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

Report Nos.: 50-259/91-21, 50-260/91-21, and 50-296/91-21

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Docket Nos.: 50-259, 50-260, and 50-296

License Nos.: DPR-33, DPR-52, and DPR-68

Facility Name: Browns Ferry Units 1, 2, and 3

Inspection at Browns Ferry Site near Decatur, Alabama

Inspection Conducted: May 18, 1991 - June 14, 1991

Inspector: T. P. Kar 7/9/91
for C. A. Patterson, Senior Resident Inspector — Date Signed

Accompanied by: E. Christnot, Resident Inspector
W. Bearden, Resident Inspector
K. Ivey, Resident Inspector
G. Humphrey, Resident Inspector

Approved by: T. P. Kar 7/9/91
for Paul Kellogg, Section Chief, — Date Signed
Inspection Programs,
TVA Projects Division

SUMMARY

Scope:

This routine resident inspection included plant restart, initial criticality, power ascension test program, sustained control room and plant observation, maintenance observation, surveillance observation, post maintenance testing, system pre-operability checklist, reportable occurrences, and action on previous inspection findings.

Results:

Unit Two was restarted after being shutdown over six years. Initial criticality occurred on May 24, 1991, paragraph two. The initial criticality and training criticals were performed in a controlled and methodical manner. A violation of containment integrity occurred on June 5, 1991. The unit was shutdown by licensee management for a detailed corrective action assessment. This event is documented in special inspection report 91-23. The unit restarted on June 12, 1991. At the end of this report Reactor pressure was being held at 250 psig for resolution of snubber interface problems and feed pump testing.

Minor equipment problems occurred during the startup and testing resulting in schedule delays. There were instances of a lack of management personnel and backshift support personnel for resolution of these items. Plant management took action to assign supervisors to 24 hour coverage for resolution of problems for the remainder of the power ascension test program.

An unresolved item was identified by the inspector concerning problems with the control room recorders for high drywell radiation, drywell radiation, and torus radiation, paragraph five. The scale unit designation and the chart recorder paper were in units of mR/hr instead of R/hr. The recorder pens for drywell and torus radiation were reversed. The licensee was conducting an incident investigation of the problem in which the preliminary results indicated that drawing errors occurred during drawing restoration, and that reinstallation of the incorrect chart recorder paper occurred due to an incorrect operator aid. The inspector will continue to follow this investigation and including why post modification testing and surveillance requirements did not identify these problems.

A non-cited violation was identified by the inspector for failure to follow the plant procedure for heat stress requirements during a drywell entry, paragraph five. The procedure requires compensatory measures when temperatures are above 80 degrees. The inspector observed that personnel exiting the drywell were sweating profusely and were flushed. The temperature was greater than 80 degrees, but Industrial Safety had not conducted a heat stress survey. Plant Operations management took prompt corrective action to conduct a heat stress survey, considered stay times, and required ice vests for personnel entering the drywell.

The inspector observed an electrician working in an energized electrical cabinet unattended by other personnel, paragraph five. This was discussed with maintenance management and actions were taken to prevent recurrence.

The examples of heat stress and work on energized electrical equipment are continuing indicators that maintenance workers are not being adequately supervised in the field. There is an absence of foreman and quality control inspectors questioning procedure adherence and safe work practices in the field.

A weakness was identified in the plant operations procedures, paragraph five. Transformer and switchgear manipulations are not covered by plant operating instructions. Licensee management initiated actions to review this.

Three licensee event reports and two violations were closed. One violation was for escalated enforcement concerning the surveillance program.

REPORT DETAILS

1. Persons Contacted

Licensee Employees:

*O. Zeringue, Vice President, Browns Ferry Operations
L. Myers, Plant Manager
M. Herrell, Operations Manager
J. Rupert, Project Engineer
M. Bajestani, Technical Support Manager
R. Jones, Operations Superintendent
A. Sorrell, Maintenance Manager
G. Turner, Site Quality Assurance Manager
P. Carier, Site Licensing Manager
*P. Salas, Compliance Supervisor
*J. Corey, Site Radiological Control Manager
R. Tuttle, Site Security Manager

Other licensee employees or contractors contacted included licensed reactor operators, auxiliary operators, craftsmen, technicians, and public safety officers; and quality assurance, design, and engineering personnel.

NRC Personnel:

P. Kellogg, Section Chief
*C. Patterson, Senior Resident Inspector
*E. Christnot, Resident Inspector
W. Bearden, Resident Inspector
K. Ivey, Resident Inspector
G. Humphrey, Resident Inspector

*Attended exit interview

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

2. Plant Restart

Unit 2 was restarted after being shutdown since 1984. All three units have been shutdown since 1985 due to deficiencies in the TVA nuclear program. An extensive corrective action program has been completed during the shutdown.

a. Major Events:

May 23, 1991 NRC authorized restart - release from NRC Holdpoint one.

May 24, 1991 Initial Criticality followed by Training Criticals

June 1, 1991 TVA Second Management Assessment Complete to increase pressure - not a NRC holdpoint.

June 5, 1991 Unit Shutdown by Plant Management following a loss of primary containment integrity event (NRC IR 91-23)

June 12, 1991 Unit Critical and Heatup to 250 psig.

