UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report No.: 50-416/85-45

Licensee: Mississippi Power And Light Company
Jackson, MS 39205

Docket No.: 50-416 License No.: NPF-29

Facility Name: Grand Gulf 1

Inspection Conducted : November 16 thru December 20,1985

Inspectors: R. C. Butcher, Senior Resident Inspector — 1/10/86 Date Signed

J. L. Caldwell, Resident Inspector — 1/10/86 Date Signed

Approved by: W. W. Panetera, Chief, Project Section 2B, Division of Reactor Projects — 1/10/86 Date Signed

SUMMARY

Scope: This routine inspection entailed 202 resident inspector-hours at the site in the areas of Operational Safety Verification, Maintenance Observation, Surveillance Observation, ESF System Walkdown, Reportable Occurrences, Operating Reactor Events, Inspector Followup and Unresolved Items, and License Conditions.

Results: Violations - failure to close LLRT valves by normal means, failure to adequately train personnel performing activities affecting quality, and failure to follow procedures when performing diesel generator maintenance. Deviation - failure to incorporate periodic test of ESF room coolers.

REPORT DETAILS

1. Licensee Employees Contacted

J. E. Cross, Site Director
*C. R. Hutchinson, General Manager
R. F. Rogers, Technical Assistant
*J. D. Bailey, Compliance Coordinator
M. J. Wright, Manager, Plant Operations
L. F. Daughtery, Compliance Superintendent
D. Cupstid, Start-up Supervisor
R. H. McAnulty, Electrical Superintendent
*R. V. Moomaw, Manager, Plant Maintenance
*B. Harris, Compliance Coordinator
J. L. Robertson, Operations Superintendent
L. Temple, I & C Superintendent

Other licensee employees contacted included technicians, operators, security force members, and office personnel.

*Attended exit interview.

2. Exit Interview

The inspection scope and findings were summarized on December 20, 1985, with those persons indicated in paragraph 1 above. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. The licensee had no comment on the following inspection findings:

a. Unresolved Item 85-45-01; Significance of Plugging of ESF Room Coolers. (Paragraph 5.a)

b. Deviation 85-45-02; Failure to Incorporate Periodic Test of ESF Room Coolers to Ensure System Operation. (Paragraph 5.a)

c. Unresolved Item 85-45-03; Unusable Fuel Oil Tank Volume. (Paragraph 5.b)

d. Unresolved Item 85-45-04; MSIV Accumulator Check Valves Not Addressed in the IST Program. (Paragraph 5.c)

e. Inspector Followup Item (IFI) 85-45-05; Permissible Leakage Rate for LLRTs. (Paragraph 7)

f. Violation 85-45-06; Failure to Close LLRT Valves by Normal Means. (Paragraph 7)

g. Violation 85-45-07; Failure to Adequately Train Personnel Performing Activities Affecting Quality. (Paragraph 9.a)

h. IFI 85-45-08; TDI Diesel Generator Intake & Exhaust Valve Spring Inspection. (Paragraph 9.c)

i. IFI 85-45-09; TDI Diesel Generator Air Intake Silencer Defect Inspection. (Paragraph 9.d)

j. Unresolved Item 85-45-10; Licensee Identified Discrepancies in Environmental Qualification Program. (Paragraph 9.e)

k. Violation 85-45-11; Failure to Follow Procedures when Performing Diesel Generator Maintenance. (Paragraph 10)

l. IFI 85-45-12; Excessive Oil Around Diesel Generators and Existence of Two Valves with Same Identification Number. (Paragraph 8)

3. Licensee Action on Previous Enforcement Matters (92702)

Not Inspected.

4. Unresolved Items

An Unresolved Item is a matter about which more information is required to determine whether it is acceptable or may involve a violation or deviation.

New Unresolved Items are discussed in Paragraph 5.a, 5.b, 5.c, and 9.f.

