UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report No.: 50-395/94-08

Licensee: South Carolina Electric & Gas Company
Columbia, SC 29218

Docket No.: 50-395 License No.: NPF-12

Facility Name: Virgil C. Summer Nuclear Station

Inspection Conducted: March 1-31, 1994

Inspectors: For R. W. Wright 4/8/94
R. C. Haag, Senior Resident Inspector Date Signed

For R. W. Wright 4/8/94
T. R. Farnholtz, Resident Inspector Date Signed

Approved by: Floyd S. Cantrell, Jr 4/8/94
Floyd S. Cantrell, Chief Date Signed
Reactor Projects Section 1B
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection was conducted by the resident inspectors onsite in the areas of monthly surveillance observations, monthly maintenance observations, operational safety verification, engineered safety features system walkdown, and reduced RCS inventory operations. Selected tours were conducted on backshift or weekends. These tours were conducted on eight occasions.

Results: (Summarized by SALP functional area)

Operations

Operations personnel exhibited good overall performance during plant manipulation for the outage. Some weaknesses and inconsistancies were noted in operator communication. Effective management oversight and prejob briefing were provided for critical plant evolutions. Differences in reactor coolant system level indications were noted during the draindown to reduced inventory conditions (paragraph 7). During an engineered safety feature system walkdown an improperly positioned valve was noted.

Maintenance and Surveillance

A non-cited violation was identified for failure to perform a weekly technical specification surveillance requirement for the safety-related batteries (paragraph 3b). A portion of the fire service piping system was delayed in being fully returned to service due ineffective scheduling of other related work.

Engineering and Technical Support

The heat exchanger monitoring program identified a degradation in the performance of an emergency diesel generator cooler and initiatied corrective action.

Plant Support

Effective and alert health physics coverage was provided for a maintenance activity that encountered unexpected radiological conditions. The licensee's use of overtime for key plant personnel was controlled and total amounts of overtime did not appear to be excessive.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   W. Baehr, Manager, Health Physics
   *C. Bowman, Manager, Maintenance Services
   M. Browne, Manager, Design Engineering
   *J. Derrick, Supervisor, Systems Engineering
   L. Faltus, Acting Manager, Chemistry
   *M. Fowlkes, Manager, Nuclear Licensing & Operating Experience
   *S. Furstenberg, Associate Manager, Operations
   *S. Hunt, Manager, Quality Systems
   A. Koon, Nuclear Operations Project Coordinator
   D. Lavigne, General Manager, Nuclear Safety
   *J. Nesbitt, Acting Manager, Technical Services
   K. Nettles, General Manager, Station Support
   H. O'Quinn, Manager, Nuclear Protection Services
   M. Quinton, General Manager, Engineering Services
   J. Skolds, Vice President, Nuclear Operations
   *G. Taylor, General Manager, Nuclear Plant Operations
   *R. White, Nuclear Coordinator, South Carolina Public Service Authority
   *B. Williams, Manager, Operations

   Other licensee employees contacted included engineers, technicians, operators, mechanics, security force members, and office personnel.

   *Attended exit interview

   Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Plant Status

   The plant was shutdown on March 1, 1994, for various plant maintenance. The major activities completed during the shutdown included repair of hydrogen leaks on the main generator, replacement of "B" reactor coolant pump seal package, and miscellaneous maintenance on the reactor building polar crane. The plant remained shutdown until March 17, when a reactor startup was commenced. The main turbine was brought on line March 18 and power was raised to approximately 30 percent. On March 21, power was increased to approximately 65 percent and remained at that level for fuel conservation during the remainder of the inspection period. On March 29, 1994, the licensee conducted an emergency preparedness drill. The inspector observed activities in the technical support center during the drill.

Other inspections or meetings:

- During the week of February 28, 1994, a regional inspection of the steam generator replacement project was performed (NRC Inspection Report No. 395/94-06).

- On March 28-29, 1994, a regional followup inspection in the area of radiological effluent monitoring and chemistry control was performed (NRC Inspection Report No. 395/94-09).

- Mr. Singh Bajwa and Mr. George Wunder, NRR, were onsite March 29-30, 1994, to tour the plant and meet with licensee management.

