U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-483/91019(DRP)

Docket No. 50-483 License No. NPF-30

Licensee: Union Electric Company
Post Office Box 149 - Mail Code 400
St. Louis, MO 63166

Facility Name: Callaway Plant, Unit 1

Inspection at: Callaway Site, Steedman, MO

Inspection Conducted: November 16, 1991 through January 31, 1992

Inspectors: B. L. Bartlett
D. R. Calhoun
K. R. Marcus

Approved By: Richard L. Hague, Chief, Reactor Projects, Section 3C — 2/12/92 Date

Inspection Summary

Inspection from November 1, 1991 through January 31, 1992 (Report No. 50-483/91019(DRP))

Areas Inspected: Routine unannounced safety inspections of onsite followup of events, inspection of licensee event reports, plant operations, maintenance/surveillance, and follow-up on previous inspection findings were performed.

Results: Of the areas inspected, no violations or deviations were identified. Discussions were held with licensee management on the seriousness of loss-of-offsite power events and precursor events. The licensee experienced one reactor trip and one turbine trip during this report period. Response by the licensee's organization to these events was prompt, thorough, and conscientious. A number of licensee event reports were reviewed during this report period. All reports reviewed were well written and detailed, with good root cause analysis and effective corrective actions. One LER reviewed was a good example of the licensee's effective self-assessment capability in action.

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DETAILS

1. Persons Contacted

D. F. Schnell, Senior Vice President, Nuclear
*G. L. Randolph, Vice President, Nuclear Operations
*J. D. Blosser, Manager, Callaway Plant
*C. D. Naslund, Manager, Nuclear Engineering
*J. V. Laux, Manager, Quality Assurance
J. R. Peevy, Manager, Operations Support
M. E. Taylor, Assistant Manager, Work Control
D. E. Young, Superintendent, Operations
R. R. Roselius, Superintendent, Health Physics
T. P. Sharkey, Supervising Engineer, Site Licensing
G. J. Czeschin, Superintendent, Planning and Scheduling
G. R. Pendegraff, Superintendent, Security
*C. E. Slizewski, Supervisor, Quality Assurance Program
*G. A. Hughes, Supervisor, Independent Safety Engineer Group
J. C. Gearhart, Superintendent, Operations Support, Quality Assurance
C. S. Petzel, Quality Assurance Engineer
J. A. McGraw, Superintendent, Design Control

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*L. Raynard Wharton, Project Manager, Office of NRR
*Anthony T. Gody, Project Manager, Office of NRR

* Denotes those present at the exit interview held on February 5, 1992.

In addition, a number of equipment operators, reactor operators, senior reactor operators, and other members of the quality control, operations, maintenance, health physics, and engineering staffs were contacted.

2. Onsite Followup of Events (93702)

a. In response to a regional request, a discussion was held with licensee management concerning outage activities in the switchyard. The discussion focused on the seriousness of the December 16, 1991, Fermi 2 crane and overhead line event and the November 15, 1991, Palo Verde partial loss of off-site power event. Through this discussion, the NRC resident inspectors ensured that senior plant management was aware of the seriousness of the events and was implementing appropriate actions to ensure that the probability of these events occurring at Callaway was minimized.

b. On January 22, 1992, at 11:06 a.m. (cst), a reactor trip occurred. The cause of the reactor trip was a spurious reactor coolant system (RCS) low flow signal. The root cause of the low RCS flow signal could not be determined. Computer printouts showed that a partial loop 3 low flow signal was received; however, it would take at least two signals in any one loop to cause a trip and a second signal could not be identified. Licensee personnel were inside containment near the loop 3 flow transmitters at the time of the trip. Troubleshooting activities could not determine any plausible mechanism that would have resulted in any of these individuals causing the trip. All other plant equipment operated as designed.

c. On January 23, 1992, at 10:58 p.m. (cst), a turbine trip and feedwater isolation signal was received due to high water level in the "D" steam generator. During the startup following the trip discussed in the paragraph above, water level was inadvertently allowed to rise such that a turbine trip signal was received. Since reactor power was below P-8 (50 percent), no automatic reactor trip signal was received. Prompt action by the operators enabled reactor power to be reduced such that the subsequent drop in steam generator level did not reach the low-low level reactor trip set-point. All equipment operated as designed.

