ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-382/95-10

License: NPF-38

Licensee: Entergy Operations, Incorporated
P.O. Box B
Killona, Louisiana 70066

Facility Name: Waterford Steam Electric Station, Unit 3

Inspection At: Taft, Louisiana

Inspection Conducted: November 12 through December 30, 1995

Inspectors: W. F. Smith, Acting Senior Resident Inspector
T. W. Pruett, Resident Inspector

Approved: Gregory A. Pick for 1/16/96
P. H. Harrell, Acting Chief, Project Branch D Date

Inspection Summary

Areas Inspected: Routine, announced inspection of onsite response to events, plant operations, maintenance observations, onsite engineering, followup of previously identified items, and review of a licensee event report.

Results:

Plant Operations

- The inspectors identified that a standing instruction that described actions for removing ultimate heat sink (UHS) dry cooling tower fans from service was nonconservative. Subsequently, the inspectors concluded that the operations staff members involved in approving and issuing the standing instruction performed a less than thorough review of the contents of the instruction (Section 2).

- The inspectors identified that not all valves in nitrogen supply lines that provided control air to auxiliary component cooling water valves were locked, as recommended in operations procedures. After informing the system engineer, the system engineer added the valves to the locked valve procedure (Section 3.1).

Maintenance

- The inspectors noted that the licensee did not perform periodic operability testing of certain control circuits associated with Remote Shutdown Panel LCP-43. Further, the requirement to functionally test components and systems from Remote Shutdown Panel LCP-43 was not included as part of the original plant licensing basis. The licensee acknowledged that such testing may be prudent and initiated a review to determine the scope of the testing (Section 3.2).

- After questioning by the inspector, the licensee determined that the governor valve stem on Emergency Feedwater (EFW) Pump AB was damaged by a vendor representative. Subsequently, the licensee counseled the maintenance staff and the person responsible in order to prevent a recurrence (Section 4.1).

Engineering

- Design engineering performed well by identifying that the UHS design did not meet design bases. Specifically, design engineers determined that the current design failed to account for component cooling water heat exchanger fouling when identifying the number of dry cooling tower fans required and the upper limit for the wet cooling basin temperature. Also, the design failed to account for the heat load added by the spent fuel pool when identifying the required minimum wet cooling tower basin level. The engineers failed to recognize and describe in an operability evaluation for the UHS that, with three dry cooling tower fans inoperable at less than or equal to 92.8°F, a violation of Technical Specification (TS) 3.7.4 would result. This was a violation of 10 CFR Part 50, Appendix B, Criterion III, because management controls failed to assure that regulatory requirements were properly translated into operating instructions (Section 2).

- The engineering approach to the EFW Pump AB speed drift problem was adequate to assure the pump would perform its intended safety function. Because of industry-wide concerns over safety-related turbine-driven pump performance, an inspection followup item was opened to assess the corrective actions when completed (Section 4.2).

- An unresolved item was opened pending further review of the circumstances surrounding, and extent of, setpoint calculation errors made related to calibration of Rosemount differential pressure transmitters (Section 5).

- A noncited violation resulted from a licensee-identified violation of TS 4.8.1.1.2.d.8. While implementing corrective actions related to inadequate emergency diesel generator (EDG) testing, the licensee determined that they failed to include the full design load on the EDG while verifying the loads could be transferred to offsite power without tripping the EDG (Section 6.2).

Summary of Inspection Findings:

New Items

- Violation 382/9510-01: Failure to issue operating instructions that comply with the Technical Specifications (Section 2).
- Inspection Followup Item 382/9510-02: Speed drift on turbine-driven emergency feedwater pump (Section 4.2).
- Unresolved Item 382/9510-03: Rosemount instrument transmitter errors (Section 5).
- A noncited violation was identified (Section 6.2).

Closed Items

- Inspection Followup Item 382/9405-02 (Section 6.1)
- Inspection Followup Item 382/9421-01 (Section 6.2)
- Inspection Followup Item 382/9503-01 (Section 6.3)
- Licensee Event Report 382/95-002 (Section 7)

Attachments:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

The reactor operated at essentially 100 percent power during this inspection period.

