ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

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Licensee: Louisiana Power and Light Company
317 Baronne Street
New Orleans, LA 70160

Facility: Waterford Steam Electric Station, Unit 3

Inspection At: Waterford SES, Unit 3, Taft, Louisiana

Inspection Conducted: February 1 through February 12, 1988

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Summary:

a. Areas Inspected

During this special, announced team inspection, the NRC inspectors assessed the licensee's quality verification organizations' ability to identify, resolve, and prevent the recurrence of safety-significant deficiencies in the functional areas of plant operations and maintenance. The inspectors also assessed line management's ability to ensure that identified deficiencies are dealt with promptly and completely.

b. Results

The NRC inspectors made seven observations in the functional areas of plant operations and maintenance that were considered to be weaknesses and two potential enforcement findings in the functional area of operations. The two potential enforcement findings are associated with the failure to report approximately 20 events to the NRC and with control room personnel's not responding to signals on the bypassed and inoperable status indication system.

The NRC inspectors determined that the licensee's current quality verification activities in the areas of operations and maintenance were such that problems were effectivly identified and problems were adequately resolved, but that the prevention of the same and similar occurrences required improvement. The inspectors also found that line management dealt with identified deficiencies promptly but not always completely.

1.0 INTRODUCTION

During this special, announced team inspection at Waterford Steam Electric Station, Unit 3, the inspectors assessed the technical credibility of the licensee's quality verification organizations. The inspectors assessed those organizations' ability to define identified deficiencies, provide insight into the root causes of deficiencies, and approve and confirm the resolution of deficiencies in a technically meaningful way. The inspectors also assessed line management's ability to ensure that identified deficiencies are dealt with promptly and completely.

The inspection was the sixth in a series of NRC headquarters-directed inspections performed under the guidance of NRC Inspection Manual Temporary Instruction 2515/78, "Inspection of Quality Verification Functions." During these multidiscipline team inspections, the inspectors directly observe in-process activities, interview licensee personnel, and review work documents to evaluate the effectiveness of quality verification organizations and management. Quality verification function inspections (QVFIs) are performance based: they are intended to verify the technical adequacy of safety-related activities; they are not intended to verify licensee compliance with administrative controls.

This QVFI at Waterford 3 emphasized plant operations and maintenance. The inspectors observed samples of activity and reviewed work documents in those and closely associated areas in order to identify safety-significant problems. Those problems were used as the vehicles for assessing the effectiveness of the licensee's quality verification organizations. The details and findings of those observations, reviews, and assessments follow.

The more significant findings of the inspection team have been categorized as potential enforcement findings (PEFs) and observations. PEFs pertain to apparent violations of regulatory requirements that will be further evaluated by NRC Region IV personnel for possible enforcement action. Observations pertain to those items that do not violate regulatory requirements and may not violate plant procedures but appear to be less than optimum.

The reader should understand that the licensee uses a multiplicity of documents and processes to record, assign, take action on, and track various identified deficiencies. Those documents and processes include condition identifications (CIs), corrective action requests (CARs), deficiency notices (DNs), plant improvement lists (PILs), potential problem notices (PPNs), potentially reportable events (PREs), quality notices (QNs), temporary alteration requests (TARs), and work authorizations (WAs). Of significance in this report are CIs to deal with hardware problems, QNs to deal with non-hardware problems, and PREs to deal with problems that have a potential for being reported to the NRC. The above documents and processes are interrelated, and more than one type may ultimately be involved in the licensee's treatment of a given problem

2.0 PLANT OPERATIONS

The NRC inspectors evaluated the effectiveness of the licensee's quality verification activities in the area of plant operations by direct observation

of control room and plant activities, interviews with licensee personnel, and reviews of appropriate plant documents.

Activities observed included control room routines (such as shift turnovers, logkeeping, annunciator response, and overall operator performance), operators' plant tours, a short outage, and various planning and status meetings. Interviews were conducted with personnel from the Departments of Operations and Quality Assurance (QA). The inspectors reviewed implementation of the locked valve and breaker control program, key control program, the CI program, the temporary alteration program, and the PRE notification program. They also evaluated the performance of the Plant Operations Review Committee (PORC).

The inspectors conducted numerous plant tours to independently assess equipment conditions and to ascertain whether appropriate corrective action had been initiated to address each identified problem. The inspectors also accompanied operators on their plant walkthroughs.

2.1 Control Room Operations

The inspectors reviewed routine control room activities, interviewed personnel, and reviewed selected documents maintained in the control room and shift supervisor's office. Overall, operator knowledge of system operation and plant status appeared adequate. Review of the control room (narrative) logs and auxiliary operator logs indicated a commitment to detail and an orientation toward the proper documentation of safety system status. The Equipment-Out-of-Service (EOS) Logbook, however, showed some minor deficiencies relating to missing limiting condition for operation (LCO) entries. These discrepancies were discussed with the control room supervisor, who agreed to take appropriate corrective action.

Several shift turnovers were observed during the inspection. Each appeared to be properly executed, and the information passed between shifts was clear, complete, and concise. All involved persons conducted themselves in an orderly and businesslike manner. Access to the main control room area and the adjacent shift supervisor's office was strictly controlled at all times.

