UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

REF: EDO 14670
Action: Denton, NRR
Suspense: 8-3-84

July 25, 1984

Q's 1, 2, 3 and 6 correspond to Q's in Udall's 7-26-84 letter noted in margin. Q's 4 & 5 (re-numbered 16 & 17) should be answered as part of the Udall letter.
TRehm

Cys: Dircks
Roe
Rehm
Stello
DeYoung
O'Reilly
GCunningham

MEMORANDUM FOR: Tom Rehm, Assistant to the Executive Director for Operations

FROM: Carlton Kammerer, Director
Office of Congressional Affairs

SUBJECT: REQUEST FOR INFORMATION ON GRAND GULF

The majority staff of the Committee on Interior and Insular Affairs (Chairman Udall) has requested that we respond to the following questions concerning the NRC's review of Grand Gulf.

#1+2 1. Has NRC reviewed past inspection reports and/or LERs to detect patterns of errors and subsequent corrective actions and to determine if utility management only addressed symptoms or took more exhaustive actions to determine the cause of problems discovered at Grand Gulf?

#3 2. Has NRC staff compiled a list of material false statements made by representatives of MP&L?

#10 3. Is a new SALP report on MP&L's performance being prepared?

16 ~~4.~~ HAS NRC staff prepared a report describing how NRC determined that Grand Gulf operators were adequately trained?

17 ~~5.~~ Does NRC staff have a listing of current MP&L managers describing their qualifications and the date of employment at MP&L?

#4 6. What inspections and/or assessments have been performed by MP&L to fulfill criteria 18 of Appendix B of Part 50?

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OFC

IN FILE COPY

Mississippi Power and Light Company
ATTN: Mr. J. B. Richard
Senior Vice President, Nuclear
P. O. Box 1640
Jackson, MS 39205

Gentlemen:

SUBJECT: REPORT NOS. 50-416/83-55 AND 50-417/83-09

The NRC Systematic Assessment of Licensee Performance (SALP) Board has completed its periodic evaluation of the performance of the subject facility. The Grand Gulf facility was evaluated for the period September 1, 1982 through September 30, 1983. The results of the evaluation are documented in the enclosed SALP Board Assessment. This evaluation will be discussed with you at your offices in Jackson, Mississippi on January 19, 1984.

The performance of your Grand Gulf Unit 1 facility was evaluated in the functional areas of plant operations, radiological controls, maintenance, surveillance and preoperational testing, fire protection, emergency preparedness, security and safeguards, licensing activities, and the quality assurance program. The SALP Board's evaluation of your performance in these functional areas is contained in the SALP Board Assessment which is enclosed with this letter. Several significant weaknesses were identified by the SALP Board during the evaluation process. It is the opinion of the Board that these concerns require concerted management attention to correct. The Board recognizes that major resource commitments have been made by you in the implementation of the Operational Enhancement Program and the Operator Recertification Program. It appears that these programs will result in significant performance improvements if they continue to receive proper management attention and the necessary resources.

The SALP Board evaluation process consists of categorizing performance in each functional area. The categories which we have used to evaluate the performance of your facilities are defined in section II of the enclosed SALP Board Assessment. Any comments which you have concerning our evaluation of the performance of your facility should be submitted to this office within twenty days following the date of our meeting in Jackson, Mississippi.

Your comments, if any, and the SALP Board Assessment, will both appear as enclosures to the Region II Administrator's letter which issues the SALP Board Assessment as an NRC Report. In addition to the issuance of the assessment, this letter will, if appropriate, state the NRC position on matters relating to the status of your safety programs.

In accordance with 10 CFR 2.790 (a), a copy of this letter, the enclosure and your response, if any, will be placed in the NRC's Public Document Room unless you notify this office, by telephone, within ten days following the date of our meeting in Jackson, Mississippi and submit written application to withhold

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information contained therein within twenty days following the date of our meeting. Such application must be consistent with the requirements of 10 CFR 2.790 (b)(1).

Should you have any questions concerning this letter, we will be glad to discuss them with you.

Sincerely,

Richard C. Lewis, Director
Division of Project and
Resident Programs
SALP Board Chairman

Enclosure:
SALP Board Assessment for
Mississippi Power and Light
Company

cc w/encl:
Ralph T. Lally, Manager of Quality
Middle South Services, Inc.
J. E. Cross, Plant Manager

bcc w/encl:
NRC Resident Inspector
NRR Project Manager, NRR
D. S. Price, RII
C. A. Julian, RII

RII	RII	RII	RII	RII	RII
DPrice:ht	CJulian	~~HCDance~~ Verrelli for	JPStohr	JAOlshinski	RCLewis
1/9/84	1/11/84	1/10/84	1/10/84	1/10/84	1/11/84

U. S. NUCLEAR REGULATORY COMMISSION
REGION II

SYSTEMATIC ASSESSMENT OF
LICENSEE PERFORMANCE
BOARD ASSESSMENT

MISSISSIPPI POWER AND LIGHT COMPANY
GRAND GULF NUCLEAR STATION UNITS 1 AND 2
DOCKET NUMBERS 50-416 AND 50-417

SEPTEMBER 1, 1982 THROUGH SEPTEMBER 30, 1983

INSPECTION
REPORT NUMBERS

50-416/83-55
50-417/83-09

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CONTENTS

I. INTRODUCTION

A formal licensee performance assessment program has been implemented in accordance with the procedures discussed in the Federal Register Notice of March 22, 1982. This program, the Systematic Assessment of Licensee Performance (SALP), is applicable to each operator of a power reactor or holder of a construction permit (hereinafter referred to as licensee). The SALP program is an integrated NRC staff effort to collect available observations of licensee performance on a periodic basis and evaluate performance based on these observations. Positive and negative attributes of licensee performance are considered with emphasis placed on understanding the reasons for a licensee's performance in important functional areas, and sharing this understanding with the licensee. The SALP process is oriented toward furthering NRC's understanding of the manner in which: (1) the licensee directs, guides, and provides resources for assuring plant safety; and (2) such resources are used and applied. The integrated SALP assessment is intended to be sufficiently diagnostic to provide meaningful guidance to the licensee. The SALP program supplements the normal regulatory processes used to ensure compliance with NRC rules and regulations.

II. CRITERIA

Licensee performance is assessed in certain functional areas depending on whether the facility has been in the construction, preoperational, or operating phase during the SALP review period. These functional areas encompass a wide spectrum of regulatory programs and represent significant nuclear safety and environmental activities. Functional areas may not be assessed because of little or no licensee activities in these areas, or lack of meaningful NRC observation.

One or more of the following evaluation criteria were used to assess each functional area:

- Management involvement in assuring quality
- Approach to the resolution of technical issues from a safety standpoint
- Responsiveness to NRC initiatives
- Enforcement history
- Reporting and analysis of reportable events
- Staffing (including management)
- Training effectiveness and qualification

The SALP Board has categorized functional area performance at one of three performance levels. These levels are defined as follows:

<u>Category 1</u>: Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety or construction is being achieved.

<u>Category 2</u>: NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and are concerned with nuclear safety; licensee resources are adequate and are reasonably effective such that satisfactory performance with respect to operational safety or construction is being achieved.

<u>Category 3</u>: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appear to be strained or not effectively used such that minimally satisfactory performance with respect to operational safety or construction is being achieved.

III. SUMMARY OF RESULTS

A. Overall Utility Evaluation

During this assessment period, the licensee has undertaken significant improvement programs to enhance communications and technical exchange between the plant and the corporate offices. During the previous SALP period significant problems were identified with management control systems and the timeliness of corrective actions. The overall assessment for this SALP period, therefore, reflects an implementation period during which comprehensive improvement programs were instituted. These programs, targeted to correct the root causes of the identified problems, have slowly resulted in improvements in management control and the timeliness of corrective actions. Management control, as it relates to adherence to procedures and indepth analysis of plant problems, needs improvement. The licensee's management presence at the site has improved, and top level management now participates to a greater degree in day-to-day activities and the resolution of problems and technical concerns.

B. Overall Facility Evaluation (Unit 1)

An analysis of facility activities during the SALP period shows that corrective actions have slowly resulted in improvements in many programs. However, some areas previously identified as being problem areas continue to exhibit major weaknesses. Areas exhibiting weaknesses include plant operations (including operator licensing), maintenance, surveillance, and the quality assurance program. By the end of the SALP evaluation period the root causes of these weaknesses appeared to include the failure to comply with established plant procedures; a failure by plant personnel to completely understand and comply with the regulations governing the evaluation of the potential safety significance of modifications which were made to systems and activities which are described in the Final Safety Analysis Report (FSAR); a failure to evaluate problems in sufficient depth to affect adequate corrective actions; and the failure to provide adequate training to facility personnel. A major strength was identified in the area of emergency preparedness.

In general, the licensee has devoted significant resources to solve the identified problem areas. These efforts have not yet been completely successful, resulting in the need for continued increased licensee attention in certain areas. NRC believes that, at the time of this report, the licensee has recognized these problems and has proposed corrective actions sufficient to solve them.

C. Facility Performance

Tabulation of ratings for each functional area:

Unit 1

1. Plant Operations - Category 3
2. Radiological Controls - Category 2
3. Maintenance - Category 3
4. Surveillance and Preoperational Testing - Category 3
5. Fire Protection - Category 2
6. Emergency Preparedness - Category 1
7. Security and Safeguards - Category 2
8. Refueling - Not Rated
9. Licensing Activities - Category 3
10. Quality Assurance Program - Category 3

Unit 2

11. Construction Activities - Not Rated

D. SALP Board Members:

J. A. Olshinski, Director, Division of Engineering and Operational Programs (DEOP), (Acting Chairman), Region II (RII)
J. P. Stohr, Director, Division of Emergency Preparedness and Materials Safety Programs (DEPMSP), RII
D. M. Verrelli, Chief, Project Branch 1, Division of Project and Resident Programs (DPRP), RII

E. SALP Board Attendees:

C. A. Julian, Chief, Project Section 1A, DPRP, RII
M. V. Sinkule, Chief, Operational Support Section (OSS), DPRP, RII
J. J. Blake, Chief, Materials and Mechanical Section, DEOP, RII
F. Jape, Chief, Test Programs Section, DEOP, RII
C. M. Upright, Chief, Management Programs Section, DEOP, RII
D. R. McGuire, Chief, Physical Security Section, DEPMSP, RII
G. R. Jenkins, Chief, Emergency Preparedness Section, DEPMSP, RII
K. P. Barr, Chief, Facilities Radiation Protection Section, DEOP, RII
W. H. Miller, Reactor Engineer, Plant Systems Section, DEOP, RII
A. G. Wagner, Senior Resident Inspector, Grand Gulf, RII
R. E. Carroll, Reactor Engineer, Project Section 1A, DPRP, RII
J. L. Caldwell, Resident Inspector, Grand Gulf, RII
D. S. Price, Reactor Inspector, OSS, DPRP, RII
M. D. Houston, Licensing Project Manager, Licensing Branch 2, Division of Licensing, Office of Nuclear Reactor Regulation

IV. PERFORMANCE ANALYSIS FOR GRAND GULF UNITS 1 AND 2

A. Functional Area Evaluations

Licensee Activities

Unit 1 was shut down after initial criticality on August 18, 1982, and entered an extended outage period that lasted until September 25, 1983. The outage period was needed to correct an inadequate drywell cooling system design and to complete other modification and maintenance activities. During hot functional testing, it was observed that cooling capacity was not adequate to maintain drywell temperatures below those assumed in the accident analysis. A closed cooling water system was installed with additional air recirculation capability in the drywell.

Safety related air accumulators for the automatic depressurization system within the drywell were found to have deteriorated interior coatings. The tanks and associated piping were inspected, cleaned, and their coatings restored. Additional plant reliability improvements were made to the plant service water system, instrument air system, and reactor protection system power supplies. Additionally, corrections as identified during the preoperational test program were performed.

On September 4, 1983, a fuel line rupture caused a fire in the Division I diesel generator. The diesel generator was demonstrated to be reliable after required repairs were completed.

Due to NRC concerns regarding the adequacy of the Surveillance Testing Program, the licensee agreed to perform a review of all surveillance procedures to verify technical adequacy of the procedures; establish an effective program to incorporate, control, and implement regulatory requirements; submit license amendments to correct administrative and technical deficiencies in the unit technical specifications; conduct formal training on the proper implementation of technical specification requirements; and establish a formal Quality Assurance audit program to assure proper completion of the above items. These commitments were confirmed by NRC in a Confirmation of Action letter dated October 20, 1982. Concerns in regard to surveillance testing, technical specification adequacy, staffing, and management control were identified by NRC during inspections in late 1982. In response to these concerns, the licensee committed to an Operational Enhancement Program (OEP).

Major revisions were made by the licensee as a part of the OEP in the following areas: 1) total review and rewrite of the surveillance program; 2) enhancements in long term planning for operator training, and improvement of training programs; 3) development of new programs to control plant modifications; 4) establishment of a plant compliance section and new programs to assure compliance with regulatory requirements; 5) development of programs to enhance management skills and effectiveness at all levels; 6) development of a program to assure procedure awareness and compliance; and 7) development of programs to attract operations personnel and improve effectiveness of the plant staff.

The licensee has devoted significant resources to correct problems related to the NRC concerns regarding the adequacy of the Surveillance Testing Program, strengthen control of plant activities, and enhance plant operations. The major portion of the SALP period has been devoted to modifying the plant and restructuring many of the basic plant procedures and programs to correct identified design and administrative problems.

The licensee completed corrective actions required by the October 20, 1982 Confirmation of Action letter, and the reactor was taken critical on September 25, 1983. The licensee subsequently started the low power startup testing program.

Inspection Activities

The routine inspection program was performed during this review period. The inspection program was augmented by additional inspections to assure operational readiness. In addition, a special assessment of training was conducted during February 1983. Numerous areas were identified where improvements were needed in the training program.

A team inspection was conducted during August 1983 to evaluate the readiness for recriticality. Numerous areas were identified where steps were planned or should be taken to enhance smooth operations and ensure conformance to technical specifications. It was concluded that the plant was ready to undertake recriticality and begin low power testing at less than 5% power.

1. Plant Operations

   a. Analysis

      Plant Operations

      During the assessment period, the area of plant operations and operational preparations was routinely inspected by the resident and regional inspection staffs.

      The licensee has had problems involving procedural compliance, control of temporary alterations, failure to perform independent verifications, and failure to perform safety evaluations which have resulted in several violations (some of which have multiple examples), as evidenced by violations 1, 2, and 3, below. An enforcement conference was held in Region II on January 17, 1983, regarding these multiple examples of violations for failure to follow procedures. The problems were attributable to inadequate training of operations personnel; inadequate attention to management control systems by supervisors; and lack of sensitivity by operations and maintenance personnel to comply with regulatory requirements and commitments. On March 11, 1983, the licensee submitted to Region II, as corrective action to the concerns discussed at the January 1983 enforcement conference, a comprehensive Operations Enhancement Program. The program included short term and long term tasks to improve safety, reliability, and operating effectiveness of the Grand Gulf facility. Additional violations and deviations (5, 11, 12, and 13, below) resulted in another enforcement conference in Region II on April 20, 1983, to discuss the continued failure to control temporary alterations and failures to follow procedures. The NRC expressed concern with the apparent inadequacy in control of modifications and maintenance, and failure to take effective corrective actions in the area of temporary alterations. The licensee outlined additional actions that would be taken to improve these problems. The actions included disciplinary action, realignment of administrative responsibilities, additional training, and periodic meetings by management with plant personnel. In addition, an incentive program for licensed operators was established.

The licensee experienced difficulty in assuring that commitments to the NRC were met. This is evidenced by repetitive deviations 11 and 13 below (in regards to the commitment to lock and control access to control room cabinets), and subsequent violation 10 below, for failure to take adequate corrective actions. This breakdown in the tracking of regulatory commitments, committed to in the Operational Enhancement Program, indicates insufficient management follow-up to assure that commitments were actually accomplished and that tracking system information was accurate.

The number of outstanding NRC concerns that have been identified in inspection reports has been reduced significantly. The licensee has established a plant compliance section responsible for the tracking and coordination of NRC concerns. The previous SALP assessment had noted that the licensee lacked an effective program for the resolution of these NRC concerns. The formation of the new plant compliance section represents a significant improvement in the licensee's handling of these items. There were, however, a number of longstanding items which continued to be uncorrected, and the system for escalating problems to management's attention, when the problems could not be resolved in a timely manner, has been ineffective and continues to require management attention.

Due to a high turnover rate of operations qualified personnel, the staffing level, though meeting technical specification requirements, was marginal during the entire evaluation period. The licensee has taken considerable actions to assure adequate licensed operator staffing in the future.

Operator Licensing

During the assessment period the inspection effort in the area of operator training and licensing consisted of one special training assessment, one special operational readiness assessment, and the administering of 21 license examinations and portions of seven requalification examinations.

The licensee initiated several quality deficiency reports associated with training records for licensed operators and senior licensed operators. These deficiencies involved submittal of incorrect information on applications for NRC licenses, and failure to provide training as discussed in the Final Safety Analysis Report and on license applications. Both the NRC and the licensee were in the process of evaluating the extent of the deficiencies at the end of the SALP period. This matter was also being reviewed by the NRC Office of Investigation. The licensee had developed corrective action and was in the process of implementing the actions at the time of the SALP report. These deficiencies are being considered for escalated enforcement actions by the NRC.

During the current SALP assessment period, nine senior reactor operator examinations, including one retest, were administered. Two of the new license candidates failed the examination. Twelve reactor operator examinations, four of which were retests, were administered. Four individuals failed the examination; three were new license candidates and one was a retest. In a total of 21 license examinations administered, six resulted in failure.

The NRC participated in the administration of written requalification examinations to two reactor operators and one senior reactor operator. One of the reactor operators failed the NRC portion as well as the overall examination. Two reactor operators and two senior reactor operators were given simulator requalification examinations; all four individuals passed.

Since the end of the SALP period, poor performance by licensed operators on NRC conducted walkthrough type evaluations, and other NRC concerns in operator training and certification, resulted in a meeting at Region II on November 18, 1983. In this meeting the licensee's program to recertify the operating staff at Grand Gulf was discussed. A Confirmation of Action letter dated December 5, 1983, was issued to confirm the commitments made in regard to the Recertification Program and other matters which were to be completed. NRC is conducting periodic reviews of this ongoing Recertification Program.

Reporting

Early in the SALP assessment period, a number of problems were experienced with the identification of technical specification required reportability of plant events to management and to the NRC. These problems were attributed to weak procedures and a lack of experience by operations personnel. The licensee had revised the procedures providing better guidance to the operators on reportability. The licensee's performance on this reportability issue has improved significantly since the start of the review period.

In general, the licensee event reports (LERs) submitted by the licensee typically provided clear descriptions of the cause and nature of the events as well as adequate explanations of the affects on both system function and public safety. In most cases the described corrective actions were considered to be commensurate with the nature, seriousness, and frequency of the problems identified. Although not a regulatory requirement, the licensee does not participate in the Nuclear Plant Reliability Data System.

Ten violations and four deviations were identified as follows:

(1) Severity Level IV violation for failure to use the system operating instruction for operation of a safety related system.

(2) Severity Level IV violation for failure to perform independent verification for safety related component tagging.

(3) Severity Level IV violation for failure to perform independent verification of safety related system switch positions, failure to have safety related valves locked or positioned as required by the system operating instruction, and failure to control safety related system information tags.

(4) Severity Level IV violation for failure to keep the station licensed operators and senior operators advised of installed station design changes.

(5) Severity Level IV violation for failure to control temporary alterations and jumpers.

(6) Severity Level IV violation for failure to provide the basis for a safety evaluation.

(7) Severity Level V violation for failure to make one hour reports for an emergency safeguards feature system challenge and a manual reactor scram.

(8) Severity Level V violation for failure to have safety related system hand switches positioned as required by the system operating instruction.

(9) Severity Level V violation for failure of the operators to read the night orders as required by procedures.

(10) Severity Level V violation for failure to take adequate corrective action.

(11) Deviation for failure to lock and control access to control room cabinets.

(12) Deviation for failure to provide administrative controls training for shift technical advisors.

(13) Deviation (repeat) for failure to lock and control access to control room cabinets.

(14) Deviation for failure to issue an administrative procedure which included the definition of safety related equipment and components, by the date committed to.

b. Conclusion

Category 3

c. Board Comments

Performance in this area was evaluated as Category 3 during the previous SALP assessment. Minimally satisfactory performance with respect to operational safety was being achieved. Subsequent to the evaluation period, significant questions and concerns relating to the operator licensing process, were identified.

Although the overall rating in this area was Category 3, there was a period when performance was unsatisfactory. Corrective actions were taken to bring performance up to the present level. It is noted that weaknesses related to operator qualifications are being evaluated and will be corrected prior to facility operation.

Management attention should be focused on the problems associated with operator license applications and the facility's personnel qualification program. The licensee's recertification program is a strong management move to correct weaknesses in this area. During the program's implementation, an increased level of management attention should continue. Increased NRC inspection activity should also be performed in this area.

2. Radiological Controls

a. Analysis

During the evaluation period, routine inspections were performed by the resident and regional inspection staffs.

NRC inspection effort in this area was primarily directed towards preoperational and startup procedures; tests of the radwaste systems; training and qualifications of personnel; and licensee response to LERs, Inspection and Enforcement Information Notices, and NRC inspector identified concerns. The licensee was responsive to the inspection effort. No major weaknesses were identified in the radiation protection program.

The licensee has maintained a training program for the health physics technicians and has established a qualification, testing, and acceptance program for contract technicians. These programs have been instrumental in upgrading the technical competence of the health physics staff. The actual experience of the health physics and chemistry technicians in nuclear power plant operations was low. However, the qualifications of the health physics staff were acceptable and met regulatory requirements.

The effectiveness of the radiological control program has not been tested, as the plant has not operated above the five percent power level. Considerable work remained to make the radioactive waste handling systems fully operable. However, the licensee had the capability to dewater radioactive resin wastes, and solidification capabilities were available through contract services. Modifications of the radwaste facilities were underway to provide additional storage capabilities of liquid wastes, to provide better sampling capabilities, and to achieve ALARA goals. It was not apparent, however, that significant progress was being made on these radioactive waste handling systems. Therefore, increased management attention should be given to this area to assure that adequate capabilities are available prior to full power operation.

