U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/92-016 50-278/92-016	License Nos. DPR-44 DPR-56
Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	July 28, 1992 through August 31, 1992	
Inspectors:	J. J. Lyash, Senior Resident Inspector M. G. Evans, Resident Inspector F. P. Bonnett, Resident Inspector J. G. Schoppy, Reactor Engineer J. Shea, NRR Project Manager	
Approved By:	C J Anderson C. J. Anderson, Chief Reactor Projects Section 2B Division of Reactor Projects	9/9/92 Date

Areas Inspected:

The inspection included routine, on-site regular, backshift and deep backshift review of accessible portions of Units 2 and 3. The inspectors reviewed operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, engineering and technical support activities, and maintenance.

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 92-016

Plant Operations

During the inspection period Unit 2 scrammed when individuals applying a permit in the south substation blocked the wrong component. The inspectors used the NRC Human Performance Investigation Process to evaluate factors contributing to the event. The factors identified included less than adequate management policies and standards, communications, and labeling. The licensee's preliminary root cause analysis was in general agreement with the inspectors findings. The licensee is implementing corrective actions to address these weaknesses (Section 2.1).

Maintenance and Surveillance

The licensee applied lessons learned during previous emergency diesel generator (EDG) maintenance outages to the planning and performance of the E-3 EDG outage. As a result, the maintenance activity and post-maintenance testing were completed well within the allowable outage time (Section 5.1).

Engineering and Technical Support

The licensee's corporate engineering management and staff have dedicated significant resources to analysis and resolution of site specific reactor water level indication accuracy problems. They have also initiated appropriate action in response to Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)." Communication between the corporate engineering and station operations staffs was good, and helped to ensure a sound understanding of the issues (Section 3.3).

The licensee is pursuing investigation and assessment of the failure of a General Electric SBM switch that prevented the automatic transfer of a safety-related electrical bus. They are performing a series of component inspections, and are performing detailed root cause evaluations of suspect components. This problem may be generic, however, a final conclusion can not be reached until the licensee inspection and testing program is complete (Section 3.4)

The licensee responded promptly to information indicating that some plant fire barriers were not qualified. They identified the effected barriers and posted compensatory fire watches where possible. For one barrier in a high radiation area, located in the Unit 3 offgas pipe tunnel, the licensee requested a Temporary Waiver of Technical Specification Compliance until a camera and monitor could be installed (Section 2.2).

Assurance of Quality

The license's program for implementation of 10 CFR 50.59 is functioning well. Management has established clear governing procedures and expectations. The training material reviewed by the inspector was comprehensive. All determinations reviewed were appropriate, and safety evaluations were complete. However, the inspector brought two potential weaknesses to licensee management's attention. The scope of review undertaken in making determinations appears to be too narrowly focused in some cases. Also, documentation of the determination basis is often lacking. The licensee agreed to evaluate these observations (Section 3.1).

The Station Qualified Reviewer (SQR) program, approved by a recent Technical Specification Amendment, is being effectively implemented. The licensee has established good procedures, personnel training and qualification, and strong program oversight (Section 3.2).

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DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)*

The inspector completed NRC Inspection Procedure 71707, "Operational Safety Verification," by directly observing safety significant activities and equipment, touring the facility, and interviewing and discussing items with licensee personnel. The inspector independently verified safety system status and Technical Specification (TS) Limiting Conditions for Operation (LCO), reviewed corrective actions, and examined facility records and logs. The inspectors performed five hours of deep backshift and weekend tours of the facility.

2.0 PLANT EVENTS (93702, 71707)

During the report period, the inspectors evaluated licensee staff and management response to plant events to verify that the licensee had identified the root causes, implemented appropriate corrective actions, and made the required notifications. Events occurring during the period are discussed individually below.

2.1 Unit 2 Generator Lock-out and Reactor Scram Due To Improper Blocking

On August 17, 1992, at about 7:12 a.m., a Unit 2 generator lock-out and reactor scram occurred from about 97% power, while licensee personnel were blocking equipment for maintenance in the South Substation. All systems responded as expected and the operators completed a normal reactor cooldown. The licensee notified the NRC of the event via the ENS.

Licensee review of this event determined that the generator lock-out occurred because the permit being applied in the South Substation was incorrect. In early July, 1992, the Load Dispatcher (LD) requested that a Peach Bottom Chief Operator (CO) write a permit to allow replacement of a muffler on the 205 circuit breaker (CB). The CO wrote LD Permit No. 6-6852 on July 6, 1992. Since the CO had limited experience in writing this type of permit, he looked for an historical permit for the 205 CB to use as a model. Unable to find one, he modeled the permit after an historical permit for the 215 CB, instead. At about 6:00 a.m. on August 17, Peach Bottom plant operators (POs) began applying the permit. The POs noted a discrepancy in the first step of the permit and corrected it. They also questioned the location of the equipment identified in the last two steps of the permit and the applicability of these steps. However, during PO turnover, the question of applicability of these steps was not adequately communicated. The two steps in question read "Gen Relay Switch" and "5014 Line B. U. Relay Block Switch." The POs discussed the location of the equipment with members of the licensee's High Voltage Group. The POs found that a "Gen Relay Switch" was located in the 215 CB, which is one of the two Unit 2 generator output circuit breakers. They also noted that a switch, informally labelled "5014", was located in the 215 CB cabinet next to the "Gen Relay Switch." The operators incorrectly assumed that this switch was the "5014 Line B. U. Relay Block

* The inspection procedure from NRC Manual Chapter 2515 that the inspectors used as guidance is parenthetically listed for each report section.

Switch" identified in the permit. Upon placing the "Gen Relay Switch" in the blocked position and opening the switch labelled "5014", the Unit 2 turbine tripped and the generator output breakers opened. The licensee determined that had the operators opened the "5014 Line B. U. Relay Block Switch" which was located in the 205 CB cabinet, the plant transient would not have occurred. In addition, the step to place the "Gen Relay Switch" in the blocked position should not have been included on the permit and several other steps were unnecessary for the maintenance work being performed.

