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

Report Nos.: 50-280/89-21 and 50-281/89-21

Licensee: Virginia Electric and Power Company
Glen Allen, VA 23060

Docket Nos.: 50-280 and 50-281 License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: July 2-29, 1989

Inspectors: S. M. Shaeffer FOR	9/1/89
W. E. Holland, Senior Resident Inspector	Date Signed
S. M. Shaeffer FOR	9/1/89
J. W. York, Resident Inspector	Date Signed
S. M. Shaeffer FOR	9/1/89
L. E. Nicholson, Resident Inspector	Date Signed

Accompanying Inspector: B. Breslau, Reactor Engineer

Approved by: P. E. Fredrickson	9/1/89
P. E. Fredrickson, Section Chief Division of Reactor Projects	Date Signed

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, licensee event report review, followup on inspector identified items, and plant startup from refueling.

Certain tours were conducted on backshifts or weekends. The resident staff maintained 24 hour coverage of the Unit 1 startup beginning on July 2 and continuing through the return to power operations on July 7. In addition, backshift or weekend tours were conducted on July 8, 9, 15, 16, 17, 18, 19, 20, 23, and 29.

Results:

During this inspection period, three violations were identified for: failure to provide adequate procedures and/or instructions for calibration of the power range nuclear instrumentation as required by Technical Specification 6.4

(paragraph 3.a); failure to place an inoperable canal level instrument in trip within one hour as required by Technical Specification Table 3.7-2, Item 5.a (paragraph 3.g); and failure to maintain the condensate storage tank level at or above the limit specified in Technical Specification 3.6.B.2 (pargraph 3.g).

Two unresolved items were identified: one regarding the reportability in accordance with 10 CFR 50.72 of two events which resulted in the tripping of safety-related chillers and charging pump service water pumps (paragraph 3.g), and the other involving the licensee's program to effectively implement requirements that are invoked by amendments to the technical specifications (paragraph 6.h).

In addition, a weakness was identified during the Unit 1 restart with regards to multiple procedure concurrent usage and a lack of sensitivity to initial conditions in procedure (paragraph 3.a). Also, a weakness was identified regarding the transmittal of data used by operations for reactivity calculations (paragraph 6.g).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

W. Benthall, Supervisor, Licensing
R. Bilyeu, Licensing Engineer
R. Blount, Superintendent of Technical Services
D. Christian, Assistant Station Manager
D. Erickson, Superintendent of Health Physics
*E. Grecheck, Assistant Station Manager
*M. Kansler, Station Manager
T. Kendzia, Supervisor, Safety Engineering
*J. McCarthy, Superintendent of Operations
*G. Miller, Licensing Coordinator, Surry
J. Ogren, Superintendent of Maintenance
T. Sowers, Superintendent of Engineering
A. Price, Site Quality Assurance Manager

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

*Attended exit interview

On July 24, 1989, one of the Commissioners of the Nuclear Regulatory Commission, James R. Curtiss, visited the Surry Power Station for a familiarization tour, to meet with licensee management and staff, and to review the current status of the station. Commissioner Curtiss was accompanied by the following personnel:

A. Gibson, Director, DRS, Region II
K. Connaughton, Technical Assistant to the Commissioner
M. Sinkule, Branch Chief, DRP, Region II
NRC Resident Inspectors

The Commissioner attended the morning management meeting, met with the resident inspectors, was given a presentation on the status of the station by licensee management, and was taken on a tour of the station including the turbine building, control room, emergency diesel generator rooms, and the independent spent fuel storage installation.

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

2. Plant Status

Unit 1 began the reporting period in intermediate shutdown with a slow heatup in progress. The unit reached hot shutdown on July 4, and the reactor was taken critical on July 5, 1989. Physics testing commenced the same day and was completed on July 6. The unit was operating at 63% power when an automatic reactor trip occurred at 0643 hours on July 9, 1989. The trip, which is discussed in paragraph 3.a, was appropriately reviewed and the unit was returned to criticality at 2353 hours on the same day. The unit recommenced power operation on July 10 and remained at power for the remainder of the period.

Unit 2 began the reporting period in cold shutdown. The unit remained in cold shutdown for the duration of the inspection period while substantial operational reviews and maintenance activities were being conducted. During the period, the hydrostatic testing of the S/G feedwater line repairs was accomplished.

3. Operational Safety Verification (71707)

a. Daily Inspections

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, technical specifications, and limiting conditions for operations; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, jumper logs, and tags on components to verify compliance with approved procedures.

The inspectors specifically focused on Unit 1 restart activities during the earlier part of the inspection period. Twenty-four hour monitoring coverage of the Unit 1 restart activities by the resident inspector staff continued from the last inspection period until July 7, 1989.

During the monitoring of the Unit 1 startup, the inspectors noted that the controlling procedures were not coordinated in a manner such that one procedure would be completed prior to the next sequential procedure being started. One example was identified when OP-1.3, Unit Startup Operation (350/450 to HSD), was not completed and OP-1.4, Unit Startup Operation - HSD to 2% Power, was being accomplished at step 5.22 in the performance section. Of special concern was the fact that OP-1.4, initial condition 3.2, required that OP-1.3 be complete, yet the operators appeared to be comfortable in OP-1.4 without all initial conditions being verified and documented. The inspector did verify that the intent of OP-1.3 had been completed and that the operators were in proper control of the startup; however, multiple procedures were unnecessarily being performed concurrently and a lack of sensitivity to initial conditions was apparent.

On July 9, 1989 at 0643 hours, Unit 1 experienced an automatic reactor trip from approximately 63% reactor power. The reactor trip was caused by a turbine trip which was initiated by a high level in S/G B. The high level in S/G B was caused by a transient (approximately 30% turbine runback in about 9 seconds) due to the protection circuitry sensing a rod drop condition on power range channel N41. The unit did not ride out the transient due in part to B S/G feedwater regulating valve being in manual control, rod control being in manual, and an inadvertent operator action in closing the main steam dump valves. The operator actions were due to misdiagnosis of the transient. All safety systems functioned as required during and after the reactor trip. However, source range channel N31 failed to reinstate automatically after the reactor trip due to improper compensation of intermediate range channel N35. Operators took the necessary actions to reinstate source range channel N31.