Operators understood annunciated conditions. Except for one area, response to annunciators and other alarms was timely and proper. That one exception involved the bypassed and inoperable status indication system (BISIS), controlled by Operational Procedure OP-4-020, "Bypassed and Inoperable Status Indication System." In the control room, the BISIS panel consists of rows of combination pushbuttons and annunciators. Step 6.1.4 of OP-4-202 requires the operator to acknowledge an "inoperable" signal by depressing the pushbutton; Step 6.1.5 requires an evaluation of the status of the equipment that caused the indication.

Previously in Quality Notice QN-QA-86-073, the QA Department had addressed a condition of general inattention to the BISIS, including lack of an operating procedure and a perception that the system had never been completely operable. The procedural deficiency was resolved by the creation of Operational Procedure OP-4-020, which the NRC inspectors reviewed. Discussions with operators indicated an understanding of and an appreciation for the system.

Technical Specification 6.8.1.a., by reference through Appendix A of Regulatory Guide 1.33, requires implementation of procedures (Operating Procedure OP-4-020) for response to offnormal conditions. However, at various times during the inspection, including February 5 and 9, 1988, the inspectors observed "standing" signals that had not been acknowledged. They also observed signal actuations at about 1:00 p.m. on February 8 (annunciator no. 6, trains A and B--containment isolation) and at about 3:20 p.m. on February 10 (annunciator no. 1, Trains A, B, and AB--emergency feedwater). On both occasions, the operator did not depress the pushbutton to acknowledge the annunciator. In both instances the inspectors questioned operators and were satisfied that the operators knew the status of the monitored systems. Nonetheless, casual disregard of an independent warning of safety system inoperability is not an attribute of prudent, safe operation (Item No. 88-200-01, Potential Enforcement Finding).

2.2 Equipment Status Control

2.2.1 Locked Valves and Breakers

While touring the facility, the NRC inspectors observed that two valves had their locking cables disconnected and were in an offnormal position and that several locking cables had sufficient slack to permit considerable valve travel. The shift supervisor was aware of the valve configuration and explained the purpose of the realignment to the inspectors. Previously, the QA Department had addressed loose cables in QN-QA-87-100, but corrective action had not been effective. The inspectors concluded from discussions, a review of the locked-valve deviation sheets, and a review of key control that the subject valves were properly controlled. The QA Department had addressed other discrepancies in this area, and those discrepancies had been resolved. The inspectors found that control of locked valves and breakers and their their respective locking devices was an area in which quality verification involvement was effective except in regard to loose cables.

2.2.2 Control of Temporary Alterations

The inspectors noted certain conditions that appeared to be unapproved alterations of plant design. Among these were two brass petcocks and temporary drain lines that were connected to the B emergency diesel generator intake air drain taps. The requirements of Procedure UNT-5-004, "Temporary Alteration Control," were not being met, in that the conditions were not reviewed, approved, and tagged; they were not under continuous observation/control; and they were not covered by any other administrative controls. Both conditions were rectified once they were identified by the NRC inspectors.

Licensee quality verification organizations have repeatedly identified discrepancies in implementing temporary alteration controls, which involved administrative rather than hardware deficiencies in every case but one--a problem with the control of lifted leads. Examples in QN-QA-86-074, initiated by the QA Department, included not following UNT-5-004 administrative controls, procedure deficiencies involving lax tracking or verification requirements, missing data, late PORC reviews, and other review deficiencies. QN-QA-86-150 identified five temporary alterations more than 12 months old for which station modification requests had not been initiated

as required. QN-QA-87-066 noted that a licensee commitment that jumpers be color coded and made distinguishable from plant wiring had not been incorporated in UNT-5-004. QN-QA-87-134 documented an example of failure to perform independent verification on removal of a temporary alteration. QN-QA-87-136 documented a premature closure of a temporary alteration request because of an error in the issuing sequence for station modification documents.

The unauthorized conditions noted by the team, the recent occurrence of a hardware problem, and the persistence of administrative discrepancies indicate that the documentation of temporary alterations is improving, in that discrepancies are less widespread, but that corrective actions have not yet fully succeeded in ensuring that adequate control is maintained over temporary alterations (Item 88-200-02, Observation).

2.3 Test Controls

No significant testing activities were underway, so none were directly observed by the inspectors. Instead, the inspectors reviewed licensee quality verification documents in this area and during that review noted three quality notices (QNs) that addressed test program discrepancies. For example, QN-QA-86-068 addressed eight valve test program deficiencies, nine pump test program deficiencies, seven miscellaneous procedure discrepancies, and dozens of instances of missing data. Because of the time limitations of the inspection, the NRC inspectors were not able to perform a detailed technical evaluation to validate findings and corrective actions. The inspectors believe that substantial corrective actions are in progress and are planned.