The violations identified during the evaluation period were not indicative of a programmatic breakdown in the radiological safety program. The two violations were:

(1) Severity Level V violation for failure to collect samples at the required frequency to make up the monthly composite sample of the liquid waste discharge basin in accordance with the technical specifications.

(2) Severity Level V violation for failure to post an area where radioactive materials were stored.

b. Conclusion

Category 2

c. Board Comments

Performance in this area was evaluated as Category 2 during the previous SALP assessment. Continued management attention should be devoted to this area to ensure the successful completion and operation of the waste management system. Implementation of the radiological controls program, during power operations, will be closely monitored by NRC to determine performance tre s. No decrease in licensee management attention, in this area, is recommended.

3. Maintenance

a. Analysis

During the evaluation period, the area of maintenance was routinely inspected by the resident and regional inspection staffs.

A large portion of this SALP review period was spent in a maintenance outage. During the outage, modifications necessary to improve plant performance and reliability, and correct design deficiencies were installed. Management involvement with the actual conduct of maintenance in the plant was minimal. There appeared to be a need for licensee management to review the manner in which the maintenance department conducted safety-related activities, and to ensure that a clear line of authority, direction, and responsibility existed.

Licensee schedules, generally, were overly optimisitic, which required them to be frequently reviewed, revised, and reissued. Being overly optimistic imposed an apparent schedule pressure on the plant maintenance technicians. However, there appears to be an adequate staff to perform the required tasks, if adequate time has been provided for accomplishment of the tasks.

Administrative procedure training was completed during the evalulation period just prior to the repair effort of the fire damaged diesel generator. This maintenance training was not totally effective to assure that the maintenance staff would meticulously adhere to procedures.

Minimal management involvement, unrealistic schedules, and the lack of effective training were the major contributors to the short-cuts of technical and procedural requirements taken by maintenance personnel which resulted in the significant number of violations identified below. These problem areas were readily apparent during the repairs to the fire damaged diesel for which violation 3, below, was issued, as well as the proposed assessment of a civil penalty for repetitive violations for failure to follow procedures, and control temporary alterations.

The licensee's performance in some areas of maintenance did indicate management involvement and responsiveness. For example, when the generic aspects of seven Hydraulic Control Unit (HCU) solenoid failures were questioned, management involvement and followup resulted in the complete overhaul and cleaning of the entire HCU system.

Six violations and one deviation were identified as follows:

(1) Severity Level IV violation for failure to follow procedures for the control of maintenance work.

(2) Severity Level IV violation for failure to provide a procedure for smoke testing of the control room, and for failure to provide cleanliness controls during maintenance on safety related systems.

(3) Severity Level IV violation for failure to obtain proper authorization for safety related equipment repairs, failure to perform a safety evaluation, and failure to properly authorize a temporary alteration.

(4) Severity Level IV violation for failure to provide adequate justification for determining that no unreviewed safety question existed on temporary alterations to the Division III diesel generator.

(5) Severity Level V violation for failure to control measuring and test equipment used on safety related systems, and for failure to properly mark restricted use equipment.

(6) Severity Level V violation for failure to complete masonry wall modifications in accordance with drawing requirements.

(7) Deviation for failure to provide maintenance personnel training.

b. Conclusion

Category 3

c. Board Comments

Lack of sufficient licensee management involvement in maintenance is evident. The use of overly optimistic schedules has, at times, been a contributor to poor maintenance practices. This scheduling problem was discussed in the previous SALP assessment and continues to be an area of concern. Increased management attention should be devoted to this area by the licensee. Increased NRC inspection activity should also be performed in this area.

4. Surveillance and Preoperational Testing

a. Analysis

During the evaluation period, the area of surveillance including preoperational testing, was inspected by the resident and regional inspection staff at a level greater than normal, based on the weaknesses identified in this area during the previous SALP assessment.

Surveillance

A special team inspection was conducted in this area from September 27, 1982 to October 8, 1982. This inspection revealed that the procedures in use failed to properly implement all technical specification requirements; several required surveillances were not being performed; significant weaknesses existed in the administrative controls for surveillance procedures and changes; and there was no formal quality assurance audit program in this area. The licensee met with the NRC staff on October 14, 1982, to discuss the actions necessary to correct these deficiencies.

As discussed above under Licensee Activities, NRC issued a Confirmation of Action Letter on October 20, 1982 documenting that the licensee had committed to revise the surveillance program, revise technical specifications, retrain operations personnel in technical specifications, and perform a quality assurance audit of these corrective actions. The licensee completed the corrective actions as documented in their letters to NRC of August 29, 1983, September 1, 1983, and September 13, 1983. The NRC staff inspected the corrective actions which were required to be completed prior to reactor restart. Additional actions remain to be completed during power escalation and/or in accordance with long term commitments.

To distinguish revised procedures resulting from this effort, all newly approved surveillances were designated as Revision 20. A massive licensee effort was put forth in this undertaking. Procedures were prioritized as to their impact on plant restart and those required for recriticality and low power testing were reviewed first. Some surveillance procedures which would not be needed for some time, such as refueling, remained to be reviewed and revised. NRC has inspected samples of the revision 20 surveillance procedures and found them acceptable prior to restart.

The containment isolation valve local leak rate test surveillance program was one area of concern. During NRC inspections the procedure for local leak rate testing was determined to be inadequate because valve alignments were not included to provide objective evidence on how the local testing was performed. During preoperational testing, containment penetration drawings were marked to indicate the proper valve alignment for testing. At that time the licensee stated that these drawings would be used to develop valve alignments for the future surveillance procedures. The approved procedure did not, however, include this information which had been developed from the preoperational testing effort. A violation, item 6 below, was issued. The licensee conducted a thorough review of the previous containment leak rate tests prior to recriticality. Retests were performed where appropriate.

Preoperational Testing

During the licensee's performance of the Loss of Coolant Accident simulation, coincident with a Loss of Offsite Power (LOP/LOCA), a design defect was discovered by the licensee in its custom load shedding and sequencing (LSS) panels. The licensee promptly modified the equipment to correct the design problem. The licensee's program for modifications and tests of the LSS panels was found, during routine NRC inspections, to be effective and performed in accordance with appropriate administrative controls and procedures.

During this same LOP/LOCA test sequence, the licensee uncovered a number of problems with improper operation of Emergency Safety Feature (ESF) valves and with the performance of the Division I diesel engine. These problems, most of which were not related to each other, were corrected and the equipment was tested in an orderly manner. During testing a fuel line rupture caused a fire in the Division I diesel generator. A valve in the fire protection deluge system initially failed to function. After recovery from the fire and completion of repairs, the diesel generator was run continuously for seven days to demonstrate reliability.

During the evaluation period the conduct of preoperational testing and the test results were reviewed and analyzed by the resident and regional inspection staffs. One such test was the thermal expansion test performed subsequent to issuance of the low power license, during non-nuclear heat up. The test procedures were technically adequate and the licensee's performance of the thermal expansion test program indicated adequate prior planning, assignment of responsibilities, decision making at appropriate levels, involvement of appropriate personnel, and understanding of the issues. Test results were reviewed and discrepancies evaluated and/or corrected prior to continuing heat up.

In addition, the licensee performed the drywell bypass leakage test. The test initially failed to meet the acceptance criteria because construction personnel had opened two previously sealed electrical conduits penetrating the drywell and had not resealed these leakage paths. This indicated a failure to monitor changing plant conditions and review these conditions relative to preoperational test requirements.

Nine violations, involving multiple examples, were identified as follows:

(1) Severity Level IV violation for failure to perform relay calibrations within the required frequency.

(2) Severity Level IV violation, with nine examples, for failure to provide adequate acceptance criteria for tests.

(3) Severity Level IV violation for failure to perform a required surveillance procedure.

(4) Severity Level IV violation for failure of the containment and drywell ventilation exhaust radiation monitoring system to meet the technical specification trip logic requirement.

(5) Severity Level IV violation for failure to maintain service water valves locked closed as required by technical specifications.

(6) Severity Level IV violation for an inadequate test procedure for performing Type C containment leak rate tests.

(7) Severity Level IV violation, with three examples, for failure to provide a procedure to implement technical specification requirements for safety related valves.

(8) Severity Level IV violation for failure to perform an independent verification of a hardware modification.

(9) Severity Level IV violation for failure to perform a safety evaluation for test equipment installed in operable safety related systems.

b. Conclusion

Category 3

c. Board Comments

Performance in this area was evaluated as Category 3 during the previous SALP assessment. Licensee resources appear to be strained. Significant problems were identified in this area early in the evaluation period. A major program was implemented to correct the problems which should result in improved performance during the next SALP assessment. Increased licensee management attention should be directed to the area. Although the overall rating in this area is a Category 3, there was a period of time when performance was unsatisfactory. Corrective action were taken to bring performance up to the present level. NRC inspection effort should be increased in this area.

5. Fire Protection

a. Analysis

During this assessment period, limited inspections were performed by the regional inspection staff to review the licensee's implementation of the operational fire protection and prevention program.

The licensee's fire protection program adhered to the NRC guidelines during the SALP period except for the violations listed below, which have been corrected. The administrative procedures for control of the fire protection program appear adequate and meet NRC requirements. Adherence to these procedures, based on limited inspections, appeared to be satisfactory considering that the plant was in transition from the construction to the operational phase. However, several temporary construction structures remained within safety related areas of the plant. These structures obstructed the permanent plant fire protection systems provided in the area but were scheduled to be removed or provided with appropriate fire protection features prior to plant operation.

Maintenance and tests of the fire protection systems were satisfactory with the exception of the control room Halon extinguishing system, battery penetration seals, and several fire detection systems, as noted below. Also, one of the pre-action sprinkler system control valves for the diesel generator building did not operate properly during a diesel generator fire on September 4, 1983. An investigation was in progress, at the end of the evaluation period, to determine the cause of the problem.

The plant fire brigade appeared to be well organized and adequately trained, as evidenced by their response to, and performance during, the diesel generator fire discussed above. A review of the plant fire brigade training and drill records indicated that each reviewed brigade member had participated in the required training sessions and drills during the assessment period. Sufficient fire fighting equipment was available to equip the brigade. Maintenance and care of this equipment was satisfactory.

Reporting of fire protection discrepancies, for the most part, has been timely and very comprehensive. A large number of fire protection related discrepancies and items for which construction had not been properly completed were identified by the licensee and promply reported to the NRC as required. For these self identified discrepancies, the licensee responded to the correct limiting condition for operation as specified in the technical specifications.

Staffing for the fire protection program appeared marginal. Although the fire protection coordinator appeared to be well qualified for his position, sufficient personnel are not permanently assigned to this area to assure that the program will continue to be adequately administered. Important fire protection tasks were assigned as collateral duties to a number of different personnel who were not under the control of the fire protection coordinator.

The following four violations and one deviation were identified:

(1) Severity Level V violation for failure to implement the technical specification requirements to submit a special report to the NRC on inoperative fire rated assemblies, and failure to assign a designated fire watch for a removed fire rated hatch cover and several blocked open fire doors.

(2) Severity Level V violation for failure to implement the fire protection program in that maintenance and test procedures had not been established for the battery power emergency lighting units, fire detection zones Z-15 and Z-18, and fire barrier penetration seals.

(3) Severity Level V violation for failure to conduct the semiannual weight and pressure verification of the

Halon fire suppression system for the control building complex as required by the technical specifications.

(4) Severity Level V violation for failure to implement the technical specification requirements to post a fire watch for two blocked open and inoperable fire doors.

(5) Deviation for failure to provide skid mounted portable air compressors for breathing air applications as committed to in the FSAR.

b. Conclusion

Category 2

c. Board Comments

Performance in this area was evaluated as Category 2 in the previous SALP assessment. Concerns were raised by the SALP Board, in the previous assessment, regarding the use of temporary structures, and the minimal staffing level in this area. These issues continue to be concerns during this assessment. Management attention should be directed to this area to assure adequate fire protection staffing.

6. Emergency Preparedness

a. Analysis

During this evaluation period, a full scale emergency exercise was monitored, and a routine inspection was conducted. No violations, deviations or deficiencies were noted during the exercise or inspection. Minor problems were identified during the exercise for followup action.

The licensee has generally shown timely response to NRC identified initiatives. All deficiencies identified during the emergency preparedness implementation appraisal were resolved, and there were few other concerns identified by NRC inspectors which required action by the licensee.

There appeared to be continued management commitment to the emergency preparedness program. Senior corporate management representatives were personnally involved in the annual emergency exercise. Management commitment was also evidenced by the prompt manner in which the licensee filled the plant Emergency Preparedness Coordinator (EPC) position when the former EPC was transferred. A reorganization of the corporate office resulted in increased visibility and management access to the emergency preparedness program. At the end of the appraisal period, key positions in the emergency preparedness program were filled. Staffing levels appeared to be adequate to handle the emergency preparedness workload.

A training program had been established and implemented. The training program for key personnel in the emergency organization appeared to be effective as demonstrated by participant performance during the 1983 annual emergency exercise. However, during this exercise, offsite monitoring teams appeared to lack experience in radiological surveillance methods. The licensee committed to provide additional training to monitoring team members.

As a result of the licensee's efforts, the emergency preparedness program has been shown to function effectively during the exercise and during an actual event. During the exercise the licensee properly assessed accident conditions, correctly classified the accident, took proper remedial action, and recommended appropriate offsite protective actions. The licensee's ability to evaluate accident conditions and take action was also demonstrated during the assessment period when a diesel generator fire occurred. Licensee assessment actions, mitigating actions, and accident classification appeared to be consistent with approved emergency plan procedures. The incident was properly reported to NRC.

b. Conclusion

Category 1

c. Board Comments

Performance in this area was evaluated as Category 2 in the previous SALP assessment. Licensee management attention and involvement in this area are aggressive. No decrease in licensee management attention is recommended.

7. Security and Safeguards

a. Analysis

Routine inspections were performed in this area by the resident and regional inspection staffs. During this evaluation period, the licensee's physical security program was implemented in accordance with approved regulatory requirements. However, some weaknesses were noted during the assessment period with regard to electronic security system failures, and personnel adherence to security procedures. With regard to the electronic security system, the removal of the anti-passback features from the computerized access control system has resulted in a significant improvement in the performance of the system.

Regarding the implementation of security procedures, the majority of the violations and reportable events reflected below were caused or contributed to by the failure of structure, from the Vice President down to Plant Superintendents. In regard to the submittals for equipment qualification, a comparison of the May 20, 1983 submittal to the corrected version of August 25, 1983, showed that the earlier version had 366 deficiencies for 1,160 pieces of equipment. The overall decline in quality is attributed to the extensive scope of these issues, and to a perceived limitation of resources in attempting to meet unrealistic schedules set by the licensee.

In response to NRC initiatives, the licensee provided timely responses for those issues which were believed to impact full power licensing. Specifically, the licensee provided extensive reports within a short time span for the issues involving hydrogen control, diesel generator reliability, and electrical relay performance. In regard to staff requests for prototype details on this, the first Mark III plant, the licensee was very cooperative and made available the resources of their architect-engineer, Bechtel-Gaithersburg. During meetings with the NRC, the licensee provided appropriate technical and management level personnel to make the meetings productive. On the other hand, a number of responses for significant issues were provided months later than the date specified by the licensee, or the licensing action was not completed as anticipated. In the matter of Safety Relief Valve Test Results, a submittal required by a license condition, the licensee provided the response in May 1983, some seven-and-one-half months after the report's known availability. Other responses, such as issues under review for closure by the first refueling outage (e.g., soil structure interaction), and some requests in generic letters, were provided three to five months later than expected and only then after NRC prodding of the licensee. In regard to late responses to generic letters, the licensee appeared to have an internal problem of routing the generic letters to the appropriate group for timely response.

b. Conclusion

Category 3

c. Board Comments

Performance in this area was evaluated as Category 2 in the previous SALP assessment. The magnitude of the licensing activities during the appraisal period appears to have contributed largely to the degradation in rating since the previous SALP appraisal. Increased licensee management attention should be devoted to this area.

10. Quality Assurance Program

a. Analysis

During this inspection period, routine and special inspections were performed by the resident and regional inspection staffs.

One special inspection was performed to review Quality Assurance audits relative to a Confirmation of Action letter issued by Region II on October 20, 1982. The reviews performed during both the special and routine inspections indicated that the licensee's Quality Assurance (QA) audits were complete, timely, and thorough. Corrective actions for audit findings have improved. The Plant Manager, Operations QA Manager, and applicable plant personnel freely communicate to reach mutual agreement on audit finding corrective actions. This open communication has improved the identification of audit problem root causes; consequently, corrective action is more meaningful.

Procurement activities were generally well controlled and documented. The licensee's responsiveness and corrective actions on previously identified NRC concerns improved in some areas.

A special design control inspection was conducted during this assessment period. Due to the large backlog of design changes, the licensee established a design change task force to specifically identify the status of approximately 2000 outstanding design changes. Management controls were considered adequate to assure proper completion of significant design changes prior to plant restart. The NRC conducted extensive interviews with design change task force personnel. Drawing control, procedure updating, and training in selected design changes was ongoing.

Improvements have been made in the control of plant drawings, and the licensee was devoting significant resources to this task. At the end of the appraisal period, however, a problem still existed with the inability to provide legible copies of control drawings for use in the control room and other important work stations. The delay in solving this problem was stated by the licensee as a logistical difficulty in obtaining legible drawings from vendors. This matter was identified for future followup during operational readiness inspections by NRC.

Although the audit program performed by the Quality Assurance staff appeared complete, NRC was concerned about the overall effectiveness of the operational Quality Assurance program. An unusually large number of significant problems were identified by the NRC and licensee in the surveillance testing program and in the operator training program during the appraisal period. These problems had either not been identified by the Quality Assurance program or they had not been pursued in the manner necessary to result in satisfactory corrective actions. Criterion XVIII of 10 CFR 50 Appendix B, and the topical quality assurance program require planned and periodic audits to verify compliance with all aspects of the Quality Assurance program and to determine the effectiveness of the program. Surveillance testing and operator training are important aspects of the overall quality assurance program, but audits by the quality assurance staff did not reveal the lack of compliance with NRC requirements in these areas. A precise cause for this lack of effectiveness was not identified. However, licensee management attention is needed to reevaluate the scope and depth of quality assurance audits to assure a more meaningful overview of NRC requirements.

Another apparent weakness in the implementation of the operational Quality Assurance program involved the line organization's direct responsibility for quality. The Plant Quality section was responsible for the quality control function and reported to the Plant Manager. They performed most of the direct observations of plant activities and therefore played an important role in the overall quality program. Quality Assurance, in turn, audited the Plant Quality section but Quality Assurance did not routinely observe the performance of licensed activities in the field. Violations 1 and 7, described below, were cited against performance of Plant Quality section personnel. Violation 1 was caused by repeated time extensions granted by the Plant Quality section for the completion of corrective actions for identified problems. An example of a documented deficient area which was given repeated extensions, involved training discrepancies and, in particular, incorrect statements submitted to the NRC on operator licensing examination applications. These problems were documented in January 1983 and, as of August 1983, month-by-month extensions of corrective action deadlines were granted by the Plant Quality section to the training department. Had plant and corporate management been responsive to the problems identified by the Plant Quality section, these training deficiencies could have been promptly corrected and may not have resulted in the critical path delay to plant startup.

A further NRC concern relates to the frequent usage in plant procedures of the words "should" and "must" as substitutes for "shall". These permissive verbs are often used inappropriately in procedures such that plant personnel are not provided with sufficient guidance as to the conservative action which should be taken. Violation 7, below, was issued as a result of a failure to implement regulatory requirements involving the use of these verbs. Licensee management attention should continue to be applied to this area to resolve this concern.

Seven violations were identified as follows:

(1) Severity Level IV violation for failure to correct conditions adverse to quality in a timely manner.

(2) Severity Level V violation for failure to issue an audit within the technical specification required time frame.

(3) Severity Level V violation for failure to store records properly.

(4) Severity Level V violation for failure of responsible personnel to initiate an incident report to management as required by procedure.

(5) Severity Level V violation for failure to have procedures in place prescribing the methods and duration of the appointment of alternates to the Safety Review Committee as specified in the technical specifications.

(6) Severity Level V violation for failure to provide prompt and adequate documentation of quality related deficiencies.

(7) Severity Level V violation for failure to implement regulatory requirements in accordance with the Quality Assurance program.

b. Conclusion

Category 3

c. Board Comments

Performance in this area was evaluated as Category 2 in the previous SALP assessment. It appears, on the surface, from a review of the QA program and its implementation at the Grand Gulf facility, that the program is effective. However, when an overall evaluation of the facility's history for this period is conducted, it becomes readily apparent that the implementation of the QA program at Grand Gulf is inadequate to identify problems and/or ineffective in bringing about adequate corrective actions. Increased licensee management attention is required in this area to assure that licensee personnel are effective in performing the QA functions as required by NRC regulations. Increased NRC inspection effort should be directed to this area.

11. Construction Activities (Unit 2)

a. Analysis

During the assessment period, the licensee has continued the construction of Unit 2, utilizing a work force of approximately 900 personnel. The decision to continue construction was based on an investment protection study which showed that extended storage of the equipment already on site could best be accomplished by finishing the major buildings, and by storing the equipment in place.

Inspection effort during the assessment period has been minimal because of the announced extension and possible deferral of the project. There have been eight inspections of construction activities during this period. Three of the inspections were primarily involved with piping and structural installation, and welding activities; and three of the inspections were primarily involved with follow-up of licensee-identified items. The installation of equipment and construction of the buildings appeared to be progressing very smoothly. The licensee has reported that construction work was ahead of schedule and below budget. The use of a small crew and an extended schedule appeared to have eliminated many of the bottlenecks and other problems which normally occur during a large construction project. There appeared to be a positive attitude displayed by those involved with construction activities.

There was one violation identified during this inspection period involving improper curing of concrete. The problem was resolved by retraining of the personnel involved, and did not appear to be indicative of a QA breakdown.

One violation was identified:

Severity Level V violation for improper concrete curing.

b. Conclusion

Not rated

c. Board Comments

An assessment of a licensee's performance in the overall categories of operation and/or construction is achieved by appraising their performance in the numerous functional areas that make up the associated overall category. Since the licensee and NRC activity in the construction functional areas was minimal, insufficient data existed to properly evaluate performance in this area.