3. Monthly Surveillance Observation (61726)

   a. Routine Surveillance Activities

   The inspectors observed surveillance activities of safety related systems and components listed below to ascertain that these activities were conducted in accordance with license requirements. The inspectors verified that required administrative approvals were obtained prior to initiating the test, testing was accomplished by qualified personnel in accordance with an approved test procedure, test instrumentation was calibrated, and limiting conditions for operation were met. Upon completion of the test, the inspectors verified that test results conformed with technical specifications and procedure requirements, any deficiencies identified during the testing were properly reviewed and resolved and the systems were properly returned to service. Specifically, the inspectors witnessed/reviewed portions of the following test activities:

   1. Quarterly capacity verification of the pressurizer heater groups (STP 506.001). TS 3.4.3 requires at least two groups of pressurizer heaters, each having a capacity of at least 125 kw. The inspector reviewed the basis of the STP acceptance criteria which stated that a minimum of 15 amperes on the control board meter was accepted to ensure a capacity of 125 kw. The STP acceptance criteria contained adequate conservatism to ensure compliance with the TS.

   2. Moveable control rod insertion test (STP 106.001). This STP was performed as the retest for an earlier problem with control rod position indication. While withdrawing shutdown bank "B" control rods, the licensee noted that the rod position on the integrated plant computer system (IPCS) did not agree with the step counters nor the digital rod position indication. An input relay to the IPCS was found to be the cause of the disagreement and the relay was

replaced. The retest verified correct control rod position from all indication systems.

3. Train "B" control room cooling unit operability test (STP 124.001). This test involved stroke testing the outside air inlet valves, XVB0003B and XVB0004B, and verifying that the opening and closing times were acceptable. The inspector verified that the plant instrumentation used during the test was listed in procedure GMP 100.022, Control of Process Instrumentation Used for Surveillance Testing. This procedure would be used if an instrument failed it's calibration, to identify which surveillance testing had previously used an instrument that could have provide erroneous indication.

4. Monthly operational test of the reactor building high range radiation monitor RM-G18 (STP 360.008).

5. Monthly flow path verification for the safety injection and residual heat removal system (STP 105.006).

6. Loop 2 delta T_{avg} loop calibration (STP 302.002). This procedure was performed when placing the spare RTD in service for loop "B" cold leg temperature. During the performance of the test, the reset point for a comparator was found to be out of tolerance. The problem was discovered to be incorrect resistance values used during the calibration. A procedure change was processed to correct the resistance values. The inspector observed the I&C technicians as they worked through this problem and noted a good level of system knowledge.

7. Quarterly leak rate test of instrument air inlet check valve XVE3B-CV1 to the air accumulator for the control room outside air inlet valves (STP 224.004B). There was no measurable leakage noted during the six hour test.

b. Missed TS Surveillance Requirement

On March 10, 1994, the licensee identified that the seven day surveillance test for "A" and "B" station batteries had not been performed as required by TS 4.8.2.1(a). In addition, the seven day surveillance test for the fire pump diesel battery was not performed as required by Station Administrative Procedure, SAP-131A, Attachment II, paragraph D.3.a. Both tests were scheduled for March 7, 1994, with the 25 percent maximum allowable extension (the end date) ending on March 9, 1994. The test for the station batteries involves a pilot cell check for proper electrolyte level, float voltage and specific gravity, and a verification of total battery terminal voltage. The fire pump diesel battery test checked electrolyte level and overall battery voltage. After the discovery of the missed surveillance, the tests were performed satisfactorily.

The inspector reviewed the licensee's controls for the surveillance testing program and the process for verifying tests are completed by the end date. Both an electronic and manual program are used for tracking surveillance tests. However, for surveillances with short test frequencies, i.e. one week, neither method was adequately structured nor properly implemented to ensure incomplete surveillances are identified prior to exceeding the end date.

As a result of this missed TS surveillance requirement the licensee initiated several action items. The surveillance coordinator was directed to track the completion of surveillances on a more timely basis such that any future missed surveillances could be identified prior to exceeding the end date. The electronic surveillance report will be revised such that it can be used as a forecasting tool. This will require timely updates on the status of scheduled surveillances and better utilization of the report. The licensee is also considering a change in the method of scheduling surveillances with short test frequencies. In lieu of issuing a surveillance task sheet for each activity the surveillance would be included on a log sheet that the responsible group performs on a specified frequency. This effort is intended to duplicate the process operations utilizes for surveillances with short test frequencies.

This violation was licensee identified and prompt corrective action was taken, therefore, it is not being cited because the criteria specified in Section VII.B. of the NRC Enforcement Policy were satisfied. This non-cited violation is identified as NCV 94-08-01, Failure to perform a TS surveillance requirement within the specified time interval.

