



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

Report Nos.: 50-321/90-20 and 50-366/90-20

Licensee: Georgia Power Company
P.O. Box 1295
Birmingham, AL 35201

Docket Nos.: 50-321 and 50-366 License Nos.: DPR-57 and NPF-5

Facility Name: Hatch Units 1 and 2

Inspection Conducted: September 15 - October 20, 1990

Inspectors: S E Sparks, Jr. 11-13-90
Leonard D. Wert, Jr., Sr. Resident Inspector Date Signed

S E Sparks, Jr. 11-13-90
Randall A. Musser, Resident Inspector Date Signed

Approved by: Kenneth E. Brockman 11-13-90
Kenneth E. Brockman, Chief, Project Section 3B Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, announced inspection involved inspection on site in the areas of operations including: two Unit One scrams; Main Steam Line Radiation Monitor Trip Settings and Setpoint controls; surveillance testing including Diesel Generator bus energization time testing; maintenance activities; Three Mile Island Action Items; and, review of open items.

Results: One violation was identified involving a failure to properly set the Main Steam Line Radiation Monitor trip setpoints. (paragraph 2c.)

The following non-cited violation was identified and reviewed during the inspection: NCV 50-366/90-02: Inadequate Isolation System Response Time/Diesel Generator Surveillance Procedure. (paragraph 3b.)

A brief overview audit of instrumentation and alarm setpoint controls was performed. The review indicated that the setpoint control program is adequate and effective. (paragraph 2d.)

REPORT DETAILS

1. Persons Contacted

Licensee Employees

- C. Coggin, Training and Emergency Preparedness Manager
- D. Davis, Plant Administration Manager
- D. Edge, Nuclear Security Manager
- P. Fornel, Maintenance Manager
- O. Fraser, Safety Audit and Engineering Review Supervisor
- G. Goode, Engineering Support Manager
- *M. Googe, Outages and Planning Manager
- *J. Hammonds, Regulatory Compliance Supervisor
- *J. Lewis, Operations Manager
- *C. Moore, Assistant General Manager - Plant Support
- *D. Read, Assistant General Manager - Plant Operations
- *H. Sumner, General Manager - Nuclear Plant
- *S. Tipps, Nuclear Safety and Compliance Manager
- R. Zavadoski, Health Physics and Chemistry Manager

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

NRC Resident Inspectors

- *L. Wert
- *R. Musser

NRC management/officials on site during inspection period:

- K. Brockman, Chief, Reactor Projects Section 3B, Region II
- A. Herdt, Chief, Reactor Projects Branch 3, Region II

- * Attended exit interview

Acronyms and initials used throughout this report are listed in the last paragraph.

2. Plant Operations (71707)

- a. Unit One operated at power until a scram occurred during power decrease for a planned shutdown on October 6, 1990. A short maintenance outage, primarily for recirculation pump seal work, was completed. After return to rated power, an additional scram occurred on October 15, 1990. Details of Unit One operations are discussed in paragraph 2b. Unit Two operated at power during the entire reporting period.

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, technical specifications, and administrative controls. Control room logs, shift turnover records, temporary modification logs, LCO logs

and equipment clearance records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, I&C, and NSAC personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and on night shifts, during weekdays and on weekends. Observations included control room manning, access control, operator professionalism and attentiveness, and adherence to procedures. Instrument readings, recorder traces, annunciator alarms, operability of nuclear instrumentation and reactor protection system channels, availability of power sources, and operability of the safety parameter display system were monitored. Control Room observations also included ECCS system lineups, containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls. Numerous informal discussions were conducted with the operators and their supervisors. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's administrative procedures. The complement of licensed personnel on each shift met or exceeded the requirements of TS.

Several safety-related equipment clearances that were active were reviewed to confirm that they were properly prepared and executed. Applicable circuit breakers, switches, and valves were walked down to verify that clearance tags were in place and legible and that equipment was properly positioned. Equipment clearance program requirements are specified in licensee procedure 30AC-7PS-001-05, "Control of Equipment Clearances and Tags." No major discrepancies were identified.

