APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report No: 50-382/92-08

Docket No: 50-382 License No: NPF-38

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

Facility Name: Waterford Steam Electric Station, Unit 3 (Waterford 3)

Inspection At: Taft, Louisiana

Inspection Conducted: March 15 through May 2, 1992

Inspectors: W. F. Smith, Senior Resident Inspector
Project Section A, Division of Reactor Projects

M. A. Satorius, Project Engineer
Project Section A, Division of Reactor Projects

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Project Section A, Division of Reactor Projects

Approved: for William D. Johnson, Chief, Project Section A 5/20/92 Date

Inspection Summary

Inspection Conducted March 15 through May 2, 1992 (Report 50-382/92-08)

Areas Inspected: Routine, unannounced inspection of plant status, followup, onsite response to events, monthly maintenance observation, bimonthly surveillance observation, operational safety verification, and engineered safety feature walkdown.

Results:

A violation was identified (paragraph 5.3) involving failure to follow procedures. During preparations for shipment of incore instruments, the licensee's representative bypassed a hold point in a work instruction contrary to administrative requirements. While he had the technical knowledge to safely bypass the hold point, he did not have the authority and, as a supervisor, should have understood the requirements.

A second violation was identified (paragraph 8) involving failure of a surveillance procedure to adequately implement the Technical Specification surveillance requirement for verifying operability of the emergency diesel generator "turning gear engaged" lockout feature. The procedure required a meaningless test by isolating control air through the feature instead of challenging the feature itself to isolate control air. Consequently, this surveillance requirement might not have been met in the past.

The licensee's responses and corrective actions with regard to Valve RC-104 failure and resultant shutdown were indicative of strengths in operations, maintenance, and engineering support capabilities (paragraph 4.1).

Although there was no apparent violation of Technical Specification requirements, the operators' failure on March 26, 1992, to consider the presence of a Xenon transient and act accordingly to maintain the shutdown margin within the 24-hour surveillance window reflected weaknesses in operator training and in the shutdown margin determination procedure (paragraph 4.2).

Maintenance activities and the controls and coordination with operations were executed in a superior manner, indicating continued improvement in maintenance. The operators' safety perspective while making operability determinations was conservative and in the best interests of safety (paragraphs 5.1, 5.2).

With the exception of the surveillance procedure for the emergency diesel generator, surveillance activities continued to be a strength. Procedures were well written and human factored as a result of the licensee's procedure upgrade program completed in 1991. Personnel involved with the surveillances followed procedures and performed their tasks in a deliberate and professional manner, reflecting good training (paragraph 6).

Operator performance and control of system configuration continued to be a strength. Housekeeping was superior with very few exceptions. Management involvement and cognizance over plant issues was a strength (paragraph 7).

The results of the emergency diesel generator walkdown were excellent, notwithstanding the list of discrepancies found, including the violation cited above. The emergency diesel generators have been well maintained and have responded well when called upon. They were determined to be capable of performing their intended safety function, based on the physical condition, configuration, and proper implementation of all (except one mentioned above) surveillances.

DETAILS

1. PERSONS CONTACTED

1.1 Principal Licensee Employees

*D. F. Packer, General Manager, Plant Operations
T. R. Leonard, Technical Services Manager
*R. S. Starkey, Operations and Maintenance Manager
*R. E. Allen, Security and General Support Manager
*J. J. Zabritski, Acting Quality Assurance Manager
*D. E. Baker, Director, Operations Support and Assessments
J. B. Houghtaling, Acting Director, Design Engineering
J. A. Ridgel, Radiation Protection Superintendent
*G. M. Davis, Events Analysis Reporting & Response Manager
*G. A. Boerschig, Events Analysis and Reporting Supervisor
R. F. Burski, Director, Nuclear Safety
*L. W. Laughlin, Licensing Manager
T. J. Gaudet, Operational Licensing Supervisor
J. G. Hoffpauir, Maintenance Superintendent
D. W. Vinci, Operations Superintendent
R. D. Peters, Assistant Maintenance Superintendent, Electrical
D. E. Marpe, Assistant Maintenance Superintendent, Mechanical
D. C. Matheny, Assistant Maintenance Superintendent, Instrumentation and Controls
*M. S. Ferri, Manager, Modification Control

*Present at exit interview.

1.2 Other NRC Personnel Present at Exit Interview

E. Lea, Jr., Reactor Engineer, Operator Licensing Section, Divisic [illegible] Reactor Safety, Region II

In addition to the above personnel, the inspectors held discussions with various operations, engineering, technical support, maintenance, and administrative members of the licensee's staff.