All the observed tests were performed in accordance with the procedural requirements and demonstrated acceptable results. A missed TS surveillance was identified as a non-cited violation due to the licensee's prompt identification and corrective action.

4. Monthly Maintenance Observation (62703)

Station maintenance activities for the safety-related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards.

The following items were considered during this review: that limiting conditions for operation were met while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, functional testing and/or calibrations were performed prior to returning components or systems to service, activities were accomplished by qualified personnel, parts and materials used were properly certified, and radiological and fire prevention controls were implemented. Work requests were reviewed to determine the status of outstanding jobs and to ensure that priority was assigned to safety-related equipment maintenance that may affect system performance. The following maintenance activities were observed:

a. Replacement of incore flux mapping detector for "D" drive unit (MWR 93N3161). The old detector was placed in one of the disposal storage thimbles and the remaining detector cable was removed. A new detector, with the complete drive cable assembly, was installed. The inspector was informed that the old detector will remain in the storage thimble. The licensee has no current plans for permanent disposal of the old detectors. The inspector noted effective and alert health physics (HP) coverage of this maintenance activity. When higher than expected loose surface contamination levels were discovered on the interior of the drive unit, the HP controls were changed to required respirators when working with the old detector cable.

b. Reassembly of the interlock mechanism for the reactor building personnel airlock doors (PMTS P0171898). The interlock assembly had been disengaged to allow both doors to remain open while the plant was in Mode 5. After reassembly, the mechanics verified the interlock would only allow one door to be opened at a time. The interlock function was tested later, during the activity which tested the door seals.

c. Investigation and repair of the improper bank overlap noted for control rod bank "C" (MWR 9403216). During the plant shutdown, the operators noted that the overlap between bank "C" and the other banks was off by four steps. For inward rod motion bank "C" should start inserting when bank "D" is at 97 steps and should be fully inserted when bank "B" is at 128 steps. After reviewing the control rod system electrical drawings, the licensee identified the bank overlap counter as a potential cause of this problem. The counter was replaced and the subsequent retest verified that proper overlap was maintained for bank "C".

d. Replacement of the pressure switch on the "B" main feedwater isolation valve (MWR 9403346). This pressure switch controls the booster pump which maintains the appropriate air pressure in the valve operator. The inspector noted that this was a well planned and well executed job.

e. Service water traveling screen "B" lubrication (PMTS P0175878). No discrepancies were noted.

f. Service water pump "C" breaker inspection, cleaning and operational check (PMTS P0175678).

g. Flow verification test for the fire service sprinkler system (PTP 114.042). This test verified system water flow up to the deluge valve for each branch line.

h. High pressure water cleaning of the fire service line in the intermediate building (MWR 94D3023). The cleaning was an attempt to improve the degrade of the FS flow condition that was recently identified (see NRC Inspection Report No. 50-395/94-03). The "hydro-lancing" technique, which operated with a discharge pressure of 3200 psig, was used to remove the buildup of material inside the piping. A subsequent flush of the piping was performed to remove any loose material. The licensee plans to perform another flow test of the FS system to determine if the low flow condition was corrected by the pipe cleaning.

While reviewing the work package for this activity the inspector noted that water cleaning of the auxiliary FS piping had started approximately one week earlier on March 1, 1994. However, it was not until the piping flushes had been completed in both buildings on March 14, 1994, when the auxiliary building FS piping was completely returned to service. The inspector concluded that the auxiliary building FS piping could have been returned to service earlier if the flushing had been performed after the cleaning activity and not delayed approximately one week.

i. Quarterly preventive maintenance task to inspect the elements in the air cleaners for "A" EDG (PMTS P0176113).

j. Cleaning the tube side of "A" EDG lube oil cooler XEH0017A-HE1 (MWR 94T3043). As a result of previous thermal performance testing of the heat exchanger, engineering initiated this maintenance task. The wording on the MWR stated to clean the cooler prior to June,1994. Engineering stated that they had previously seen a decrease in the efficiency of the heat exchanger. The current frequency for thermal performance testing of the cooler is every six months. This maintenance activity demonstrated the effectiveness of the heat exchanger performance monitoring program and the ability to identify degrading trends before the component/system is not able to perform it's safety function.

