UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

Report Nos.: 50-259/84-26, 50-260/84-26, and 50-296/84-26

Licensee: Tennessee Valley Authority
500A Chestnut Street
Chattanooga, TN 37401

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

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

Facility Name: Browns Ferry 1, 2, and 3

Inspection Dates: June 26 - July 27, 1984

Inspection at Browns Ferry site near Decatur, Alabama

Inspectors: Ross Butcher for — 9/28/84
G. L. Pauik, Senior Resident Inspector — Date Signed

Ross Butcher for — 9/29/84
C. A. Patterson, Resident Inspector — Date Signed

Approved by: F. Cantrell, Jr. — 9/28/84
F. S. Cantrell, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine inspection involved 252 resident inspector-hours in the areas of operational safety, maintenance observation, surveillance observation, reportable occurrences, trip reports, Technical Specification Table 3.1.A, and independent verification. An enforcement conference on the inoperable residual heat removal service water pumps was held at the Browns Ferry site on August 30, 1984. The meeting summary is detailed in IE Report 50-259/260/296/84-35.

Results: VIOLATIONS - five violations were identified:

(1) Technical Specification (T.S.) 6.3.A.1 - failure to follow procedure on Standard Practice 12.20.
(2) T.S. 4.5.C.4 - failure to perform required surveillance on residual heat removal service water control valves.
(3) T.S. 3.7.E.1 - failure to maintain control room emergency ventilation system operable.
(4) T.S. 3.5.C.6 - failure to initiate an orderly shutdown.
(5) Failure to follow tag clearance procedure 10 CFR 50 Appendix B, Criterion V.

DEVIATIONS - one deviation identified - failure to issue report on required date.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   J. A. Coffey, Site Director
   G. T. Jones, Plant Manager
   J. E. Swindell, Superintendent - Operations/Engineering
   J. R. Pittman, Superintendent - Maintenance
   J. H. Rinne, Modifications Manager
   L. W. Jones, Quality Engineering Supervisor
   D. C. Mims, Engineering Group Supervisor
   R. Hunkapillar, Operations Group Supervisor
   C. G. Wages, Mechanical Maintenance Supervisor
   T. D. Cosby, Electrical Maintenance Supervisor
   R. E. Burns, Instrument Maintenance Supervisor
   A. W. Sorrell, Health Physics Supervisor
   R. E. Jackson, Chief Public Safety
   R. Cole, QA Site Representative
   T. L. Chinn, Technical Services Manager
   T. F. Ziegler, Site Services Manager
   J. R. Clark, Chemical Unit Supervisor
   B. C. Morris, Plant Compliance Supervisor
   A. L. Burnette, Assistant Operations Group Supervisor
   R. R. Smallwood, Assistant Operations Group Supervisor
   T. W. Jordan, Assistant Operations Group Supervisor
   S. R. Maehr, Planning/Scheduling Supervisor
   G. R. Hall, Design Services Manager
   W. C. Thomison, Engineering Section Supervisor
   A. L. Clement, Radwaste Group Controller

   Other licensee employees contacted included licensed reactor operators, senior reactor operators, auxiliary operators, craftsmen, technicians, public safety officers, quality assurance, quality control and engineering personnel.

2. Exit Interview

   a. The inspection scope and findings were summarized on July 13 and August 2, 1984, with the Plant Manager and/or Assistant Plant Managers and other members of his staff. NUREG 0737, Item I.C.6 was discussed in detail to insure licensee understanding of the regional position on independent verification. The regional position provided the licensee for their review and guidance is attached to this report. Five violations and one deviation were discussed:

      (1) Violation of TS 6.3.A.1 - failure to follow procedure of Standard Practice 12.20.

(2) Violation of TS 4.5.C.4 - failure to perform required surveillance on residual heat removal service water control valves.

(3) Violation of TS 3.7.E.1 - failure to maintain control room emergency ventilation system operable.

(4) Violation of TS 3.5.C.6 - failure to initiate an orderly shutdown.

(5) Violation of 10 CFR 50, Appendix A, Criterion V - failure to follow tag clearance procedure.

(6) Deviation - failure to issue stated report on required date.