The inspectors also noted QN-QA-87-128, which involved instrument testing. Seven findings resulted in six areas or items of procedure enhancement. These actions strengthen the assurance that testing properly indicates actual system performance. However, the seventh finding had not been corrected. Two contacts on relay K410, which close to control valves ACC-126A and ACC-126B, were not checked by using Procedure OP-903-094, "ESFAS Subgroup Relay Test Operating," to see if they closed. The response of engineering personnel to the QN indicated that "standard industry practice is to consider a relay operational if some but not all of its contacts are checked to operate properly." At the time of the inspection, the response had not been accepted by the QA Department. Further action is required to ensure that the stated practice has not been implemented, because the failure to adequately test and thereby confirm that all contacts are functional could lead to safety system unreliability (Item No. 88-200-03, Observation).

2.4 Trending

The NRC inspectors examined documents associated with the trending of deficiencies identified in the operations area. The trending program developed and implemented by the QA Department over the last 2 years was used in the review. Procedure QAP-103, "Trending," describes this program and was also reviewed by the inspectors.

In summary, the trending database has been developed from a variety of corrective action documents, responses, and commitments that are classified as to significance, type of problem, activity in progress when the problem occurred, affected plant discipline, and primary and secondary causes. The documents include NRC notices of violation, licensee event reports (LERs), deficiency notices (DNs), quality notices (QNs), and those condition identifications (CIs) identified as nonconforming. Potentially reportable events (PREs) that are precursors to LERs (about one-fourth of all PREs), DNs, and QNs are covered by review of the duplicative documents. The remaining three-fourths of the PREs have not been trended, which is a significant omission the licensee plans to correct.

At the time of the NRC inspection, a revised and broadened trending program was being developed as part of a licensee organizational responsibility change. The licensee plans the new program to be under the Events Analysis, Reporting, and Response staff organization, rather than under the QA Department. The NRC inspectors recommended to the licensee's representative that the QA Department maintain an oversight involvement in the program for trending deficiencies.

Quarterly reports are compiled covering some aspects of the trending process. Two major graphic displays are generated for each plant functional area addressed under the NRC Systematic Assessment of Licensee Performance (SALP) program. One display is an overall indicator for each area, presented along with three previous indicators to show a visual trend. The other display is the average significance calculated for the reports reviewed in each area, also presented along with the three previous results. Neither category of indicator is sensitive to changes in problem type, activity, or cause code, but both are strongly affected by the NRC-assigned SALP rating. Additionally, the mechanism for smoothening the graphic presentations was such that the fact that 13 (of 15) instances of personnel error occurred in the same quarter was not highlighted. The NRC inspectors concluded that the sophistication of the statistical treatment in the current trending program could be enhanced. This issue was discussed with licensee personnel, who stated they would review the matter and take appropriate action.

Discussions with QA Department personnel and with plant operations management revealed that the available trending information had not been commonly used. Further, no effort had been made to analyze problems in the operations area by significance, activity in progress, or cause. The Operations Department reviews, develops, and implements corrective and preventive actions and processes documentation for assigned corrective action items individually, in isolation from other corrective action items.

The inspectors discussed with licensee personnel their conclusion that the licensee should be more sensitive to creating a comprehensive, integrated system to develop and respond to trends (Item No. 88-200-04, Observation).

2.5 Condition Identification (CI) System

The licensee has a tracking system whereby plant hardware problems are specifically identified, corrective actions recorded, and their status tracked to completion. Both the system and the document are called CI. Any person who

notes an adverse condition in the plant can initiate a CI, and all CIs are evaluated to determine whether a work authorization is warranted. To verify proper implementation of this program, the inspectors conducted walkdowns of diesel generators A and B, the reactor auxiliary building ventilation system, the component cooling water system, and steam generator feedpumps A and B. They identified 62 CI tags identifying abnormal conditions. The inspectors determined that all CIs were current and that appropriate work authorizations (WAs) had been initiated. Each WA was checked for priority status and reviewed for current stage of completion. The inspectors found that none of the CI tags found on plant equipment during the walkdowns were left in place after work was completed. The inspectors concluded that quality verification activity, with emphasis on the area walkdown program and use of plant improvement lists, was effective in this area.

The CI and WA systems have been computerized and made part of the station information management system (SIMS). Information for CIs and WAs is entered, tracked, scheduled, and documented in SIMS. As part of their review, the inspectors requested information related to the initiation of and corrective actions taken or scheduled for each of the subject 62 items. Although the information was ultimately available, the searches through the SIMS databases and subsequent retrieval of the requested information were complex and time consuming in several cases. Licensee personnel acknowledge this deficiency and are currently in the process of making modifications to the SIMS to allow greater search capabilities and to ease the retrieval process.

Within the last year, five QNs were written by the QA Department concerning CIs. QN-QA-87-058, -059, -086, -106, and -125 addressed the closure of a CIWA before work was completed, multiple CIWAs with the same serial number, violations of UNT-5-002, "Condition Identification," and CI tags in the control room that were not removed upon completion of work activities associated with those tags. In each case, the corrective actions taken appeared adequate to address the individual problems. The inspectors discerned no trend in this area.

