UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

Report Nos.: 50-321/83-27 and 50-366/83-29

Licensee: Georgia Power Company
P. O. Box 4545
Atlanta, GA 30302

Docket Nos.: 50-321 and 50-366

License Nos.: DPR-57 and NPF-5

Facility Name: Hatch 1 and 2

Inspection at Hatch site near Baxley, Georgia

Inspectors: John F. Rogge for | Nov 8, 1983
R. V. Crlenjak | Date Signed

John F. Rogge for | Nov 8, 1983
P. Holmes-Ray | Date Signed

John F. Rogge | Nov 8, 1983
J. F. Rogge, Project Engineer | Date Signed

Approved by: V. W. Panciera | 11/8/83
V. W. Panciera, Chief, Project Section 2B | Date Signed
Division of Project and Resident Programs

SUMMARY

Inspection on August 29 - September 30, 1983

Areas Inspected

This inspection involved 222 inspector-hours on site in the areas of Technical Specification compliance, operator performance, overall plant operations, quality assurance practices, station and corporate management practices, corrective and preventive maintenance activities, site security procedures, radiation control activities, surveillance activities, and TMI Task Action Plan Items.

Results

Of the areas inspected, one violation was identified (Improper Plant Review Board review of a procedure resulting in Technical Specification requirements not being implemented - Paragraph 7).

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   H. C. Nix, Site General Manager
   *T. Greene, Deputy Site General Manager
   S. Baxley, Superintendent of Operations
   *C. Belflower, QA Site Supervisor
   *B. Tipps, Superintendent of Regulatory Compliance
   P. D. Rice, General Manager, QA & HP

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

   *Attended exit interview

2. Exit Interview

   The inspection scope and findings were summarized on August 26 and September 30, 1983, with those persons indicated in paragraph 1 above. NUREG 0737 Item I.C.6 was discussed in detail to insure licensee understanding of the regional position on independent verification. The regional position provided the licensee for their review and guidance is attached to this report.

3. Licensee Action on Previous Enforcement Matters

   Not inspected.

4. Unresolved Items

   Unresolved items were not identified during this inspection.

5. Plant Tours (Units 1 and 2)

   The inspectors conducted plant tours periodically during the inspection interval to verify that monitoring equipment was recording as required, equipment was properly tagged, operations personnel were aware of plant conditions, and plant housekeeping efforts were adequate. The inspector also determined that appropriate radiation controls were properly established, critical clean areas were being controlled in accordance with procedures, excess equipment or material is stored properly, and combustible material and debris were disposed of expeditiously. During tours, the inspector looked for the existence of unusual fluid leaks, piping vibrations, pipe hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment, and instrument calibration dates. Some tours were conducted on backshifts.

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

6. Plant Operations Review (Units 1 and 2)

The inspectors, periodically during the inspection interval, reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs, operating orders, standing orders, jumper logs and equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. During normal events, operator performance and response actions were observed and evaluated. The inspectors conducted random off-hours inspection during the reporting interval to assure that operations and security remained at an acceptable level. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures.

During this reporting period, backshift and weekend surveillance of control room activities was increased. Special consideration was given to the items mentioned in IE Circular 81-02. Control room activities were found to be satisfactory.

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

7. Technical Specification Compliance (Units 1 and 2)

During this reporting interval, the inspector verified compliance with selected limiting conditions for operations (LCO's) and results of selected surveillance tests. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, switch positions, and review of completed logs and records. The licensee's compliance with selected LCO action statements were reviewed on selected occurrences as they happened.

LER 366/83-39 stated that Procedure HNP-2-3901, Relief Valve Operability, was revised April 1, 1982, to change the method of verification during the functional testing of the ADS valves. This change (Rev. 7) provided for monitoring of safety relief valve tailpipe pressure sensors. The Technical Specification 4.5.2 requires that the ADS shall be demonstrated OPERABLE at least once per 18 months by:

a. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

b. Manually opening each ADS valve when the reactor steam dome pressure is $\geq$ 100 psig and observing that either:

(1) The control valve or bypass valve position responds accordingly, or

(2) There is a corresponding change in the measured steam flow.

Although the monitoring of the tailpipe pressure sensors will indicate the opening of the relief valve, Technical Specifications do not recognize this method.

On June 14, 1983, the licensee became aware of the above error and on July 8, 1983, the procedure was revised to comply with Technical Specifications. Revisions 7, 8, 9, 10, and 11 had cleared the PRB with this problem undetected. This is a violation 366/83-29-01.

This violation closes Unresolved Item 366/83-26-03.