The maintenance activities observed were well executed and procedures were followed. Portions of the FS piping could have been returned to service earlier if a related activities had been performed earlier. The health physics coverage of a maintenance activity was alert in identifying unexpected radiological conditions and altering the precautionary measures. The heat exchanger monitoring program was effective in identifying degraded performance and initiating corrective action.

5. Operational Safety Verification (71707)

   a. Plant Tour and Observations

      The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and limiting conditions for operations; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, and tags on components to verify compliance with approved procedures.

      The inspectors conducted weekly inspections for the operability verification of selected ESF systems by valve alignment, breaker positions, condition of equipment or component(s), and operability of instrumentation and support items essential to system actuation or performance. The reactor building instrument air and the safety-related chill water systems were included in these inspections.

      Plant tours included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, physical security controls, plant housekeeping conditions/cleanliness, and missile hazards. Reactor coolant system leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated; and that appropriate actions were taken if required. Selected tours were conducted on backshifts or weekends.

   b. Control Room Observations During Maintenance Outage

      The inspectors observed portions of the following evolutions from the control room which were associated with the maintenance outage completed during this inspection period:

      - Power reduction and main turbine shutdown in accordance with GOP-4.

      - Reactor shutdown in accordance with GOP-5 (Mode 2 to Mode 3).

- Plant shutdown in accordance with GOP-6 (Mode 3 to Mode 4).

- Plant cool down in accordance with GOP-7 (Mode 4 to Mode 5).

  Reduced inventory operations in accordance with GOP-9.

- Plant startup and heatup in accordance with GOP-1 (Mode 5 to Mode 4).

- Plant heatup in accordance with GOP-2 (Mode 4 to Mode 3).

- Reactor startup in accordance with GOP-3 (Mode 3 to Mode 2).

- Power increase and main generator synchronization to the grid in accordance with GOP-4.

During these evolutions, the inspectors noted that the control room operators generally made good use of procedures and demonstrated good knowledge and awareness of changing plant conditions. In addition, management oversight was maintained during critical portions of the above procedures. Dedicated management oversight was provide on the back shifts. The prejob briefing were considered a positive aspects of management's control and oversight of operational activities. The briefing were thorough and focused on caution and the need for deliberate actions when performing the activity. Based on the following observations the inspectors noted several areas that could be improved.

1. While shutting down the reactor in accordance with GOP-5, the operators were instructed to insert the control rods. In the process of doing this, the operators were instructed to halt rod insertion. At this point, reactor power was less than 10^{-6} percent. After discussions between the operations manager and the shift supervisor, further instructions were given to the operators to withdraw control rods and stabilize reactor power at 10^{-3} percent. This was to allow accomplishment of surveillance test procedure, STP 102.001, on the source range instrumentation. The intent was to perform this STP by pausing at the appropriate power level during the shutdown but there was some confusion which resulted in going past the desired power level and then having to return as described above. The inspector attributed this confusion to inadequate attention to detail during the shutdown.

2. During extended control room observations, the inspectors noted that when some annunciators came in on the main control

board, the board operators were not announcing the alarm condition or referring to the Annunciator Response Procedures (ARP). Management expectations with regard to annunciator response by the board operators is documented in OS-001, which states that when an annunciator comes in, the operators will notify the control room supervisor of the alarm condition, state if the condition is expected or not expected, and refer to the ARP to ensure that all followup actions have been taken. The inspector recognizes that this is not practical or even desirable during all conditions such as an annunciator which repeatedly alarms and then clears. At other times, however, there was an apparent difference between management expectations and operators response to annunciators.

3. While establishing a pressurizer bubble in accordance with GOP-1, the operators were instructed by the procedure to adjust the pressurizer level to 25 percent. A note contained in GOP-1 stated that at the reduced pressurizer temperature (at which this procedure was performed), the hot calibrated pressurizer level instruments will indicate higher than actual level while the cold calibrated level instrument will indicate lower than actual level. The procedure did not specify which level instrument to use while establishing the 25 percent pressurizer level. The shift supervisor made the decision to use the cold calibrated level instrument. Additional evaluation of this item and procedural clarification would avoid confusion in the future.

c. Controls on Overtime Usage

In response to an NRC survey, the inspectors reviewed the licensee's program for controlling overtime and the previous amounts of overtime for key plant personnel. Section 6.2.2.e of the TS specifies administrative controls on overtime usage. These controls apply to all unit staff personnel who perform safety-related work. While the routine heavy use of overtime is not allowed, the TS recognizes that overtime will be periodically needed for outages, major maintenance activities, or major plant modifications. For these types of activities the TS provides guidelines on the amount of overtime to be worked. Any deviation from these guidelines shall be authorized by the General Manager, Nuclear Plant Operations, or his deputy, or higher levels of management.