The initial and training criticals were performed in a controlled and methodical manner. During the startup and testing minor equipment problems occurred resulting in scheduling delays in the power ascension test program. There were instances of a lack of management and backshift support personnel for resolution of these items. Plant management took action to assign supervisors to 24 hour coverage for resolution of problems for the remainder of the power ascension test program.

b. Master Startup Procedure (72300,72504)

The inspector reviewed Master Startup Operations/Testing Instruction, 2-SOI-100-1, Revision 4, dated May 16, 1991, to determine that adequate controls were provided for reactor operation from cold shutdown to 100% reactor power. This procedure detailed the approvals, management assessments, precautions, limitations, and procedure steps to operate Unit 2 reactor from cold shutdown to 100% power and back to cold shutdown. The instruction categorizes the power ascension into three major phases: phase 1, open vessel testing; phase 2, zero power to 55% power; and phase 3, 55% power to 100% power. Phase 2 was further divided into several sub-categories; zero power which included reactor startup prerequisites, initial critical and shut down margin determinations, operator training criticals, power operation to rated temperature and pressure, transfer of the mode switch to run, and reactor operation to 55% power. Phase 3 was divided into 2 sub-categories; operation from 55% to 80% power and 80% to 100% power. Reactor and plant tests to verify proper equipment response and systems operation were specified before proceeding to the next phase or sub-category of operation. Plant management assessment hold points were provided in the instruction prior to entering each level of reactor operation.

Attachments provided detailed guidance or requirements for specific segments of the procedure. Attachment 1 to the instruction provided appropriate guidelines for the management assessment points. Attachments 2 and 3, Fuel Loading Prerequisite Checklist and Restart Prerequisite Checklist respectively, detailed the systems and BFNP departments and organizations required readiness for those evolutions. Attachment 4, Refueling Test Program Overview, provided a table of tests and surveillances to be conducted during each phase of the power ascension program. Attachment 5 was a remarks log for the startup program. Attachment 6 specified the requirements and documented the operator training criticals that occurred following initial critical operations.

NRC concurrence hold points were specified for initial startup, prior to placing the mode switch in run, prior to operation above 25% and prior to operation above 55% reactor power. The inspector concluded that this instruction provided adequate guidance and management assessment hold points for control of reactor operations from cold shutdown to 100% power.

3. Initial Criticality

The initial criticality was performed by TI-115 to demonstrate adequate shutdown margin. The licensee verified the rod sequence prior to control rod withdrawal. A reactivity management program was also implemented.

a. Full Core Shutdown Margin Determination (72300,72301)

The inspector reviewed Test Instruction 2-TI-115, Full Core Shutdown Margin, which was completed on May 24, 1991. The purpose of this TI was to determine that the Unit 2 Cycle 6 core will be subcritical throughout the fuel cycle with any single control rod fully withdrawn and all other rods fully inserted. Procedure 2-SI-4.3.A.1, Reactivity Margin Test, directs that TI-115 shall be performed following refueling outages in which core alterations are performed. The licensee determined that the full core shutdown margin was adequate and that the difference between actual critical rod configuration and the expected rod configuration, was within the required specification

One TD was written. The startup was performed using 2-GOI-100-1B, Unit Startup From Cold Shutdown to Hot Standby, which requires that the reactor period be determined from the IRMs. For this evolution the period was determined from the SRM chart recorder. The licensee was concerned that allowing reactor power in the intermediate range would have resulted in a scram due to a high range signal to the reactor protection system channels from the SRMs. The licensee determined that using reactor period, as read from the SRMs, would not affect the results of this test. The inspector discussed the test results and calculations with the licensee and was satisfied that the procedure was properly conducted.

b. RWM Rod Sequence Loading

The inspector reviewed the methods for loading the rod sequences into the RWM portion of the plant process computer with the reactor engineer. Separate magnetic tapes containing the rod sequences (A1, A2, B1, B2) were located in the plant computer room and were used to load the proper sequence into the computer as required for either the shutdown margin test, TI-115, or for normal sequence rod withdrawal in accordance with GOI-100-1A, GOI-100-1B, or SOI-100-1.

Prior to the initiation of the rod withdrawal for determination of the shutdown margin, Cycle 6, the inspector confirmed the reactor engineer's verification of the correct rod sequence for the test as required by Step 7.5 of 2-SI-4.3.B.3.a, RWM and RSCS Functional Test for Startup, Revision 4. This sequence was a special B-1 sequence, in that the most reactive rod was withdrawn first, rather than in its normal sequence.

The inspector also observed the performance of the substeps associated with Step 7.11, RSCS Comparator Check and Sequence Control Logic Functional Test, at panel 9-28 in the Unit 2 auxiliary instrument room. The ASOS and the reactor engineer followed the procedure steps as written, but the test could not be performed successfully. The test was suspended and test deficiency TD-1 was issued. The problems noted were: some of the red LED lights on the sequencer cards remained lit following the checks of the B through D Comparators and the Comparator Check Insert and Withdraw Blocks; the Test Failed light immediately lit when the test switch was placed to start and released; and the final step, to allow the test to go to completion, was not completed successfully. The procedure had been recently revised, and validation of the procedure was being performed as required by Form SSP-1 of SSP-2.3, Administration of Site Procedures. The licensee reviewed the operation of the RSCS and determined that the test should include steps to require the operator to depress all Rod Group Notch Control RESET pushbuttons following each of the comparator checks rather than just depressing them at the beginning of the test, thereby clearing any illuminated LEDs before performing a subsequent comparator check. These steps were added per NIC-08 and the test was completed satisfactorily. Test deficiency TD-1 was cleared as a result of the successful test performance