3.0 MAINTENANCE

The NRC inspectors evaluated the licensee's quality verification activities in the area of maintenance by direct observation of ongoing maintenance activities, discussions with Maintenance and QA Departments personnel, and review of maintenance work packages and corrective action programs that the quality verification organizations use for identifying, resolving, and preventing recurrence of safety-significant deficiencies. The work packages and corrective action documents were reviewed to verify appropriate work authorization clearances, quality control involvement, restoration of equipment following maintenance, post-maintenance testing, corrective actions when required, and procedural compliance by station personnel during the observed maintenance activities. The inspectors also assessed the effectiveness of line management in ensuring that identified deficiencies were dealt with appropriately and that the corrective actions were adequate.

At Waterford 3, all authorized maintenance activities are performed under work authorizations (WAs). Corrective maintenance activities are initiated by the issuance of CIs which describe the observed deficiency and identify

the deficient component in the field by the placement of a CI tag on or adjacent to the component. All CIs are reviewed by the control room supervisor (CRS) to determine equipment operability and applicability of any Technical Specification action statements. Control of plant equipment on which maintenance is performed is implemented by a clearance request (CR), which is controlled and approved by the CRS. The CR provides for tagging out plant systems and components for the protection of plant personnel and establishment of the boundary around the affected system or component. Procedures are in place for the safe performance of maintenance.

3.1 B Diesel Outage

The NRC inspectors witnessed a maintenance outage for the B emergency diesel generator (EDG). Principally, the outage was to repair the air-operated valve that cuts off oil to the turbocharger bearings when the diesel generator is stopped. The valve had been previously found partially open and oil had been leaking into the engine air intake while the diesel was stopped. The remainder of the outage was spent in locating and repairing air leaks in the diesel engine control air system. The outage was controlled by one clearance and five WAs. The planned sequence was to work on the post-stop oil valve problem and then locate and repair the air leaks in the control air system.

The clearance identified the maintenance boundary with five danger tags: (1) the overspeed trip on the diesel engine (tripped), (2) the control switch in the control room, (3 and 4) 3-inch air valves on the left and right sides of the diesel engine (closed), and (5) the maintenance air valve (open). The job required the clearance to be executed in sequence: the first two tags would be hung and, when the air was no longer needed, the last three would be hung.

Although craft personnel were familiar with the scope, boundary, and hazards involved in the activity and had accepted the implemented clearance as sufficient for the maintenance activity, and operations personnel were present and controlling all valve manipulations, the maintenance activity was performed in an order and method different from that expected by the control room staff. (It appears that similar instances were documented by eight quality notices as discussed in Section 3.4 of this report.) The fundamental reasons for this confusion were the use of maintenance summary notes and the absence of a plan of the day in the control room. The notes had been provided by the system engineer in an attempt to describe the required outage activities; however, the notes were brief and vague.

Contrary to earlier planning, the jobs were performed in parallel. Also, an air pressure greater than the 90 psig plant was found to be required. However, 30 psig control air had to be secured before the control air system repair. The revised work sequence required leaving open the two 3-inch air valves and opening the maintenance air valve; that is, three of the tags on the clearance were not to be used. To isolate the engine control air system, four additional valves (two on each side of the engine) were secured by a plant operator with the approval of the shift supervisor. The valve numbers and positions were written on informal notes by the operator and the control room supervisor. However, the valves were not added to the clearance, and

no danger tags were hung on the valves. Thus, the clearance inaccurately identified the boundary.

The following situations not conducive to safe plant operation were found with respect to the clearance:

1. The shift supervisor did not have formal control of the separation of maintenance activity from the safe operation of the rest of the plant because the clearance did not identify the actual isolation boundary (as defined in Section 3.5 of UNT-5-003, "Clearance Requests, Approvals, and Release") and no caution or danger tags were used on the added four valves (Item No. 88-200-05a, Observation).

2. The shift supervisor could not formally and safely control the work in progress because the clearance document listed only one of the five WAs being performed and described none of the work activity (Item No. 88-200-05b, Observation).

3. The systems could not be restored formally and safely in order to complete the activities (that should have been specified) in the clearance in accordance with Sections 4.3.7, 5.9.7, and 5.9.7.2 of UNT-5-003 because four boundary valves were not included in the clearance (Item No. 88-200-05c, Observation).

The NRC inspectors found that the crews who performed the work specified in the five WAs were technically knowledgeable and efficient, the technical knowledge of the system engineer was excellent, and the specific task of each WA was accomplished. The NRC inspectors concluded that a comprehensive pre-maintenance briefing involving all participants would have reduced the observed safety concerns.

During the outage, QA Department personnel were monitoring the work in progress. In this instance, their audit activities apparently did not result in the same observations as those of the NRC inspectors. This may be in part due to a weakness in disciplinary cross-training for Operations QA personnel as discussed in Section 4.2 of this report. By the end of the inspection, no QN had been initiated by Operations QA personnel concerning errors that occurred during the outage.