2. PLANT STATUS (71707)

The plant was operating at full power at the beginning of this inspection period. On March 25, 1992, the plant was shut down to Hot Standby (Mode 3) for a forced outage. The outage duration was approximately 3 days to repair a packing gland failure on a primary sampling line valve. The outage is discussed in paragraph 4.1. The unit was restored to full power operation by March 28, where it remained through the end of the inspection period.

3. FOLLOWUP

3.1 Followup of Previous Inspection Findings (92701)

3.1.1 (Closed) Inspection Followup Item IFI 90026-2

This item involved a review of the licensee's documented critique report, following the December 27, 1990, chlorine release from the Occidental Chemical Company, and the licensee's implementation of their toxic chemical contingency procedure. On April 16, 1992, the inspectors reviewed the critique report and noted that the licensee found no problems with activation and response, communications and dissemination of information, direction and control, and material and equipment. This was consistent with the inspectors' assessment in NRC Inspection Report 50-382/90-26. The licensee did identify, however, a need to update Emergency Plan Implementing Procedure EP-004-10, "Toxic Chemical Contingency Procedure." Changes were implemented and approved on February 21, 1992. They included updates in inventories of materials used or produced by neighboring industries, providing compass sectors on a map attachment, providing an emergency coordinator closeout checklist, and making the procedure consistent with the radiological emergency procedures in terms of management contact requirements. The inspector reviewed the revised procedure and noted that it was a complete rewrite, including the above updates and an improved format for easier use. This item is closed.

3.1.2 (Closed) Violation VIO 91003-3

This violation involved a failure to properly review a change to a postmodification retest. While installing a new digital volt meter on the plant protection system bistable control panel, plant technicians conducted the retest for operability using a procedure that had not been reviewed by the Plant Operations Review Committee as required by Technical Specification 6.5.1.6.a and implemented by Administrative Procedure UNT-007-028, "Design Change Initiation and Review." The licensee identified the root cause to be the system engineer's failure to verify that proper reviews of the acceptance tests were conducted. In addition, the licensee noted that other causal factors exacerbated the root cause. These causal factors included inappropriate personnel making changes to the acceptance test without initially involving the system engineer, and design engineering and maintenance personnel not being aware of recent changes to Procedure UNT-007-028, which clarified conditions when postmodification tests required review by the Plant Operations Review Committee. The licensee's corrective actions included clarifying the contents of Procedure UNT-007-028 to the responsible system engineer. The retest was reviewed and approved by the Plant Operations Review Committee.

Additional corrective actions included issuing a change to Procedure UNT-007-028 that clarified the acceptance testing responsibilities of the system engineer. Briefings were conducted with all maintenance, operations, design engineering, and system engineering personnel. During this briefing, the requirements of Procedure UNT-007-028 were explained, and the new changes to this procedure were delineated.

Administrative Procedure UNT-005-020, "Post Maintenance Testing," was also revised to more clearly differentiate between postmaintenance testing and acceptance testing. This item is closed.

3.2 <u>In-Office Review of Licensee Event Reports (LERs) (90712)</u>

The following LER was reviewed. The inspectors verified that reporting requirements had been met, causes had been identified, corrective actions appeared appropriate, generic applicability had been considered, and that the LER forms were complete. The inspectors confirmed that unreviewed safety questions and violations of technical specifications, license conditions, or other regulatory requirements had been adequately described. The Region IV staff determined that an onsite inspection followup of the event was not appropriate. The NRC tracking status is indicated below.

3.2.1 (Closed) LER 91-014, "Main Feed Isolation Valve Inoperable Due to Accumulator Leak."

4. <u>ONSITE RESPONSE TO EVENTS (93702)</u>

4.1 <u>Reactor Coolant System Leak</u>

On March 25, at 2:47 a.m., the licensee commenced a reactor shutdown due to unidentified reactor coolant system leakage of approximately 13 gpm. At 12:45 a.m., the operators had noticed containment particulate activity trending up. At about the same time, containment in-leakage, as measured by the containment sump weir flow detector, increased to approximately 7 gpm. The licensee entered the action statement for Technical Specification 3.4.5.2, "RCS Leakage," and sent personnel into the containment to attempt to identify the source of the leakage. Steam and water was observed in the vicinity of the Reactor Coolant Pump 1B seal area, but the actual source of the leakage could not be identified at that time. At 1:40 a.m., a reactor coolant system water inventory balance was completed and unidentified leakage was determined to be 13 gpm. This value corresponded to the indicated containment sump weir flow. The licensee declared an Unusual Event and commenced a reactor shutdown as required by Technical Specifications. The NRC was notified as required by 10 CFR Part 50.72 and the resident inspector reported to the control room and observed the plant shutdown. The shutdown was uneventful and the plant entered Mode 3, Hot Standby, at 5:45 a.m.

