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

Report No.: 50-416/85-46

Licensee: Mississippi Power And Light Company
Jackson, MS 39205

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

Facility Name: Grand Gulf Unit 1

Inspection Conducted: December 21, 1985 - January 17, 1986

Inspectors: HC Dance/for 2/4/86
R. C. Butcher, Senior Resident Inspector Date Signed

HC Dance/for 2/4/86
J. L. Caldwell, Resident Inspector Date Signed

Approved by: HC Dance 2/4/86
H. C. Dance, Chief, Project Section 2B Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine inspection entailed 177 resident inspector-hours at the site in the areas of Operational Safety Verification, Maintenance Observation, Surveillance Observation, Cold Weather Preparations, Reportable Occurrences, Operating Reactor Events, and Inspector Followup and Unresolved Items.

Results: Violation - Three examples of failure to follow procedures for placing shutdown cooling in effect, to maintain reactor vessel water level and feedwater pump discharge pressure as required.

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## 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, Technical Support Superintendent
   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
   J. Mueller, Mechanical 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 January 17, 1986, 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. 416/85-46-01, Violation. Failure to follow procedures for placing shutdown cooling in effect when in operational condition 2. Failure to follow procedures to maintain reactor vessel water level and reactor feed pump discharge pressure as required. (Paragraph 5.a and 9.e)

   b. 416/85-46-02, IFI. Licensee prepare comprehensive procedure for placing shutdown cooling in effect when in operational condition 2. (Paragraph 5.a)

   c. 416/85-46-03, IFI. Incorporate requirement to declare affected Emergency Core Cooling System (ECCS) inoperable when minimum flow path is unavailable. (Paragraph 5.b)

   d. 416/85-46-04, IFI. Documentation of significant events that are not reportable by the licensee. (Paragraph 9.a)

e. 416/85-46-05, IFI. Prepare comprehensive cold weather preparations procedure. (Paragraph 11)

3. Licensee Action on Previous Enforcement Matters (92702)

   a. (Closed) Deviation 416/85-28-01. The Surveillance Procedure 06-OP-1C61-R-0002 committed to be issued by August 31, 1984 in letter AECM 84/0418 dated August 20, 1984 was issued on August 30, 1985. This item is closed.

   b. (Closed) Violation 416/85-22-01. The inspectors reviewed the corrective actions taken by the licensee and found them acceptable. Subsequent inspections have not revealed any recurrence of this violation. This item is closed.

4. Unresolved Items

   Unresolved items were not identified during this inspection.

5. Operational Safety Verification (71707)

   The inspectors kept 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, selected ESF system were 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. On December 22, 1985, the licensee initiated a reactor startup following an outage to repair some condenser tube leaks. At 11:27 a.m., the reactor mode switch was placed in startup (operational

condition 2). Control rod withdrawal was initiated at 11:31 a.m. At 12:25 p.m. with the reactor subcritical, the B Residual Heat Removal (RHR) system was placed in the shutdown cooling mode to maintain plant conditions. This made the Low Pressure Coolant Injection (LPCI) B system inoperable and the plant entered action statement b.1 of Technical Specification (TS) 3.5.1 which states "with either LPCI subsystem B or C inoperable, restore the inoperable LPCI subsystem B or C to operable status within 7 days." The licensee used the provisions of a special test exception in TS 3.10.5, Training Startups, which permits one loop of RHR to be aligned for shutdown cooling for training startups provided the reactor vessel is not pressurized, thermal power is less than or equal to 1% of rated thermal power and reactor coolant temperature is less than 200°F.

A similar reactor startup on June 6, 1985 was discussed in Report 85-20 and the licensee had committed to referencing the requirements of TS 3.10.5 in their procedure to ensure the operators are aware of the requirements. This was inspector followup item 416/85-20-03. The licensee revised Integrated Operating Instruction (IOI) 03-1-01-1, Rev. 30, paragraph 2.1.11 to state "with shutdown cooling inservice, while performing cold criticalities, limit the reactor coolant temperature to less than or equal to 150°F and thermal power less than or equal to 1%." Paragraph 5.26 states "If reactor startup is for training purposes per TS 3.10.5, or cold criticals begin recording reactor vessel unpressurized, thermal power and reactor coolant temperature on Data Sheet III. These readings must be taken hourly."