4. Inspection of Licensee Event Reports (LER) (92700)

Through direct observations, discussions with the licensee personnel, and a review of records, the following licensee event reports were reviewed to determine that reportability requirements were fulfilled and that immediate corrective action was accomplished in accordance with Technical Specifications (TS). The LERs listed below are considered closed.

a. (Closed) LER 91001: Technical Specification 4.0.4 Violated During Power Ascension Following Refuel by Entering Modes 3, 2, and 1 with the Surveillance not Current for Over Temperature Delta Temperature, Over Power Delta Temperature and Vessel Delta Temperature

Background

On March 1, 1991, while at 100 percent power, the licensee determined that TS 4.0.4 had been violated during startup following refueling outage 4. This TS requires that "entry into an operational mode or other specified condition shall not be made unless the surveillance requirement(s) associated with the limiting condition for operation have been performed within the stated surveillance interval or as otherwise specified." The plant had entered Modes 3, 2, and 1 following refueling outage 4 with the surveillance on delta temperature nought (DTo) not current. The DTo value is the full power delta temperature across the core, and can vary from cycle to cycle. Even though DTo, by definition, can not be determined at less than 100 percent power, TS did not grant an exception to TS 4.0.4 in order to allow the plant to go to full power to measure DTo.

Licensee's Evaluation of Root Cause and Corrective Action

Root Cause

Prior to Operating Licensee Amendment number 28, issued on October 9, 1987, a constant value of DTo was utilized by the licensee. The license amendment changed this constant value to the standard definition of DTo. This change equated DTo to indicated DT at rated thermal power. When the license amendment was requested, licensee personnel failed to request an exception to TS 4.0.4.

Corrective Action

The licensee submitted an operating license amendment request to grant an exception to TS 4.0.4.

Inspector's Review

The failure of the licensee to meet the surveillance does not reflect any safety significance; however, it does reflect a failure to pay attention to detail when requesting TS changes.

It was noted in this LER that upon the return to 100 percent power following the refueling outage, the loop delta Ts were reading considerably lower than actual power. At 100 percent power loops 1, 2, 3, and 4 were reading 94.2, 92.7, 96.4, and 96.7 percent respectively. During the power escalation following the refueling outage, the licensee re-scaled the delta Ts at 50 percent power. No further checks were performed at various power levels between 50 percent and 100 percent. The licensee has modified the surveillance procedure to ensure that this error is corrected.

The licensee's Quality Assurance (QA) organization was performing a routine review of internal problem reports when they became aware of this issue. QA determined that this issue was reportable and informed management. The original conclusion reached by the licensee's organization was that this item was not reportable to the NRC. Quality Assurance gathered additional data and, after discussions with the On-site Review Committee, the original conclusion was revisited. This issue is one example of the licensee's effective self-assessment capability.

The licensee issued two revisions to this LER in order to add additional information. Revision 0, revision 1, and revision 2 of this LER are closed.

b. (Closed) LER 91002: Blown Fuse For An Ultimate Heat Sink Cooling Tower Fan Caused Entry Into TS 3.0.3 With Inoperability Of Both Trains of Safety Injection Pumps

Background

With the "A" train safety injection pump (system designator EM) out-of-service (OOS) for pre-planned maintenance, a non-licensed equipment operator (EO) mistakenly attempted to perform a test scheduled for the A train cooling tower fans on the B train fans. In performing the test, the EO failed to follow procedural precautions, causing a fuse to be blown, which resulted in the "D" UHS cooling tower fan becoming inoperable. Since this was a support system required for the operability of the EM system, this rendered the "B" train EM system inoperable at a time when the "A" train EM system was already inoperable, resulting in an entry into TS 3.0.3.

Licensee's Evaluation of Root Cause and Corrective Action

Root Cause

The licensee attributed the primary root cause of this event to be the failure of the EO to comply with the surveillance procedure.

Additional contributors included the failure of the operator's management to clearly indicate which train of equipment was to be tested; that the procedure did not clearly indicate which train was to be tested; and the difficulty in determining that a blown fuse was causing equipment problems, which added to the corrective action time delay.

Corrective Action

The licensee replaced the blown fuse and restored the "B" train EM system to service.

