APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/91-35 50-499/91-35

Operating Licenses: NPF-76 NPF-80

Dockets: 50-498
50-499

Licensee: Houston Lighting & Power Company
P.O. Box 1700
Houston, Texas 77251

Facility Name: South Texas Project Electric Generating Station (STP), Units 1 and 2

Inspection At: STP, Matagorda County, Texas

Inspection Conducted: December 26, 1991, through January 3, 1992

Inspectors: J. I. Tapia, Senior Resident Inspector

Approved: A. T. Howell 1-27-92
A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted December 26, 1991, through January 3, 1992 (Report 50-498/91-35; 50-499/91-35)

Areas Inspected: Special, announced inspection of onsite followup of a reactor trip and an engineered safety features actuation.

Results: During this inspection, a violation of 10 CFR Part 50, Appendix B, Criterion XII, was identified (Section 2.b). The violation involved a failure to assure conformance between the procurement documents (design drawings) and the as-built condition of the pressurizer spray valves. This nonconforming condition was directly related to the December 24, 1991, Unit 2 reactor trip and engineered safety features actuation. A weakness in the implementation of prior service requests for these valves existed because the discrepant condition was never identified. This weakness is attributable to the use of references to vendor manuals in work instructions rather than providing specific work instructions or details. The adequacy of maintenance procedures and work instructions will be reviewed during future inspections and be tracked by an inspection followup item (IFI) (section 2.b). The response of the plant to actions taken in accordance with the off-normal procedure was not entirely as expected. It was expected that when the reactor coolant pumps (RCPs) in the affected spray loops were secured, pressurizer spray flow and depressurization would stop. The licensee is investigating the plant hydraulic design to verify that this response was attributable to the larger core and larger RCP motors at STP. The resolution of this will also be tracked by an IFI (section 2.b).

DETAILS

1. PERSONS CONTACTED

*C. R. Albury, Principal Engineer
*C. A. Ayala, Supervising Engineer, Nuclear Licensing
*L. R. Casella, Manager, I&C Design Engineering
*M. K. Chakravorty, Executive Director, NSRB
*R. W. Chewning, Vice-President, Nuclear Support
*G. S. Chitwood, Senior Reactor Operator, Training
*D. W. Clark, Supervisor, I&C Design Engineering
*F. J. Comeaux, Consulting Engineer, ISEG
*R. A. Dally, Engineering Specialist, Licensing
*D. J. Denver, Manager, Nuclear Engineering
*R. P. Garris, Manager, Nuclear Purchasing
R. S. Graham, Shift Supervisor
*D. P. Hall, Group Vice President, Nuclear
*R. R. Hernandez, Manager, Design Engineering
*T. J. Jordan, General Manager, Nuclear Assurance
*W. J. Jump, Manager, Nuclear Licensing
*W. H. Kinsey, Vice President, Nuclear Generation
*D. A. Leazar, Manager, Plant Engineering Department
*J. R. Lovell, Manager, Technical Services
*B. L. McLaughlin, Operations Engineer, Central Power & Light Company
*R. P. Murphy, Manager, Plant Analysis
*D. W. McCallum, Manager, Unit 1 Operations
*S. L. Rosen, Vice-President, Nuclear Engineering
D. P. Sanchez, Director, Maintenance
*J. D. Sharpe, Manager, Maintenance
*D. D. Tran, Electrical Engineer
*T. E. Underwood, Director, ISEG
*L. G. Weldon, Manager, Operations Training
*M. R. Wisenburg, Plant Manager

The inspector also interviewed other licensee employees during the inspection.

*Denotes those individuals attending the exit interview conducted on January 3, 1992.

2. Reactor Trip and Engineered Safety Features Actuation (93702, 71707)

2.a Details of Event

On December 24, 1991, Unit 2 had completed testing at the 75 percent power plateau and had reduced power to 15 percent to adjust the controls of the main feedwater regulating valves. Following repair of the main feedwater regulating valves, Unit 2 began increasing power at 3 percent per hour when, at 4:48 p.m., a reactor trip and a safety injection (SI) actuation signal from 30 percent rated thermal power occurred because of low pressurizer pressure.

The transient began 4 minutes earlier when the screw connecting the Bailey controller feedback arm linkage to the valve actuator shaft on pressure control valve (PCV) 655C loosened to the point that the feedback arm linkage became disconnected. With the feedback arm disconnected, the range spring relaxed, causing the available instrument air to be ported to the valve actuator and forcing the valve to the full open position. As the valve opened, increasing spray flow caused pressurizer pressure to decrease. As the pressure decreased, pressurizer Backup Heaters 2A and 2B automatically energized and the control room received a pressurizer pressure deviation "LOW/BACKUP HEATERS ON" annunciator. The operating crew properly diagnosed the depressurization event as a loss of pressure control and entered Off-Normal Procedure 0POP04-RP-0001, Revision 1, "Loss of Automatic Pressurizer Pressure Control." Operators verified that there were no failed instrument channels and that all pressurizer heaters were in service. Operators found that both pressurizer spray indicating lights indicated that both of the spray valves were not closed. The primary operator placed the controllers in manual and forced the controller demand to zero. The secondary operator reduced the turbine power in an effort to increase temperature and pressure in the reactor coolant system (RCS) and slow the depressurization event.

The Unit Supervisor and Shift Supervisor reviewed the off-normal procedure and discussed the steps to "trip the RCP in the loop with the failed open spray valve," in order to stop pressurizer spray flow. Both spray valves indicated open, but two RCPs could not be tripped at 30 percent power without generating an automatic reactor trip (one RCP can be tripped below 40 percent without generating an automatic reactor trip). A decision was made to reduce power rapidly to below 10 percent power and then trip RCPs 2A and 2D.

