U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-272/88-17
50-311/88-17

License Nos. DPR-70
DPR-75

Licensee: Public Service Electric and Gas Company
P. O. Box 236
Hancocks Bridge, New Jersey 08038

Facility Name: Salem Nuclear Generating Station - Units 1 and 2

Inspection At: Hancocks Bridge, New Jersey

Inspection Conducted: August 23, 1988 - September 26, 1988

Inspectors: R. W. Borchardt, Senior Resident Inspector
K. Halvey Gibson, Resident Inspector
C. G. Miller, Reactor Engineer

Approved by: Paul D. Swetland 10/13/88
P. D. Swetland, Chief, Reactor Projects Section No. 2B, Projects Branch No. 2, DRP — date

Inspection Summary:
Inspections on August 23, 1988 - September 26, 1988 (Combined Report Numbers 50-272/88-17 and 50-311/88-17)

Aeas Inspected: Routine inspections of plant operations including: operational safety verification, maintenance, surveillance, refueling activities, engineered safety feature walkdown, assurance of quality, review of licensee event reports, and followup on outstanding inspection items.

Results: The inspectors are continuing to assess licensee actions with regard to a Unit 1 steam generator steam flow instrumentation discrepancy which resulted in an Unusual Event declaration during the report period (paragraph 2). Unit 2 refueling activities (paragraph 5) reviewed during the inspection period generally appear to be planned, implemented and controlled satisfactorily. Increased management attention is needed with regard to housekeeping in the Unit 2 containment and the auxiliary building (both Units). Another example of poor administrative control of documents used in the control room is discussed in paragraph 9 and indicates the need for further licensee corrective actions in this area.

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DETAILS

1. Persons Contacted

Within this report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activity.

2. Operational Safety Verification (71707, 93702)

2.1 Inspection Activities

On a daily basis throughout the report period, inspections were conducted to verify that the facility was operated safely and in conformance with regulatory requirements. The licensee's management control system was evaluated by direct observation of activities, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation, and review of facility records. The licensee's compliance with the radiological protection and security programs was also verified on a periodic basis. These inspection activities were conducted in accordance with NRC inspection procedures 71707 and 93702 and included weekend and backshift inspections.

2.2 Inspection Findings and Significant Plant Events

2.2.1 Unit 1

Unit 1 began the report period operating at 100% power. On August 31, the unit tripped from full power as a result of a main turbine trip caused by a loss of turbine auto stop oil pressure during the performance of an on-line surveillance test of the low vacuum trip device. Licensee investigation of the trip did not determine the conclusive cause of the loss of the auto stop oil pressure as the condition could not be reproduced during follow up testing by the licensee. However, during their investigation the licensee found debris in a pressure reducing orifice in the supply line to the auto stop oil system. The licensee surmised that an intermittent blockage of the pressure reducing orifice could have resulted in the reduction of the auto stop oil pressure and the turbine trip. It appeared to the inspector that while the licensee's conclusion is plausible, personnel error in performing the low vacuum trip test cannot be positively ruled out in that movement (1-2 inches) of the manual test lever will also reduce auto stop oil pressure to the turbine trip setpoint. All plant systems responded as expected following the trip, and the unit was taken to cold shutdown in order to repair two leaking valves in the pressurizer spray line (1PS29 and 1PS1). The licensee cleaned the debris from the auto stop oil system and ran the low vacuum trip surveillance test during unit startup (turbine spinning at 1800 rpm) to verify proper operation of the auto stop oil system prior to synchronizing the generator to the grid.

The unit was returned to service on September 7, 1988. On September 19, 1988 the licensee declared an unusual event and initiated a unit shutdown after determining that the number 12 and 14 steam generators (SG) each had both steam flow channels out of calibration. This condition requires shutdown to hot standby within 6 hours according to Technical Specification (T.S.) 3.0.3. Steam flow transmitter output from channels 1 and 2 of SG 12, 13 and 14 indicated as low as 95% steam flow at 100% calorimetric power.

A team led by systems engineering discovered this low flow condition while taking steam flow transmitter voltages in order to troubleshoot a previously identified steam flow indication problem. These voltages were taken on September 16 and analyzed on September 19, at which time they determined the channels to be inoperable and in need of calibration. The calibrations were performed prior to completion of the shutdown, and the unit was returned to 100% power.