Operating crews were issued a night order requiring train specific communications between EOs and their management. In addition, the night order remind 1 the EOs of the procedural requirement that was missed during the performance of the surveillance and of the importance of verbatim compliance with all procedures.

The surveillance procedure was split into two separate train related procedures so that identification of which train is to be tested can be clearly identified.

An alarm response procedure is being developed to assist operators in troubleshooting events of this type.

Plant management discussed this event with licensed and non-licensed operators.

Inspector's Review

This LER was initially reviewed and documented in NRC inspection report 483/91013, issued July 18, 1991.

The NRC inspector attended the event review team meeting and verified that effective root cause analysis and corrective action had been implemented by the licensee.

This LER is closed.

c. (Closed) LER 91003: Mispositioned Safety Injection System Throttle Valve Caused Inoperability of Both Safety Injection Pumps and Entry Into TS 3.0.3

This LER documented an event that was addressed in NRC inspection reports 483/91013 (EA91-091) and 483/91014. A notice of violation was issued for this event. The followup of this event will be documented in the followup of violation 483/91013-01.

This LER is closed.

d. (Closed) LER 91006: A Reactor Trip Due To A Failure Of A Gating/Sequencing Card In The Invertor For A 120 Volt AC Instrument Bus

Background

On November 5, 1991, at 10:31 a.m. (cst), a reactor trip occurred due to a unit trip/turbine trip on high water level in the "A" steam generator (S/G). A gating/sequencing card in invertor NN12, which supplies power to vital bus NN02, had failed causing a loss of voltage to bus NN02. This resulted in an indicated low water level in the S/G, and the control circuit demanded more flow to the affected S/Gs. The operators were unable to recover S/G level with manual control before the turbine tripped on high water level in "D" S/G. All equipment operated as designed.

Licensee's Evaluation of Root Cause and Corrective Action

Root Cause

The root cause of the reactor trip was the failure of the invertor gating/sequencing card.

An additional contributing factor was that the operators did not have a procedure to help them identify which control circuits would be affected by an event of this type and what instruments would need to be removed from control.

Corrective Action

The licensee sent the failed card to the vendor for testing, along with a similar card which had been replaced in another invertor. When the results of this failure analysis are received, the licensee will determine what additional action will be required.

This LER is closed.

e. (Closed) LER 91008: Failure To Verify That Containment Penetration Vent Valve Was Locked Closed Per Technical Specification 4.6.1.1.a Prior to 1989 Due To Incorrect Locked Valve List

Background

On December 10, 1991, the licensee identified that Residual Heat Removal Pump "A" suction header vent valve EJ V-0154 had not been verified locked closed as required by TS. The valve had not been included on the locked valve list since initial plant start up. On October 21, 1987, it was identified that the valve should be included on the locked valve list as a containment integrity valve. The valve was added to the list, but there was a failure to recognize that this was a reportable condition. Since October 1987, the surveillance has been regularly performed on valve EJ V-0154 as required by TS.

Licensee's Evaluation of Root Cause and Corrective Action

Root Cause

The root cause of the initial failure to properly perform the surveillance on valve EJ V-0154 was an incorrect list of locked components, developed by a procedure review group prior to initial plant startup.

The root cause of the failure to report the TS non-compliance was a failure of engineering and operations personnel to recognize the applicability of the appropriate TS.

Corrective Action

The applicable drawing and valve line-up procedures were revised to require that valve EJ V-0154 be locked closed. The personnel involved in the 1987 evaluation were reminded of their responsibility to ensure that TS are reviewed for applicability.

Inspector's Review

The NRC inspectors reviewed the applicable drawing and procedures to verify that appropriate revisions had been implemented. In addition, during a routine containment entry at power, the inspectors verified that valve EJ V-0154 was locked closed as required.

A review of the licensee's corrective action system was performed to identify any pattern of failure to correctly perform surveillances on containment isolation valves. No such pattern was identified.

This LER is closed.

5. Plant Operations (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with license and regulatory requirements, and that the licensee's management control systems were effectively discharging the licensee's responsibilities for continued safe operation.

The methods used to perform this inspection included direct observation of activities and equipment, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation (LCOs), corrective actions, and review of facility records.

Areas reviewed during this inspection included, but were not limited to, control room activities, routine surveillances, engineered safety feature operability, radiation protection controls, fire protection, security, plant cleanliness, instrumentation and alarms, deficiency reports, and corrective actions.