After the trip, the plant was stabilized in the hot shutdown condition. The licensee held a post trip review meeting with those operators involved in the trip to review the sequence of events. The inspectors attended that meeting and with the information provided from the meeting and other charts provided from computer printouts determined the sequence of events as follows:

T_o minus 162 seconds - initiation of turbine runback signal

T_o minus 157 seconds - all steam dumps receive open signal

T_o minus 153 seconds - turbine runback stops (approx. 50% load reduction)

T_o minus 145 seconds - all steam dumps open

T_o minus 120 seconds - S/G A, B and C level at 25%

T_o minus 96 seconds - S/G A, B, and C level at 32%

T_o minus 48 seconds - S/G A and C level at 44% ; S/G B level at 55%

T_o minus 40 seconds - steam dumps receive close signal by operator action

T_o minus 24 seconds - S/G A and C level at 50% ; S/G B level at 68%

T_o minus 5 seconds - steam dumps start to close

T_o minus 2 seconds - S/G A and C level at 54% ; S/G B level at 75%; turbine trip

T_o - reactor trip

T_o plus 12 seconds - steam dumps receive open signal based on operator action and Tave-Tref mismatch

T_o plus 20 seconds - steam dumps full open

T_o plus 50 seconds - steam dumps mostly closed due to Tave-Tref match

As shown above, the initial transient caused the S/G to decrease in level (shrink). Steam generators A and C were in automatic feed control and were maintained in a band which would not have resulted in a turbine/reactor trip. However, B S/G feed control was in manual due to the automatic control experiencing some electrical problems earlier. Operator action was required to maintain the proper S/G level during the transient. Due to an apparent overfeeding of the B S/G during the early part of the transient to compensate for shrink, the B S/G level increased to the turbine trip setpoint (75% level) approximately 2 minutes and 40 seconds after the transient began, resulting in the turbine trip/reactor trip.

After evaluation of the transient, the inspectors focused specifically on the cause of the turbine runback. During the licensee's post trip review meeting with the operators, the licensee determined that the cause of the transient was due to a blown control fuse in NI cabinet N41. The blown fuse was caused by the I&C technicians use of an ungrounded volt meter during recalibration of the NI flux setpoints. It was also noted that several discussions had been held between the I&C technicians and their supervisor on whether to use a grounded or an ungrounded meter during the calibration. However, no clear resolution was provided to this concern prior to the mistake being made. Also, the procedure used for the calibration did not specify the type of meter to use.

The inspectors, after hearing the discussions above, concluded that the I&C shop sensitivity to resolving problems prior to them becoming a significant event was not what is required to ensure that safety systems would not be unnecessarily challenged. The inspectors discussed this concern with station management and were reassured that ensuring that the job is correctly performed each time is a requirement. This assurance was confirmed by aggressive management actions with regard to changes in the shop supervision along with other personnel actions. The licensee also instituted a performance improvement program in the I&C area.

After reviewing all the above, the inspectors concluded that appropriate corrective actions were being implemented; however, the above event was a result of a failure to provide adequate procedure and/or instructions for calibration of components involving the nuclear safety of the station. Technical Specification 6.4 requires that detailed written procedures with appropriate check-off lists and instructions be provided for calibration of instruments, components, and systems involving the nuclear safety of the station. Failure to provide an adequate procedure and/or instruction for calibration of the power range nuclear instrumentation is a violation of TS 6.4 (280/89-21-01).

b. Weekly Inspections

The inspectors conducted weekly inspections in the following areas: verification of operability 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. Plant tours were conducted which 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. The inspectors routinely monitored the temperature of the auxiliary feedwater pump discharge piping to ensure steam binding is prevented.

c. Biweekly Inspections

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagout(s) in effect; review of sampling program (e.g., primary and secondary coolant samples, boric acid tank samples, plant liquid and gaseous samples); observation of control room shift turnover; review of implementation of the plant problem identification system; verification of selected portions of containment isolation lineup(s); and verification that notices to workers are posted as required by 10 CFR 19.

d. Areas Inspected

Inspections included areas in the Units 1 and 2 cable vaults, vital battery rooms, steam safeguards areas, emergency switchgear rooms, diesel generator rooms, control room, auxiliary building, Unit 2 containment, cable penetration areas, independent spent fuel storage facility, low level intake structure, and the safeguards valve pit and pump pit areas. 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. The inspectors routinely independently calculated RCS leak rates using the NRC Independent Measurements Leak Rate Program (RCSLK9). On a regular basis, RWPs were reviewed and specific work activities were monitored to assure they were being conducted per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequency were verified.

The residents observed chemical analyses being performed for boron concentrations in the hot laboratory. These analyses were for operations information and to support certain parameter requirements being used in physics testing. On July 7, 1989, the inspectors discussed with chemistry personnel a reactor power level hold at 30 percent because chlorides on the secondary side were 34 ppb. Chemistry limits are 20 ppb chlorides. The chloride level was lowered by using S/G blowdown and adding clean makeup water. The licensee's chemist stated that it is not unusual to have chloride spikes after having a unit down for such a long period of time (Unit 1 had been down 10 months). All actions appeared to be conservative.

e. Physical Security Program Inspections

In the course of monthly activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital areas access controls; searching of personnel, packages and vehicles; badge issuance and retrieval; escorting of visitors; and patrols and compensatory posts.

f. Licensee 10 CFR 50.72 Reports

(1) On July 9, 1989, the licensee made a report in accordance with 10 CFR 50.72 with regards to an automatic reactor trip/turbine trip on Unit 1. Details of this event are discussed in paragraph 3.a.

(2) On July 9, 1989, the licensee made a report in accordance with 10 CFR 50.72 with regards to degradation of the emergency assessment capability in that the SPDS displays from the ERF computer were not functioning properly. This condition occurred during downloading of data from the Unit 1 reactor trip that occurred earlier that day. The licensee diagnosed the problem as SPDS hardware related. The problem was corrected and the unit returned to power.

g. Operations Related Problems

The inspectors expressed concern regarding indications of poor operator performance that surfaced during the latter part of the inspection period. Discussions were held with appropriate levels of station and corporate management with everyone in agreement that operator performance warranted corrective actions. Specific examples of the problems included the following:

(1) Intake Canal Level Instrumentation

On July 14, 1989, the licensee identified via station deviation S2-89-610 that an inoperable intake canal level channel was not placed in the tripped condition within one hour as required by TS Table 3.7-2, Item 5.a. Channel III of the intake canal level instrumentation system was rendered inoperable when stop logs were installed in accordance with TM S2-89-76 at 1210 hours on July 14, 1989. The channel was not placed into a tripped condition until 1910 hours that day. Further evaluation of this event by the licensee revealed that a similar event occurred when Unit 1 exceeded the 350 DEGF/450 PSIG limitations on July 2, 1989, and continued operation with an inoperable level channel until July 5, 1989, without placing the channel in the tripped condition. The safety consequence during these two evolutions were minimal, however, due to the waterbox being dewatered and therefore causing the level channel to automatically go to the trip condition.