Selected portions of the containment isolation lineup were reviewed to confirm that the lineup was correct. The review involved verification of proper valve positioning, verification that motor and air-operated valves were not mechanically blocked and that power was available (unless blocking or power removal was required), and inspection of piping upstream of the valves for leakage or leakage paths.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

- Reactor Buildings
- Station Yard Zone within the Protected Area
- Turbine Building
- Intake Building
- Diesel Generator Building
- Fire Pump Building
- Recombiner Building
- Central and Secondary Alarm Stations

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

The inspectors participated as observers and evaluators in the annual evaluated emergency planning exercise which was conducted on September 27, 1990. Details of the exercise and results of the evaluation are contained in Inspection Report 50-321,366/90-19.

On September 26, 1990, an inspector attended a scheduled PRB meeting. Included in the items specifically addressed during the meeting were two SORs and several procedural changes. Of approximately 75 items submitted for the PRB to review, about six were specifically addressed in detail at the meeting. The remaining items had been reviewed by the PRB members prior to the meeting and no comments or concerns had been noted. Both the discussions that were held during the meeting and the comment sheets which were reviewed by the inspector indicated that the PRB members' reviews had been sufficiently detailed.

On August 21, 1990, an SAER representative found Warehouse Three unlocked and unattended. Warehouse Three is located outside the protected area and contains special nuclear material in the form of twelve LPRM strings (new). The entrance door into this warehouse was marked "Keep Doors Locked- Special Nuclear Material". Procedure 42FH-ENG-030-0S, Rev. 2: Special Nuclear Material Inventory and Transfer Control, states that Warehouse Three is an ICA and further states that an ICA is an area established for physical and administrative control of SNM. The inspectors discussed the issue of controls of this type of material with the appropriate NRR and Regional personnel. It was determined that since Warehouse Three is within a restricted area (as interpreted from the TS definition of an unrestricted area), there is not a specific regulatory requirement to keep the warehouse doors locked. In discussions with the inspectors, the licensee stated that intentions are to keep the doors secured. One concern that was identified during the inspectors review of this issue was the fact that a SNM inventory in the warehouse was conducted several hours after the door was found unlocked and only after the inspector prompted an inventory. No discrepancies were identified by the inventory. The inspectors will continue to periodically verify SNM storage areas during their tours of the plant.

b. Unit 1 Reactor Scrams (71707) (Unit One)

On October 6, 1990, at approximately 0437, while in the process of shutting down for a planned maintenance outage, Unit 1 automatically scrammed from 22 percent RTP due to a main turbine trip. The turbine trip was caused by high turbine vibration (greater than 12 mils). Prior to the high vibration trip, the main turbine high vibration alarm (vibration above 7 mils) had not been received in the control room. Because of the failure of this alarm, plant operators were not aware of the increased turbine vibration (Turbine vibration was later determined to have been consistently above 7 mils at 0400 on October 6, 1990). Following the scram, reactor water level decreased to approximately 10.5 inches above instrument zero (the scram set point is approximately 12.3 inches above

instrument zero), and was returned to the normal band using reactor feed pumps.

At the time of the scram, operations personnel were investigating why the "Turbine Control Valve Fast Closure and Stop Valve Scram Bypass" annunciator had not been received. This annunciator indicates a condition such that if a turbine trip occurs, a reactor scram will not be automatically initiated (below 30 percent RTP). Operators are trained (on the plant simulator) that a main turbine trip bypass is received when below 30 percent power when increasing or decreasing power. Licensee investigation revealed that the bypass would have occurred between 18 and 22 percent power (on a power decrease), due to the resetting characteristics of the circuitry involved. The circuit performed as expected.