Later that morning, the licensee's maintenance and operations personnel entered the containment and were able to identify the leakage source as RC-104, a 3/4 inch air operated valve. RC-104 was the sample line isolation valve for reactor coolant system Hot Leg No. 1. The valve was in close proximity to Reactor Coolant Pump 1B. The packing gland hold down plate studs were broken off, the hold down plate and packing follower were pushed up the stem to the valve operator, and the packing had been blown out. The valve had been shut earlier in the morning after a reactor coolant system sample had been obtained. With the valve shut, the packing area was isolated from full reactor coolant system pressure and leakage was significantly lower. Operators were able to further reduce the leak rate by manually gagging the valve shut and venting the downstream piping by lining up to the sample sink. Reactor coolant system pressure was reduced to 1300 psia to further reduce the leakage.

An attempt to repair and repack the valve was unsuccessful because the valve stem was bent and the follower could not be reinserted into the valve bonnet. Maintenance personnel fabricated a clamping device to hold a plate down on the packing area of the valve bonnet so that leak repair sealant could be injected into the packing area through a threaded port in the valve bonnet. The licensee prepared an engineering evaluation for the nonconformance repair which took into account the integrity of the clamping device, the effect of the additional weight of the clamp on the seismic qualification of the valve, and the chemical compatibility of the leak repair compound with the stainless steel and reactor coolant. Based on this evaluation, the licensee determined that the repair could be made as allowed by 10 CFR 50.59.

The valve was manually reopened as the leak repair sealant was injected and was left danger tagged in the open position to prevent future operation of the valve. The leak was stopped after several injections of sealing compound. The licensee revised their sampling procedures to account for the valve being left open. Several valves downstream of RC-104, including the containment isolation valves, PSL-105 and 107, would be used to isolate the sample line. The licensee installed a leakage collection device and a remote camera to monitor the valve during subsequent operations.

After returning the plant to normal operating temperature and pressure, a reactor coolant system inventory balance was performed as required by Technical Specifications, and unidentified leakage had returned to its previous low level. The plant was restarted on March 27 and returned to full power on March 28. No problems were encountered during the startup.

The licensee located the failed studs and planned to perform a failure analysis. It was theorized that boric acid corrosion of the carbon steel studs could have been involved but this had not been verified. The licensee stated they would remove the clamp and repair the valve during the upcoming refueling outage scheduled for September 1992. The inspectors questioned whether there were other valves subject to reactor coolant system pressure and boric acid concentrations that could fail in a similar manner, due to carbon steel fasteners being used where boric acid leakage and corrosion could occur. The response was that they were conducting a study on the issue and would inform the inspectors of the results of the study and of any actions planned. This event will be reviewed further during followup of LER 92-002.

4.2 Potential Loss of Shutdown Margin Due to Xenon Decay

At 1:09 a.m. on March 27, approximately 2 days after shutting down the reactor due to the RC-104 packing leak described above, the operators performed a shutdown margin calculation. Technical Specification 3.1.1.2 required the shutdown margin to be greater than, or equal to, that shown on Technical Specification Figure 3.1-0. Technical Specification 4.1.1.2 required the shutdown margin to be verified within Technical Specification 3.1.1.2 requirements at least once per 24 hours. The licensee implemented this using Surveillance Procedure OP-903-090, Revision 5, "Shutdown Margin." The results indicated a required shutdown margin boron concentration of 558.2 parts per million (ppm), but the last boron sample indicated 506 ppm in the system. The operators immediately entered Off-Normal Procedure OP 901-013, Revision 7, "Emergency Boration," to implement the Technical Specification 3.1.1.2 action statement. At 1:10 a.m., reactor coolant system boron concentration was 646 ppm, which was greater than the Xenon-free concentrationof 640 ppm. The operators exited the off-normal procedure and terminated the emergency boration.

At about 10 p.m. on March 26, the operators had commenced normal boration to raise reactor coolant system concentration to an estimated critical concentration of 800 ppm in preparation for startup. They determined that between .30 p.m. on March 26 and 1:10 on March 27, there was a period when the shutdown margin required by Technical Specification 3.1.1.2 was not met. Since there was only a 24-hour frequency requirement to determine shutdown margin, the Technical Specification surveillance requirements were met.

