



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

Report Nos.: 50-259/91-43, 50-260/91-43, and 50-296/91-43

Licensee: Tennessee Valley Authority  
6N 38A Lookout Place  
1101 Market Street  
Chattanooga, TN 37402-2801

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: December 16, 1991 - January 16, 1992

Inspector: Paul Kellogg for  
C. K. Patterson, Senior Resident Inspector

2/4/92  
Date Signed

Accompanied by: E. Christnot, Resident Inspector  
W. Bearden, Resident Inspector

Approved by: Paul Kellogg  
Paul Kellogg, Chief,  
Reactor Projects, Section 4A  
Division of Reactor Projects

2/4/92  
Date Signed

SUMMARY

Scope: This routine resident inspection included surveillance observation, maintenance observation, operational safety verification, fire protection, Unit 3 restart activities, contractor oversight program, and action on previous inspection findings.

Results: A violation for failure to follow the Unit Separation procedure was identified by the inspector, paragraph six. Personnel assigned to Unit 3 only are required to be designated by blue hardhats and uniquely identified access badges (blue stickers). During a Unit 3 walkdown two of the five team members did not have uniquely identified access badges. Both individuals had a security access code to all vital areas of the plant. Prior to this occurrence, the inspector identified this problem to management and action taken did not correct the problem.



An unresolved item was identified for an unintentional start of a diesel generator during maintenance activities, paragraph three. The diesel started and tripped on overspeed. The licensee is continuing to evaluate this event and a final event report will be issued. The inspector will review the final report when issued.

The maintenance activities associated with the recirculation motor generator problems were reviewed, paragraph three. The troubleshooting activities did not correct the problems and the scoop tube positioning arm bolt sheared. It was determined that the probable cause of various problems and speed perturbations was misalignment of the mechanical linkage to the scoop tube. The licensee did not inspect the 2A set, but this has been added to the forced outage schedule.

Electrical walkdowns for vertical drop, cable conduit raceway support, environmental qualification, and electrical installation practices continue on Unit 3, paragraph six. Some of these activities are departures from the integrated walkdown concept and require opening of previously opened components such as junction boxes. This was a decision by licensee management to limit the number of people in the plant and minimize the time components were opened.



## REPORT DETAILS

### 1. Persons Contacted

#### Licensee Employees:

- \*O. Zeringue, Vice President, Browns Ferry Operations
- H. McCluskey, Vice President, Browns Ferry Restart
- \*J. Scalice, Plant Manager
- J. Swindell, Restart 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
- R. Baron, Site Licensing Manager
- \*P. Salas, Compliance Supervisor
- \*J. Corey, Site Radiological Control Manager
- A. Brittain, 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:

- \*C. Patterson, Senior Resident Inspector
- \*E. Christnot, Resident Inspector
- W. Bearden, Resident Inspector

\*Attended exit interview

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

### 2. 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:

- a. 2-SI-4.2.K.2.a FT, Reactor Building Vent Exhaust Monitor 2-RM-90-250 Detector Channel Functional Test. This test provides for the

functional testing of the noble gas monitor detector channel 2-RM-90-250 and satisfies the requirements specified in TS Table 4.2.K. The activity is performed once per quarter and the inspector reviewed the documentation associated with the two most recently completed performances for this surveillance requirement. The inspector did not identify any deficiencies with the completed surveillance tests dated July 30, 1991 and October 10, 1991.

- b. 1-SI-4.5.B.11, RHR Unit 1 X-Tie for Unit 2 Operability. This test demonstrates that the Unit 1 crosstie to RHR pumps, heat exchangers, and motor operated valves is operable to support Unit 2 requirements identified in Unit 2 TS 4.5.B.11. The activity is performed once per quarter. The inspector reviewed the documentation associated with the two most recently completed performances for this surveillance requirement dated July 15, 1991 and October 10, 1991. The inspector did not identify any deficiencies with the completed surveillance tests.
- c. 2-SI-4.5.B.14, Reactor Recirculation Pump Discharge Valve Cycling. This test demonstrates operability of the closure function of the recirculation pump discharge valves and to satisfy requirements identified in TS 4.5.B.14. The inspector reviewed the documentation associated with the two most recent completed performances for this surveillance requirement. The activity is performed during any period of cold shutdown greater than 48 hours if not done within last 31 days. The inspector did not identify any deficiencies with the completed surveillance tests dated October 18, 1991 and October 19, 1991.
- d. 3-SI-4.9.A.2.a-3, Weekly Check for Diesel Generator 3A, 3B, 3C, and 3D Batteries (Unit 3). This test demonstrates operability of the Unit 3 D/G Batteries and satisfies requirements identified in TS 4.9.A.2. The inspector reviewed the documentation associated with the most recent performance of this surveillance requirement. This test was last performed on December 26, 1991. During the performance of the SI, temperature readings taken in accordance with step 7.3.9.2 were found to be below the lower limit of the acceptance criteria stated in the SI. Actual electrolyte temperature was 55 degrees F and the required range was 60 to 110 degrees F. Although the battery and associated D/G were initially declared inoperable, they were later declared operable based on a satisfactory disposition of TD-1 to this SI. To disposition this TD the licensee processed an urgent intent change to change the lower limit from the acceptance criteria from 60 degrees F to 40 degrees F. The inspector requested the licensee to provide any documentation which might serve as a technical basis to support this procedural change. The inspector was provided with a copy of TVA Engineering Calculation, ED-Q2000-0046, Load Study - Diesel Generator Batteries. The inspector reviewed this calculation and determined that the calculation was bounded based on a lower battery electrolyte temperature limit of 40 degrees F. Based