The licensee determined that the cause of the high main turbine vibration was due to a thermal imbalance. More specifically, due to the fact that the steam source valve to MSR "A" and MSR "B" was partially open, and the steam source valve to MSR "C" and MSR "D" was closed, higher temperature steam was entering the turbine from MSR "A" and MSR "B" than from MSR "C" and MSR "D", thus inducing a thermal imbalance and resultant turbine vibration.

Since the licensee had planned a five day maintenance outage, the unit was taken to cold shutdown. The purpose of the outage was to determine and correct the cause of the failure of the first stage of the 1B recirculation pump seal and replace the seal. Additionally, minor BOP repairs (steam leaks, etc.) were to be performed. It was determined that the seal purge lines were crossed (purge supply and return lines were incorrectly connected) during the previous refueling outage. This condition was corrected and a new seal cartridge was installed. Unit 1 reactor startup commenced on October 9, 1990, at 1025, and reached critical status at 0332 on October 10, 1990. The unit was tied to the grid at 0857 on October 11, 1990, and reached rated power on October 12, 1990 at 0510.

On October 15, 1990, at approximately 1520, with Unit 1 operating at RTP (approximately 776 GMWe), the operating shift observed an increase in generator output to approximately 806 GMWe. In conjunction with the increased generator output, numerous feedwater heater alarms were received including low levels in both the "A" and "B" 5th stage heaters. In response to these events, the operating crew initially assumed that a loss of feedwater heating had occurred, thus prompting entry into the AOP covering the loss of feedwater heating transient. As directed by the AOP, a 20 percent power reduction was commenced. The resident inspector was in the control room and observed this event in its entirety.

At approximately 1527, the operators determined that the 2nd stage MSR supply valves (RSSVs) had closed, diverting additional steam to the main turbine, which explained the increased generator output. At this point, the operating crew determined that a loss of feedwater heating event was not in progress, and, therefore, the power reduction was stopped at approximately 82 percent rated

thermal power and 615 GMWe. As a result of the loss of 2nd stage reheat steam, main turbine vibration began to increase. At 1537, the main turbine vibration alarm was received indicating turbine vibration was greater than 7 mils. (Turbine vibration had actually increased to 10 mils on some bearings; therefore, in accordance with the ARP for high main turbine vibration, the operating crew entered a 15 minute time clock to trip the main turbine). At this point, a decision was made to increase power to 700 GMWe (approximately 90 percent RTP). At approximately 1545, with average turbine vibration at about 11 mils (an automatic turbine trip occurs at 12 mils), plant management (the Operations Manager and the acting General Manager were now present in the control room) directed that the main turbine high vibration trip be disabled. This was done to prevent a vibration spike from causing a turbine trip while sustained vibration remained below the trip setpoint. A reactor operator was stationed at the turbine control panel to monitor turbine vibration on the recorder.

At 1557, with vibration still greater than 10 mils, a power reduction from 700 GMWe to 500 GMWe was commenced. At 1603, when main turbine vibration increased to greater than 12 mils, a fast reactor shutdown was ordered. The shift supervisor calmly briefed his crew on the decision to scram the reactor and ensured that each operator was aware of their responsibilities for their assigned location. At 1607, the reactor was manually scrammed. The main turbine was then manually tripped. The lowest water level reached during the transient was approximately 10 inches below instrument zero, or 158 inches above the top of active fuel. Water level was restored using the reactor feed pumps and maintained using feedwater and RCIC. RCIC was manually initiated for level control when the operating crew opened the condenser vacuum breakers so that the main turbine speed would be reduced more rapidly.

Following the shutdown of the unit, an inspection of the main turbine was performed and no visible damage was noted. After an exhaustive investigation, the licensee was unable to determine the cause of the RSSVs going closed. All components which could have failed and caused valve closure were found to be in good working order. The licensee is continuing to evaluate the most probable root cause for this event.