5. Operational Safety Verification (71707)

The inspectors kept themselves informed on a daily basis of the overall plant status and any significant safety matters related to plant operations. Daily discussions were held with plant management and various members of the plant operating staff. The inspectors made frequent visits to the control room such that it was visited at least daily when an inspector was on site. Observations included instrument readings, setpoints and recordings status of operating systems; tags and clearances on equipment controls and switches; annunciator alarms; adherence to limiting conditions for operation; temporary alterations in effect; daily journals and data sheet entries; control room manning; and access controls. This inspection activity included numerous informal discussions with operators and their supervisors.

Weekly, when onsite, a selected ESF system is confirmed operable. The confirmation is made by verifying the following: accessible valve flow path alignment; power supply breaker and fuse status; major component leakage, lubrication, cooling and general condition; and instrumentation.

General plant tours were conducted on at least a biweekly basis. Portions of the control building, turbine building, auxiliary building and outside areas were visited. Observations included safety related tagout verifications; shift turnover; sampling program; housekeeping and general plant conditions; fire protection equipment; control of activities in progress; radiation protection controls; physical security; problem identification systems; and containment isolation.

The following comments were noted:

a. It came to the inspectors attention that during the performance of flow balancing testing of the new Standby Service Water (SSW) B pump the licensee discovered several Engineered Safety Feature (ESF) room coolers plugged with sand. The inspectors questioned the licensee about the safety significance and reportability of plugged ESF room coolers. The licensee responded that they would have the Nuclear Plant Engineering (NPE) Department evaluate the flow through the coolers to determine if flow was sufficient to ensure operation of the associated ESF equipment during an accident and verify that the plant was not in an unanalyzed condition. Pending NPE's evaluation the question of safety significance and reportability will be identified as an Unresolved Item. (50-416/85-45-01).

   Further review by the inspectors revealed a commitment in the FSAR, paragraph 9.4.5.4, that the ESF room coolers be periodically inspected to ensure that all normally operating equipment is functioning properly and standby components are periodically tested to ensure system operation. From a discussion with the licensee, the inspectors discovered that no program existed to inspect and test the ESF room coolers as required by the FSAR. In fact, the only reason the B train of ESF room coolers were discovered to be plugged with sand was due to the testing of a new SSW pump. The licensee has replaced the plugged coolers and is in the process of testing the A train of the ESF room coolers. The failure of the licensee to have a program to inspect and test the ESF room coolers as committed to in the FSAR will be identified as a Deviation (50-416/85-45-02).

b. During a review of one of the plant's Incident Reports (IRs), the inspectors discovered that the minimum level for the Emergency Diesel Generator (EDG) storage tank appeared to be in error in the non-conservative direction. Consequently, the possibility existed that the plant could have operated with the EDG fuel tank levels below the limits allowed in Technical Specifications (TS). This discovery by the licensee resulted from a review of a TS change that was being implemented into a surveillance procedure to raise the minimum fuel storage tank level to compensate for new larger Standby Service Water (SSW) pump motors being placed on the EDGs' busses. This review revealed a Bechtel drawing (JK-M-2003) of the fuel oil tanks showing an unusable fuel oil volume to be approximately 8,200 gallons. This 8,200 gallons was used to compute the new minimum fuel oil tank levels corresponding to 57,200 gallons needed to support the new SSW pump motors. However the figure of 8,200 gallons was not used to determine the level which

corresponded to the previous TS limit of 48,000 gallons. An unusable volume of 3,400 gallons was used to determine the minimum level for the TS limit. The licensee has stated that conversations with the diesel fuel transfer pump vendor, some informal calculations and statements in the FSAR indicate that the value used for the unusable volume (3,400 gallons) to determine the minimum EDG fuel oil tank level corresponding to the 48,000 gallon TS requirement is appropriate for this application. The only documentation other than the FSAR which the licensee can provide is the Bechtel drawing of the tank supplied to MP&L showing the unusable volume to be 8,200 gallons.