At 12:15 p.m., the A and B recirculation loop suction temperatures were 189°F and 188°F respectively which exceeds the temperature limits specified in IOI 03-1-01-1. At 2:00 p.m., the A and B recirculation loop suction temperatures were both 159°F indicating a cooldown of 30°F (which is an appreciable positive reactivity addition) in less than two hours. During this period, data sheet III of IOI 03-1-01-1 was not being used. TS 6.8.1 requires written procedures be established, implemented and maintained covering the procedures recommended in Appendix A of Regulatory Guide (RG) 1.33. RG 1.33 requires written procedures for plant operation from hot standby to minimum load. The failure to follow IOI 03-1-01-1 is a Violation (416/85-46-01). Other examples of procedural violations are discussed in paragraph 9.e.

Discussions with the Manager, Plant Operations, indicate that he thoroughly discussed the above evolution with the on shift operations personnel and they were aware of the plant conditions. The resident inspector contacted Region II supervision and NRR regarding the incorporation of shutdown cooling during startup for other than training or cold criticalities. Certain other facility TS have provisions for operating shutdown cooling while in operational condition 2 (startup) and, if properly controlled, such operation is permissible. The resident also confirmed that NRC does not consider all potential plant evolutions not specifically prohibited and/or discussed in TS to be permissible. A conservative approach to plant operations is recommended when off normal operational conditions arise.

Although IOI 03-1-01-1 has a few specific TS limitations for having shutdown cooling inservice when in mode 2, it appears a specific detailed procedure giving precautions, i.e., avoid pulling control rods while cooling down, etc, would be necessary to perform this evolution in the future. The licensee committed to prepare a comprehensive procedure for placing shutdown cooling in effect when the plant is in operational condition 2 with appropriate precautions and limitations by February 2, 1986. This will be Inspector Followup Item (416/85-46-02).

b. IE Information Notice 85-94, Potential for Loss of Minimum Flow Path Leading to ECCS Pump Damage During a LOCA, was discussed with the licensee. Although the review of IE Notice 85-94 is not complete the Manager, Plant Operations stated that any time the minimum flow provisions might not be available for the Emergency Core Cooling Systems (ECCS), the affected ECCS should be declared inoperable. Until incorporated into plant procedures or position statements, this will be Inspector Followup Item (416/85-46-03).

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.

One event occurred regarding the inadvertant starting of the Division 3 diesel generator. This event is discussed in Paragraph 9.d.

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.

On January 10, 1986, the licensee identified two containment penetration isolation valves, E61F009 and E61F010, which are used for containment purge and which have not been local leak rate tested every 92 days as required. TS 4.6.1.2.j states that purge supply and exhaust isolation valves with resilient material seals shall be tested and demonstrated operable per surveillance requirement 4.6.1.9.2. TS 4.6.1.9.2 states that at least once per 92 days each containment purge supply and exhaust isolation valve with resilient material seals shall be demonstrated operable by verifying that the measured leakage rate is less than or equal to 0.01 La when pressurized

to Pa. Containment penetration 65 isolation valves E61F009 and F010 are the suction valves for the containment purge system. E61F009 and F010 were last local leak rate tested on October 11, 1984 but they were included as boundary valves in the integrated leak rate test conducted during the October 11, 1985 thru December 7, 1985 outage. The licensee immediately conducted a local leak rate test which the valves successfully passed. The licensee has now included the above valves in their program to be local leak rate tested every 92 days. Failure to test the valves as required is a violation. The inspector's review determined that this matter met the criteria of 10 CFR 2, Appendix C for licensee identified violations and therefore will not be cited.

No other violations or deviations were identified.

8. Reportable Occurrences (90712 & 92700)

The below listed event reports were reviewed to determine if the information provided met the 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 Reports (LERs) are closed.

| LER No. | Event Date | Event |
|---|---|---|
| 85-44 | November 18, 1985 | Control Room Emergency Filtration System Actuates on False Chlorine Signal. |
| 85-47 | December 16, 1985 | Control Room Emergency Filtration System Actuates on False Chlorine Signal. |
| *85-45 | December 5,1985 | Valve Limit Switches Found In Noncompliance With 10 CFR 50.49 |

See Paragraph 10.d for a discussion of LER 85-45.

No violations or deviations were identified.

9. 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.