on this review the inspector determined that the licensee's decision to change the above acceptance criteria was an acceptable option.

- e. 2-SI-4.2.B-35(A) and 2-SI-4.2.B-35(B), Core and Containment Cooling Systems Reactor High Water Level HPCI Trip Instrument Channel Calibration. These tests check the calibration of core cooling systems Reactor High Water Level Channels 2-L-3-208B and 2-L-3-208D. When performed in conjunction with each other these calibrations satisfy requirements identified in TS Table 4.2.B. The inspector reviewed the documentation associated with the most recently completed performance for each of these channels of instrumentation. The surveillance is required to be performed quarterly and was performed last on November 7-8, 1991. The inspector did not identify any deficiencies with the completed surveillance tests.
- f. 2-SI-4.1.B-2, APRM Output Signal Adjustment. This test demonstrates operability of the APRMs output signal to satisfy requirements in TS Table 4.1.B. The inspector reviewed the documentation associated with the most recently completed surveillance which was performed on November 2, 1991. The activity is performed once per seven days. During performance of this test an OD-3 program is run on the process computer to determine GAFs, for each of the APRM channels. If the value for GAF associated with one of the APRMs is out of tolerance then that channel is bypassed the GAF adjusted and OD-3 reperformed. For this performance APRM A had an as found GAF that was initially out of tolerance requiring action as stated above. The remaining APRM channels had GAFs which were initially within tolerance and the inspector did not identify any deficiencies with the completed surveillance tests.

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

### 3. Maintenance Observation (62703)

Plant maintenance activities were observed and/or 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/or 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 (MR, 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. Penetration 2-X-26

The inspector followed licensee activities associated with removal of a circular ring which was bolted to existing concrete in the drywell outer wall and surrounds the 18 inch diameter drywell purge exhaust line at the penetration. The ring as installed serves no function and may have been left over from a previous boot that covered the penetration. Although the circular ring would not normally present a problem for most penetrations, there are three one inch pipe stubs which stick outward at 120 degree intervals from the purge exhaust line. These three stubs are located within the circular ring and could represent a potential interference with thermal growth during a LOCA. One of the stubs only has approximately 1/32 inch of clearance between the end of the stub and the circular ring. This condition was discovered by a licensee engineer during a routine tour of the area outside of the primary containment.

Although this condition was discovered by the licensee and Work Request C030488 was written to remove the circular ring, the inspector was concerned about the potential affect on operability of the primary containment until the circular ring would be removed. The thermal growth of the drywell liner during a LOCA would result in additional vertical movement of the purge line. The inspector met with various members of licensee management and the onsite engineering organization for determining the basis for considering the primary containment operable during the interim period. The inspector was provided a copy of civil calculation, CD-Q2064-910577, which documented the licensee evaluation of the integrity of this penetration. The calculation was a stress evaluation for all components that showed that in the event of a LOCA that the 3/8 inch A307 bolting used to attach the circular ring would fail well below the value required to fail the 18 inch exhaust line or the individual stub tubes. This calculation was also reviewed by an inspector from the regional office who concurred that the stresses were within allowable values and acceptable. During a subsequent tour of the area the inspector noted that the circular ring had been removed from the penetration.

## b. Unit 1/2 A Diesel Generator Outage

The inspectors followed licensee activities associated with the scheduled outage on the Unit 1/2 A D/G. This outage was originally started as planned on December 8, 1991, but the D/G had to be returned to operable status on December 9, 1991, to support Unit 2 restart following an unplanned scram. Following the restart, the D/G was removed from service at 3:10 a.m. on December 16, 1991. The work performed included various preventative maintenance requirements including the annual inspection and the six year inspection of the diesel engine and generator. The inspector noted that the licensee entered LCO 2-91-333-3.9.B.3 to track the LCO associated with this equipment which required that the D/G be returned to operable status



within 7 days. The D/G was removed from service under Hold Orders 0-91-865, 0-91-864, 0-91-863, 0-91-862, and 0-91-861.

