procedures for blocking and procedural revisions (4.2.2); RHR system operating procedures (4.2.2); and, a surveillance procedure for the portal monitor (4.1). Three of the 11 main steam safety relief valves on Unit 3 apparently were not tested during the last operating cycle (7.2). During the period August 29 through October 10, 1985 eight RPS actuations occurred in Unit 3 and no reports were made to the NRC in accordance with 10 CFR 50.72. The actuations were not reported due to a misinterpretation of the requirements of 10 CFR 50.72 and 50.73 (4.3). Control Room operator response during a feedwater transient and scram on Unit 2 was good.

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DETAILS

1. Persons Contacted

J. F. Mitman, Maintenance Engineer
*R. S. Fleischmann, Manager Peach Bottom Atomic Power Station
A. Fulvio, Technical Engineer
A. E. Hilsmeier, Senior Health Physicist
D. L. Oltmans, Senior Chemist
F. W. Polaski, Outage Planning Engineer
S. R. Roberts, Operations Engineer
D. C. Smith, Superintendent Operations
S. A. Spitko, Administration Engineer
J. E. Winzenried, Superintendent Plant Services

Other licensee employees were also contacted.

*Present at exit interview on site and for summation of preliminary findings.

2. Plant Status

2.1 Common

NRC Commissioner Zech toured the Peach Bottom facility on September 19, 1985. He met with the licensee management, the NRC Resident Inspectors and Region I management personnel including the Regional Administrator. The Commissioner also held discussions with licensee Control Room licensed operators.

On September 23, 1985, a PECo chemistry technician drowned while obtaining a sample in the discharge canal. His body was recovered on September 25, 1985, by Pennsylvania State Police divers.

The annual Peach Bottom Emergency Exercise was held October 17, 1985. NRC Inspection 277/85-36 and 278/85-34 evaluates this exercise.

2.2 Unit 2

The unit began the report period at 100% power. On September 19, 1985, the unit was shutdown due to simultaneous inoperability of the E-2 diesel generator and the 2A RHR pump (see detail 4.2.1).

The unit remained shutdown until October 4, 1985, when unit startup was effected. The unit achieved 100% power on October 6, 1985.

The unit remained at 100% power until October 17, 1985, when Unit 2 scrammed on low reactor water level due to loss of feedwater (see detail 4.2.3). The unit was restarted on October 18, 1985, and achieved 100% power on October 19, 1985. The unit remained at 100% power the remainder of the report period.

2.3 Unit 3

Unit 3 remained in a refueling/outage status during the entire report period.

Major items completed during the inspection period were LPRM exchange, SRM and IRM dry tube replacement, fuel reconstitution, diesel generator annual inspections, core spray sparger repair, IGSCC inspections and recirculation suction pipe N-1 safe end plug sample removal.

Major items remaining are completion of recirculation and RHR piping overlays, completion of system work and return to service, fuel reload, vessel assembly and hydro, ILRT and unit startup (see detail 4.4).

Startup is scheduled for January 1986.

3. Previous Inspection Item Update

3.1 (Closed) Violation (277/84-17-02). Failure to take prompt corrective action in response to identified failures to comply with maintenance department administrative (MA) procedures. The licensee responded to the violation in a letter dated August 8, 1984. The inspector reviewed the licensee response and determined it to be adequate. Five MA procedures had been identified as overdue for their required two year review. The inspector verified that the five MA procedures (MA-4, MA-8, MA-11, MA-15 and MA-17) were reviewed and revised in 1984. In addition, a check was made of all other MA procedures to ensure they were reviewed within two years. All MA procedures were reviewed in calendar year 1984 or 1985. The licensee instituted a tracking system for ensuring MA procedures are reviewed and revised as required. This item is closed.

3.2 (Closed) Unresolved Item (277/83-37-01). Secondary Containment Door Alarms. The inspector had noted many malfunctioning secondary containment door indicators (blue lights and position switches) and numerous instances of personnel disregarding the blue light interlock. In order to meet secondary containment integrity, Technical Specification 3.7.C/4.7.C, at least one door in each access opening in the reactor building must be closed. The blue light system reminds personnel of this requirement. If a blue light is lit above a secondary containment door, the door is not to be opened as another door is already opened. Opening both of these doors would thus breach secondary containment integrity. The secondary containment access system is tested every 2 months by performance of routine test, RT-1.8.1, "Secondary Containment Access Control System Alarm Test," Revision 4, September 20, 1983. This test verifies operability of the blue light

system, the local audible alarms, and the remote control room annunciator alarms. The inspector verified that this test is being performed as required with satisfactory results. Also, the inspector observed the satisfactory operation of the secondary containment access control system on both Unit 2 and Unit 3. Based on licensee satisfactory performance of RT-1.8.1 and inspector observations, this item is closed.

3.3 (Closed) Violation (277/84-07-01; 278/84-07-01). Failure to follow Standby Gas Treatment System (SGTS) Procedure. The licensee responded to the violation in a letter dated June 7, 1984. The response was reviewed by the inspector and found to be acceptable. The licensee revised the SGTS operating procedure of concern. The inspector reviewed the revised procedure, S.10.5.G, Manual Swap Over of Reactor Building Equipment Cell Exhaust to Standby Gas, Revision 2, October 22, 1984. The revised procedure S.10.5.G deletes two steps that were done locally in the SGTS room. These deleted steps are addressed adequately in another procedure, SGTS Setup for Automatic Operation, S.10.5.A, Revision 2, May 18, 1979. This item is closed.

3.4 (Closed) Inspector Follow Item (277/84-15-02). Standby Gas Treatment System (SGTS) fan logic problem. A failure of the SGTS fan A inlet and outlet dampers occurred on a system start on Unit 2 on April 27, 1984. This damper failure concurrent with a SGTS automatic initiation caused by a group III isolation, would have made the SGTS inoperable. This was due to the design of the B SGTS standby fan start circuit differential pressure switch (DPS). This DPS senses SGTS differential pressure (DP) and automatically starts the B SGTS fan on a no flow condition. In this case, a no flow condition would have occurred; however, the DPS would have sensed adequate DP, and the B SGTS fan would not have been given a start signal. The licensee issued LER 2-84-08, May 29, 1984, and LER 2-84-08, Revision 1, dated July , 1985. The inspector reviewed both these LERs. The revised LER referenced a system modification that would replace the DPS with pitot tube flow elements and flow switches (FE/FS). These FE/FS numbered 70004 and 70005 would ensure that the B SGTS fan would auto start on no flow conditions for the A SGTS fan (Unit 2) or for the C SGTS fan (Unit 3). Modification 1505 (plant MOD 84-088) was completed on both Unit 2 and 3 on January 10, 1985. The inspector reviewed the completed MOD package including the following documentation: Modification correspondence, PORC approval sheet, safety evaluation, maintenance request forms, construction job memo, field engineer checkout, modification acceptance test, vendor information, and revised electrical drawings (E-206 Rev. 24). The inspector discussed the modification with the licensee. The inspector noted that the current Q-list, Revision 20, August 21, 1984, did not include the modified FE/FS 70004 and 70005. The inspector contacted the licensee's Mechanical Engineering Department to ensure that the FE/FS 70004 and 70005 were to be included in the next revision to the Q-list. The inspector had no further questions. This item is closed.