The inspectors asked the licensee if the tank levels had ever dropped to a level below 48,000 gallons when using 8,200 gallons as unusable volume. The assistant to the Operations Superintendent informed the inspectors that a review of the EDG operations log revealed that the only times the fuel oil levels were below 48,000 gallons, using 8,200 gallons as an unusable volume, were when the corresponding EDG was declared inoperable for other reasons. The licensee has been requested to provide written documentation from the fuel pump vendor and MP&L's Engineering organization to support their contention that 3,400 gallons unusable volume is appropriate for this application. Since the possibility existed that the previous surveillance procedures would have allowed the EDGs to be operated with fuel oil tank level below the limit of Technical Specifications, this will be identified as an Unresolved Item (50-416/85-45-03) pending the written documentation supporting the licensee's previous values.

c. A situation similar to that described in IE Information Notice 85-84, Inadequate Inservice Testing of Main Steam Isolation Valves, existed at GGNS. The instrument air system is a non-safety-related system which normally supplies operating air for the Main Steam Isolation Valves (MSIVs). There are safety related accumulators which provide stored air for MSIV operation in the event the instrument air system is lost (i.e. isolated, etc). Each MSIV has an accumulator with an in-line check valve from the instrument air system. The check valves B21F024A, F024B, F024C, F024D, F029A, F029B, F029C, and F029D, do not appear to have been included in the licensee's Inservice Testing (IST) program, nor in the licensee's type C testing per Appendix J of 10 CFR 50. The instrument air lines just upstream of the noted check valves are non-seismic piping. T.S. table 3.6.4-1 requires a maximum isolation time of 5 seconds for the MSIVs. The licensee conducted testing with the instrument air line isolated, the accumulators charged with instrument air and no steam flow. The MSIV closure times were within the 5 second requirement. The licensee is investigating to determine the reason the accumulator check valves were not included in the IST program or IST program relief request.

This will be an Unresolved Item (50-416/85-45-04).

6. Maintenance Observation (62703)

During the report period, the inspector observed selected maintenance activities: The observations included a review of the work documents for adequacy, adherence to procedure, proper tagouts, adherence to Technical Specifications, radiological controls, observation of all or part of the actual work and/or retesting in progress, specified retest requirements, and adherence to the appropriate quality controls.

In the areas inspected, no violations or deviations were identified.

7. Surveillance Testing Observation (61726)

The inspector observed the performance of selected surveillances. The observation included a review of the procedure for technical adequacy, conformance to Technical Specifications, verification of test instrument calibration, observation of all or part of the actual surveillances, removal from service and return to service of the system or components affected, and review of the data for acceptability based upon the acceptance criteria.

Technical Specifications (TS) 3.6.1.2 states that containment leakage rates shall be limited to an overall integrated leakage rate of less than or equal to L_a where L_a equals 0.437 percent by weight of the containment air per 24 hours at P_a, 11.5 psig. The Final Safety Analysis Report (FSAR), paragraph 15.6.5.5, states that the design basis leak rate of the primary containment and its penetrations (excluding the main steam lines) is 0.35 percent per day. The Main Steam Line Isolation Valves (MSLIVs) are assumed to leak at 25 SCFH per valve. The proposed TS for containment leak rate was discussed in a letter dated December 31, 1981 from Mr. L. Dale, MP&L to Mr. H. Denton, NRC (AECM-81/510). Attachment 1 to the letter presented a summary of the method used to calculate an overall integrated leak rate. A review of calculations by a Region II inspector indicated that the TS allowable of 0.60 La for all penetrations and all valves subject to type B and C tests would equal approximately 325.25 SCFH. The Licensee's Surveillance Procedure, 06-ME-1M61-V-0001, Rev 26, Local Leak Rate Test, paragraph 5.11.2 states the overall allowable leakage limit of all type B & type C tests shall not exceed 0.60 La or 182.5 SCFH. A review of the licensee's letter of December 31, 1981 indicates an error in attachment 1, step 1, in that the 204.20 is titled "SCFH" while in fact the 204.20 is "CFH" at accident pressure, not standard pressure. Since the licensee's error appears to be in the conservative direction, the licensee was notified of the error and is presently reviewing the FSAR to determine the basis for allowable leakages. The licensee was informed that any change to the 0.437 % per 24 hours presently specified would require a TS amendment. This will be an Inspector Followup Item (50-416/85-45-05).