Operational Safety Verification

a. The reactor trip which occurred on January 22, 1992, was classified by the licensee as a Category I trip (root cause unknown). As required by plant procedures, the On-Site Review Committee (ORC) assessed the event and subsequently authorized the plant to return to power. The NRC inspectors attended the ORC restart meeting and observed root cause determination activities by the licensee. The activities were accomplished in a timely, efficient, and safety oriented fashion. All reasonable methods of determining the root cause were attempted and the trip cause was labeled as unidentified only after much investigation and probing.

b. Technical Specification (TS) surveillance requirement 4.1.1.3.b specifies that the Moderator Temperature Coefficient (MTC) be measured within 7 Effective Full Power Days (EFPD) after reaching an equilibrium boron concentration of 300 parts per million (PPM). The end of core life MTC needs to be measured to ensure that it is within analyzed parameters, and 300 ppm is what is used to define the end of core life (EOL). The limit as specified in the Core Operating Limits Report (COLR) was -32 percent milli-rho per degree fahrenheit (PCM/degree F). If at the time of measurement the value was found to be more negative than -32, but more positive than -41 pcm/degree f, the licensee would be required to perform the test periodically prior to the end of the operating cycle. If the value was found to be more negative than -41 pcm/degree F, TS 3.1.1.3.b would require that the licensee be in Hot Shutdown within 12 hours.

On December 6, 1991, at 2:27 a.m. (cst), the licensee measured the EOL MTC and found it to be -48 pcm/degree F. After discussions with the reactor vendor, the licensee commenced a unit shutdown. About one and a half hours after the shutdown was commenced, the reactor vendor informed the licensee that the -48 value was within the safety analysis and that within 48 hours a revised calculation which would support a COLR change could be sent to the licensee. The licensee requested permission from the NRC to extend the time required to be shutdown in order to allow the reactor vendor the time to complete the analysis. The NRC concluded that the as found MTC value was within the safety analysis value and that no safety hazard would exist if the licensee was allowed to extend the shutdown time. Accordingly, the NRC allowed the licensee to extend the shutdown time requirement.

Using approved methodologies, the vendor revised the limit to -58.2 pcm/degree F. On December 9, 1991, the licensee performed the MTC again with a slight change in the procedure. Previously it had been assumed by the vendor and the licensee that slight changes in power level would not significantly affect the results of the MTC test. In order to reduce the number of unknowns in the test process and thus increase the test accuracy, the licensee decided to hold power constant during the test. The results of the new test identified a MTC value of -31.5 pcm/degree F. This result was much closer to the expected value. The licensee believed that allowing power to droop caused the axial flux difference (the power in the upper portion of the core minus the power in the lower portion of the core) to shift less negative. This increased the power in the upper portion of the core, which added positive reactivity that had not been anticipated. In addition, the increase in power caused a change in the Doppler-only fuel defect, and the resulting correction factor had not been of sufficient magnitude. The test was performed again two weeks later, using the new procedure guidance, with similar results.

The licensee has been experiencing problems with achieving critical positions during reactor startups that are within the administratively required 500 pcm band. This problem has existed for several operating cycles and gets larger with increased burnup (core life). In addition, the licensee has been unable to accurately predict axial flux difference (Delta I) and Delta I has not been behaving in the expected manner. The licensee had instituted a task force to evaluate the problem and determine a solution. The task force was given additional resources and emphasis following the identification of the MTC problem. The task force polled other licensees to determine if similar problems existed in the industry. None were identified. To determine the root cause of the problems, the licensee compared the Callaway core design to other core designs and looked for differences. The task force concluded that while other licensee's had some of the various modifications that Callaway had implemented, no other licensee had implemented all of the modifications that Callaway had or to the extent that Callaway had. Examples of this included:

- Callaway has installed 11,000 Integral Fuel Burnable Assemblies (IFBAs), while no other licensee has more than 8500 IFBAs. An IFBA is a fuel assembly that contains fuel which has been "painted" with a thin coat of a neutron absorbing material. This material is slowly "burned off" during core operation, thus allowing additional positive reactivity to be loaded into the core during refueling outages.

- Callaway has an axial blanket of natural uranium in the top and bottom 12 inches of fuel. Most other licensee's have only 6 inches.