The inspectors expressed concern that, despite a 24-hour frequency requirement to determine shutdown margin, that requirement alone was not adequate to ensure that Technical Specification 3.1.1.2 was being met, particularly shortly after shutdown when a significant Xenon transient existed. The licensee concluded that there was a weakness in Procedure OP-903-090 in that it did not address the potential for a Xenon transient that could reduce shutdown margin below the minimum permitted by Technical Specification 3.1.1.2 before the next 24-hour determination. Licensee personnel also indicated that they will address this issue in licensed operator training. The inspectors will follow up on the licensee's actions taken, and this item will be tracked under Inspection Followup Item 92008-3.

Conclusions:

The licensee's responses and corrective actions with regard to the reactor coolant system leak were indicative of strengths in operations, maintenance, and engineering support capabilities. The failure to maintain shutdown margin requirements between samples reflected a weakness in operator training as well as a weakness in the shutdown margin determination procedure.

5. MONTHLY MAINTENANCE OBSERVATION (62703)

The station maintenance activities affecting safety-related systems and components listed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with approved work authorizations (WAs), procedures, Technical Specifications, and appropriate industry codes or standards.

5.1 WA 01091799: Troubleshooting Electrical Ground on Emergency Feedwater (EFW) Pump A/B Speed Control

On March 24, the operators detected a 70 volt DC ground on the vital 125 volt DC bus, AB-DC-S. The ground was isolated to Breaker EFW-EBKR-AB-37, which supplied the governor circuit for EFW Pump A/B. The inspector observed troubleshooting of the circuit by maintenance personnel. The troubleshooting WA was properly prepared and approved and provided the appropriate precautions and limitations for the work. The maintenance technicians were well qualified and familiar with the equipment. During the initial work, the circuit was deenergized and operators took the necessary precautions to ensure that the pump would not inadvertently start by tagging closed the steam supply valves, MS-401A and -B. Since this rendered the pump inoperable, the inspector verified that compliance with the applicable Technical Specification limiting condition for operation (LCO) was maintained. Leads lifted during the work were properly documented and the workers systematically eliminated components until they determined that the ground was in the governor servo unit mounted on the turbine. Since a replacement servo unit was not immediately available, the pump was returned to service and thus was available even though the operators still considered it inoperable and continued to comply with the LCO action requirements. A replacement servo was obtained and installed and the pump was successfully tested and returned to service on March 27. No problems were identified with the work.

5.2 WA 01092523: Correcting Slow Stroke Time on Flow Control Valve SI-129B

On April 14, while the operators were performing Surveillance Procedure OP-903-032, "Quarterly IST Valve Tests," the stroke time for Valve SI-129B was 17 seconds, with an acceptance criterion of 15 seconds. Historically, the valve normally stroked in about 3 seconds. This valve was the Train B reactor cooldown flow control valve. During a safety injection actuation, the valve would provide a low pressure safety injection path and, therefore, it was normally locked open at the control room panel. After cleaning the air operator booster valves, the technicians found that the air pressure distribution above and below the piston was not balanced. The inspector observed portions of the air operator balancing, which successfully restored the valve response. The technicians appeared very knowledgeable of the work to be performed. The valve was in a 50 millirem per hour field, and the technicians exhibited sensitivity to this and minimized their exposure. The licensee's as-low-as-reasonably-achievable (ALARA) coordinator was cognizant of the job and personally ensured that exposures of the technicians and the inspector were minimized. No component clearances were required in order to work on or cycle the valve, and the inspector considered it appropriate to the circumstances.

The inspector witnessed the retest of the valve after cleaning and calibration and noted that the stroke time was restored to 3.7 seconds. The exact cause of the valve operator being out adjustment was not evident. Valve SI-129B functioned properly when it was stroke tested.