2 ONSITE RESPONSE TO EVENTS (93702, 37551)

On November 30, 1995, design engineering identified conditions where a single redundant train of the UHS was not capable of cooling down the plant to a safe shutdown condition following a design basis accident, as described in Section 9.2.5.2 of the Waterford 3 Updated Final Safety Analysis Report (USAR). Engineers discovered this deficiency while reviewing the test data taken to assess fouling of the component cooling water heat exchangers, during Refueling Outages 6 and 7, pursuant to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The engineers identified, from review of the data, that the maximum temperature of the UHS wet cooling tower basin had to be lowered to maintain the design heat duty of the component cooling water heat exchangers. Specifically, the engineers identified two areas of concern.

The first concern involved the UHS minimum fan requirements. The UHS minimum fan requirements and wet cooling tower basin water temperature requirements for operability were based upon initial plant startup testing, without consideration for heat exchanger fouling that occurs over the life of the plant. As a result, the TS 3.7.4 requirements for operability of each of the UHS trains were nonconservative because the listed temperature had no allowance for a fouled component cooling water heat exchanger.

The second concern involved the amount of water inventory available in each wet cooling tower basin. With one UHS train inoperable, the remaining redundant train did not contain sufficient water inventory in the wet cooling tower basin to successfully cool the plant to a safe shutdown condition after a design basis accident. Engineers had not considered the additional heat load of the spent fuel pool. The engineers used conservative assumptions in the revised calculation that included a recently offloaded one-third core. Consequently, operator action would be necessary to provide makeup water to the UHS basin within at least 5.5 days after the accident.

The UHS was designed and constructed with safety-related cross-connect valves between the wet cooling tower basins such that, if one train became inoperable, makeup water could be obtained from the inoperable basin. However, Section 9.2.5.3.1 of the USAR stated that each wet cooling tower basin contained sufficient water to provide sufficient cooling for 30 days or longer, to permit safe shutdown and cooldown of the plant, and to maintain it in a safe shutdown condition without additional makeup water. The safety analysis originally postulated that one wet cooling tower basin would be needed for 10 days after the design basis accident, after which the dry cooling towers were capable of providing the required UHS.

Condition Report 95-1242 was initiated and included actions required of the operators in order to consider the UHS operable with appropriately conservative margins. The licensee implemented the compensatory actions below, and the shift supervisor declared the UHS operable:

- Procedure OP-903-001, "Technical Specification Surveillance Logs," was changed to require a maximum UHS basin water temperature of 89°F in lieu of the TS-required maximum of 95°F to compensate for component cooling water heat exchanger fouling over plant life.
- Standing Instruction 95-13 was issued with the intent of requiring more UHS fans to be operable for given atmospheric conditions than specified in TS 3.7.4 and requiring more conservative actions when fans were inoperable. These actions also compensated for heat exchanger fouling over plant life.
- Standing Instruction 95-14 was issued requiring operators to initiate makeup water to the operable UHS basin within 5 days after a loss-of-coolant accident, if one train of the UHS is inoperable. These instructions compensated for the additional load from the spent fuel pool.

The inspectors reviewed the licensee's actions in response to this event. The licensee determined that this event was not reportable under 10 CFR 50.72 nor 10 CFR 50.73 because the engineers determined, from review of the maintenance history, that the UHS was not inoperable in the past. Maintenance history on the fans did not show more fans out of service than allowed by TS. Wet cooling tower basin temperatures averaged 80°F, which provided sufficient margin below the new maximum established at 89°F. Credit was taken for the safety-related, motor-operated Valves ACC-138A, ACC Wet Cooling Tower A cross-connect isolation, and ACC-138B, ACC Wet Cooling Tower B cross-connect isolation. Operators could operate the remote-manual valves from the main control room 5 days after the postulated accident, if one wet cooling tower became inoperable. The inspectors considered these compensatory actions to be a reasonable approach to assure operability, in view of the time that would elapse after the accident and of the alarms available to alert the operators of low water level in the basin.