Steam flow indication has been a problem for some years at Salem, and has received increased attention since the Unit 1 restart in the spring of 1988. Transmitter output generally increased slowly over the period of March 1 to July 16. Control technicians decreased gain on the transmitters several times during this period, lowering indicated steam flow to match calorimetric power. This was performed using the calibration procedure 1IC-2.5 series and entering calculated differential pressure (d/p) data derived from current transmitter output voltage readings. On September 16, the transmitter outputs were discovered to have shifted significantly lower (non conservative) and required increased gain adjustments. The licensee has not determined what causes the transmitter output shifts. The systems engineering group has made several attempts in past years to find a pattern and cause for the problem. They feel that the problem is caused by an actual change in steam flow nozzle d/p for a given steam flow, and not by transmitter drift. As of yet no testing has been performed by the licensee to determine the effect of containment temperature changes on transmitter output. However, the licensee has experienced environmental temperature associated drift on a similar transmitter (Rosemount 1153) which resulted in the transmitter being replaced.

The output of the steam flow transmitters provides signals for a steam/feed flow mismatch reactor trip and an engineered safety features main steam isolation and safety injection actuation. Steam flow indication is available at the control room console, and the T.S. require shiftly channel checks comparing steam flow channels and steam flow to feed flow mismatch. Although the unit was at 100% power while steam flow was indicating approximately 95% and the steam to feed flow mismatch was at or near the maximum limit of 4% specified by the control room logs, the operators did not take action to determine the accuracy of the steam flow indications or declare them inoperable. The licensee could not determine how long the steam flow indications had been reading low prior to September 19. In the two days immediately following the identification of the low out of specification steam flow indication, the inspectors interviewed several operators and operations supervisory staff to determine whether there was increased watchfulness on the part of the operators regarding the steam flow instrumentation. The inspectors determined that adequate shift turnover apparently did not occur with regard to this problem, in that one control room operator interviewed was not aware that the instruments had been declared inoperable the day before. The operations supervisory staff interviewed said they would look at the steam flow indications more frequently, however the inspector was concerned that no method was put into place to ensure that excessive transmitter drift would not go unnoticed.

Subsequently on September 22, a meeting was held with the Salem General Manager and members of the operations and engineering staff to discuss the licensee's plan of corrective actions. The short term corrective actions mentioned included: making a night order entry to have operators inform their supervisors when steam flow indicated 3% less than indicated power; instructing all operators on how to properly perform the steam/feed flow mismatch channel checks (which the operations engineer discovered were conducted improperly by some operators); and briefing all operators on the importance of informing supervisory personnel when indications or equipment are not operating as expected. Long term corrective actions included: performing an engineering review of certain control room log parameters to verify that proper maximum and minimum setpoints are included to prevent operation outside T.S. values; performing a human performance evaluation of steam flow indication; and continuing the troubleshooting effort of the steam flow channels. The licensee also committed to take as found d/p calibration data as required by the established calibration procedures. The inspectors verified that increased operator awareness was indeed focused on the steam flow instrumentation after the meeting. The inspectors are continuing their assessment of this issue and are closely following licensee activities in this regard. (UNR 272/88-17-01)

2.2.2 Unit 2

Unit 2 began the report period operating at 100% power.

On August 31, 1988, the unit tripped from full power due to high No. 23 steam generator (SG) level resulting from the SG feed regulating valve (23BF19) failing open. The unit was then borated for cold shutdown and cooled to Mode 6 for its fourth refueling outage. The outage was originally scheduled to commence on September 2 and is planned for 54 days duration. Licensee investigation of the 23BF19 failure determined that the nuts on the feedback linkage to the valve positioner vibrated loose and resulted in the valve going full open. The licensee concluded that the age of the bolts and possible overtightening during previous preventive maintenance activities resulted in degradation of the threads, which contributed to the loosening of the nuts. Corrective actions planned by the licensee prior to Unit 2 restart include applying locktight to the threads and using overlap lockwashers. These actions were accomplished on Unit 1 prior to its return to service on September 7, 1988.

At the close of the report period the core off-load had been completed and numerous design changes are in progress. See Section 5 for outage details.