Based upon interviews with personnel involved in this event and licensee management, the inspector used the NRC's Human Performance Investigation Process (HPIP) to determine independently the root causes of the event. The inspector found that the factors contributing to this event were 1) management's policies regarding responsibilities related to substations were less than adequate in that they were unclear, 2) management's standards regarding content and format of LD permits were communicated less than adequately, 3) the CO who wrote the incorrect permit did not have the knowledge or information available to write the permit, 4) the permit used for blocking of the 205 CB included incorrect facts and confusing format, 5) labelling of components in the South Substation was less than adequate, and 6) communication among the POs at the substation was less than adequate.

The inspector reviewed the licensee's preliminary root cause evaluation and found that the results generally agreed with the inspector's conclusions. Licensee's immediate corrective actions included the requirement for review of all LD permits by Technical personnel onsite and the Shift Supervisor prior to application and the clear identification of the location of all blocking points on the permits. Licensee management also stated that an Administrative Guideline to clarify the responsibilities related to high voltage equipment which interfaces with Peach Bottom facilities was being developed and that substation equipment would be appropriately labelled. The inspector found the licensee's initial and planned corrective actions to be acceptable. The licensee is tracking completion of the root cause analysis and corrective actions through Reportability Evaluation/Event Investigation Form 2-92-322. Licensee management at Peach Bottom continues to discuss the generic issues regarding substation responsibilities with Limerick management. The inspector had no additional questions.

2.2 Temporary Waiver of Technical Specification Compliance for Certain Fire Barriers

On June 24, 1992, the NRC issued Bulletin (BU) 92-01, "Failure of Thermo-Lag 330 Fire Barrier System to Perform its Specified Fire Endurance Function." The Bulletin identified that certain fire barrier configurations using Thermo-lag had failed qualification testing. In response to the Bulletin the licensee reviewed the specified configurations, declared the barriers inoperable and implemented the required compensatory fire watches (see Inspection Report 92-13 for additional information). On August 28, 1992, the NRC issued Supplement 1 to Bulletin 92-01, identifying, based on additional test results, that all fire barriers using Thermo-lag were suspect.

The licensee performed a prompt review of the affected barriers. Continuous fire watches were posted in the high pressure service water pump rooms within one hour as required by TS 3.14.D.2. However, the licensee could not post the required fire watch for residual heat removal system cables running through the Unit 3 offgas pipe tunnel because it is a high radiation area. Late on August 28, the licensee requested, and the NRC verbally approved, a waiver of TS compliance to allow time for installation of a camera and monitor before establishing the continuous fire watch in the offgas pipe tunnel. On September 1, the licensee submitted their written request and justification to the NRC. On September 2 the NRC issued a letter to the licensee documenting approval of the waiver request. The inspector concluded that the licensee had taken prompt action to review the Bulletin, to establish compensatory measures where possible, and had expedited actions to put alternate compensatory measures in place for the affected high radiation area.

3.0 ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (37702, 37703, 92701)

The inspectors routinely monitor and assess licensee technical support staff activities to determine if they are appropriately involved in evaluation and resolution of significant issues. During this inspection period, the inspectors focused on review of the process for implementation of 10 CFR 50.59 and the newly established Station Qualified Reviewer Program, and follow-up to reactor vessel water level issues and the recent failure of a safety-related breaker control switch. The results of these reviews are discussed in detail below.

3.1 10 CFR 50.59 Process

The inspector conducted a review of the licensee's program for implementing the requirements of 10 CFR Part 50.59 on Changes, Tests and Experiments (CTE). The inspection included review of the licensee's procedural controls, training program and implementation.

3.1.1 Procedures

Formal requirements for the conduct of 10 CFR 50.59 reviews are currently governed by Nuclear Group Administrative Procedure (NGAP) NA-02R002. The procedure provides instruction for the performance of both 50.59 determinations and safety evaluations. The 50.59 determination serves to screen the CTE against the requirements for performing safety evaluations. The 50.59 safety evaluation analyzes the safety significance of the CTE and evaluates whether the CTE involves an unreviewed safety question. The procedure provides specific direction on addressing the elements of a change that would constitute an unreviewed safety question, and provides guidance on the need to document the basis for 50.59 determinations and safety evaluations. The procedure incorporates industry guidance on the 50.59 process as described in NSAC-125, "Guidelines for 10 CFR 50.59 Safety Evaluations."

The licensee ensures that CTEs receive 50.59 determinations as necessary by referencing NA-02R002 in whichever administrative procedure governs the particular CTE. The inspector reviewed the administrative procedures that control various CTEs including modifications, design equivalent changes, nonconformance reports, several administrative procedures that govern procedure changes, temporary plant alterations and temporary procedure changes. With two exceptions, each of the administrative procedures directs that the CTE receive a 50.59 determination and/or safety evaluation. Of those exceptions, Administrative Procedure A-3, Temporary Changes (TC) to Procedures, does not require a 50.59 determination since a TC is assumed to involve no change of intent from the original procedure. The other exception is Administrative Procedure A-20," Generation, Revision, and Implementation of Operating Procedures (System(S), System Operating (SO), Abnormal Operation(AO), General Plant (GP), Alarm Response Card (ARC))." This procedure was being revised at the time of the inspection and will include references to the 50.59 process.

3.1.2 Training

The inspector reviewed the licensee's training module on the 10 CFR 50.59 process. The module provides expanded guidance on the performance of determinations and safety evaluations beyond that provided in NA-02R002. The inspector reviewed training records related to 10 CFR 50.59. The licensee requires an individual to attend classroom instruction and to perform independent reading assignments in order to qualify to perform 50.59 determinations and safety evaluations. A cross check of the list of qualified individuals against a sample of determinations did not reveal any discrepancies. As noted in Section 3.1.3 below, the licensee's Nuclear Quality Assurance (NQA) organization had identified a problem with the 50.59 qualification of some Plant Operations Review Committee (PORC) members. The training department had responded to this discrepancy by increasing emphasis in the training module.