The inspector reviewed Station Administrative Procedure, SAP-152, Control of Overtime For Station Personnel. Paragraph 1.0, Purpose, of SAP-152, states that the requirements of the procedure are not applicable during extended shutdown periods.

After questioning the licensee the inspector was informed that no other procedures exist for guidance on overtime for extended shutdowns. While reviewing the overtime records of 1993 and those available for 1994, the inspector noted that SAP-152 approval forms were used for authorizing overtime usage during outages which exceeded the TS guidelines. The licensee stated that it was their intent to use SAP-152 for overtime control during all modes of plant operation and that SAP-152 will be revised to reflect the applicability of SAP-152 during outages.

The approval authority specified in SAP-152 for deviations from the TS overtime guidelines was delegated to the applicable manager or general manager for personnel under their supervision. Also, SAP-152 states that supervisors are responsible to assure reasonable efforts are taken to prevent exceeding overtime guidelines and work outside the guidelines should be minimized.

When reviewing the 1993 and 1994 overtime deviation records, the inspector noted only occasional use of overtime above the guidelines during non-outage time period. However, during the outages the amount of overtime that exceeded the guidelines could not be determined from the records review because overtime deviation approvals were generally given on a groups basis for the entire outage. The overall percentage of overtime worked in 1993 and 1994 also indicates that overtime usage is not excessive. For 1993 and 1994 the amount of key personnel overtime worked, including all outages, ranged from a high of 19.3% for electrical maintenance to 8.6% for I&C.

The inspector noted numerous authorization forms which had an approved date after the overtime period, yet the box designated, "Deviation has not occurred without prior authorization" was checked. Step 6.4, of SAP-152, states that deviations must be approved by the immediate supervisor and accountable manager prior to being allowed to deviate from the overtime guidelines. The forms also contain a signature block for verbal authorizations, but these blocks were not completed for many of the late authorizations. No guidance is contained in SAP-152 on the need to document authorizations prior to deviating from the guidelines. However, if the approval (either verbal or written) is given prior to working the overtime then the inspector considered that the approval should be documented at the same time.

With the exception of some minor items the licensee is properly utilizing the overtime control procedure and maintaining overtime usage within the requirements of TS. The inspector reviewed previous quality assurance audits of overtime usage. The questions regarding the scope of SAP-152 and documentation of overtime deviation approvals were also identified by QA.

6. ESF System Walkdown (71710)

The inspectors verified the operability of an ESF system by performing a walkdown of the accessible portions of the high head safety injection system and the safety injection accumulators. The portions of these systems that are located in the reactor building were also inspected while the reactor building was accessible during the outage. The inspectors confirmed that the licensee's system line-up procedures matched plant drawings and the as-built configuration. The inspectors looked for equipment conditions and items that might degrade performance (hangers and supports were operable, housekeeping, etc.). The inspectors verified that valves, including instrumentation isolation valves, were in proper position, power was available. and valves were locked as appropriate. The inspectors compared both local and remote position indications to ensure that they matched. Items noted by the inspectors during the walkdown include the following:

a. The inspectors noted scaffolding had been erected in the 397 foot elevation of the auxiliary building during November, 1993. The inspectors questioned the purpose of this scaffolding and why it had been in place so long. The scaffolding was erected to support the installation of a cooling unit located on the level directly above. This job was assigned a relatively low priority and took longer than originally planned. As a result, the scaffolding remained in place for an extended period of time. The inspector reviewed the records for this scaffolding, including the engineering evaluation, and determined that they were complete and had been updated as required.

b. During the system walkdown, one valve was found to be out of position (XVT08959-SI, high root valve to IPI0942). According to the valve lineup sheet in SOP-112, this valve should have been closed but appeared to be open. The inspectors requested that an operator verify the position and it was found to be open. While the safety significance of the mispositioned valve was minimal, it does represent an error in the licensee's valve control program. The licensee identified the cause as personnel error. In August, 1993, a revision was made to SOP-112 which changed the required position of this valve to match the system drawing. The actual valve position should have been changed during the review process but was not. The licensee believes this was an isolated occurrence but is reviewing the process to determine if any changes are needed. The inspectors were not aware of similar problems with procedure revisions to the valve lineup sheets.