The licensee acknowledged the findings and took no exceptions.

b. Other inspector concerns and comments discussed during the exit included the below listed items:

(1) General inspection of newly installed throttle valves for the diesel generator Emergency Equipment Cooling Water (EECW) supply indicates an apparent generic problem with mechanic training as related tc packing gland retainer installation criteria. Fifty percent of the throttle valves installed had packing gland retainers incorrectly installed (IFI 259/84-26-07).

(2) PI 26-47, discharge pressure indicator for fire pump 'B' disembarked its mounting brackets on panel 25-139 (IFI 259/84-26-08).

(3) Numerous electrical conduit supports and moisture protectors for electrical connectors were noted missing for all Residual Heat Removal (RHR) heat exchanger rooms on Units 1 and 2. System return to service after maintenance activities is a continuing generic problem. Additionally, cable conduit to RHR cooler fan, S.W. corner, on Unit 2 was found falling from the overhead (IFI 259/84-26-09).

(4) Failure to verify locks installed on required locked valves was noted with several examples. This item will be further addressed in the next monthly resident report (IFI 259/84-26-10).

(5) Various caution tags missing on the demineralized water supply to the torus water level system (T.O. 76-1635) were discussed (IFI 259/84-26-11).

(6) Demineralized water system drawings do not reflect in-plant configuration as identified by the inspector. The Browns Ferry Improvement Plan has a generic item to verify designated system drawings correct. This item is generic for numerous systems that connect to various safety systems (IFI 259/84-26-12).

(7) Generic problem is apparent with reactor water cleanup system "after DEMIN" pressure gages that are routinely found pegged offscale high (IFI 259/84-26-13).

(8) The inspector questioned the Quality Assurance (QA) controls applied during maintenance of "open systems" to verify foreign material is exempted. Case in point was the discovery during a routine tour of the Standby Liquid Control (SBLC) pump for Unit 2 under maintenance with the system fully opened in all respects and no person or work boundary was noted at the work site to prevent any foreign intrusion. Paragraph 5 discusses a padlock which fell in the SBLC supply tank which would indicate that foreign material intrusion is a real possibility (IFI 259/84-26-14).

(9) Other personnel and plant safety items discussed included the importance of personnel not resting in the cable spreading or instrument rooms during plant operations if not performing necessary activities (IFI 259/84-26-15).

(10) There is an apparent drain problem with drains from the operator's lunch room, via the plant emergency battery rooms such that water backs up in the floor drains and sink in the battery rooms (IFI 259/84-26-16).

(11) The Containment Atmosphere Dilution (CAD) system drawing 10B335 reflects that the CAD tank foundation bolts and nuts will be galvanized and zinc chromated. Observation of the nuts and bolts does not indicate this since all bolts and nuts are rusted (IFI 259/84-26-18).

(12) The Unit 1 scram report number 173 dated June 2, 1984, did not indicate that any relief valves had lifted on the cover evaluation sheet. Four valves actually lifted (IFI 259/84-26-19).

3. Licensee Action on Previous Enforcement Matters (92702)

This area was not inspected this report period.

4. Unresolved Items* (92701)

Unresolved items were not identified during this inspection.

5. Operational Safety (71707, 71710)

The inspectors kept informed on a daily basis of the overall plant status and any significant safety matters related to plant operations. Daily discussions were held each morning with plant management and various members of the plant operating staff.

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*An Unresolved Item is a matter about which more information is required to determine whether it is acceptable or may involve a violation or deviation.

The inspectors made frequent visits to the control rooms such that each was visited at least daily when an inspector was on site. Observations included instrument readings, setpoints and recordings; status of operating systems; status and alignments of emergency standby systems; onsite and offsite emergency power sources available for automatic operation; purpose of temporary tags on equipment controls and switches; annunciator alarm status; adherence to procedures; adherence to limiting conditions for operations; nuclear instruments operable; 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 their supervisors.