3.1.3 Implementation

The inspector reviewed the licensee's most recent annual 10 CFR 50.59 report dated December 9, 1991. The inspector reviewed the summary safety evaluations and several complete 50.59 packages for the various CTEs described in the report. The inspector found no safety evaluations that appeared to have unseen unreviewed safety questions. The inspector reviewed 50.59 determinations and safety evaluations for a variety of CTEs. The implementation portion of the inspection focused primarily on the determination part of the 50.59 process but also examined a number of safety evaluations for thoroughness and appropriateness of the conclusions. The inspector did not find any apparent unreviewed safety questions. In general, the determinations appeared to screen CTEs appropriately. The inspector did not find evidence of any CTEs that did not receive safety evaluations when a safety evaluation was, in fact, warranted. However, the inspector concluded that certain weaknesses exist in the documentation of the bases for 50.59 determinations, as discussed below.

The inspector noted weaknesses in the justification section of the 50.59 determination form for many 50.59 determinations. Procedure NA-02R002 requires that the preparer answer four questions and provide the basis for the answer to each of the questions. The form provides space to document the basis for the determination and prompts the preparer to cite the sections of the SAR reviewed. Often the justification for each answer consists of a negative restatement of the question. NSAC-125, which is incorporated into NA-02R002 and into 50.59 training, specifically says that this type of justification is to be avoided. It should be noted that the conclusions and justifications of safety evaluations reviewed were thorough and the weakness described above pertains primarily to 50.59 determinations.

Both NA-02R002 and the licensee's training emphasize that the SAR is a body of documents that includes the Updated Final Safety Analysis Report (UFSAR), the TS, NRC safety evaluations and other commitments to the NRC. The licensee has instituted a program to develop a comprehensive commitment tracking and maintenance data base. The licensee has captured programmatic commitments made since 1988 in the data base and is in the process of tagging those commitments to specific station implementing procedures. In addition, the licensee performed a search of documents in the NRC Public Document Room and of correspondence with INPO and ANI since 1974. These documents were reviewed for programmatic commitments and these commitments are being systematically evaluated for applicability and compliance. These older commitments are being added to the data base as they are evaluated. The licensee expects to complete this data base compilation by the end of 1993.

A potential weakness in the program exists in that preparers and reviewers of 50.59 determinations don't uniformly review portions of the SAR outside of the UFSAR and TS. The SAR can also include safety evaluations issued in support of license amendments, as part of the response to a generic issue or as stand alone documents. Evidence of this was found in the review of numerous 50.59 determinations where the documents cited as the basis of the conclusions consisted solely of sections of the UFSAR. This was confirmed in interviews where it was determined that while preparers of 50.59 determinations more routinely access the commitment maintenance program in performing their review, reviewers of determinations did not systematically review areas of the SAR outside the UFSAR.

The inspector reviewed the processes the licensee employed to evaluate the 50.59 program. The Nuclear Review Board (NRB) is required by TS 6.5.2.7.a to review all safety evaluations generated under the 50.59 process to support CTEs. The NRB has delegated the review of site generated safety evaluations to the Independent Safety Engineering Group (ISEG). ISEG reviews completed safety evaluations after they have been approved by the PORC but does not review negative 50.59 determinations. Discussions with ISEG members determined that the number of safety evaluations returned with comments by ISEG has remained at a low number since the station instituted NGAP NA-02R002. The inspector discussed the 50.59 process with members of the site NQA organization. NQA examines portions of the 50.59 process periodically. Recent NQA reviews had discovered discrepancies in the area of training and qualification of PORC members in the 50.59 process and the 50.59 review of License Event Reports. Corrective action had been taken by the training department in response to the NQA findings. NQA had not recently reviewed implementation of the 50.59 determination process. The inspector concluded there was adequate NRB and NQA oversight of the process.

3.2 Station Qualified Reviewer Program

The licensee has implemented the Station Qualified Reviewer (SQR) program described in Amendment 167 and 171 to the TS which became effective May 7, 1992. The Amendment revised the methodology for review and approval for certain types of procedures. Under the previous TS, all new procedures and procedure revisions, no matter how minor, had to be reviewed by the PORC. The review and approval of the large number of procedure revisions and new procedures developed each year consumed a significant amount of PORC time. In July 1990, the licensee requested a change to the TS to allow the review and approval of implementing procedures to be delegated to qualified, designated reviewers and supervisors. After several revisions to the proposal, the NRC issued the Amendment in May, 1992.

The licensee has instituted Administrative Procedure A-4.2, "Station Qualified Reviewer Program," to govern the SQR program. As described in A-4.2, the SQR program will be used to review all procedures, temporary changes and other items requiring plant management approval. The procedure describes the revised process by which procedure changes can be made. For any new or revised implementing procedure, a licensee staff member will prepare the new procedure and will prepare the 10 CFR Part 50.59 determination and safety evaluation as required. A SQR cognizant over that procedure type will then review the procedure, will determine the necessary cross discipline reviews and will evaluate the 50.59 determination as the independent reviewer. After the SQR has completed his/her review, the procedure is transmitted to the cognizant responsible superintendent (RS).

Procedure A-4.2 defines which changes the RS can approve and also defines certain changes which the RS must review but for which he/she does not have approval authority. Certain classes of procedures, including any procedure requiring a 10 CFR 50.59 safety evaluation and all non-procedural CTEs, still require PORC review for approval. The procedure describes the training and qualification requirements for both SQR and RS. SQRs and RSs must meet certain prerequisite qualifications, must attend a four hour course on SQR program controls and expectations and must be designated in writing by PORC.