2.2.3 Both Units

As a result of the unusually hot and dry weather conditions experienced throughout the summer months the inspectors reviewed summer service water temperature conditions as they relate to the ability to cool various safety related components. Both Units have an FSAR service water inlet temperature limit of 90 degrees F. No power reductions or shutdowns were required due to the extended heat spell. Technical specification relief was not sought for items related to cooling water temperatures due to the summer heat; however the licensee did perform preliminary calculations to justify an increase in FSAR service water inlet temperatures to 92 degrees F. Additionally, the licensee increased monitoring of service water inlet temperatures when the circulating water inlet temperatures approached 90 degrees F. This included adding a strip chart recorder to monitor service water inlet temperatures. No major equipment degradations or failures were attributed to the high ambient temperatures in August. Although service water inlet temperatures reached 89 degrees F during the period, no special procedures or equipment operating configurations were required to maintain normal operations within the technical specification and design basis limits.

The licensee was well aware of the potential for high temperature problems if the hot, dry spell continued, and had contingency plans available if the FSAR limits were reached. These plans included finalizing the FSAR change to 92 degree F and notification of licensee management and NRC if 90 degree F limit was exceeded. In addition, the licensee was informed of service water problems experienced by other plants in this period by INPO contacts and discussions with the inspectors.

No violations were identified.

3. Maintenance Observations (62703)

The inspector reviewed the following safety related maintenance activities to verify that the activities were conducted in accordance with approved procedures, technical specifications, NRC regulations, and industry codes and standards.

Work Order Number	Procedure	Description
880905006	Relay Test Manual	2B Diesel Generator Protective Relays - 24 month P.M.
	Subsection 4C2	Reverse Power Relay Westinghouse Type CRN-1
	Subsection 9C	Negative Phase Sequence Phase Time Overcurrent Relay GE Type INC-7783A

The inspector noted that the licensee's Relay Department performs these P.M. activities. The inspector discussed with Relay technicians and supervisors the method used by the licensee to ensure that all safety related relays are maintained and tested as required. A comprehensive tracking system for relay testing does not exist, however, the inspector will continue to assess the effectiveness of the licensee's existing relay test tracking method during the next report period.

880425188	2SM-0457	Service water pipe replacement - 22 component cooling heat exchanger loop
881001109	Various	2C 460V Vital Bus transformer and breaker cubicles preventative maintenance

No violations were identified.

4. Surveillance Observations (61726)

During this inspection period the inspector performed detailed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspector verified that the surveillances were performed in accordance with technical specifications, licensee approved procedures, and NRC regulations. These inspection activities were conducted in accordance with NRC inspection procedure 61726.

The following surveillance tests were reviewed, with portions witnessed by the inspector:

Unit 1

SP(O)4.0.5-V-CC-1	Inservice Inspection - Component Cooling Valves (Modes 1-4)
SP(O)4.0.5-V-CC-5	IST - CC Valves (Modes 5 and 6)
SP(O)4.0.5-P-CC(11)	IST - No. 11 CC Pump
SP(O)4.0.5-P-CC(12)	IST - No. 12 CC Pump
SP(O)4.0.5-P-CC(13)	IST - No. 13 CC Pump
OP II-7.3.2	Component Cooling System - Normal Operation

Unit 2

SP(O)4.8.1.1.2C7C	2C Diesel Generator Endurance Run and Load Rejection Test
OP IV-16.3.1	Emergency Power - Diesel Operation
IOP-7	Cold Shutdown to Refueling

No violations were identified.

5. Unit 2 Outage Activities (60710, 37702)

5.1 Refueling Activities

On August 31, 1988, Unit 2 entered its fourth refueling outage scheduled for a 54 day duration.

Prior to and during refueling activities the inspectors conducted inspections of in-process work, reviewed procedures and surveillance test results, and interviewed licensee and contractor personnel to verify that refueling activities were conducted as required by T.S. and approved station procedures. Daily tours were conducted of plant areas including the containment to verify proper radiological controls, adherence to work procedures, and adequate general plant housekeeping conditions.

The inspector verified the licensee's completion of T.S. surveillance tests, equipment checkout, new fuel receipt and inspection, refueling crew qualification, RCS and refueling pool level controls, and establishment of loose object controls, fuel accountability, and the communication link between the control room and the refuel floor. The inspectors witnessed fuel movement activities both in containment and in the control room. In addition, the inspectors followed licensee activities related to troubleshooting and repair of the fuel transfer trolley and observed ultrasonic testing of old fuel assemblies in the spent fuel pool.