3.5 (Closed) Violation (277/84-17-02). Inadequate acceptance criteria in surveillance procedures. The licensee responded to the violation in a letter dated August 8, 1984. The inspector reviewed the response and determined it to be acceptable. The licensee revised the 3 affected procedures, ST12.15.1-3, ST 12.15.3-3, and ST 12.15.4-3, to include more definitive acceptance criteria. The inspector reviewed the 3 revised STs and determined that they were adequate. This item is closed.

3.6 (Closed) Violation (277/84-15-05). Failure to post a radioactive contamination area. The licensee responded to the violation in a letter dated August 10, 1984. The inspector reviewed the licensee's response and found it acceptable. The licensee has instructed all HP personnel to include fire barrier seals in the swipe surveys as they are potentially contaminated areas. The inspector verified this through discussions with HP personnel. This item is closed.

3.7 (Closed) Unresolved Item (50-278/80-21-02). Withdrawing a control rod with badly damaged seals. The licensee developed a procedure to provide instructions for withdrawing a control rod with badly damaged seals. The inspector reviewed procedure S.4.3.Q, "Withdrawal of a Control Rod With Badly Damaged CRD Seals", Revision 0, August 25, 1980. The inspector noted that the procedure requires implementation under the direction of a reactor engineer and that precautions are included to provide actions if a control rod block alarm occurs. If a control rod block alarm occurs from the Rod Block Monitor system, the procedure requires immediate removal of the jumper that was applied in order to cause the rod withdrawal motion. The inspector discussed the use of this procedure with the licensee and verified that operators were knowledgeable. Based on the licensee's procedure S.4.3.Q, the inspector's review of the procedure and discussions with licensee personnel, this item is closed.

3.8 (Closed) Unresolved Item (277/79-09-01; 278/79-10-01). Administrative Procedure A-42, Revision 7, Jumper Log Procedure, did not require PORC review and approval for jumper installation on safety related equipment. Procedure A-42 was revised and the current A-42, Revision 9, dated April 25, 1985, requires that "all jumpers shall be installed via specific PORC approved procedures or the PECo blocking permit if required as part of the permit". The inspector reviewed several recent safety related jumpers and the implementing procedures listed in the jumper log. The inspector verified that the use of the jumpers had been PORC approved prior to jumper installation. This item is closed.

3.9 (Closed) Unresolved Item (277/79-09-07; 278/79-10-07). Completed surveillance tests were filed in standard file cabinets with no fire rating pending shipment to permanent storage and microfilming. Some completed tests had been stored for an extended period of time. A system for the collection and storage of records was discussed in the letter from S. L. Daltroff to T. T. Martin (NRC) dated October 19, 1981. The letter stated that the licensee would be in full compliance with the requirements of ANSI N45.2.9 by June 1983. In November, 1983, the NRC found a backlog of completed maintenance request forms (MRFs) stored in several cardboard boxes under desks and along aisles and radiation work permits stored in stacks on desks. Violations 277/83-32-01 and 278/83-30-01 were subsequently issued. The licensee actions to comply with ANSI N45.2.9 will be inspected as part of the inspection of the corrective action to the violations. This unresolved item is closed.

3.10 (Closed) Unresolved Item (277/79-09-09; 278/79-10-09). Administrative Procedure A-26, Procedure for Corrective Maintenance, did not require the licensee to document the cause of the failure, malfunction, or defect, and corrective action taken to preclude repetition. Equipment failures are documented on the Maintenance Request Form (MRF), which includes documentation of corrective actions. Administrative Procedure A-26 covers the use of the MRF. The Computerized History and Maintenance Planning System (CHAMPS) maintains a history file on all equipment. A-26 also states that the preparation of the Licensee Event Report (LER) provides a mechanism for evaluating malfunctions of items specified in the Technical Specifications. The LERs include cause, corrective action, and action to prevent recurrence. In addition, the I&C Engineer and Maintenance Engineer are responsible for the review of failure of "Q" listed equipment and equipment essential to electric power generation. Based on the above, this item is closed.

3.11 (Closed) Unresolved Item (277/79-09-04; 278/79-10-04). No written program or documentation to demonstrate that the Plant Operation Review Committee (PORC) and Off Site Review Committee (OSRC) performed review, evaluation, and corrective action relative to failure to follow procedures as required by Technical Specification 6.5.1.6.e. The inspector reviewed Technical Specification 6.5.1.6.e, Administrative Procedure A-4, Plant Operations Revew Committee Procedure, and recent PORC meeting minutes. When a violation or suspected violation of Technical Specifications, internal rules, procedures, or regulations is identified, the PORC investigates the cause and recommendations to prevent recurrence as documented in the PORC minutes. The PORC minutes are then sent to the Nuclear Review Board (NRB) which replaced the OSRC. The NRB reviews the PORC minutes and documents this in the NRB minutes. The inspector reviewed selected NRB meeting minutes to verify this. Based on the above, this item is closed.

3.12 (Closed) Unresolved Item (277/79-09-05; 278/79-10-05). Only those nonconformance reports (NCRs) deemed significant by the QA Division Superintendent were sent to the OSRC (currently called the Nuclear Review Board) for their review. All NCRs are listed and discussed in the PORC minutes. All PORC minutes are reviewed by the NRB. Also, a log of all QA NCR's is distributed to the NRB members. Based upon this information being available to NRB members for further review as desired, this item is closed.

3.13 (Closed) Inspector Follow Item (278/85-27-01). Unit 3 core spray sparger cracks. This item is closed based on detail 4.4.1.

4. Plant Operations Review

4.1 Station Tours

The inspector observed plant operations during daily facility tours. The following areas were inspected:

-- Control Room
-- Cable Spreading Room
-- Reactor Buildings
-- Turbine Buildings
-- Radwaste Building
-- Pump House
-- Diesel Generator Building
-- Protected and Vital Areas
-- Security Facilities (CAS, SAS, Access Control, Aux SAS)
-- High Radiation and Contamination Control Areas
-- Shift Turnover
-- Unit 3 Drywell

During a daily plant tour on September 25, 1985, the inspector noted that the portal monitor on the 165 foot level of the administrative building bridge was due for its 6 month calibration on July 7, 1985, as indicated on the calibration sticker attached to the monitor. This portal monitor, Eberline model PMC-4B serial number 332, checks for potential personnel contamination when exiting the power block at the 165 foot level of the turbine building and proceeding to the administrative building. The inspector immediately notified the licensee of the potential out of calibration portal monitor. The licensee began an investigation to determine the calibration status of the portal monitor.

There are two types of portal monitors in use at the station; Eberline model PMC-4B and Instrumentation Research Technology (IRT) model PRM-110. At the 165 foot administrative building bridge there is one Eberline portal monitor. At the 116 foot turbine building/power block exit there are two IRT portal monitors with a backup Eberline monitor which is not normally in use. At the securi-

ty building exit concourse there are two IRT portal monitors with two backup Eberline monitors which are not normally in use.

The inspector checked the calibration status of the IRT portal monitors. Procedure RT-7.32, Portal Radiation Monitor Model PRM-110 Sensitivity and Source Check, Revision 1, January 27, 1983, was reviewed. The inspector verified that all four IRT portal monitors currently in use were in calibration by reviewing the completed monthly RT 7.32 procedures performed during the period April to September 1985.