The inspectors noted that Standing Instruction 95-13, issued by engineering, contained provisions that were in violation of TS 3.7.4, Table 3.7-3, "Ultimate Heat Sink Minimum Fan Requirements." The instruction allowed three dry cooling tower fans to be inoperable when ambient temperature was less than or equal to 92.8°F, whereas TS 3.7.4, Table 3.7-3 only allows three dry cooling tower fans to be inoperable when ambient dry bulb temperature is less than 90°F and the wet bulb temperature is less than 81°F.

In addition, based on the engineering disposition in Condition Report 95-1242, the standing instruction addressed wet bulb temperatures and dry bulb temperatures as separate criteria for establishing dry cooling tower and wet cooling tower fan outages, respectively. However, TS 3.7.4.f specifies that the dry bulb temperature should be determined every 2 hours for outside air temperatures greater than 70°F. In addition, for wet bulb temperatures greater than or equal to 80°F, operators are required to comply with the minimum fan requirements of TS 3.7.4, Table 3.7-3, which did not differentiate between dry or wet cooling tower fans. Consequently, the inspectors determined that Standing Instruction 95-13 had insufficient guidance to assure operators identified the required wet bulb temperature criterion that must be satisfied in order to allow three dry cooling tower fans to be inoperable.

The licensee concurred with these findings and explained that they had not intended to implement instructions that would have personnel perform actions in violation of TS 3.7.4. Both the engineer and the senior reactor operator involved with the implementation of Standing Instruction 95-13 did not recognize the conflicts until they were identified by the inspectors.

The licensee revised the standing instruction to reflect the TS requirements and added additional margins to the conservatisms initially intended by engineering. The revised standing instruction complied with the TS. The licensee continued to refine their calculations and assumptions in order to develop an appropriate amendment request for TS 3.7.4, which alters the UHS maximum temperature and establishes appropriate, and separate, requirements for the minimum number of wet and dry cooling tower fans. On December 4, 1995, the inspectors reviewed all other standing instructions that were in effect at the time and determined that none of them were in conflict with the applicable TS.

The inspectors concluded that the engineers demonstrated good performance in identifying the above errors in the UHS design basis. The safety significance of the issue was minor given the actual meteorological and system conditions experienced in the past. The potential premature loss of wet cooling tower basin water inventory was also of minor safety significance because operator intervention could be reasonably expected.

The engineers failed to adequately review all regulatory requirements and issue an operability evaluation that complied with the Operating License. Further, the operations staff involved with the issuance of the standing instructions failed to have a questioning attitude to ensure that the instructions would not be contrary to the applicable TS. Failure to assure that applicable regulatory requirements (the Operating License and the TSs) were correctly translated into instructions is a violation of 10 CFR Part 50, Appendix B, Criterion III (382/9510-01).

3 PLANT OPERATIONS (71707)

3.1 Plant Tours

Procedure OP-100-009, "Control of Valves and Breakers," Section 5.4.1.2.a, states that engineered safety features system manual valves in the process flow path, which, if improperly positioned, could prevent the system from performing its intended function, should be locked. During a tour of plant spaces on November 24, 1995, the inspectors noted that some nitrogen accumulator outlet isolation valves that provided control air to auxiliary component cooling water valves were not locked open. Further, the inspectors noted that isolation valves downstream of the accumulator isolation valves near the valve actuators were locked open.

The system engineer stated that the valves appeared to meet the criteria of OP-100-009 for locking and initiated Condition Report 95-1125 to install locking devices on the accumulator outlet isolation valves. The inspectors concluded that the omission of the nitrogen accumulator outlet isolation valves from Procedure OP-100-009 resulted in an unsatisfactory valve lineup in that positive assurance was not available to ensure that control air could always be supplied. The inspectors found that the licensee had always left the upstream process valves in this position. The inspectors determined that other control air systems (e.g., emergency diesel generator) had all of the process line valves locked in the required position.