Previous SSFI issues required the installation of four independent level indicators at the high level intake structure that provide input to a 3 out of 4 logic circuit for initiation of non-essential SW isolation. The four level sensors are located in the individual high level intake screenwell bays (Unit 1-bays 'B' and 'D', Unit 2-bays 'A' and 'C'), between the rotating screens and trash bar racks. This is a shared system that provides input to both units ESF logics. The stop logs are essentially large plates that are installed in the canal at the intake structure and allow dewatering of the plant systems downstream of the intake structure. The installation of stop logs on the bays that contain the level instrumentation isolates the level sensors from the actual canal.

The operators failed to realize that installation of stop logs on certain Unit 2 intake structures rendered the downstream level indicators inoperable that were required for Unit 1 operation. The affected channel automatically goes to the tripped position, however, when the waterbox is dewatered below the actuation setpoint. A review of the sequence of events revealed that the licensee operated for approximately 3 hours with a less conservative 3 out of 3 logic instead of the required 3 out of 4.

A sequence of events is summarized as follows (times indicated in parentheses):

6/14/89	New level system placed in service.
6/23	Technical Specification amended requiring system operability.

6/25	Stop log installed & unit 2-A waterbox dewatered.
7/2 (2200)	Unit 1 enters mode requiring operable level instrumentation.
7/5 (2100)	Unit 2-A waterbox refilled and stop logs removed.
7/14 (1210)	Unit 2-A stop logs installed.
7/14 (1521)	Unit 2-A waterbox dewatered.
7/14 (1910)	Canal level channel III placed in trip.
7/17 (1157)	Unit 2-A stop logs removed.

The stop logs were installed and removed using the station TM system as prescribed in station administrative procedure SUADM-O-11. The station does not have a specific procedure outlining the method and precautions involved with stop log installations. The inspectors reviewed the TM log sheets for the installations noted above and concluded that an inadequate review and analysis were performed prior to authorization by the shift supervisor for stop log installation. Paragraph C.2 of the subject TM logs was marked "N/A", therefore deleting any need for a safety analysis or 10 CFR 50.59 review for the impact on the UFSAR or TS requirements. In addition, subsequent review of this TM by both the Superintendent of Operations and the SNSOC failed to identify and correct the lack of a review or analysis on the initial TM stop log installation.

The inspectors reviewed the training lesson plans given to all licensed operators regarding the installation of the new canal level instrumentation. Three separate lesson plans contained information on the location and function of the new sensors. Although the fact that the stop log installation would interfere with the level sensors was not specifically detailed in the lesson plans, the inspector concluded that sufficient training was conducted.

The licensee performed a human performance evaluation of this event and presented the preliminary findings to the resident inspector staff on July 24 and 25. A general conclusion was given that this problem was essentially a human performance problem with a lack of attention to detail. In addition, several weaknesses were identified that contributed to the TS violation. The inspectors reviewed the licensee's evaluation of this situation and agreed with the following conclusions:

- No procedures existed for the installation and removal of stop logs. This work was performed under a TM with no formal procedure in place.

- The closeout process for the design change package that installed the new level system failed to adequately identify the need for revision of applicable procedures.

- The review and safety analysis of the TM that installed and removed the stop logs were inadequate.

Technical Specification Table 3.7-2, Item 5.a, requires that inoperable low intake canal level channels be placed in a tripped condition within one hour. Failure to place the low intake canal level channel III in a tripped condition when it became inoperable on July 14, 1989, is a violation of the TS (280/89-21-02).

Corrective actions were being evaluated by the licensee as the inspection period ended. A standing order (S.O. 10) was issued on July 27 that requires the Superintendent of Operations approval prior to installation of stop logs.

(2) Service Water Cooling

On July 18, 1989, a total loss of SW cooling to the Units 1 and 2 charging pumps occurred apparently due to the operation of an adjacent MOV and therefore connecting an empty line to the SW flowpath. A six hour LCO to place the unit in hot shutdown was initiated after both SW pumps to the charging pumps became airbound. In addition, since the Unit 2 SW pumps also became airbound, a seven day LCO was entered due to the loss of crosstie charging capability. A report of this event was being prepared in accordance with 10 CFR 50.73.

Maintenance was performing stroke testing on a MOV (2-SW-MOV-201A) that supplies water to the Unit 2 bearing cooling water heat exchangers when the event occurred. The six inch SW supply to the subject pumps taps off a thirty-six inch supply line to the bearing coolers. The perturbation occurred when the large MOV was cycled open. The licensee stated at the time that air in the large bearing cooling line was drawn into the suction of the safety-related SW lines and resulted in the air binding. Station engineering later stated, after the July 23 event, (see next paragraph), that the SW discharging to a basically empty Unit 2 discharge tunnel could have contributed to pulling air back up into the system. The system configuration contributes to the problem in that the SW charging pumps for both units (1 & 2- SW-P-10 A & B) and all three main control room envelope chillers take SW suction off a common header. Air entrainment into this common header results in a loss of both trains of equipment for both units.

On July 23, 1989, operation of the SW system again resulted in a total loss of SW to mechanical equipment room #3, which resulted in a loss of main control room envelope chillers and cooling water to the charging pumps. This event was similar to that discussed above in that it was initiated by the operation of a SW valve (2-SW-MOV-201B) to the Unit 2 bearing cooling water heat exchanger. Although system engineering could not identify the exact cause of this pertubation, it does indicate that the operation of the SW system is extremely sensitive to pertubations in this area. The operations staff was aware of the previous event and was prepared to close the bearing cooling valve upon indications of air binding. It became apparent following this event that the full implications of discharging to an empty Unit 2 discharge tunnel was not understood. The licensee is preparing a report to the NRC on this event in accordance with 10 CFR 50.73.