Technical Specification 6.8.1 requires implementation of procedures for Surveillance Testing. Surveillance Test Procedure ST 4.9.B, Portal Monitor Calibration and Source Check, Revision 3, June 21, 1983 and HPA-53, Calibration of Portal Monitors, Revision 1, August 8, 1978, detail the calibration frequency and calibration procedures for the Eberline Model PMC-4B portal monitors. The inspector checked the most recently completed ST 4.9.B test results. Quarterly source checks were performed on August 10, 1984, October 1, 1984, January 7, 1985 and April 2, 1985. Semi-annual calibrations were performed on August 10, 1984 and on January 7, 1985. The source check and calibration were due again on July 7, 1985; however no records of the completion of this surveillance were available. On September 26, 1985, the licensee informed the inspector that the ST 4.9.B procedure performance was missed for the Eberline portal monitors on July 7, 1985, due to an oversight. All Eberline portal monitors were calibrated on September 25, 1985; and verified by the inspector. Failure to perform a required surveillance test procedure is an apparent violation of Technical Specification 6.8.1. (277/85-29-02).

4.1.1 Control Room and facility shift staffing was frequently checked for compliance with 10 CFR 50.54 and Technical Specifications. Presence of a senior licensed operator in the control room was verified frequently.

4.1.2 The inspector frequently observed that selected control room instrumentation confirmed that instruments were operable and indicated values were within Technical Specification requirements and normal operating limits. ECCS switch positioning and valve lineups were verified based on control room indicators and plant observations. Observations included flow setpoints, breaker positioning, PCIS status, and radiation monitoring instruments.

4.1.3 Selected control room off-normal alarms (annunciators) were discussed with control room operators and shift supervision to assure they were knowledgeable of alarm status, plant conditions, and that corrective action, if required, was being taken. In addition, the applicable alarm cards were checked for accuracy. The operators were knowledgeable of alarm status and plant conditions.

4.1.4 The inspector checked for fluid leaks by observing sump status, alarms, and pump-out rates; and discussed reactor coolant system leakage with licensee personnel.

4.1.5 Shift relief and turnover activities were monitored daily, including backshift observations, to ensure compliance with administrative procedures and regulatory guidance. No inadequacies were identified.

4.1.6 The inspector observed main stack and ventilation stack radiation monitors and recorders, and periodically reviewed traces from backshift periods to verify that radioactive gaseous release rates were within limits and that unplanned releases had not occurred. No inadequacies were identified.

4.1.7 The inspector observed control room indications of fire detection instrumentation and fire suppression systems, monitored use of fire watches and ignition source controls, checked a sampling of fire barriers for integrity, and observed fire-fighting equipment stations. No inadequacies were identified.

4.1.8 The inspector observed overall facility housekeeping conditions, including control of combustibles, loose trash and debris. Cleanup was spot-checked during and after maintenance. Plant housekeeping was generally acceptable.

4.1.9 The inspector verified operability of selected safety related equipment and systems by in-plant checks of valve positioning, control of locked valves, power supply availability, operating procedures, plant drawings, instrumentation and breaker positioning. Selected major components were visually inspected for leakage, proper lubrication, cooling water supply, operating air supply, and general conditions. No significant piping vibration was detected. The inspector reviewed selected blocking permits (tagouts) for conformance to licensee procedures. No inadequacies were identified.

4.1.10 The inspector observed portions of the Unit 2 plant startup on October 4, 1985, including the following:

-- Rod Sequence Control System and Rod Worth Minimizer System operations.

-- Control Rod Withdrawal.

-- Main turbine startup and generator synchronization.

-- Implementation of procedure GP-2, Normal Plant Startup, Revision 39, March 20, 1985.

-- Additional licensed operator present for startup.

-- Shift Supervisor and Shift Superintendent frequent supervision of licensed reactor operators involved in startup activities.

The startup was being performed in accordance with plant startup and system operating procedures. No unacceptable conditions were identified.

4.2 Followup On Events Occurring During the Inspection

4.2.1 Unit 2 2A RHR Pump Abnormalities

At 7:15 p.m. on September 19, 1985, the licensee declared an Unusual Event and began to shutdown Unit 2 because the 2A RHR pump was declared inoperable due to low flow (Technical Specification 4.5.A), concurrent with the E-2 diesel generator out of service for annual maintenance. Technical Specification 3.5.F.1 requires the reactor to be in cold shutdown within 24 hours with one low pressure emergency core cooling system and a diesel generator out of service. The reactor was manually scrammed at 9:51 p.m. from 30% power. Group II and III primary containment isolations occurred because of the low water level transient resulting from the scram. The E-2 diesel generator was returned to service at 2:55 a.m. on September 20, 1985, and the Unusual Event was terminated. The licensee tested the pump in accordance with ST 6.8, RHR A Pump, Valve, Flow and Cooler Test, Revision 27, August 24, 1985, and based upon these tests decided to disassemble the pump and inspect the pump internals. The licensee proceeded to cold shutdown to investigate the 2A RHR pump problem. During the period September 20-23, 1985, the 2A RHR pump was disassembled, the pump internals and suction strainer were inspected, and the pump was reassembled. No problems nor abnormalities were noted. Subsequently, on September 23, 1985, pump testing in accordance with ST 6.8, led to unsatisfactory results.

The unit remained shut down during the period September 23 - October 3, 1985, as the licensee continued to investigate the 2A RHR pump flow and pressure abnormalities. The 2A RHR pump exhibited lower than expected discharge pressure at pump flows greater than 11,200 gpm. The licensee plotted the 2A RHR pump curve data, pump developed head versus flow. The licensee additionally examined the pump internals, piping, suction valve and torus strainer for obstructions and found none. The pump was run with the suction

strainer removed and then with the strainer installed. There was no difference in the flow characteristics as the ST 6.8 data was unable to meet the test acceptance criteria.

The inspector reviewed the ST 6.8 data taken during the period September 19 through October 4, 1985. The inspector also reviewed selected test data (pump head and flow) when plotted on the Bingham pump curve M-1-V-284-1. Normal pump discharge pressure was 200 psig at flows of 11,500 gpm; however, the pump was exhibiting discharge pressures of the range 140 to 170 psig at pump flows of 11,500 gpm.

Technical Specification 4.5.A requires that each RHR pump deliver 10,900 gpm against a system head corresponding to a vessel pressure of 20 psig based on individual pump tests. ST 6.8 acceptance criteria for RHR pump flow is 11,500 gpm. Previous tests for the 2A RHR pump met the acceptance criteria of 11,500 gpm. The inspector reviewed selected completed ST 6.8 for the period 1977 - 1985. No abnormalities were observed. On October 2, 1985, the licensee submitted an emergency Technical Specification change request to allow a lower 2A RHR pump flow. On October 3, 1985, the licensee informed the inspector that PECo engineering had evaluated the 2A RHR pump flow problem and had determined that the pump could currently meet the Technical Specification requirement of 10,900 gpm. The licensee stated that the ST 6.8 acceptance criteria of 11,500 gpm was based on pump runout criteria and not Technical Specification requirements. The 2A RHR pump data shows that at a flow of 10,900 gpm, the pump operates on the pump curve. The inspector verified this by independently plotting pump head and flow data. Based on this PECo engineering evaluation, the licensee declared the 2A RHR pump operable after satisfactory completion of ST 6.8 on October 3, 1985. Unit 2 was then prepared for restart. The inspector reviewed the ST 6.8 test results and the temporary procedure change (TPC) to ensure compliance with Technical Specification 6.8.3 and Administrative Procedure A-3, Procedure for Temporary Changes to Approved Procedures, Revision 7, January 7, 1985. The TPC was approved by two people, one SRO and one member of PORC. The inspector also verified that the PORC approved this TPC by attending the PORC meeting on October 4, 1985. (See detail 4.6.)