The licensee has designated seven RSs and approximately [illegible] SQRs to date. Of those designated, all except seven have completed the licensee's training required for qualification. The inspector attended one of the SQR training courses and found that it was excellent in communicating plant management's expectations for those individuals designated as SQRs. The licensee has developed a handbook for SQRs containing applicable procedures and a continuing series of information notices which provide updates and clarifications on the implementation of the program. Program guidance during the implementation phase of the program has been strong. The licensee is considering turning over responsibility for management of the program from the Site Support Group to a yet undetermined group. The licensee is also in the process of turning over training responsibilities for the program to the training department.

The inspector interviewed 7 SQRs and 1 RS about the implementation of the program. All exhibited a solid understanding of the requirements of the program. The inspector determined that SQRs and RSs exhibited a heightened sense of procedure ownership now that they were personally responsible for the review and approval of all implementing procedures under their cognizance.

Through interviews, the inspector determined that implementation of the SQR program has reduced the procedure review load on PORC significantly. The increase in work load on individual SQRs has varied. None of the SQRs interviewed indicated that the increased work load had become an excessive burden.

3.3 Licensee Follow-up of Reactor Vessel Water Level Issues

During this inspection period the NRC issued Information Notice (IN) 92-54, "Level Instrumentation Inaccuracies Caused By Rapid Depressurization," and Generic Letter (GL) 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)." These documents discussed potential problems with reactor vessel water level instruments indicating falsely high values. Some problems have been experienced at other BWRs with level indication fluctuations during normal depressurizations. However, the central concern was that during accident conditions a sudden uncontrolled depressurization of the primary coolant system could cause complete loss of reference leg inventory. The reduced inventory would result in control room indication that water level was higher than actual, and might prevent certain safety system actuations. The inspectors reviewed the referenced NRC documents, licensee procedures and engineering analyses, and discussed them with the technical and operations staff to determine if the licensee had taken appropriate short-term corrective actions for both the site specific and generic reactor water level issues.

3.3.1 Background

In 1988 the licensee modified the reactor vessel water level monitoring system to remove the originally installed Yarway columns. Four condensing chambers and cold reference legs (two narrow range and two wide range) were installed. In addition, the modification also installed Rosemount differential pressure transmitters and analog trip units for the associated water level indication and trip functions. Wide range condensing chamber 2B and narrow range condensing chamber 3B use the same reactor vessel penetration. The 2B chamber is mounted about four feet above the 3B chamber, and is connected to the reactor vessel penetration via a vertical run of pipe. The 2A and 3A chambers are mounted in the same manner, using a second penetration 180 degrees around the reactor vessel.

Peach Bottom has not experienced the type of level indication anomalies during controlled reactor vessel depressurizations described in the IN and GL. However, Peach Bottom had experienced level instrument errors due to gradual reduction in reference leg inventory. In August 1990, the licensee identified that the Unit 2 level instrumentation served by the 2B condensing chamber and reference leg was indicating values about 11 inches higher than similar instruments served by the 2A condensing chamber. The indicated level offset had developed undetected due, in part, to less than adequate channel surveillance procedure acceptance criteria.

Upon identification the licensee evaluated the effect of the offset. They concluded that the actuation setpoints for several safety systems would be exceeded during transients or accidents, declared the instruments inoperable and completed a plant shutdown. Following the 1990 event, the licensee revised the channel check procedures to provide better monitoring and evaluation of the instruments. The licensee's channel check procedures now include acceptance criteria on the range and maximum channel deviation. In addition, they implemented measurement and trending of transmitter output signals as a way of more effectively monitoring the instrumentation (for additional information see Inspection Report 91-17).

A second level offset event, again involving the Unit 2 2B condensing chamber, occurred in March 1992. The improved surveillance procedures helped the licensee to identify the offset before it had exceeded 3 inches. In response, the licensee established a 4 1/2 inch offset operability limit, and closely monitored the instrumentation. On March 27, the level offset between the instruments tied to the 2A and 2B condensing chambers increased to the 4 1/2 inch administrative limit. The licensee declared the instruments inoperable, entered TS 3.0.C, and completed a prompt plant shutdown (for further information see Inspection report 92-07, Unresolved Item 92-07-02).

The condensing chamber is designed to maintain the reference leg full by providing continuous steam condensation as a make-up source at a rate of .5 lbm/hr. Following these two events, the licensee believed that as the operating cycle progressed noncondensible gases collected in the chamber, reducing the condensation rate. A small leak through an instrument equalizing valve or at a fitting existed, exceeding the reduced condensing chamber makeup capacity, and the reference leg level decreased. The net effect of this decrease was to increase indicated level on those instruments tied to the reference leg. When calibrating the individual level sensor trip setpoints the licensee typically leaves a margin of about 6 inches, so some offset was acceptable. Following each event the licensee inspected the piping, instruments and equalizing valves for leaks. While they found several damp fittings and equalizing valves that could be more tightly seated, no leak sufficient to explain the behavior was found.

3.3.2 Results of the Licensee's Site Specific Study

Following the August 1990 event, the licensee initiated a study to determine the probable cause of the reference leg inventory reduction. The licensee developed an analytical model and computer code of condensing chamber operation. They used the heat transfer and solubility model to determine the equilibrium condensing rate, noncondensible gas concentrations and the effect of small reference leg leaks. In addition, the licensee performed a series of parametric studies to evaluate the effects of variations such as insulation thickness and ambient drywell temperatures. This study, issued on December 17, 1990, concluded that the current design is not leak tolerant. Leaks on the order of .5 to 1.0 lbm/hr are sufficient to cause a loss of level in the cold leg. A 150 micron opening will allow a 1.0 lbm/hr leak. The reduction in condensate return flow to the reactor vessel reduces the amount of noncondensible gases swept from the chamber, and eventually to binding due to noncondensible gas buildup. In order to provide for collection of additional important data, the licensee installed temperature measurement devices on the 2A, 2B, and 3B condensing chambers, and primary containment temperature in the vicinity of the 2B chamber.