3.2 Reactor Coolant Pump Thrust Bearing Overheating

The inspectors reviewed the licensee's lubrication program to evaluate the proposed root cause of the recent forced outages because of reactor coolant pump (RCP) 2B motor bearing high temperatures. The 2B RCP upper thrust bearing temperature had increased significantly on three occasions between September 1987 and January 1988. On each occasion, a plant shutdown was required to prevent damage to the bearing. The inspectors noted that, each time, the licensee removed and cleaned the clogged lubrication oil system strainer as corrective action. The substance clogging the strainer had not been identified. The system engineer stated that he had left verbal instructions to preserve the strainer mesh in the as-found condition during the last forced outage. His plan was to send the strainer to a testing laboratory for analysis; however, the inspectors determined that, since the instructions

were not written into the work authorization, the maintenance mechanics performed the normal cleaning of the strainer without preserving the clogging substance.

The inspectors noted that the period between strainer cloggings had become shorter: 6 months, 3 months, and 1 month. After conferring with the vendor, licensee personnel decided to increase the filter mesh size from 200 to 64, thereby reducing the chance of clogging before the planned refueling outage in April 1988. In a January 26, 1988 letter to the licensee, the vendor indicated that the 200 mesh filter could be removed without affecting the operation of the motor. The inspectors reviewed the technical manual and noted it stated that when the oil and system are known to be clean, the motor may be operated continuously either with or without the 200 mesh strainer basket. The licensee stated that another utility removes the strainer basket after the completion of the vendor-recommended 24-hour continuous cleaning period without clogging of the strainer. The licensee also stated that changing to the 64 mesh strainer resulted in the reduction of the thrust bearing temperature from 185°F to 175°F. The inspectors noted, however, that the recurrence of clogging is an indication that either the oil is being degraded or there is some foreign substance in it. The inspectors communicated their concerns to licensee personnel, who stated that efforts to discover and eliminate the cause for clogging would continue.

The failure to have the material clogging the strainer identified after both the second and third occurrences indicated a weakness in the licensee's corrective action program. This is another specific instance of promptly identifying a problem, fixing that problem (cleaning the filter), but not preventing a recurrence.

As further review of the lubrication program, the inspectors examined the licensee's procedure, UNT-05-007, for changing the type of oil or other lubrication used in all plant equipment. The inspectors noted the following two deficiencies in the procedure: (1) the lubrication evaluation was not reviewed for technical adequacy, and (2) concurrence of the equipment vendor was neither required nor requested. The inspectors communicated their concern to licensee personnel that the licensee should assure itself that the designated lubricant is adequate. The licensee's representative stated that the matter would be reviewed and appropriate action taken.

3.3 Observation of Other Maintenance Activities

Seven other maintenance activities were observed by the inspectors. Observation of the activities and review of the work packages for those activities resulted in several minor procedural observations that were discussed with licensee personnel and closed.

3.4 Corrective Actions

The licensee utilizes the quality notice (QN) as a major part of the corrective action program because it is a document that is used to identify conditions considered to be adverse to quality and provides the mechanism for identifying appropriate corrective actions and verifying that they are completed. The inspectors selected approximately forty 1986-87 QNs for review.

The inspectors noted the following four trends of recurring deficiencies:

1. expansion of work scope by the Maintenance Department without proper authorization: eight QNs

2. failures in independent verification program/failure to follow procedures: seven QNs

3. deficiencies in the equipment lubriciation program: three QNs

4. inadequate controls over maintenance activities performed by contractors: three QNs

The inspectors concluded that, for the trends noted above, the licensee's corrective actions have not been effective. For example, the QNs on the expansion of scope and failure to follow procedures detailed sequences of increasing corrective action efforts, each of which was ineffective, as described by the subsequent QNs. As another example, the review of problem-reporting documents in the trending records showed that, over the past 2 years, approximately 21 percent of the maintenance problems were attributable to failure to adhere to procedures. On the basis of interviews and the review of management memoranda and general employee procedures, the inspectors found that the licensee's management was aware of the problem of compliance with procedures and stressed this compliance in frequent communications to the plant staff. However, the NRC inspectors observed instances of the operators and maintenance personnel not complying with procedures, as documented in Sections 2.1, 2.2.2, and 3.1 of this report. The NRC inspectors, therefore, concluded that corrective actions to improve compliance with procedures by both plant operators and maintenance personnel continue to be ineffective and questioned whether a comprehensive corrective action program was being used to correct the root causes of identified problems (Item No. 88-200-06, Observation).

3.5 Maintenance Advisory Group

The inspectors reviewed the minutes of all of the Maintenance Advisory Group (MAG) meetings and the issues which are being followed by the MAG. The MAG was formed in 1987 to address problems with Maintenance Department activities and is composed of the Maintenance Department manager, several maintenance supervisors, and several technicians or crafts personnel. The inspectors noted that four of the MAG issues involved deficiencies in regard to compliance with procedures. The corrective actions for these issues are planned but had not been implemented at the time of this inspection.

4.0 QUALITY VERIFICATION FUNCTIONS

4.1 Plant Operations Review Committee (PORC)

The inspectors evaluated the functioning of the (onsite) PORC to determine the level and quality of PORC involvement in the management of plant operation. The inspectors attended two PORC meetings and reviewed PORC meeting minutes for the period of November-December 1987 to assess the adequacy of reviews and proceedings.