During the performance of the Integrated Leak Rate Test (ILRT) in early November 1985, the licensee discovered that valve C41F150, the outboard isolation for penetration 61, was not fully closed. In order to complete the ILRT the licensee closed the vent valve down stream of C41F150. Subsequent to the ILRT the licensee performed a Local Leak Rate Test (LLRT)

on the two isolation valves associated with penetration 61, C41F150, the outboard isolation valve and C41F151, the inboard isolation valve. The resulting leakage for each valve was so excessive that test pressure could not be reached. The inboard isolation valve C41F151 is a stop check valve and the required position of the handwheel for the ILRT is to be in the open direction. With the handwheel in the open direction C41F151 acts as a check valve preventing flow in the outboard direction. The previous LLRT of C41F151, performed on June 18,1985, indicated zero leakage. The only operation connected with this valve since the LLRT was the reclosure of the handwheel after the June LLRT and the opening of the handwheel in preparation for the ILRT. This movement of the handwheel should not have any affect on the position of the disk. The licensee has disassembled valve C41F151 and lapped the disk and seat. During the disassembly it was observed that the packing was loose and the seat was dirty. The subsequent LLRT performed in November was satisfactorily.

After the unsuccessful LLRT of C41F150, following the ILRT, the licensee attempted to shut the valve. The operator was able to get approximately one (1) more turn by hand but the valve still would not pass the LLRT. Finally the licensee placed a valve wrench on the valve and was able to get another one quarter (1/4) of a turn in the closed direction. This time the LLRT was performed satisfactorily but the zero leakage rate achieved in June 1985 was not reproduced. Since the successful LLRT on June 18, 1985, C41F150 had only been repositioned one time and that was to perform the LLRT on C41F151 also performed on June 18,1985. C41F150 had been closed or verified closed on at least six (6) different occasions, including the valve lineup in preparation for the ILRT, since the repositioning in June 1985. The inspectors questioned the licensee personnel, who perform an LLRTs, on the requirement in Appendix J of 10 CFR 50, that a valve shall be closed by normal operation prior to the performance of the LLRT. The licensee informed the inspectors that they considered the use of excessive force and valve wrenches to close manual isolation valves for the purpose of passing the LLRT to be normal operation. The inspectors informed the licensee that the use of excessive force and valve wrenches did not constitute normal operation as required by Appendix J of 10 CFR 50, and requested a list of any other valves requiring abnormal operation to pass their respective LLRTs. The Mechanical Maintenance Superintendent notified the inspectors that there were no other valves requiring excessive force or valve wrenches to pass their LLRTs.

It is important to note that the piping associated with penetration 61 does not connect to any system in the plant. The piping is capped at both ends, inside and outside the containment. Consequently operation of the isolation valves is not required except for the performance of their LLRTs. The licensee however does not know if excessive measures were taken to get C41F150 and C41F151 to pass their respective LLRTs with zero leakage in June of 1985.

Subsequent to conversations with the inspectors the licensee performed maintenance on C41F150 and reperformed the LLRT successfully. The failure of the licensee to meet the requirement of 10 CFR 50, appendix J to shut valve C41F150 using normal operation in order to achieve a successful LLRT following the ILRT will be identified as a Violation (50-416/85-45-06).

8. ESF System Walkdown (71710)

A complete walkdown was conducted on the accessible portions of the Division 1 Emergency Diesel Generator. The walkdown consisted of an inspection and verification, where possible, of the required system valve alignment, including valve power available and valve locking, where required; instrumentation valved in and functioning; electrical and instrumentation cabinets free from debris, loose materials, jumpers and evidence of rodents; and system free from other degrading conditions.