During the period of power operation preceding the March 1992 event, the condensing chamber external temperature in the steam space area associated with the 2A and 2B chambers decreased by about 150 degrees to near area ambient. This temperature decrease was indicative of a slow buildup of noncondensible gas in the chambers, and identified that both the 2A and 2B chambers experienced the problem. The temperature of the 3B chamber decreased only about 10 degrees.

Using the new information, the licensee performed a series of diffusion calculations coupled with the previous heat transfer and solubility study. The analysis, issued on July 8, 1992, identified a flow separation phenomenon associated with the long vertical run of piping feeding the 2A and 2B chambers. In the vertical pipe the natural buoyancy of hydrogen prevents it from migrating in the radial direction and contacting the condensate return flow. Therefore the hydrogen is not being returned to the reactor vessel along with the flow. Instead, the hydrogen rises axially and accumulates in the chambers. The hydrogen buildup eventually reduces the chamber condensing rate to zero. In this condition, any leakage results in development of level indication errors. In response to the two events and studies described above, the licensee initiated development of modification options to alleviate the problem, including venting the chamber steam space. These efforts were ongoing at the time the generic BWR level instrumentation concerns were raised.

3.3.3 Licensee Short-Term Actions in Response to Generic Letter 92-04

Following identification of the generic BWR design concern related to the response of water level instrumentation to sudden reactor vessel depressurization events, the licensee initiated an extension of the previous studies to assess the impact at Peach Bottom. This study, concluded that the reference legs could become saturated with noncondensible gases. The dominant mechanism would be mass transport through system leakage. The projected offset in level indication varied considerably with changes in initial conditions and assumptions. The licensee is participating with the BWR Owners Group in development of analytical models and testing programs targeted at quantification of the response. The results of that analysis and testing will be used to design site specific modifications if needed.

The licensee's engineering personnel responsible for the site specific analyses, and involved with industry groups studying the generic problem, confirmed the adequacy of the current emergency response procedures for coping with this postulated event and that the current installation conforms to the GE specifications. In addition, they met with the station operations and technical staff, and the PORC, to brief them on the issues. Following those meetings the licensee issued a required reading package to all licensed operators describing 1) the cause of the water level anomalies previously seen at Peach Bottom, and 2) the possible generic water level indication that could occur following rapid reactor vessel depressurization. The package explicitly stated management's expectation that all operators be aware of the following: 1) there is a potential for false high level indication during rapid depressurizations; 2) there is no quantitative method for assessing the effect of degassing on instrumentation accuracy following an event; 3) the determination of indication reliability will depend on the judgement of shift management, based on comparison of multiple independent level instruments; and 4) if level cannot be determined, then operators should proceed to reactor pressure vessel flooding as specified in the emergency response procedures. The inspector reviewed the package, and discussed it with a sample of operations personnel. The material was well prepared and understood by the operations staff.

3.3.4 Conclusion

The inspector concluded that the licensee has aggressively pursued evaluation of the specific reactor vessel water level indication problems experienced at Peach Bottom. In addition, the licensee's engineering staff is knowledgeable of and involved with industry efforts to evaluate the effect of the generic level issues associated with rapid depressurization events. Plant management, with support from the corporate engineering organization, has taken adequate short-term steps to sensitize the staff to this potential problem.

3.4 Licensee Follow-up of SBM Control Switch Failures

On July 4, 1992, a transformer located in the north substation failed and caused the loss of one offsite power source. Two of the four Unit 3 safety-related 4KV busses are normally energized from that primary source, and are designed to auto-transfer to the alternate offsite power source. If neither offsite source is available, the emergency diesel generator (EDG) starts and energizes the bus. During the July 4 event, 4KV bus E13 did not auto-transfer to the alternate offsite source on loss of the primary source, and the EDG did not start. This dead bus ultimately caused the plant to scram (see Special Inspection 92-14 for additional information on this event). During the current inspection period the inspector monitored the licensee's short-term corrective actions, reviewed the failure analysis reports, and met with members of the staff to discuss their long-term corrective action plans.

The results of licensee troubleshooting identified that certain contacts on the control switch for the E313 breaker feeding bus E13 from its primary offsite power source, had not closed after its last operation. The switch is a GE Type SBM; commonly used for remote breaker operation from the control room and other locations. The switch has "open" and "closed" positions, and spring returns to the neutral or "normal" position on release. The safety bus auto-transfer and EDG start logic uses the E313 control switch normal after close contacts. These contacts must be closed to energize the timing relays that drive the transfer. After the last operation of breaker E313, the control switch had not returned fully to the normal position, and the normal after close contacts had not made up. This prevented the bus auto-transfer. The licensee verified that the failure to return to normal repeated during subsequent switch operations.

The licensee removed the failed switch from the panel and sent it to their Corporate Laboratories Division for analysis. They concluded that the switch failed due to excess internal friction forces that exceeded the capability of the switch spring to return the shaft to the normal position.

A significant contributor to the friction was a raised area on the switch shaft rear collet, apparently caused when the rear collet retaining pin was staked during original assembly. This raised area bore against the aluminum retaining plate and caused a plowing or machining action. Inspection of the components identified clear evidence of this interaction. Also, contacts #4 and #5 showed chipping and wear of the cams and nylon cam followers. This appeared to have been caused by some misalignment of the cam and follower. While the switch repeatedly failed testing before disassembly, after re-assembly following the inspection the failure could not be duplicated. The licensee's search of plant and industry data did not identify any other similar failures. Information available from the vendor did not provide any useful insights into expected component service life.

While the excess friction prevented the spring from returning the switch to normal, it does not prevent the operator from manually returning it using slight hand pressure. Movement of the switch to the normal position is evident, as the switch cams come to rest in their detentes. Immediately after the July 4 event, the licensee visually, and using slight hand pressure, verified that the switches associated with the other Unit 2 and 3 safety busses were properly positioned. Operations Department management issued required reading package RE-92-1A, that included a description of the observed failure, warned against potential future failures and provided instructions in the event that a similar failure is identified. During later equipment manipulations, licensed operators identified four additional nonsafety-related SBM switches demonstrating similar tendencies. Three of these were for 13KV balance of plant breakers, and one was for the emergency cooling tower load center breaker. In each case the licensee moved the switch to the correct position and applied an information tag highlighting the problem. The licensee also has some indication that failures of this type of switch may have occurred at their simulator, and they are investigating.