General plant tours were conducted on at least a weekly basis. Portions of the turbine building, each reactor building and outside areas were visited. Observations included valve positions and system alignment; snubber and hanger conditions; containment isolation alignments; instrument readings; housekeeping; proper power supply and breaker alignments; radiation area controls; tag controls on equipment; work activities in progress; radiation protection controls adequate; vital area controls; personnel badging, personnel search and escort; and vehicle search and escort. Informal discussions were held with selected plant personnel in their functional areas during these tours. Weekly verifications of systems status which included major flow path valve alignment, instrument alignment, and switch position alignments were performed on the RHRSW and SBLC systems.

A complete walkdown of the accessible portions of the SBLC system was conducted to verify system operability. Typical of the items checked during the walkdown were: lineup procedures match plant drawings and the as-built configuration, hangers and supports operable, housekeeping adequate, electrical panel interior conditions, calibration dates appropriate, system instrumentation on-line, valve position alignment correct, valve locked as appropriate and system indicators functioning properly.

During a routine inspection tour of Unit 2 on July 9, 1984, the resident observed that the hold order tag for HCV 2-2-1260 (demineralized water to the torus level indicating system) was incorrectly placed on an adjacent drain valve. The adjacent valve was not indicated on the TVA system drawing (47W856-2). The hold tag had been hung on April 18, 1984 and second-person verified at that time. The tag was recorded on hold order 84-412.

The Plant Manager was informed of the incorrect hold order placement on July 9, 1984, and informed that this item was a violation of clearance procedures (Standard Practice 14.25) at the exit on July 13, 1984. (260/84-26-01)

Also, the Plant Manager was informed that the demineralized water systems drawings are not consistent with as-designed configuration. A similar concern was brought to the licensee's attention on the control air system in I.E. Report 84-15.

Unit 1 reactor was shutdown on June 20, 1984, because unidentified drywell leakage exceeded the TS limit of 5 gallons per minute. A drywell entry was made and the leakage source was determined to be from the upper seal of the 'B' recirculation pump. The seal was replaced and a startup conducted on June 27, 1984.

During the heatup on June 27, 1984, at 350 to 400 psig, a safety relief valve (PCV-1-4) opened at 5:57 a.m. and would not close after several attempts with the handswitch. At 6:08 a.m., the reactor was manually scrammed. Reactor pressure continued to decrease to 100 psig at which time the valve reseated itself. The cooldown rate exceeded 100°F per hour and was determined to be 108°F in less than one hour. The relief valve has been removed and sent to Wyle Laboratories for testing and disassembly to determine the failure mechanism. This is the second instance of a two-stage Target Rock Relief Valve failing to close at Browns Ferry. On February 5, 1983, safety relief valve (1-1-22) failed to close (LER 259/83-06). The cause of the previous failure was the pilot inlet tube mounting bracket had broken permitting the inlet tube to get under the seat of the valve. The formal report covering the recent failure is expected by September 1, 1984.

Unit 2 operated at 50 to 70 percent power during this period to conserve fuel burnout. Unit 3 remained in a refueling outage.

The inspector was told on June 28, 1984, by the licensee that the valve vendor had informed them that a contributing factor to the inability to achieve shutdown cooling on February 14, 1984, (alert declared) was that the torque switch setting on the shutdown cooling suction valve was improperly set. The torque switch which stops the closing of the valve was set two and one-half times too high. This may have resulted in the motor burn-out for the valve. Details are in LER 259/840012.

On July 15, 1984, while viewing the level in the standby liquid control tank, a brass padlock used to lock the inspection cover was dropped in the tank. A safety evaluation was performed and no adverse condition found since the pump suction line penetration is off the side of the tank and a 1/8 inch screen is over the inlet of the suction line.

On June 22, 1984, the main phone cables were severed outside the protected area as a trench was being dug in preparation for new building construction. The inspector observed at 2:00 p.m. that all phones in his office were dead including the ENS system (red phone). A check of the red phone in the control rooms revealed they were dead also. Communications to the NRC Headquarters were made through other available communication equipment. All lines were restored at 4:48 p.m. the same day.