The inspector reviewed the licensee's formal engineering evaluations of the 2A RHR pump test data, dated October 4, 1985 and October 9, 1985. The evaluations state that the Technical Specification requirement of 10,900 gpm at 20 psig reactor pressure can be met if the 2A RHR pump operates "on the pump curve" at 10,900 gpm and at a minimum of

205 psig discharge pressure. The evaluations also state the original ST 6.8 acceptance criteria of 11,500 gpm was based on pump runout criteria in a broken loop. An acceptance criteria of 10,900 gpm was considered satisfactory to meet the Technical Specification 4.5.A required flow.

The inspector discussed the status of the 2A RHR pump with the Station Manager. Based on these discussions, the licensee intended to declare the 2A RHR pump operable, perform plant startup, and perform the following:

(1) Weekly testing of the 2A RHR pump per ST 6.8.

(2) Trending test data for the 2A RHR pump to monitor potential further degradation.

(3) Pursuing 2A RHR pump repairs during a Unit 2 outage currently scheduled for late November, 1985.

The inspector reviewed 2A RHR pump ST data performed on October 3, 10, 11, 16 and 25, 1985. This test data met the 2A RHR pump acceptance criteria of greater than 205 psig discharge pressure at a flow of 10,900 gpm.

The inspector will continue to follow these activities. (IFI 277/85-29-03.)

4.2.2 Unit 2 Engineered Safeguards Features (ESF) Actuation

At 6:07 p.m. on September 24, 1985, an ESF actuation occurred on Unit 2 while in cold shutdown. The ESF actuation was due to low reactor water level and caused a reactor scram signal and Group II/III primary containment isolation. The low reactor water level condition was caused by the draining of the reactor vessel via the shutdown cooling suction lines for the 2C RHR pump and through the RHR full flow test line to the torus. The licensee initially estimated that reactor water level decreased from a level of an initial value of +25" to about -20". The reactor was shutdown prior to the event and no control rod motion occurred. The Group II/III isolations operated correctly. Reactor level was restored to normal, and the scram signal and the Group II/III isolations were reset. The licensee made an ENS call per 10 CFR 50.72.

The inspector reviewed the control room logs, recorder traces and discussed the event with the operators. Further discussions were conducted with licensee operations supervision.

The Unit 2 licensed reactor operator was completing RHR system operating procedure S.3.2.C.1, Shutdown Cooling Mode, Revision 13, July 26, 1984, in order to remove the 2C RHR pump from shutdown cooling. The operator did not close valve MO-2-10-15C, 2C RHR pump shutdown cooling suction valve as required by S.3.2.C.1. The operator then began implementing RHR system operating procedure S.3.2.C.3, Placing Torus Cooling In Service, Revision 9, March 28, 1985, for the 2A RHR pump. Procedure S.3.2.C.1 opened RHR torus return valves MO-2-10-39A and 34A. This valve alignment allowed the reactor vessel to gravity drain from the shutdown cooling lines through the 2C RHR pump to the torus via the torus cooling return line. Once the vessel level reached zero inches reference, a Group II/III primary containment isolation occurred, closing the RHR shutdown cooling valves MO-2-17 and 18. This isolated the drain path. Reactor water level was recovered by the condensate pumps that were operating in automatic startup level control on long path recirc. The licensee estimated that level dropped about 35 inches.

Inspector review of control room reactor water level recorders indicated the following:

(1) The reactor water level recorder LR-96 trace which is fed from level indicator LI-94, went from +25 inches to zero inches. The scale is from zero inches to +60 inches and the instrument is calibrated at 1000 psig and is automatically density compensated; and the level trace indicates true level.

(2) The reactor water level recorder LR-110 trace, which is fed from level transmitter LT-110A, went from greater than +50 inches to +15 inches. The scale is +50 inches to -165 inches and the instrument is calibrated at 1000 psig. Since the plant was in cold shutdown, the +15 inches indicated level has to be adjusted to obtain true level. The licensee determined that the actual level was -7 inches based on instrument calibration data.

The inspector discussed this event with the licensee. Disciplinary action was taken against the licensed operator. The licensee indicated that RHR procedure S.3.2.C.1 would be revised to ensure procedure completion prior to entry into another RHR procedure. The inspector reviewed the licensee's upset report regarding the event, including the analysis for actual level based on instrument calibration data. The inspector independently calculated the level decrease, and this calculation concurs with the licensee

determined value. The licensee issued a LER for this event. (See detail 6.2.5.)

The cause of this event was a violation of the RHR system operating procedure S.3.2.C.1, however because the NRC wants to encourage and support licensee initiative for self-identification and correction of problems no notice of violation is issued since (1) the licensee identified the problem, (2) it fits Severity Level IV or V, (3) the violation will be reported as an LER, (4) measures were taken to correct the problem and additional measures were taken to prevent recurrence, and (5) it is not a violation that could reasonably be expected to have been prevented by correction of a previous violation. The inspector had no further questions at this time.

4.2.3 Unit 2 Scram On Loss of Feedwater

At 9:21 a.m. on October 17, 1985, Unit 2 scrammed on low reactor level (0 inches) from 100% power due to a total loss of reactor feedwater. All three operating turbine-driven reactor feedwater pumps tripped on overspeed due to a malfunction of the automatic feedwater control system. Reactor water level decreased to -95 inches indicated (-178 inches is the top of the active fuel). Primary containment isolations occurred for Groups I, II, III and the reactor recirculation pumps tripped on low-low level. RCIC and HPCI auto initiated and injected into the reactor vessel to recover level to +50 inches by 9:25 a.m. The licensee declared an Unusual Event, made an ENS call, and issued a press release.

The cause of the feedwater control system malfunction was determined by the licensee to be a loose connection in the feedwater flow summer unit, General Electric supplied device FSUM-2-6-103. The flow summer unit is connected by use of a retractable ribbon cable. This cable has 18 male connections which slip fit into the flow summer unit and lock with the use of two tabs. The flow summer unit then may slide in and out of the control cabinet. The licensee discovered that the connector was loose causing a loss of flow summer unit output signal. This loss of output signal was sensed by the steam flow/feed flow comparator unit as a false loss of feed signal. This then resulted in a signal being sent to all three reactor feed pump turbines to increase feed flow, resulting in a transient which caused all 3 reactor feed pumps to trip on overspeed. The licensee replaced the flow summer unit with an identical device from Unit 3, which was shutdown for refueling. The inspector reviewed electrical schematic drawing (ESD) on the feedwater control system, 6280-MI-5-25, Revision 40, dated

June 17, 1985. This ESD shows that a zero output from the total feedwater flow summer unit (FSUM-2-6-103) would be sensed by the feed flow/steam comparator unit, causing a command signal to be sent to all operating reactor feedwater pumps to increase speed. The inspector also reviewed the preliminary licensee upset report for the event and the completed GP-18, Scram Review Procedure.

The Senior Resident Inspector and 3 other NRC Region I inspectors were in the control room at the time of the transient and scram observing the annual emergency exercise. The licensee recovery actions were good. Once reactor level was stabilized, the licensee secured HPCI and RCIC, reopened the MSIVs and placed the C reactor feed pump in service. Unit 2 restarted on October 18, 1985, and the reactor was critical at 6:35 a.m. The unit achieved 100% power on October 20, 1985. The feedwater control system responded normally in automatic 3-element control during power escalation.