The inspector reviewed the equipment out of service status log to verify that the proper Technical Specification action statements were identified and followed. The operators had identified Technical Specification 3.4.1.3, which referred to shutdown cooling loops required for Mode 4 (Hot Shutdown). Since this Technical Specification was not applicable to Mode 1 (power operation), no action was taken. However, Valve SI-129B was also in the low pressure safety injection path (Train B), which was required by Technical Specification 3.5.2 to be operable. The inspector questioned the operators and discussed the issue with licensee management. The operators explained that they were briefed and aware of the brief times the valve was not open and would have reopened the valve in the event a safety injection actuation was needed. Section 5.1.1.2 of Operations Administrative Procedure OP-100-014, Revision 0, "Technical Specification Compliance," allowed the operators to consider a system operable when, as in this case, an operator was stationed by the controls for a valve that was briefly taken out of its safety position. The inspector agreed that it was in the best interest of safety to be prepared to immediately restore the valve to its safety position in the event of an accident, rather than to administratively remove the system from an operable status and leave the valve unattended. The redundant train was maintained operable so there was no loss of function.

5.3 WA 01092496: Perform Incore Instrument Disposal

On April 15 and 16, the inspectors observed portions of the licensee's handling and loading of incore instruments for disposal and shipment. These instruments were removed from the core during the previous refueling outage. The incore instruments were cut up and deposited in a cask liner located in the spent fuel pool cask handling pit.

On April 15, the inspectors commenced observing the evolution at the point when the tractor-trailer carrying the empty shipping cask was in the fuel handling building train bay. The floor plug above the train bay was removed and tools were being hoisted into the refueling floor. Upon reviewing the WA, the inspectors noted a hold point requiring the door to the train bay to be closed before proceeding and removing the refueling floor plugs. The step subsequent to the hold point was completed, but the hold point was not signed off. Upon questioning this, the licensee's representative in charge, who was also signing off the WA steps, explained that he intended to change the WA to allow the floor plugs to be removed while the door was open, because the refueling crane was needed to lift a tool box that interfered with truck entry. The inspectors understood that the purpose of the hold point was to prevent a direct path between the outside environment and the refueling floor where contamination existed. The licensee's representative explained that he verified that a negative pressure existed in the refueling building before opening the floor plugs. Failure to comply with the hold point or change the work instructions in accordance with the required administrative controls was in violation of NRC requirements (VIO 92008-1).

Conclusions

Maintenance troubleshooting activities on the EFW pump were excellent and a good maintenance and operations safety perspective was demonstrated by making the EFW pump available for possible emergency use while waiting for parts, even though the pump could not meet all of the administrative requirements for Technical Specification operability.

The maintenance performed on Valve SI-129B was superior and the operators' actions to support the work were appropriate to the circumstances. The shift supervisors judgment to maintain low pressure safety injection Train B in an operable configuration rather than simply removing the train from service and entering the emergency core cooling Technical Specification action statement appeared to be in the best interest of safety.

Failure of a licensee supervisor to comply with a hold point during the preparations for incore instrument shipment was considered a weakness in the licensee's past efforts to ensure that all site personnel understood and complied with the licensee's policy to not proceed beyond a hold point until it is completed.

6. BIMONTHLY SURVEILLANCE OBSERVATION (61726)

The inspectors observed the surveillance testing of safety-related systems and components listed below to verify that the activities were being performed in accordance with the Technical Specifications. The applicable procedures were reviewed for adequacy, test instrumentation was verified to be in calibration, and test data was reviewed for accuracy and completeness. The inspectors ascertained that any deficiencies identified were properly reviewed and resolved.

6.1 Procedure OP-903-068, Revision 8, "Emergency Diesel Generator and Subgroup Relay Operability Verification"

On March 30 and 31, the inspector observed the monthly emergency diesel generator (EDG) operability verification. The test was performed by a recently licensed control room operator, with support from a nonlicensed auxiliary operator (NAO) at the EDG who was performing the verification of prerequisites and initial conditions for the first time without being under instruction. The EDG performed satisfactorily and all acceptance criteria were met. The operators performed the test in a careful, deliberate manner in accordance with the procedures. On March 30, during the verification of initial conditions in accordance with System Operating Procedure OP-009-002, Revision 12, "Emergency Diesel Generator," the NAO noted that engine lube oil temperature was 132°F when the procedure required verification that the temperature was 120°F to 130°F. The NAO informed the control room, and the shift supervisor cancelled the test until the discrepancy was resolved. Upon reviewing the setpoint document, the shift supervisor noted that the heater controller setpoint was 120°F to 135°F. OP-009-002 was appropriately changed in accordance with the licensee's administrative controls, and the test was conducted satisfactorily on March 31. The operators' actions to stop and permanently correct a procedure problem was viewed as a strength. The inspector questioned the licensee as to the cause of the temperature discrepancy between the setpoint document and the operating procedure. At the end of this inspection period, the licensee had not found the cause, but was in the process of reviewing the procedure histories.