B. Supporting Data

1. Reports Data

a. Licensee Event Reports (LERs)

During the assessment period, there were 254 LERs submitted. The distribution by Licensee Cause Code and SALP Functional Area is as follows:

Cause Code	No. of LERs
Personnel	52
Design	19
External	17
Procedure	16
Component	41
Other	109
TOTAL	254

SALP Functional Area	No. of LERs
Operations	59
Radiological Control	1
Maintenance	37
Surveillance	61
Fire Protection	70
Quality Assurance	17
Other	9
TOTAL	254

Twenty percent of the events were attributed to personnel error, sixteen percent were due to component failure, and forty-three percent of the events were classified as "other". Of the personnel error LERs, fifty percent were caused by licensed or unlicensed operators, twenty-one percent were caused by maintenance personnel, and twenty-eight percent were caused by personnel from other organizations. Of the events classified as "other", fifty-six percent were reported because the licensee was in an Action Statement caused by the propping open of fire doors for the purpose of construction activities.

Overall, the relatively large number of LERs was due, in part, to the facility having standard technical specification reporting requirements which involved a high level of required reports. Additionally, the ongoing construction activities at the plant resulted in many reports that would not have been required had the construction activity been complete.

b. Construction Deficiency Reports (CDRs)

Twelve Unit 1 CDRs, and thirteen Unit 2 CDRs were reported for this assessment period. The distribution of these reports into cause related categories is as follows:

Category	Unit 1	Unit 2
Mechanical	2	2
Electrical	2	1
Design	5	5
Quality Assurance	2	2
Supports and Anchors	1	2
Welding	0	1
Total	12	13

c. Part 21 Reports

Unit 1 - 11
Unit 2 - 0

2. Investigation and Allegation Review

One allegation concerning an emergency preparedness issue was closed during the SALP assessment period. Additionally, one allegation concerning diesel repair maintenance was ongoing at the end of the SALP period; and two investigations, one concerning missing rebar and one concerning operator licensing applications, were in progress.

3. Enforcement Actions

a. Violations

	Unit 1	Unit 2
Severity Level III -	1 violation	
Severity Level IV -	24 violations	
Severity Level V -	19 violations	1 violation
Deviations -	6 deviations	

b. Civil Penalties

There was one civil penalty assessed for the failure to provide positive access control to a vital area.

Subsequent to the evaluation period, one civil penalty was proposed for repetitive violations for failures to follow procedures and control of modifications that occurred during the evaluation period.

c. Orders

None

d. Administrative Actions - Confirmation of Action Letters

There was one Confirmation of Action Letter dated October 20, 1982, concerning surveillance procedures, technical specifications, training on technical specification requirements, and quality assurance reviews of regulatory requirements.

e. Management Conferences

October 14, 1982, Enforcement Conference concerning surveillance procedures, technical specifications, and training on technical specifications which led to the issuance of a Confirmation of Action Letter dated October 20, 1982.

November 2, 1982, Management Meeting concerning staff attrition, qualification of staff, use of consultants, and overtime.

December 2, 1982, Enforcement Conference concerning a security violation.

January 17, 1983, Enforcement Conference concerning failure to follow procedures.

April 8, 1983, Management Meeting to discuss the Operations Enhancement Program.

April 20, 1983, Enforcement Conference concerning control of modifications and maintenance, and failure to take effective corrective actions in the area of temporary alterations.

May 11, 1983, Management Meeting to discuss changes to technical specifications required prior to startup of Unit 1.

May 11, 1983, Enforcement Conference concerning a security violation.

June 2, 1983, Management Meeting related to proposed Physical Security Plan modifications at Grand Gulf.

July 15, 1983, Management Meeting to discuss problems encountered with scram solenoid valves in unit 1.

July 29, 1983, Management Meeting related to the licensee's investigation on rebar in the standby service water basin.

August 12, 1983, Management Meeting to discuss the licensee's actions to satisfy matters of a Confirmation of Action letter dated October 20, 1982.

September 9, 1983, Management Meeting related to changes in the Physical Security Plan.

September 23, 1983, Management Meeting to discuss Agastat Relay failures, proposed corrective actions, and other topics of current interest.

S. Kubin

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

JUN 17 1983

MEMORANDUM FOR: Karl V. Seyfrit, Chief
Reactor Operations Analysis Branch
Office for Analysis and Evaluation
of Operational Data

AEOD/T323

THRU: Stuart D. Rubin, Lead Engineer
Reactor Systems 4
Reactor Operations Analysis Branch, AEOD

FROM: Sagid Salah
Reactor Systems 4
Reactor Operations Analysis Branch, AEOD

SUBJECT: TECHNICAL REPORT FOR GRAND GULF UNIT 1

Forwarded herewith is the subject Technical Report for your information. As a result of this investigation, no further evaluation of this problem is considered necessary. Therefore, this technical review is complete.

Sagid Salah

Sagid Salah
Reactor Systems 4
Reactor Operations Analysis Branch, AEOD

Enclosure:
As stated

cc w/enclosure:
CHeltemes

~~8307290284 PDR~~

AEOD TECHNICAL REVIEW REPORT

UNIT: Grand Gulf Unit 1
DOCKET NO.: 50-416
LICENSEE: Mississippi Power & Light Company
NSSS/AE: GE/Bechtel

TR Report No. AEOD/T323
DATE: June 17, 1983
EVALUATOR/CONTACT: S. Salah

SUBJECT: TURBINE TRIP BYPASS DELAY

EVENT DATE: November 24, 1982

SUMMARY

Mississippi Power and Light Company has reviewed the Architect Engineer's request which recommended a design change to initiate a direct turbine trip upon loss of the main circulating water pumps. According to the request, incorporation of the proposed change would satisfy a GE criterion which requires that the steam line bypass be open for at least 5 seconds following a turbine trip during a loss of condenser vacuum transient.

After a detailed review of this issue, the licensee concluded that the proposed design change is not necessary. The 5 second bypass operation was not a GE criterion but rather a pressurization transient response based upon an assumption of 2 inches of Hg/second vacuum decay rate, considered to be conservative at the time the FSAR was implemented.

DISCUSSION

Technical Specification 6.9.1.1.2.h requires prompt notification of errors discovered in the transient or accident analysis or in the methods used for such analyses as described in the safety analysis report, or in the basis for the technical specification that have or could have permitted reactor operation in a manner less conservative than that assumed in the analyses.

The licensee reviewed Bechtel's request to Allis-Chalmers Power Systems, Inc. for design change to initiate a direct turbine trip upon loss of main circulating water pumps. In the process of review it was discovered that General Electric in their FSAR accident analysis used a plant condition which is less conservative than the design change requested by Bechtel. In the analysis General Electric assumed five seconds of steam bypass operation after a turbine trip. Such a requirement is not explicitly stated in the system design specification.

After a further review of this issue, the licensee concluded that the proposed design change is not necessary. The 5 second bypass operation was not a GE assumption but rather a pressurization transient response based upon an assumption of 2 inches Hg/second vacuum decay rate, considered to be conservative at the time the FSAR was implemented.

~~8307290287~~ PDR

The loss of condenser vacuum transient is categorized as a reactor pressure increase event. For the loss of condenser vacuum transient, based on a FSAR assumption of 2 inches Hg/second vacuum decay rate, the steam bypass would be available for 5 seconds provided that the bypass is signaled to close at a vacuum of 10 inches Hg less than the stop valve closure. The results (maximum vessel pressure of 1179 psig and MCPR greater than 1.13) are expected to be less severe than the limiting transient of this category.

The Architect-Engineer determined by analysis that the present Grand Gulf Nuclear Station (GGNS) logic will not allow the steam bypass valve to remain open for 5 seconds because the vacuum decay rate was estimated to be about 10 inches Hg/second. Therefore, the actual bypass operation period is only about one second. With one second bypass operation, a new analysis for loss of condenser vacuum transient would result in the maximum vessel pressure greater than 1179 psig quoted for 5 second bypass, but still less than the limiting 1234 psig of the load rejection without bypass transient.

FINDINGS

Actual steam bypass operation following Loss of Condenser Vacuum transient is approximately 1 second rather than 5 seconds due to vacuum decay rate of about 10 inches Hg/second instead of 2 inches Hg/second.

CONCLUSIONS

Technical Specification 6.9.1.1.2.h requirements were fulfilled by the licensee by immediately issuing an LER comparing the differences between the actual design logic with GE's FSAR analyses. To narrow this difference the Architect-Engineer has requested a direct turbine trip upon a loss of main circulating water pump. In addition licensee has pointed out in their follow up report that FSAR assumes a vacuum decay rate of 2 inches Hg/second compared to real value of around 10 inches Hg/second. This difference in vacuum decay rate results in one second for the steam bypass valves to remain open instead of 5 seconds. Since the proposed design change would merely improve the system behavior for a less limiting transient, it is not necessary to implement the change from the viewpoint of improving overall safety and operating margins.

Loss of condenser vacuum transient is categorized as an increase in reactor pressure event and since there are other more severe limiting pressurization transients, such as, load reject without bypass, consequences of loss of condenser vacuum does not limit the GGNS component design. Therefore this technical review is complete.

REFERENCES:

1. LER 82-105/01T-0
2 LER 82-105/01X-1 (Supplementary information)
3. Grand Gulf Nuclear Station Unit 1 FSAR Chapter 15.

2Q2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

NOV 15 1983

MEMORANDUM FOR: Karl V. Seyfrit, Chief
Reactor Operations Analysis Branch
Office for Analysis and Evaluation
of Operational Data

AEOD/T334

THRU: Stuart D. Rubin, Lead Engineer
Reactor Systems 4
Reactor Operations Analysis Branch

FROM: Sagid Salah
Reactor Systems 4
REACTOR Operations Analysis Branch

SUBJECT: TECHNICAL REPORT FOR GRAND GULF UNIT 1

Forwarded herewith is the subject Technical Report for your information. As a result of this investigation, no further evaluation of this problem is considered necessary. Therefore, this technical review is complete.

Sagid Salah
Sagid Salah
Reactor Systems 4
Reactor Operations Analysis Branch, AEOD

Enclosure:
As stated

cc w/enclosure:
C. Heltemes, AEOD

~~8312140197~~ PDR

AEOD TECHNICAL REVIEW REPORT*

UNIT: Grand Gulf Unit 1
DOCKET NO.: 50-416
LICENSEE: Mississippi Power & Light Company
NSSS/AE: GE/Bechtel

TR REPORT NO. AEOD/T334
DATE: November 15, 1983
EVALUATOR/CONTACT: S. Salah

SUBJECT: REACTOR VESSEL DRAINAGE

EVENT DATE: April 3, 1983

SUMMARY

When the RHR mode of operation was changed from Low Pressure Coolant Injection (LPCI) to shutdown cooling, a drainage path was created from the reactor vessel to the suppression pool. This caused 10,000 gallons of vessel water to be drained into the suppression pool before action was taken to stop the flow. The consequences of this event were within tolerable limits because draining was stopped before reactor vessel level reached the low level alarm setpoint.

DISCUSSION

On April 3, 1983, around 9:45 a.m. approximately 10,000 gallons of water drained from the reactor vessel to the suppression pool through the RHR system. This drainage was caused by two RHR valves (F004 and F006) being open simultaneously. At the time, the reactor was at atmospheric pressure, with vessel water temperature approximately 100°F.

Prior to this incident, loop "A" of the RHR system was lined up for the LPCI mode and loop "B" was lined up for the Shutdown (SD) cooling mode. Figure 1 shows this lineup of the RHR system. In order to change the lineup of loop "A" from LPCI to SD cooling mode the operator went to close valve F004. Full closure of the valve would normally result in the red valve position indicating light bulb (on the control panel) being extinguished. The operator observed that the light bulb was not illuminated and assumed that the valve was fully closed. However, unknown to the operator at the time, the indicating light bulb was burnedout which resulted in a faulty indication of full valve closure. The operator, not realizing this, assumed F004 was fully closed when it was in fact still partially open. Then the operator opened the valve F006 to put loop "A" in the SD cooling mode.

Opening valve F006 resulted in an unintended open flow path from the reactor vessel to the suppression pool which drained 10,000 gallons of water out of the reactor vessel. Water drained out because of the higher reactor vessel elevation. The control room operator noticed the indicated reactor vessel water level going down, and took immediate action to stop the flow of reactor vessel water before reactor vessel level reached the low level alarm setpoint. The water drain rate from the reactor vessel to the suppression pool was approximately 18,000 gpm. Since the LPCI system discharges into the reactor vessel above the top of the active core, there was no danger of core uncovery at any time.

*This report supports ongoing AEOD and NRC activities and does not represent the position or requirements of the responsible NRC program office.

There was a similar incident at LaSalle on September 15, 1983. Water drained from the reactor vessel to the suppression pool when an operator opened the LPCI B s[illegible] ion valve in accordance with the approved surveillance procedure. The static head of water in the reactor vessel caused water to drain through the check valve. The check valve failed to seat properly. This caused the draining of 5,000 to 10,000 gallons of water from the reactor vessel to the suppression pool in approximately three minutes. The control room operator noticed indicated reactor vessel water level going down and terminated the drainage manually while the automatic system isolated the primary containment.

FINDINGS

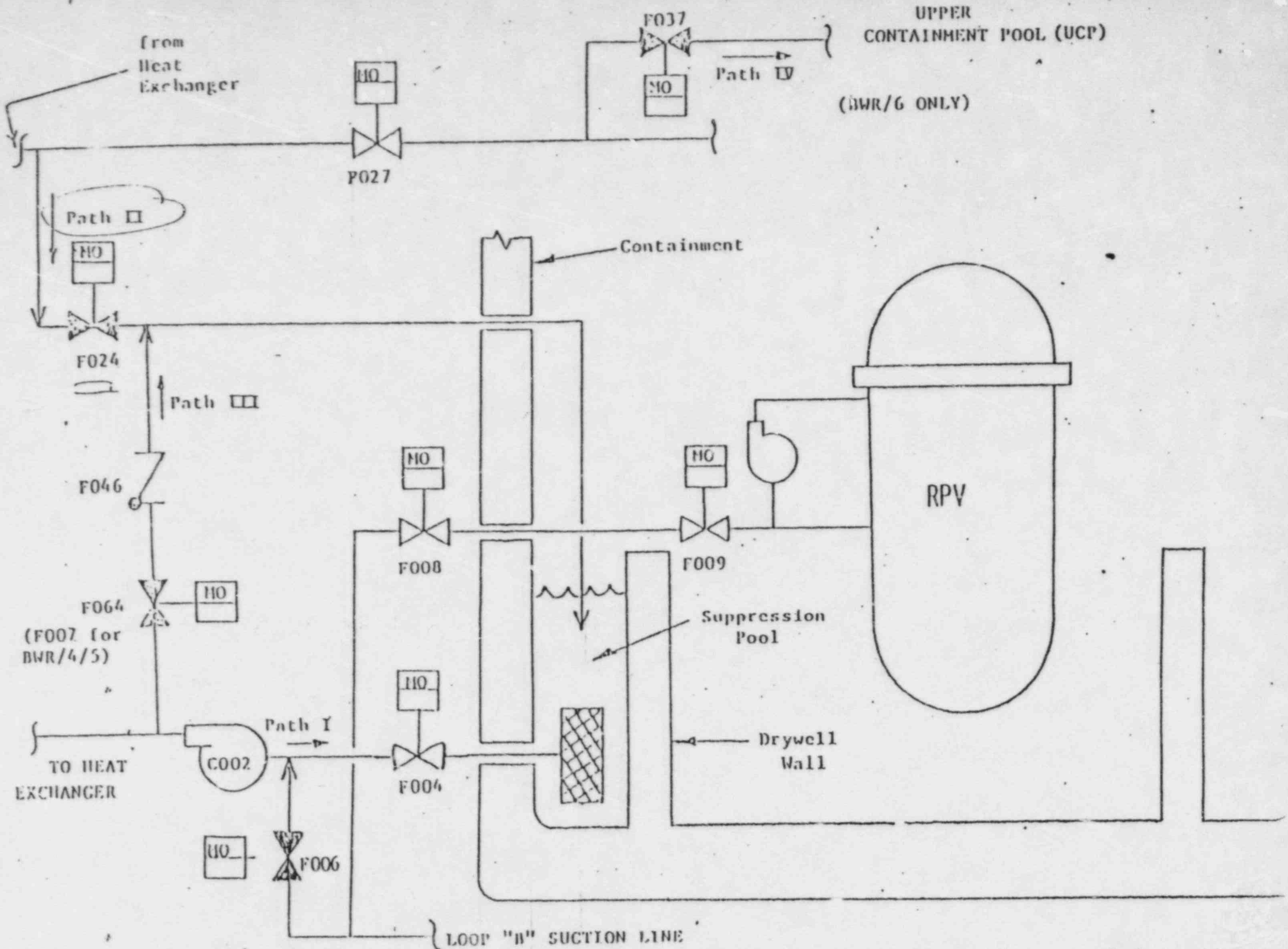
For the event at Grand Gulf a burned out indicating light bulb caused a misleadingposition status for the RHR pump suppression pool suction valve which resulted in a brief drainage path from the reactor vessel to the suppression pool.

CONCLUSIONS

When the operator changed the mode of operation of the "A" RHR train from LPCI to SD cooling, a flow path was created from the reactor vessel to the suppression pool. This caused reactor vessel water to flow into the suppression pool. The main cause of the problem was created by the burned out light bulb which erroneously indicated that the F004 valve was closed.

As a result of this incident, there were no significant consequences except that 10,000 gallons of reactor vessel water was drained into the suppression pool. The operator took immediate action to stop the flow of reactor vessel water before reaching the automatic initiation setpoint for the standby low pressure core cooling system.

There was no danger of core uncovery at any time. This is due to the fact that the LPCI line comes into the reactor vessel above the top of the active core.



Valve prefexes:

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

Enclosure 2

FEB 2 7 1984

MEMORANDUM FOR: Thomas Novak, Assistant Director
for Licensing
Division of Licensing

FROM: Frank J. Miraglia, Assistant Director
for Safety Assessment
Division of Licensing

SUBJECT: GRAND GULF OPERATING EXPERIENCE

In response to your request (memorandum of October 6, 1983) the Operating Reactors Assessment Branch (ORAB) has reviewed operating experience during the past year at the Grand Gulf facility and prepared the attached report.

The ORAB review included a survey of reported events at Grand Gulf during the past 15 months (i.e. the low power license period) and a comparison of the event reports with reports from two other recently licensed BWRs (LaSalle and Susquehanna) filed during their low power license periods. The sources of event reports included prompt (telephone) notifications filed per 10 CFR 50.72 as well as Licensee Event Reports (LER) required by the Technical Specifications. Operating reactor events briefing summaries were also examined to identify the more significant events. AEOD provided us with substantial support in obtaining event reports.

In general the review revealed that high number of prompt reportable events (10 CFR 50.72) have occurred at Grand Gulf in the past year. The rate of occurrence of these events has been at least three times greater than that of the two other recently licensed BWRs used for comparison. The large number of prompt reports are concerned for the most part with inadvertent actuations of engineered safety features. According to the 50.72 reports, equal numbers of these events have been caused by equipment failure and errors on the part of operators and technicians.

Review of operating reactor event briefing summaries indicates that five "significant" events have been reported for Grand Gulf during the year. They include a low temperature vessel pressurization incident, electrical system malfunction causing inadvertent RPS trips, a diesel generator room fire incident, simultaneous malfunction of both Transamerica DeLaval diesel generators, and an operator error which resulted in 10,000 gallons of water being drained from the reactor vessel to the suppression pool. The number of significant events at Grand Gulf during the low power license period is higher than that for the two other recently licensed BWRs considered in the review. LaSalle had only one event significant enough to be reported at a briefing and Susquehanna had none. It should also be noted that the periods of low power license for LaSalle and Susquehanna were much shorter than Grand Gulf.

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Based on our review we have concluded that operating experience at Grand Gulf during the past year has been atypical. Comparison of Grand Gulf experience with that of other BWRs indicates that the period of operation with the low power license at Grand Gulf has been abnormally long (greater than 12 months versus 4 months for Susquehanna and LaSalle) and that the rate of prompt reportable events has been much greater than expected. Based on discussions with Region II we believe that the high rate of reported events is at least in part related to the large amount of construction and testing activities which have gone on during the past year. This construction and testing activity is the result of design changes being implemented at the plant. The fact that many events which have occurred are related to personnel errors may indicate a lack of experience, on the part of plant personnel.

The rate at which events have occurred at Grand Gulf has not decreased steadily over the long term as the plant has moved closer to commercial operation. However, a sudden sharp decrease in the rate did occur in November 1983 which may be attributed to site inactivity following completion of low power testing in October. On this basis it would be reasonable to expect the incident rate to continue this decreasing trend as the plant moves closer to commercial operation, and testing and construction activities are completed.

We have discussed the results of our review with IE Region II, and they have informed us that our conclusions are consistent with their most recent SALP review. Region II will continue to monitor plant performance and take appropriate actions should problems continue to occur at a high rate.

Frank J. Miraglia

Frank J. Miraglia, Assistant Director
for Safety Assessment
Division of Licensing

Enclosure:
As Stated

OPERATING EXPERIENCE REVIEW

AT GRAND GULF UNIT #1

INTRODUCTION

The staff review of operating experience included a survey of reported events at Grand Gulf during the past 15 months (i.e. the low power license period) and a comparison of the event reports with reports from two other recently licensed BWRs (LaSalle and Susquehanna) filed during their low power license periods. The sources of event reports include prompt (telephone) notifications filed per 10 CFR 50.72 as well as Licensee Event Reports (LER) required by the Technical Specifications. Operating reactor events briefing summaries were also examined to identify the more significant events. These briefings are regularly scheduled meetings among NRC management to discuss recent events at operating reactors.