Rod withdrawal for the restart of Unit 1 commenced at 0047 on October 17, 1990, with the unit attaining criticality at 0444. Unit 1 was synchronized with the grid at 2034 on October 17, 1990, and achieved rated thermal power on October 18, 1990 at 1651.

Review of these events by the resident inspectors will remain open pending review of the Event Review Team Reports, the LERs, and the licensee's corrective actions.

c. Main Steam Line Radiation Monitor Trip Setpoints Incorrectly Set (71707) (Unit One)

Since September 1987, the licensee has been injecting hydrogen into the Unit 1 condensate/feedwater systems at the suction of the condensate booster pumps. The purpose of the hydrogen injection system is to reduce free oxygen concentration in the reactor coolant, thus reducing the susceptibility of reactor materials (recirculation piping/reactor internals) to IGSCC. In conjunction with hydrogen injection, oxygen is injected into the offgas flowstream to ensure sufficient oxygen is present to recombine with hydrogen evacuated from the main condenser. The injection of hydrogen increases the MSL radiation levels which consequently affects the MSLRM setpoints. These monitors are utilized to initiate a reactor scram and PCIS Group One isolation at elevated radiation levels.

On September 20, 1990, following repairs to the Unit 1 hydrogen injection system flow controller, preparations to return the system to service had been initiated. As a part of these preparations, the MSLRM setpoints were calculated in accordance with Procedure 62CI-CAL-005-0S and then reset. The adjustments of the setpoints took place at about 0855 EDT on September 21, 1990. At approximately 1629 on September 21, 1990, the hydrogen injection system was returned to service at an indicated hydrogen flowrate of 16 SCFM.

In accordance with 62CI-CAL-005-0S, chemistry technicians take daily readings of the MSLRMs and verify that the Hi-Hi alarm setpoints (the PCIS Group 1 and reactor scram setpoint) are less than 3 times the MSLRM readings. This is required by TS Table 3.2-1 and the procedure. From September 21 to September 25, this comparison was performed using erroneous data. The technicians performing the verifications used a data package that reflected the setpoints in effect prior to the setpoint adjustments performed on September 21, 1990.

On September 25, 1990, at 1040, the Unit 1 Shift Supervisor was informed that the Hi-Hi setpoint for all four MSLRMs was approximately 6 to 7 times the actual full power MSLRM readings. Immediately, all four of the MSLRMs were declared inoperable and an LCO was entered which required a reduction in power and closure of the MSIV's within eight hours if the condition could not be corrected. At approximately 1230, the trip setpoints were readjusted to the correct values and the LCO was cleared.

During the review of this issue by the inspectors, the following observations were noted:

- The chemistry technician had initially identified the discrepancy on the MSLRM setpoints (not within 3 times normal background readings) on September 24, 1990. He failed to inform the Shift Supervisor as required by the procedure he was

utilizing (Procedure 62CI-CAL-005-0S). Although he did inform his supervisor of the problem and a MWO was initiated, proper corrective action was not taken until September 25, after he brought it to the Shift Supervisor's attention.

- Procedure 62CI-CAL-005-0S does not specifically require the chemistry technicians to compare the displayed MSLRM trip settings to the actual MSLRM readings (the settings are only compared to the value listed in the procedure data package). Incorrect data was used from September 21-25, 1990. There is no requirement to change the data package setpoints when the monitors are adjusted.
- Discussions with various personnel indicated that confusion existed in the interpretation of TSs 3.1.A and 3.2 among various SROs. Some SROs erroneously believed that the requirement for a MSLRM trip setting of less than or equal three times full power background did not apply when the hydrogen injection system was in service. Note "c" of TS Table 3.1-1 specifically addresses the hydrogen injection system with respect to the setpoint.
- Since the condenser retubing (titanium tubing replaced the old admiralty brass tubes) during the last Unit 1 refueling outage, the required amount of hydrogen injection for proper protection of the reactor coolant system has decreased from approximately 22 SCFM to 16 SCFM. The hydrogen injection rate dramatically affects MSL radiation levels. Sufficient guidance does not exist in procedure 62CI-CAL-005-0S to properly calculate MSLRM trip setpoints with hydrogen injection in service.