- Callaway has a linear power density of 5.66 kilo-watts per linear foot (kw/ft). Very few other licensee's have such a high power density. Most others are in the 5.4 kw/ft range or smaller.

The task force has not yet identified the root causes of the reactivity differences. However, it has determined that no safety hazard existed. This is based upon Delta I still being within accident assumptions, the shutdown margin remaining adequate (for conservatism, 650 pcm has been added), the heat flux hot channel factor (F sub Q, ?) which is measured monthly is within limits, control rod worths and MTC boron endpoints matched predictions, measured radial power distributions were within limits, and radial peaking factors were within limits.

The licensee's task force continues to meet and evaluate the causes of the reactivity differences. The licensee has agreed to meet with the NRC the first quarter of 1992 in order to keep the NRC knowledgeable of their progress.

No violations or deviations were identified.

6. Maintenance/Surveillance (62703) (61726)

Selected portions of the plant surveillance, test, and maintenance activities on safety-related systems and components were observed or reviewed to ascertain that the activities were performed in accordance with approved procedures, regulatory guides, industry codes and standards, and the Technical Specifications. The following items were considered during these inspections: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibration was performed prior to returning the components or systems to service; parts and materials that were used were properly certified; and appropriate fire prevention, radiological, and housekeeping conditions were maintained.

a. Maintenance

The reviewed maintenance activities included:

Work Request No.	Activity
W143596	Replacement of regulator valve for air operator on ABV0003.
W506780	Troubleshooting and repair on loop 1 Average Temperature
P506211	Replaced filter in Spent Fuel Pool pump room cooler
A504904	Installed flow indicator on 3A low pressure feedwater heater
P474063	Inspection of Essential Service Water Pump "B" Pre-Lube Storage Tank
P457378	Closed Cooling Water Pump "A" Discharge Check valve Six Year Inspection

b. Surveillance

The reviewed surveillances included:

Procedure No.	Activity
CTP-ZZ-04039	Memolitrator operation for

boron analysis.

MPE-ZZ-QS005	Inspection and service of feeder breaker to centrifugal charging pump, DPBG05B.
OSP-GN-00002	Containment Coolers B and D flow rate verification
ESP-ZZ-00010	At-Power Moderator Temperature Coefficient Measurement
OSP-EF-P001B	B Essential Service Water Pump run
OSP-NE-00002	B Diesel Generator one hour load/start test
OSP-AL-P001B	B motor-driven auxiliary feedwater pump run
ISF-AL-00P38	Functional test of condensate to auxiliary feedwater pump suction header pressure transmitter
OSP-SF-00001	Shutdown Margin Calculation
OSP-BB-00006	Reactor Coolant System Flow for Mode 3
ISF-EG-000L1	Functional Check of Component Cooling Water Surge Tank Level Transmitter

The shutdown margin calculation reviewed was the one performed for the reactor restart following the reactor trip of January 22, 1992. As noted in paragraph 5 of this report, the licensee has been having difficulties in achieving their estimated critical positions (ECP). As a result, the licensee, in conjunction with the reactor vendor, had started adding a correction factor to each ECP. For the restart of January 23, 1992, this correction factor was approximately 900 percent milli-rho (PCM). Even after this correction factor had been applied, the ECP was off by approximately 450 PCM.

No violations or deviations were identified.

7. Followup On Previous Inspection Findings (92700)

(CLOSED) Unresolved Item 483/91011-02 (DRSS) Adherence to protection requirements of 10 CFR 73.21 was questioned when documentation (management logs and checklists) associated with a shipment of six defective fuel rods was left uncontrolled and not identified as safeguards information. The logs and checklists contained the date and time of departure of the radioactive shipment.

The issue has been reviewed by regional specialists and management, along with the Nuclear Materials Safety and Safeguards Transportation Branch, Division of Safeguards. The review concluded that Operations' management logs and checklist containing the date and time of departure of spent fuel shipments do not constitute schedules and, therefore, are not considered safeguards information.

This item is considered closed.

8. Exit Meeting (71707)

The inspectors met with licensee representatives (denoted under Persons Contacted) at intervals during the inspection period. The inspectors summarized the scope and findings of the inspection. The licensee representatives acknowledged the findings as reported herein. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents/processes as proprietary.