SURVEY OF EVENT REPORTS

In the period between mid-August 1982 and September 1, 1983 160 incidents requiring prompt notification were reported as required by 10 CFR part 50.72 One hundred and twenty-two of these events involved plant systems. The remaining 38 events involved the plant physical security system. This review has focused on the non-security related events. The security related events were not considered significant and were expected based on the testing and construction occurring at the plant. Thirty-five percent (35%) of the non-security related events have root causes related to operator and technician activities (e.g. testing, troubleshoorting). Equipment problems (mostly electrical) account for thirty-two (32%) of the events. The direct causes of the remaining one-third of the events are unknown or not apparent from the brief 50.72 reports. Most of the events involve inadvertent actuations of safety systems with the plant shutdown (e.g., standby gas treatment system, control room fresh air system, reactor trip, diesel generator start). The average monthly rate at which these events have been reported is approximately 10 events/month. This rate is compared with rates for LaSalle and Susquehanna in Table 1 and appears to be abnormally high. Region II inspectors attribute the high rate to the large amount of testing and construction going on at the plant. A review of the data by month does not reveal any particular trend in the incident rate. Data for the past three months shows a rate of occurrence close to the average in September and October with a sharp decrease in November to 3 events/month. The sharp decrease is attributed to site inactivity following completion of low power tests. A steady reduction in the rate of occurrence is expected as the plant nears commercial operation, since design changes and associated tests are expected to be completed.

In the period beginning August 1, 1982 and ending July 1, 1983 a total of 227 LERs were issued from Grand Gulf. The average monthly rate at which LERs have been issued is shown in table 1 along with comparable rates for LaSalle and Susquehanna. The Grand Gulf rate is similar to the rates for LaSalle and Susquehanna. This is in sharp contrast with the 10 CFR part 50.72 reports discussed above where the Grand Gulf rate was significantly higher than the other two plants. Review of the Grand Gulf LERs indicates that about one-half of the reports relate to problems with fire protection systems. These problems include many instances of smoke detector alarms caused by dust from construction; and, removal of fire barriers for construction purposes. Only nineteen percent

TABLE 1

RATE OF REPORTED EVENTS AT

THREE BWR PLANTS

DURING LOW POWER LICENSE PERIOD

Facility	Period of Low Power License (months	Rate of Reported Events (Avg. No. reports/month) 50.72	LER
Grand Gulf	12*	10	21
LaSalle 1	4	1	19
Susquehanna 1	4	3	12

* The study period consists of the first 12 months of the low power license period. The actual period of the low power license will be longer than 12 months.

deficiencies. Other causes of reported events include equipment problems and planned entry of technical specification action statements for purposes of testing or construction.

REVIEW OF SIGNIFICANT EVENTS

Significant events which have occurred at Grand Gulf during the past year have been identified through a review of issues raised at the regularly scheduled briefings of NRR management on operating reactor experience. The review consisted of a review of the Operating Reactor Event Briefing meeting minutes. For purposes of comparison a similar review has been performed for LaSalle and Susquehanna for the periods they held low power licenses. Events which are discussed at operating reactor event briefings have been subjected to a screening process in which five or six significant events are selected every two weeks for discussion based on the review of 100 to 150 events reports during the two week period. The purpose of identifying those events here is to provide a measure of the severity and extent of significant operational problems.

During the Grand Gulf low power license period, five significant problems at Grand Gulf were reported. Our review indicates that only one significant event was reported for LaSalle during the period of its low power license. No events were reported for Susquehanna. The Grand Gulf events are summarized below.

Violation of RTNDT Heating Limits During ECCS Injection October 5, 1982

During surveillance testing with the plant in cold shutdown a high DC voltage spike occurred which initiated an ECCS injection. Low pressure core spray injected and caused the reactor vessel to become water solid (extending to the MSIVs). The resulting pressure transient violated the Technical Specification on nil-ductility reference temperature, RTNDT.

Reactor Protection System (RPS) MG-Set Output Breaker Trips, May 19, 1983

Inadvertent tripping of the RPS MG-set output breakers has occurred repetitively resulting in isolation of the instrument air system and a reactor scram signal. The causes of the trips have been identified as thermal overload due to insufficient cabinet ventilation, and low voltage due to voltage swings while the RPS bus is fed from the alternate power supply. To reduce the number of output breaker trips the licensee increased cabinet ventilation, installed voltage regulators to smooth out voltage fluctuations, and installed a new station electrical transmission line from off-site. In addition instrument air system isolation relays have been re-aligned to an interruptable power supply. This problem re-occurred in January 1984. Upward voltage spikes remaining above the setpoint longer than .1 second have caused the protective MG-set output breaker to trip, resulting in de-energization of containment isolation system logic circuits followed by isolation of the RHR system. The licensee has been unable to identify the source of the voltage spikes. To correct the problem, the licensee has increased the output breaker delay time from .1 second to 1.4 seconds. The new delay time is based on measurements of spike duration and consultation with suppliers of the electrical equipment. The modification assures that spikes lasting less than 1.4 seconds will not result in a trip of the protective breaker. Additional corrective actions are also under discussion between the licensee and Region II.

<u>Inadvertent Reactor Vessel Drainage During Shutdown April 3, 1983</u>

On April 3, 1983, approximately 10,000 gallons of water drained from the reactor vessel to the suppression pool through the residual heat removal (RHR) system. This drainage was caused by two RHR valves (F004 and F006) being open simultaneously. At the time of the event, the reactor was at atmospheric pressure with vessel water temperature approximately 100°F (cold shutdown conditions). The vessel water level continued to decrease until the low level isolation signal was received and shutdown cooling isolation valves closed to terminate the leakage.

<u>Diesel Generator Room Fire September 4, 1983</u>

A diesel generator engine fire was caused by a ruptured fuel oil supply line which sprayed oil on the hot exhaust manifold of the diesel. The diesel which caught fire was running at 25 percent load for testing at the time. Two other diesel generators were not affected by the fire. The water deluge system failed to function automatically, but was manually activated to extinguish the fire. The diesel generator governor and turbo chargers were damaged. In addition some electrical equipment in the room suffered water damage.

<u>Inoperability of Delaval Diesel Generators October 28, 1983</u>

On October 28, 1983, a Technical Specification Action Statement was entered when two of the three diesel generators became inoperable. The Division I diesel generator was inoperable due to gasket failure on a lube oil line. The Division II diesel generator became inoperable due to a loose base plate nut on the turbocharger which resulted in a trip of the vibration sensor which tripped the diesel. Corrective action was taken to repair both diesel generators. Both of the diesel generators were manufactured by Transamerica Delaval Inc. (TDI). TDI diesel generators have recently come under close scrutiny by the staff following a crankshaft failure in a TDI diesel generator at the Shoreham plant. Staff review of the Transamerica Delaval diesel generator problem at Grand Gulf is still ongoing.

CONCLUSIONS

Based on our review, we have concluded that operating experience at Grand Gulf during the low power license period has been atypical. Comparison of Grand Gulf experience with that of other BWRs indicates that the period of operation with the low power license at Grand Gulf has been abnormally long (12 months versus 4 months for Susquehanna and LaSalle) and that the rate of prompt reportable events has been much greater than expected. Based on discussions with Region II we believe that the high rate of reported events is related, at least in part, to the large amount of testing and construction activities which have gone on during the past year. This construction and testing activity is the result of design changes being implemented at the plant. The fact that many of the events are related to personnel errors may indicate a lack of experience on the part of plant personnel. The rate at which events have occurred at Grand Gulf has not decreased steadily over the long term as the plant has moved closer to commerical operation. However, a sudden sharp decrease in the rate did occur in November 1983 which may be attributed to site inactivity following completion of the low power testing in October. On this basis, we believe it is reasonable to expect the incident rate to continue this decreasing trend as the plant moves closer to commercial operation, and testing and construction activities cease. Should an abnormally high rate of incidents re-appear, appropriate actions such as initiating a review of personnel training programs and plant procedures should be initiated to identify the root cause of the continuing problem so that necessary corrective measures measures can be taken.

Enclosure 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

FEB 24 1984

MEMORANDUM FOR: Chairman Palladino
Commissioner Gilinsky
Commissioner Roberts
Commissioner Asselstine
Commissioner Bernthal

FROM: William J. Dircks
Executive Director for Operations

SUBJECT: PERSONNEL ERRORS AT SELECTED OPERATING PLANTS

The Office of Inspection and Enforcement and the Office for Analysis and Evaluation of Operational Data were requested by Commissioner Gilinsky's staff to provide information on the frequency of personnel errors at selected operating plants (i.e., Grand Gulf, Sequoyah, and Quad Cities). The Commission should understand that the information presented here is strictly a staff effort based on information available to the staff and has not been verified with the individual licensees.

The NRC Operations Center data base contains information on events that are required to be reported under the provisions of 10 CFR 50.72. Many different types of events are reported, including all plant trips and safety system actuations.

The following characteristics of the IE data base should be kept in mind when using the information presented here:

1) The information is called in to the NRC shortly after the event, and at that time an accurate determination of the cause may not be available.

2) Corrections to original reports are not routinely made if later information would indicate a different event cause.

3) Because the search capability of the system relys partially on a text search routine, some events which involve operator error may be missed. This search used "operational failure" and "personnel error." We believe these to be the most frequently used categories for labeling operational errors.

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Table 1 provides a summary of our findings. The tabulated events were reported as operator errors, personnel errors, or procedural errors. Some events were judged to affect the combined units. These are counted separately and not included as Unit 1 or Unit 2 events.

Table 1

Personnel Errors Reported to the NRC Operations Center 1983*

	Personnel Errors	Site Total
Quad Cities, Unit 1	4	
Quad Cities, Unit 2	1	
Quad Cities (both)	4	9
Grand Gulf, Unit 1	27	27
Sequoyah, Unit 1	6	
Sequoyah, Unit 2	3	
Sequoyah (both)	1	10

* These reports are from calendar year 1983.

In addition, AEOD searched the Sequence Coding and Search System (SCSS) for LERs from Grand Gulf, Quad Cities, and Sequoyah that stated or implied that a personnel action was involved in the event.

Because of the extensive amount of information from each LER that is coded in the SCSS, it was not necessary to rely on text searches for particular words (e.g., "personnel error") or to rely on the data coded by the licensee on the LER form. Thus, if the LER text expressly stated that a "personnel error" occurred, or if the LER implied that a personnel error occurred (e.g., "Inadvertently he operated an incorrect valve"), the information was coded into SCSS and was captured by the subsequent search.

The results of this search were manually reviewed to identify personnel errors that could be attributed to plant personnel (e.g., design errors and fabrication/manufacturing errors were excluded). A rather broad definition of "personnel error" was used which included both errors of commission (e.g., inadvertent operation of the wrong valve) and errors of omission (e.g., missed surveillance requirements).

The results of this analysis are summarized in Table 2.

Table 2

Personnel Errors Reported in LERs

Plant/Unit	Period	Personnel Errors	LERs Received
Quad Cities, Unit 1	1983*	7***	36
Quad Cities, Unit 2	1983*	4	20
Grand Gulf, Unit 1	1983*	58	162
Grand Gulf, Unit 2	1983*	0	0
Sequoyah, Unit 1	1983*	18	85
Sequoyah, Unit 2	1983*	9	64
Sequoyah, Unit 1	June 1, 1982- June 1, 1983**	7	90
Sequoyah, Unit 2	August 1, 1981- August 1, 1982**	18	61

* Some LERs for 1983 have not yet been received and added to the data base. However, the period is essentially the same for all units.

** First year of commercial operation.

*** Many of the personnel errors reported to the Operations Center were also reported in LERs. Therefore, the numbers in Tables 1 and 2 should not be added.

Clearly from Tables 1 and 2, Grand Gulf has reported more personnel errors than the other units analyzed. However, care should be taken in reaching conclusions from this data. As the ACRS discussed in Appendix E to NUREG-0572 (enclosed) there are many reasons for non-randomness (e.g., outliers) in operational data, including differences in reporting requirements, differences in reporting philosophies, etc. It should be noted that many of these differences have been reduced by the recent publication of 10 CFR 50.73, "Licensee Event System", and 10 CFR 50.72, "Immediate Notification Requirement for Operating Nuclear Reactors," which became effective on January 1, 1984. In addition, a review of a count of personnel errors does not consider the severity of the error or its consequences. For example, many of the errors reported by Grand Gulf were missed surveillance requirements that did not directly affect plant operation.

Finally, because of the time available to prepare this analysis and the size of the computer printout, we were not able to make copies of the printout. Consequently the printouts have been provided (separately) only to Commissioner Gilinsky's office and have not been provided to other interested parties and have not been retained by the staff. If other interested parties want a copy, copies can be made from the enclosed original, or the search strategy can be rerun on the computer and additional printouts produced.

(Signed) William J. Dircks

William J. Dircks
Executive Director for Operations

Enclosures:
As stated

cc w/enclosures:
OGC
OCA
OPE
SECY

APPENDIX E

STATISTICAL ANALYSIS OF
LERs: A TRIAL STUDY

Introduction

Approximately 8700 LERs were submitted by the licensees of U.S. commercial nuclear power plants during the years 1976, 1977, and 1978. For several reasons, the number of LERs varies from unit to unit. These variations are important, because, rightly or wrongly, they are often viewed by government agencies and the public as indications of relative safety. While such variations may be indicative of actual differences in safety among nuclear power units, they may have other explanations. It is therefore important to understand all possible explanations and their contributions to variations in the numbers of LERs from unit to unit.

Certain differences in the frequency of submission of LERs from unit to unit will occur as a result of the apparent random nature of the events being reported. Because of this "randomness", it is possible--in fact, probable--that, even among identical nuclear power plant facilities with identical failure probabilities, there will be variations in the reporting rate for LERs. In reality, however, variations beyond those due to "randomness" will frequently be observed. The reasons for such non-random variations include the facts that:

(1) Technical Specifications and license provisions vary among nuclear power plant facilities, because of differences in reactor suppliers, architect/engineers, and constructors, and changes in designs over the years. These variations cause differences in the reporting requirements among facilities.

(2) There may be a tendency at some facilities to report events more readily than at others in cases of marginal reportability. This consideration pertains to events other than obvious "reportable occurrences" (ROs), which all licensees must report[1]*. This tendency can also change with time.

(3) The occurrence of an event may affect the probability of future events. Repair of a facility component or improvement of a deficient procedure may significantly reduce the likelihood of an associated event. On the other hand, ineffective corrective action following an event may result in its repeated occurrence.

(4) The mode of operation (e.g., on-line or shutdown) affects the frequency of various kinds of inspections and the susceptability of systems to random failures. The amount of reactor down-time, for example, may affect the frequency with which LERs are submitted.

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*See reference list following Chapter 4.

(5) Misinterpretations by licensee or NRC personnel involved in the preparation, submission, and processing of LERs can affect relative reporting frequencies among reactor systems.

(6) At some multi-unit power stations, such as Oconee and Browns Ferry, events which involve plant systems or components common to all units, such as swing diesels and electrical switchyards, are filed in the NRC data bank under the docket number of the first unit.

(7) The actual presence of more safety-related deficiencies in a system at an individual facility should result in more frequent submission of LERs. Differences in the number of LERs due to this cause would be a measure of relative safety.

Although the above factors affect the frequency with which LERs are reported, their effects are often relatively small. Frequently the variations produced by these effects are too small to be distinguished from those occurring on a random basis. For example, the Point Beach Nuclear Station in 1976 had 11 reportable occurrence LERs for Unit 1 and 16 for Unit 2. Does this necessarily indicate that one or a combination of the causes listed above produced this difference, or is it possible that a deviation of this magnitude could have been expected if both units had the same average probability of occurrence of reportable events? Statistical analysis indicates that 11 and 16 in one year are both consistent with average occurrence rates in the range of one per 20 days to one per 37 days (10-18 per year). In fact, the pair of numbers, 11 and 16, is the most probable one-year outcome for two units with an average rate of one per 27 days (13.5 per year). In 1978, the Zion Nuclear Station had 85 reportable occurrence LERs for Unit 1 and 39 for Unit 2. In this case, the deviation in the number of LERs between the two units is too large to be attributed solely to random effects. If randomness alone were involved, Unit 1 probably could not have had a reporting rate less than one per 5.2 days (70 per year), while Unit 2 probably could not have had a rate greater than one per 7.2 days (51 per year). In fact, if both Zion units had identical probabilities of reportable events, there is no more than one chance in one million that a deviation this large could occur by chance.

Naturally, there are differences between the Point Beach units. Unit 1 is two years older than Unit 2. During 1976, Unit 2 produced 11% more electrical energy than Unit 1. The results in this example indicate that one should not necessarily conclude that differences in the rates of LER submission between the two units are significant. At Zion, however, one should expect to find that the two units reported at significantly different rates for reasons other than randomness.

Methodology

Methods from probability theory can be used to calculate the impact of randomness on the distribution of the number of LERs among identical nuclear power units. Often, probability tables from reference textbooks are sufficient to perform the analyses. Computer simulations are necessary for the more complicated analyses.

In interpreting the resulting data, it is important to note several basic facts:

(1) The numerical size of expected random variations in event rates increases as the average event rate increases. Deviations of 10 or more are readily expected on a random basis for an average yearly rate of 100, but are unlikely for an average yearly rate of 20. The relative size or percentage variation, however, decreases as the average rate increases.

(2) The chance of large random variations among units increases as the number of units being compared increases. For two units with an assumed average annual LER submission rate of 100, there is only a small chance that one rate will deviate by more than 20 from the average because of randomness. For a comparison among 30 units, however, there is a good chance that at least one will deviate by more than 20 from the annual average rate of 100 because of randomness.

A selected set of LERs was used here to demonstrate the application of this methodology. The sources of the LERs were the 22 BWRs that achieved commercial operation prior to 1976. Records show that this group submitted a total of 27 LERs for 30-day reportable occurrences in auxiliary process systems during 1976, 1977, and 1978. Thus, for this group of units, the average was about one LER of this type for the three-year period. It is first assumed that all units in the group were identical with respect to their chances of generating LERs of this type. Further, it is assumed that if a nuclear power plant experiences a reportable occurrence in an auxiliary process system, the chance of another occurrence is unaffected. Throughout this study a Poisson distribution of events is assumed. Probability theory indicates that, while the average is one, it is very unlikely that each individual unit would experience exactly one. In fact, the probability that all 22 units would each report this number is less than one in ten billion. The most likely result is that about eight units will have no LERs, about eight will have one LER, about four will have two LERs, and about two will have three LERs. Further, it is unlikely (8% chance) that any one unit will have six or more LERs. Comparison to actual LER data shows nine units with no LERs, seven with one LER, two with two LERs, one with three LERs, two with four

LERs, and one with five LERs. The distribution of LERs for the 22 BWRs is consistent with the assumptions stated above.

This example, does not prove, however, that the 22 BWRs are identical to each other with regard to the causes of auxiliary process systems failures. It simply indicates that one should not expect to find significant differences among these units, even though some submitted as few as zero and others as many as five LERs. The value of this analysis is that it provides a methodology through which significantly high deviations can be readily identified among a population of expected random deviations.

Analyses

For purposes of this study, the LERs from 67 nuclear power plants were reviewed. For purposes of analyses, these were divided into PWRs (total = 42) and BWRs (total = 25) and each of these groups was further separated into "older" and "newer" power plants. In this case, "older" was arbitrarily defined as those power plants that went into operation prior to 1976 (see Table E-1). For this group, all LERs submitted during calendar years 1976 through 1978 represent events that occurred during commercial operation.

Data used in these analyses were based on the NRC computer bank and included reportable occurrences only. The ROs were separated into those required to be submitted on a prompt or two-week basis and those submitted on a thirty-day basis. These were analyzed separately since there did not appear to be any correlation in the relative numbers of each type as reported by licensees at the 67 power plants. Lastly, the LERs were further separated according to the system to which they pertained. A listing of these systems is shown in Table E-2.

The primary goal in the analyses was to identify significant deviations or variations in the number of LERs reported from plant to plant and system to system. A deviation was considered to be significant if there was a 5% chance or less that it could have resulted from random variations.

Conclusions

On the basis of these analyses, the following conclusions and/or observations were made:

(1) The frequencies of reportable occurrence LERS among the various nuclear power units were significantly different. There were no identifiable groups of reactor units whose members generated the same average number of reportable occurrence LERs during each of the three years in the study.

(2) Considering the three-year period as a whole, 5 units among the 29 older PWRs deviated significantly from the others in terms of the total number of two-week ROs. The numbers of LERs from Calvert Cliffs-1, Palisades, Rancho Seco, and Three Mile Island-1 were high; Maine Yankee was low. The remaining 24 PWRs reported numbers of LERs consistent with an average of about 20 per unit for the period from 1976 through 1978.

(3) For the same 29 older PWRs, considered year by year, the data showed that the total number of two-week ROs steadily decreased in each successive year. The averages were ten per unit in 1976, six in 1977, and four in 1978. Significant deviations from these occurred at Calvert Cliffs-1 in 1977, Palisades in 1977 and 1978, Point Beach-1 in 1978, Rancho Seco in 1977, and Three Mile Island-1 in 1978. All had higher than normal reporting rates. Maine Yankee had a rate in 1976 significantly lower than normal. These results indicate that the high three-year totals for the four units listed in paragraph 2 above were basically due to high reporting rates in just one of the three years, while the rates for the other two years appear to be normal.

(4) Further analysis of the data showed that the high totals of two-week ROs in four of the older PWRs were attributable to abnormally high numbers of LERs concerning specific systems. Calvert Cliffs-1 had significantly high three-year totals for electric power systems and for reactor systems. Palisades reported high totals for the same two systems, in addition to engineered safety features. Rancho Seco reported a high total for electric power systems. Three Mile Island-1 had high totals for radiation protection systems and for events classed as "systems code not applicable." Many of the electric power system LERs were related to off-site power systems and emergency diesel generators. Reactivity control systems were the source of most of the reactor system LERs from Palisades.

(5) Among the older PWRs with normal yearly totals for two-week ROs, some nevertheless reported significantly higher than normal totals of LERs for specific systems. The number of LERs in reactor systems was higher than normal at Arkansas Nuclear One-1, Oconee-2 and -3, and H.B. Robinson-2. The number for Zion-1 was higher than normal for radiation protection systems. LERs for electric power systems were higher than normal at Fort Calhoun, Oconee-1 and -3, Prairie Island-1, and Turkey Point-3. The systems mentioned here, however, did not contribute significantly to the total number of LERs, since LERs from engineered safety features and reactor coolant systems dominated the two-week ROs from older PWRs. As a result, deviations from normal in the less often reported systems did not have a significant impact on the total number of LERs for these plants.

(6) The data show that newer PWRs, after they achieved commercial operation, had significantly higher LER submission rates for two-week ROs than did older PWRs. The exception was Indian Point-3. As with the older plants, engineered safety features and reactor coolant systems were responsible for a large fraction of the LERs.