The inspector reviewed selected documentation associated with this outage and observed various work in progress including engine disassembly/reassembly and D/G battery bus bar and bolt replacement. During the performance of these activities the D/G experienced an unintentional start on December 18, 1991. This event is still being investigated by the licensee. The inspector will review the licensee's final event report when completed. This item will be tracked as URI 259, 260, 296/91-43-01, Unintentional D/G Start. The D/G was returned to service and tested at 2:00 a.m. on December 20, 1991.

Other than the mentioned unintentional D/G start the inspector did not identify any problems associated with the planned D/G outage.

c. Recirculation Motor Generator Set Broke Positioning Arm

During the reactor trip on December 8, 1991, the recirculation pump trip breaker opened. When the 2B MG set was reset, the scoop tube operating arm began oscillating rapidly and the bolt sheared to the scoop tube arm. The MG set was manually tripped. The 2B MG set scoop tube was physically verified to be frozen in position, which caused the positioner connecting bolt to shear. To correct the condition the cover on the fluid coupling was removed. Corrosion was found on one surface of the scoop tube. Also, the mechanical linkage was out of alignment. The inspector observed the maintenance activities in progress and later reviewed a video tape of the scoop tube and linkage with a maintenance supervisor. It appeared that the misalignment resulted in one area of the scoop tube not being wiped clean periodically as the scoop tube moved resulting in the corrosion. A bushing was added to the linkage arm to correct an 1/8 inch misalignment of the linkage. This misalignment had apparently caused binding of the scoop tube.

Significant problems were encountered with the MG sets prior to this event. On November 20, 1991, the recirculation MG set experienced a spurious increase in speed of 40 RPM. The position of the scoop tube was locked to prevent further perturbations. There had been two previous occurrences of speed deviation. The first occurrence of speed change was attributed to a loose connection in the Bailey Positioner on the MG set. After the second occurrence all connections were checked in the positioner, the linkages were lubricated, and the positioner tuned. It was decided to instrument the control circuit with a recorder to catch the occurrence and determine the faulty component. The vendor was contacted to send a representative to the site to assist in the troubleshooting. On November 21, 1991 it was decided to reset the scoop tube in order to attain better data. During this resetting the speed of the MG set increased. After this occurrence, the scoop tube was again locked.



On November 22, 1991, it was decided to replace all modules in the control loop if the faulty component could not be pin pointed within the next two days. On November 23, 1991 the vendor arrived on site. A calibration of the Bailey Positioner was performed under the guidance of the vendor. Some adjustments were made to the positioner, however the speed change could not be attributed to this. On November 24, 1991, the recorder traces from the previous night were reviewed by the System Engineer and a deviation was noted which would have caused the noted speed changes. The faulty component was determined to be the converter module. The output of the module shifted without a change in the input signal from the tachometer. On November 24, 1991, the faulty module was replaced and the scoop tube was reset and returned to service. During the reset, a momentary speed decrease of 60 RPM was noted. It was also noted that the speed was oscillating by approximately 15 RPM rather than the normal oscillation of approximately 7 RPM. The scoop tube was again locked. A slight gain adjustment was made to the amplifier in the Bailey Positioner to correct the oscillation. The MG set was returned to service and appeared to be working satisfactorily, however a mismatch occurred between the two MG sets when the controls were placed in master control.

On November 26, 1991, speed control adjustments were made with the scoop tube locked. After the adjustments were made, the scoop tube was reset with no speed change. Operations was briefed on how to perform some voltage checks of the speed control circuitry prior to resetting the scoop tube.

While some of the other conditions may have existed, the inspector felt that the troubleshooting was ineffective to determine the cause. In several weekly exit meetings, the inspector commented that the real problem was being masked and resulted in failed components. It was suggested that possibly the scoop tube positioner drive motor operation was erratic causing the MG set problems. The inspector concluded that the troubleshooting was not done in a systematic fashion and was ineffective to determine the real cause of the speed control problems until the component sheared.

To date, the licensee has not determined if the misalignment was due to improper maintenance in the past or an original problem with the MG set from the vendor. The inspector reviewed the vendor manual, Variable Frequency MG Set and Ass. Control Equipment for TVA, and in Tab 12, under assembly instructions for the linkage connections, it is clearly stated to level the linkage arms.