The inspector researched several earlier versions of the SI, namely SI 4.3.B.3, Revision dated November 25, 1975, and SI 4.3.B.3-a, Revision dated April 14, 1982. These earlier procedure requirements were similar to the current procedure in that requirements for depressing the Rod Group Notch Control RESET pushbuttons following the completion of each comparator check were not present. The inspector had no further concerns.

c. Reactivity Management Program

The licensee issued SSP-12.54, Reactivity Management Program, Revision 0, prior to the restart of Unit 2. The inspector performed a review of the procedure and discussed its contents and background with the Reactor Engineering supervisor and Nuclear Fuel representatives. The procedure was prepared at the direction of plant

management, with the purpose of defining the guidelines for the management of reactivity by responsible plant organizations during fuel handling, refueling and reactor operations. The guidelines were obtained by reviewing INPO SOER-84-2, "Control Rod Mispositioning", SOER-88-2, "Premature Criticality Events During Reactor Startup", and SOER-90-3, "Nuclear Instrument Miscalibration". Additionally, the November 1990, draft version of the "Reactivity Control Management Program - Guidelines for Excellence" prepared by the BWROG Reactivity Controls Review Committee were used to develop the procedure.

The inspector also reviewed the implementation plan for the program, and noted that additional reviews of plant programs, procedures and equipment were intended to ensure comprehensive coverage of all areas which could impact reactivity management, and that lessons learned from the BFN Power Ascension Program and the Sequoyah Reactivity Program would be incorporated. The procedure appeared to be a useful tool in consolidating and defining reactivity management considerations.

4. Power Ascension Test Program

After restart, the licensee is conducting a detailed power ascension test program similar to a new plant. The testing program is governed by PMI-26.1, Power Ascension Test Program.

a. Power Ascension Test Program Procedure (72300)

The inspector reviewed PMI-26.1, the upper tier document in the Browns Ferry PATP hierarchy of documentation. The instruction defines the PATP requirements. Particular tests in the program come from the PMI-26.1 references, principally the FSAR, TS, PMTs, and restart test program requirements.

PMI-26.1 required that each critical (FSAR 13.10 or cycle specific commitment) test have a startup test description, an executive summary document which provided a test overview and included the test acceptance criteria. A multi-discipline review process was required culminating in approval by the JTG, a subcommittee of the PORC augmented by GE technical participation. A master startup operations and testing instruction was also required. For the Unit 2 PATP, that document was 2-SOI-100-1.

PMI-26.1 defined the general families of test procedures to be included in the PATP and established the review process for tests and test results, a process which included JTG review and plant manager approval. General test guidelines were established. The test organization was specified as were the duties and responsibilities of the test staff and their interface with other organizations. The instruction required an integrated living operations schedule for all testing, a schedule which specified prerequisite plant conditions for

each test and served as authority to conduct specific tests, given prerequisite plant conditions. Interim PATP plateau reports and a final PATP summary test report were required. Report format and content was specified to include test status, deficiencies and deficiency disposition, by test, for each test. These reports must be reviewed by PORC and approved by the plant manager.

Due to the prolonged outage following the Unit 2 shutdown, several formal TVA management assessment "hold points" were established within the PATP to ensure a controlled return to full power operation.

The inspector concluded that the instruction provided adequate upper tier guidance for the development and conduct of the Browns Ferry PATP.

b. Test Plateau Report (72301)

The inspector reviewed the summary report of the power ascension test results for the Open Vessel Test Plateau. The Open Vessel Test Plateau included that time between the beginning of fuel load and TVA Management approval for startup. The report was prepared in accordance with the requirements of PMI-26.1 and was approved by PORC on May 22, 1991. The tests included in the report were:

TI-20	CRD Testing
TI-131	Feedwater Level Control
TI-132	Recirculation Flow Control
TI-135	Process Computer and Core Performance
TI-147A	Fuel Load
TI-149	Reactor Water Level Measurements
TI-190	Thermal Expansion
PMT-201	Piping Vibration Qualification

The test data included in the report were reviewed; no deficiencies were identified. Test Deficiencies were reviewed and it was noted that appropriate closure was accomplished for the majority of the TDs prior to submittal of the report. Seven of the TDs remained open pending corrective maintenance or further evaluation of observed conditions; the inspector concurred with the licensee assessment that no open TDs existed that would restrain continued plant startup to the next test plateau.

5. Sustained Control Room and Plant Observation (71715)

The inspectors reviewed and observed the licensee's activities in the control room on a continuing basis. The observation and reviews included control room conduct, shift turnover and relief, shift logs and records, event response, surveillance testing, and maintenance activities. The inspectors attended licensee operational and management meetings,

performed plant walkdowns, and discussed observations and reviews with licensee personnel. Specific observations and reviews are noted below.

a. Radiation Monitors

On May 24, 1991, at 5:00 p.m. while observing control room activities, the inspector monitored the unit operator's response to an annunciator that alarmed from control room panel 2-9-7. The alarm was annunciator 2-XA-55-7C window #15, Drywell/Suppression Pool High Radiation. The purpose of this annunciator is to alert Unit 2 control room personnel to a high radiation condition in the primary containment for either the drywell or the suppression chamber.