(7) With regard to 30-day ROs, there were no identifiable units among the 29 older PWRs that deviated significantly from the average totals for the three-year period. It is possible, however, to identify three separate subgroups among the units in this category. A first subgroup includes seven units with an average reporting rate of about twenty 30-day ROs for the three years. These were Oconee-2, Point Beach-1 and -2, Rancho Seco, San Onofre-1, and Turkey Point-3 and -4. Another group had an average of about forty-five 30-day ROs for the three years. The 10 units in this group were H.B. Robinson-2, Haddam Neck, Indian Point-2, Maine Yankee, Oconee-1 and -3, Prairie Island-1 and -2, R.E. Ginna, and Three Mile Island-1. A third group of 5 units with a normal reporting rate of about 70 for the three-year period included Arkansas Nuclear One-1, Kewanee, Palisades, and Surry-1 and -2. Significant deviations from these groups occurred in 7 units with high reporting rates. These were Calvert Cliffs-1, D.C. Cook-1, Fort Calhoun, Millstone-2, Yankee Rowe, and Zion-1 and -2. It is interesting to note that three of the five operating Combustion Engineering reactors are in this category. These are Calvert Cliffs-1, Fort Calhoun, and Millstone-2. In addition, this category includes all three of the older PWRs having a power level of 1000 MWe or more. These are D.C. Cook-1 and Zion-1 and -2.

(8) The data show that the one-year totals for thirty-day ROs in older PWRs were similar to the three-year totals in that definite subgroups can be identified. In general, a unit that was in a low or higher reporting subgroup in one year remained in the same subgroup in later years. The exceptions were Yankee Rowe, which was in a higher reporting subgroup in 1977, but in lower reporting subgroups in the other two years, and Surry-1 and -2, which were in a lower reporting subgroup during the first two years but in the higher subgroup in 1978. Several significant correlations were found. Those units which tended to remain in the lowest reporting subgroups nevertheless increased their reporting rates for thirty-day ROs from year to year. The sum of their thirty-day and two-week ROs, however, remained essentially constant in time, since the two-week RO total steadily decreased during the three-year period. Large units of 1000 MWe or more reported higher numbers of 30-day ROs, except when the plant factor for the year was low (less than one-third). Later Combustion

Engineering units (not including Maine Yankee) also submitted higher numbers of LERs for thirty-day ROs, except when the plant availability factor was low (less than one-half).

(9) Newer PWRs reported thirty-day ROs at rates consistent with the higher reporting subgroups among older PWRs.

(10) The systems most responsible for the higher LER submission rates for thirty-day ROs in Combustion Engineering units were auxiliary process systems, electric power systems, instrumentation systems, and steam and power conversion systems. These units usually deviated from the normal reporting rate for these systems. In large units the systems involving a higher than normal number of thirty-day ROs were auxiliary process systems, engineered safety features, instrumentation systems, and radiation protection systems.

(11) With regard to two-week ROs among the 22 older BWRs, eight units deviated from the normal reporting rate during the three-year period. These were Dresden-2, Duane Arnold, E.I. Hatch-1, Fitzpatrick, and Peach Bottom-2 and -3, with higher rates than normal and Dresden-1 and LaCrosse with lower rates than normal. The remaining units reported an average rate of about twenty-four two-week ROs for the three-year period. The rate remained constant at about eight per year.

(12) E.I. Hatch-1 reported two-week ROs at a comparatively high rate for each of the three years. The number of reports pertaining to nearly every system deviated from normal reporting rates for those systems.

(13) Duane Arnold reported two-week ROs at a comparatively high rate in 1976 and 1977. The systems with higher than normal numbers of reports were related to electric power. For Fitzpatrick, the number of two-week ROs for 1976 was high. This unit also had a high number of ROs in instrumentation systems. For Peach Bottom-2 and -3, the number of two-week ROs for 1976 and 1977 was high. Unit 2 had an abnormally high number of ROs for reactor coolant systems and steam and power conversion systems. Unit 3 reported a high number in engineered safety features and for other auxiliary systems. Dresden-3 reported a higher-than-normal number of LERs in 1977. Further, this unit reported an abnormally high number of ROs in electric power systems. Nine Mile Point-1 reported higher-than-normal totals of LERs concerning instrumentation systems. Quad Cities-1 reported a high incidence of two-week ROs in steam and power conversion systems.

(14) Among the three newer BWRs, only Browns Ferry-3 reported abnormally high numbers of two-week ROs in reactor systems after the unit began commercial operation.

(15) Two BWR units, Fitzpatrick and Brunswick-1, reported abnormally high numbers of thirty-day ROs in nearly every system.

As an extension to the above, LERs pertaining to set point drift were analyzed using as a data source the computer bank at the Nuclear Safety Information Center (see Appendix D-III). These analyses showed that there was no significant deviation in the total annual LER submittal rate for setpoint drift among older BWRs or among older PWRs. The average rate for BWRs, however, was approximately five times as large as that for PWRs. Six older PWRs reported rates higher than normal for the three-year period. These were Zion-1 and -2, Fort Calhoun, Millstone-2, Palisades, and Kewanee. It is interesting to note that three of these are Combustion Engineering units. Among newer PWRs, four units reported at high rates in 1978. These were J.M. Farley-1, Indian Point-3, North Anna-1, and Salem. Three older BWRs reported set point drift events at abnormally high rates for the entire three-year period. These were Duane Arnold, Brunswick-2, and Nine Mile Point-1. Six older BWRs reported at abnormally low rates. These were Big Rock Point, Browns Ferry -1, -2, and -3, LaCrosse, and Monticello.

Commentary

This portion of the study has clearly demonstrated the potential usefulness of statistical analyses in the evaluation of LERs submitted by licensees. Such analyses make it possible to distinguish deviations in the numbers of LERs which would be expected on the basis of randomness from those that almost certainly would not. The latter can be used as a means for the identification of areas for possible further investigations. While the deviations noted in this study do not necessarily imply safety-related problems, they should nonetheless be pursued in order to determine the true implications.

It would probably be desirable to computerize these analyses for automatic processing of reports as they are logged into the LER data base. Utilization of the data base in this manner would make it possible to detect significant deviations from normal. Further, an automated system could be programmed to obtain detail beyond the system level, in order to identify reporting rate deviations for relevant subsystems and components.

Table E-1

Number of Reportable Occurrence LERs from Commercial Nuclear Power Plants (1976-1978)

GROUP I: Older PWRs (commercial operation prior to 1976) Total = 29

Nuclear Power Plant	Reportable Occurrences 30-day	Reportable Occurrences 2-week
Arkansas Nuclear One-1	71	17
Calvert Cliffs-1	169	35
D.C. Cook-1	147	20
Fort Calhoun	109	24
H.B. Robinson-2	53	26
Haddam Neck	41	19
Indian Point-2	57	26
Kewanee	75	19
Maine Yankee	47	6
Millstone-2	118	21
Oconee-1	42	34
Oconee-2	21	26
Oconee-3	41	21
Palisades	64	55
Point Beach-1	15	30
Point Beach-2	18	20
Prairie Island-1	51	17
Prairie Island-2	36	18
Rancho Seco	17	40
R.E. Ginna	44	24
San Onofre-1	19	11
Surry-1	79	19
Surry-2	71	8
Three Mile Island-1	44	41
Turkey Point-3	24	11
Turkey Point-4	20	16
Yankee Rowe	99	13
Zion 1	186	25
Zion 2	122	15
Average	65.6	22.7

Table E-I Continued

GROUP II: Newer PWRs (commercial operation after January 1, 1976) Total = 13

Nuclear Power Plant	Reportable Occurrences 30-day	2-week
Arkansas Nuclear One-2	21	7
Beaver Valley-I	216	27
Calvert Cliffs-2	135	25
Crystal River-3	154	32
D.C. Cook-2	96	7
Davis-Besse-I	220	32
Indian Point-3	85	15
J.M. Farley-I	138	23
North Anna-I	98	29
St. Lucie-I	123	22
Salem-I	118	68
Three Mile Island-2	42	17
Trojan	63	44
Average	116.5	26.8

Table E-1 Continued

GROUP III: Older BWRs (commercial operation prior to 1976) Total = 22

Nuclear Power Plant	Reportable Occurrences 30-day	2-week	Nuclear Power Plant	Reportable Occurrences 30-day	2-week
Big Rock Point	105	31	LaCrosse	27	10
Browns Ferry-1	55	26	Millstone-1	80	27
Browns Ferry-2	33	19	Monticello	65	30
Brunswick-2	261	34	Nine Mile Point-1	93	27
Cooper	122	18	Oyster Creek-1	56	35
Dresden-1	70	10	Peach Bottom-2	146	56
Dreaden-2	153	51	Peach Bottom-3	107	56
Dresden-3	109	29	Pilgrim-1	103	25
Duane Arnold	120	88	Quad Cities-1	94	31
E.I. Hatch-1	94	162	Quad Cities-2	75	14
Fitzpatrick	181	41	Vermont Yankee	95	18
			Average	102.0	38.0

Table E-1 Continued

GROUP IV: Newer BWRs (commercial operation after January 1, 1976) Total = 3

Nuclear Power Plant	Reportable Occurrences 30-day	2-week
Browns Ferry-3	58	12
Brunswick-1	211	9
E.I. Hatch-2	65	12
Average	111.3	11.0

Table E-2

System Codes for LERs

System		System	
1.	Auxiliary Process Systems	8.	Other Major Systems
2.	Auxiliary Water Systems	9.	Radiation Protection Systems
3.	Electric Power Systems	10.	Radioactive Waste Management Systems
4.	Engineered Safety Features	11.	Reactor Systems
5.	Fuel Storage and Handling Systems	12.	Reactor Coolant Systems
6.	Instrumentation and Control Systems	13.	Steam and Power Conversion Systems
7.	Other Auxiliary Systems	14.	System Code Not Applicable

4Q2

APR 25 1984

AEOD/T406

MEMORANDUM FOR: Karl V. Seyfrit, Chief
Reactor Operations Analysis Branch, AEOD

THRU: Stuart D. Rubin, Lead Engineer
Reactor Systems 4, ROAB

FROM: Thomas R. Wolf, Reactor Systems Engineer
Reactor Systems 4, ROAB

SUBJECT: TECHNICAL REVIEW REPORT OF AN IMPROPER SPARE PARTS PROCUREMENT EVENT AT GRAND GULF UNIT 1

Enclosed is a technical review report of an improper spare parts procurement event which occurred at Grand Gulf Nuclear Station Unit 1 on September 19, 1983. While the actual event was minor, the main concern of proper equipment quality level classification is generic to Grand Gulf and the industry. However, NRC Generic Letter 83-28 sufficiently addresses the problem. Therefore, no additional AEOD/ROAB review and actions are necessary at this time.

/S/

Thomas R. Wolf, Reactor Systems Engineer
Reactor Systems 4
Reactor Operations Analysis Branch
AEOD

Enclosure:
As stated

Distribution:
ROAB RF
ROAB SF
AEOD CF
T. Wolf
S. Rubin
T. Ippolito
C.J. Heltemes

~~8405210047 PDR~~

OFFICE	RS4/ROAB	C/RS4/ROAB					
NAME	TWolf:eh TRW	SRubin SR					

AEOD TECHNICAL REVIEW REPORT*

UNIT: Grand Gulf 1
DOCKET NO.: 50-416
LICENSEE: Mississippi Power Light Company
NSSS/AE: GE/Bechtel

TR REPORT NO.: AEOD/T406
DATE: April 25, 1984
EVALUATOR/CONTACT: T.R. Wolf

SUBJECT: EVALUATION OF AN IMPROPER SPARE PARTS PROCUREMENT EVENT AT GRAND GULF UNIT 1

EVENT DATE: September 19, 1983

Summary:

Licensee Event Report 50-416/83-147 documents that due to improper quality level specifications, incorrect spare parts were procured and installed in the control room chlorine detection system. Review of other industry documents indicates that there may exist a generic problem in the programs designed to assure that proper equipment quality levels are maintained over the plant life span. NRC Generic Letter 83-28 "Required Actions Based On Generic Implications of Salem ATWS Events" properly and sufficiently addresses this problem. Consequently, no further AEOD/ROAB action is necessary at this time.

*This document supports ongoing AEOD and NRC activities and does not represent the position or requirements of the responsible NRC program office.

Discussion and Findings

As a result of an internal plant audit which indicated that there might exist a generic problem in the quality levels specified in spare part procurements, Grand Gulf personnel initiated a review of all procurement documents. It was determined during this review that spare parts purchased and installed in the control room chlorine detection system had, indeed, been procured utilizing erroneous quality level specifications. Consequently, on September 19, 1983, the detection system was declared inoperable and a Limiting Condition for Operation was entered. This condition remained in effect until October 11, 1983. During this time span properly qualified components, i.e., a gasket, a washer, a spring and an indicator pipe, were purchased and installed. To help preclude similar problems from happening to any other systems and components, procedures were modified to include the engineering design group in the review of all procurement documents. This event was documented in Licensee Event Report (LER) 50-416/83-147 and closed out by NRC Region II in Inservice Inspection Report 50-416/83-52. See Refs. 1 and 2, respectively.

A similar occurrence was discovered in September of 1982 at the Quad-Cities Nuclear Power Station. As documented in LER 50-254/82-027 (Ref. 3), replacement main valve guides and piston rings in the electromatic relief valves for the main steam system were procured as non-safety related. This problem was attributed to inadequate implementation of procurement requirements. One of the corrective actions taken to prevent recurrence of such a problem was the revising of station procedures governing component classification.

Although not specific to any failure, it is noted in a March 1984 NRC Region IV inspection report for Arkansas Nuclear One Units 1 and 2 (see Ref. 4) that similar procedure problems exist. It is stated in the inspection report that the licensee presently has no documented program to ensure that the maintenance program incorporates the technical requirements contained in the ASME Boiler and Pressure Vessel Code, manufacturer's technical manuals and instructions, and other sources. The licensee, the report further notes, has proposed a program to rectify the problem.

The Commission recognizes the vital role which a proper operational quality assurance program has on the safe operation of each nuclear power plant. Recently, this was demonstrated in the findings of an NRC Task Force which studied the generic implications of the 1983 Salem Nuclear Power Plant, Unit 1 anticipated transient without scram event (Ref. 5). These findings were transformed into required licensee actions and transmitted to all power reactor licensees and applicants in NRC Generic Letter 83-28 (see Ref. 6). Specifically, this generic letter requires all licensees and applicants to provide the NRC with descriptions of their programs which assure that all safety-related system components are identified in all documents used in the plant to control safety-related activities. These activities include maintenance, work orders, and replacement parts. As presently planned, each submittal will be individually and generically reviewed with individual safety evaluation reports produced and issued.

Conclusions

The occurrences examined in this study indicate that a generic problem may exist in the programs designed to assure that proper equipment quality levels are maintained throughout the plant life. Without adequate programs, including items such as replacement parts, proper functioning of essential systems and components cannot be assured.

NRC Generic Letter 83-28 properly and sufficiently addresses this problem. Actions taken by each licensee and applicant to respond to this letter should be sufficient to preclude this problem in the future. Consequently, it is concluded that no additional AEOD/ROAB review of this matter be taken at this time.

References

1. Mississippi Power and Light Company (L.F. Dale) letter to Nuclear Regulatory Commission Region II (J.P. O'Reilly). Subject: Grand Gulf Nuclear Station Unit 1. Docket No. 50-416, "Inadequate Quality Level Parts Installed in the Chlorine Detection System". LER 83-147/03 L-0. October 19, 1983.

2. Nuclear Regulatory Commission, Region II (D.M. Verrelli) letter to Mississippi Power and Light Company (J.B. Richard). Subject: Grand Gulf Nuclear Station Unit 1. NRC Inspection Report: 50-416/83-52. December 14, 1983.

3. Commonwealth Edison (N.J. Kalivianakis) letter to Nuclear Regulatory Commission Region III (J. Keppler). Subject: Quad-Cities Nuclear Power Station Unit 1. Docket No. 50-254. LER 82-027/03 L-0. September 29, 1982.

4. Nuclear Regulatory Commission, Region IV (J.E. Gagliardo) letter to Arkansas Power and Light Company (J.M. Griffin). Subject: Arkansas Nuclear One Units 1 and 2. NRC Inspection Reports: 50-313/84-06; 50-368/84-06. March 8, 1984.

5. Nuclear Regulatory Commission (NRR), "Generic Implications of ATWS Events at the Salem Nuclear Power Plant", NUREG-1000/Vol. 1, April 1983.

6. Nuclear Regulatory Commission (D.G. Eisenhut) letter to All Licensees of Operating Reactors, Applicants for Operating License, and Holders of Construction Permits. Subject: Required Actions Based on Generic Implications of Salem ATWAS Events. Generic Letter 83-28. July 8, 1983.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

FEB 27 1984

MEMORANDUM FOR: Thomas Novak, Assistant Director for Licensing
Division of Licensing

FROM: Frank J. Miraglia, Assistant Director for Safety Assessment
Division of Licensing

SUBJECT: GRAND GULF OPERATING EXPERIENCE

In response to your request (memorandum of October 6, 1983) the Operating Reactors Assessment Branch (ORAB) has reviewed operating experience during the past year at the Grand Gulf facility and prepared the attached report.

The ORAB review included a survey of reported events at Grand Gulf during the past 15 months (i.e. the low power license period) and a comparison of the event reports with reports from two other recently licensed BWRs (LaSalle and Susquehanna) filed during their low power license periods. The sources of event reports included prompt (telephone) notifications filed per 10 CFR 50.72 as well as Licensee Event Reports (LER) required by the Technical Specifications. Operating reactor events briefing summaries were also examined to identify the more significant events. AEOD provided us with substantial support in obtaining event reports.

In general the review revealed that high number of prompt reportable events (10 CFR 50.72) have occurred at Grand Gulf in the past year. The rate of occurrence of these events has been at least three times greater than that of the two other recently licensed BWRs used for comparison. The large number of prompt reports are concerned for the most part with inadvertent actuations of engineered safety features. According to the 50.72 reports, equal numbers of these events have been caused by equipment failure and errors on the part of operators and technicians.

Review of operating reactor event briefing summaries indicates that five "significant" events have been reported for Grand Gulf during the year. They include a low temperature vessel pressurization incident, electrical system malfunction causing inadvertent RPS trips, a diesel generator room fire incident, simultaneous malfunction of both Transamerica DeLaval diesel generators, and an operator error which resulted in 10,000 gallons of water being drained from the reactor vessel to the suppression pool. The number of significant events at Grand Gulf during the low power license period is higher than that for the two other recently licensed BWRs considered in the review. LaSalle had only one event significant enough to be reported at a briefing and Susquehanna had none. It should also be noted that the periods of low power license for LaSalle and Susquehanna were much shorter than Grand Gulf.

~~8405150342 PDR~~

Based on our review we have concluded that operating experience at Grand Gulf during the past year has been atypical. Comparison of Grand Gulf experience with that of other BWRs indicates that the period of operation with the low power license at Grand Gulf has been abnormally long (greater than 12 months versus 4 months for Susquehanna and LaSalle) and that the rate of prompt reportable events has been much greater than expected. Based on discussions with Region II we believe that the high rate of reported events is at least in part related to the large amount of construction and testing activities which have gone on during the past year. This construction and testing activity is the result of design changes being implemented at the plant. The fact that many events which have occurred are related to personnel errors may indicate a lack of experience, on the part of plant personnel.

The rate at which events have occurred at Grand Gulf has not decreased steadily over the long term as the plant has moved closer to commercial operation. However, a sudden sharp decrease in the rate did occur in November 1983 which may be attributed to site inactivity following completion of low power testing in October. On this basis it would be reasonable to expect the incident rate to continue this decreasing trend as the plant moves closer to commercial operation, and testing and construction activities are completed.

We have discussed the results of our review with IE Region II, and they have informed us that our conclusions are consistent with their most recent SALP review. Region II will continue to monitor plant performance and take appropriate actions should problems continue to occur at a high rate.

Original signed by
Frank J. Miraglia

Frank J. Miraglia, Assistant Director
for Safety Assessment
Division of Licensing

Enclosure:
As Stated

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01/11/84	01/11/84	02/22/84	02/27/84

OPERATING EXPERIENCE REVIEW

AT GRAND GULF UNIT #1

INTRODUCTION

The staff review of operating experience included a survey of reported events at Grand Gulf during the past 15 months (i.e. the low power license period) and a comparison of the event reports with reports from two other recently licensed BWRs (LaSalle and Susquehanna) filed during their low power license periods. The sources of event reports include prompt (telephone) notifications filed per 10 CFR 50.72 as well as Licensee Event Reports (LER) required by the Technical Specifications. Operating reactor events briefing summaries were also examined to identify the more significant events. These briefings are regularly scheduled meetings among NRC management to discuss recent events at operating reactors.

SURVEY OF EVENT REPORTS

In the period between mid-August 1982 and September 1, 1983 160 incidents requiring prompt notification were reported as required by 10 CFR part 50.72 One hundred and twenty-two of these events involved plant systems. The remaining 38 events involved the plant physical security system. This review has focused on the non-security related events. The security related events were not considered significant and were expected based on the testing and construction occurring at the plant. Thirty-five percent (35%) of the non-security related events have root causes related to operator and technician activities (e.g. testing, troubleshoorting). Equipment problems (mostly electrical) account for thirty-two (32%) of the events. The direct causes of the remaining one-third of the events are unknown or not apparent from the brief 50.72 reports. Most of the events involve inadvertent actuations of safety systems with the plant shutdown (e.g., standby gas treatment system, control room fresh air system, reactor trip, diesel generator start). The average monthly rate at which these events have been reported is approximately 10 events/month. This rate is compared with rates for LaSalle and Susquehanna in Table 1 and appears to be abnormally high. Region II inspectors attribute the high rate to the large amount of testing and construction going on at the plant. A review of the data by month does not reveal any particular trend in the incident rate. Data for the past three months shows a rate of occurrence close to the average in September and October with a sharp decrease in November to 3 events/month. The sharp decrease is attributed to site inactivity following completion of low power tests. A steady reduction in the rate of occurrence is expected as the plant nears commercial operation, since design changes and associated tests are expected to be completed.