8. Physical Protection (Units 1 and 2)

The inspector verified by observation and interviews during the reporting interval that measures taken to assure the physical protection of the facility met current requirements. Areas inspected included the organization of the security force, the establishment and maintenance of gates, doors, and isolation zones in the proper condition, that access control and badging was proper, and procedures were followed.

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

9. Review of Nonroutine Events Reported by the Licensee

The following Licensee Event Reports (LERs) were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events which were reported immediately were also reviewed as they occurred to determine that Technical Specifications were being met and that the public health and safety were of utmost consideration. The following LERs are considered closed:

Unit 1 83-35, 57, 58, 63, 65, 66, 67, 68, 69, 70, 71, 73, 75, 76, 77 and 96

Unit 2 83-48, 49, 50, 51, 53, 55, 56, 58, 63, 68, 69, 70, 71, 72, and 73

LER 321/83-96 states that two (inboard and outboard) service air primary containment isolation valves were opened on June 16, 1983, and not closed prior to unit startup on June 18, 1983. Unit 1 Technical Specification 3.7.A.2 requires these valves to be shut. These valves were found to be open on August 27, 1983, when an operator went to open them. The unit had been in power operations with these manual, not instrumented, valves open. Review of the event showed that while the valves were open, both the service air system (100 psi) was applied on the penetration and other valves inside containment were shut. This item will not be cited as a violation as allowed by the NRC enforcement policy for licensee identified items.

10. Verification of the Correct Performance of Operating Activities

The issue of proper independent verification is being reviewed by the resident inspectors. The scope of independent verification was discussed with the licensee and, with the concurrence of Region II, a copy of the Region II position on independent verification was provided to the licensee.

The licensee has recently issued a new procedure for the control of locked valves which has independent verification of those valves. The licensee is also evaluating other independent verification programs. The resident inspectors are monitoring this evaluation and any subsequent changes. The licensee expects to complete this evaluation and have in place any required changes by about April 1984.

11. TMI Action Plan Requirement Followup (Units 1 and 2)

The inspector has reviewed the licensee implementation of the following requirements associated with the NUREG 0737 TMI Action Plan.

I.A.1.3.2.A (Open) Minimum Shift Crew Composition

The licensee has implemented the Minimum Shift Crew Composition in procedure HNP-16. HNP-16 contains two tables which delineate the minimum number of shift personnel required versus various operating conditions of the two units. These tables were found to be consistent with NUREG-0737 except for the condition where no fuel is present in one unit. In this regard, with the fueled unit in condition 4 or 5, three nonlicensed operators are required and with the fueled unit in condition 1, 2 or 3 only two nonlicensed operators are required. NUREG-0737 calls for, with one unit operating, three auxiliary operators (i.e., nonlicensed). This appears to be a typographical error and the licensee is reviewing this item.

Similar tables contained in the Technical Specifications (TS) for Units 1 and 2 were identified to be not consistent with the tables in HNP-16. The licensee has two TS change requests, June 11, 1982 and October 15, 1982, which when approved, will make the TS consistent with HNP-16. The licensee will need to make a correction to this TS request to resolve the nonlicensed operator discrepancy.

II.K.3.18.C (Open) ADS Logic Modifications

This item concerns the selection of alternatives to the present ADS actuation logic and identification of modifications that would eliminate the need for manual actuation to ensure core coverage. In a June 3, 1983 letter, NRC completed its review of a BWR owners group study and found two of the seven options acceptable. This letter requires all licensees to select and provide a schedule for implementation. In a letter dated July 28, 1983, the licensee proposed to use the acceptable method of bypassing of the high drywell pressure permissive after a sustained low water level and the addition of a manual inhibit switch. An analysis is being performed on the option to ensure the bypass timer provides a significant margin above the two minute delay.

II.K.3.21.C (Closed) Restart of Core Spray and Low Pressure Coolant-Injection

In a NRR Safety Evaluation Report (SER) dated June 16, 1982, the evaluation concluded that this modification would result in a net decrease in safety and no modifications are required.

II.K.3.22.B (Open) RCIC Automatic Suction Switchover

This item requires the licensee to complete the automatic switchover modification and change the Technical Specifications. Design Change Request (DCR) No. 81-175 which includes a functional test is complete for both units. TS changes have been submitted, April 22, 1983 for Unit 1, and September 9, 1983 for Unit 2. This item remains open pending approval and issuance of the TS changes.

II.K.3.24 (Closed) Confirm Adequacy of Space Cooling for HPCI and RCIC Systems

The licensee evaluation, dated December 31, 1981, and NRR SER dated August 24, 1982, determined that the design of the HPCI and RCIC support systems, including space coolers, is adequate to sustain a complete loss of offsite power for two hours. A review of the power supplies was also verified during this inspection. This item is closed.