During the walkdown of the Division 1 Emergency Diesel Generator (EDG), the inspectors observed several items of concern. One item deals with a condition where several areas on and around the the EDG contained pools of lube oil which appear to be more than just normal amounts. Another item deals with the discovery of two valves on the valve lineup sheet and existing in the plant with the same identification number. The valve lineup sheet Attachment 1A of System Operating Instruction (SOI) 04-1-01-P75-1 contains two valves with the same identification number of F112A. Even though these valves appear on the same lineup sheet there was no mention by the operators of this problem in the comments section of the completed lineup sheet. A quick look at Division 2 EDG valves revealed that the same condition exists there also. The inspectors have notified the licensee of their concerns and will be following up these items to ensure proper resolution. This will be identified as Inspector Followup Item (50-416/85-45-12).

In the areas inspected, no violations or deviations were identified.

9. Reportable Occurrences (90712 & 92700)

The below listed Event Reports were reviewed to determine if the information provided met NRC reporting requirements. The determination included adequacy of event description and corrective action taken or planned, existence of potential generic problems and the relative safety significance of each event. Additional inplant reviews and discussions with plant personnel as appropriate were conducted for the reports indicated by an asterisk. The Event Reports were reviewed using the guidance of the general policy and procedure for NRC enforcement actions.

The following License Event Report (LERs) are closed.

LER No.	Event Date	Event
*85-039	October 10, 1985	Personnel Error Causing Loss Of Power To ESF Bus 12.
*85-042	November 2, 1985	Incorrect Wiring Configuration Caused the Loss of ESF Transformer 11.

a. LER 85-039. On October 17, 1985 while moving a relay from a tagged out feeder breaker to the Engineered Safety Feature (ESF) Division 2 electrical bus for the purpose of calibration, a personnel error caused the other feeder breaker to trip deenergizing the entire bus. At the time of the event the plant was in mode 4 with the safety and shutdown cooling systems associated with the Division 2 ESF bus declared inoperable for various reasons. However as a direct result of the event the operable mode of shutdown cooling, Residual Heat Removal (RHR) system A, was isolated from the vessel. Shut down cooling was restored and since the reactor had been in cold shutdown since October 13, 1985 the impact on the reactor was minimal. The personnel error consisted of an electrician removing a relay from ESF Division 2 feeder breaker 152-1601 and placing the relay connection plug back in the empty relay case. This plug caused the bus lockout relay to sense a trip signal tripping the other feeder breaker 152-1601 causing a total loss of power to the Division 11 ESF electrical bus. The electrician did understand that the connection plug should not be placed back into the empty relay case but he did not understand that the protective relay circuits remained energized even though the breaker was tagged out. He, therefore, was not knowledgeable in the protection circuits relationship between the feeder breakers.

10 CFR 50, Appendix B, Criterion II states in part that the Quality Assurance Program shall take into account the need for special controls, processes, test equipment, tools and skills to attain the required quality, and the program shall provide for indoctrination and training of personnel performing activities affecting quality as necessary to assure that suitable proficiency is achieved and maintained. The failure of the licensee to ensure that the electrician was trained in the protection characteristics and interfaces of feeder breakers resulting in the loss of power to an ESF electrical bus and subsequent loss of the shutdown cooling operation of the RHR A system will be identified as a Violation (50-416/85-45-07).