6.2 Procedure MI-003-126, Revision 7, "Core Protection Calculator (CPC) Functional Test"

On April 29, the inspector observed the performance of the monthly functional test of CPC B. This surveillance was performed by a lead instrument and controls technician, with a trainee under instruction.

The inspector reviewed the procedure and noted that it was well written with good human factor enhancements such as independent verification points clearly marked and steps requiring performer's initials well annotated. All test equipment was noted to be within its required calibration date.

The technician thoroughly briefed the control room operator on the expected alarms that would be received during the surveillance and the effect that placing the CPC into bypass would have on the reactor protection system. After receiving permission to begin work from the shift supervisor, the technician commenced the surveillance.

A problem developed during Step 8.4 of the procedure. This step tested the operability of the CPC cabinet door limit switch that caused the reactor protection system auxiliary cabinet condition abnormal annunciator to alarm. When the CPC cabinet door was shut and then opened, the reactor protection system auxiliary cabinet condition abnormal alarm did not actuate. Further investigation by the technician revealed that the limit switch was dirty and was not functioning. The lead technician reported this condition to his supervisor and the shift supervisor. Condition Identification 280075 was generated to correct the limit switch problem. The technicians annotated the signature record to note the failed limit switch condition and the unsatisfactory portion of the test.

The remainder of the surveillance procedure was completed without any problems. Since the door alarm had no effect on the operability of the CPC, the Technical Specification surveillance requirements were satisfied.

The inspector considered the actions to document the failed portion of the procedure appropriate, and no other problems were identified.

Conclusions

Surveillance activities continued to be a strength. Procedures were well written and human factored as a result of the licensee's procedure upgrade program completed in 1991. Personnel involved with the surveillances followed procedures and performed their tasks in a deliberate and professional manner, reflecting good training.

7. OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with regulatory requirements, to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation, to assure that selected activities of the licensee's radiological protection programs were implemented in conformance with plant policies and procedures and in compliance with regulatory requirements, and to inspect the licensee's compliance with the approved physical security plan.

The inspectors conducted control room observations at least once daily when on site. Shift turnover meetings were held by the control room supervisors. In general, the meetings were informative and helped all the staff on shift to be aware of plant conditions and activities planned. Plant engineering, health physics, maintenance, radwaste, and the duty plant manager were among those represented to provide timely operations support.

The inspectors made plant tours, covering all of the accessible areas inside and outside the power block in a week's time. Housekeeping continued to improve, with a few exceptions. On April 6, the inspectors noted that, after replacing the cylinder block on Charging Pump B, the technicians left a large pile of anticontamination clothing scattered about the contamination area access point. This was promptly attended to when the inspector brought it to the attention of health physics and the shift supervisor. The pump had been worked on over the weekend, and April 6 was a day off for most licensee personnel. The inspectors noted two instances where welding machines were left energized and unattended in close proximity to safety-related equipment and ladders left standing but not in use. This was discussed with the licensee, and efforts to continue improving housekeeping practices continued.

Control room logs, equipment out of service status logs, and clearance logs all were reviewed by the inspectors on a routine basis and no significant problems were found.

The inspectors periodically visited the central alarm station and each time found the security officers attentive to their post.

Activities at the primary access point were assessed on a daily basis by the inspectors. Performance of the security officers stationed there was excellent. Responses to the various detector alarms was prompt and appropriate.

The inspectors attended daily plan-of-the-day meetings held by the licensee's staff and note. n excellent cross section of representation and good management involvement in the issues raised.

Conclusions:

Operator performance and control of sy:tem configuration cor:inued to be a strength. Housekeeping was superior wi.h very few exceptions. Management involvement and cognizance over plant iss es was a strength.

8. ENGINEERED SAFETY FEATURE SYSTEM WALKDOWN (71710)

During this inspection period, the inspectors performed a detailed procedure review and walkdown of the emergency diesel generator system to determine overall system condition and operational readiness.