The inspector noted that licensed personnel did not immediately investigate the alarm condition to determine if an actual high radiation level existed in the drywell. When questioned about the alarm the operator stated that a recurring problem existed with the associated equipment which often resulted in frequent actuation of this annunciator. Additionally, the operator stated that the alarmed condition could not have actually existed due to then existing plant conditions with the RPV depressurized and insufficient recent power operation. Although no sticker or label was present near the annunciator to indicate documentation of any outstanding deficiency, the SOS stated that an outstanding work request existed to document the problem.

The inspector noted problems with the associated radiation monitors located on control room panels 2-9-54 and 2-9-55 while following up on the above event. This annunciator is designed to alarm if a high radiation condition is detected by either 2-RM-90-272A, Division I Drywell Gamma Radiation Monitor, 2-RM-90-273A, Division II Drywell Gamma Radiation Monitor, or 2-RM-90-272B, Division I Suppression Chamber Gamma Radiation Monitor, or 2-RM-90-273B, Division II Suppression Chamber Gamma Radiation Monitor, which are located on panels 2-9-54 and 2-9-55. In this case, 2-RM-90-273A was the source of the alarm with the associated downscale, upscale and upscale indicating lights all illuminated. The inspector noted that the corresponding blue pen on the associated multipen recorder 2-RR-90-273CD on panel 2-9-55 did not show any spikes which would have corresponded to the event. However, the green pen on this recorder did show a series of spikes. The inspector requested the SOS to investigate this condition since the green pen corresponded to a non alarming radiation monitor. A similar situation existed on panel 2-9-54 with recorder 2-RR-90-272CD. The SOS generated two WRs (C040863 and C040864) to allow instrumentation personnel to utilize system drawings and trace the respective equipment to determine if a problem existed with either the labeling on the recorders or the wiring between the radiation monitors and the recorders. The inspector noted that the above radiation monitors were not included in TS as required equipment.

The inspector noted that each of these recorders contained a third red pen which provided a remote indication for high range drywell radiation. This function is associated with radiation monitors 2-RM-90-272C and 2-RM-90-273C which are located outside the control room. The recorders for these monitors are required by TS Table 3.2.F and are designed to provide a range of 1 X 10 E7 R/hr. This required range was not supported by the radiation recorders located in the control room. Each of the recorders had a label on the face of the recorder stating that the range for all three pens was in MR/hr. Additionally, the paper contained in both recorders was marked MR/hr. Based on this observation, the inspector requested the SOS to evaluate the effect on operability of the required high range radiation recorders. On May 23, the SOS declared both High Range Drywell Radiation Monitors inoperable until the scaling information and recorder paper were made to agree with that of the remote radiation monitors. An LCO was entered in accordance with action statement #8 of TS Table 3.2.F.

Additionally, the inspector noted that similar recorders associated with Unit 1 located on panels 1-9-54 and 1-9-55 had been changed to state that the range was 1 X 10 E7 R/hr. This change appeared to have been done in an informal manner with what appears to have been a marker.

Additionally, the inspector noted that 2-RM-90-272A, Division I Drywell Radiation Monitor, had been removed from panel 2-9-54. A label stating that the drawer was to be removed for an extended time was attached to the empty bay. Note 2 to TVA Mechanical Control Drawing 2-47E610-90-2 states that this radiation monitor will be removed from service for Unit 2 Cycle 5 only. Since this constituted an opening in the panel which could allow entry of dust or other foreign objects directly into the electronics of other components, and this condition would apparently last for an extended period, the inspector requested the SOS to clarify the licensee's policy concerning this potential problem. The SOS immediately directed maintenance personnel to provide a temporary cover for the drawer opening.

Subsequent to the above, the inspector was informed that the correct recorder paper had already been available on site and was placed in the respective recorders. Based on this and conversations with licensee personnel the inspector determined that the use of the incorrect recorder paper had been known by licensee personnel prior to May 24, 1991. Additionally the inspector was informed that the wiring between the non-TS radiation monitors and their respective recorders was determined to be incorrect due to various drawing errors. The wiring errors were corrected and the required recorders declared operable on May 26, 1991.

A unresolved item was identified concerning the problems with the control room recorders. The licensee was conducting an incident investigation of the problem in which the preliminary results indicated that drawing errors were introduced during drawing restoration, and that reintroduction of the incorrect chart recorder paper occurred due to an incorrect operator aid. The inspectors will continue to follow this investigation and are reviewing why the post modification testing and surveillance requirements did not identify these problems. This URI is identified as 259, 260, 296/91-21-01, Radiation Monitor Recorder Problems.