II.K.3.25 (Closed) Effect of Loss of A-C Power on Pump Seals

No modification or further effort is required. Hatch has the Byron Jackson type pumps which were part of the BWR Owner's Group report. NRR completed the Hatch SER, dated November 1, 1982. This matter is considered resolved.

II.K.3.28 (Open) Verify Qualification of Accumulators on ADS Valves

NRR completed an SER, dated September 2, 1983, concluding the licensee has acceptably verified that the accumulators on the ADS valves meet the requirements of this item. This inspection reviewed DCR 80-116 and DCR 80-117, which replaced the check valves from the hard seat to the soft seat type. This item remains open pending approval of TS changes and review of the plant emergency procedures.

ATTACHMENT

NRC REGION II POSITION ON INDEPENDENT VERIFICATION

Item I.C.6 of NUREG-0737, the Clarification of TMI Action Plan Requirements, presented guidance to the licensees on procedures for verifying correct performance of operating activities. All operating reactors were required to respond and commit to item I.C.6. The NRC issued confirmatory orders to most plants which adds regulatory emphasis to this requirement. Licensees have responded in varying degrees and with diverse methods to this requirement. The purpose of this discussion is to outline an acceptable method of performing independent verification.

Item I.C.6 states the following:

(1) In lieu of any designated senior reactor operator (SRO), the authority to release systems and equipment for maintenance or surveillance testing or return-to-service may be delegated to an on-shift SRO, provided provisions are made to ensure that the shift supervisor is kept fully informed of system status.

(2) Except in cases of significant radiation exposure, a second qualified person should verify correct implementation of equipment control measures such as tagging of equipment.

(3) Equipment control procedures should include instructions that control-room operators are to be informed of changes in equipment status and the effects of such changes.

(4) For the return-to-service of equipment important to safety, a second qualified operator should verify proper systems alignment unless functional testing can be performed without compromising plant safety, and can prove that all equipment, valves, and switches involved in the activity are correctly aligned.

Note: A licensed operator possessing knowledge of the systems involved and the relationship of the systems to plant safety would be a "qualified" person.

The requirement applies not only to valves but to breakers, switches, blank flanges, pipe plugs or any component that would, if mispositioned, degrade a safety function or present a safety concern.

Item (4) states that when returning to service equipment that is important to safety an independent verification should be performed, unless it is possible to functionally test the equipment. It is generally preferable to perform a functional test to demonstrate operability, but this is not always possible.

Functional tests used in lieu of independent verification must be examined to assure they are valid. For example, performing a normal surveillance by running a pump on recirc does not suffice to verify correct alignment of all valves in the system.

Independent verification must be independent, i.e., two appropriately qualified individuals, operating independently, will verify that equipment has been properly returned to service. Both verifications are to be implemented by procedure and action documented by the initials or signature of the two individuals performing the alignment and verification.

In certain instances it may be possible to accomplish one verification from observing control room instruments, annunciators, valve position indicators, etc. This is acceptable as long as the control room indication is a positive one and is directly observed and documented, and provides a reliable indication. For example, if an individual is sent out from the control room into the plant to open a manual valve, it is an acceptable independent verification for another control room operator to observe that a control room instrument begins to register flow in the line as a result of the valve being opened, or a control board indication of valve position shifts from closed to open, or an annunciator indicating that the valve is closed, clears and can be reset. The operator must, of course, subsequently document his part of the independent verification.

Questions have arisen as to what areas require independent verification. Item (2) states that all tagging operations will be verified. Particular care must be taken to independently verify the removal of tags to restore equipment to service, but the placing of tags to remove equipment from service must also be independently verified. There have been occurrences at operating reactors in which an "A train" component was declared inoperable and an individual was sent to tag out the equipment, mistakenly operated and tagged the wrong valves and made the redundant "B train" component inoperable, resulting in a complete loss of the safety function in question.

Removal from service for preventive maintenance and repairs is normally accomplished by operations personnel using equipment control tagging procedures. Routine surveillance does not normally employ tagging. Therefore there needs to be independent verification and associated documentation applied to the removal of equipment from, and the restoration of equipment to, service for surveillance.

Clearly, all components which provide a safety function should be independently verified when alignment changes have been made in a mode where the system is required. Similarly, the alignments of safety systems and individual components relating to safety made in preparation for entering a mode in which the systems or components are required, must be independently verified.

Following a plant outage where maintenance is performed, all safety system lineups should be performed using independent verification prior to entering the mode where that equipment is required to be operable.

It is often hard to determine which items require independent verification. Item (4) above specifies that "equipment important to safety" require independent verification. NRC memorandum of November 20, 1981 from Mr. Harold R. Denton, Director of NRR to all NRC personnel defines the following terms.