Within the scope of this review, no violations were identified.

4.3 Logs and Records

The inspector reviewed logs and records for accuracy, completeness, abnormal conditions, significant operating changes and trends, required entries, operating and night order propriety, correct equipment and lock-out status, jumper log validity, conformance to Limiting Conditions for Operations, and proper reporting. The following logs and records were reviewed: Shift Supervision Log, Reactor Engineering Log Unit 2, Unit 2 Reactor Operator's Log, Unit 3 Reactor Operator's Log, Control Operator Log Book and STA Log Book, Night Orders, Radiation Work Permits, Locked Valve Log, Maintenance Request Forms and Ignition Source Control Checklists. Control Room logs were compared against Administrative Procedure A-7, Shift Operations. Frequent initialing of entries by licensed operators, shift supervision, and licensee on-site management constituted evidence of licensee review.

On October 11, 1985, while reviewing the Unit 3 Operator's Log in the Control Room, the inspector noted that on October 10, 1985, at 1:52 p.m., Unit 3 experienced a scram from the IRM monitoring system. At the time of the scram no fuel was in the reactor vessel and a special procedure was in effect to prevent automatic starting of the ECCS. The control rods were withdrawn to reduce radiation exposures for work planned on repairing the core spray "T" box. The control rods were blocked and there was no position indication on any of the 185 control rods. Neither control rod drive pump was operating nor were there accumulator pressure and the reactor was at atmospheric pressure. The licensee was questioned about making an ENS call to the

NRC to report the reactor protection system actuation in accordance with 10 CFR 50.72(b)(2)(ii). The inspector determined that on August 29, 1985, the licensee issued written guidance on reporting scrams during the Unit 3 refueling outage when there was no fuel in the reactor. The licensee determined that with no fuel in the reactor vessel there was no longer a reactor and therefore no need for a reactor protection system. Based upon this logic the licensee reasoned that actuations of the reactor protection system were not reportable. This interpretation was limited to scram signals with no fuel in the vessel. All other actuations of engineered safety features were to be reported as required by, Administrative Procedure A-31. The licensee was informed that 10 CFR 50.72 requires notification of the NRC within 4 hours of any event or condition that results in manual or automatic actuation of any engineered safety feature, including the reactor protection system, and that this requirement applied to each nuclear power reactor licensed under 10 CFR 50. In addition, 10 CFR 50.73 requires that a Licensee Event Report be prepared for such events. When informed on October 11, 1985, the licensee immediately rescinded the August 29, 1985 guidance memorandum. Upon further review of the Unit 3 Operator Log by the inspector it was determined that while the August 29, 1985 guidance was in effect there were seven additional reactor protection system actuations, as follows:

Date	Time	Scram
8/29/85	5:30 p.m.	"D" IRM spike with A channel tripped for relay work
9/11/85	1:55 a.m.	Scram Discharge Volume High Level
9/11/85	7:43 p.m.	"A" IRM spike
9/12/85	11:57 p.m.	"C" IRM spike and B RPS channel tripped
9/13/85	12:10 a.m.	"C" IRM spike
9/13/85	9:33 a.m.	"A" IRM spike
9/14/85	1:49 a.m.	"C" IRM spike

None of the above actuations were reported to the NRC via the ENS telephone nor was a Licensee Event Report submitted to the NRC.

Failure to make reports to the NRC as required by 10 CFR 50.72 and 50.73 is an apparent violation (278/85-33-03).

4.4 Refueling/Outage Activities

4.4.1 Unit 3 Core Spray Sparger Cracks

During in-vessel remote visual inspection of the B loop of core spray piping, per IE Bulletin 80-13, crack indications were observed in the annulus area on Unit 3. The licensee proposed repair of the core spray piping by welding two brackets to the T-box junction core spray and pipes. The inspector attended a meeting on September 17, 1985, among the NRC (NRR), the licensee and General Electric, to discuss the status of the core spray pipe inspections, crack indications and repair dispositions. The inspector reviewed the Licensee Event Report #3-85-14 dated September 25, 1985, regarding the core spray cracks. The licensee performed repairs on the core spray piping during the period October 4-9, 1985. The inspector reviewed the core spray sparger repair work including the following: mockup training, ALARA review, modification package, safety evaluation, repair activities, HP controls and QC. The inspector observed some of the welding of the brackets in the reactor vessel from the fuel floor. NRC Inspections 278/85-36 and 278/85-37 further review HP controls and maintenance activities for the core spray sparger crack repairs. Within the scope of this review, no unacceptable conditions were identified.

4.4.2 Control of Unit 3 Equipment During Refueling/Outage

On October 10, 1985, the inspector reviewed the licensee's procedures and requirements for writing permits and blocking sequences for tagging and control of safety related equipment. In early September 1985, the licensee instituted a practice of allowing three non-licensed Plant Operators-Nuclear (PON) to write permits on equipment not covered by Technical Specifications in order to increase permit production during the Unit 3 outage. Each of these PONs have about five years plant experience in their current position. In addition, they were given special training in the rules for permits and blocking, and in writing permits. The licensee revised the scope of permits written by the PONs in early October 1985 to include safety-related systems for which an approved blocking sequence existed or for which a member of shift supervision had defined how to block the system. The inspector reviewed the following Administrative Procedures for requirements on writing permits:

-- A-40, Working Hour Restrictions, Rev. 2, 2/15/84

-- A-41, Procedure for Control of Safety Related Equipment, Rev. 2, 8/31/82

-- A-26, Procedure for Corrective Maintenance, Rev. 24, 1/4/85

-- A-26A, Procedure for Corrective and Preventive Maintenance Using Champs, Rev. 2, 2/21/85

Administrative Procedures A-26 and A-26A require that a Control Operator prepare permits for tagging and controlling safety-related equipment.

The Control Operator is defined in procedure A-26A as the posted Control Operator (a licensed reactor operator). Procedure A-26A further states that the Control Operator is responsible for preparing, applying and issuing blocking permits, equipment turnover, and for removal of blocking permits. The inspector noted that PONs had written the following permits:

-- Unit 3 Control Rod Drives on September 16, 1985

-- Unit 3 HPSW Crossover Valve on September 25, 1985

-- Unit 3 HPCI Turbine Exhaust on October 4, 1985

The preparation of these permits was not in agreement with the revised guidance the licensee provided to expedite permit preparation. The inspector brought the discrepancy between A-26 and A-26A and the revised practice to the licensee's attention on October 11, 1985. Procedures A-26 and A-26A were revised, reviewed and approved by PORC (Meeting 85-148) and subsequently reviewed and approved by the QA Division on October 11, 1985. Both A-26 and A-26A were revised, on an expedited basis, to state that as necessary shift supervision shall direct preparation of a permit.

Procedure A-2, Rev. 27, dated January 7, 1985, Administrative Procedure for Control and Use of Documents states that revised "A" Procedures must be reviewed against QA Program Requirements and must contain equivalent, more conservative or additional requirements to be issued on an expedited basis.