b. Containment Atmosphere Monitoring Problems

On June 1, 1991, during preparations for a Unit 2 startup from cold shutdown, the inspector noted three outstanding work requests on the "B" containment atmosphere H2/O2 system. The control room meters indicated 1.5% hydrogen and 16% oxygen while the local panel instruments read 0 and 19% respectively. The logs and logging requirements were reviewed. The inspector found that control room operators were not required to log or monitor the H2/O2 system until the mode switch was in other than startup and auxiliary unit operators were never procedurally required to monitor or log the H2/O2 system local boards. Since TS 3.7.H required two hydrogen analyzer systems to be operable whenever the reactor was not in cold shutdown, the inspector questioned the licensee about the operability of the "B" system. After review, the licensee stated that both H2/O2 systems were operable and that the local station contained the TS instrumentation meters. The control room meters were acknowledged to be inconsistent with the local meters. The licensee acknowledged a history of degraded performance due to low pump discharge flows caused by condensate buildup in the discharge lines, a problem which cleared soon after containment inerting. Past experience dictated that pending inerting, the discharge lines required blowdown about every two days and that the system would remain operable until the low flow alarm had been received. The licensee committed to revise the startup procedure to include the H2/O2 panels as a part of the control board walkdown prior to startup.

c. Switchyard

The inspector continued to monitor the licensee's activities in the electrical and transformer yard. This consists of the main transformers, 161 KV switchyard, unit station service transformers, and common station service transformers. The inspector also reviewed the OIs for the electrical systems.

Specifically, the inspector reviewed OI-57A, Switchyard and 4160V Electrical System Operating Instructions. This OI involves the controls for the 4KV shutdown boards, unit boards, bus tie boards, common boards, and cooling tower boards. The inspector noted and

observed that no instructions existed for activities associated with the 500 KV or 161 KV power lines switch gear. The OIs did not contain instructions for isolating the Athens or Trinity 161 KV power lines. The inspector on various occasions observed licensee operations personnel manipulating the switchyard switchgear for the 500KV and 161KV lines. The inspector also observed and reviewed an incident involving the automatic transformer tap changes, which were not covered in the OIs. The inspector concluded from this review and observations that the OI did not adequately address the control and transfer of power for the 161 KV or 500 KV system. The inspector considered this a weakness in the plant operating instructions and discussed this item with the licensee management. Licensee management initiated action to review this.

d. Post Trip Review Procedure

The inspector reviewed PMI-15.8, Unit Trip, Reactor Transient, and Plant Transient Analysis, Revision 2, dated February 19, 1991, to determine if it provided adequate guidance to determine the root cause for a reactor trip, reactor transient, or a plant transient. The purpose of this instruction is to evaluate reactor scrams to ensure safety criteria are met prior to unit restart; to analyze the causes for scrams and transients to provide preventive measures to reduce the frequency of these events; and to provide reporting responsibilities for these events. Definitions of scrams and transients are provided in this instruction. The STA is assigned the responsibility for completing the preliminary evaluation for a reactor scram using form PMI-57 provided in the instruction. Separate forms are provided for the other events defined in this instruction.

During the review of this document the inspector referred to other plant instructions and noted inconsistencies. For example: 2-AOI-100.1, Reactor Scram, Revision 12, dated January 24, 1991 does not reference PMI-15.8 and does not require the use of PMI-15.8 prior to unit restart. PMI-15.8, Attachment 1, Reactor Scram Initiations, and 2-AOI-100-1, Attachment 1, Conditions Causing A Reactor Scram, were inconsistent. PMI-15.8 listed the setpoint for APRM Hi Hi as (.58 W + 62)R while the AOI stated the condition as (0.66w + 54%). The AOI listed main condenser low vacuum (.8" Hg Vac.) as a scram condition, no equivalent scram initiation was provided in the PMI.

PMI-15.8, Attachment 7, Scram Package Contents, lists charts to be included in the scram package "IRM/APRM (4 Charts)." PMI-12.12, Conduct of Operations, Revision 14, dated March 28, 1991, Attachment 11, Scram Package Contents list this as "IRM/APRM (4 Channels-2 Charts)." Nomenclature for drywell pressure and primary containment temperature differs between these attachments. PMI 15.8 lists charts XR-64-50 and XR-64-52 and PMI-12.12 describes these charts as PR-64-50 and TR-64-52.

These items were discussed with the Operations Supervisor on May 29, 1991.

The inspector concluded that PMI 15.8, "Unit Trip, Reactor Transient, and Plant Transient," adequately details the guidance necessary to determine the cause of a reactor trip, reactor transient, and plant transient. However, nomenclature and trip setpoint inconsistencies between plant instructions should be resolved. Nomenclature used in plant documents and instructions that refers to control board instrument or charts recorders should use the exact nomenclature found on the control board for that instrument or recorder.

e. Electrical Safety Precautions on Energized Equipment

The inspector observed portions of WO 91-33412-00, Troubleshoot, Repair or Adjust Limit Switches on MVOP-24-0057, RCW Isolation Valve Precooler, during the evening shift of June 8, 1991. After the electrical craft crew of two men, assisted by an operations person, were unable to cause the MOV to move electrically, one of the electrical craft returned to 480 VAC MOV Board 2C to initiate troubleshooting of the MOV controller at approximately 2100 hours. He worked in the energized switchgear unattended by plant personnel for approximately ten minutes, after which his crew partner returned. The electrical craft continued work for another five minutes until stopped for other reasons by Operations.