"Important to Safety" is defined in 10 CFR 50, Appendix A (General Design Criteria) in the first paragraph of "Introduction."

"Those structures, systems, and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public" are "Important to Safety."

This encompasses the broad class of plant features, covered (not necessarily explicitly) in the General Design Criteria, that contributes in an important way to safe operation and protection of the public in all phases and aspects of facility operation (i.e., normal operation and transient control as well as accident mitigation).

"Important to Safety" includes Safety-Grade (or Safety-Related) as a subset.

"Safety-Related" is defined in 10 CFR 100, Appendix A (see sections III.(c), VI.a.(1), and VI.b.(3)) as those structure, systems, or components designed to remain functional for the SSE (also termed 'safety features') necessary to assure required safety functions, i.e.:

(i) the integrity of the reactor coolant pressure boundary;

(ii) the capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) the capability to prevent or mitigate the consequences of accidents which could result in potential off-site exposures comparable to the guideline exposures of this part.

"Safety-Related" is a subset of "Important to Safety." These definitions are helpful but not always definitive. The following guidance will be useful.

Emergency systems that are required to prevent or mitigate a LOCA are "Safety-Related" and "Important to Safety." In general, equipment required to be operable by the Technical Specifications is "Important to Safety." Equipment described in the FSAR and credited with controlling the reactor, preventing or mitigating an accident or transient considered in the FSAR is "Important to Safety." Equipment that the licensee has committed by letter, to the NRC to install, such as TMI Action Item equipment, is "Important to Safety."

There will be a number of exceptions to these guidelines which, in the judgment of the licensee and the NRC, independent verification will not be required. Examples are peripheral support equipment that are often mentioned in the more recent Technical Specifications but do not meet the definition or intent of "Important to Safety." When in doubt, inspectors must use reasonable judgment and counsel with NRC management.

The use of double verification should not be limited to safety systems and mode requirements. If any situation where the consequences of misalignment are extremely severe, a second verification is prudent. There are many situations, particularly in plant effluent system or liquid waste handling, where a second check should be provided.

It is constructive to review recent experiences in the industry that were not fully successful in performing independent verification. One BWR licensee found that, although major valve lineups were required to be independently verified, some routine plant evolutions were not. Following use of an RHR heat exchanger, it was the procedural practice to flush the secondary side with well water to remove brackish water for corrosion control. This operation involved disabling the service water pump, an item required to be operable by Technical Specifications (TS). Although the flushing operation was covered by a normal operating procedure it was not made subject to independent verification and no signoffs were required for individual steps. This resulted in an operator forgetting to properly restore the service water pump to service, causing a TS violation.

A PWR licensee implemented independent verification for tagging operations but left it ambiguous as to the need for item (4) above, during temporary lifts of tags for testing and restoration. Item (4) was not used on a restoration of tags after a temporary lift for hydrostatic testing. The person performing the valve manipulation apparently closed the wrong valves and no one verified the work. This resulted in the total absence of auxiliary feedwater capability for five days while the reactor was operating at full power.

A PWR licensee did not apply item (4) to the restoration of pressure sensing instruments after calibration by instrument technicians. This resulted in a small pipe cap being left off after the calibration of an instrument sensing containment pressure. The reactor was operated at full power with an open pathway from the containment atmosphere to the environment.

Multiple examples have been observed where licensees applied item (4) to valve lineups following major outages with the valve lineups only checking the large major valves in the flow paths and did not check instrument root valves, sensor isolation, equalization valves, or branch flow paths. This has resulted in individual components and whole safety systems being found valved out and inoperable in violation of TS after the reactor has restarted.

Following restart after a refueling outage, a licensee discovered several TS related components inoperable because electrical instrument supply links were left open. The links were apparently opened during the outage by instrumentation personnel to facilitate instrument maintenance. Item (4) was performed on their restoration prior to restart and numerous instruments were found to be inoperable.

It is important that all plant supervisors and operators have the proper attitude toward independent verification and recognize its value to enhanced safety of operation. Licensees often express the concern that independent verification is too time consuming and shows a lack of confidence in operators. This is an understandable sentiment but is shortsighted. Independent verification is simply a recognition that even the best operators will make an occasional error. Where the risks and consequences of such an error are extreme, it is not only common sense to make a second check, it is required by the Nuclear Regulatory Commission.

This is one of the most important and potentially beneficial requirements resulting from the TMI Action Plan. A large number of escalated enforcement actions since TMI involve events that could have been prevented had the licensee adequately applied independent verification. The NRC will meticulously enforce this requirement.