In the period beginning August 1, 1982 and ending July 1, 1983 a total of 227 LERs were issued from Grand Gulf. The average monthly rate at which LERs have been issued is shown in table 1 along with comparable rates for LaSalle and Susquehanna. The Grand Gulf rate is similar to the rates for LaSalle and Susquehanna. This is in sharp contrast with the 10 CFR part 50.72 reports discussed above where the Grand Gulf rate was significantly higher than the other two plants. Review of the Grand Gulf LERs indicates that about one-half of the reports relate to problems with fire protection systems. These problems include many instances of smoke detector alarms caused by dust from construction; and, removal of fire barriers for construction purposes. Only nineteen percent (19%) of the 227 reported events involved personnel errors and/or procedural

TABLE I

RATE OF REPORTED EVENTS AT

THREE BWR PLANTS

DURING LOW POWER LICENSE PERIOD

Facility	Period of Low Power License (months	Rate of Reported Events (Avg. No. reports/month) 50.72	LER
Grand Gulf	12*	10	21
LaSalle 1	4	1	19
Susquehanna 1	4	3	12

* The study period consists of the first 12 months of the low power license period. The actual period of the low power license will be longer than 12 months.

deficiencies. Other causes of reported events include equipment problems and planned entry of technical specification action statements for purposes of testing or construction.

REVIEW OF SIGNIFICANT EVENTS

Significant events which have occurred at Grand Gulf during the past year have been identified through a review of issues raised at the regularly scheduled briefings of NRR management on operating reactor experience. The review consisted of a review of the Operating Reactor Event Briefing meeting minutes. For purposes of comparison a similar review has been performed for LaSalle and Susquehanna for the periods they held low power licenses. Events which are discussed at operating reactor event briefings have been subjected to a screening process in which five or six significant events are selected every two weeks for discussion based on the review of 100 to 150 events reports during the two week period. The purpose of identifying those events here is to provide a measure of the severity and extent of significant operational problems.

During the Grand Gulf low power license period, five significant problems at Grand Gulf were reported. Our review indicates that only one significant event was reported for LaSalle during the period of its low power license. No events were reported for Susquehanna. The Grand Gulf events are summarized below.

Violation of RTNDT Heating Limits During ECCS Injection October 5, 1982

During surveillance testing with the plant in cold shutdown a high DC voltage spike occurred which initiated an ECCS injection. Low pressure core spray injected and caused the reactor vessel to become water solid (extending to the MSIVs). The resulting pressure transient violated the Technical Specification on nil-ductility reference temperature, RTNDT.

Reactor Protection System (RPS) MG-Set Output Breaker Trips, May 19, 1983

Inadvertent tripping of the RPS MG-set output breakers has occurred repetitively resulting in isolation of the instrument air system and a reactor scram signal. The causes of the trips have been identified as thermal overload due to insufficient cabinet ventilation, and low voltage due to voltage swings while the RPS bus is fed from the alternate power supply. To reduce the number of output breaker trips the licensee increased cabinet ventilation, installed voltage regulators to smooth out voltage fluctuations, and installed a new station electrical transmission line from off-site. In addition instrument air system isolation relays have been re-aligned to an interruptable power supply. This problem re-occurred in January 1984. Upward voltage spikes remaining above the setpoint longer than .1 second have caused the protective MG-set output breaker to trip, resulting in de-energization of containment isolation system logic circuits followed by isolation of the RHR system. The licensee has been unable to identify the source of the voltage spikes. To correct the problem, the licensee has increased the output breaker delay time from .1 second to 1.4 seconds. The new delay time is based on measurements of spike duration and consultation with suppliers of the electrical equipment. The modification assures that spikes lasting less than 1.4 seconds will not result in a trip of the protective breaker. Additional corrective actions are also under discussion between the licensee and Region II.

Inadvertent Reactor Vessel Drainage During Shutdown April 3, 1983

On April 3, 1983, approximately 10,000 gallons of water drained from the reactor vessel to the suppression pool through the residual heat removal (RHR) system. This drainage was caused by two RHR valves (F004 and F006) being open simultaneously. At the time of the event, the reactor was at atmospheric pressure with vessel water temperature approximately 100°F (cold shutdown conditions). The vessel water level continued to decrease until the low level isolation signal was received and shutdown cooling isolation valves closed to terminate the leakage.

Diesel Generator Room Fire September 4, 1983

A diesel generator engine fire was caused by a ruptured fuel oil supply line which sprayed oil on the hot exhaust manifold of the diesel. The diesel which caught fire was running at 25 percent load for testing at the time. Two other diesel generators were not affected by the fire. The water deluge system failed to function automatically, but was manually activated to extinguish the fire. The diesel generator governor and turbo chargers were damaged. In addition some electrical equipment in the room suffered water damage.

Inoperability of Delaval Diesel Generators October 28, 1983

On October 28, 1983, a Technical Specification Action Statement was entered when two of the three diesel generators became inoperable. The Division I diesel generator was inoperable due to gasket failure on a lube oil line. The Division II diesel generator became inoperable due to a loose base plate nut on the turbocharger which resulted in a trip of the vibration sensor which tripped the diesel. Corrective action was taken to repair both diesel generators. Both of the diesel generators were manufactured by Transamerica Delaval Inc. (TDI). TDI diesel generators have recently come under close scrutiny by the staff following a crankshaft failure in a TDI diesel generator at the Shoreham plant. Staff review of the Transamerica Delaval diesel generator problem at Grand Gulf is still ongoing.

CONCLUSIONS

Based on our review, we have concluded that operating experience at Grand Gulf during the low power license period has been atypical. Comparison of Grand Gulf experience with that of other BWRs indicates that the period of operation with the low power license at Grand Gulf has been abnormally long (12 months versus 4 months for Susquehanna and LaSalle) and that the rate of prompt reportable events has been much greater than expected. Based on discussions with Region II we believe that the high rate of reported events is related, at least in part, to the large amount of testing and construction activities which have gone on during the past year. This construction and testing activity is the result of design changes being implemented at the plant. The fact that many of the events are related to personnel errors may indicate a lack of experience on the part of plant personnel. The rate at which events have occurred at Grand Gulf has not decreased steadily over the long term as the plant has moved closer to commerical operation. However, a sudden sharp decrease in the rate did occur in November 1983 which may be attributed to site inactivity following completion of the low power testing in October. On this basis, we believe it is reasonable to expect the incident rate to continue this decreasing trend as the plant moves closer to commercial operation, and testing and construction activities cease. Should an abnormally high rate of incidents re-appear, appropriate actions such as initiating a review of personnel training programs and plant procedures should be initiated to identify the root cause of the continuing problem so that necessary corrective measures measures can be taken.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

FEB 27 1984

MEMORANDUM FOR: Carl H. Berlinger, Manager
TDI Project Group

AEOD/P401

FROM: Frederick J. Hebdon, Chief
Program Technology Branch
Office for Analysis and Evaluation
of Operational Data

SUBJECT: OPERATING HISTORY OVERVIEW FOR DIESEL GENERATORS IN NUCLEAR SERVICE

Enclosed is our comparison between problems experienced with Transamerica Delaval, Inc. (TDI) diesel generators and diesel generators from other manufacturers. If you have any questions concerning this material, please call Bob Dennig (x24491) or Matt Chiramal (x24441).

Frederick J. Hebdon

Frederick J. Hebdon, Chief
Program Technology Branch
Office for Analysis and Evaluation
of Operational Data

Enclosure:
As stated

cc w/enclosure:
P. Baranowsky, RES

~~8403140203 PDR~~

Report No. AEOD/P401
Date February 1984

OPERATING HISTORY OVERVIEW
FOR DIESEL GENERATORS
IN NUCLEAR SERVICE

Prepared by

Office for Analysis and Evaluation
of Operational Data

The subject matter is under continuing review. This report supports ongoing NRC activities and does not represent the position or requirements of other NRC program offices.

Background

As a result of the evaluation of the failure of the main crankshaft in a Transamerica Delaval, Inc. (TDI) diesel engine at the Shoreham Nuclear Plant on August 12, 1983, the staff raised questions concerning the reliability of TDI diesel engines used in nuclear service. An operating history of TDI diesel engines in both nuclear and non-nuclear applications identified operational problems which were believed to be unique to TDI diesels. AEOD was asked to review operational data to determine if the TDI problems are, in fact, unique to TDI diesel engines.

We have not attempted to address the broader issue of diesel generator reliability at sites with TDI supplied engines vs. the operational reliability at sites with engines by other manufacturers. The subject of onsite AC system reliability at operating plants is treated in great detail in NUREG/CR-2989 "Reliability of Emergency AC Power Systems at Nuclear Power Plants" July 1983. For operating plants, manufacturing defects are just one contributor to system unavailability. There are contributions from operation and maintenance deficiencies and other component failures which have not been found in the TDI experience. (See for example NRC meeting summaries dated 8/10/81 and 11/9/81 on diesel generator reliability at Joseph M. Farley.)

Approach

AEOD focused on the TDI experience for nuclear applications as listed in Enclosure 1. This listing was an enclosure to a draft Commission paper prepared by R. Caruso, NRR. We subsequently grouped the failure-related items in Enclosure 1 into six categories based on the subsystem in which the failure occurred. The subsystems include:

- Engine Subsystem
- Turbocharger Subsystem
- Lube Oil Subsystem
- Fuel Oil Subsystem
- Cooling Subsystem
- Air Start Subsystem

For the six categories, we reviewed Section 9.4 of NUREG/CR-2989 "Reliability of Emergency AC Power Systems at Nuclear Power Plants," July 1983 to determine if there were problems with non-TDI diesels that were comparable to the TDI experience. Section 9.4 is a table of operational events associated with emergency diesel generators for the years 1976-1980. The events were compiled from Licensee Event Reports, station blackout questionnaire responses, and responses to a questionnaire for NUREG-0737 "Clarification of TMI Action Plan Requirements," November, 1980.

For each category, Enclosure 2 lists the experience for TDI from Enclosure 1, followed by comparable experience for other diesel engines from Section 9.4 of NUREG/CR-2989. Items were selected as "comparable" if they concerned the same failure mode of the same or similar components or they described a similar situation (e.g., a design error, use of wrong material); and they were possibly associated with the design and fabrication of the diesel engine [i.e., they could not be readily ascribed to maintenance-related problems (e.g., dirty oil, sticking components, maladjusted setpoints, gasket leaks, minor oil leaks, minor cooling leaks)].

The last section of Enclosure 2 is entitled "Modifications." The TDI items listed here are items in Enclosure 1 which were not themselves failures or modifications undertaken as a result of a failure elsewhere. In order to provide comparable information for other manufacturers we have included as Attachment 1 to Enclosure 2 the entire Table E.4 from the draft version of NUREG/CR-2989.

AEOD also reviewed LERs associated with diesel engines for the period 1981-1983 and selected events which described major problems in the categories of Engine Subsystem, Turbocharger Subsystem, Fuel Subsystem, Cooling Subsystem and Design Error. The results are provided in Enclosure 3.

Finally, for your information, population data for the TDI and non-TDI diesels is provided as Enclosure 4 as a function of manufacturer and continuous power rating.

Discussion

The operating history of the TDI diesels and non-TDI diesels, and hence the data generated, may not be comparable, depending on the issue being examined. Specifically:

1. The operational experience for Grand Gulf and Shoreham, where the vast majority of TDI failures and deficiencies have occurred, was generated during a period of preoperational testing. During such a time, the contribution of the manufacturer to difficulties should be easier to recognize and should dominate any contribution by the operating and maintenance staff. Also, one expects a relatively high number of "bugs" or deficiencies to crop up during early operation. In contrast, the information available to us for other manufacturer's engines comes from the operational phase, wherein the contribution from operational and maintenance personal can reasonably be expected to increase. The data supplied to us for San Onofre 1 engines, which reflect few manufacturer problems, come from the operational period.

2. We suspect that operating hours, loadings, number of demands, and the spacing of these demands all play a role in diesel generator performance. Again, the Grand Gulf and Shoreham engines where the majority of the problems have occurred appear to have accumulated a large number of operating hours in a short period of time as compared with most diesels in nuclear service. A good comparison would require selection of engines from other manufacturers which have seen similar service. We did not have enough information to make such a selection, and the influence of operation and maintenance still might be difficult to isolate and exclude.

3. The testing of both TDI diesels and non-TDI diesels varies considerably depending on whether the diesel was tested in accordance with Regulatory Guide 1.108. We know, for example, that the TDI diesels at Grand Gulf were tested in accordance with Regulatory Guide 1.108 while the TDI diesels at San Onofre were not.

4. We have no data on the maintenance practices for TDI and non-TDI engines. This makes it difficult to determine which failures are attributable to the manufacturer's design and which were caused or exacerbated by licensee operation and maintenance practices.

5. We assume the information for the TDI engines is complete. While NUREG/CR-2889 contains the most complete record on diesel experience assembled to date, the information was provided via LERs and questionnaires and variation in completeness of reporting is still present to some extent in the non-TDI information.

Thus, we do not have complete or necessarily comparable data for the TDI diesels or the non-TDI diesels. Consequently, statistical analyses of diesel reliability (e.g., failure rate analysis), and even qualitative analysis of the prevalence or magnitude of problems based on available data should be approached with caution.

We have been able, however, to review the experience and note whether or not similar difficulties have been reported for engines of different manufacturers. The following sections attempt to summarize this information but the reader is urged to read the enclosures for himself, since his notion of "comparability" and ours may differ.

Engine Subsystem Experience

Instances of piston crown separation and catastrophic crankshaft failure which have occurred in some TDI engines were not found in non-TDI experience reviewed.

Non-TDI diesels have recorded incidents of damage or failure of basic engine components such as bearings, cylinder heads, pistons, and bolts. Some of the failures have been repetitive (e.g., six incidents of cylinder head cracks in the same diesel generator at Surry (GM) which ultimately resulted in replacement of all cylinders) and some have been quite serious (e.g., at least three incidents where engines were replaced - Millstone 2 (Fairbanks Morse), Arkansas-2 (Fairbanks Morse) and Quad Cities 1 (GM).

A key concern of the TDI project appears to be whether or not the experience with basic engine parts in non-TDI diesels reflects a "generic" problem with basic engine components. While we cannot unequivocally rule out the possibility due to the quality and completeness of our information, the evidence for the most part suggests isolated difficulties. For example, the GM experience in the basic engine area is comparatively sparse in contrast with the GM experience in the turbocharger subsystem, where it appears a generic problem existed for GM engines.

Turbocharger Subsystem

Problems with non-TDI diesels have been principally associated with GM diesels. Most failures were associated with bearing failure that caused the turbocharger to fail. In some cases fires resulted. In several cases the turbocharger was replaced. These problems seem comparable to the TDI problem of bearing wear due to lack of lube oil.

Lube Oil Subsystem

The only lube oil problem at a TDI diesel was the oil leak and fire at San Onofre 1. Several non-TDI diesels have had lube oil problems, however, most of these problems were water leakage int the lube oil. Kewaunee reported a single instance associated with a GM diesel which was very similar to the San Onofre event in failure mode and mechanism.

Fuel Oil Subsystem

Instances of fuel oil leaks or replacement of fuel oil supply lines were noted for GM, Fairbanks Morse, ALCO and Cooper Bessemer diesels. In at least two cases fires resulted. The TDI experience does not appear unique as far as mode, mechanism, or consequences are concerned.

Cooling Subsystem

Shoreham reported that the engine jacket water pump of a TDI diesel failed by fatique. While licensees with non-TDI diesels have experience pump failures, none reported the mechanism (i.e., fatigue) experienced at Shoreham. A few instances of jacket water leaks (that were not associated with major engine damage) were noted for non-TDI engines.

Air Start Subsystem

Air start valve failures have occurred with GM, Fairbanks Morse, Cooper Bessemer and Worthington diesels. However, ongoing maintenance by the licensee may be a more important factor here than original equipment manufacturer; specifically, cleanliness of the air start system. The specific Grand Gulf and Shoreham problem with air start valve capscrews was not noted in non-TDI experience; however, problems of a similar magnitude with other air start system parts have been noted in non-TDI engines.

Modifications

A review of Enclosure 3 shows numerous reliability improvements made throughout the operating lives of non-TDI engines. These appear to be comparable to the TDI experience listed in the modifications section of Enclosure 2.

ENCLOSURE 1

U.S. NUCLEAR EXPERIENCE
WITH TDI ENGINES

U. S. Nuclear Experience with TDI Engines

San Onofre 1

- Two TDI Diesel Engines Installed - Model DSRV-20
  Serial No. 75041/42, Rated at 6000KW (nominal)
  8800KW (peak)

Problem	Cause/Solution
Excessive Turbocharger thrust bearing wear.	No lube oil during standby. Lube oil system modified. 10 CFR Part 21 report issued because problem generic.
Lube oil leak and fire.	Excessive vibration. Line re-supported.
Piston modification to prevent crown separation.	Pistons reworked by TDI to respond to Part 21 report. Problem identified at Grand Gulf.

Shoreham

- Three TDI Diesel Engines installed, Model DSR-48
  Serial No. 74010/12, Rated at 3500KW

Problem	Cause/Solution
Excessive turbocharger thrust bearing wear.	No lube oil during standby. Lube oil system modified.
Piston modifications to prevent crown separation.	Pistons reworked by TDI to respond to Part 21 report. Problem identified at Grand Gulf.
Engine jacket water pump modifications.	Water pumps reworked by TDI in response to Part 21 report.
Air starting valve capscrews replaced. Too long for holes.	Response to Part 21 report.
Engine jacket water pump shaft failed by fatigue.	Pump shafts redesigned and replaced.
Cracks in engine cylinder heads.	Fabrication flaws. All heads replaced.

Problem	Cause/Solution
Two fuel oil injection lines ruptured.	Manufacturing defect in tubing. Tubing replaced with shielded design.
Engine rocker arm shaft bolt failure.	High stress cycle fatigue. Bolts replaced with new design.
Broken crankshaft. Cracks in remaining crankshafts.	Inadequate design. Replaced with larger diameter crankshafts.
Cracked connecting rod bearings.	Inadequate design and substandard material. Replaced with new design.
Cracked piston skirts.	Replaced all piston skirts with new design. Generic problem.
Broken cylinder head stud nuts.	Replaced all head stud nuts.
Cracked bedplates in area of main journal bearings.	Cracks evaluated by LILCo and determined to not be significant.
Unqualified instrument cable.	Replaced in response to Part 21 report.

Grand Gulf

- Two TDI engines installed - Model DSRV-16 Serial No. 74033/34, Rated at 7000KW

Problem	Cause/Solution
Piston crown separation during operation.	Holddown studs failed. Pistons returned to TDI for rework. Generic problem.
Excessive turbocharger thrust bearing wear.	No lube oil during standby. Lube oil system modified.
Air starting valve capscrews replaced. Too long for holes.	Response to Part 21 report.
Flexible drive coupling material incompatible with operating environment.	Replaced with different material.
Latching relay failed during testing.	Relay replaced.

Problem	Cause/Solution
Air start sensing line not seismically supported.	Sensing line relocated and properly supported.
Governor lube oil cooler located too ~~low~~ high. Possibility of trapping air in system.	Lube oil cooler relocated to lower elevation.
Engine pneumatic logic improperly designed. Could result in premature engine shutdown.	Pneumatic logic design corrected.
Non-Class 1E motors supplied with EDG auxiliary system pumps.	Motors replaced with Class 1E qualified motors.
Crankcase cover capscrew failed. Head lodged in generator and shorted it out.	Capscrews replaced with higher strengh screws. Lock tab washers installed. Generator screens installed.
High pressure fuel injection line failed.	Manufacturing defect in tubing. Tubing replaced.
Fuel oil line failed. Caused major fire.	High cycle fatigue of Swagelock fitting. Additional tubing supports to be installed.
Cracks in connecting push rod welds.	All push rods replaced.
Turbocharger vibration.	Turbocharger replaced.
Cracked jacket water welds.	Excessive turbocharger vibration. Cracks re-welded.
Turbocharger mounting bolt failures.	Excessive turbocharger vibration. Bolts replaced.
Air start valve failures.	Cause unknown. System cleaned and several valves replaced. More frequent maintenance scheduled.

Problem	Cause/Solution
Cracks in piston skirts on Division II EDG.	Division II pistons replaced. Division I pistons to be inspected.
Cylinder head cracks.	Two cylinder heads replaced.

ENCLOSURE 2

COMPARISON OF EXPERIENCE
1976 - 1980

Plant	LER #	Date	Diesel #	Description
Shoreham	-	-	-	Broken cylinder head stud nuts. Replaced all head stud nuts.
Shoreham	-	-	-	Cracked bedplates in area of main journal bearings. Cracks evaluated by licensee and determined to not be significant.
Grand Gulf	-	-	-	Piston crown separation during operation. Hold-down studs failed. Pistons returned to TDI for rework. Generic problem.
Grand Gulf	-	-	-	Cracks in connecting push rod welds. All push rods replaced.
Grand Gulf	-	-	-	Cracks in piston skirts on Division II diesel. Pistons replaced.
Grand Gulf	-	-	-	Two cylinder heads replaced.
Grand Gulf	-	-	-	Crankcase cover capscrew failed. Head lodged in generator and shorted it out. Capscrews replaced with higher strength screws. Lock tab washers installed. Generator screens installed.

B. General Motors Experience

Plant	LER #	Date	Diesel #	Description
Davis Besse	80-52	7/9/80	All	Exhaust supports received too much stress. Supports added during refueling outage.

Plant	LER #	Date	Diesel #	Description
Prairie Island 1*	80-30	10/8/80	D2	Eductor hose broke and diesel tripped on high crankcase pressure.
Surry 1	76-7	7/2/76	1	Heat stress caused cylinder head crack.
Surry 1	76-6	5/8/76	1	Crack in cylinder head.
Surry 1	76-04	5/12/76	1	Crack in cylinder head, bent rod, and broken piston. Engine not turned over before testing. Water in cylinder.
Surry 1	76-10	9/4/76	1	Heat stress caused cylinder head crack. Water in cylinder. Sixth failure. All cylinders to be replaced.
Vermont Yankee*	77-17	6/23/77	B	Eductor hose came loose. Diesel tripped on high crankcase pressure. Improved hose clamps to be installed.