During the period of December 30, 1985 - January 1, 1986, five events occurred at the Grand Gulf Nuclear Station (GGNS) which resulted in major reductions in power or challenges to safety systems. These events include two trips of the recirculation pumps, two reactor scrams and an inadvertant start of Division 3 Emergency Diesel Generator (EDG). The inspectors reviewed each of these events and a discussion of these events is provided below.

a. The first event which occurred at approximately 11:15 a.m. on December 30, 1985, involved the inadvertant tripping of both recirculation pumps to the Low Frequency Motor Generator (LFMG) set. At the time of the event, the plant was operating at approximately 100% power and Instrumentation and Control (I&C) technicians were performing surveillance procedure 06-IC-1C34-M-0001. During the performance of this surveillance procedure, the recirculation pump trip system received a false low reactor water level trip signal which caused the recirculation pumps to transfer to the LFMG set rapidly reducing reactor power from 100% to approximately 55%. This rapid reduction in power caused vessel water level to increase to approximately 51 inches, just below the high level scram trip, turbine trip and feed pump trip setpoints. The licensee's investigation into the event involved repeating the sequence of events which the I&C technicians performed prior to the recirculation pump trip. This repeat of the I&C technicians actions and the surveillance procedure failed to reproduce the false low water level signal which caused the trip. The licensee has been unable to determine the cause of the recirculation pump transfer to the LFMG Set.

   During the review of this event, the inspectors discovered the licensee had not performed any documentation of the occurrence. A review of the plant requirements for documenting operating events revealed an interpretation problem with the threshold used to determine when an event should be written up and hence evaluated. The licensee agreed that this event should have been documented and has committed to taking the necessary actions to ensure that all significant events will be documented. This will be identified as an Inspector Followup Item (416/85-46-04).

b. The second event which occurred at 7:15 p.m. on December 30, 1985, involved the inadvertant tripping of B recirculation pump using the Anticipated Transient Without a Scram (ATWS) trip function. At the time of the event, the reactor was operating at 80% power recovering from the previous recirculation pump trip discussed above. I&C

technicians were performing surveillance procedure 06-IC-1B21-M-1012, ATWS Reactor Vessel Level/Reactor Pressure Functional Test, when the B recirculation pump tripped. This ATWS trip of B recirculation pump caused reactor power to rapidly decrease to approximately 55% but the plant was able to withstand the transient without shutting down completely. The licensee's investigation into the event involved repeating the I&C technicians actions prior to the event but they were unable to reproduce the inadvertant ATWS trip signal. The cause of this event as well as the previous recirculation pump trip discussed above remain undetermined by the licensee.

c. Scram No. 35. The third event involved a reactor scram from 100% power at 12:51 p.m. on December 31, 1985. Prior to the scram the plant had been receiving low level alarms on the Intermediate Pressure (IP) condenser hotwell but the control room level instrumentation indicated a level well above the low level setpoint. To ensure that an actual low level condition existed operations dispatched I&C technicians to the level instruments to fill and vent their reference legs. Performance of the fill and vent procedure required the automatic level control on the condenser hotwells to be placed in manual since the control signals come from the level instruments. As the I&C technicians were securing from the fill and vent procedure, the condensate pumps tripped due to a low water level signal in the IP condenser hotwell. This trip of the condensate pumps resulted in a loss of feed to the vessel and a low level reactor scram.

It was determined later that an actual low level condition did exist in the IP condenser hotwell. The combination of placing the hotwell level controls in manual and the performance of the fill and vent procedure prior to filling the condenser hotwell to clear the low level alarm caused the low level trip of the condensate pumps.

Just after the scram in response to the decreasing level in the vessel, the operator manually initiated both Reactor Core Isolation Cooling (RCIC) and High Pressure Core Spray (HPCS). These two systems would have automatically initiated if left alone because the vessel level dropped well below their trip setpoint. During the manual initiation of HPCS, the operator noticed that it was taking a long time for the injection valve to open so he opened it manually. An investigation by the licensee determined that the HPCS injection valve failed to open automatically due to a defective relay base. This defective base was an Agastat relay type CR0009 base and problems associated with this base were identified in a General Electric (GE) SIL No. 384 in October 1982 and a NRC IE Information Notice 82-48 in December 1982. The licensee had taken the actions recommended by GE SIL NO. 384 in June of 1983 and replaced all unsatisfactory relay bases on safety related equipment. This particular base has now been replaced with a better type and the injection valve was tested satisfactorily prior to restart.