The undesirability of electrical craft working alone in energized switchgear was mentioned to the SOS who advised the inspector that the practice was contrary to TVA policy. The licensee took administrative action to prevent recurrence of the event.

f. Failure to Follow Heat Stress Requirements

The inspector observed that persons exiting the U-2 drywell June 7, 1991, were sweating profusely and flushed. Discussions were held with a mechanical craft person on the scene, acting as a helper to workers in the drywell working on reactor recirculation pump 2B seals (WO 91-33904-00, Remove and replace 2B recirculation pump seals), concerning the work conditions, the amount of work being performed, and whether safety surveys of the work site had been performed. The inspector learned that temperatures and humidity were high in the pump seal area, that the work was difficult and strenuous, and that no heat stress related surveys had been performed that the mechanical craft were aware of. The inspector reviewed the work package located at the job site, and noted no evidence of a heat stress survey. The helper informed the inspector that the subject of heat was not mentioned during the radcon ALARA (safety) pre-work safety briefing. The inspector reviewed the Nuclear Safety officer's security log of persons entering the drywell on June 7, 1991 and noted that no members of the Industrial Safety group entered the drywell on that date.

The inspector reviewed SDSP-14.24 Revision 0001, Heat Stress Requirements, and noted that supervisors/foremen should notify Industrial Safety when work is scheduled in a suspected hot area so that monitoring of the work environment to obtain WBGT may be initiated. Temperatures above 80 degrees require compensatory measures.

The inspector notified the SOS of the apparent failure to follow procedure on June 7, 1991. The SOS promptly contacted Industrial Safety representatives who initiated a heat stress survey; the inspector later learned that the WBGT was 82 degrees, necessitating stay time considerations and protective clothing (ice vests) use. The inspector observed that these compensatory measures were in use by the licensee on June 8, 1991. This NRC identified violation is not being cited because criteria specified in Section V.A of the NRC Enforcement Policy were satisfied.

One noncited violation was identified in the Sustained Control Room and Plant Operation area.

6. Maintenance Observation (62703)

Plant maintenance activities were observed and reviewed for selected safety-related systems and components to ascertain that they were conducted in accordance with requirements. The following items were considered during these reviews: LCOs maintained, use of approved procedures, functional testing and calibrations were performed prior to returning components or systems to service, QC records maintained, activities accomplished by qualified personnel, use of properly certified parts and materials, proper use of clearance procedures, and implementation of radiological controls as required.

Work documentation (WR and WO) were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which might affect plant safety. The inspectors observed the following maintenance activities during this reporting period:

a. Turbine Oil Flush

b. SBGT Duct Repair

c. RHR Heat Exchanger Leak Repair

d. Repair of 2-FCV-3-53, Reactor Water Level A Startup Bypass Control Valve.

e. Troubleshooting of Control Room Annunciator Problems.

No violations or deviations were identified in the Maintenance Observation area.

7. Surveillance Observation (61726)

The inspectors observed and/or reviewed the performance of required SIs. The inspections included reviews of the SIs for technical adequacy and conformance to TS, verification of test instrument calibration, observations of the conduct of testing, confirmation of proper removal from service and return to service of systems, and reviews of test data. The inspectors also verified that LCOs were met, testing was accomplished by qualified personnel, and the SIs were completed within the required frequency. The following SIs were reviewed during this reporting period:

2-SI-4.2.C-1.2 FT, Instrumentation That Initiates Rod Block/Scram, APRMs Functional Test

2-SI-4.2.C.3.2 FT, IRM Functional Test

2-SI-4.2.C-4 FT, SRM Functional Test

2-SI-4.1.A-ATU(A), Reactor Protection and Primary Containment Isolation Systems Analog Trip Unit Channel A1 Functional Test

2-SI-4.6.A.1, Reactor Heatup and Cooldown Rate Monitoring

No violations or deviations were identified in the Surveillance Observation area.

8. Post Maintenance Testing (37700, 72701)

An inspector observed PMT activities associated with WO 91-33783-00. This work order covered replacement of mechanical seal for the 2B condensate pump. During the observed activities licensee personnel locally monitored the pump operation as it was returned to service. One poor practice was noted by the inspector. Licensee personnel took various pieces of equipment including a relatively bulky and expensive vibration instrument into the contamination zone for monitoring pump operation. After the PMT was complete the equipment including the vibration instrument was bagged until released by radiological control personnel. The attending technician stated that the particular method utilized in such work was normally left up to personnel performing the work. The more generally industry accepted practice of bagging items of this nature prior to taking them into a containment area would provide a reasonable level of assurance that such equipment would not be contaminated. The inspector discussed the observation with the SOS and duty Manager. The inspector was informed that the practice as observed was not in accordance with TVA policy in this area and the information would be provided to the appropriate licensee management personnel.

9. System Pre-Operability Checklist (71707)

The inspectors continued to review the licensee's progress to upgrade the plant equipment and documentation to insure that systems are acceptable to support restart of unit 2. At the end of this reporting period all of the systems were completed. The following below systems were reviewed.

a. Transversing Incore Probe (System 94)

This system provides a means of measuring and recording local incore power levels in order to perform LPRM calibrations. Additionally, the inspectors had monitored portions of the licensee's testing of the system during the final stages prior to Unit 2 initial criticality.