The inspectors reviewed Chapter 8.3 of the Waterford 3 Updated Safety Analysis Report, Technical Specification 3.4.8, and the licensee's Design Basis Document No. 2, "Emergency Diesel Generator and Automatic Load Sequencer." Using the above documents as a reference, the inspectors reviewed the following procedures:

- OP-003-009, Revision 7, "System Operating Procedure, Fuel Oil Receipt"
- OP-009-002, Revision 12, "System Operating Procedure, Emergency Die. Generator"
- OP-901-057, Revision 0, "Off-Normal Procedure, Loss of 4160 Volt Safety Bus B"
- OP-903-066, Revision 5, "Surveillance Procedure Electrical Breaker Alignment Check"
- OP-903-067, Revision 6, "Surveillance Procedure, Unit Power Supply Transfer Check"
- OP-903-068, Revision 8, "Surveillance Procedure, Emergency Diesel Generator and Subgroup Relay Operability Verification"
- OP-903-115, Revision 0, "Surveillance Procedure, Train A Integra' J Emergency Diesel Generator/Engineering Safety Features Test"
- CE-02-030, Revision 2, "Technical Procedure, Maintaining Diesel Fuel Oil"
- PE-5-031, Revision 2, "Surveillance Procedure, Emergency Diesel Dual Start Test"

- MM-003-042, Revision 0, "Ten Year Emergency Diesel Generator Inspection"

- ME-004-0<1, Revision 7, "Maintenance Procedure, Emergency Diesel Generator"

The inspectors found that the surveillance requirements of Technical Specification 3.8, as they related to the EDGs, were implemented by the licensee's procedures in an appropriate manner, with one exception identified below. The procedures were well written and formatted with human factors incorporated to minimize personnel errors. The following discrepancies were noted and discussed with the licensee:

- Procedure OP-003-009 had a temporary change issued in October 1991 to close injector return line Valves EGF-123A(B) and EGF-124A(B) when filling the diesel fuel oil storage tanks (DOSTs), because Check Valve EGF-125A(B) did not appear to prevent back flow from the fill line to the injector return line vents in the EDG room. The temporary change was designated to expire upon inspecting Valve EGF-125A(B), but the licensee could not find corrective action documentation, i.e., a condition identification report, that would initiate appropriate scheduling of the inspection and repair, if needed. Operation of the EDGs indefinitely with this condition would be undesirable. During the time that fuel oil is being loaded into the DOST, if the affected EDG started automatically, fuel oil would spill into the EDG room via the injector return line vents, creating a fire hazard, until an operator could respond and open the return line valves. The alternative would be to take the EDG out of service, which would be less desirable. The licensee demonstrated a weakness in failing to schedule timely and appropriate corrective action to solve this problem.

- Procedure OP-009-002, Section 8.2.2, transfer of diesel fuel oil from DOST B to DOST A could not be performed as written. Throughout the procedure steps, the author incorrectly interchanged A and B components. This demonstrated a weakness in the preparation and technical review of this section of the procedure.

- Procedure OP-903-115, Section 7.2, EDG A lockout test, did not fully verify that the "turning gear engaged" lockout feature prevented the EDG from starting. Valves EGA-303A and EGA-304A, which were mechanically interlocked with the movement of the turning gear engaging mechanism, were not challenged. Instead, the procedure isolated control air. Testing in this manner appeared to be meaningless, because the EDG would not start whether the lockout feature was functional or not. The same problem existed for EDG B in Procedure OP-903-116. Consequently, Technical Specification Surveillance Requirement 4.8.1.1.2.d.12.(a) was not met by this procedure or any other procedure reviewed by the inspectors. This is a violation of NRC requirements (VIO 92008-2).

  The significance of this violation was that a feature designed to warn the operators by annunciating "turning gear engaged" and to protect the EDGs from potential damage caused by attempting to start the engine with the turning gear engaged, might never have been surveillance tested to verify operability as directed by the Technical Specifications. The licensee acknowledged this issue by initiating a potentially reportable event report, thus entering the corrective action program and promptly affixing a red danger tag on the turning gear engagement mechanism so that the turning gear would not be engaged without specific approval of the shift supervisor. The inspector was satisfied, from a safety perspective, that the operability aspect of this particular surveillance was temporarily met until the licensee developed a procedure that would appropriately challenge this lock-out feature as intended by the Technical Specification. This was a second recent instance where Technical Specification surveillance requirements were not met as written. See NRC Inspection Report 50-382/91-31 regarding a licensee identified case where core azimuthal tilt alarm checks were not properly implemented.

- In Procedure OP-903-115, Section 7.3, Step 12, the acceptance criterion of 4160 plus or minus 420, minus 290, volts was confusing and conflicted with the Technical Specification value of 4160 plus or minus 420 volts. The minus 290 volts appeared to be an editorial error, until the inspector reviewed Procedure OP-903-116 (for EDG B) and found the same acceptance criterion expressed as between 3870 and 4580 volts. In addition, the allowable frequency band conflicted between the two procedures.