d. The fourth event which occurred at 10:40 p.m. on December 31, 1985 involved the inadvertant starting of Division 3 Emergency Diesel Generator (EDG). At the time of the event, plant personnel were performing troubleshooting, under Maintenance Work Order (MWO) 58932, to isolate the cause of the HPCS injection valve failure to open automatically. The performance of troubleshooting involved lifting various leads by I&C technicians to prevent automatic initiation of the EDG while checking the operation of the injection valve circuits. However, the technicians overlooked a seal-in relay which would give the EDG a start signal. Since this relay was still in the circuit the trouble shooting not only checked the automatic opening circuit for the injection valve but also automatically initiated the Division 3 EDG. The diesel generator was brought up to speed, loaded, run for 30 minutes and then secured as required. The trouble shooting was then completed without further incident.

e. Scram No. 36. The fifth event which occurred at 9:12 a.m. on January 1, 1986 involved a reactor scram from less than 1% power during a reactor startup. Reactor power was being monitored in the intermediate range with pressure approximately 600 psig. The control room operator received an annunicator indicating a high or low vessel water level condition. The level indication available to the operator consisted of three level meters just above a level recorder. The operator only looked at the level recorder and decided that the high low alarm was due to a high level condition which was normal for this stage of the startup. However, unknown to the operator, the level recorder had stuck and the level meters indicated a decreasing water level. The actual water level finally decreased to the low level scram setpoint and automatically scrammed the reactor. The operator not only missed the decreasing water level but also failed to keep the feed pump discharge pressure 100 psig above reactor pressure as required, which prevented the feed pump from maintaining the vessel water level.

The root cause of this scram was the failure of the operator to monitor all the required instrumentation available to ensure the reactor was maintained in a stable condition. The failure of the operators to monitor the three level meters installed above the level recorder was also identified earlier in the post trip analysis associated with scram number 21. Scram number 21, involved a malfunction of the switch used to select the level instrument channel monitored by the feedwater control system to maintain reactor vessel level. This switch failure caused a decreasing water level signal to the feedwater control system and the level recorder to indicate decreasing level. The operator noticed the level recorder decreasing and feed pump flow increasing to compensate for the level decrease but failed to monitor the three level instruments above the recorder, which indicated actual level was increasing toward the high level scram setpoint. One of the recommendations of the post trip analysis of scram number 21 was that control room operators should compare recorder readings to indicator readings often when monitoring reactor vessel water level. Administrative Procedure (AP) 01-S-06-2, Conduct of Operations, step 6.3.6

requires in part that one licensed operator be dedicated to monitoring important parameters such as water level and pressure during a reactor startup. Licensed operators are also trained to monitor all the instrumentation available when monitoring a parameter. The failure of the operator to monitor all the reactor vessel level instrumentation during startup and in response to a water level annunciator resulted in an automatic scram and will be identified as a second example of Violation (416/85-46-01). See also Paragraph 5.a.

The operator also failed to monitor the feed pump discharge pressure to ensure the feedwater pump was able to maintain vessel water level. Integrated Operating Instruction (IOI) 03-1-01-1, Cold Shutdown to Generator Carrying Minimum Load, step 6.2.14.b requires a feedwater pump be placed in service to maintain feedwater to the vessel and the caution just below step 6.2.14.b requires the feedwater pump turbine speed be increased as necessary to maintain feedwater pump discharge pressure 100 psig above reactor pressure. The failure of the operator to maintain feedwater pump discharge pressure 100 psig above reactor pressure resulted in a reactor scram and will be identified as a third example of Violation (416/85-46-01).

The five events appear to indicate a decreasing trend in performance which could be a precursor to more serious events. The inspector discussed the events and the inspector's concerns with the General Manager. The inspector was told by the General Manager and the Site Director that actions were already being taken to address what they also considered to be an unacceptable trend. Corrective actions were reviewed by the inspector and Region II Management and were considered appropriate at this time.