The secondary operator reduced turbine power and the primary operator monitored pressure and manually drove control rods into the core (from Control Bank D at 170 to 110 steps). Before reaching 10 percent, a low pressure (1870 psig) automatic reactor trip, SI actuation signal (1869 psid), and Phase A containment isolation occurred at 4:48 p.m. Reactor power was at 16 percent at the time of the trip. Both RCPs 2A and 2D were manually stopped and placed in the pull-to-lock position. The operating crew entered the applicable emergency operating procedures and stabilized the plant.

The depressurization of the RCS ended when the Phase A containment isolation blocked all instrument air to the spray valves, forcing the valves into the failed closed position. The core was at the beginning of life with low levels of decay heat and a low moderator temperature coefficient.

When the SI and Phase A isolations were reset in accordance with the emergency operating procedures, instrument air was resupplied to the containment and Spray Valve PCV 655C failed open again, initiating a second depressurization event. A third RCP was then secured (2B), thereby terminating the pressure transient. The initiation of the emergency core cooling systems did not actually inject cooling water into the RCS because the minimum pressure experienced was 1725 psig and the shutoff head of the high head SI pumps is 1680 psid.

2.b Detailed Inspection Findings

As a result of this event, the adequacy of the off-normal procedure was questioned by the licensee. The operators expected that when the RCPs in the affected spray loops were secured, the spray flow and depressurization would stop. This expectation was predicated on training and reinforced in the simulator. The licensee commenced discussions with Westinghouse to address the plant hydraulic response to a stuck open spray valve. Preliminary information suggests that the impact of the 14-foot core and 8000-horsepower RCP motors on a stuck open pressurizer spray valve was not adequately predicted. Typical Westinghouse plants with 12-foot cores and 6000-horsepower RCP motors lose pressurizer spray flow when the RCPs are secured in the loops that have spray lines. The larger core and RCP motors at STP require that three RCPs be secured before pressurized spray flow is lost. The licensee is continuing to investigate this issue. The resolution of this issue is considered an IFI (498; 499/9135-01).

Maintenance inspected the spray valves and videotaped their initial findings. The Loop A spray valve, PCV 655C, had the feedback arm linkage disconnected from the valve stem connecting plate. The connecting screw was still in the linkage and the valve was observed to be approximately 25 percent open. The Loop D spray valve, PCV 655B, was in the closed position but the limit switch was just above threshold of actuation, causing a false indication that the valve was not closed.

The configuration of the feedback arm linkage to the valve stem connecting plate did not conform with the Bailey vendor manual drawings. The licensee verified that the installed configuration has never been modified. It therefore appears to have been received in this configuration from the vendor. The design which was supplied and installed by the vendor utilizes a 1/8-inch plate with a threaded hole to which the feedback arm is attached with a 0.19-inch diameter pan head screw having 32 threads per inch. The vendor manual drawing depicted a different type of feedback arm which had subcomponents that were attached by a locknut. The licensee is attempting to obtain the correct design drawings from the vendor. The nonconformance of the as-built drawings provided by the vendor is considered a violation of 10 CFR Part 50, Appendix B, Criterion VII (498; 499/9135-02).

The last work package relevant to the spray valve feedback linkage prior to this event was implemented in early December 1991. The Configuration Change Log (OPGP03-AM00[illegible]) indicated that the linkage was removed and verified to be removed. Upon completion of the valve work, the linkage was reconnected and verified to be reconnected. There have been additional instances in the past where the linkage was removed and reconnected. In none of those instances was the discrepancy between the as-built condition and the referenced vendor manual drawings noted. This is a weakness in the implementation of service requests that can be attributed to the use of references to vendor manuals rather than specific work instructions. The adequacy of work instructions will be reviewed during future inspections and will be tracked as an IFI (498; 499/9135-03).

The last work package also checked the correct limit switch settings of the spray valves. Operations personnel cycled the valves three times to verify that the limit switch settings were giving the correct valve position indication. However, these checks were performed with the system cold. Subsequent to the transient, it was determined that pressurizer Spray Valve PCV 655B indicated open while the valve was actually closed. The licensee plans to evaluate the spray valve limit switch adjustment calibration procedure and evaluate the adequacy of the limit switch design application.

Subsequent to the transient, maintenance reattached the feedback arm linkage on PCV 655C and added a locking nut to prevent a repeat event. Maintenance adjusted the limit switch on PCV 655B and added a locking nut to the feedback arm linkage. Both spray valve controllers were then calibrated, found to be in calibration, and left as found. Operations then stroked both spray valves and observed that both spray valves stroked fully and smoothly.

Operations inspected Unit 1 on December 30, 1991, and found both spray valves to have a similar feedback arm linkage arrangement. On December 31, 1991, maintenance replaced the screw on each Unit 1 spray valve linkage arrangement with a longer screw and a locking nut.

2.c Industry Experience

The inspector was made aware of a similar spray valve transient which occurred at Diablo Canyon (see LER 50-275/90-017). On December 24, 1990, at 3:18 a.m. (PST), with Unit 1 in Mode 1 at 88 percent power, a reactor trip and SI occurred because of low pressurizer pressure. The cause of the trip was a pressurizer spray valve that failed open because its feedback linkage became disconnected. The feedback linkage became disconnected because a locking device was not installed on the screw holding the linkage to the valve stem. The installed configuration of the pressurizer spray valve feedback arms at Comanche Peak Steam Electric Station was also found to be similar to the STP pressurizer spray valve feedback arms.

3. Exit Meeting

The inspector met with licensee representatives (denoted in paragraph 1) on January 3, 1992. The inspector summarized the scope and findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

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