These concerns were discussed with licensee management. The licensee had assigned an Event Review Team to this issue. The team noted most of the above items in its conclusions. Additionally, the team identified that while the injection rate had been set (and the radiation monitor setpoint calculated) for 16 SCFM, problems with the flow controller had resulted in an actual injection rate of only 12 SCFM. This resulted in lower MSLRM readings.

On October 4, 1990, an Operating Order was issued to clarify the required operator's actions concerning MSLRM setpoints during hydrogen injection.

The bases of TS 3.2.A and Section 14.4.2 of the FSAR discuss that the MSLRM initiated closures of the MSIVs limits the activity (released from any failed fuel) that is transferred to the condenser in the event of a control rod drop accident. The bases further state that initiation of MSIV closure at or below the TS setpoint ensures that 10 CFR 100 limits are not exceeded. However, NRR is currently reviewing a generic safety evaluation which would permit removal of the MSIV closure and the reactor scram functions of the MSLRM from TS. General Electric Report (NEDO-31400): Safety Evaluation for Eliminating the BWR MSIV Closure Function and Scram

Function of the MSLRM, concludes that these functions are not required to ensure compliance with 10 CFR Part 100. Additionally, the control rod drop analyses illustrate that fuel failures are not expected to result from rod drop accidents which occur at greater than 10 percent power levels. (This is primarily due to the increased void fraction and doppler feedback at higher power levels). During the time that the MSLRMs were incorrectly set, the unit remained at about 100 percent of rated thermal power.

The failure to properly set the Unit 1 MSLRM Hi-Hi trip setpoint to less than 3 times normal full power background radiation levels is a violation of TS 3.1.A (Table 3.1-1, item 9), 3.2.A (Table 3.2-1, item 4), and 3.2.H (Table 3.2-8, item 5). The failure to properly set the trip setpoints is identified as Violation 50-321/90-20-01; Improperly Set Main Steam Line Radiation Monitors.

One violation was identified.

d. Instrumentation and Alarm Setpoint Controls Audit (71707)

As a result of findings by the EOP followup inspection recently conducted at Plant Hatch (Inspection Report 50-321,366/90-16), the inspectors performed a brief overview audit of setpoint controls. The team had noted that several operator action setpoints listed in the EOPs did not accurately reflect actual plant setpoints and appeared to be incorrect values. A random sampling of setpoints tested in the control room ARPs was selected from each unit. These setpoints were compared to those values in the plant setpoint index, the applicable calibration procedure, and the appropriate TS requirements. In all cases, the setpoints listed agreed with the setpoint index values. The inspector also reviewed many of the calibration procedures to ensure setpoints were appropriately calculated and maintained. Two setpoints which had recently been affected by completion of DCRs were among those sampled and had been correctly changed to the new values. All setpoints accurately reflected TS requirements.

The inspection indicated that the overall plant setpoint controls program is adequate and effective.

3. Surveillance Testing (61726)

- a. Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable, and systems restoration was completed.

The following surveillances were reviewed and witnessed in whole or in part:

1. Diesel Generator 1A Monthly Test, in accordance with procedure 34SV-R43-001-1S, Rev. 8.
 2. RHR Valve Operability, in accordance with procedure 34SV-E11-002-1S, Rev. 6.
- b. Emergency Diesel Generator (EDG) Bus Energization Times Longer Than Expected (61726)

In January 1990, the licensee submitted a proposed TS change which involved EDG testing. This change would include a new requirement to measure emergency bus energization time (time from EDG initiation to the energization of the bus by the EDG output breaker) during the 18 month surveillance testing. Existing TS (specifically 4.9.A.2.a.2 for Unit 1 and 4.8.1.1.2.b for Unit 2) require timing from EDG initiation to reaching synchronous speed and verification that the EDG does tie to the emergency bus. The principle time difference between reaching speed/voltage and energizing the bus is caused by a voltage permissive time delay relay (Westinghouse CV-7 Relays). This relay actuates upon the EDG reaching proper voltage and after a time delay permits closure of the EDG output breaker.