The system checklist was completed on May 17, 1991. The inspector reviewed the SPOC package with the system engineer on May 26, 1991. During the review the inspector determined that plant staff had accepted the system for status and configuration control and for operability. The SPOC package included one deferral for PMT required following replacement of neutron detectors with gamma detectors. Although the physical work is complete, the required testing must be done during power operation. The inspector determined that the licensee had adequately identified work associated with this system necessary to support Unit 2 restart.

b. Plant Computer (System 261)

System 261 is composed of two independent computer systems, the PPC and the Interim SPDS. Although both computer systems are classified as non-safety related and not required to operate to safely shutdown the reactor, there are separate functions which are important to safety. These are as follows:

The PPC works with the RWM to supplement procedural requirements for control rod worth during control rod manipulations during reactor startup and shutdown. Additionally it provides a quick and accurate determination of core thermal performance during reactor operation.

The interim SPDS is a partial implementation of NUREG-0737, Supplement 1, Item I.D.2 requirements. This system serves as an aid for control room and TSC personnel during abnormal and emergency conditions in determining safety status of plant.

The system checklist was completed on May 11, 1991. The inspector reviewed the SPOC package with the system engineer on May 27, 1991. During the review the inspector determined that plant staff had accepted the system for status and configuration control and for operability without any deferrals or exceptions. The inspector determined that the licensee had performed an acceptable job of reviewing system status and this system was ready to support Unit 2 restart.

10. Reportable Occurrences (92700)

The LERs listed below were reviewed to determine if the information provided met NRC requirements. The determinations included the verification of compliance with TS and regulatory requirements, and addressed the adequacy of the event description, the corrective actions taken, the existence of potential generic problems, compliance with reporting requirements, and the relative safety significance of each event. Additional in-plant reviews and discussions with plant personnel, as appropriate, were conducted.

a. (CLOSED) LER 260/91-01, Unplanned Safety Features Actuation Due To A Blown Fuse Caused By A Failed Relay

An unplanned actuation of various engineered safety features occurred on January 16, 1991, due to a blown fuse in the PCIS circuitry. The blown fuse was the result of faulted coil in a GE type CR120 relay.

The licensee immediate corrective actions consisted of replacing the blown fuse and replacing the faulted relay coil. The licensee also performed a review of NPRDS, NER, BFN failure history and reviewed vendor documentation on the CR120 relays. The licensee determined from this review that problems were occurring in GE CR120 relays that were approaching the end of their predicted service life of 15 to 20 years. Other LERs (LER-91-05, LER 91-08) also indicate that GE type CR120 relays have experience end of life coil failure. Based on the trend noted, the licensee will replace the relay coils in each of the GE type CR120 relays. Unit 2 relays are scheduled to be replaced prior to the unit startup following the Unit 2, Cycle 6 refueling outage. Units 1 and 3 relay coils are scheduled to be replaced prior to each respective unit's startup. LER 91-05 and LER 91-08 will also be closed based on the licensee's commitment to replace the relay coils as scheduled.

b. (CLOSED) LER 260/91-05, Unplanned Engineered Safety Features Actuation Due to A Fuse Caused By A Failed Relay Coil.

The unplanned ESF actuation discussed in this LER was attributed to a faulty GE type CR120 relay coil. These relays are identical to those identified in paragraph 10.a.

c. (CLOSED) LER 260/91-08, Unplanned Engineering Safety Features Actuation Due to a Failed PCIS Relay

The unplanned ESF actuation discussed in this LER was attributed to a faulty GE type CR120 relay coil. These relays are identical to those identified in paragraph 10.a.

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

a. (OPEN) IFI 260/91-21-03, Discrepancies In EECW Check Valve Testing.

This item originated from a team inspection effort documented in IR 89-56, that identified the EECW System was not aligned to supply cooling water to the control bay chillers by automatic actuation as described in the FSAR. The licensee committed to submit Amendment 8 to the FSAR to correct the description and operational discrepancies in that RCW was utilized as the cooling water as opposed to the EECW as indicated in the FSAR. Based on this commitment, URI 259, 260/89-56-02, Use of Closed Manual Valves in EECW Line Control Bay Chillers was closed in IR 91-10.

The licensee has since changed their mode of operation, and the EECW System is utilized to supply cooling water to the control bay chillers. Amendment 8 to the FSAR will reflect the latest operational mode as opposed to that previously proposed.

The inspector has verified that drawing changes have been made to depict the proper valve alignments (ie. normally open vs. normally closed) and that operating and surveillance instructions have been revised to reflect the change. The maintenance program for the check valves in the EECW System was reviewed and found to be acceptable except for one area. This dealt with taking exception to reverse flow testing based on valve disassembly and visual inspection. Generic Letter, GL 89-04, Guidance on Developing Acceptable Inservice Testing Program, was cited as the basis. However, the Generic Letter requires that prior to taking this exception, formal request and approval must be obtained. The licensee stated that the request had been submitted and that the approval had not been formally received. Based on this, the inspector determined that the check valve testing exception will remain open as IFI 260/91-21-03, Approval of EECW Check Valve Testing Exception.

b. (CLOSED) EA 89-226 (VIO 259, 260, 296/89-43-01), Surveillance Program Violations.