During the event on July 23, the inspector was in the control room during part of the recovery of some of the components. The inspector observed that the operators were following the required procedures; however, with the loss of multiple components, it was noted that limited guidance was provided regarding the appropriate sequence of recovery for components. Also, the inspector observed recovery operations at the location of most of the components (MER3) and again concluded that procedural guidance regarding the appropriate venting of the system was not available to the operators. These areas are under review by the licensee for possible enhancements.

The inspectors questioned the licensee with regards to reportability of the two above events as required by 10 CFR 50.72. The licensee stated that although there is no formal analysis documenting an acceptable duration of operation without SW cooling, they have historically been able to vent the air from the system and restore flow prior to any adverse effects on the charging pumps. A review of the Unit 2 charging pump data during the 47 minute duration that the SW was inoperable indicated that the thrust bearing temperature increased over that period.

The inspection period ended prior to resolution of the reportability of these events. This issue is identified as an unresolved item (280/89-21-03) pending additional NRC and licensee review of reportability and appropriate classification of charging pump operability.

(3) Component Cooling Water Perturbation

On July 26, 1989 at 2119 hours, operators were attempting to refill a CCW heat exchanger (1-CC-E-1B) and caused a rapid level drop in the CCW head tank that resulted in low CCW pump discharge header pressure and an automatic start of a standby pump. The motor amperage for the running CCW pumps fluctuated, but the reactor coolant pump parameters remained stable during this transient. The procedure used to return the heat exchanger to service, MOP-1.6, Return To Service Of Safety Related Heat Exchangers (Generic), is a generic procedure with no instructions pertaining to the CCW heat exchangers.

The inspectors reviewed this event and discussed the facts with station management. The transient was formally identified on station deviation S1-89-1752 that was submitted on July 27. The immediate safety consequence of this event is a loss of cooling to the reactor coolant pumps on Unit 1. Component cooling also provides cooling to the RHR system and various primary heat exchangers. The licensee stated that this event was caused by a lack of adequate supervision of an inexperienced auxiliary operator. Corrective actions were being developed as the inspection period ended.

Although this event was not considered to be a violation of regulatory requirements, the inspector agree with licensee managements assessment that proper overview and control of an evolution which could affect the safe operation of the station must be maintained.

(4) Emergency Condensate Storage Tank Level Drop

On July 27, 1989, operators allowed the level in the Unit 2 emergency condensate storage tank (2-CN-TK-1) to fall approximately 10,000 gallons below the TS limit while transferring water to fill the underground condensate tank. This condition is in violation of TS 3.6.B.2 that requires a minimum of 60,000 gallons of water be available from the opposite unit to supply the auxiliary feedwater crossconnect.

The transfer of water was being performed in accordance with operating procedure 2-OP-31.2.5, Filling The Emergency Condensate Makeup Tank, 2-CN-TK-3. Section 4.0 of this procedure references a requirement to maintain greater than 60,000 gallons in tank 2-CN-TK-1. A review of the reactor operator logs indicated that the level was adequate at 1000 hours and had fallen to 44 percent (50,000 gal) at 1400 hours. The operator logged this level without realizing that the level was in violation of TS. The problem was detected at 1822 hours and the tank level was refilled to greater than 60,000 gallons by 1844 hours.

Technical Specification 3.6.B.2 requires that a minimum of 60,000 gallons of water shall be available in the tornado protected condensate storage tank of the opposite unit to supply emergency water to the auxiliary feedwater pump suction of that unit. Failure to maintain greater than 60,000 gallons of water in tank 2-CN-TK-1 on July 27, 1989, is a violation of TS (280/89-21-04).

The above problems indicate a lack of attention to detail. Two of the events, i.e. stop log and condensate level, are related in that the operators for Unit 2 were not sensitive to the effects of their action on the opposite unit at power. The SW events indicate that the performance of this system is very sensitive to inappropriate operation.

Within the areas inspected, three violations and one unresolved item were identified.

4. Operational Readiness Program Review - Unit 2 (71710)

The inspectors reviewed the Unit 2 restart action items list. Currently 75 of 211 items still remain open. All of these items and any additional items added to the list will be resolved before Unit 2 is restarted. Items will be added as a result of the system walkdowns. The licensee has completed 100 percent of the system walkdowns in Unit 2 containment and is evaluating the results. A review of the containment charging and ventilation systems revealed that six items would be added to the restart list for the ventilation system and two would be added for the charging system. In the case of the six items, three involved cleaning filters and three involved repairing or evaluating a valve. In the case of the two items for the charging systems, one involved a missing flow transmitter (the transmitter had been removed to repair one on Unit 1) and the second item involved the necessity to add several supports for a charging line.

The inspectors reviewed selected findings from the system engineering walkdown of the Unit 2 SI system. A problem was identified (station deviation S2-89-682) pertaining to the labeling of certain valves and instrumentation in the hot leg SI lines. Components indicated on station drawing 11548-FM-089B, sheet 4 of 4, as injection lines to the hot leg of the reactor coolant loop 1 are actually associated with the hot leg loop 3, and vice versa. The problem was limited to components downstream of any MOVs or components requiring operator actions. The Operations Superintendent reviewed the situation and concluded that the problem would not have an adverse effect on operation during any accident scenario. The inspectors reviewed the evaluations and concurred with the findings.

On July 22, 1989, the inspectors observed a Unit 2 containment walkdown for parts of the auxiliary feedwater system and S/G blowdown system by systems engineers. The methods used for the evaluation and the findings appeared to be acceptable.

Within the areas inspected, no violations or deviations were identified.

5. Maintenance Inspections (62703 & 42700)

During the reporting period, the inspectors reviewed maintenance activities to assure compliance with the appropriate procedures. Inspection areas included the following:

a. Pressurizer Power Operated Relief Valve

The inspectors reviewed the repair of the pressurizer PORV 2-RC-PCV-2455C following the valve failure that occurred on June 21, 1989. The RCS was being maintained in a reduced inventory condition with the PORVs open and vented to the primary relief tank. The control room operator noticed that the subject valve went from open to close when the "Lo Air Bottle Pressure" annunciator came on. The operator attempted unsuccessfully to reopen the valve. Field inspections revealed that the valve actuator had cocked and several capscrews within the actuator had sheared. The backup air bottles had depressurized.