5.2 Design Change Activities

The following is a list of the major work activities scheduled for completion during the outage:

- Steam generator hydrostatic testing (10 year ISI requirement)
- Steam generator eddycurrent and tube plugging (2 of 4 generators)
- Steam generator J-nozzle replacement (4 of 4 generators)
- Replacement of 23 RCP motor
- Reactor disassembly and reassembly, and refueling activities
- Inservice inspections of ASME code components
- Replacement of 2 RCP seals
- Reactor thermocouple and spare CRDM modifications
- Elimination of RTD bypass manifold piping
- Control room redesign for human factors
- Reactor protection system modifications
- Main turbine disassembly, inspection and reassembly
- Secondary piping repairs and replacements
- 22 CCHX service water piping replacement
- Replacement of 21, 22, 23, CFCU service water piping
- Replacement of butterfly valves/expansion joints in service water structure

A brief description of the major design change packages being implemented during this outage is provided below. The inspector reviewed the station design change and modification program, design change packages and witnessed infield work associated with these design changes.

2EC-2151 Implementation of human factors enhancements in the control room

This design change implements the significant enhancements resulting from the Detailed Control Room Design Review (DCRDR). The enhancements include relocation of control room instrumentation, correcting abbreviations, adding demarkation between controls and instrumentation, correcting scales of instruments, labeling, and replacing indicators with an improved design. The new indicators will show a zero indication upon failure and are equipped with an LED to indicate power is available to the indicator. These same modifications are scheduled for Unit 1 during the unit's next refueling outage (April, 1989). During the period that the two unit's control panels are different, the licensee has stated the control room operators will normally be dedicated to one unit and they will not alternate between units.

The inspector attended a meeting held by the licensee to review Work Package No. 3, which provides direction for installation and relocation of bezels associated with the residual heat removal system on the Unit 2 control board. The work package is one of 30 to 40 work packages associated with Design Change Package (DCP) number 2EC-2151, which deals with modification of the Unit 2 control room.

The meeting was held in the simulator where the control board modifications have been completed and was attended by personnel representing all the disciplines involved in the planning, installation, and testing of the modification. Issues such as the need to explicitly specify what test procedures would be required after relocation of a bezel and the need to install accurate labeling immediately after relocation of a bezel were discussed. Based on the conduct of the meeting, discussions with licensee personnel and review of the installed changes on the simulator control boards, it appears that adequate planning has been conducted for the modification.

On September 15, 1988, the licensee's Quality Assurance Department (QA) issued a Stop Work Order (SWO) with regard to this DCP after identifying that traceability of indicating modules and interface connectors was not maintained. Traceability was reestablished, verified by QA and the SWO was lifted on September 16.

2EC-2232 Bottom Mounted Instrumentation

This design change replaces the existing movable flux monitoring system and the top mounted core exit thermocouples with an integral bottom mounted instrumentation system consisting of movable flux detectors and two thermocouples per thimble tube (one as an installed spare). Chrome plating of the flux thimble high wear area and installation of wear reduction inserts into the guide tube holes should resolve tube wall thinning concerns. Cutting and capping of the core exit thermocouple columns should reduce the possibility of boric acid leakage on the reactor vessel head at these 5 locations. The inspector observed portions of the old thimble tube removal and cutup and flushing activities of the guide tube conduit through the lower reactor head and internals.

Also as part of this design change the licensee plans to install mechanical clamps on four spare control rod drive (crd) columns on the reactor head to reduce the possibility of boric acid leakage from these locations. This use of clamps for the CRD application is under review by NRC Licensing

2-SM-0567 Steam Generator "J" Nozzle Replacement

This DCP replaces the existing carbon steel steam generator (SG) feed ring "J"-nozzles with inconel "J"-nozzles which have a carbon steel collar. The inspector observed installation and loose object control activities with respect to "J"-nozzle replacement in the No. 21 SG. The inspector was informed by the licensee that an Alnor dosimeter required retrieving from the No. 24 SG secondary and that loose object controls are being more vigorously implemented.

2EC-2230 Reactor Coolant Loop Resistance Temperature Detector (RTD) Bypass Elimination

This DCP removes RTD bypass piping including 68 valves and provides for the installation of an in-line narrow range RCS temperature measurement system. The inspector witnessed portions of the bypass piping removal and preparations for in-line thermocouple installation.

2EC-2187 Boron Injection Tank (BIT) Removal

This DCP provides for removal of the BIT as a borated water source by cutting and capping recirculation lines between the BIT and boric acid storage tanks (BAT), disconnect associated heat tracing, and reduction of BIT boron concentration from 21,000 ppm to less than 7000 ppm. The inspector witnessed portions of the BIT recirculation piping removal activities.