The inspector reviewed the training given to operators associated with permits and blocking, plant systems, safety systems, and Technical Specifications. The inspector determined that Control Operators get more training than PONs in plant systems, safety systems, Technical Specifications, and permit writing. In addition to this extra training,

the Qualification Manual (August, 1983) for Control Operators requires the trainee to show competence in the requirements for writing: (a) blocking permits, (b) radiation work permits, (c) temporary clearance forms, and (d) safety permits.

The inspector stated that the October 11, 1985 expedited change to A-26 and A-26A was in a less conservative direction because of the additional training and demonstrated knowledge of Control Operators in the areas of safety systems, plant systems, Technical Specifications and permits and blocking over and above that demonstrated by PONs. In addition, the change did not contain equivalent or additional requirements. Therefore, it appears that the licensee did not follow procedure A-2 in making the change to procedures A-26 and A-26A.

Technical Specification section 6.8.1 states that written procedures and administrative policies shall be established, implemented and maintained that meet the requirements of Regulatory Guide 1.33, November 1972. Failure to follow procedures A-26, A-26A and A-2 is an apparent violation of Technical Specification 6.8.1. (277/85-29-01; 278/85-33-01)

4.5 Engineered Safeguards Features (ESF) System Walkdown

The inspector performed a detailed walkdown of portions of the Standby Gas Treatment System (SGTS) in order to independently verify the operability of the Unit 2 and Unit 3 common system. The SGTS walkdown included verifications of the following items:

-- Review of SGTS documentation listed in the Attachment to this report.

-- Inspection of system equipment conditions.

-- Confirmation that the system check-off-list (COL) and operating procedures are consistent with plant drawings.

-- Verification that system valves, dampers, breakers, and switches are properly aligned.

-- Verification that instrumentation is properly valved in and operable.

-- Verification that valves required to be locked have appropriate locking devices.

-- Verification that control room switches, indications and controls are satisfactory.

-- Verification that surveillance test procedures properly implement the Technical Specifications surveillance requirements.

No unacceptable conditions were identified.

4.6 Plant Operations Review Committee (PORC)

The inspector attended the PORC meeting #85-142 on October 4, 1985. The inspector reviewed the requirements of the administrative procedure A-4, Plant Operations Review Committee Procedure, Revision 20, July 30, 1985, and Technical Specifications (TS) section 6.5.1. The PORC meeting was conducted in accordance with A-4 and TS 6.5.1 as verified by checking the following items:

-- A quorum of the PORC was present.

-- The meeting composition was adequate.

-- Written minutes were generated.

-- Procedure changes and plant modifications were reviewed.

Within the scope of the PORC meeting review, no unacceptable conditions were identified.

4.7 General Employee Training (GET)

The inspector attended the Peach Bottom GET requalification training on October 9, 1985. The inspector monitored GET course content to ensure it met the requirements of FSAR Section 13.3.4 and A-50, Training Procedure, Revision 10, September 6, 1984. The GET course included the following areas: radiation protection, security, emergency and evacuation procedures, quality assurance and industrial safety. Within the scope of the review of this GET course, no unacceptable conditions were identified.

5. TMI Action Plan (TAP) Item Status

5.1 TAP Item II.F.1.4, Containment Pressure Monitor and II.F.1.5, Containment Water Level Monitor (Closed)

Instrumentation required for these TAP items was addressed under plant modification 80-31. This modification work was reviewed during Inspections 277/82-07; 278/82-07, and 277/83-34; 278/83-32. The inspector reviewed the completed modification package including the safety evaluation, maintenance request forms, and acceptance testing. The recorders and indicators installed in the control room were examined to verify that they were installed as described. The inspector reviewed relevant drawings and FSAR section 7.20 to ensure appropriate changes had been made. The licensee submitted a Technical Specification change request by letter dated February 11, 1982,

to incorporate the instrumentation into the Technical Specifications. This change has not been issued by NRC as of this time. No unacceptable conditions were noted. TAP items II.F.1.4 and 5 are considered complete and are closed.

5.2 TAP Item II.K.3.57, Manual Activation of ADS (Closed)

TAP item II.K.3.57 requires that the emergency procedures include verification that a source of cooling water is available prior to actuation of the automatic depressurization system (ADS). Alternate water sources should be identified and referenced in the procedures.

The inspector reviewed the licensee's Transient Response Implementation Plan (TRIP) procedures T-101, RPV Control and T-111, Level Restoration. Based on these procedures, the alternate water source requirements prior to ADS manual actuation of TAP item II.K.3.57 have been incorporated into the emergency procedures. This item is closed.

5.3 TAP Item II.K.3.16.B Reduction of Challenges and Failures of Relief Valves (Open)

NRR letter dated April 23, 1984, endorsed the following four modifications for implementing TAP item II.K.3.16.B. These modifications are based on the BWR Owner's Group Evaluation BWR OG-8134 dated March 31, 1981.

5.3.1 Low-Low Set (LLS) Relief Logic System or Equivalent Manual Action (Closed)

The LLS relief logic system will open a selected relief valve on concurrent signals of reactor high pressure scram and any safety relief valve (SRV) opening. The BWR Emergency Procedure Guidelines, Revision 1, January 31, 1981, call for equivalent manual action. An SRV is manually held open beyond the reclosure setpoint.

The inspector reviewed Peach Bottom TRIP procedure T-101. This procedure directs the operator to manually open one or more relief valves if the relief valves are cycling to maintain reactor pressure below 1090 psig and to reclose the relief valve at 950 psig.

NRR letter dated October 23, 1984, concurred with this action. This item is closed.

5.3.2 Increase Relief Valve Simmer Margin (Closed)

Increasing the difference between the SRV set pressure and the reactor pressure vessel operating pressure is intended to minimize leakage and reduce potential spurious openings.

The inspector reviewed Technical Specification 2.2, Reactor Coolant System Integrity. The relief valve settings listed in the Technical Specification conform to the set point increases specified in License Amendment Nos. 36 and 41 for Units 2 and 3, respectively. The NRC's safety evaluation supporting Amendment 36 dated August 18, 1977 concluded that the higher SRV setpoints reduce the probability of excessive leakage and spurious valve openings. NRR letter dated October 23, 1984, concurred with these actions. This item is closed.

5.3.3 Preventive Maintenance Program (Closed)

Each licensee should have a preventive maintenance program to enhance the performance of SRVs. During each refueling outage, 50% of the target rock SRVs "top works" containing the pilot stage should be steam/nitrogen tested for recalibration of setpoints, pilot leakage determination, and refurbishment.

Peach Bottom Technical Specification 4.6.D requires the following actions be performed at least once per operating cycle:

(1) The removal of at least five of eleven target-rock relief valves for checking or replacement so that all valves are tested every two cycles.

(2) At least one relief valve shall be disassembled and inspected.

(3) All piping, switches, and accumulators for continuous valve bellows monitoring shall be inspected.

(4) Each relief valve shall be manually opened once at reactor pressure greater than or equal to 100 psig. (See detail 7.2.)

NRR letter dated October 23, 1984, concurred with the above actions.

A review of procedure M-1.6 Relief Valve Replacement, confirms that before a relief valve is installed its setpoint must be determined and indicated.

The inspector reviewed all surveillance test ST-13.32, Safety and Relief Valve Replacement, forms for the last six years. From these ST's all relief and safety valves have been removed, tested, and inspected as per Technical Specification 4.6.D. This item is closed.

5.3.4 Lower the reactor vessel water level isolation setpoint for main steam isolation valve (MSIV) closure level 2 to level 1 (Open).