On July 20, 1984, at 9:45 p.m., four RHRSW pumps (B1, B2, C1, D1) were declared inoperable because they failed to meet the flow and head specified to be considered operable. Unit 1 was operating at 100% power and Unit 2 at 55% power. The 'A' diesel generator was also inoperable at this time making the redundant RHRSW pumps A1 and A2 inoperable. Technical Specification Table 3.5-1 requires a minimum of four operable RHRSW assigned to RHRSW service for the plant to be in a seven day limiting condition for operation. If this condition is not met then TS 3.5.C.6 applies and an orderly shutdown is required, and the unit is to be in cold shutdown within 24 hours. Of the six available pumps A3, B3, C3, C2, D3 and D2, only two of these pumps could have been assigned to RHRSW service. The plant was in a 24 hour LCO condition and an orderly shutdown was required. An orderly shutdown was not initiated and steady state power operation continued. Three pumps B1, B2, and C1 were declared operable at 10:40 a.m., on July 21, 1984. This is a violation of TS 3.5.C.6. The plant manager was informed of this violation in an exit meeting on August 2, 1984 (259, 260/84-26-02).

Some confusion existed about which LCO was in effect with the inoperable 'A' diesel generator and RHRSW pumps. The plant licensee reportable event determination form (BF-19) stated the units were in a seven day LCO. This form is prepared by the shift technical adviser and reviewed by the shift engineer. The inspector reviewed Browns Ferry Standard Practice 12.20, Actions Required by TS Definition 1.C.2-LCO, and found this plant instruction specifically addresses operability of any equipment with either its offsite or onsite (diesel) power source unavailable. This procedure was written to clarify operability of equipment and contains a checklist, Form BF-126, for the shift engineer to use to clarify equipment operability. Form BF-126 is designed to use with an inoperable diesel, but must be checked in the reverse direction if any other safety equipment listed on the form is inoperable. This form was not checked in the reverse direction when the RHRSW pumps were declared inoperable at 9:45 p.m., on July 20, 1984. The review of BF-126 by the operations supervisor failed to identify this error also. This is a violation for failure to follow procedures as required in TS 6.3.A.1 (259, 260, 296/84-26-03).

The second example of this violation came from a review of plant records of Form BF-126. The following is a list of times the form was not filled out when a diesel generator was declared inoperable. This list is not all inclusive and is just a brief review by the inspector:

Diesel Generator	Date	
B	1815	6/16/84
D	0550	6/18/84
3EA	0115	6/08/84
B	2340	5/30/84
C	0820	5/28/84

A form dated November 2, 1983, for the 'C' diesel was not signed by the shift engineer and operations supervisor.

The assistant plant manager was notified of this violation in an exit meeting on August 2, 1984.

TS 4.5.C.4 requires the immediate testing of equipment when it is determined that one of the RHRSW pumps supplying standby coolant is inoperable. The RHRSW pumps D1 or D2 supply Unit 1 and B1, B2, D1, or D2 supply Unit 2. When B1, B2, and D1 were declared inoperable on July 20, 1984, plant Surveillance Instruction (S.I.) 4.5.C should have been carried out to comply with TS 4.5.C.4 for Units 1 and 2. The unit cross-connect valve 23-57 was never tested as specially addressed in S.I. 4.5.C. The Assistant Plant Manager was informed in an exit meeting on August 2, 1984, this was a violation for failure to comply with TS 4.5.C.4. (259, 260/84-26-04).

On July 25, 1984, at 12:35 p.m., the inspector found the 'B' Control Room Emergency Ventilation (CREV) pressurization suction automatic damper linkage disconnected making the 'B' train inoperable. The 'A' diesel generator was already inoperable at this time and not returned to service until 3:00 p.m., on July 25, 1984. In this configuration, the plant had no operable train of the CREV systems because the 'A' diesel generator supplied the redundant 'A' train. The 'B' system was last known to be operable during surveillance testing on July 2, 1984. During this testing, the damper linkage was connected and disconnected per test instructions. No independent verification of reconnecting the damper linkage nor operability of the system was performed after the surveillance testing. Discussions with plant personnel showed no operation of the system had occurred since July 2, 1984. Technical Specification 3.7.E.1 requires that both CREV pressurization systems and the diesel generator required for their operation shall be operable at all times when any reactor vessel contains irradiated fuel. The Assistant Plant Manager was informed of this violation in an exit meeting on August 2, 1984 (259, 260/84-26-05).