2EC-2174 ATWS Mitigation System Actuation Circuitry

This design change installs a new control system called the ATWS Mitigation System Actuation Circuity (AMSAC). Upon receiving a low steam generator water level condition the output of AMSAC starts the auxiliary feed pumps and trips the main turbine. Although AMSAC is not designated as safety related equipment this modification involves work in and around safety related process cabinets and electrical separation is provided by electro mechanical relays.

5.3 Inspection Findings

No violations were identified with regard to refueling preparations and activities, however the inspector noted that the core reload 10 CFR 50.59 safety evaluation has not yet been reviewed by the Station Operating Review Committee (SORC) and that the licensee had not verified the qualifications of the NSSS vendor (Westinghouse) refueling crew until questioned by the inspector. These items will be followed up by the inspector during the next inspection period.

On several occasions during the report period the inspectors discussed with licensee management concerns with regard to substandard housekeeping practices in the Unit 2 containment and both units' auxiliary building. Discrepancies identified included not well defined contaminated area boundaries, anti-contamination clothing strewn in contaminated areas and across contaminated area boundaries, and substandard control of material (i.e. scaffolding, tools, and demolition residue) in contaminated areas to prevent the spread of contamination and maintain a neat, organized work place.

Within the scope of the inspectors review of the design change program, no violations were observed. However, the following two areas for improvement were discussed with the licensee; (1) the maintenance training program does not appear to have a formalized process for review of DCPs to identify appropriate training needed for maintenance personnel as a result of extensive or complicated plant modifications, and (2) timeliness of revisions to plant drawings following completion of modifications. Positive findings identified with regard to the design change process include; (1) the new design change procedures and checklists provide prompts to ensure configuration management control and (2) supporting information provided with the packages appears to be appropriate to aid installation in the field.

No violations were identified.

6. Engineered Safety Feature (ESF) System Walkdown (71710)

6.1 Inspection Activity

The inspectors independently verified the operability of selected ESF systems by performing a walkdown of accessible portions of the system to confirm that system lineup procedures match plant drawings and the as-built configuration. The ESF system walkdown was also conducted to identify equipment conditions that might degrade performance, to determine that instrumentation is calibrated and functioning, and to verify that valves are properly positioned and locked as appropriate. This inspection was conducted in accordance with NRC inspection procedure 71710. The Unit 1 component cooling water system was inspected. Two minor drawing discrepancies and a concern with the material condition of the reactor coolant system, steam generator, and pressurizer chemistry sample heat exchangers were discussed with system engineering.

No violations were identified.

7. Assurance of Quality

On August 29, 1988, Salem station management effected a smooth transition with John Zupko outgoing as General Manager - Salem Operations and Lynn Miller assuming that position. On the same date, Stanley LaBruna was assigned Vice President - Nuclear Operations responsible for both Salem and Hope Creek stations. In addition, John Zupko became General Manager - Quality Assurance/Nuclear Safety Review and various other personnel and organizational changes were implemented.

Aggressive preplanning and prestaging for Unit 2 refueling outage activities were observed by the inspectors. The licensee compiled an Outage Information Manual and an Outage Implementation Procedure which delineate management philosophy and goals, outage organization and key personnel, and administrative protocols. These documents appear to focus personnel attention on safe and efficient use of outage resources and controlled implementation of outage activities. Effective oversight of outage activities by the licensee's Quality Assurance Department (QA) was evidenced by the identification by QA of a loss of material traceability related to control room design modifications and the issuance of a Stop Work Order until the discrepancy was resolved. On several occasions during the report period, the inspectors discussed with licensee management a concern with regard to substandard housekeeping practices in the radiologically controlled areas (RCA). Increased management attention is warranted in this area.

The licensee's control room operations group exhibited an acceptable level of control, response, and recovery in handling reactor trips which occurred on both units within less than a one hour time frame during this report period.

With regard to Unit 1 steam generator steam flow indication discrepancies, the inspector noted that this had been a long standing issue which may not have received adequate management attention. Our investigation found weaknesses in the calibration adjustment methodology, root cause determinations, immediate corrective action implementation, and sensitivity to the safety significance of this issue.