As stated in licensee letter dated June 19, 1984, this modification will be implemented r later than the first refueling outage after issuance of a licensee amendment. The licensee amendment application was transmitted to the NRC by letter dated April 19, 1984. NRR issued Amendments Nos. 111 and 115 on October 2, 1985. This item is open pending licensee implementation of the Amendment and inspector review.

5.4 Status of Closed TMI Action Plan Items

The inspector evaluated the TMI Action Plan Items that were closed to determine whether problems have been experienced subsequent to the item being closed. The inspector noted that with regards to Item I.A.1.3, the licensee uses overtime for operators on a routine basis. Overtime data through September, 1985, for licensed reactor operators indicates a low of 574 hours and a high of 1258 hours of overtime. The licensee's letter to Region I dated August 16, 1985, in association with an enforcement conference held on June 21, 1985, acknowledged a problem in this area and indicates that they are pursuing a solution. The inspector also noted in reviewing Item I.A.1.1 that while the STA is effectively used at Peach Bottom, the position is a three year assignment and therefore the STA is not likely to have many years of experience in the job. Currently, the most experienced STA has two years on shift. In an emergency situation the on-shift STA could be rather inexperienced.

TMI Items II.F.1 and II.F.2 required installation of wide range instruments as described below:

Instrument	Range
Torus level, LR 8123	1' to 21'
Torus Temperature, TR 8123	30 degrees to 230 degrees F
Drywell Pressure, PR-8102	5-25 psia 0-225 psig
Reactor Level, LR 110	-165" to +50" 0" to -325"
Reactor Pressure, PR 404	0 to 1500 psig

The accuracy and range of the instruments is such that slight drifts in the electronics can cause readings which prompt the operators to request corrective maintenance. The apparent instrument drift has resulted in a high rate of unavailability of the instruments and operators to have less confidence in the instruments. The inspector

has noted that these instruments are tagged out of service more frequently than other instruments. This instrumentation which is infrequently used requires a considerable amount of licensee attention. The inspector will continue to review the performance of these instruments and operator attitudes about them.

6. Review of Licensee Event Reports (LERs)

6.1 The inspector reviewed LERs submitted to NRC:RI to verify that the details were clearly reported, including the accuracy of the description and corrective action adequacy. The inspector determined whether further information was required, whether generic implications were indicated, and whether the event warranted on-site followup. The following LERs were reviewed:

LER No. LER Date Event Date	Subject
*2-85-12 September 6, 1985 August 7, 1985	Full Scram Due To IRM high Flux
2-85-14 September 24, 1985 August 20, 1985	Scram and Group II/III Isolations On Reactor Low Level
2-85-15 September 20, 1985 August 22, 1985	RPS and PCIS Actuation
*2-85-16 September 20, 1985 August 26, 1985	RPS and PCIS Actuation

LER No. LER Date Event Date	Subject
2-85-17 September 24, 1985 August 25, 1985	Torus Low Level During Startup
*2-85-18 October 11, 1985 September 12, 1985	Reactor Water Cleanup System Isolation
*2-85-19 October 18, 1985 September 19, 1985	2A RHR Pump Inoperable

*2-85-20 October 21, 1985 September 24, 2985	Low Level Scram and Group II/.II PCIS Isolation in Cold Shutdown
3-85-11 October 1, 1985 June 21, 1985	Degraded Fire Barriers
3-85-13 August 22, 1985 July 26, 1985	Crack Indications in RHR Pipe Welds
3-85-14 September 25, 1985 August 26, 1985	Core Spray Sparger Junction Box Cracks

6.2 <u>On-Site-Followup</u>

For LERs selected for on-site followup and review (denoted by asterisks above), the inspector verified that appropriate corrective action was taken or responsibility assigned and that continued operations of the facility was conducted in accordance with Technical Specifications and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements and applicability to other site systems and components were also reviewed.

6.2.1 LER 2-85-12 concerns a reactor scram on Unit 2 during startup due to high IRM flux. This event was reviewed in detail 4.2.2 of NRC Inspection 277/85-30. No discrepancies were identified relative to this LER.

6.2.2 LER 2-85-16 concerns a reactor scram on Unit 2 during startup due to a spurious low level signal while returning a pressure transmitter to service. This event was reviewed in detail 4.2.4 of NRC Inspection 277/85-30. No inadequacies were identified relative to this LER.

6.2.3 LER 2-85-18 concerns an isolation of the Reactor Water Cleanup (RWCU) system due to personnel error. The Unit 2 RWCU system isolated on high flow at 10:30 a.m. on September 12, 1985. This group IIA primary containment isolation system (PCIS) actuation occurred while operators were returning the 2A RWCU filter demineralizer to service upon completion of backwash and precoat operations. The apparent cause of the high flow and isolation was a momentary excessive RWCU system flow as the filter demineralizer was valved too quickly into service. The PCIS actuated correctly and the licensee made a 4 hour report on the ENS per

10 CFR 50.72. The licensee reset the PCIS signal and returned the RWCU to service. The inspector reviewed the event, checked operator logs and discussed the isolation with the shift operators and licensee management. The non-licensed operator involved in valving in the filter demineralizer was counselled on the correct procedure for return to service. No inadequacies were identified relative to this LER.

6.2.4 LER 2-85-19 concerns the 2A RHR pump inoperability and the event is reviewed in detail 4.2.1 of this report. No inadequacies were identified relative to this LER.

6.2.5 LER 2-85-20 concerns a reactor low level scram signal and PCIS Group II/III isolation while in cold shutdown due to vessel draining through the RHR system to the torus. This event is reviewed in detail 4.2.2 of this report. No inadequacies were identified relative to this LER.

7. Surveillance Testing

7.1 The inspector observed surveillance tests to verify that testing had been properly scheduled, approved by shift supervision, control room operators were knowledgeable regarding testing in progress, approved procedures were being used, redundant systems or components were available for service as required, test instrumentation was calibrated, work was performed by qualified personnel, and test acceptance criteria were met. Parts of the following tests were observed:

-- ST 6.8, RHR A Pump, Valve, Flow and Cooler Test, Revision 27, August 24, 1985, performed on October 3, 10, 11, and 16, 1985.

-- ST 6.8.1, Daily RHR A System and Unit Cooler Operability, Revision 16, October 25, 1985, performed on October 25, 1985.

In addition, a review of the following completed surveillance tests was performed:

-- ST 4.9.B, Portal Monitor Calibration and Source Check, Revision 3, June 21, 1983, performed on April 2, 1985, January 7, 1985, August 9, 1984, and October 1, 1984.

-- RT 7.32, Portal Radiation Monitor Model PRM-110 Sensitivity and Source Checks, Revision 1, January 27, 1983, performed on April 17, 1985, May 26, 1985, and on June 13, 1985.

No inadequacies were identified.

7.2 The inspector reviewed ST 10.4, Rev. 10, Relief Valve Manual Actuation, performed on Unit 3 on September 3, 1983. The inspector noted that four relief valves (71 B, G, K and L) were not tested during the September 1983 performance of ST 10.4. ST 10.4 was also performed on November 21, 1983 and February 28, 1985, and tested Unit 3 valves 71E and 71L respectively. No other copies of ST 10.4 for Unit 3 could be found, therefore it appears that relief valves 71 B, G, and K were not tested for Unit 3 during operating cycle 6 (September 1983 through July 1985). Technical Specification paragraph 4.6.D.4 requires that each relief valve be manually opened once per operating cycle with the reactor pressure equal to or greater than 100 psig to demonstrate its ability to pass steam. Surveillance Test 10.4 implements this requirement.