6. Maintenance Observation (62703)

Plant maintenance activities of selected safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review: the limiting conditions for operations were met; activities were accomplished using approved procedures; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; proper tagout clearance procedures were adhered to; TS adherence; and radiological controls were implemented as required.

Maintenance requests were reviewed to determine 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 below listed maintenance activities during this report period:

a. MMI 122 High pressure fire protection systems flush

b. '1DN' Low pressure coolant injection motor-generator set - installation

c. Installation of diesel generator EECW throttle valves in piping system

d. Post modification test of EECW throttle valve PMT-WP 10452 R-1.

There were no violations or deviations in this area.

7. Surveillance Testing Observation (61726)

The inspectors observed and/or reviewed the below listed surveillance procedures. The inspection consisted of a review of the procedure for technical adequacy, conformance to TS, verification of test instrument calibration, observation on the conduct of the test, removal from service and return to service of the system, a review of test data, limiting condition for operation met, testing accomplished by qualified personnel, and that the surveillance was completed at the required frequency.

a.	PMT 118	Diesel generator test to parallel Unit 1/2 and 3 diesels.
b.	S.I. 4.2.B-27	Suppression chamber high level
c.	S.I. 4.8.B.4-3	Reactor building vent monitoring systems
d.	S.I. 2	Operator daily logs

During the observation of S.I. 4.2.B-27 on Unit 1, the inspector observed the torus level indicators LI 64-54A and 66 differed by 3 inches. Inspection revealed that this difference was due to the differential reference leg height for the instrument lines. The plant had identified the problem and was taking action to affect a redesign of the system. The differential reference leg height was due to the recent installation of a flexible sensing line during torus modification design work. The licensee was tracking the corrective action on MR A267436, MR 265463, and MR 263867.

8. Reportable Occurrences (90712, 92700)

The below listed licensee event reports (LERs) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of event description, verification of compliance with TS and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event. Additional in-plant reviews and discussion with plant personnel, as appropriate, were conducted for those reports indicated by an asterisk. The following licensee event reports are closed:

LER No.	Date	Event
*259/82-13	Feb. 2, 1982	Degraded voltage relay drift.
*259/82-64R1	Aug. 23, 1982	Unit 1, cable tray fixed spray system inadequate.

(cont'd)

LER No.	Date	Event
*259/83-16R2	March 9, 1983	CREV charcoal sample efficiency less than required.
*259/83-64R1	Aug. 23, 1982	Unit 1, Station II, cable tray fixed spray system inoperable.
*259/83-68R1/R2	Dec. 10, 1983	RHR pump motor failure
*259/84-20	May 5, 1984	Diesel generator parallel mode problems
*259/84-21	May 5, 1984	ADS/HPCI cable separation problems.

During the closeout review of LER 259/83-68, the inspector found that a required followup report had not been issued as committed to. The report was due July 16, 1984, but due to administrative tracking inadequacies it was not issued until July 24, 1984. The Assistant Plant Manager was informed of this deviation at the exit on August 2, 1984 (259/84-26-06).

The inspector reviewed LER 296/84-07 dated July 13, 1984, entitled "Diesel Generator 3B Started Inadvertently During Special Testing" and took exception to the statement that the diesel automatic starts have no safety significance. Two inadvertent starts of the diesel generator occurred. The cause of the second start is unclear. The licensee was informed that any inadvertent start of safety equipment is considered safety significant, especially, when the cause of the start is unclear. A followup report is due September 1, 1984.

9. Reactor Trips

The inspectors reviewed activities associated with the below listed reactor trips during this report period. The review included determination of cause, safety significance, performance of personnel and systems, and corrective action. The inspectors examined instrument recordings, computer printouts, operations journal entries, scram reports and had discussions with operations, maintenance and engineering support personnel as appropriate.

Unit 1 scrammed from 100% power at 5:39 p.m., on June 2, 1984, following a generator load rejection. The turbine tripped due to operation of the generator field ground relay. Four relief valves opened automatically to limit reactor pressure to 1115 psig. The recirculation pumps tripped on turbine control valve fast closure as required. FR-1-81/PR-3-59 (narrow range pressure) failed to track recorder pressure and TR-1-1 (safety relief valve tailpipe temperature) failed to print at the time of the scram. The electrical system sequential events recorder and the first-out sequential events recorder printer in the control room were not operating at the time of the scram.