Also, the licensee did not inspect the 2A MG set for a similar problem. The inspector conducted a review of all maintenance activities on the MG sets since 1985. One work request, A-794096 dated June 22, 1987, was found which stated to investigate the cause of excessive scoop tube vibration on "A" recirculation pump during initial startup. Another work request, A-794099, was referenced to



check the bearing and joints inside the fluid coupling. The inspector reviewed this MR but could not positively identify what work was performed since the failure discussed was for an oil leak on the fluid coupler. It was noted two bearings were replaced.

The licensee provided a copy of the forced outage schedule and an inspection of the 2A MG is planned under WO C038183.

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

#### 4. Operational Safety Verification (71707)

The NRC inspectors followed the overall plant status and any significant safety matters related to plant operations. Daily discussions were held with plant management and various members of the plant operating staff. The inspectors made routine visits to the control rooms. Inspection observations included instrument readings, setpoints and recordings, status of operating systems, status and alignments of emergency standby systems, verification of onsite and offsite power supplies, emergency power sources available for automatic operation, the purpose of temporary tags on equipment controls and switches, annunciator alarm status, adherence to procedures, adherence to LCOs, nuclear instruments operability, temporary alterations in effect, daily journals and logs, stack monitor recorder traces, and control room manning. This inspection activity also included numerous informal discussions with operators and supervisors.

General plant tours were conducted. Portions of the turbine buildings, each reactor building, and general plant areas were visited. Observations included valve position and system alignment, snubber and hanger conditions, containment isolation alignments, instrument readings, housekeeping, power supply and breaker alignments, radiation and contaminated area controls, tag controls on equipment, work activities in progress, and radiological protection controls. Informal discussions were held with selected plant personnel in their functional areas during these tours.

##### a. Plant Status

The unit was on line for 36 days of continuous operation at the end of this report period. No significant problems were encountered. The 2B RFP tripped on January 10, 1992 and January 11, 1992 resulting in temporary load reduction to 90% power. The licensee is evaluating the RFP vibration trip device for resolution of this problem.

##### b. Leaking HPCI Steam Admission Valve

During a routine tour on December 18, 1991, the inspector observed a small trickle of water running down the valve stem of the HPCI stop valve 73-18. The valve is normally closed. The flowpath of steam from the main steam line to the HPCI turbine consists of two normally



open containment isolation valves, a normally closed steam admission valve 73-16, a normally closed stop valve 73-18, and a normally closed control valve. The inspector expressed a concern to the plant manager concerning the leakage and toured the HPCI room with the plant manager.

It was determined that the steam admission valve 73-16 was leaking through to the stop valve. On December 23, 1991, HPCI was declared inoperable to troubleshoot the problem. It was found that the torque switch was not functioning correctly which prevented the 73-16 valve from fully closing. The torque switch was repaired and the leakage stopped after the valve closed properly. Although this problem was corrected after discussion with the plant manager, routine activities did not correct this problem.

c. Plant Simulator Upgrade

The licensee has certified to the NRC in accordance with 10 CFR 55.45(b)(5) that the simulator and software has been upgraded to increase the scope of simulation to ANS 3.5 - 1985 requirements. The licensee had requested and received an extension on the certification deadline of March 26, 1991 to December 31, 1991. The upgrade effort was completed in November 1991 and is intended to include state of the art reactor core and thermal hydraulic modeling, extensive electrical system modeling and a new improved instructor station. The licensee's certification along with supporting information required by 10 CFR 55.45(b)(5) is contained in a licensee submittal dated December 17, 1991.

d. Reactor Trip Reports

1.) (Closed) Scram No. 2-157

Unit 2 tripped from 80% power on December 8, 1991, ending 48 days of continuous operation. A 30 ampere fuse blew in the secondary side of a potential transformer. This resulted in actuation of the main generator protective circuit and a generator load reject. A turbine trip and reactor trip followed. The licensee conducted an incident investigation of the event and restarted the unit on December 10, 1991. The inspector reviewed the licensee's Preliminary Scram Evaluation dated December 8, 1991, the Final Event Report dated December 16, 1991, and the associated control room charts and logs. Although the licensee's evaluation of the event appeared to be thorough, no reason other than unexpected fatigue failure of the fuse could be identified.

During the review of the licensee's findings and corrective actions resulting from this event the inspector noted two

particular concerns which should receive special attention by the licensee. These concerns are as follows:

Low pressure feedwater heater isolations occurred after the turbine trip on this and other recent trips. These problems appear to be due to reference leg flashing and/or flashing in the flash tank/collector tank. An evaluation associated with the scram that occurred on September 14, 1991, has resulted in development of DCR 3724 which is scheduled to be completed by Unit 2 Cycle 7 startup. This item should receive special attention because isolations of this type are undesirable and occur at a time when control room personnel are especially busy attending to other duties.