8. Review of Licensee Event Reports (90712, 92700, 90713)

Upon receipt, the inspector reviewed licensee event reports (LERs) as well as other periodic and special reports submitted by the licensee. The reports were reviewed for accuracy and timely submission. Additional followup performed at the discretion of the inspector to verify corrective action implementation and adequacy is detailed with the applicable report summary. The following reports were received and reviewed during the inspection period:

- Unit 1 Monthly Operating Report - July and August 1988
- Unit 2 Monthly Operating Report - July and August 1988

- Unit 1 LER 88-13 Inoperable Fire Barrier Penetrations

  This LER discusses the inoperability of fire barrier penetration seals due to the seals not conforming to color and/or cell structure requirements. The nonconformance of the seals with respect to color/cell structure is attributed to the lack of proper post-installation verification of color and cell structure. Fire watches have been assigned to affected fire zones as required by Technical Specifications and procedures have been revised to require the performance of post-installation inspection of fire penetration seals for color and cell structure. Replacement of the deficient seals is included as part of the licensee's ongoing Penetration Review Program.

- Unit 1 Special Report Supplement 88-3-1 Fire Penetration Seals Impaired for Greater Than 7 Days

  The Special Report Supplement identified additional degraded fire penetration seals discovered by the licensee's Penetration Seal Task Force which had not been repaired within the 7 day Technical Specification requirement. The inspector verified that fire watches have been appropriately assigned IAW Technical Specifications. In addition, on August 26, 1988, NRC Region I confirmed via conference call with the licensee, the licensee's plans and commitments with respect to timely repair of the degraded seals.

- Unit 2 Special Report 88-4 Valid Test Failure of 2A Diesel Generator

On August 8, 1988, the 2A diesel generator (D/G) failed to reach the required load of 2600 KW within 60 seconds (126 seconds actual) during a post maintenance surveillance test. Troubleshooting determined that the Woodward Governor was defective and it was subsequently replaced. Because this was the second valid failure in the last 100 starts the test frequency was changed from 31 days to 14 days in accordance with Regulatory Guide 1.108. The inspector has no further questions.

- Unit 2 Special Report 88-5 Fire Penetration Seals Impaired for Greater Than 7 Days

The Special Report discusses planned fire penetration seal impairments necessary for Unit 2 refueling outage activities which may not be repaired within 7 days due to engineering review that may be required to ensure installation of a proper seal. The licensee has committed in the Special Report and via a conference call with NRC Region I, which took place on August 26, 1988, to keep the resident inspector informed on a real time basis of specific seals impaired and will supplement this Special Report at the end of the outage identifying those seals which have not been repaired as discussed above.

- Unit 2 LER 88-017 High-HIgh S/G Turbine Trip/Reactor Trip due to a Design/Equipment problem (23BF19)

This event is discussed in Section 2.2.2 of this report. The inspectors had no further questions following review of the LER.

No violations were identified.

9. Followup on Outstanding Inspection Items (71707)

(Open) Partial Completion of TI 2515/73 Inspection Activities Related to IEB 85-03, "Motor-Operated Valve Common Mode Failure During Plant Transients Due to Improper Switch Settings."

The licensee's letter of May 27, 1986 contained their response to IEB 85-03, "Motor-Operated Valve Common Mode Failure During Plant Transients Due to Improper Switch Settings." NRC review of this response led to the issuance of a request for additional information on April 7, 1988, and a response by the licensee on May 23, 1988. NRC review of the additional information provided by the licensee indicates that the licensee's selection of the applicable safety-related valves, the valves' maximum differential pressures and the licensee's program to assure valve operability as requested by action item e. of the bulletin is acceptable. Further inspection is required to review the licensee's final response dated January 5, 1988 and to verify implementation of the licensee's valve operability program.

(Closed) TI 2515/98 Information of High Temperature Inside Containment/Drywell in PWR and BWR Plants

The inspectors gathered containment temperature data, performed a walkdown of Unit 2 temperature sensor locations and concluded that the licensee's temperature monitoring arrangement appears to accurately reflect containment bulk average air temperature. Information requested by the TI was provided to NRR as requested. During the inspection, the inspectors identified a discrepancy with Unit 2 control room logs and Doric computer reference notebook in that these documents do not appear to accurately reflect sensor locations and corresponding computer points. This issue will be followed with a previously identified deficiency with licensee administrative control of control room documents. (Refer to Combined Inspection 88-14 and cover letter with 88-17 report).

10. Exit Interview (30703)

The inspectors met with Mr. L. K. Miller and other licensee personnel periodically and at the end of the inspection period to summarize the scope and findings of their inspection activities.

Based on Region I review and discussions with the licensee, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.