The inspectors noted that the PORC meeting minutes were of a checklist type with little, if any, substantive information provided as justification for particular PORC actions taken or decisions and recommendations made. This same concern was identified by the Safety Review Committee, which recommended that the meeting minutes be upgraded.

One of the PORC's functions is to review each potentially reportable event (PRE) and provide an independent verification of the proper classification, either reportable or nonreportable. In this manner, the initial decision made by the Manager, Events Analysis, Reporting and Response group, is given an independent check. Deficiencies that are not classified as reportable appear to get less thorough and less timely attention than items that are classified as reportable. Review of the PRE summary index for 1987 showed much more timely reviews (always well within 30 days) for reported PREs than for PREs deemed not reportable.

The inspectors noted that, of the 11 reportable failures discussed in Section 5.0.j of this report, 5 events had been reviewed and approved by the PORC as not reportable. In addition, PORC concurred that the overspeed trips and the fuel oil failure discussed in Sections 5.0.h and i, respectively, were not reportable. In one instance, the PORC meeting minutes stated that the PORC had been assured by the PRE reviewer that the event was not reportable. That statement indicates that the PORC needs to provide more effective independent verification of events (Item No. 88-200-07, Observation).

4.2 Operations Quality Assurance

The NRC inspectors reviewed activities of the Operations QA personnel and found that the personnel monitor plant operating activities by performing audits and surveillances and by attending planning and status meetings. An independent QA organizational arm at the site developed and operates a performance trending program covering all plant activity areas, including operations, using various corrective action documents.

The Operations QA organization appeared to be performance oriented and staffed by personnel well qualified to function as auditors and QA inspectors. The organization employs four licensed operators who perform detailed audits and surveillances of control room and operational activities. A sample of audit and surveillance reports generated by this group was reviewed, and each appeared performance oriented, was well written, and identified areas of concern in a clear, concise manner.

During discussions with the Operations QA Manager, the inspectors were informed of an apparent weakness in QA reviews of activities affecting multiple disciplines; that is, it is difficult for a person expert in only one of the disciplines to obtain an overview of activities affecting more than one department, such as the interaction between operations and maintenance personnel when preparing for an equipment outage. This situation has been recognized by licensee management, and an effort to cross-train QA personnel in other disciplines is being planned.

4.3 Safety Review Committee (SRC)

Because there was no meeting of the (offsite) SRC during this inspection, the inspectors reviewed minutes from the last two SRC meetings. They found that the SRC was involved in a number of issues germane to the scope of this inspection. For example, the SRC was attempting to improve its review of PORC activities, was recommending a general root cause analysis process for all plant trips, and was recommending the establishment of a system for controlling individual interpretations of the Technical Specifications. The activities of the SRC appeared appropriately oriented to plant safety.

4.4 Nuclear Operations Support and Assessments (NOSA)

NOSA is an organization on the staff of the Vice President, Nuclear. Among its responsibilities are the performance of independent safety reviews of plant activities and of plant system problems and performance. The inspectors reviewed NOSA personnel and activities and found that highly experienced personnel perform safety-oriented audits and surveillances. The draft schedule of NOSA's 1988 planned activities showed an appropriate level of involvement with plant operations and safety.

5.0 REPORTING

During review of PREs, the inspectors noted that the following events had not been reported to the NRC as required by 10 CFR 50.73 and Technical Specification 4.8.1.1.3:

1. PRE-87-015 concerned an event of February 1, 1987 during which the broad range toxic gas detection system (BRTGDS) actuated to isolate the control room ventilation systems. The BRTGDS is significant to safety at Waterford because of the location of the plant in the near vicinity of several chemical plants. An original license condition required development of the system and incorporation of operating requirements in the unit Technical Specifications. The system is not a defined engineered safety feature per the Final Safety Analysis Report (FSAR)--a fact on which the licensee bases its argument that reporting is not necessary. Technical Specification Basis 3/4.3.3.7 describes the system as providing prompt detection of toxic gas releases that could pose "an actual threat to safety of the nuclear power plant or significantly hamper site personnel in performance of duties necessary for the safe operation of the plant." This is the language of 10 CFR 50.73(a)(2)(iii) for reporting such threat or hampering. Inasmuch as the event of February 1, 1987 was considered a valid actuation because of the detection of some noxious gas by both instrument channels, the event should have been reported (Item No. 88-200-08a, Potential Enforcement Finding).

2. PRE-87-019 discusses the licensee's February 10, 1987 discovery that the main steam isolation valves were both provided with actuator nitrogen pressure transmitter taps that were positioned so that the transmitter was not exposed to nitrogen pressure when the valve was fully open. Loss of actuator nitrogen pressure would be undetectable. Therefore, the capability of the valve to close could be lost or would

at least be slowed from the 3-second stroke time required, and this would not be known. The licensee's rationale for not reporting relies on an absence of requirements in Technical Specifications directly addressing this nitrogen pressure and an absence of evidence that nitrogen pressure was ever too low to close the valve in 3 seconds. Since the nature of the problem was to make nitrogen pressure impossible to determine, lack of evidence that it was low is a given and contributes nothing to the question of reportability. Had an undetected loss of pressure occurred between quarterly tests, the plant would have been in a configuration not protected from single failure of the opposite valve--a condition "outside the design basis of the plant" and reportable per 10 CFR 50.73(a)(2)(ii)(B) (Item No. 88-200-08b, Potential Enforcement Finding).