The inspectors observed certain failed parts from this valve and reviewed the corrective actions and failure analysis associated with this event. It appears that the regulator in the backup air bottle supply failed and allowed the full 2400 psig pressure to be applied to the valve actuator. The licensee performed an evaluation of the failure as documented in EWR 89-499, dated July 8, 1989. The results of this evaluation concluded that this event did not constitute an unreviewed safety question. The inspectors reviewed the evaluations and documentation pertaining to this event and agreed with the licensee's assessment. No discrepancies were identified.

b. Feedwater Regulating Valve

On July 14, 1989, the inspectors observed the repair on the Unit 1 feedwater regulating valve 1-FW-FCV-1488. This valve is the main feedwater regulating valve for the B S/G. The valve was sticking in certain positions making it more difficult to control the water level of the S/G. In order to make the repair, the licensee reduced power on Unit 1 to 19 percent, isolated the valve, and used the feedwater bypass line to supply feedwater to the S/G. The inspector observed replacement of the valve cage and the double plug and stem. The internal part of the valve and adjacent piping were inspected for cleanliness and foreign objects. The torquing technique for the cage and some of the bolts was observed. The inspectors examined the procedure being used, Procedure No. MMP-C-FW-145, Disassembly, Repair, Reassembly, and Testing of Feedwater Regulating Valve. The torquing values being used were in accordance with the procedure and the appropriate steps were being initialed. A later evaluation by the licensee showed that the valve external spring was rubbing against one side of the yoke inhibiting it's feedwater control function. No discrepancies were identified.

Within the areas inspected, no violations or deviations were identified.

6. Surveillance Inspections (61726 & 42700)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures as follows:

- Test prerequisites were met.
- Tests were performed in accordance with approved procedures.
- Test procedures appeared to perform their intended function.
- Adequate coordination existed among personnel involved in the test.
- Test data was properly collected and recorded.

Inspection areas included the following:

a. Containment Spray System

On July 2, 1989, the inspector reviewed test documentation for periodic test 1-PT-17.1, Containment Spray System, for spray pumps 1-CS-P-1B, tested on June 3, 1989 and both 1-CS-P-1A and 1-CS-P-1B, tested on June 12, 1989. Documentation was complete; the test results indicated that satisfactory performance was obtained, with the exception that pump 1B was placed in an alert status due to high axial vibration from the inboard bearing. The licensee issued EWR 89-433 to evaluate the results, and subsequently determined and approved on June 20, 1989, new reference values based on prior performances of the pumps. These new values permitted the licensee to remove pump 1B from an alert status. No discrepancies were noted.

b. Charging Pump Operability Test

On July 2, 1989, the inspector reviewed test documentation for periodic test 1-PT-18.7, Charging Pump Operability and Performance Test, for charging pumps: 1-CH-P-1A, tested June 4, 1989, 1-CH-P-1B, tested June 18, 1989, and 1-CH-P-1C, tested June 27, 1989. Documentation was complete; results indicated satisfactory performance with the exception of pump 1B. Pump 1B was placed in an alert status due to a high axial vibration on the inboard bearing.

The licensee had several ISI pumps listed in the alert status in June due to high vibration measurements as compared to their respective reference values. The licensee issued EWR-89-445 to evaluate the existing baseline values, which were established using computer generated reference values taken by the predictive analysis group over the last year. It was determined that these values were not reflective of actual component operating conditions. The licensee establish new reference values using the actual data from the last two tests; these values were approved by SNSOC on June 27, 1989. Based on these new values, pump 1-CH-P-1B was not considered as being in an alert status. No discrepancies were noted.

c. Motor Driven Auxiliary Feedwater Pumps

On July 3, 1989, the inspector reviewed periodic test 1-PT-15.1A, Motor Driven Auxiliary Feedwater Pump, for pumps 1-FW-P-3A, tested on June 9, 1989 and 1-FW-P-3B, tested on June 15, 1989. Test results indicated that both pumps were in an alert status due to high vertical vibration on the outboard pump bearing. The test critique sheet for pump 3A did not correctly reflect this condition however, and the licensee was informed of this error in documentation. The licensee promptly corrected the documentation discrepancy. Based on the new reference values noted in EWR 89-445, both pumps were removed from an alert status by the licensee. No further discrepancies were noted.

d. Containment Inside Recirculation Spray System

On July 3, 1989, the inspector reviewed periodic test 1-PT-17.2, Containment Inside Recirculation Spray, for pumps 1-RS-P-1A and 1-RS-P-1B, tested on June 21, 1989. Documentation was complete; test results indicated that pump 1A was satisfactory and 1B was unsatisfactory because the ERFSC failed to display the required information. The licensee adjusted the ERFCS and retested pump 1B on June 23, 1989. The test results indicated that pump 1B performance was satisfactory. No discrepancies were noted.

e. Containment Outside Recirculation Spray System

On July 4, 1989, the inspector reviewed periodic test 1-PT-17.3, Containment Outside Recirculation Spray, for pump 1-RS-P-2A, tested on June 16, 1989. Documentation was adequate; test results indicated that the pump was satisfactory but placed on the alert status due to high axial vibration on the inboard bearing. The new reference values, which were subsequently determined by EWR 89-445, permitted pump 2A to be removed from an alert status. No discrepancies were noted.

f. Emergency Service Water Pumps

On July 4, 1989, the inspector reviewed periodic tests 1-PT-25.3A, .3B, and .3C, Emergency Service Water Pump, for pumps 1-SW-P-1A, tested on June 20, 1989; and 1-SW-P-1B and 1-SW-P-1C, tested on February 15, 1989. Documentation was adequate and test results indicated that the pumps performed as desired. No discrepancies were noted.

g. Control Rods

On July 4, 1989, the inspector witnessed hot rod testing of the Unit 1 rods in accordance with periodic test 1-PT-7.2, Hot Rod Drops, dated January 29, 1989. This test measured the drop time for each of the 48 control rods from fully withdrawn to dashpot entry. The inspector reviewed selected timing traces to independently verify that the drop time was within the 2.4 seconds allowed by TS.