C. Fairbanks Morse Experience

Plant	LER #	Date	Diesel #	Description
Arkansas 2	79-32	4/19/79	2	Engine bearings failed. Engine was replaced. Design/Manufacturing error - see Attachment 2 for details.
Duane Arnold	76-64	10/4/76	IGa1	Vertical drive coupling hub broke. Wrong material (cast iron instead of ductile iron).

* NUREG/CR-2989 shows these plants have GM engines; NUREG/CR-1362 shows manufacturer as Fairbanks Morse.

Plant	LER #	Date	Diesel #	Description
Duane Arnold	76-12	3/26/76	-	Front cover plate on engine leaked oil. Oil caught fire, but was quickly extinguished.
Millstone 2	76-63	12/18/76	13U	No. 3 upper piston connecting rod bearing capscrews sheared and ejected rod through the upper crankcase cover. Diesel was replaced. Probably failed from a series of unlubricated or dry starts.
Millstone 2	76-08A	2/23/76	12U	Piston failed. Overhauled engine.
Hatch 2	80-159	11/26/80	2C	The cotter pins for the rod cap retaining nuts on two cylinders were broken permitting excessive clearance between the connecting rod bearings and the crankshaft. One of the connecting rods separated from the crankshaft and caused engine failure.

D. ALCO Experience

Plant	LER #	Date	Diesel #	Description
Salem 2	80-31	-	-	Coupling connecting two sections of camshaft had eight of its attaching bolts sheared. New camshafts and bolts installed.

Plant	LER #	Date	Diesel #	Description

E. Cooper Bessemer Experience

Cooper	80-27	5/8/80	2	Piston rod pins broke. Damaged parts replaced. All piston bolts were replaced.
Cooper	79-36	11/10/79	2	Four cylinder sleeves were damaged. All damaged parts were replaced.

F. Worthington Experience

None noted.

G. Nordberg Experience

None noted.

H. Allis Chalmers Experience

None noted.

I. Caterpillar Experience

None noted.

2. TURBOCHARGER SUBSYSTEM

A. TDI Experience

San Onofre 1	-	-	-	Excessive turbocharger thrust bearing wear. No lube oil during standby. Lube oil system modified (Part 21).

Plant	LER #	Date	Diesel #	Description
Shoreham	-	-	-	Excessive turbocharger thrust bearing wear. No lube oil during standby. System modified.
Grand Gulf	-	-	-	Excessive turbocharger thrust bearing wear. No lube oil during standby. Lube cil system modified.
Grand Gulf	-	-	-	Turbocharger vibration caused cracked water jacket welds and mounting bolt failures.

B. General Motors Experience

Plant	LER #	Date	Diesel #	Description
Arkansas 1	79-6	6/7/79	All	Vendor design error. Rapid start after shutdown could damage turbocharger bearings.
Arkansas 1	78-17	7/15/78	2	Oil leak into turbocharger. Diesel could have operated with leak. Turbocharger replaced.
Arkansas 1	78-8	3/20/78	2	Bearing failure in turbocharger. Exhaust caught fire. Turbocharger replaced. Diesel could have continued to operate in an emergency.
Davis Besse	80-69	9/2/80	1-1	Bolt fragment found in crankcase during oil change. Bolt was from turbo-gear assembly.

Plant	LER #	Date	Diesel #	Description
Davis Besse	79-46	3/30/79	1-1	Turbocharger bearings failed. The turbocharger was replaced.
Davis Besse	78-18	2/8/78	1-1	Turbocharger failed and was replaced.
Dresden 2	77-051	10/30/77	2/3	Clutch and shaft bearing failure.
Fitzpatrick	76-65	10/11/76	A	Oil leak in turbocharger caused fire. Turbocharger replaced.
Maine Yankee	79-066	10/16/79	1B	Catastrophic failure of turbocharger due to bearing failure. Fire resulted. (Turbocharger in DG-1A also replaced).
Conn. Yankee	79-09	8/31/79	All	Design error could cause turbocharger failure if started within 3 hours of being shutdown.
Kewaunee	77-23	9/20/77	1A	Fire in exhaust, but diesel was operable. Monthly tests changed to 4 hour duration.
Monticello	79-010	4/26/79	All	Design error. Lack of turbocharger lube oil after shutdown.
Point Beach	79-7	4/24/79	All	Design error. May cause turbocharger failure if there is a start 15 to 100 minutes after a diesel shutdown.

Plant	LER #	Date	Diesel #	Description
Saint Lucie	79-21	6/25/79	All	Design error. Insufficient turbocharger lubrication may occur on a second start within 3 hours of diesel shutdown.
Saint Lucie	77-42	9/20/77	1A	Diesel loaded to full emergency load. Attempted to pick up full design load. Turbocharger thrust bearing and clutch were damaged. Turbocharger replaced.
Saint Lucie	77-2	1/18/77	1B	Turbocharger failed. New unit installed.
Surry 1	79-44	12/30/79	3	Turbocharger failed and was replaced.
Surry 1	79-17	5/2/79	All	Design error. Turbocharger bearing damage may result from start too soon after shutdown.

C. Fairbanks-Morse Experience

Crystal River 3	80-30	-	-	Turbocharger ductwork separated from turbocharger. Diesel unavailable for 95 hrs.
Duane Arnold	76-21	-	-	Exhaust gases leaked onto engine and burned. Gasket and insulation replaced.

D. ALCO Experience

Salem 1	77-80	-	-	Turbocharger and exhaust gas expansion joint failed. Cause determined to be turbine blade failure. Modifications made to turbine to improve blade reliability.

Plant	LER #	Date	Diesel #	Description

E. Cooper Bessemer Experience

None noted.

F. Worthington Experience

None noted.

G. Nordberg Experience

None noted.

H. Allis Chalmers Experience

None noted.

I. Caterpillar Experience

None noted.

3. LUBE OIL SUBSYSTEM

A. TDI Experience

Plant	LER #	Date	Diesel #	Description
San Onofre 1	-	-	-	Lube oil leak and fire. Caused by excessive vibration. Line re-supported.
Shoreham	None noted.			
Grand Gulf	None noted.			

B. General Motors Experience

Plant	LER #	Date	Diesel #	Description
Arkansas 1	79-16	8/27/79	2	Lube oil cooler leaked water into oil. Replaced cooler.

Plant	LER #	Date	Diesel #	Description
Arkansas 1	• 79-17	9/11/79	1	Lube oil cooler leaked water into oil. Replaced cooler.
Kewaunee	79-25	9/22/79	-	Broken lube oil line. Copper tube replaced with stainless steel. Vibration caused break.

C. Fairbanks-Morse Experience

None noted.

D. ALCO Experience

None noted.

E. Cooper Bessemer Experience

Cooper	78-31	9/12/78	2	Insufficient oil to bearings during engine coastdown. Bearing replaced.
Zion 1	78-09	-	-	Oil cooler tube leak caused high pressure across filter.
Zion 1	78-65	7/17/78	1A	Lube oil cooler tube leak of water into oil. High velocity water eroded tube.
Zion 2	77-67	11/10/77	0	Water leaked in oil through lube oil cooler.
Zion 2	80-25	11/1/80	2A	Lube oil leak at cracked weld in pipe.

Plant	LER #	Date	Diesel #	Description

F. Worthington Experience

None noted.

G. Nordberg Experience

None noted.

H. Allis Chalmers Experience

None noted.

I. Caterpillar Experience

None noted.

4. FUEL OIL SUBSYSTEM

A. TDI Experience

Plant	LER #	Date	Diesel #	Description
San Onofre	None noted.			
Shoreham	-	-	-	Two fuel oil injection lines ruptured. Manufacturing defect in tubing. Tubing replaced with shielded design.
Grand Gulf	-	-	-	High pressure fuel injection line failed. Manufacturing defect in tubing. Tubing replaced.
Grand Gulf	-	-	-	Fuel oil line failed. Caused major fire. High cycle fatigue of Swagelock fitting. Additional tubing supports to be installed.

Plant	LER #	Date	Diesel #	Description
B. General Motors Experience				
Beaver Valley	78-32	4/18/78	1	Fuel oil pump leak.
Quad Cities	78-27	9/28/78	1	Fuel supply lines replaced.
Turkey Point 3	79-15	4/26/79	B	Fuel starvation caused by cracked nipple in fuel line.
C. Fairbanks Morse Experience				
Duane Arnold	76-75	11/4/76	IG-21	Crack in fuel line leaked fuel which caught fire. Supports added for fuel lines.
Calvert Cliffs	79-69	11/27/79	11	Leaking fuel line.
Crystal River	-	10/23/79	-	Crack in fuel line. It was resoldered.
Hatch 1	-	10/5/76	1C	Fuel line repaired.
H. B. Robinson	-	12/14/77	A	Fuel oil line modified.
Millstone 1	77-29	9/27/77	DG	Nipple in cylinder 12 was cracked and leaking.
Millstone 1	77-7	2/1/77	DG	Nipple in cylinder 12 was cracked and leaking.
Millstone 2	78-19	8/3/78	13u	Leaking fuel injectors. Diesel could have continued to run in emergency.
Millstone 2	78-19A	1/28/79	13u	Leaking fuel injection. Manufacturing defect. Other assemblies checked okay.

Plant	LER #	Date	Diesel #	Description
Millstone 2	76-52	9/1/76	13u	Injector leaking fuel and small fire resulted.
Peach Bottom 2 and 3		4/27/79	2	Fuel oil line replaced.
		5/18/79	2	Leak in fuel line.
		10/5/79	2	Fuel oil line repaired.

D. ALCO Experience

Palisades	79-5	1/3/79	1-1	Fuel line broke. One hundred eighty gallons of fuel sprayed out.
Pilgrim	80-62	9/3/80	A	Fuel line to cylinder 9R had broken.

E. Cooper Bessemer Experience

Cooper	77-47	9/12/77	1	Fuel line to day tank vibrated and broke. Support was improved.
Cooper	76-34	8/23/76	1	Fuel line to injector broke.

F. Worthington Experience

None noted.

G. Nordberg Experience

None noted.

H. Allis Chalmers

None noted.

Plant	LER #	Date	Diesel #	Description

I. Caterpillar Experience

None noted.

5. COOLING SYSTEM

A. TDI Experience

Plant	LER #	Date	Diesel #	Description
San Onofre 1	None noted.			
Shoreham	-	-	-	No failure. Engine jacket water pump reworked by TDI in response to Part 21 report.
Shoreham	-	-	-	Engine jacket water pump shaft failed by fatigue. Pump shafts redesigned and replaced.
Grand Gulf	None noted.			

B. General Motors Experience

Plant	LER #	Date	Diesel #	Description
Conn. Yankee	-	6/21/76	-	Diesel fresh water pump leak. Pump rebuilt.
Dresden 3	77-38	9/14/77	3	Outboard bearing worn on pump.
Quad Cities 1	80-26	10/11/80	1/2	Cooling water pump motor shorted.

C. Fairbanks Morse Experience

Plant	LER #	Date	Diesel #	Description
Crystal River	79-108	12/1/79	1B	Shutdown cooling water pump failed. Bearing failure.

Plant	LER #	Date	Diesel #	Description
Millstone 2	-	5/5/78		Jacket water pump failed.
Prairie Island 1	79-2	1/26/79	D2	Cooling water pump did not start because of a speed switch failure.
Hatch 1		3/5/76		Coolant jacket system modified.

D. ALCO Experience

Plant	LER #	Date	Diesel #	Description
Indian Point 2	77-29	8/29/77	-	Jacket water leaks repaired.

E. Cooper Bessemer Experience

None noted.

F. Worthington Experience

None noted.

G. Nordberg Experience

None noted.

H. Allis Chalmers Experience

Plant	LER #	Date	Diesel #	Description
LaCrosse	-	5/20/77	1B	Cooling water leak. Rewelded bad weld.

I. Caterpillar Experience

None noted.

6. AIR START SUBSYSTEM

A. TDI Experience

Plant	LER #	Date	Diesel #	Description
San Onofre	None noted.			
Shoreham	-	-	-	Air start valve capscrews replaced. Too long for holes. Response to Part 21 report.
Grand Gulf	-	-	-	Air start valve capscrews replaced. Too long for holes. Response to Part 21 report.
Grand Gulf	-	-	-	Air start sensing line not seismically supported. Sensing line relocated and properly supported.
Grand Gulf	-	-	-	Air start valve failures. Cause unknown. System cleaned and several valves replaced. More frequent maintenance scheduled.

B. General Motors Experience

Dresden 2	79-014	3/5/79	2	Bendix air solenoid failures. Scheduled modifications should improve performance.
Dresden 2	77-071	12/3/77	2/3	Air regulator diaphragm ruptured.

Plant	LER #	Date	Diesel #	Description
Quad Cities 1	* 79-5	1/23/79	1/2	Air start solenoid stuck open.
Quad Cities 1	76-5	2/11/76	-	Air start solenoid stuck.

C. Fairbanks Morse Experience

Farley 1	78-18	3/8/78	1C	Air start solenoid valve failed. corrosion prevention improvements being studied.
Farley 1	77-26	9/13/77	1B	Air start solenoid stuck open.
Farley 1	77-27	9/16/77	1-2A	Air start solenoid stuck open.
Farley 1	77-15	8/17/77	1B	Air start solenoid stuck open.
Farley 1	77-27	8/28/77	1B	Air start solenoid stuck open.
Hatch 1	76-24	5/15/76	1A	Air start solenoid stuck closed.
Millstone 2	-	1/13/76	13U	Air pilot valve failed.
Calvert Cliffs 1	79-061	10/24/79	11/12	Diesels started and left running until seismic supports installed (Air start).
Calvert Cliffs 2	80-035	7/30/80	All	Design error. Tubing not seismically qualified (Air start).
H. B. Robinson	-	5/26/76		Leaking air start solenoid repaired.
H. B. Robinson	-	7/03/78		Air start solenoid replaced.

Plant	LER #	Date	Diesel #	Description
H. B. Robinson	-	10/18/78	A	Air start solenoid replaced.
Vermont Yankee	77-18	7/26/77	A	Air start valve failed to open. Debris in line. Valves to be replaced by improved valves.

D. ALCO Experience

None noted.

E. Cooper Bessemer Experience

Zion 1	78-72	8/17/78	1B	Air start pilot valve leaked.
Zion 2	79-34	5/11/79	0	Air valve leaked air from reservoirs.

F. Worthington Experience

Cook 2	78-13	3/19/78	2CD	Air start check valve on cylinder #5 broke.

G. Nordberg Experience

None noted.

H. Allis Chalmers Experience

None noted.

I. Caterpillar Experience

None noted.

MODIFICATIONS

A. TDI Experience

Plant	LER #	Date	Diesel #	Description
San Onofre 1	None noted.			
Shoreham	-	-	-	Unqualified instrument cable replaced.
Grand Gulf	-	-	-	Flexible drive coupling material incompatible with operating environment. Replaced with different material.
Grand Gulf	-	-	-	Governor lube oil cooler located too high. Possibility of trapping air in system. Lube oil cooler relocated to lower elevation.
Grand Gulf	-	-	-	Engine pneumatic logic improperly designed. Could result in premature engine shutdown. Pneumatic logic design corrected.
Grand Gulf	-	-	-	Non Class 1E motors supplied with diesel auxiliary system pumps. Motors replaced with Class 1E qualified motors.

B. Other Manufacturers

See Attachment 1 to this enclosure.

ATTACHMENT 1

TO

ENCLOSURE 2

DIESEL GENERATOR MODIFICATIONS

Table E.4 Diesel Generator Modifications

Plant	Date	Subsystem	Modification
✓ Arkansas Nuclear One 1	6/22/74	Governor	Overspeed trip changed from 980 to 1035.
	3/77	Cooling water	Replaced DG heat exchanger with one of larger capacity.
✓ Beaver Valley	1978	Air-start	Stagger test on air-start motors.
	1978	Air-start	Blowdown air receivers 3 times/day. Upgrade fuel oil standards.
	2/4/81	Air-start	Installed air dryers.
	4/3/79	Annunciation	Add alarm on DG status - control room.
	9/20/79	Control	Prevent breaker closure for no field and change undervoltage relays to solid state.
	8/23/79	Sequencer	Sequencer receives power from #1 or #4 vital buses. Provide separate control transformer from 480V emergency buses.
	10/3/78	Exciter	Improve manual field flash - bypass some contacts.
	10/13/78	Lube and cooling water instruments	Install isolation valves for instruments for calibration.
	10/22/80	Fuel	Install tank to temporarily hold fuel for test. Add sampling connections.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Beaver Valley (continued)	5/18/81	Air-start	Install union to permit check valves to be replaced.
	5/20/81	Air-start	Install horizontal check valves.
	8/5/81	GM design changes	GM has a design that will eliminate turbo bearing damage in the .25 to 3 hour period after a run greater than one hour.
			Replaced crankshaft vibration damper.
			Replaced soldered lube oil cooler with rolled tube cooler.
			New screen with trap to remove material that would damage turbo.
			New turbo gear.
			Idler gear assembly.
			Lube oil sampling connection.
Big Rock Point	10/21/76	Electric-start	Change starter from crank/pause to continuous 25 second crank.
	1/10/77	Governor	New oil line to governor to improve start time.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Big Rock Point (continued)	5/27/77	Governor	Install throttle arm to replace governor control.
Brunswick 1 & 2	1/12/75	Annunciators	Fuel oil alarms.
	2/7/75	Dampers	Dampers modified. Did not work correctly.
	2/25/75	Cables	Cable separation.
	11/25/75	Air-start	Air compressor relief valve.
	2/22/79	Regulator	Auto-transfer from ac to dc regulator upon loss of voltage regulator potential transformer.
	5/24/76	Room temperature	Individual temperature switches in each DG room.
	5/6/77	Lube and cooling water	Increase lube and jacket water heater setpoints.
	4/21/77	Instruments	Increase lube oil pressure trip tees with valves for instruments.
	2/23/79	Annunciator	Separate alarms for low air pressure and bearing gear engaged added to Not Available.
	8/4/80	Fire Protection	Modify ventilation to remove fumes.
	8/29/79	Control	Change tank pack setpoint from 510 to 500 rpm. Controls service water valve.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Calvert Cliffs 1 & 2	5/15/79	Blower	Procedure to prevent blower damage.
	11/13/79	Governor	Semi-annual flush of governor. Manufacturer recommendations.
	1/20/79	Fuel	Inspect injectors every 6 months instead of 18 months.
	7/24/79	Exciter	Potential transformer was grounded and smoked. It was replaced.
	6/21/79	Procedure	Procedure review made to assume steps for returning DG are included.
	8/8/79	Vent fan	Added relay to provide positive start of fan.
	5/5/80	Air-start	Press sensors vibrated. Relocated. Also moved sense line upstream of check valve.
Cooper	10/10/78	Air-start	Root valves on pressure switch.
	3/2/74	Control	Speed sense modified.
	3/17/74	Exciter	Two parallel contacts to assure field flashes.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Cooper (continued)	4/30/75		Add air-operated valve in oil line to turbo. Prevents oil accumulation in inlet header.
	11/2/76	Air-start	Installed time delay in air-start to assure start.
	4/29/79	Annunciator	Added annunciator.
	5/22/79	Lube	Time delay relay keeps oil pump working for 30 seconds after DG trip. It is for crankshaft lube during coastdown.
	5/25/80	Logic	Protect DG if offsite power lost while testing DG. Trip non-essential loads.
	6/10/80		Modify DG silencer bypass control to assure adequate air pressure to fuel racks during start.
	6/6/80	Cooling water	Added continuous vent on jacket water pump to prevent air vapor lock.
Crystal River 3	3/16/81	Cooling water	Vent valve for refilling coolant.
	11/21/80	Generator	Generator stator temperature relay-change for relay with higher setting.
	10/9/80	Lube	Lube oil alarm setpoint too low.
	7/3/79	Logic	DG could not be reset in normal manner after low lube pressure trip.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Crystal River 3 (continued)	5/22/79	Annunciator	Add alarms that will annunciate any condition that will prevent an auto-start.
	5/3/79	Annunciator	Eliminate battery ground alarm while flashing field.
	11/15/79	Engine	Replace cam rollers - colt.
Dresden 2 & 3	10/77	Governor	Change governor speed with engine operating.
	7/78	Air-start	Add capability to blowdown starting air.
	10/78	Logic	Install tachometer for display.
	8/79	Annunciator	Alarm bus tie and emergency bus breaker test position.
	9/79	Annunciator	Alarm air shutoff valve in closed position.
	9/79	Air-start	Install multiple air-start system.
	8/79	Annunciator	Install droop alarm in control room.
	11/79	Air-start	Provide more positive relay action for two air-start systems.
	8/78	Annunciator	Separate alarm for 2 and 2/3 DGs.
	10/30/79	Cooling water	Make cooling water valves motor-operated from control room.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Farley 1 & 2	5/7/77	Lube	Increase pre-lube time on 2850kW.
	2/26/79	Sequencer	Modify master test switch so sequencer will not remain in test (spring return switch).
	7/26/81	Procedure	Load reject - open DG breaker instead of supply breaker.
	12/80	Fuel	Fuel oil consumption was low so installed a connection to auxiliary boiler fuel tank.
	11/78	Air start	Installed stainless steel pipes and non-regenerative air dryer.
	9/79	Inverter	During DG start inverter ac breakers tripped on transient. Upgraded breakers.
	2/79	Sequencer	Test mode select switches are wrong type - removed and installed specified switches.
	10/79	Synchronizer	Auto synchronizer does not work. It was removed.
Fitzpatrick	10/8/76	Fuel	Make fuel oil low level switch independent of pump motor control circuit.
	10/15/76	Logic	Replace UV relays.
	10/15/76	Air-start	Primary and secondary air-start motors start simultaneously. Simplify design.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Fitzpatrick (continued)	11/24/76	Control	DG not adequately protected. Add droop-normal switch in control room.
	10/31/78		Move panel from DG to eliminate vibration.
	12/15/78	Annunciator	Monitor control power to DG.
	12/6/76	Logic	Block low lube oil and high jacket water temperature trips for LOCA.
Fort Calhoun	10/81	Logic	Add interlock to sequencer reset and DG breaker. Prevent complete train failure because of single relay failure.
	11/81	Control	Filter tachometer output with 0.1 uf cap.
Ginna	10/11/81	Fuel	Install water-tight doors on fuel oil tanks.
Hatch 1 & 2	1976	Air-start	Ped. oxide on valve causes failure. Replace valve.
	1976	Logic	Make UV logic 1/2 taken twice.
	6/77	Fuel	Synthetic hoses are failing. Replace with steel piping.
	7/77	Cooling water	Gauge for jacket water.
	8/77	Distribution	Replace 4160V cables to bus bar. Cables are heating.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Hatch 1 & 2 (continued)	10/77	Logic	Reset undervoltage relays to prevent continuous operation at low voltage.
	11/77	Air-start	Make moisture detection indicator lights function.
	11/77	Fuel	Replace vent line with stainless steel.
	11/77	Fuel	Eliminate injector leakage. Install clean fuel oil drain tanks on each DG.
	4/78	Control	Move voltage regulator adjustment inside cabinet.
	6/78	Logic	Make undervoltage relay contacts normally open. Eliminate vibration sensitivity.
	6/78	Logic	Lockout DG breaker for overcurrent, etc.
	7/78	Cooling water	Low pressure shutdown switch too high.
	10/78	Distribution	Provide capability for DG 1B to serve units 1 or 2.
		Cooling water	Add a service water pump with local and remote control.
	6/80	Logic	Eliminate relay. It may hang up in emergency mode.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Hatch 1 & 2 (continued)	10/80	Control	Add synchro check relay.
	1/81	Governor	Replace governor booster servometer.
	1/81		Seal conduit to keep cold, moist air out.
	1/81	Governor	Alarm if DG is not synchromous speed.
	9/77	Lube	Change pre-lube time. See LER 77-62.
	2/81	Fuel	Clean spilled fuel. This is a procedure change.
	11/80	Procedure	Open MCC circuit breaker for RHR test valve. Jumper replacement for coolant high temperature trip.
	2/81	Procedure	Reset LOCA signal after jumpers are removed to allow auto RHR pump start.
Indian Point 3	1978	Annunciator	Alarm shutdown, lockout, loss of dc, or not auto-start.
	1979	Control	Isolate control circuits of DG 31.
	1980	Intake air	Isolate air intakes to prevent DG breathing CO_2 if CO_2 actuates.
La Crosse	8/76	Engine	Add DG 1B.
	6/77	Annunciator	Add low water temperature and low voltage alarms.