Stated in the plant's evaluation was the fact that all four safety relief valves (two 1105 and two 1115 psig setpoints) came off the 'B' main steam line, and this pattern was observed last cycle (which contributed to PCV-1-22 sticking open on February 2, 1983). Also stated was that this may indicate a higher pressure wave in 'B' main steam line and a greater chance of challenging those valves and of them sticking open. This is being left as an open item pending further evaluation (IFI 259/84-26-17).

A material buildup on the excitation rectifiers contributed to the generator field ground relay activation. The details of this are explained in LER 259/84-24.

On June 20, 1984, at 12:50 a.m., Unit 1 was manually scrammed from 58.6% power. Unidentified drywell leakage exceeded TS 3.6.C.1 limit of five gallons per minute and a shutdown was initiated when leakage was 5.125 gpm. On drywell entry and inspection, the leak was determined to be from the '1B' recirculation pump seals. All safety equipment performed satisfactorily.

During a plant heatup on June 27, 1984 at 6:08 a.m., the reactor was scrammed from less than 1% power due to a safety relief valve sticking open. At 350-400 psig, the 1-PCV-1-4 opened and would not reset. The valves opened at 5:57 a.m. and the unit was scrammed at 6:08 a.m. Pressure decreased until 100 psig and the valve reseated itself. The cooldown rate was exceeded and determined to be 108°F in less than one hour. The safety relief valve was replaced with one from Unit 3. The failed valve was sent to Wyle Laboratories for testing and disassembly. All other safety equipment responded as expected.

10. Technical Specification Guidance

The following guidance for TS Table 3.1.A was received from Nuclear Reactor Regulation. The table specifies that in the event the minimum number of operable APRM channels per trip system cannot be met for both trip systems, the operator shall take the following appropriate action:

a. Initiate insertion of operable rods and complete insertion of all operable rods within four hours. In refueling mode, suspend all operations involving core alternations and fully insert all operable control rods within one hour.

or

b. Reduce power level to IRM range and place mode switch in the Startup/Hot Standby position within eight hours.

The operator is faced with a choice of two different action statements. This choice can be explained by the fact that certain portions of APRM channels serve multiple trip functions (e.g., averaging amplifiers), whereas other portions serve only one trip function (e.g., flow biasing circuits). To provide protection for analyzed events only certain trip functions need be available in certain reactor modes. The appropriate action statement is the one which will take the reactor to a safe condition. For example, if the LCO cannot be met because of flow biasing circuit failures then note 'b' would be the appropriate action, since the flow-biased trip function is not required in the IRM range. If the LCO cannot be met because of averaging amplifier failure then note 'a' would be the appropriate action, because the 15% power APRM trip, which is required in the IRM/Startup mode, would be inoperable.

11. Regulatory Performance Improvement Program

As part of Region II review of the Regulatory Performance Improvement Program (RPIP), the responsible section chief reviewed minutes of the RPIP Oversite Group Meetings on May 21, 1984 (84-08); June 4, 1984 (84-09) and June 18, 1984 (84-10), during a site visit July 11-12, 1984. A report of a special assistance visit by Institute of Nuclear Power Operations dated April 12, 1984, to review plant operations in slected areas and to provide technical support; a report dated May 18, 1984, by IMPELL Corp. of their evaluation of the modification process, and a report dated June 8, 1984, by Management Analysis Corp. of their assessment of the Browns Ferry RPIP and related administrative burden were also reviewed. Discussions with plant personnel and review of RPIP revisions confirmed that appropriate comments by TVA consultants had been evaluated and incorporated in the RPIP for action and tracking purposes. Training sessions to implement the requirements of RPIP Item II-3.4, Define the method and limitation imposed for temporary procedures changes, and RPIP Item I-3.8.3, Regulatory Compliance, were audited.