At 11:43 p.m. following the above scram the 2B Recirc Pump was placed back in service. Shortly thereafter, the 2B Recirc Pump Fluid Drive Scoop Tube mechanically bound. Force of the positioner attempting to move the scoop tube eventually caused the positioner connection bolt to shear, resulting in the manual trip of the 2B Recirc MG Set. Subsequent inspection by the licensee revealed corrosion, pitting, and oil varnish on the surface of the scoop tube along with a slight misalignment of the mechanical linkage. This item is of particular concern to the NRC considering the large amount of maintenance that has been necessary on these components since Unit 2 restart.

The inspector determined that DCR 3724 was issued by the licensee to determine the root cause problems and initiate any changes required to improve feedwater heater level control. Implementation is scheduled to be complete prior to restart of Unit 2 following the next refueling outage. Further discussion of recirc MG set problems including corrective action for the above problem is described in paragraph 3.

Based on the above review the inspector determined that the licensee did an adequate post trip review of this event. The inspectors will monitor the licensee's future corrective actions associated with the above mentioned problems. This item is closed.

2.) (Closed) Scram No. 2-155 and 2-156

Subsequent to the completion of the Unit 2 Power Ascension Test Program Unit 2 tripped on two different occasions, due to a failed air fitting which resulted in a feedwater transient (Scram No. 2-155) and due to a manual scram inserted during a shutdown due to a reverse power signal sensed on the main generator (Scram No. 2-156). The licensee's post trip reviews associated with these reactor trips were reviewed by the inspectors and documented in Inspection Reports 91-38 and 91-40. These items are closed.

No violations or deviations were identified in the Operational Safety Verification area.

5. Fire Protection (64704)

The inspector reviewed the Sequoyah Nuclear Plant FPIT Final Report dated June 18, 1991. That report had been issued by the corporate FPS to document the results of a special evaluation team established by FPS at the request of the Sequoyah Plant Manager. The team reviewed organizational, engineering design, operational, technical, and training aspects of the Sequoyah fire protection program. Since 1989 the licensee had identified various problems at Sequoyah related to the fire protection program involving both administrative and procedural issues. Many of these problems can be found in the Sequoyah NQA Audit dated December 13, 1990. According to the FPIT Final Report many of the problems resulted from the 1989 reorganization which reduced technical personnel headcount and fragmented the program with no single point of contact and/or defined area of responsibilities. An additional factor mentioned in that report was that the fire protection organization has reported to over 13 different managers since the early 1980s. This constant change in the responsible management over this functional area contributed to the inconsistency in the program.

The inspector reviewed various documents provided by the licensee that were intended to show the extent that licensee personnel at Browns Ferry had reviewed the problems at Sequoyah to determine generic applicability to Browns Ferry. The inspector reviewed Quality Assurance Audit BFA91104 dated April 25, 1991, and Nuclear QA Assessments QBF-A-91-0368 dated May 8, 1991, and QBF-A-91-0555 dated August 19, 1991. The QA audit was performed to satisfy an annual requirement specified in TS and Generic Letter 82-21. The audit team concluded that the Browns Ferry program was acceptable and effective in meeting the identified requirements. The assessments were performed as special QA reviews of the program to determine the extent of generic applicability of problems identified at Sequoyah to Browns Ferry. The assessment teams concluded that the Browns Ferry program was being adequately implemented and that those areas which had potential generic applicability with problems identified at Sequoyah had been adequately addressed and/or implemented in the Browns Ferry program. An additional audit intended to satisfy the annual and triannual audit requirements is scheduled to be completed in the spring of 1992.

The inspector held discussions with members of the site QA and Fire Protection organizations. Based on information provided in those meetings the inspector determined that the licensee had at least considered all the problems or potential problem areas that could have had generic applicability at Browns Ferry. The basis for this determination include the following:

The Fire Protection organization and structure of the fire brigade at Browns Ferry have been different from Sequoyah. The organization at



Browns Ferry has not suffered from being fragmented as was the case at Sequoyah.

The Fire Protection program at Browns Ferry has been the responsibility of a single designated manager since the new program was adopted in 1988. This has resulted in more stability than that has existed at Sequoyah.

The assessment teams reviewed areas such as training, personnel response during drills, failure to evaluate storage areas for transient fire loading, and calculations that represented problems at Sequoyah. No similar problems were identified at Browns Ferry.

The inspector determined that the licensee's program at Browns Ferry does not appear to have experienced problems similar to those identified at Sequoyah. However further review of the licensee's program by the inspector will be needed prior to determining overall adequacy. This review will include observation on activities and inspection of the conditions in the plant during upcoming inspection periods.