In most applications of this switch type, the normal after close contacts are used only for annunciation. The licensee's engineering organization reviewed application of SBM switches at Peach Bottom, and developed a preliminary list. The applications were divided into priority 1 (switches whose neutral contacts are used in automatic functions) and priority 2 (switches whose contacts are used for annunciation or other control functions) for inspection by the plant staff. These inspections are to be completed as allowed by plant conditions. The licensee also ordered replacement components. When the four problem switches discussed above are replaced, they will be sent intact to receive detailed failure analyses. At least one switch will be sent to GE for inspection. At the close of the period, the licensee had begun implementing the switch inspection program and the replacement switches had arrived onsite.

The identification of five SBM switches exhibiting similar behavior (failure to spring return to neutral) indicates that this failure mode may be generic. However, removal and analysis of the four additional suspect switches, and testing of the remaining population, is necessary to reach a supportable conclusion. The licensee is planning to perform these tasks. The inspector concluded that the short-term corrective actions implemented by the licensee have heightened operator awareness, and will minimize the likelihood of an undetected mispositioned switch. The inspector will continue to monitor licensee follow-up activities.

4.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspector observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. The inspector verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspector routinely verified adequate performance of daily surveillance tests including instrument channel checks and jet pump and control rod operability. The inspector found the licensee's activities to be acceptable.

On August 8, 1992, the Unit 3 reactor core isolation cooling (RCIC) system was declared inoperable due to the failure of testable check valve AO-3-13-22 to satisfy the in-service test (IST) program acceptance criteria. The check valve's position indication in the control room did not change from the closed position when stroked. The position limit switches had previously been identified as unreliable. The PORC reviewed the test results on August 9th and directed that the system be declared operable based on a RCIC system injection to the reactor pressure vessel (RPV) that had occurred on July 12th during the plant startup. This decision was reversed, however, on August 10th, when the system engineer identified that the indication response during the July 12th test differed from those observed during the current test. Therefore, PORC declared the RCIC system inoperable as of August 8th and determined that an injection of the RCIC system to the RPV was the only way to prove the operability of the check valve.

The licensee wrote special test SP-1456, "RCIC Testable Check Valve AO-3-13-22 IST Operability Determination," to procedurally direct the injection of RCIC to the RPV at high power levels. The inspector reviewed the special test and determined that the licensee had incorporated the proper precautions and limitations to safely perform the test. Also, the test included an IST verification of the valve in the closed position. The inspector observed the performance of the special test on August 13, 1992. The control room staff acted in a professional manner and maintained good plant control throughout the test. The test results were satisfactory, and the RCIC system was declared operable.

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspector observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspector verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspector reviewed maintenance procedures, action requests (AR), work orders (WO), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. During observation of maintenance work, the inspector verified appropriate QA/QC involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspector found the licensee's activities to be acceptable.

5.1 Emergency Diesel Generator E-3 Outage

On August 10, 1992, at 9:15 a.m., the licensee began a maintenance outage on the E-4 EDG and entered a seven day TS LCO action statement. The scope of the outage included the mechanical portion of the TS-required 18 month inspection, replacement of the cylinder liners, and a 36 hour engine run-in-test required by the manufacturer whenever engine wear-in parts are replaced. The liners were being replaced based upon information received from the vendor that the liner O-rings had reached the end of their expected life.

The licensee incorporated lessons learned during previous EDG outages in planning for the physical outage work and the required testing to be completed within the allowed seven days LCO. The engine was torn-down with all cylinder liners removed within 24 hours. During this time, the licensee identified that the bearing for the vertical drive was out of tolerance and it was replaced. The EDG was re-built and mechanically ready for its 36 hour run by 9 p.m., on Friday, August 14. The EDG was returned to service at 3:25 a.m. on August 17, 1992.

The inspector observed activities associated with the diesel outage including operations support prior to the start of the outage, conduct of maintenance, and testing activities. The inspector observed that the outage was well planned and followed an aggressive schedule. The craftsmen were skilled and very knowledgeable about the EDG as evidenced by the rapid tear-down and re-build times. Also, the licensee incorporated lessons learned from previous outages by identifying and changing the vertical drive early in the outage. Overall, the inspector found that the outage was well planned and managed.

5.2 Replacement of a Failed Topaz Inverter

On August 20, 1992, at about 7:55 p.m., a Unit 3 Emergency Core Coolant System (ECCS) power supply failed. Annunciator 322 E-5, "ECCS Trip Unit Out of File/Power Failure," alarmed in the control room alerting the reactor operator. The licensee's follow-up investigation revealed that the negative side 125 vdc supply fuse to Topaz inverter 3-02-3-402B was blown. The Topaz inverter is the emergency backup power supply that converts DC power from a 1-E Battery source to AC power. It feeds ECCS trip units for the High Drywell Pressure trip and the confirmatory reactor low level.

The licensee exercised caution in their troubleshooting approach to prevent any spikes in the circuitry that would cause a scram. Since the main power supply providing was still providing power to the instrument rack, the licensee replaced the fuse which immediately blew. The licensee isolated and tested the topaz inverter and found that the sine wave inverter had failed. It was replaced with a refurbished inverter. The licensee conducted tests on the remaining portion of the power supply to verify no further misoperation, and it was returned to service.

The inspector found that the licensee's actions regarding the planning and conduct of the power supply repair were very good.

6.0 RADIOLOGICAL CONTROLS (71707)

The inspector examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspector monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspector verified compliance with RWP requirements. The inspector reviewed RWP line entries and verified that personnel had provided the required information. The inspector observed personnel working in the RWP areas to be meeting the applicable requirements and individuals frisking in accordance with HP procedures. During routine tours of the units, the inspector verified a sampling of high radiation area doors to be locked as required. All activities monitored by the inspector were found to be acceptable.