During on site efforts to develop the procedures to implement the proposed TS change, the licensee determined that due to the time delay settings of the CV-7 relays and the fact that the EDG bus energization time had not been part of the surveillance procedure, the 12 second bus energization time utilized as an assumption in the HELB analysis may have been exceeded. FSAR Table 8.4-4 (Unit 1) and Table 8.3-3 (Unit 2) state that power is to be applied to the 600V and 4kV load centers and isolation valve motors within 12 seconds of a LOCA or a LOSEP signal. Additionally, the proposed TS limit of 12 seconds on EDG bus energization times might not be met.

This situation was discussed with the inspectors and regional management in August, 1990. Two special test procedures: 42SP-072090-0I-1-1S: "Diesel Generator 1A, 1B, and 1C Data Collection" and 42SP-072690-0I-1-2S: "Diesel Generator 2A, 2B, and 2C Data Collection" were developed to measure the time from EDG start until the EDG output breaker received a close permissive signal. Also, the licensee obtained an assessment of the effect of increasing the 12 second input value of the HELB analysis. This assessment was performed by the A/E and reviewed by the NSSS vendor. It was completed on August 3, 1990, and concluded that increasing the subject time interval to as high as 19 seconds would not significantly effect the results of the HELB analysis. The current LOCA analysis for Hatch was approved by the NRC in 1987 and utilized a 24 second energization time. Plans were made to measure the actual emergency bus energization times for each EDG in late August.

At approximately 1330 on August 29, 1990, the resident inspector questioned the licensee about the status of the timing test on the "2A" diesel generator (the first to be tested). He was informed that earlier in the morning the test had been run and a time of 23 seconds had been obtained. The inspectors questioned the operability of the "2A" EDG and also discussed the possibility that all the EDGs may have such long energization times. At 1630, the inspectors were provided a copy of the above assessment which concluded that up to a 19 second delay was acceptable in the HELB analysis. Due to the potential significance of the issue, discussions were held with Region II management and NRR personnel. Later that evening, further investigation by the licensee revealed an error had been made in interpreting the test results and the actual time was about 18.5 seconds. On the morning of August 30, the test results and details of the initial erroneous conclusion were discussed with the inspectors. Meanwhile, since the special test procedure specified a 12 second acceptance criteria, a deficiency card had been written, MWO's initiated and a DCR implemented to reset the time delays of the "2A" EDG. After several delays due to problems with the "2A" EDG governor system, the bus energization time was measured as 9.6 seconds, well within the 12 second criteria. Additionally, the licensee requested that the above discussed operability assessment be revised to consider a delay time of bus energization to as long as 24 seconds. On September 12, 1990, a safety evaluation was completed on the revised assessment which concluded that a 24 second emergency bus energization time was acceptable. This was provided to the inspectors on September 19, 1990.

During the period between August 30 and September 3, 1990, the remaining four EDGs were tested. These diesels also would not have energized their buses within 12 seconds. The longest time measured was 22.1 seconds on the "1A" EDG on September 1, 1990. By September 3, 1990, all of the diesel generator's undervoltage relays had been reset and the energization times verified by testing to be within the 12 second criteria. LER 50-321/90-17, voluntarily submitted by the licensee, addresses this issue and contains further details.

During followup analysis, the licensee determined (actually identified by PRB review of the safety analysis) that Unit 2 TS Table 3.3.2-3 had been violated. Table 3.3.2-3 lists "Isolation System Instrumentation Response Time" limits for the various primary and secondary containment isolation actuation instrumentation. The table states that isolation actuation instrumentation response time is to be measured and recorded as part of "isolation system response time". For 10 of the instruments, the instrumentation response times specified are the accident analysis assumed diesel generator start delay times (12 seconds) and an instrument delay time (1 second). The definition section of the Unit 2 TS states that "Isolation System Response Time" is that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays where applicable.