3.2 Remote Shutdown Panel LCP-43

The purpose of Remote Shutdown Panel LCP-43 is to provide sufficient instrumentation and controls outside the control room to achieve hot shutdown, to maintain the unit in a safe condition, and to achieve cold shutdown of the reactor through the use of suitable procedures. In the event an evacuation of the control room was required, operators would trip the reactor and transfer control stations from the main control board to Remote Shutdown Panel LCP-43.

During a review of licensee procedures and TS, the inspectors noted that there were not any provisions to test the controls located at Remote Shutdown Panel LCP-43. The USAR, safety evaluation report, Regulatory Guides, and industry standards did not include a specific regulatory requirement for Waterford 3 to test the controls on Remote Shutdown Panel LCP-43. Nevertheless, the inspectors noted that the failure to test the ability of the controls on Remote Shutdown Panel LCP-43 was not consistent with other Combustion Engineering plants and was contrary to NUREG 1432, "Standard Technical Specifications Combustion Engineering Plants Specifications-September 1992." NUREG 1432, Section 3.3.12, "Remote Shutdown System," required licensees to verify that each required control circuit and transfer switch was capable of performing the intended function every 18 months.

USAR Section 7.4.2 indicated that IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Station," Item 4.10, "Capability for Testing and Calibrating," was incorporated into the design of instrumentation and control systems required for safe shutdown of the plant. Further, USAR Section 7.4.2.j indicated that the instrumentation and control components required for safe shutdown, which are not normally in operation, will be periodically tested. This includes instrumentation and controls for the emergency feedwater system, the atmospheric dump valves, and the emergency power system. All automatic and manual actuation and control devices will be tested to verify their operability. In response to the inspectors' questions related to testing the control functions for components located on Remote Shutdown Panel LCP-43, the licensee initiated a review of testing requirements for Remote Shutdown Panel LCP-43.

Licensing personnel determined that NUREG 0787, "Safety Evaluation Report Related to the Operation of Waterford Steam Electric Station, Unit No. 3," Section 7.4, documented the review of safe shutdown systems for Waterford 3. The safety evaluation report indicated that capability is provided for test and calibration to verify that all automatic and manual actuation and control devices are operable. The Final Safety Analysis Report, at the time of the initial licensing review, indicated that periodic testing for Remote Shutdown Panel LCP-43 was described in Chapter 16. Chapter 16 referred to the Technical Specifications, which required periodic testing of instrumentation located at Remote Shutdown Panel LCP-43 but did not require periodic testing of systems and components from Remote Shutdown Panel LCP-43. Today, the USAR does not reference Chapter 16 or the Technical Specifications. Therefore, the licensee concluded that a specific requirement to periodically test Remote Shutdown Panel LCP-43 was never included as part of the licensing basis but that appropriate functional testing may be prudent.

In response to licensing's review of testing requirements, system engineering initiated a review to determine appropriate methods and requirements for testing components and systems from Remote Shutdown Panel LCP-43.

4 MAINTENANCE OBSERVATIONS (62703, 37551)

The station maintenance activities affecting the safety-related structures, systems, and components discussed below were observed to ascertain that the activities were conducted safely and in accordance with regulatory requirements.

4.1 Repair of EFW Pump AB Governor Valve Stem

On November 16, 1995, the system engineer noticed that the governor valve stem for EFW Pump AB had been damaged with pliers. Apparently, during governor linkage adjustments performed on November 3, 1995, maintenance personnel had gripped the stem with pliers to adjust the nut on the end of the stem for governor valve travel. The system engineer, being sensitive to industry problems with stem binding causing turbine overspeed trips, notified the shift supervisor and initiated a condition report. The governor valve was manually stroked several times, and the damaged metal did not come in contact with the packing gland seal rings. Operators considered the pump operable and initiated Work Authorization 01142529 to remove the damaged metal from the stem.