b. LER 85-042. The event associated with this LER consisted of ESF transformer 11 output breakers tripping due to a differential protection relay signal on two different occasions, resulting in loss of power to ESF electrical buses. These two events appear to have resulted from wiring errors made some years back. The licensee stated that back in 1979 Bechtel personnel discovered that the differential relays for each of the ESF transformers were wired backwards. This wiring error was corrected on the transformers but the General Electric (GE) drawing showing this wiring error was not corrected. Also unknown to the licensee another wiring error existed on a secondary side current transformer to ESF transformer 11. The licensee speculates that this wiring error caused ESF transformer 11 to trip on a protection relay signal sometime during the startup or preoperational testing of Division 3 High Pressure Core Spray (HPCS) Pumps. Since the General Electric drawing had not been corrected and the differential relay would be suspected, the engineers probably discovered that the differential relay was wired differently than the General Electric drawing had specified and, therefore, changed the relay to be consistent with the drawing. The relay and current transformer, each being wired backwards, cancelled each other therefore the starting of the HPCS pump on ESF transformer 11 would not have tripped the transformer indicating the problem had been solved.

On November 2, 1985, the first trip of ESF transformer 11 occurred resulting in a loss of power to the Division 2 ESF electrical bus. This started Diesel Generator 12, and caused several isolations and secured RHR B shutdown cooling. This trip uncovered the problem of the differential relay being wired backwards and the fact that the General Electric drawing had not been corrected. However, it did not disclose the reason why the relay had been changed back to the incorrect GE drawing configuration. The reason this wiring error had gone undetected until November 2, 1985, was the current needed for normal operation of equipment connected to ESF transformer 11 was just under the trip threshold of the differential relay. However, the licensee had just replaced the B Standby Service Water (SSW) Pump motor with a larger one and this was the first time this equipment had been started and operated off of ESF transformer 11. This new larger SSW pump motor caused the current load requirement to just exceed the trip threshold of the differential relay and tripped the transformer.

The second trip of ESF transformer 11 occurred on November 23, 1985, when both Division 1 and Division 3 ESF electrical buses were being supplied off of ESF transformer 11. The trip was caused by starting the HPCS pump for testing and resulted in the loss of power to both ESF bus 1 and 3. The loss of power started division 3 diesel generator and caused numerous isolations, one of which was instrument air that eventually resulted in a reactor scram signal due to a scram discharge

instrument volume high water level trip signal. The plant was shutdown in mode 4 at the time of the event. The investigation by the licensee discovered the secondary current transformer wiring problem which had been masked by the previous differential relay wiring problem. The current transformer being wired backwards only became a problem when the ESF transformer 11 differential relay wiring was corrected after the trip on November 2, 1985, and then only when the secondary side of ESF transformer 11 associated exclusively with the Division 3 ESF bus, is lined up to Division 3 and the HPCS pump is started. It is important to note that the Division 3 electrical bus can be lined up to any of the three ESF transformers and the secondary side of ESF 11 associated with Division 3 can only supply power to Division 3 on Unit 1. Therefore, the improperly wired current transformer only comes into play when ESF transformer 11 is supplying power to the Division 3 ESF bus. The licensee has corrected the current transformer wiring problem and the GE drawings were corrected earlier. The other ESF transformer differential relays have been verified to be hooked up properly.

c. By letter dated November 6, 1985, Transamerica DeLaval, Inc. (TDI) notified the NRC of a potential 10 CFR Part 21 defect in the TDI Diesel Generators (DGs). The defect concerned recently experienced isolated failures of the intake and exhaust valve springs. TDI stated that all springs failed after an extensive operating experience of approximately 5,000 to 7,000 operating hours. The suspect valve springs are manufactured by Betts Spring Co., San Leandro, California and are identified by a white stripe painted on the spring. TDI is requesting all users report the results of their inspection to determine if corrective action is required. No action was recommended other than inspection. The licensee's inspection of the Division 1 DG indicated that all valve springs had a white stripe on the side. The Division 2 DG will be inspected during the first refueling outage. No broken valve springs have been identified at Grand Gulf and the DGs have less than 2,000 hours operating time. This will be an Inspector Followup Item (50-416/85-45-08).