The inspector discussed the missing test data with the licensee who indicated a data search was being made to determine if these relief valves had been tested. No additional surveillance records were found during this report period. The inspector checked the similar test for Unit 2, recorded on ST 10.4, Rev. 14, performed July 9, 1985. All eleven relief valves were tested. Failure to manually test relief valves 71 B, G, and K is an apparent violation of Technical Specification 4.6.D.4 surveillance requirements (278/85-33-02).

7.3 The inspector reviewed the core spray sparger line break differential pressure (d/p) instrument Technical Specification (TS) surveillance requirements. This instrument senses d/p between the core spray injection line and above the core plate. The instrument alarms in the control room on high d/p, indicative of a break in the core spray sparger line within the vessel annulus region.

The inspector noted a discrepancy with respect to the TS surveillance requirements. TS Table 4.2.B item (8) references the "core spray sparger d/p" instrument with a required calibration frequency of once per six months. TS 4.5.A item (e) references the "core spray header delta-P instrumentation" with a required calibration frequency of once per three months. The inspector informed the licensee of this discrepancy. The licensee calibrates the core spray d/p instrument using surveillance test procedures ST 2.2.01 A and B for Unit 2 and ST.2.7.01 A and B for Unit 3. The core spray d/p instrument, DPIS-2(3)-14-43A and B, calibration is performed every three months. The inspector reviewed completed ST records to verify that the above surveillance test is performed every three months. The licensee intends to submit a TS change request to clarify this discrepancy. The inspector will review this item in a future inspection (IFI 277/85-29-04).

8. <u>Maintenance</u>

For the following maintenance activities the inspector spot-checked administrative controls, reviewed documentation, and observed portions of the actual maintenance:

Maintenance Procedure/ Document	Equipment	Date Observed
SP-863	Unit 3 Core Spray "T-Box" Repair	October 8, 1985

Administrative controls checked included maintenance requests, blocking permits, fire watches and ignition source controls, item handling reports, and shift turnover information. Documents reviewed included procedures, material certifications and receipt inspections, welder qualifications and weld information data sheets.

No inadequacies were identified.

9. Radiation Protection

During this report period, the inspector examined work in progress in both units, including the following:

-- Health Physics (HP) controls

-- Badging

-- Protective clothing use

-- Adherence to Radiation Work Permit (RWP) requirements

-- Surveys

-- Handling of potentially contaminated equipment and materials

The inspector observed individuals frisking in accordance with Health Physics procedures. A sampling of high radiation doors was verified to be locked as required. Compliance with RWP requirements was verified during each tour. RWP line entries were reviewed to verify that personnel had provided the required information and people working in RWP areas were observed to be meeting the applicable requirements. No unacceptable conditions were identified.

10. Physical Security

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures, including: operations of the CAS and SAS, checks of vehicles on-site to verify proper control, observation of protected area access control and badging procedures on each shift, inspection of physical barriers, checks on control of vital area access and escort procedures. No inadequacies were identified.

11. In-Office Review of Public and Special Reports

The inspector reviewed the following documents:

-- Unit 2 Inservice Inspection Program Final Report, dated July 13, 1985.

-- Peach Bottom Monthly Operating Report for September, 1985.

-- Unit 2 Containment Integrated Leak Rate Test Report, dated June 11, 1985.

-- Semi-Annual Effluent Release Report No. 19, Revision 1, dated October 8, 1985.

Within the scope of the review of these documents, no unacceptable conditions were identified.

12. Inspector Follow Items

Inspector follow items are items for which the current inspection findings are acceptable, but due to on-going licensee work or special inspector interest in an area, are specifically noted for future follow-up. Follow-up is at the discretion of the inspector and regional management. Inspector follow items are discussed in Detail 4.2.1 and 7.3.

13. Management Meetings

13.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the Station Superintendent at the conclusion of the inspection. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

13.2 Attendance at Management Meetings Conducted by Region-Based Inspectors

The resident inspectors attended entrance and exit interviews by region-based inspectors as follows:

Date	Subject	Inspection Report No.	Reporting Inspector
10/15/85 (Ent) 10/18/85 (Exit)	Emergency Preparedness Annual Exercise	277/85-36 278/85-34	Hawxhurst
9/30/85 (Ent) 10/4/85 (Exit)	Local Leak Rate Testing	278/85-35	Kucharski

Date	Subject	Inspection Report No.	Reporting Inspector
10/8/85 (Ent) 10/11/85 (Exit)	Unit 3 Core Spray Sparger Repair	278/85-36	Bicehouse
10/15/85 (Ent) 10/18/85 (Exit)	SNM Accountability and Control	277/85-37 278/85-38	Della Ratta
10/21/85 (Ent) 10/25/85 (Exit)	Unit 3 Pipe Repairs	277/85-38 278/85-37	Reynolds

ATTACHMENT

S.10.5.A, Setup of The Standby Gas Treatment System for Auto Operation, Revision 2, 05/18/79

S.10.5.A C.O.L., Standby Gas Treatment Auto Operation, Revision 6, 09/28/81

S.10.5.B, Manual Start of Standby Gas Treatment System, Revision 4, 10/01/84

S.10.5.C, Shutdown of Standby Gas Treatment System Following "Auto" Initiation Caused by Group 3 Isolation, Revision 4, 05/18/79

S.10.5.C.1 C.O.L., Unit 2 S.G.T.S. Return To Normal, Revision 3, 12/21/83

S.10.5.C.2 C.O.L., Unit 3 S.G.T.S. Return To Normal, Revision 3, 12/22/83

S.10.5.D, Shutdown of the Standby Gas Treatment System Following Manual Start, Revision 1, 04/15/73

S.10.5.E, Routine Inspection of S.G.T.S., Revision 5, 08/02/84

S.10.5.F, Manual Operation of the S.G.T.S. for DOP and Halogenated Hydrocarbon Testing, Revision 2, 07/11/84

S.10.5.G, Manual Swap Over of Reactor Building Equipment Cell Exhaust to Standby Gas, Revision 2, 10/22/84

FSAR Section 5.3, Secondary Containment System

Technical Specifications 3.7.B/4.7.B, Standby Gas Treatment System

Technical Specifications 3.7.C/4.7.C, Secondary Containment

P&ID M-388, Reactor Building Ventilation Flow Diagram, Revision 19, 3/13/85

P&ID M-391, Containment Isolation Control Diagram, Revision 17, 3/21/79

P&ID M-397, Standby Gas Treatment Control Diagram, Revision 27, 10/29/82

E-206 Sheet 1 of 1, ESD Standby Gas Treatment System, Revision 24, 7/19/84

E-206 Sheet 2 of 2, ESD Standby Gas Treatment System, Revision 24, 7/19/84

E-208 ESD Standby Gas Treatment System Isolation Valves, Revision 13, 11/4/75

M-I-S-23 Sheet 18, ESD Primary Containment Isolation System, Revision 68, 9/17/84
M-I-S-23 Sheet 16, ESD Primary Containment Isolation, Revision 60, 1/15/82

ST-13.9, Secondary Containment Capability Test, Revision 7, 5/16/83

ST-13.7A, SGTS Differential and Heater Capacity, Revision 3, 7/11/84