- Procedure OP-903-115, Section 7.5, Step 5 NOTE, stated that the subsequent loss of off-site power test "should" be performed within 5 minutes after completion of the 24-hour run. This implied an option by the licensee's definition of "should." Technical Specification 4.8.1.1.2.d.6 required performance of the off-site power test.

- Procedure OP-903-115, Section 7.6, interchangeably used the terms DAY TANK and FEED TANK for the same tank. This was a poor practice.

- Procedure PE-5-031, Section 8.3, required the operators to manually remote start both EDGs to commence the 10-year dual start surveillance requirement in accordance with Section 6.4 of Procedure OP-009-002. Procedure OP-009-002 had since been revised, and Section 6.4 was no longer applicable.

The inspectors conducted a physical walkdown of the EDGs. The EDGs appeared to be in a state of readiness to respond if called upon to perform their design safety function. Recent successful test runs of the EDGs supported this conclusion. However, the discrepancies listed below were identified and discussed with the licensee:

- Relief Valve EGA-141B, the relief valve on Air Receiver B1 for EDG B was leaking by the seat. The leak was bleeding down the air receiver causing the air compressor to cycle more frequently than normal. Should the compressor fail (it is not safety related), the receiver would bleed off, leaving only Air Receiver B2 to start the diesel. While one air receiver is all that the Updated Safety Analysis Report required to sustain operability of the EDG, the safety margin would be reduced with only one available. The leak was identified on Condition Identification No. 279564 on March 17, 1992. By April 21, no action was taken to repair the valve. The inspector questioned the licensee and found that the repair was not scheduled to occur until June 1992. The inspector expressed concern that more prompt corrective action was not being taken. The licensee responded by repairing the valve during the week of April 27.

- While conducting a valve lineup check in accordance with the EDG B standby system valve lineup check sheets provided in Procedure OP-009-002, the inspectors noted that at least 15 instrument valves listed for positioning did not have a unique identification tag or label. Also, many of these valves were described as being 3/8, 1/2 or 1 inch nominal size, when in fact they were 1/4 inch. The inspectors questioned nonlicensed auxiliary operators on how they have been able to positively identify and document verification of positions without labels. The response was that they relied on the instrument the valves were connected to, which also was described on the check sheets. The inspectors expressed concern with the increased chance of human error and resultant misalignment of important EDG instrument and control system valves which could ultimately render the EDGs inoperable.

- Trash, debris, and oil were found on the EDG B cylinder block between the right and left bank cylinders, under the exhaust manifold. This reflected a poor housekeeping practice.

- On the EDG B local control panel, the indicating lights for the jacket water circulating pump and the jacket water heater illuminate in red to indicate "ON," but the engraving on the lights indicated "OFF." The same was found on the EDG A local control panel for the jacket water heater. While the operators and the inspectors have been accustomed to this condition, the indications were incorrect, and should be corrected.

Correction or resolution of the above identified deficiencies, with exception of the violation, shall be tracked under Inspection Followup Item 92008-4.

Conclusions

The EDGs were determined by the inspectors to be capable of performing their intended safety function, based on the physical condition and configuration, as well as proper implementation of Technical Specification surveillances and preventive/predictive maintenance.

Although a violation was identified where a surveillance procedure failed to fully verify the operability of the EDG "turning gear engaged" lockout feature, the procedures associated with the EDG systems were well written and human factored with relatively few exceptions as listed above.

The licensee demonstrated minor weaknesses in their corrective action programs by not following through with timely and appropriate corrective action for deficiencies on the EDG injector return line check valves and the B1 air receiver relief valve.

9. SUMMARY OF TRACKING ITEMS IDENTIFIED IN THIS REPORT

The following is a synopsis of the status of all open items generated, closed, or left open in this inspection report:

IFI 90026-2 was closed.
VIO 91003-3 was closed.
LER 91014 was closed.
VIO 92008-1, "Failure to comply with a work instruction hold point," was opened.
VIO 92008-2, "Failure to meet Technical Specification surveillance for EDG lockout," was opened.
IFI 92008-3, "Tracking of procedure upgrade to calculating shutdown margin," was opened.
IFS 92008-4, "Tracking of EDG ESF walkdown deficiency correction," was opened.

10. EXIT INTERVIEW

The inspection scope and findings were summarized on May 5, 1992, with those persons indicated in paragraph 1 above. The licensee acknowledged the inspectors' findings. The licensee did not identify as proprietary any of the material provided to, or reviewed by, the inspectors during this inspection.