Table E.4 Continued

Plant	Date	Subsystem	Modification
La Crosse (continued)	8/77	Control	Power "on" light added for DG 1B.
	10/78	Annunciator	DG 1A not in auto-alarm.
	4/80	Annunciator	Alarm loss of inverted 1C.
	8/77	Annunciator	Install hydrogen alarms in battery room.
Millstone 1	11/6/74	Cooling water	DG can get emergency cooling water from the fire system.
	3/17/78	Engine	Cam rollers were replaced.
	7/5/79	Annunciator	Alarm when the DG is not ready for start.
	9/7/79	Synchrometer	Synchrometer check relay.
Millstone 2	1/28/76		Prevent DG start when output of primary transformer is open.
	12/1/77	Heat exchanger	Corrosion. Add additional zincs.
	1/19/76	Control	Time delay relays unreliable. They were replaced.
	4/21/78	Air-start	Make the air-start system more reliable.
	3/29/76	Fuel	Replaced flex hose to injectors with copper.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Millstone 2 (continued)	8/11/76	Logic	Delete non-emergency signals in DG logic.
	12/9/76	Air-start	Modify air compressor sense lines.
	10/19/76	Air-start	Install isolation valves in air compressor pressure sense lines.
	7/22/77	Lube	Remove low lube oil level trip.
	1/21/77	Engine	Add stiffeners to prevent DG vibration.
	4/30/79	Logic	Remove OTL, CTL, and CLL trips. See LER 77-32.
	5/22/78	Annunciator	Alarm loss of control power to circuit breaker or circuit breaker racked out.
	4/25/81	Air-start	Put unions in air lines.
	5/11/78	Annunciator	Alarm auto-start.
	11/8/78	Exhaust	Add silencers in exhaust line.
	4/30/79	Logic	Prevent DG start on reactor trip.
	5/12/79	Synchrometer	Synch. check relay.
	1/28/81	Lube	Isolate lube oil filter lines.
	5/12/79	Annunciator	Remote annunciator of DG trouble alarm.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Millstone 2 (continued)	8/28/79	Annunciator	Alarm on fuel oil valves closed.
	1/28/81	Lube	Install vent lines on lube oil strainer.
	3/77	Logic	Undervoltage relays were not sufficient. Added additional relays.
	3/80	Annunciator	Separate alarms for low fuel level.
		Exhaust	Install tornado missile shields on exhaust.
North Anna 1	12/79	DG fan	Increase rating from 180 to 230 hp by strengthening power takeoff.
	3/80	Logic	Change crankcase vacuum trip setting for more reliable starts.
	7/81	Logic	Auto-reset in governor motor operated pot circuit.
Palisades	3/80	Procedures	Modified procedures to reduce operator errors.
Peach Bottom 2 & 3		Logic	Solid state relays were sensitive to voltage spikes. Installed agastot time delay relays.
		Logic	BFD relays were not reliable. Installed agastot relays.
		Engine	Improve fuel header and cam follower.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Peach Bottom 2 & 3 (continued)		Governor	Install governor EG-B10C.
		Fuel/Fire	High temperature switch on fuel tank.
		Fuel	Fuel sample lines added.
Point Beach 1 & 2	9/79	Exhaust	Exhaust manifold inspection post-examine exhaust screen.
	11/80	Fire	Vent DG during turbine hall fire. Reverse vent fan direction.
Prairie Island 1 & 2	8/13/76	Fuel	Replaced fuel hoses with pipes.
	11/26/80	Logic	Remove 2 minute delay after DG stop.
	9/1/77	Fuel	Replaced unreliable fuel oil level switches.
	8/20/78	Logic	Revised circuit to prevent burn out of lockout relays.
	8/17/80	Turbo	Installed screens at inlet to turbo.
	5/26/77	Fuel	Changed power supply for D2 clean fuel pump.
Robinson 2	7/71	Cooling water	Alarm for expansion tank level. Early warning of leaks.
	2/72	Logic	Install key switch to bypass DG trips (alarmed).

Table E.4 Continued

Plant	Date	Subsystem	Modification
Robinson 2 (continued)	10/75	Air-start	Add a second air start solenoid on each DG.
	10/74	Exciter/battery	Replace lead acid battery with Nicad and locate in DG room.
	8/74	Fuel	Replace synthetic hoses with steel tubes.
	8/74	Switches	Replace components in defective switches.
	6/78	Lube	Time delay starts. Prelube changed from 15 seconds to 2 minutes.
	8/80	Annunciator	Alarm DG out of service.
	2/81	Start logic	Make start signal last 10 seconds instead of 1 second.
	8/81	Lube	Change prelube time from 2 to 4 1/2 minutes.
	In progress	Air-start	Service water piping to air dryer is being changed from carbon steel to stainless steel.
St. Lucie	5/78	Turbo	Turbo soak back pump used to stop at 200 rpm. Now pump continues to run (seems to have eliminated problem).
	5/78	Procedure	To prevent turbo problem operate DG at 100% instead of 37% (eliminate on turbo generator).

Table E.4 Continued

Plant	Date	Subsystem	Modification
St. Lucie	5/79	Cooling fan	Improved crankshaft coupling to fan. Similar marine couplings have failed.
	6/79	Lube	No non-emergency starts until lube oil cools so pressure could be maintained.
	3/80	Exciter	Install larger sized exciter leads. One failure had resulted.
	10/81	Cooling water	Add vents to cooling water high points.
	10/80	Cooling water	Procedure to ensure proper venting.
Trojan	9/77	Logic	Voltage permissive relay could reset on voltage dip. Add a seal-in contact.
	5/77	Immersion heaters	Motor overload devices trip heaters - now bypassed.
	9/80	Procedure	Monitor fan filter delta P for volcano-proof systems.
	9/80	Air-start	Revised test procedure to have independent and simultaneous test of each air starting system. See INPO SOER 80-1.
Maine Yankee	9/78	Fuel	Prevent fuel oil transfer pumps from operating when fill valves are open.
	6/78	Annunciator	Improved alarms.

Table E-4 Continued

Plant	Date	Subsystem	Modification
Maine Yankee (continued)	7/81	Cooling water	Provide cooling for DG 1A from primary component cooling water and DG 1B from secondary component cooling water.
Quad Cities 1 & 2	2/11/78	Exciter	Replace exciter transformer suppress[illegible] state-of-the-art devices.
	1/20/80	Logic	Trip 4kV breaker if shutdown relay operates. Prevent motoring.
	9/15/80	Air-start	Install check valve for the C-D DG receiver upstream of the tie with A-B set.
	9/28/78	Fuel	Put sleeves on fuel transfer lines to protect.
	2/23/79	Breaker	Install test switches for 4kV undervoltage functional test.
Surry 1 & 2	7/2/80	Lube	Check motor-driven lube oil vibration - several failures. Also there were turbo vibration checks.
	4/2/80	Procedure	Insure safety-related valve positions are independently verified.
Turkey Point 3 & 4	6/11/79	Exciter	Removed connection of neutral from exciter to DG transformer.

Table E.4 Continued

Plant	Date	Subsystem	Modification
Turkey Point 3 and 4 (continued)	1/27/81	Indicator	Replaced indicator light that could cause start failure.
	3/21/78	Fuel	Steel seamed tubing was replaced with stainless steel.
Vermont Yankee	10/14/80	Vent	Damper will fail open or loss of air or power.
	10/20/80	Lube	Improved lube oil temperature indication.
	1/16/80	Damper	Shut vent fans off on low temperature. Prevent governor malfunction.
	10/6/79	Exciter	Monitor auto and manual rheostats to ensure sufficient excitation.
	2/7/76	Exciter	Move exciter to the station batteries.

Attachment 2 - Additional detail on Arkansas 2 Diesel Failure 4/19/79.

The following material was quoted from "Nuclear Power Experience":

- Arkansas One 2 - Nov. 78 (prior to initial criticality)

  During a test, Fairbanks Morse DG B tripped from 100% load. Inspection revealed damage to bearings (rod and main), crankshaft and several pistons. The cause of failure was postulated as oil aeration; however, analysis showed the oil to be within specs. They changed oil with Mobilgard 445. They found a loose baseplate mounting screw which could have contributed to the failure by not allowing uniform expansion. The DG was load tested successfully following repairs. (gzs)

- In Apr. DG #2 engine failed during a routine surveillance test. The unit developed a severe vibration after being unloaded and was immediately tripped by an operator observing the test. Investigation revealed 4 upper crankshaft bearings wiped and 3 piston skirts cracked. Repair of the diesel engine continued throughout the remainder of the month. See XI.A.323 for additional information. (hua, hub)

- Arkansas One 2 - Apr. 79 - hot standby

  While performing a surveillance run of the "B" Emergency DG, the engine exhibited excessive vibration. DG "A" was proven operable immediately and the unit was brought to cold shutdown. Investigation revealed failure of the forward half of the upper main bearings. Damage was found at the rod bearings and crankshaft. The failure was caused by poor lubrication due to bearings being improperly located relative to the position of the journals of the crank. The main bearing caps were relocated by redwelling. Extensive load testing was successfully completed following repairs. (ibe)

ENCLOSURE 3

NON-TDI EXPERIENCE
1981 - 1983

1. ENGINE SUBSYSTEM

General Motors Experience

Plant	LER #	Description
Fort Calhoun	82-07	While testing DG 2, a leak was discovered in the copper tubing vent line from the thermal mixing valve to the coolant expansion. The vent line was found to be cracked at the point where it was connected to a fitting. The defective tubing was replaced. An engineering evaluation has been initiated to determine if flexible hose can be used.
Quad-Cities 1	81-22	1/2 DG during maintenance found babbitt in the oil pan. Further inspection revealed that No. 11 bearing cap was warped. The cause was a pin-hole leak found in a cross-over fuel line which possibly diluted the lube oil to the bearing. The bearing apparently overheated and warped the bearing cap. The diesel engine was replaced with an identical model.
Sequoyah 1	83-70	1A-A EDG tripped on high crankcase pressure. After trouble-shooting, the engine oil cooler and the No. 8 cylinder power pack were replaced. The probable cause of the oil cooler failure was normal end of life. The cylinder head was sent to GM for analysis.

Fairbanks Morse Experience

Plant	LER #	Description
Duane Arnold	81-015 81-016	During annual inspection of DG 21, the lower crankshaft bearing of crankshaft No. 14 was found wiped on the journal surface. Redundant 1G-31 revealed a similar problem -

Plant	LER #	Description
		lower crankshaft thrust bearing #13 and adjacent bearing No. 12 were found wiped on the journal surface. The bearings were replaced and the crankshafts relapped.
Calvert Cliffs 1	81-36	On 12 EDG it was discovered that the upper crankshaft thrust bearing was worn excessively, due to inadequate pre-lube of the engine prior to starting. The thrust bearing was replaced. A test was run to determine pre-lube requirements of each DG. The results of the test were used as the basis for establishing minimum times for pre-lube on all non-emergency starts.
Calvert Cliffs 1	81-78	DG 12 was taken out for PM. Two cylinder injectors and a water jacket relief developed leaks. The injectors were replaced and the relief was installed with new O-rings. Eight airblower discharge flange bolts were discovered broken - the failure of the bolts were determined to be by material analysis to be fatigue. All 14 bolts and their inserts were replaced.
Farley 1	81-53	On 7/28/81, DG 1C tripped under load. On 7/30/81, while attempting to perform DG 1C operability test, it failed to start. Investigation revealed that an O-ring between No. 11 cylinder lining and cylinder had failed allowing water to enter the No. 1 cylinder and overflow to reveal other cylinders via the intake air manifold and caused a "hydraulic lock"

Plant	LER #	Description
		of the engine. This resulted in damage to Nos. 1 and 11 piston inserts and bushings, the lower thrust bearing and vertical drive assembly. All damaged parts were replaced.
Farley 1	81-32	DG 1C failed to start. The cause was a leaking seal between the inner and outer cylinder which caused the No. 10 cylinder to fill with water. The cylinder liner was replaced.
Farley 1	81-67	DG 2C tripped under load due to high crankcase pressure. No. 8 cylinder liner was found scored and the No. 8 cylinder O-ring was faulty which allowed water to enter the cylinder. The scoring of the cylinder caused localized heating and exhaust leakage into the oil sump which caused the high crankcase pressure. Due to the No. 8 cylinder O-ring failure a decision was made to replace all 12 cylinder liners.
Farley 2	81-43	DG 1C tripped under load due to high crankcase pressure. Nos. 1 and 11 cylinder liners were found to be scored. The engine was repaired.
Hatch 2	82-79	DG 2C tripped after 37 minutes of operation, was restarted and tripped again. The cause was found to be bearing failure. This engine had multiple manual starts (an estimated 120-150 fast starts) as a result of increased surveillance. The first

Plant	LER #	Description
		bearing to fail was the No. 8 connecting rod bearing, with other bearings showing damage. During the 20 hour run-in check, one main bearing showed minor scoring. The bearing was replaced. The multiple manual starts revealed that a longer pre-lube time would allow the bearings to be better lubricated before the diesel was started to avoid bearing failures. The operating procedures were revised to incorporate a new pre-lube time as recommended by the manufacturer.
Hatch 2	81-127	2C DG failed during testing. Investigation revealed one of two rod cap retaining bolts had come out, allowing engine torque to break the second retaining bolt which caused the rod to separate from the crankshaft. The engine was repaired and returned to service. 2C DG has an identical failure in November 1980.
North Anna 2	83-50	EDG-2J tripped during surveillance testing. Internal cooling water leakage resulted in a high crankcase pressure trip and caused a cracked piston and cylinder liner. The unit was repaired and returned to service.

Cooper Bessemer Experience

Plant	LER #	Description
Cooper	82-20	During testing the No. 2 DG shutdown with no alarms or indications. DG was declared inoperable when

Plant	LER #	Description
		water was found in the lube oil system. A 3-inch L-shaped rupture of the No. 8 left cylinder liner expansion seal was found. The seal was replaced.
Cooper	82-16	During surveillance testing 1 DG tripped with no other alarms or indication. The unit tripped due to drift in the holding mechanism of the safety trip valve overspeed device. The valve was replaced. A section of the 125 psi control air line to the trip valve was also replaced after a small hole in the line was observed.
Zion 1	81-36	While testing 1A DG, an abnormal amount of lube oil was seen leaking from No. 6 right cylinder head covers as well as an unusual noise from the same cylinder. The engine was manually shutdown. The intake rocker arm broke due to binding between it and the rocker stand. The engine was repaired and returned to service.
Zion 2	82-20	2B DG was declared inoperable when it failed to start. A broken coupling between the camshaft and the starting air distributor prevented the engine from cranking. The coupling was replaced.

Worthington Experience

Cook 1 and 2	81-38 81-45	During a routine inspection of 1AB EDG, a taper pin in the fuel rack assembly was found to be loose and the pin was found to be broken. All other taper pins

Plant	LER #	Description
		of the Unit 1 EDG's were cracked and found to be tight. Some loose pins were found on Unit 2 diesels and corrective actions were taken.

2. TURBOCHARGER SUBSYSTEM

General Motors Experience

ANO 1	82-05	EDG 2 failed to start during testing. The turbocharger had failed and was replaced. The failed turbocharger was returned to the manufacturer for repair. An evaluation will be made to determine the root cause of failure and long term corrective action.
Beaver Valley 1	81-30	During monthly surveillance testing of 2 EDG, the unit tripped apparently due to overspeed. The diesel would not restart. The diesel failure was attributed to a failed taper pin and bent lever in the governor. The turbocharger also failed. The turbocharger and taper pin and lever were replaced.
Saint Lucie 1	82-24	During testing, the 1B EDG turbocharger failed. Subsequent inspection revealed a deteriorated soak back oil pump not providing sufficient lubrication to the turbocharger guide and thrust bearing. The turbocharger and oil pump were replaced.
Saint Lucie 1	82-33	1B EDG turbocharger failed - caused by a broken coupling of soak back pump.

Plant	LER #	Description
Saint Lucie 1	81-47	During a retest following modifications, 1A EDG turbocharger failed. Cause not determined, however, in the weeks prior to failure there were approximately 60 engine starts and a great deal of light load operation associated with maintenance and modification retesting.

Cooper Bessemer Experience

Zion 1	83-02	0 DG failed to accept greater than 50% load. The turbocharger had seized which reduced load capacity to 50%. The turbocharger was replaced. (Second failure of this type since 1973.)

3. FUEL OIL SUBSYSTEM

Fairbanks Morse Experience

Farley 2	81-13	On 5/5 and 5/6/81, DG 2B was declared inoperable due to a lube oil leak and a fuel oil leak respectively. The cause of the lube oil leak was a leaking O-ring on the lube oil strainer. The cause of the fuel oil leak was a fatigue failure, due to vibration of a compressor filling on a copper line. The line was replaced with stainless steel and re-routed to reduce vibration.

Plant	LER #	Description

Cooper Bessemer Experience

Cooper	81-21	During testing of 2 DG, an injector line failed. Cause of failure of fuel injector supply line is believed to be metal fatigue and vibration. Tubing severed completely near injector compressor fitting. Component was replaced.

4. COOLING SUBSYSTEM

Nordberg Experience

Brunswick 1	82-78	2 EDG tripped due to low jacket water pressure. The two dowel pins and eight capscrews in the flex drive coupling drive plate had sheared, allowing the plate to separate from the engine crankshaft. A new drive plate and new dowel pins and capscrews were installed. The same will be done for the other EDG's.

ALCO Experience

Salem 1	81-18 81-53 83-04	DG 1A was declared inoperable because of a cooling water leak. Similar occurrences: 76-12, 77-59, 77-77, 77-80, 80-02, 80-22, 80-31, 80-60 and 81-02. The nipple connecting jacket water valve 1DA45A and jacket water pipe was cracked and leaking. The nipple was replaced in kind.

Plant	LER #	Description
5. DESIGN ERROR		
GM Experience		
Browns Ferry 1	83-09	Design review of EDG engine coolers showed that the coolers may not be capable of maintaining the engine cooling water below the 190°F hot alarm setpoint when the diesel is at full power. Cooling water maximum temperature necessary to maintain a jacket water temperature of 190°F has been conservatively calculated to be 76°F. Apparent design error made in sizing engine coolers for inlet cooling water at 95°F.
Browns Ferry 1	83-24	Design review of EDG room ventilation showed system may not keep electrical components below maximum temperature limits when ambient air temperature is above 87.3°F and diesels are at full load. Deflectors installed to direct exhaust air away from components.
Sequoyah 1	83-38	DG's would become inoperable when outside air temperature is greater than 88°F. The heat load of the DG is higher than that originally used.
Fitzpatrick	82-39	EDG A & C were declared inoperable. Overheating of a ventilation cowling within the generator due to an original design error was the cause. Evaluation by vendor and licensee continues.

ENCLOSURE 4

POPULATION DATA FOR DIESEL GENERATORS
IN NUCLEAR SERVICE

Table 1 shows the population of non-TDI diesel engines for licensed nuclear service as a function of generator output and engine manufacturer. The data for non-TDI engines was taken from Table A.1 of NUREG/CR-2989 (which includes active LWR's licensed through 1981 with the exception of McGuire). Although some discrepancies in the generator output rating were noted between information found in LERs, staff memoranda, NUREG/CR-1362 ("Data Summaries of Licensee Event Reports of Diesel Generators at U.S. Commercial Nuclear Power Plants," March 1980) and Table A.1, the discrepancies do not significantly affect the general distribution of the population.

Table 1

			Generator Output (KW)					
Manufacturer	Total	<500	500-1749	1750-2499	2500-3499	3500-3999	4000-4999	>5000
General Motors	52	3		8	41			
Schoonmaker	10			8	2			
Bruce	4				4			
Fairbanks Morse	42				40		2	
Alco	18			8	10			
Cooper Bessemer	7						7	
Worthington	4					4		
Nordberg	4					4		
Allis Chambers	2	2						
Caterpillar	1	1						
Total	144	6	0	24	97	8	9	
Transamerica Delaval	7					3		4

As Table 1 shows, most of the diesel engine experience from manufacturers, other than TDI, is with engines having output ratings between 1750 KW and 3000 KW. By contrast the TDI engines are generally much larger machines.