d. By letter dated September 3, 1985, American Air Filter (AAF) notified the NRC of a 10 CFR Part 21 defect in the Division 1 and 2 Diesel Generator (DG) air intake silencers, model TDM or FTDM. The defect was a possibility of an internal part not being welded in place. On a commercial diesel engine installation identical in most respects to standby diesel generator nuclear installations, a turbocharger and diesel engine failure was experienced when an internal part of an AAF intake silencer was ingested into the turbocharger shortly after startup. The ingested part was found <u>not</u> to have been welded in place per design. Air pressures and vibration existing during engine

operations were sufficient to dislodge the part and convey it downstream into the engine turbocharger. AAF stated that if the DG has been in service, the likelihood of the weld not being in place is much lower and the licensee should schedule an inspection for verification. The licensee inspected the DGs and visual inspection revealed that the welds had been made.

This will be an Inspector Followup Item for record purposes (50-416/85-45-09).

e. On December 5, 1985, Mississippi Power and Light (MP&L) notified the NRC that they had discovered equipment installed in the plant which appeared to be in violation of 10 CFR 50.49 "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." This equipment consisted of 17 limit switches, 8 of which had not been environmentally sealed and 9 had date codes missing. The plant was in cold shutdown at the time of the notification and the licensee corrected all of the identified discrepancies prior to startup.

The investigation by the licensee to determine if these limit switches are in fact required to be environmentally qualified and if there are any other discrepant equipment is continuing. Pending the licensee's final resolution of the scope and extent of the problem this will be identified as an Unresolved Item (50-416/85-45-10).

10. Operating Reactor Events (93702)

The inspectors reviewed activities associated with the below listed reactor events. The review included determination of cause, safety significance, performance of personnel and systems and corrective action. The inspectors examined instrument recordings, computer printouts, operations journal entries, scram reports and had discussions with operations, maintenance and engineering support personnel as appropriate. The licensee's investigation into the Diesel Generator (DG) overspeed that occurred on November 6, 1985, has been completed and the DG has been reassembled. The cracks in the main generator base were evaluated by a consulting group, Failure Analysis Associates, and it was determined that continued use of the existing base was permissible. Two meetings were held at the Grand Gulf Plant with NRC representatives to explain what the licensee's investigation had shown. On November 14, 1985, Mr. Carl Berlinger and Mr. Emmett Murphy from NRR were present and on November 21, Mr. Carl Berlinger, NRR and Mr. Paul Louzecky, NRC consultant, were on site. The Division 1 DG was completely disassembled and the results of nondestructive examinations were available for review. It appears the DG overspeed was the result of the inadequate refilling and venting of the Woodward Governor following maintenance that required the removal and draining of the Woodward Governor (including the booster and cooler). This overspeed condition resulted in substantial damage to the DG. A description of the damage, inspection and repair is provided in the summary of the meetings noted above. Also, a meeting was held in the NRC Region II office on December 13, 1985, where the licensee presented the results of their investigation.

T.S.6.8.1 requires written procedures be established, implemented and maintained covering activities recommended in Appendix A of R.G. 1.33. R.G. 1.33 requires written procedures for performing maintenance that can effect performance of Safety related equipment. The Division 1 DG retest was performed by Maintenance Work Order (MWO) M57687 dated November 6, 1985. A review of the MWO indicated the following discrepancies.

(a) Maintenance Section Procedure (MSP) 07-S-09-40, revision 1, Control of Retest Requirements, Paragraph 6.3.2.d.(1) states" when maintenance retest (Special Instructions) are required that do not exist, and are subsequently developed by a Maintenance Planner, an Engineer will review the maintenance retest and approve, disapprove, or modify accordingly." Contrary to the above, the special instruction included in the MWO does not have the approval signature of the Responsible Maintenance Engineer (RME).

(b) MSP-07-S-09-40, Revision 1, Paragraph 6.3.2 requires the RME/Responsible Field Engineer (RFE) specify maintenance retests. Contrary to the above, maintenance retests were specified by a Mechanical Supervisor.