3. PRE-87-039 concerns a non-safety (i.e., non-Class 1E) electrical load (telephone cabinet PEC-2) that was found connected to a Class 1E circuit through a single breaker. The FSAR, by reference to Regulatory Guide 1.75-1975, requires double protection for all such connections. Two interpretations of FSAR language summarizing circuit design are possible. The word "some" is used so that it can be interpreted that some non-Class 1E loads do not have double protection. The other interpretation is that some non-Class 1E are connected to Class 1E circuits and some are not. The licensee chose to make the first interpretation in its rationale for not reporting. This treats the summary description as an exception to Regulatory Guide 1.75-1975. The alternate interpretation is consistent with the regulatory guide, gains credence by way of this consistency, and appears the more appropriate in establishing the design basis of the plant. Discovery of a non-Class 1E load not provided with double protection from Class 1E is thus "outside the design basis of the plant" and is reportable per 10 CFR 50.73(a)(2)(ii)(B) (Item No. 88-200-08c, Potential Enforcement Finding).

4. PRE-87-076 addresses the discovery that wires to relay SVS-EREL-1242BS had been connected to the wrong relay terminal. This condition, which existed from July 7 until August 17, 1987, would have prevented an autostart of the AH-30(A) switchgear ventilation recirculation fans on an engineered safety features actuation system actuation. Manual and high-temperature starts remained available. The justification for not reporting involves reliance on manual or high-temperature circuits to start the fans and maintain an acceptable environment for the safety equipment (A train ac and dc switchgear) that is supported. Manual actuation is generally not creditable in accident analysis, however, and no argument or information is provided concerning whether the temperature-controlled circuit is safety grade. Further, since the problem was caused by an undetected error in the performance of a periodic (10-year) replacement of the relay, substantial potential may have existed for a like error in the redundant circuit. This also was not addressed. If the temperature circuit is not safety grade, the supported systems may not have been fully operable, a condition that is prohibited by Technical Specifications and that is reportable per 10 CFR 50.73(a)(2)(i)(B). If it is not known that a similar error was very unlikely to place the opposite train at risk, both trains could have been affected by a single cause (personnel

error), which is reportable per 10 CFR 50.73(a)(2)(v)(D) (Item No. 88-200-08d, Potential Enforcement Finding).

5. PRE-87-078 addresses delinquent sampling and analysis of an onservice waste gas decay tank. With both automatic monitoring channels inoperable, Action 40 of Technical Specification Table 3.3-13 permits continued operation of the waste gas holdup system provided "that a grab sample is taken and analyzed from the onservice gas decay tank at least once per four hours." The licensee interpreted this statement to mean 4 hours to sample and 4 hours thereafter to analyze, for a total of 8 hours. On August 19, 1987, a 5:00 a.m. sample was collected but, because of an equipment problem, could not be analyzed. The gas holdup system continued in operation until 1:30 p.m., 8.5 hours later. The licensee's rationale for not reporting in this case involved application of a 25-percent interval extension (from Technical Specification 4.0.2) to the presumed 8-hour interval, giving a new total of 10 hours--which had been met. The licensee has taken some liberties with the requirement to sample and analyze "at least once per four hours" in its initial interpretation that 8 hours are allowed. Furthermore, application of the 25-percent "grace period" to extend this interval is inappropriate. Specification 4.0.2 applies to routine (Section 4) periodic surveillance testing requirements, not to compensatory (Section 3) action requirements.

   Routine tests verify that conditions believed to be satisfactory are in fact so. Compensatory tests relate to known unsatisfactory (i.e., lost automatic monitoring) conditions. This occurrence is reportable in accordance with 10 CFR 50.73(a)(2)(i)(B) on the basis that operation of the holdup system with required testing not performed is a condition prohibited by Technical Specifications (Item No. 88-200-08e, Potential Enforcement Finding).

6. The inspectors found that the licensee had repeatedly misapplied the grace period of Technical Specification 4.0.2 to action requirements involving testing, with PRE-86-021 being another example (Item No. 88-200-08f, Potential Enforcement Finding).

7. PRE-87-099 addresses a failure to complete routine surveillance testing on valve CAP-205. Pursuant to Technical Specification 4.0.5, a stroke time test is to be performed at quarterly (92-day) intervals, but no such test was performed from May 6 until September 29, 1987, a period of 146 days. Upon expiration of the surveillance interval (plus 25 percent) on August 29, 1987, the valve should have been declared inoperable. Unaware the required test had not been done, licensee operators continued to rely on and to utilize the valve as though it were operable. This included use of the valve in purging the containment on September 3, 4, 21, and 22. The rationale for not reporting was that cumulative leakage past associated valves was so small as to make the operability of CAP-205 immaterial in meeting containment leakage limits. Thus, limiting conditions for operation were not exceeded. This is important information relating to the significance of the matter but is a consideration separate from reportability. Failure to perform

required testing is itself a condition prohibited by Technical Specifications and, as such, is reportable per 10 CFR 50.73(a)(2)(i)(B) whether or not events later prove the missed testing lacked significance (Item No. 88-200-08g, Potential Enforcement Finding).