The inspectors observed the completed work and verified that the damaged metal would not have contacted the gland seal rings. Mechanics satisfactorily removed the damaged metal and smoothed the stem except for the indents made by the pliers. The inspectors determined that the use of pliers on the valve stem was an example of a poor maintenance work practice that resulted in damage to safety-related equipment.

Two weeks later the inspectors questioned maintenance supervisors to determine who damaged the stem and what corrective actions were underway. The maintenance supervisors had not determined who damaged the stem but stated that they would do so. On December 7, 1995, the licensee informed the inspectors that the turbine-vendor representative damaged the stem, and a licensee maintenance mechanic had challenged the use of pliers. However, the vendor representative persisted on using the pliers and explained to the mechanic that he was not damaging the part of the stem that contacted the carbon gland seal. The mechanic accepted the response assuming the vendor had sufficient expertise to use his own methods. This response by the mechanic was unacceptable to the mechanical maintenance supervisor, and he initiated actions to counsel maintenance personnel on the expectation that they must not accept substandard work practices from vendors and contractors.

4.2 Replace Oil Filter on EFW Pump AB

After replacement of the EFW Pump AB lube oil filter in accordance with Work Authorization 01142424, the licensee slow-rolled and ran EFW Pump AB to remove the air from the lube/control oil systems. The pump operated at 4550 rpm by control room indication; however, it was set two weeks earlier at 4450 ± 25 rpm. The speed drift was nearly identical to that experienced during the startup test on November 1, 1995, which was documented in NRC Inspection Report 50-382/95-09. The licensee reset the operating speed to 4450 rpm and operated EFW Pump AB five times with no further speed drift. The pump was operationally tested and declared operable. The system engineer's written evaluation supported that position.

The inspectors found the corrective actions acceptable for the short term because the pump performed well within the inservice test acceptance criteria. The licensee also indicated that they were investigating the root cause(s) of the speed drift.

With assistance from a Woodward Governor service representative, the licensee determined that the speed drift could have been caused by mechanical agitation and oil temperature increases brought on by the "slow-rolling" process used to ensure there was no air in the governor hydraulics after maintenance. The demonstrated repeatability of the speed setting after calibration appeared to support this observation. For the long term, the licensee placed the EFW Pump AB on an increased frequency test schedule so that speed profiles could be trended.

The licensee operated EFW Pump AB on December 12, 1995, and on January 1, 1996. Preliminary indications were that turbine speed increased by about 35 rpm as governor oil heated up to operating temperatures. This was considered normal for the governor design and could be accounted for during pump testing. The licensee indicated plans to obtain more data to confirm the speed increase and plans to evaluate the pump testing programs for changes that would ensure consistent and valid data, as well as demonstrate operability.

The inspectors considered the actions taken by the licensee to resolve the speed drift problems associated with EFW Pump AB to be appropriate to the circumstances. In view of the history of problems with safety-related turbine-driven pumps, review of the final corrective actions and disposition of the speed drift issue is considered an inspection followup item (382/9510-02).

5 ONSITE ENGINEERING (37551)

On November 2, 1995, while reviewing main steam flow loop calculations, the licensee discovered that the calibration input data for some safety-related and nonsafety-related Rosemount, differential pressure flow and level transmitters was in error. The misapplication of the calibration input data and subsequent instrument calibrations resulted in safety injection tank and steam generator indicated levels being slightly higher than actual levels. Records indicated that the safety injection tank actual levels were, at times during the previous fuel cycle and since startup this cycle, below the minimum allowed by Technical Specification 3.5.1 for periods longer than their allowed outage time. The licensee issued Licensee Event Report 382/95-005 on December 4, 1995, to document this issue as required by 10 CFR 50.73.

A principal root cause for this event was attributed to an ineffective review process for these instrument calculations, which allowed errors to go undetected. Immediate corrective actions included establishing administrative controls for safety injection tank level control and resetting the steam generator low level trip bistable to a slightly higher, more conservative setpoint. The licensee established a team to: (1) review the adequacy of immediate corrective actions taken, (2) review calibration data packages for all safety-related level and flow instruments subject to similar errors, as well as nonsafety-related but important balance of plant instruments, and (3) establish corrective actions to prevent a recurrence.