#### 6. Unit 3 Restart Activities (30702)

The inspector reviewed and observed the licensee's activities involved with the Unit 3 restart. This included reviews of procedures, post-job activities, and completed field work; observation of pre-job field work, in-progress field work, and QA/QC activities; attendance at restart craft level, progress meetings, restart program meetings, and management meetings; and periodic discussions with both TVA and contractor personnel, skilled craftsmen, supervisors, managers and executives.

##### a. Restart Projects Committee

On January 2, 1992, the inspector attended a meeting of the Restart Projects Committee. This committee is a subcommittee of PORC. The membership, quorum requirements, and responsibilities are provided in SSP-12.10, PORC. The RPC is the review, approval, and coordinating body for activities limited to Units 1 and 3 restart projects. The RPC recommends to PORC and the Plant Manager in writing, approval, disapproval, or deferral of activities considered.

During the meeting, a contractor procedure for resin drying (dewatering) for equipment used in the Unit 3 decontamination process was reviewed. The procedure did not address the connection of temporary electrical power, water, and air necessary to support the operation. The RPC delayed approval of the procedure until these issues were resolved. The inspector concluded that the RPC did a thorough review of the procedure and appropriately addressed the concern for potential contamination of plant systems.

b. Chemical Decontamination

The Unit 3 fuel pool cooling heat exchangers were decontaminated during this report period. A decontamination factor of 10 was obtained decreasing the dose rate from 150 mr/hr to 15 mr/hr. Preparations were being made to decontaminate the reactor water cleanup and recirculation system until foreign material (paper) was found in a contractor connection hose. The licensee stopped the activities and conducted an incident investigation to correct the problem. The inspector concluded the licensee actions were correct and will review the incident investigation as part of the routine inspection activities.

c. Unit Separation Control

On December 18, 1991, the inspector discussed with operations management that personnel were observed in the plant with blue hard hats and personnel access badges but without required blue dot or sticker. SSP 12.50, Unit Separation for Recovery Activities, requires that personnel assigned to only Unit 3 activities to be designated by blue hard hats and uniquely identified access badges (blue stickers). A memorandum was issued on December 23, 1991 addressing this issue. It was confirmed that for the organization involved that some personnel did not have the required blue sticker. Supervisors were directed to inform all Unit 3 personnel to check their badge for the blue stickers. This issue was also discussed in the Unit 3 plan of the day meeting later.

On January 8, 1992, during a Unit 3 walkdown, the inspector observed that two of the five members of the walkdown team did not have the uniquely identified access badges with the blue stickers. All the five were wearing blue hard hats. The inspector questioned a general foreman over the walkdown team why the two did not have the proper access badges. The inspector discussed this issue with the two electricians. One of the individuals was not aware that he was required to have a badge with a blue sticker. Both individuals had a security access code to permit them entry into all vital areas of the plant site. This issue was discussed with the Unit 2 Plant Manager and other Unit 3 managers.

The inspector concluded that the requirements of SSP 12.50 were not being implemented. Previous actions by licensee management had been ineffective to resolve this issue once raised by the inspector. This issue is a concern because of the potential for a person without a blue sticker to obtain a white hard hat and enter the operating unit undetected and without proper authorization. Also, both of the individuals involved had been transferred between units or organizations on-site. These transfers were performed without adequate controls. Accordingly, this is a violation for failure to follow procedure SSP 12.50 and identified as VIO 259, 260, 296/91-43-02, Failure to Follow Unit Separation Procedures for Personnel Access.

Licensee management initiated action to correct this problem by requiring all of the personnel in the contractor organization involved to read and sign a statement indicating their understanding of the requirements for badges. Since this issue was identified by the inspector in both instances and not corrected after the first occurrence, consideration of a NCV is not warranted.

Additionally, Section 3.4.2 of SSP 12.50 discussed the issuance of a standing list of selected Unit 3 management personnel who can be granted continuous permission to enter Unit 2 operating spaces. The inspector obtained a copy of this list and asked various supervisors and managers if they were aware of the list and their status on the list. Each responded adequately.

d. Electrical Walkdowns

1.) Vertical Drop Walkdown

On January 8, 1992, the inspector observed a walkdown conducted to obtain data for the vertical drop program. The walkdown consisted of opening three junction boxes and counting the number and description of cables coming into the box. The work orders were WO-91-46929-0V, WO-91-46921-00, and WO-91-46927-00.

WO-91-46929-00 on junction box 3891 for the neutron monitoring system at drywell penetration BH, the inspector noted a blue walkdown tag already on the junction box. The tag was 03999 for work package 0175-15 on WO C065839. The inspector questioned if a worker should question if the data was already available. A licensee representative stated that for the vertical drop program that specific data was requested and some duplication may exist.