Step 3.1 of the above test procedure requires the calculation of the shutdown margin prior to changing core reactivity. The inspector reviewed the calculated shutdown margin and noted that the data used (i.e. critical boron, rod worth, etc.) was supplied by the reactor engineer in lieu of the curve book. Although the procedure that performs this calculation, OP-1F, specifies that approved data may be supplied by the reactor engineer, the data used for the above calculation was obtained from a single sheet of paper marked "for reference only", with no review or approval process evident. The inspector reviewed the data and concluded that the figures used were more conservative; however, the use of the substitute data constituted a revision to the station curve book without a comparable review process. The licensee concurred that this is an apparent weakness and plans to revise their method for supplying engineering data regarding reactor startup. The inspector reviewed a station memorandum, dated July 24, 1989, that addressed this weakness and outlined the need for improvement. This item is identified as a weakness with the control of data used for reactivity calculations.

h. Reactor Trip Bypass Breaker

The inspectors reviewed the details regarding the inability to test the automatic shunt trip feature on the reactor trip bypass breakers as required by TS Table 4.1-1. This condition was identified by the licensee (station deviation S1-89-1646) during a review of the TS. Because Surry does not have automatic shunt trips on their reactor trip bypass breakers, the licensee could not comply with the TS.

Amendment 117 to the TS, issued in 1987, required that the reactor trip bypass breaker local manual undervoltage trip be tested prior to placing the breaker in service and the automatic shunt trip be tested every refueling. A local manual undervoltage trip and an automatic shunt trip feature do not exist at Surry. The inspectors discussed the existing breaker features with NRC regional management and NRR, and ascertained that the existing condition is acceptable for continued operations. The licensee is planning to submit a TS change for this compliance issue.

The above discrepancy indicates a potential weakness in the licensee's program that implements TS requirements and assures that compliance is achieved. The fact that a specific requirement was added in 1987 and the normal implementation and review/audit functions did not identify that compliance was impossible until 1989 raises questions regarding the effectiveness of the programs. This item is identified as an unresolved item (280,281/89-21-05) pending a more thorough review of the licensee's program that implements TS requirements.

Within the areas inspected, one unresolved item was identified.

7. Licensee Event Report Review (92700)

The inspectors reviewed the LER's listed below to ascertain whether NRC reporting requirements were being met and to determine appropriateness of the corrective actions. The inspector's review also included followup on implementation of corrective action and review of licensee documentation that all required corrective actions were complete.

LERs that identify violations of regulations and that meet the criteria of 10 CFR, Part 2, Appendix C, Section V shall be identified as NCV in the following closeout paragraphs. NCVs are considered first-time occurrence violations which meet the NRC Enforcement Policy for exemption from issuance of a Notice of Violation. These items are identified to allow for proper evaluations of corrective actions in the event that similar events occur in the future.

(Closed) LER 280/88-021, Lifting of PORV Due to Overly Conservative Setpoint. This event was initiated with Unit 1 in cold shutdown, and was caused by a pressure transient during a start of the RCP with a solid plant. The licensee's corrective actions, which included increasing the PORV lift pressure setpoint by 10 lbs. to account for instrument inaccuracies and revising operating procedure OP-5.1.2 to reflect the desired RCP operations during solid water plant conditions appeared to be adequate. This LER is closed.

(Closed) LER 280/88-023, "C" S/G Steam Flow Channel IV Failed Low Due to Failed Multiplier/Divider. The licensee was not able to determine the cause for the failed multiplier/divider power supply transformer. However, corrective actions were routine, e.g., replaced failed component and conducted logic circuit tests. Since the reactor protection and SI instrumentation is periodically tested and calibrated, no additional corrective actions are necessary. This LER is closed.

(Closed) LER 280/88-025, Control/Relay Room Chillers Inoperable Due to Inadequate Service Water Flow. The licensee believed that the cause of the event was due to inadequate SW flow to the chiller condensers as a result of the method used to start/stop the chillers. The licensee's corrective action consisted of developing a procedure for starting/stopping control room chillers. The inspector determined from a review of operating procedure OP-21.4, dated September 20, 1988, that the procedure provides adequate details to operate the control room chillers. This LER is closed.

(Closed) LER 280/88-028, Spent Fuel Assembly Placed in Wrong Location Due To Inadequate Procedure. The licensee determined that the cause of this event was due to deficiencies in the methods used when spent fuel movement was initiated and directed by on-site personnel. The licensee revised procedure OP-4.22, dated May 9, 1989, to include a verification that Region I spent fuel pool area contains only Region I applicable fuel assemblies prior to moving a dry storage cask into the fuel building. The inspector's review of this procedure indicated that the procedure is adequate to prevent recurrence of this event. This LER is closed.

(Closed) LER 280/88-034, Control Room Chiller Tripped Due to Inadequate Service Water Flow. This event was caused by pressure control valves being incorrectly adjusted. The licensee's corrective action of overhauling and setting the pressure control valves to their correct setting is similar to the corrective actions of LER 88-007, which is a similar event. The corrective actions for LER 88-007 included a design review to upgrade the SW supply to the control room and relay room chillers; this review is not complete. The inspector believes that the licensee's actions for LER 88-034 are adequate, but will continue to monitor the status of the design work to upgrade the SW supply to the chillers. This LER is closed.

(Closed) LER 280/88-035, Iodine Spike. This event is suspected to have been caused by fuel element defects. The licensee's corrective actions consisted of inspecting the fuel assemblies during their outage coupled with subsequent shipment of fuel assemblies. The inspector noted during this review that one leaking assembly was identified during the inspections. The licensee replaced the defective assembly and removed debris from 10 other assemblies. The inspector considers the licensee's corrective actions as adequate. This LER is closed.

(Closed) LER 280/88-036, Charging Pump Component Cooling Pumps Inoperable Due To Air Binding. This event was caused by an inadequate system design in that the system does not allow for adequate venting of the CCW side of the intermediate seal coolers, without air binding of the pumps, after the system has been opened for maintenance. The licensee's corrective action consisted of performing an engineering review to resolve system design inadequacies. The inspector determined that the licensee has installed high point vents to mitigate future air binding problems and that related drawings and procedures have been adequately updated to reflect these changes. This LER is closed.