8. PRE 86-113 identified four overspeed trips of emergency diesel generator (EDG) A during the monthly engineered safety features actuation system testing specified in procedure OP-903-069. Since the overspeed trip is not bypassed in the emergency mode of the EDG, the failures are required to be the subject of a special report in accordance with Technical Specification 4.8.1.1.3, which has required the reporting of diesel failures since December 1984 (Item No. 88-200-08h, Potential Enforcement Finding).

9. PRE 87-013 identified a failure of EDG B during the monthly surveillance test, OP-903-068, because of a fuel oil leak in fuel injector 4L. The failure was not reported because, according to the PRE, the leakage would not have resulted in damage or failure of the EDG. However, the auxiliary operator indicated in his log that the turbocharger was smoking after the leak was discovered. A special report was required by Technical Specification 4.8.1.1.3 because the smoking fuel oil should have been judged a precursor to an EDG fire and subsequent failure (Item No. 88-200-08i, Potential Enforcement Finding).

10. Since August 1, 1985, the licensee has not reported 11 failures of the EDGs as required by Technical Specification 4.8.1.1.3. Included in this total is one that was reported, but that report was later rescinded. The subject PREs are 86-007, 86-020, 85-028, 87-047, 87-059, 87-061, 87-073, 87-106, 87-113, 88-005, and 88-015. Each of these failures was not reported because the failure involved EDG trips that were bypassed in the emergency mode. Since these trips would not have prevented the EDG from operating in the emergency mode, the licensee correctly classified the failures as non-valid tests. However, the licensee erroneously concluded that, because the test was not valid, the test did not occur; therefore, a failure as defined by Regulatory Guide 1.108 did not occur, and a special report of the failure was not required. The determination of valid or nonvalid tests is necessary in order to determine the periodicity of the required surveillance and does not influence the requirement to report (Item No. 88-200-08j, Potential Enforcement Finding).

The licensee's logic for not reporting these failures was in error and appeared to be driven by a desire to minimize the reporting of events. The reduction of licensee event reports by 50 percent in 1988 was a corporate goal. That goal was rescinded midway through this NRC inspection. This non-reporting attitude has prevented the NRC from recognizing a significant deficiency in the performance of the EDGs at Waterford. Since May 8, 1987, EDG A has tripped seven times as a result of spurious signals attributed to low turbo lube oil pressure. As a result of inadequate or ineffective corrective actions, the diesel has failed to start on the initial attempt during every periodic surveillance since May 1987. Although subsequent attempts to start the EDG have always been successful, the failure of the EDG to start when requested is a

significant degradation of the reliability of this engineered safety feature system.

Further action is necessary to determine the root cause of the repetitive EDG failures, the adequacy of corrective actions to resolve these failures, and the operability status of the engine (Item No. 88-200-09, Observation).

6.0 EXIT INTERVIEW

The inspectors met with the licensee's representatives (included in the list in Appendix A) on February 12, 1988. The purpose, scope, and results of the inspection were discussed.

APPENDIX A

Persons Contacted

Louisiana Power and Light Company

*S. A. Alleman, Nuclear Quality Assurance Manager
*P. N. Backes, Special Projects Manager
*D. E. Baker, Event Analysis Reporting and Response Superintendent
*R. P. Barkhurst, Vice President, Nuclear
*R. F. Burski, Nuclear Safety and Regulatory Affairs Manager
*N. S. Carns, Nuclear Plant Operations Manager
D. W. Clemens, SIMS Coordinator
*J. G. Dewease, Senior Vice President, Nuclear Operations
*C. R. Gaines, Staff Assistant
*T. F. Gerrets, Nuclear Services Manager
R. H. Jenquine, I&C Supervisor
R. A. Legere, EDG System Engineer
T. R. Leonard, Planning and Scheduling Manager
*M. J. Meisner, Licensing Manager (Acting)
R. J. Murillo, Nuclear Licensing
*L. W. Myers, Nuclear Operations Support and Assessments Manager
*D. F. Packer, Assistant Plant Manager, Operations and Maintenance
J. P. Rooney, Data Processing Supervisor
R. S. Starkey, Operations Superintendent
D. W. Vinci, Maintenance Superintendent
*G. E. Wuller, Operational Licensing Supervisor
*J. J. Zabritski, Operations Quality Assurance Manager

NRC

*F. C. Hawkins, Chief, Quality Operations Section, NRR
*R. E. Ireland, Technical Assistant to the Director, Division of Reactor Safety, RIV
*W. F. Smith, Senior Resident Inspector
*T. R. Staker, Resident Inspector
*D. L. Wigginton, Waterford 3 Project Manager, NRR

Other licensee employees contacted included operators, engineers, auditors, technicians, mechanics, and office personnel.

*Denotes those attending the exit meeting on February 12, 1988.

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05/12/88	05/12/88	05/12/88	05/12/88	05/12/88	05/12/88

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