This item was previously reviewed in IR 91-13. In that report, the inspector concluded that each of the examples had been closed out in previous NRC inspection reports. In addition, the inspector concluded that the programmatic actions taken for the EA were acceptable with the exception of: 1) the validation process and 2) management involvement in the verification and validation processes. Upon further review, the licensee determined that 59 SIs had been performed without validation. This item remained open pending the resolution of SIs which had been previously performed without validation and implementation of an adequate process to ensure the remaining SIs are validated prior to Unit 2 restart.

Since the end of the inspection period for IR 91-13, the inspectors followed the licensee's actions to implement an effective program for SI validation. The inspectors discussed the licensee's actions and the status of the validation for the identified SIs on a weekly basis with cognizant management personnel. In addition, the inspectors reviewed and observed the conduct of SIs and the performance of SI validations.

The licensee revised SSP-2.3, Administration of Site Procedures, to include the Technical Support Manager as the licensee manager responsible for implementation of the validation process. The revision also included a provision requiring validation comments to be incorporated within 14 days or prior to the next performance.

In addition to the program enhancements, the licensee took the following actions to validate the 59 identified SIs.

(1) 23 were reperformed and validated.

(2) 20 were validated by using validation comments for the SI from another loop or train of the same system. These SIs should be the same except for component or system designations.

(3) 13 were validated by recreating the validation comments from the most recent performance.

(4) Two were on a 5 year frequency and were last performed in 1988. These SIs have been revised extensively and will be validated during the next performance.

(5) One SI was revised extensively and separated into two "loop" SIs. These SIs will be validated during the next performance.

The inspector concluded that the licensee had resolved the concerns for each of the 59 identified SIs. The inspector also concluded that the licensee had implemented an adequate process to ensure completion of the NRC commitment to validate SIs. No further concerns were identified during the review of this item.

c. (CLOSED) VIO 259, 260, 296/91-06-02, Failure to Maintain a System Drawing.

During a System 31 inspection, conducted on March 6, 1991, the inspector identified a drawing which failed to appropriately illustrate existence fire dampers. A violation was issued against 10 CFR 50, Appendix B, Criterion V. The licensee responded to this violation by letter on May 10, 1991. In the response, the licensee agreed that the example given in the NOV violated the regulatory requirements. The licensee attributed the violation to personnel error and noted it to be an isolated incident.

The inspector reviewed the affected drawing(s) and verified that the drawing was revised and reflects existing plant configuration. The inspector also reviewed the memorandum issued to the contractors requiring counseling/and or disciplinary action against the appropriate individual(s) and the need to assure that all personnel involved in the resolution of DDs are aware of the incident and its subsequent violation. No further concerns were identified during the review of the licensee's actions.

12. Exit Interview (30703)

The inspection scope and findings were summarized on June 14, 1991 with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
259, 260, 296/91-21-01	URI, Radiation Monitor Recorder Problems, paragraph five.
259, 260, 296/91-21-02	NCV, Failure to Follow Heat Stress Requirements for Drywell Work, paragraph five.
260/91-21-03	IFI, Approval of EECW Check Valve Testing Exceptions, paragraph 11.

Licensee management was informed that 3 LERs and 2 VIO were closed.

13. Acronyms and Initialisms

AOI	Abnormal Operating Instruction
APRM	Average Power Range Monitor
ASOS	Assistant Shift Operations Supervisor
ATU	Analog Trip Unit
BFNP	Browns Ferry Nuclear Plant
BWROG	Boiling Water Reactor Owners Group
CFR	Code of Federal Regulations
CRD	Control Rod Drive
DD	Drawing Deficiency
EA	Enforcement Action
EECW	Emergency Equipment Cooling Water
ESF	Engineered Safety Feature
FSAR	Final Safety Analysis Report
GE	General Electric
GL	Generic Letter
GOI	General Operating Instruction
JTG	Joint Test Group

INPO	Institute of Nuclear Power Operations
IR	Inspection Report
IRM	Intermediate Range Monitor
KV	Kilovolt
LCO	Limiting Condition for Operation
LED	Light Emitting Diodes
LER	Licensee Event Report
LPRM	Local Power Range Monitor
MMI	Mechanical Maintenance Instruction
MOV	Motor Operated Valve
MR	Maintenance Request
NCV	Non-Cited Violation
NER	Nuclear Experience Review
NPRDS	Nuclear Plant Reliability Data System
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OI	Operating Instruction
PATP	Power Ascension Test Program
PCIS	Primary Containment Isolation System
PMI	Plant Manager Instruction
PMT	Post Modification Testing
PORC	Plant Operations Review Committee
PPC	Plant Process Computer
QC	Quality Control
RCW	Raw Cooling Water
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
RSCS	Rod Sequence Control System
RWM	Rod Worth Minimizer
SBGT	Standby Gas Treatment System
SDSP	Site Directors Standard Practice
SI	Surveillance Instruction
SOER	Significant Operating Event Report
SPDS	Safety Parameter Display System
SPOC	System Pre-Operability Checklist
SRM	Source Range Monitor
SSP	Site Standard Practice
STA	Shift Technical Advisor
TD	Test Deficiency
TI	Test Instruction
TSC	Technical Sport Center
TS	Technical Specification
TVA	Tennessee Valley Authority
URI	Unresolved Item
VAC	Volts Alternating Current
VIO	Violation
WBGT	Wet Bulb Globe Temperature
WO	Work Order
WR	Work Request