(Closed) LER 280/88-037, Fire Watch Not Posted at Improperly Sealed Penetration Within One Hour Due to Personnel Error. The cause of this event was attributed to the failure of a QA inspector in promptly reporting the unsealed penetration to the control room. Also, operations personnel, once notified, failed to post a fire watch within one hour. The licensee's corrective actions consisted of personnel being counseled on the need to take prompt corrective actions when discovering or receiving reports of any abnormal plant conditions. The inspector believes these actions are adequate to prevent recurrence. This LER is closed.

(Closed) LER 280/88-039, Control/Relay Room Chillers Trip Due To Inadequate SW Flow. This event was cause by a small refrigerant leak in combination with insufficient SW cooling. SW flow was being controlled manually because normal pressure control valves were out of service, thus preventing automatic increase in SW flow when higher demand was required. The licensee's corrective action was to overhaul the pressure control valves and recharge the refrigerant. The inspector's review of the licensee's corrective action indicated that these actions were adequate. This LER is similar to LERs 88-007 and 88-034, which substantiates the need for the licensee to resolve SW flow design problems with this system. The actions of this LER are adequate, but as noted above, the inspector will monitor the licensee's design review to resolve SW flow problems. This LER is closed.

(Closed) LER 280/88-042, Process Ventilation System Hi-Range Radiation Monitors Out of Service Due to Failed Circuit Board. The licensee's corrective action consisted of replacing the failed circuit board, and is considered adequate. This LER is closed.

(Closed) LER 280/88-043, RSHX SW MOVs Discovered With Wrong Size Torque Motors. This event was noted during the licensee's engineering evaluation, conducted in response to IE Bulletin 85-03. The above MOVs were noted as having undersized motors. The licensee's corrective actions included replacing the undersized motors with the required 5 ft-lb torque motors and expanding the MOV program to include all safety-related MOVs. The inspector determined that the correct motors were installed and that the licensee expanded its MOV program. The MOV program is tracked as part of commitment 89-0101-001 in response to NRC Inspection Report 280,281/88-45. The licensee's corrective actions are adequate. This LER is closed.

(Closed) LER 280/88-044, Unplanned Actuation of ESF Components, TV-DG-108A and SOV-VS-101A. This LER is germane to both units. The event was presumed to occur due to personnel in the area of the SOV disturbing it, resulting in its actuation. No conclusive evidence for the cause of this event was determined in the ensuing investigation. The licensee's actions included normal refueling SI functional testing during the outage to ensure operability. This testing will be completed prior unit startup. The inspector's review concluded that successful SI testing was completed for Unit 1. This corrective action is considered adequate. This LER is closed.

(Closed) LER 280/88-046, Operating MCR/ESGR Chiller Turned Off Due To Personnel Error. The cause of this event was attributed to the control room shift supervisor incorrectly assuming that only one chiller was in operation, therefore, when 1-SW-263 closed, the shift supervisor incorrectly assumed all SW to the chillers had been isolated. The shift supervisor thus directed a control room operator to stop the "C" chiller. The licensee's corrective action consisted of counselling the shift supervisor concerning his responsibility to maintain an accurate status of plant components and systems. The inspectors review determined that the corrective actions are adequate. This LER is closed.

(Closed) LER 280/88-048, Diesel Fire Pump Batteries Not Seismically Qualified. This event was due to the failure in identifying the operability concern of the system when the deficiency was noted in June 1986. The licensee's corrective action consisted of re-emphasizing the policy of prompt reporting of discrepant conditions and to upgrade the battery racks to meet seismic qualifications. The inspector reviewed these actions and determined that the battery racks meet seismic qualifications. This LER is closed.

8. Plant Startup from Refueling (71711)

During this inspection period, the inspectors witnessed selected portions of the Unit 1 restart special testing as follows:

The inspectors witnessed testing and monitored activities associated with periodic test 1-PT-28.11, Startup Physics Testing. This procedure was the controlling procedure for several of the tests that were required to be performed at low power levels following refueling. The inspectors witnessed pre-test briefings, verified that specified conditions were met, and witnessed selected portions of the following tests:

Reactivity Computer Accuracy Determination

This test determines the reliability range of the reactivity computer that is used in subsequent testing by inserting and withdrawing control rods to subtract or add reactivity. The computer was determined to be accurate within plus or minus 30 pcm. No discrepancies were noted.

Isothermal Temperature Coefficient

This test involves measuring the moderator temperature coefficient by determining the effects of plant temperature changes on reactivity while maintaining constant rod position and boron concentration. The MTC was determined to be -3.61 pcm/°F. No discrepancies were noted.

Rod Swap Reference Bank Measurement

This test allows for measurement of rod worth (pcm) of the reference bank (Control Bank B) when fully inserted from 225 steps to 0 steps. No discrepancies were noted.

Integral Rod Worth Measurements Using the Rod Swap Technique

This test allows for determination of the differential rod worth of the reference bank (Control Bank B) when each of the remaining rod banks is fully inserted from 225 to 0 steps. The inspector witnessed selected portions of this test when control banks C and D were the test banks. During this testing, several urgent rod control failure alarms were received. The operators were able to immediately clear the alarms. The cause of the alarms was determined to be the rod bank selector switch. Several times when the selector switch passed through the C control bank position to another bank position, the alarm would come in. A deviation report was written to identify the problem. However, the licensee determined that the problem did not affect proper operation of the rod control system and testing was completed satisfactorily. No other discrepancies were noted.

In the areas inspected, no violations or deviations were noted.

9. Allegation Case No. RII 89-A-0010

a. Background:

An individual, herein after referred to as the alleger, contacted Region II staff and reported that a worker modified a cable tray label (identification) to match the tray identification entered for the cable on the pull ticket.

b. Allegation Inspection:

The inspectors had discussions with two of the licensee's engineers concerning the marking and identification of electrical cable trays. The engineers stated that the letter designations were the most important part of the marking because these letters determine the type of cable that will go into that tray. The designations are as follows:

A- instrumentation cables
B- power cables
C- control cables plus power cables for up to 60 h.p. motors or 60 amperes.

The engineers stated that a 1 was added in front of the letter designation, and was not important to the cable tray designation.

During an NRC electrical inspection conducted May 10-12, 1989, violation 280/89-12-01, failure to maintain cable tray covers in place as required by Appendix R, was issued. As a result of this violation, the licensee has agreed to walk down the cable trays, making sure that the cable trays are properly marked, and issue new drawings as necessary.