10. Inspector Followup And Unresolved Items. (92701).

a. (Closed) IFI 416/85-20-03. The startup on December 22, 1985 as discussed in paragraph 5.a of this report addresses the subject of initiating shutdown cooling when in operational condition 2. This item is closed.

b. (Closed) LIC 416/83-SC-01. This event was reported in LER 83-126. LER 83-126 was closed in IE Report 416/84-30. This item is closed.

c. (Closed) IFI 416/85-09-03. Step 8.3.1.1.4.1.d of the GGNS FSAR has been revised to reflect the correct configuration in the plant relating to the initiation logic for Division 1 and Division 2 diesel generators. This item is closed.

d. (Closed) Unresolved Item (416/85-45-10). On December 2, 1985, Grand Gulf Nuclear Station (GGNS) maintenance personnel discovered several environmentally qualified valves with limit switches that appeared to be unqualified. The maintenance personnel documented their findings an a Material Nonconformance Report (MNCR) and submitted this MNCR to the Nuclear Plant Engineering (NPE) department for evaluation. On

December 5, 1985, NPE determined that some of the limit switches were required to be qualified and were still evaluating the others. The plant staff then notified the NRC of the identification of these unqualified limit switches. The plant was in cold shutdown at the time of discovery of the unqualified limit switches. Walkdowns were performed by plant staff of other environmentally qualified equipment and no other discrepancies were discovered. The licensee concluded from the walkdowns that a generic breakdown of their Environmental Qualification Program did not exist. The licensee also replaced or otherwise qualified all of the suspected limit switches prior to restart on December 7, 1985.

Subsequent evaluations by NPE determined that of the 17 suspected limit switches only 13 were required to be qualified. These 13 limit switches only provided indication or inputs to computer points and their failure could not affect the operation of their associated valves. This item is closed.

e. (Open) Unresolved Item 416/85-45-01. By memo dated December 9, 1985, the plant requested Nuclear Plant Engineering (NPE) evaluate the low flow for Standby Service Water (SSW) system B to certain electrical switchgear room coolers. NPE was specifically asked if the rise in temperature would be significant enough to cause a safety system inoperability, a loss of a safety function, or in anyway significantly compromise plant safety? NPE's response stated that the Material Nonconformance Report (MNCR) reported low flow conditions on the B loop of SSW and the redundant A train coolers are available for cooling their respective switchgear rooms. Also per Final Safety Analysis Report (FSAR) Table 9.4-8, if a cooler loses its cooling capability resulting in a loss of operation of electrical switchgear in that room, the other ESF electrical switchgear located in other rooms is available for operation. The plant then decided to check the flow capability of the A SSW system to the electrical switchgear room coolers and found that the A SSW system also experienced low flows. NPE was verbally requested to evaluate the additional information and by memo dated December 20, 1985. NPE concluded that the effect of low SSW flow to the electrical switchgear room coolers would not have resulted in the rooms exceeding 140°F (which is the upper temperature limit for the safety related equipment located in the ESF switchgear rooms). This evaluation took into account the fact that the ceiling of room 1A410 is the roof of the auxiliary building and during winter conditions provides a large area for heat to be lost to the atmosphere. No comment was made regarding the effect of operation in the heat of summer. It appears NPE's original evaluation in response to the plants December 9,1985 memo was very cursory in that no consideration was given to the root cause of the B SSW ESF room coolers low flow (which is the deposit of sand from the Plant Service Water (PSW) system that supplies the ESF switchgear room coolers during normal operations) and which did in fact cause low flow in the A SSW ESF room coolers. The plant staff questioned the operability of the A SSW ESF room coolers which caused them to test the A SSW loop and determine low flow was

present there also. NPE's second evaluation also appears cursory in that it did not address operability during warm weather and failed to address what actions would be necessary to continue operating with the possibility of the ESF room coolers becoming stopped up again. No mention of changing out room coolers, conducting periodic flow tests, or other surveillance methods to ensure operability was discussed. The licensee failed to recognize that FSAR paragraph 9.4.5.4 requires the ESF room coolers be periodically inspected to ensure all normally operating equipment is functioning properly and standby components are periodically tested to ensure system operation. This last item was a deviation in Report 416/85-45.

11. Cold Weather Preparations (71714)

The licensee has initiated certain cold weather protection actions based on past experience. The daily plant work schedule for December 13, 1985 listed several cold weather action items, however the items listed on the work schedule was not complete for all affected areas. The licensee's cold weather preparations are not procedurally defined nor are there any cold weather periodic maintenance requirements specified to ensure operability. The resident inspector has discussed this with plant management and the licensee has committed to prepare a comprehensive procedure, including necessary periodic maintenance requirements, for cold weather preparations by February 15, 1986. This will be an Inspector Followup Item (416/85-46-05).