7.0 PHYSICAL SECURITY (71707)

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspector observed security staffing, operation of the Central and Secondary Access Systems, and licensee checks of vehicles, detection and assessment aids, and vital area access to verity proper control. On each shift, the inspector observed protected area access control and badging procedures. In addition the inspector routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspector found the licensee's activities to be acceptable.

8.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701)

(Closed) Violation 90-22-01, Failure to Perform Timely Corrective Action to Repair Leaks in Seismic Backup Valves.

On November 5, 1990, a leak developed in the backup nitrogen (N_2) supply for the boot seal of the inboard containment purge isolation valve (AO-2520). This leak had the potential to degrade the primary containment in the event of a loss of off-site power or seismic event. At the time of this event, an outboard containment purge isolation valve in the same penetration (AO-2521A) was blocked with its boot seal deflated. The leak was not properly repaired and the bottle was found empty the next day. AO-2520 was declared inoperable causing the simultaneous inoperability of two in-series penetration valves and the action statement for loss of primary containment was entered. Primary containment was never lost because the normal air supply to AO-2520 remained available. However, a leak path would have existed through the boot seals of the inboard and outboard isolation valves had there been a loss of instrument air.

During the initial response to the leak event, the licensee demonstrated that they did not fully understand the importance of the backup N_2 system and the TS LCO was misinterpreted by several licensee personnel. Further, the acceptance criteria in Surveillance Test (ST) 7.9.2-2, "Daily Checks of Seismic Gas Supply," did not adequately identify the problem. As a result of a this event, the licensee committed to:

- provide immediate verbal operator training and follow-up written instructions to improve the understanding of the backup nitrogen system and its relationship to equipment operability;

- heighten operator sensitivity to proper review and disposition of surveillance test results;

- complete their evaluation of TS 3.7.D.2 and 3.7.A.3 and train operators concerning the correct interpretation;

- implement a near-term temporary change and long-term permanent revision to ST 7.9.2-2 to include explicit guidance on operability and to address increased gas leak rates;

- have the system engineer review results of ST 7.9.2-2 daily to aid in early identification of increased leakage;

- complete planned modifications to remove gas bottles and install a backup supply from the safety-related containment atmosphere dilution (CAD) system.

During this inspection period, the inspector reviewed the licensee's activities related to each of these corrective actions.

The licensee prcformed an in-house event investigation to determine the root causes of the event. The operators were given verbal training and follow-up written instruction in the form of required reading. The required reading summarized the event, discussed operator and procedural weaknesses that were identified, and explained the backup nitrogen system and its relationship to equipment operability. An emphasis was placed on the operator's impact in conducting plant operations. Specifically, the operator's responsibility to properly review surveillance test results and the importance of notifying the Shift Manager/system engineer when the ST results were unsatisfactory or a N_2 bottle was replaced. This training was completed by December 21, 1990. The inspector reviewed the required reading package and had no further questions.

During the event, the operators questioned what the TS required if both valves in a penetration became inoperable. Confusion resulted regarding the applicability of TS 3.7.D.2 when the operators tried to interpret it for two inoperable valves. An analysis was written to clarify the application of the TS to this scenario concluding that TS 3.7.A.3, for breach of primary containment should be entered. The inspector reviewed the TS analysis and noted a statement that indicated that a PORC Position may be written. Discussions with the licensee revealed that the PORC position was not issued. Interviews with several Shift Supervisors indicated that some confusion still existed in how TS 3.7.D.2. should be interpreted, although all personnel indicated that they would contact management for guidance. The licensee agreed that a PORC position was warranted to assure a consistent interpretation, and to put one in place.

The licensee implemented a TC to ST 7.9.2-2 on December 4, 1991. This TC provided clarification regarding operability requirements for all butterfly valves with inflatable boot seals. It increased the gas bottle replacement criteria from 1300 pounds per square inch (psig) to 1400 psig. This was to ensure the capability of providing a 20 day supply of N_2 with 20% degradation to the system. The system engineer reviewed results of ST 7.9.2-2 weekly until the Unit 2 refueling outage began and primary containment was no longer required to be operable. Since the event occurred, no bottles lost greater than 50 psig per day.

The planned modification to remove the N_2 bottles and install a backup supply from the CAD system was completed and turned over for operation on April 11, 1991. Modification 1316 installed the safety-grade instrument gas (SGIG) system. It is a Q-listed, seismically-mounted, permanent hard-piped system that supplies 85 psig nitrogen gas to the boot seals of the air-operated primary containment valves in the event instrument air was lost. A single nitrogen storage tank is maintained at a level greater than 33 inches of water column to assure the volume necessary to meet the requirements for CAD and SGIG are available. ST 9.9, "Liquid Nitrogen Quantity Report - CAD Tank Daily," is performed daily to verify the tanks level.

The inspector reviewed the FSAR and TS and noted that they were both updated to include the SGIG system and new required CAD tank level. The inspector reviewed the ST, alarm response procedure (ARP), and observed an operator's response to a CAD tank low level alarm in the control room. The operator used the ARP and notified the Shift Supervisor, who promptly ordered more nitrogen when actual tank level was verified by the plant operator. The inspector concluded that the licensee had taken appropriate corrective actions concerning this issue.

(Closed) Unresolved Item 90-22-02, Standby Liquid Control (SLC) Squib Valve and Junction Box Corrective Actions.

On November 2, 1990, the inspector walked-down the Unit 3 SLC system following completion of the SLC explosive valve maintenance. Two electrical junction boxes, that supply power to the 'A' and 'B' explosive valves, were not properly supported. In addition, four spacers between the explosive valve flange and spool piece flange for each valve were misplaced.