(c) Preventive Maintenance Instruction 07-S-24-P75-E001AB-5, Revision 0, Periodic Oil Change of the Standby Emergency Diesel Woodward Governor Model #EGB-35-C, paragraph 7.10.1 states "Run engine 15 minutes, stop engine and drain governor oil and fill with fresh oil." Contrary to the above, the retest specified by MWO M57687 did not specify the draining of governor oil & refill with fresh oil following a 15 minute run.

The failure to follow procedures as noted above is a violation (50-416/85-45-11).

The Woodward Governor manual for the EG-B35 and EG-B50 hydraulic actuators, Grand Gulf (GG) TDI diesels use EG-B35C governors, has a warning that the engine should be equipped with separate overspeed shutdown devices to protect against runaway or damage to the engine should the mechanical-hydraulic governor, or electric controls, the actuators, fuel control, the driving mechanism, the linkages or the controlled devices fail. The GG diesels have a separate overspeed device manufactured by the Woodward Governor Company. The overspeed trip is set at 15% over the normal governor speed of 450 rpm (or 517 rpm). During tests following the overspeed event the licensee measured the response time of their overspeed trip and found a 2.25 second time delay. This was on Unit 2. Also, TDI has stated that the DGs on an unloaded start from rest will be accelerating at approximately 50 rpm/sec at 350 rpm and accelerating at approximately 100 rpm/sec at 517 rpm. It can be surmised then that a DG without the benefit of a governor would probably be damaged to some extent by the time the overspeed trip would take effect. The Woodward Booster and Cooler are part of the Woodward Governor

assembly used on the Division 1 & 2 DGs. The Booster Servomotor Bulletin, 36684 B, the latest vendor document that the licensee had available on site, does not have any cautions or warnings about purging air. However, Bulletin 36684 J, which is a later issue, contains a caution regarding proper purging of air to prevent possible sluggish governor response. The licensee returned the Woodward governor to the manufacturer for testing, and when tested with an equal amount of oil as found following the overspeed event, the governor was erratic in operation which would probably explain the loss of governor control. The licensee's procedure for changing oil in the Woodward governor is Preventive Maintenance Instruction (PMI) 07-S-24-P75-E001AB-5, Periodic Oil Change of the STBY. EMER. Diesel Woodward Governor Model #EGB-35-C. Paragraph 7.9 fills the governor with new clean oil to the top of the gauge glass and then paragraph 7.10 has the operator turn the governor speed control down to idle speed (300 rpm approximately) and start the engine (DG) unexcited. The procedure does not require purging air from the governor prior to start. It is not clear that the licensee had adequate warning that starting the DG and then venting the Woodard Governor could result in an overspeed event. This appears to be a generic issue which the licensee has initiated action to inform other DG users of the potential for damage.

11. IFI & Unresolved Items (92701)

    a. (Closed) IFI 50-416/85-39-02. The licensee has completed the investigation into the DG overspeed event. This item is discussed in paragraph 10 of this report. This item is closed.

    b. (Closed) IFI 50-416/85-06-05. The inspector has received a response regarding the adequacy of Technical Specifications. This item is closed.

    c. (Closed) IFI 50-416/85-14-01. The licensee has submitted an updated FSAR. This item is closed.

    d. (Closed) IFI 50-416/85-14-02. The inspectors have reviewed the licensee's actions addressing the concerns associated with this followup item. Reviews of subsequent post trip analysis indicate that these actions were adequate to prevent further occurrence. This item is closed.

12. License Condition

    The Grand Gulf operating license, NPF-29, paragraph 2.C. (9) requires that prior to startup following the first refueling outage, MP&L shall complete structural modifications, if required, as a result of the NRC staff's completion of its review of the licensee's response to IE Bulletin 80-11. By letter dated November 4, 1985, from Mr. T. Novak, NRC to Mr. J. Richard, MP&L, the NRC stated that the GGNS submittals were acceptable and license condition 2.C.(9) has been fulfilled.

    In the areas Inspected, no violations or deviations were identified.