For WO-91-46927-00 for junction box 3653 on panel 25-213, the cover was previously sealed with RTV sealant but not applied when assembled. The inspector questioned this practice and it was stated that as long as a gasket was on the cover no RTV sealant was necessary. The inspector questioned what torque must be applied to seal the cover.

SWEC management reviewed this issue with the inspector in detail. The WO's specify the requirements for sealing. A snug tightness for the J-box is considered skill of the craft. Additionally, SWEC management reviewed this with all the electricians to insure the requirements were clear.

2.) Cable Conduit Raceway System Walkdown

The inspector observed and reviewed Bechtel and Unit 3 TVA maintenance personnel walkdowns of the CCRS. The specific activity observed and reviewed involved documenting the type of electrical cable installed between 480 V RMOV Board 3A,





compartment 9C, and Unit 3 Control Room Panel 3-9-4. The walkdown package was uniquely identified as 0515-44, the work activity was controlled by WO 92-47089-00, and the cable was identified as TCP-1972, PNJ-600, 7 conductor AWG 14. The walkdown team was able to verify the cable at the control room panel. The inspector concluded from the observation and review that cable verification was achieved. The inspector noted that after a total of 55 CCRS walkdown packages were completed 33 electrical cables could not be verified. These cables were scheduled to be verified by other methods. The inspector will continue to monitor the CCRS walkdowns.

### 3.) Electrical Installation Practices Walkdowns

The inspector observed and reviewed EIP walkdowns. These walkdowns were performed by Bechtel, TVA Unit 3 maintenance personnel and industry experts who were contracted for these special walkdowns. The specific activities observed were controlled by WOs 91-45978-00 and 91-45977-00 and involved the removal of junction box and conduit raceway covers in the Unit 3 Reactor Building. The experts observed the condition of the cables at these possible cable pull points and documented their observations. The items being addressed included cable damage by visual and touch method, cable tightness, and evidence of cable pulling compound. These walkdowns were scheduled to be completed on January 17, 1992. After the walkdown completion the industry experts were to write their report. The inspector noted that the EIP walkdown team discovered a cover missing from a conduit raceway. This was not unexpected due to the condition of the Unit 2 conduit raceway system prior to the restart. The Unit 3 maintenance personnel documented this condition for future corrective action.

The inspector discussed all of the walkdown activities with licensee management. It was asked why some duplication was occurring when junction boxes had to be reopened after being already identified by a blue walkdown tag. This appeared to be a departure from the integrated walkdown concept. Management stated that some duplication would occur. This was a decision to limit the number of people in the plant and minimize the time components were opened for inspection.

#### e. Contractor Activities

The inspector observed and reviewed the activities of TVA's Unit 3 contractors and TVA Unit 3 personnel. The activities included the following:

##### 1.) Prototypical/Pilot Programs

The inspector observed and reviewed SWEC activities associated with electrical cable/raceway installation. These activities



were a part of the contractor work authorization program and were reviewed by TVA project management, field services, and QA. The specific activities involved a temporary alteration, TACF 3-91-004-001, which installed additional 480 volt AC power into the Unit 3 reactor building for construction purposes. The activities were controlled by WO's 91-45509-01, 91-44565-01, and 91-45591-01. The inspector observed during field observations that the work documents were present at the work area, QC inspectors were performing required verifications and craft personnel were under continuous supervision.

During the review the inspector noted that the electrical QC inspector rejected cable terminations due to inadequate conductor insertion at the terminations. This item was corrected by the craftsmen. The inspector concluded from reviews and observations that the work activities were performed in accordance with approved procedure, work documents, and QC inspection requirements. The inspector also noted that the QC inspectors involved with the work activities generated separate QC inspection reports. This was also done during the Unit 2 recovery and the inspector considered this a strength in the QC inspection program.

Due to the rejected cable terminations the inspector was informed by licensee representatives that the Prototypical/Pilot Program was extended to the next work activities involving electrical terminations. The inspector will continue to monitor the Prototypical/Pilot Program.

- 2.) During this reporting period, the inspector was informed by licensee representatives that two contractor personnel had crossed over into the Unit 2 operating spaces without prior approval. The inspector was also informed that during the preparation of a TACF, SWEC personnel signed for NE. In both instances immediate corrective action was taken. The inspector discussed these instances with TVA management.

f. Design and Modifications Procedures

The inspector reviewed various administrative procedures used in the engineering/design process for the Unit 2 modifications and the Unit 3 restart. These procedures consisted of SSP 9.1, Nuclear Engineering, SSP 9.3, Plant Modifications and Design Control, SSP 9.4, Configuration Management/Control, SSP 9.5, Design Engineering, SSP 9.6, Engineering Information, and SSP 9.7, Engineering Work Management. At the end of this reporting period both the Unit 2 and Unit 3 engineering/design organization were in place. The inspector noted that the procedures clearly indicate the responsibilities of the Site Engineering Manager and the Restart Engineering Manager.