ATTACHMENT

NRC REGION II POSITION ON INDEPENDENT VERIFICATION

Item I.C.6 of NUREG-0737, the Clarification of TMI Action Plan Requirements, presented guidance to the licensees on procedures for verifying correct performance of operating activities. All operating reactors were required to respond and commit to item 1.C.6. The NRC issued confirmatory orders to most plants which adds regulatory emphasis to this requirement. Licensees have responded in varying degrees and with diverse methods to this requirement. The purpose of this discussion is to outline an acceptable method of performing independent verification.

Item I.C.6 states the following:

(1) In lieu of any designated senior reactor operator (SRO), the authority to release systems and equipment for maintenance or surveillance testing or return-to-service may be delegated to an on-shift SRO, provided provisions are made to ensure that the shift supervisor is fully informed of system status.

(2) Except in cases of significant radiation exposure, a second qualified person should verify correct implementation of equipment control measures such as tagging of equipment.

(3) Equipment control procedures should include instructions that control-room operators are to be informed of changes in equipment status and the effects of such changes.

(4) For the return-to-service of equipment important to safety, a second qualified operator should verify proper systems alignment unless functional testing can be performed without compromising plant safety, and can prove that all equipment, valves, and switches involved in the activity are correctly aligned.

Note: A licensed operator possessing knowledge of the systems involved and the relationship of the systems to plant safety would be a "qualified" person.

The requirement applies not only to valves but to breakers, switches, blank flanges, pipe plugs or any component that would, if mispositioned, degrade a safety function or present a safety concern.

Item (4) states that when returning to service equipment that is important to safety and independent verification should be performed, unless it is possible to functionally test the equipment. It is generally preferable to perform a functional test to demonstrate operability, but his is not always possible.

Functional tests used in lieu of independent verification must be examined to assure they are valid. For example, performing a normal surveillance by running a pump on recirc does not suffice to verify correct alignment of all valves in the system.

Independent verification must be independent, i.e., two appropriately qualified individuals, operating independently will verify that equipment has been properly returned to service. Both verifications are to be implemented by procedure and action documented by the initials or signature of the two individuals performing the alignment and verification.

In certain instances, it may be possible to accomplish one verification from observing control room instruments, annunciators, valve position indicators, etc. This is acceptable as long as the control room indication is a positive one and is directly observed and documented, and provides a reliable indication. For example, if an individual is sent out from the control room into the plant to open a manual valve, it is an acceptable independent verification for another control room operator to observe that a control room instrument begins to register flow in the line as a result of the valve being opened, or a control board indication of valve position shifts from closed to open, or an annunciator indicating that the valve is closed, clears and can be reset. The operator must, of course, subsequently document his part of the independent verification.

Questions have arisen as to what areas require independent verification. Item (2) states that all tagging operations will be verified. Particular care must be taken to independently verify the removal of tags to restore equipment to service, but the placing of tags to remove equipment from service must also be independently verified. There have been occurrences at operating reactors in which an "A train" component was declared inoperable and an individual was sent to tag out the equipment, mistakenly operated and tagged the wrong valves and made the redundant "B train" component inoperable, resulting in a complete loss of the safety function in question.

Removal from service for preventive maintenance and repairs is normally accomplished by operations personnel using equipment control tagging procedures. Routine surveillance does not normally employ tagging. Therefore, there needs to be independent verification and associated documentation applied to the removal of equipment from, and the restoration of equipment to, service for surveillance.

Clearly, all components which provide a safety function should be independently verified when a alignment changes have been made in a mode where the system is required. Similarly, the alignments of safety systems and individual components relating to safety made in preparation for entering a mode in which the systems or components are required, must be independently verified.

Following a plant outage where maintenance is performed, all safety system lineups should be performed using independent verification prior to entering the mode where that equipment is required to be operable.

It is often hard to determine which items require independent verification. Item (4) above specifies that "equipment important to safety" require independent verification. Nuclear Regulatory Commission memorandum of November 20, 1981, from Mr. Harold R. Denton, Director of NRR, to all NRC personnel defines the following terms:

"Important to Safety" is defined in 10 CFR 50, Appendix A (General Design Criteria) in the first paragraph of "Introduction".

"Those structures, systems, and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public" are "Important to Safety".