The licensee secured the junction boxes on November 2, 1990. The system engineer determined that the junction boxes had been disconnected from their pedestal since September 6, 1989. Nuclear Engineering performed an evaluation (EWR A0004591) of the unsecured junction boxes on system seismic qualification in response to the inspector's concern. On April 10, 1991, the licensee determined that the conduit or conduit support failure would not have affected equipment operability.

The licensee correctly installed the flange spacers on the 3B explosive valve following valve maintenance in December, 1991. The inspector noted, during a system walkdown on July 20, 1992, that the 3A explosive valve's flange spacers were still improperly installed. The inspector also identified cable degradation, resulting from an excessive cable bend, due to the location of the explosive valve terminal box. The licensee evaluated these problems, concluded that they did not impact operability and initiated corrective maintenance action requests (A/R A0646200 and A/R A0599700), to correct these problems. This item is closed.

(Closed) Unresolved Item 91-29-001, Working Hour Restrictions for Senior Reactor Operators Limited to Fuel Handling.

During the 1991 Unit 3 refueling outage, the NRC conducted a safety inspection of the activities performed by the Senior Reactor Operators limited to fuel handling (LSRO). The NRC inspector identified that the facility's interpretation of the working hour restrictions for LSROs appeared to be inconsistent with NRC requirements. The facility did not clearly define in the Administrative Procedure (AP) or TS what overtime restrictions applied to the LSROs.

Peach Bottom has a TS that addresses more restrictive working hour requirements for operations shift personnel than those for plant personnel. Each licensed and non-licensed shift operator has a certain payroll number and is governed by the more restrictive TS requirements. When the licensee initiated the LSRO program, the personnel in the program did not conform to this payroll number criteria and therefore, the licensee did not hold them accountable to these TS requirements. The NRC inspector was concerned that the more restrictive TS requirements did apply to the LSROs, and that the licensee's policy was unclear.

The licensee revised AP-40, "Working Hour Limits," to clarify their position on the working hour limitations for LSROs. The new AP specifically states that the LSROs are required to conform to the plant staff work hour requirements and not to the control room operator work hour requirements. The licensee's justification for this position was that the LSROs duties are cyclic in that they only spend a portion of the year fulfilling the LSRO function at Peach Bottom. The other portion of their time is spent performing other duties. The LSROs hours are controlled during outages to ensure that they do not violate the overtime requirements for plant staff.

Based upon review of the administrative procedure, discussions with the licensee's staff, and the consistency in the working hour requirements being maintained between Peach Bottom and Limerick, the inspector concluded that the licensee clearly defined the working hour limitations for LSROs. This item is considered closed.

(Closed) Violation 91-30-001, Inadequate Performance of Independent and Double Verifications (IV/DV).

On September 26, 1991, during implementation of troubleshooting control form (TCF) 91-1099, the licensee did not perform adequate initial and independent verifications. As a result, ECCS room cooler inlet valve HV-2-33-21084F was not returned to the locked open position as required. ECCS Compartment Cooler 2FE057 and the 2B Core Spray Pump were made inoperable for a period of about seven days.

On November 20, 1991, the licensee issued procedure A-C-33, "Nuclear Group Process for Verification of Quality," a common nuclear procedure addressing the personnel responsibilities and process for determining, assigning and performing verifications of station Maintenance/I&C and Radwaste activities. The procedure also provides consistent definitions for IV used throughout the Nuclear Group. Administrative Procedure A-42.1, "Troubleshooting, Minor Rework, and Testing Support Process," was revised to clarify the requirements for the use of IV and DV during troubleshooting activities. The revision involved a complete rewrite of the procedure and was implemented on August 1, 1992.

I&C personnel received IV and DV training during August, 1991. This training covered the verification process and the criteria for proper instrument valving verification. This lesson plan, #213-40100, is presented to new I&C employees and then every two years as continuing training. Training was presented to maintenance and quality control personnel during December 1991 and January 1992. Each Technical Section Branch Head reviewed and discussed A-C-33 with their appropriate personnel on or before January 31, 1992. Additionally, IV/DV training for operations personnel was conducted April 13 through May 22, 1992 (Lesson Plan 92-02L).

The inspector interviewed shift supervisors, reactor operators, I&C technicians and supervisors, and plant operators regarding IV/DV concerns. Individuals were questioned on A-C-33 training, IV/DV procedures, and recent IV/DV work experiences. All required training has been received, personnel were very knowledgeable in proper verification procedures, and IV/DV related incidents have diminished significantly. The inspector verified numerous valve positions, which had required independent verification. No deficiencies were noted. The inspector found that the corrective actions were effective in addressing past weaknesses in the IV/DV process.

(Update) Unresolved Item 92-07-02, Reactor Water Level Condensing Chamber Design Problem.

The investigation and development of potential design changes in response to site specific problems with reactor water level instrumentation performance are ongoing. The licensee is also responding to related industry water level instrumentation problems. Additional discussion of this issue is included in Section 3.3 of this report.

(Update) Unresolved Item 92-14-02, Evaluate the Licensee's Root Cause Analysis of a Failed Type SBM Breaker Control Switch.

The licensee continues to pursue an inspection and testing program intended to define the scope and potential generic impact of this failure. The status and progress of that review, and the NRC follow-up inspections, are described in Section 3.4 of this report.

9.0 MANAGEMENT MEETINGS (71707)

The Resident Inspectors provided a verbal summary of preliminary findings to the Peach Bottom Station Plant Manager at the conclusion of the inspection. During the inspection, the Resident Inspectors verbally notified licensee management concerning preliminary findings. The inspectors did not provide any written inspection material to the licensee during the inspection. This report does not contain proprietary information. The inspectors also attended the entrance and/or exit interviews for the following inspection during the report period:

Date	Subject	Report No.	Inspector
8/10-8/14	Training Team Inspection	92-81	Williams
8/17-8/21	Confirmatory Measurements	92-21	Kottan
8/18-8/21	Inservice Inspection	92-22	McBrearty
8/25-8/28	Emergency Preparedness	92-19	Eckert