The electrical engineer performing the walk down under EWR 89-283 found trays with numbers peeled off, trays with added numbers (numbers added with ink markers), and trays that had the wrong color code. The new markings will be of a standard height and stenciled onto the cable tray. All of the trays in Unit 1 containment were walked down before startup. Unit 2 containment will be walked down before startup.

c. Conclusions

Visual inspection of the electrical cable tray in question from approximately 20 feet below appears to substantiate the allegation, however, this marking of a 1 in front of a letter had no safety significance. As discussed previously, all safety-related electrical cable trays will be walked down and properly identified.

10. Action on Previous Inspection Findings (92701, 92702)

(Closed) VIO 280,281/87-32-01, Inadequate Emergency Operating Procedure for Natural Circulation Cooldown, e.g., Cooldown Curves Exceed Those in the Technical Specifications. The inspector determined from a review of the licensee's corrective actions that a TS change request was submitted which indicates the cooldown curve, Figure 3.1-1, is based on RCS cold leg temperature. The inspector also noted that emergency procedures EP-1.02A and EP-1.02B, reflect the corrected TS cooldown curve. The licensee's corrective actions are adequate; this item is considered closed.

11. Exit Interview

The inspection scope and findings were summarized on August 2, 1989, with those individuals identified by an asterisk in paragraph 1. The following new items were identified by the inspectors during this exit:

One violation was identified (paragraph 3.a) for failure to provide adequate procedures for the calibration of instrumentation (280,/89-21-01).

One violation was identified (paragraph 3.g) for failure to place an inoperable low intake canal level channel in trip as required by TS Table 3.7-2, Item 5.a (280/89-21-02)

One violation was identified (paragraph 3.g) for failure to maintain greater than 60,000 gallons of water in 2-CN-TK-1 as required by TS 3.6.B.2 (280/89-21-04).

One unresolved item was identified (paragraph 3.g) for additional NRC and licensee review of reportability in accordance with 10 CFR 50.72 of two events which resulted in the tripping of safety-related chillers and charging pump service water pumps (280/89-21-03).

One unresolved item was identified (paragraph 6.h) for additional inspections of the licensee's program for implementing TS requirements (280,281/89-21-05).

In addition, a weakness was identified (paragraph 3.a) during the Unit 1 restart with regards to multiple procedure concurrent usage and a lack of sensitivity to initial conditions in procedures. Also, a weakness was identified (paragraph 6.g) regarding the transmittal of data used by operations for reactivity calculations.

The licensee acknowledged the inspection findings with no dissenting comments. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

12. INDEX OF ACRONYMS AND INITIALISMS

AP	-	ABNORMAL OPERATING PROCEDURE
CCW	-	COMPONENT COOLING WATER
CFR	-	CODE OF FEDERAL REGULATIONS
CW	-	CIRCULATING WATER
DEGF	-	DEGREE FAHRENHEIT
DR	-	DEVIATION REPORT
DRP	-	DIVISION OF REACTOR PROJECTS
DRS	-	DIVISION OF REACTOR SAFETY
ERF	-	EMERGENCY RESPONSE FACILITY
ERFSC	-	EMERGENCY RESPONSE FACILITY STATUS COMPUTER
ESF	-	ENGINEERED SAFETY FEATURE
ESGR	-	EMERGENCY SWITCHGEAR ROOM
EWR	-	ENGINEERING WORK REQUEST
ft-lb	-	FOOT-POUND
GAL	-	GALLONS
GPM	-	GALLONS PER MINUTE
HPSI	-	HIGH PRESSURE SAFETY INJECTION
HSD	-	HOT SHUTDOWN
IA	-	INSTRUMENT AIR
I&C	-	INSTRUMENTATION AND CONTROL
IFI	-	INSPECTOR FOLLOWUP ITEM
ISI	-	INSERVICE INSPECTION
LCO	-	LIMITING CONDITION FOR OPERATION
LER	-	LICENSEE EVENT REPORT

MER3	-	MECHANICAL EQUIPMENT ROOM 3
MOV	-	MOTOR OPERATED VALVE
MCR	-	MAIN CONTROL ROOM
MTC	-	MODERATOR TEMPERATURE COEFFICIENT
NCV	-	NON-CITED VIOLATION
NI	-	NUCLEAR INSTRUMENTATION
NRC	-	NUCLEAR REGULATORY COMMISSION
NRR	-	NUCLEAR REACTOR REGULATION
OP	-	OPERATING PROCEDURE
PCM	-	PERCENT MILLIRHO
PM	-	PREVENTATIVE MAINTENANCE
PORV	-	POWER OPERATED RELIEF VALVE
ppb	-	PARTS PER BILLION
PSI	-	POUNDS PER SQUARE INCH
PSIG	-	POUNDS PER SQUARE INCH GAUGE
PT	-	PERIODIC TEST
QA	-	QUALITY ASSURANCE
QC	-	QUALITY CONTROL
SNSOC	-	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SPDS	-	SAFETY PARAMETER DISPLAY SYSTEM
SW	-	SERVICE WATER
RCS	-	REACTOR COOLANT SYSTEM
RHR	-	RESIDUAL HEAT REMOVAL
RAI	-	RESIDENT ACTION ITEM
RCP	-	REACTOR COOLANT PUMP
RO	-	REACTOR OPERATOR
RPS	-	REACTOR PROTECTION SYSTEM
RSHX	-	RECIRCULATION SPRAY HEAT EXCHANGER
RSS	-	RECIRCULATION SPRAY SYSTEM
RWP	-	RADIATION WORK PERMIT
SER	-	SAFETY EVALUATION REPORT
S/G	-	STEAM GENERATOR
SI	-	SAFETY INJECTION
SNSOC	-	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SOV	-	SOLENOID OPERATED VALVE
SPDS	-	SAFETY PARAMETER DISPLAY SYSTEM
SRO	-	SENIOR REACTOR OPERATOR
SSFI	-	SAFETY SYSTEM FUNCTION INSPECTION
SW	-	SERVICE WATER
Tave	-	AVERAGE TEMPERATURE
Tref	-	REFERENCE TEMPERATURE
TM	-	TEMPORARY MODIFICATION
TS	-	TECHNICAL SPECIFICATIONS
UFSAR	-	UPDATED FINAL SAFETY ANALYSIS REPORT
URI	-	UNRESOLVED ITEM
VIO	-	VIOLATION