This encompasses the broad class of plant features, covered (not necessarily explicitly) in the General Design Criteria, that contributes in an important way to safe operation and protection of the public in all phases and aspects of facility operation (i.e., normal operation and transient control as well as accident mitigation).

"Important to Safety" includes Safety-Grade (or Safety-Related) as a subset.

"Safety-Related" is defined in 10 CFR 100, Appendix A (see Sections III.(c), VI.a.(1), and VI.b.(3)) as those structure, systems, or components designed to remain functional for the SSE (also termed' safety features') necessary to assure required safety functions, i.e.:

(i) the integrity of the reactor coolant pressure boundary;

(ii) the capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) the capability to prevent or mitigate the consequences of accidents which could result in potential off-site exposures comparable to the guideline exposures of this part.

"Safety-Related" is a subset of "Important and Safety". The definitions are helpful but not always definitive. The following guidance will be useful.

Emergency systems that are required to prevent or mitigate a LOCA are "Safety-Related" and "Important to Safety." In general, equipment required to be operable by the TS is "Important to Safety." Equipment that the licensee has committed by letter, to the NRC to install, such as TMI Action Item equipment, is "Important to Safety."

There will be a number of exceptions to these guidelines which, in the judgment of the licensee and the NRC, independent verification will not be required. Examples are peripheral support equipment that are often mentioned in the more recent TS but do not meet the definition or intent of "Important to Safety."

The use of double verification should not be limited to safety system and mode requirements. If any situation where the consequences of misalignment are extremely severe, a second verification is prudent. There are many situations, particularly in plant effluent system or liquid waste handling, where a second check should be provided.

It is constructive to review recent experiences in the industry that were not fully successful in performing verification. One BWR licensee found that, although major valve lineups were required to be independently verified, some routine plant evaluations were not. Following use of an RHR heat exchanger, it was the procedural practice to flush the secondary side with well water to remove brackish water for corrosion control. This operation involved disabling the service water pump, an item required to be operable by TS. Although the flushing operation was covered by a normal operating procedure, it was not made subject to independent verification and no signoffs were required for individual steps. This resulted in an operator forgetting to properly restore the service water pump to service, causing a TS violation.

A PWR licensee implemented independent verification for tagging operations but left it ambiguous as to the need for Item (4) above, during temporary lifts of tags for testing and restoration. Item (4) was not used on a restoration of tags after a temporary lift for hydrostatic testing. The person performing the valve manipulation apparently closed the wrong valves and no one verified the work. This resulted in the total absence of auxiliary feedwater capability for five days while the reactor was operating at full power.

A PWR licensee did not apply Item (4) to the restoration of pressure sensing instruments after calibration by instrument technicians. This resulted in a small pipe cap being left off after the calibration of an instrument sensing containment pressure. The reactor was operated at full power with an open pathway from the containment atmosphere to the environment.

Multiple examples have been observed where licensees applied Item (4) to valve lineups following major outages with the valve lineups only checking the large major valves in the flow paths and did not check instrument root valves, sensor isolation, equalization valves, or branch flow paths. This has resulted in individual components and whole safety systems being found valved out and inoperable in violation of TS after the reactor has restarted.

Following restart after a refueling outage, a licensee discovered several TS related components inoperable because electrical instrument supply links were left open. The links were apparently opened during the outage by instrumentation personnel to facilitate instrument maintenance. Item (4) was performed on their restoration prior to restart and numerous instruments were found to be inoperable.

It is important that all plant supervisors and operators have the proper attitude toward independent verification and recognize its value to enhanced safety of operation. Licensees often express the concern that independent verification is too time consuming and shows a lack of confidence in operators. This is an understandable sentiment but is shortsighted. Independent verification is simply a recognition that even the best operators will make an occasional error. Where the risks and consequences of such an error are extreme, it is not only common sense to make a second check, it is required by the Nuclear Regulatory Commission.

This is one of the most important and potentially beneficial requirements resulting from the TMI Action Plan. A large number of escalated enforcement actions since TMI involve events that could have been prevented had the licensee adequately applied independent verification. The NRC will meticulously enforce this requirement.