7. Reduced RCS Inventory Operations (71707)

Prior to entering reduced inventory operations for reactor coolant pump (RCP) seal maintenance activities, the inspectors evaluated the licensee's program and initiatives for reduced inventory operations. The inspectors referred to Region II letter, dated April 30, 1993, which provided specific guidance concerning Generic Letter 88-17, "Loss of Decay Heat Removal" and reduced inventory operations.

The aspects of this RCS drain down differed from the normal reduced inventory/mid-loop conditions. These differences were: RCS level was lowered to approximately one foot below the RCP seal which was approximately two feet above the top of the hot leg; the S/G U-tube remained full of water which would have allowed the S/G to be used for decay heat removal; and the RCS was not breached by any maintenance activities with the exception of the RCP seal replacement. As part of the evaluation, the following items were reviewed:

- The licensee's responses to Generic Letter 88-17 were found to be adequate and consistent with the action taken for reduced inventory operations.

- The licensee reviewed their controls and administrative procedures governing reduced inventory operation prior to the drain down. The independent safety engineering group (ISEG) reviewed the proposed reduced inventory operation schedule for this shutdown and the conditions that would be different from a "normal" refueling type mid-loop operation. Also, operations personnel reviewed their controls and procedures for reduced inventory operations.

- The licensee maintained both EDGs and both offsite power supplies available during the entire reduced inventory operations.

- With exception of the personnel hatch, containment closure was maintained. The personnel hatch was capable of being closed and sealed if required.

- All the core exit thermocouples were available to provide continuous temperature indication during reduced inventory operations.

- The two independent and continuous water level indications utilized during the draindown were tygon tubing and RVLIS. The inspector walked down the tygon tubing installation prior to usage and verified that it was installed per the procedural requirements. During the draindown the inspector noted that the RVLIS level indication lagged behind the tygon tubing indication. When the tygon was at 437.5 ft. elevation, RVLIS indicated 89 percent (elevation 439.5 ft.). A similar difference was noted at this level when reviewing the draindown records for the last refueling outage. This two feet difference was the largest noted during the draindowns. The licensee believes the level difference was caused by the small vent size for the reactor head in comparison to the large vent path for the pressurizer.

The tygon tubing upper tap is connected to the pressurizer, while RVLIS measures the differential pressure across the elevation of the reactor vessel. For both draindowns the draining was stopped at approximately 437 ft. elevation to allow the level indications to equalize. After several hours both indications were providing consistent readings. The licensee compared the level differences experienced similar to a manometer effect, but once the high side is given an opportunity to vent to the same pressure as the low side (atmosphere) the two indications will become equal. In addition the licensee stated that as long as the most conservative indication is used this difference in level should not adversely affect the ability to safely drain the RCS. The inspector noted that no mention of the manometer effect is mentioned in the draindown procedure. The resolution of the difference between the RVLIS and the tygon tubing manometer was identified as IFI 395/94-08-02.

. Two additional methods for adding inventory to the RCS were a charging pump and a gravity drain flowpath from the RWST to the RCS.

8. Exit Interview (30703)

The inspection scope and findings were summarized on March 31, 1994 with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed the inspection findings.

No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during the inspection.

Item Number	Description and Reference
94-08-01	NCV - Failure to perform TS surveillance requirement.
94-08-02	IFI - Difference in indicated level between RVLIS and tygon tubing manometer.

9. Acronyms and Initialisms

ARP Annunciator Response Procedure
EDG Emergency Diesel Generator

ESF	Engineered Safety Feature
FS	Fire Service
GOP	General Operating Procedure
HP	Health Physics
IPCS	Integrated Plant Computer System
ISEG	Independent Safety Engineering Group
KW	Kilowatt
LER	Licensee Event Report
MWR	Maintenance Work Request
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PMTS	Preventive Maintenance Task Sheet
PSIG	Pounds Per Square Inch Gauge
PTP	Plant Test Procedure
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RTD	Resistance Temperature Detector
RVLIS	Reactor Vessel Level Indicating System
RWP	Radiation Work Permit
RWST	Refueling Water Storage Tank
SAP	Station Administrative Procedure
S/G	Steam Generator
SOP	Standard Operating Procedure
SPR	Special Report
STP	Surveillance Test Procedure
T_{avg}	Average Temperature
TS	Technical Specification