Both the SEM and the REM positions were filled with experienced personnel from the TVA Unit 2 restart organization.

The inspector concluded from this review that the same processes that were effective in Unit 2 restart are the same for the Unit 3 effort. The governing procedures are referred to as Site Standard Practices and the Unit 2 procedures were the SDSPs. The process by which design information is forwarded to the field was not changed by the new procedures.

#### 7. Contractor Oversight Program

Due to the recent boot incident discussed in IR 91-41, the licensee developed an integrated approach to provide effective oversight of contractor activities. This approach is called the contractor oversight program. The program consist of three phases. Three processes will be used to provide the oversight. These are contractor work release, technical assessments, and quality assurance monitoring.

The first phase of the program is the contractor work release including pilot and or prototypical program. This will verify that the contractor has adequate procedures, training and qualifications, and an organization to achieve the activity's objectives. A pilot program is performance of a sample work process prior to validating the contractor's ability to perform. A prototypical program is examination of the real work process during first time performance.

The second phase of the program is establishment of confidence in the contractors implementation of the process/program. This phase will involve establishing hold points at various stages of the early implementation of the process/program by the contractor until the desired confidence level is achieved. A key part of this phase is the technical assessment process. This is defined in RPP-9.2, Technical Assessment Program. This procedure is to assure the technical adequacy of scope, methodology, processes, and deliverables for each restart program, task, or activity.

The third phase of this program is periodic oversight of the contractor's implementation of the process/program to determine if the contractor maintains proper implementation of the process/program throughout the implementation of the work activity. Key elements of this will be quality assurance audits, monitorings, and quality control inspections.

Increased visibility has been given to these programs. They are discussed and reviewed in the plan of the day meetings. QA has increased monitoring of the implementation of these programs by using hold points.



## 8. Action on Previous Inspection Findings (92701, 92702)

(CLOSED) IFI 259, 260, 296/90-27-06, Electrical Distribution Panel and Breaker Labeling.

During a review of the ENS phone power supply it was noted that the as-built drawing did not adequately indicate the correct power supply for the ENS phone. The inspector indicated that the as-built drawing, 55N2788-2RB, was a secondary drawing and was not required to be updated prior to Unit 2 restart. The inspector also indicated that certain secondary drawings should be of a high priority for updating the other drawings.

The inspector reviewed a list of 512 essential secondary drawings, identified by plant staff, which were to be updated on a priority basis. The inspector also noted that the secondary drawing discussed in this IFI was updated.

## 9. Exit Interview (30703)

The inspection scope and findings were summarized on January 17, 1992 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, 296/91-43-01	URI, Unintentional D/G Start, paragraph three.
259, 260, 296/91-43-02	VIO, Failure to Follow Unit Separation Procedure for Personnel Access, paragraph six.

Licensee management was informed that one IFI was closed.

## 10. Acronyms and Initialisms

AC	Alternating Current
APRM	Average Power Range Monitor
CCRS	Cable Conduit Raceway System
CFR	Code of Federal Regulations
DCR	Design Change Request
DG	Diesel Generator
ENS	Emergency Notification System
FPIT	Fire Protection Improvement Team
FPS	Fire Protection Service
GAF	Gain Adjustment Factor
HPCI	High Pressure Coolant Injection
IFI	Inspector Followup Item





IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MG	Motor Generator
MR	Maintenance Request
NCV	Non-cited Violation
NE	Nuclear Engineering
NQA	Nuclear Quality Assurance
NRC	Nuclear Regulatory Commission
PORC	Plant Operations Review Committee
QA	Quality Assurance
QC	Quality Control
REM	Restart Engineering Manager
RFP	Reactor Feed Pump
RHR	Residual Heat Removal
RM	Radiation Monitor
RMOV	Reactor Motor Operated Valve
RPC	Restart Project Committee
RPP	Restart Project Procedure
SDSP	Site Directors Standard Practice
SEM	Site Engineering Manager
SI	Surveillance Instruction
SSP	Site Standard Practice
SWEC	Stone Webster Engineering Corporation
TACF	Temporary Alteration Control Form
TD	Test Deficiency
TS	Technical Specification
TVA	Tennessee Valley Authority
URI	Unresolved Item
VIO	Violation
WO	Work Order
WR	Work Request



0