Further review of the corrective actions and results will be necessary in order to determine the appropriate regulatory response. Review of the corrective actions and evaluation to determine if additional instrument calibrations are affected in the nonconservative direction is an unresolved item (382/9510-03).

6 FOLLOWUP OF PREVIOUSLY IDENTIFIED ITEMS (92901, 92903)

6.1 (Closed) Inspection Followup Item 382/9405-02: Auxiliary Component Cooling Water Operating Problem

This item was reviewed during NRC Special Inspection 50-382/95-23.

6.2 (Closed) Inspection Followup Item 382/9421-01: Review of Engineering Evaluation of Loads Required for Emergency Diesel Generator (EDG) Testing

During a review of the surveillance test, the licensee initiated Condition Report 94-1109 that questioned the actual loads required for testing the EDG, during transfer of "emergency loads" to the offsite power source. TS 4.8.1.1.2.d.8 requires, upon a simulated restoration of offsite power, verifying the capability of the EDG to synchronize with the offsite power source while the EDG is loaded with its emergency loads, to transfer its loads to the offsite power source, and to be restored to its standby status. The licensee's test procedures did not have all of the plant emergency loads on the EDG when this test was done.

The inspectors reviewed the design engineering evaluation of this issue. The evaluation explained that, in addition to demonstrating the operability of the synchronizing and switching circuits, the overcurrent protective relays monitoring the associated bus tie-breakers must not trip during the transfer process. The evaluation demonstrated that a large margin existed prior to relay actuation for the momentary current surges caused by a possible slight phase mismatch, even at EDG full design load, when making the transfer to offsite power. The failure to properly test the EDGs ability to transfer to offsite power carrying the full design emergency load violated TS 4.8.1.1.2.d.8. However, this licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

Procedures OP-903-115(116), "Train A(B) Integrated Emergency Diesel Generator/Engineered Safety Features Test," were changed to verify the above surveillance requirements when there was a simulated loss-of-coolant accident coincident with a loss of offsite power, which assured the expected emergency loads were powered by the EDG for the transfer test. These procedure changes adequately implemented the requirements of TS 4.8.1.1.2.d.8.

6.3 (Closed) Inspection Followup Item 9503-01: Minimum Staff Manning Requirements

In response to Task Interface Agreement 95-008, "Review of TIA Regarding Minimum Manning Requirements at Waterford 3," the Office of Nuclear Reactor Regulation determined that the same personnel could be assigned to both the fire brigade and the licensed operations on-shift staff. However, licensees are expected to staff to ensure that sufficient personnel are available to adequately respond to emergencies. NRR determined that the Waterford 3 staffing levels were consistent with NRC requirements and guidance specified in Technical Specifications, Waterford 3 Emergency Plan, NUREG 0737, Supplement 1, "Clarification of TMI Action Plan Requirements," and NRC Information Notices 91-77, "Shift Staffing at Nuclear Power Plants," and 95-48, "Results of Shift Staffing Study."

7 ONSITE REVIEW OF LICENSEE EVENT REPORTS (92700)

(Closed) Licensee Event Report 95-002: Reactor Trip and Nonsafety-Related Switchgear Fire

This licensee event report was reviewed during NRC Special Inspection 50-382/95-17.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

R. E. Allen, Manager, Operational and Engineering Experience
R. F. Burski, Director, Nuclear Safety
G. G. Davie, Quality Assurance Manager
T. J. Gaudet, Supervisor, Licensing
J. D. Hologa, Manager, Design Engineering
D. R. Keuter, General Manager, Plant Operations
R. J. Killian, Quality Assurance Specialist
R. LeBlanc, Supervisor, Engineering
D. F. Litolf, Licensing Engineer
D. E. Marpe, Mechanical Maintenance Superintendent
D. C. Matheny, Operations Superintendent
D. W. Vinci, Licensing Manager

The personnel listed above attended the exit meeting. In addition to these, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on January 4, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position contrary to the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.