In summary, the "isolation system instrumentation response times" are to be added to valve movement times (Tables 3.6.3-1, 3.6.5.2-1, and 3.9.5.2-1) to obtain the "isolation system response times." The isolation system instrumentation response times had not been properly measured previously since the diesel generator delays were not measured. Additionally, the CV-7 relays were not set properly. When the delay time was measured, the isolation system instrumentation response times exceeded the Table 3.3.2-1 times. The licensee also determined the system response times required by TS 4.3.3.3 were not being determined correctly in that emergency bus energization times were not being included in the ECCS response times. The licensee promptly adjusted all the relays such that time from diesel generator start to output breaker closure is less than 12 seconds. This along with the fact that the licensee has completed a safety evaluation and analysis to support an extension of diesel generator delay time to as far as 24 seconds, reduces the safety significance of the times exceeding the response times listed in the TS. However, the time limits listed in TS 3.3.2-3 were exceeded and in fact were not being properly measured due to inadequate surveillance procedures.

During the development and subsequent review of this issue, one item which caused the inspectors some concern was that the completion of the safety assessment of energization times up to 24 seconds seemed excessively delayed. On September 1, the "1A" EDG tested at 22.1 seconds. Although the relay was promptly reset such that the energization time was reduced to within 12 seconds, it was not until September 12, 1990, that a safety evaluation stating that the 22 seconds was acceptable from an HELB analysis viewpoint was completed.

A primary underlying cause of this issue was the fact that the time delay setting of the CV-7 undervoltage relays had not been properly specified or controlled. The inspectors requested the licensee review any other safety related applications of similar relays to ensure that those relays were properly set. The licensee checked approximately 70 applications of relays. The investigation indicated that there was no other safety related application of a CV-7 relay onsite in which the time delay setting would be critical in the functioning of a system.

The fact that the undervoltage relay time was not being measured was identified by the licensee. The inspectors were informed in early August. A special test procedure was developed to measure this time and the relays were adjusted to within limits in a timely manner. The licensee reported the fact that the diesel delay times had exceeded 12 seconds by voluntary LER and addressed the inadequate surveillance aspects in LER 50-366/90-007. This licensee-identified violation is not being cited because criteria specified in Section V.G of the NRC Enforcement Policy were satisfied. This issue will be followed as NCV 50-366/90-20-02: Inadequate Isolation System Response Time/Diesel Generator Surveillance Procedures.

One NCV was identified.

4. Maintenance Activities (62703)

- a. Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

The following maintenance was reviewed and witnessed in whole or in part:

1. Adjustment of the Main Steam Line Radiation Monitor Setpoints in accordance with MWO 1-90-6432 and 57SV-CAL-005-05, P. 4.
2. Mechanical seal pressure indication for the 1B Recirculation Pump, in accordance with MWO 1-90-6545 and 42SP-070390-OY 1-1S.

No violations or deviations were identified.

5. Three Mile Island Action Items (NUREG 0737) (TI 2515/65)

During the report period, the SIMS status of generic issues with TI guidance available was reviewed by the inspectors and regional personnel. Several administrative issues were identified and corrected. Additionally, TMI item II.K.3.19, which is not applicable to the Hatch units, did not list a reference inspection report number. Item II.K.3.19 concerns the installation of interlocks to assure that at least two recirculation loops are open for recirculation flow during all modes other than in cold shutdown. This requirement applies to BWRs without jet pumps and addresses a level indication concern in that type of plant under certain alignment conditions. Hatch units 1 and 2 are of the BWR 4 design (jet pumps utilized). Item II.K.3.19 is not applicable to Hatch and is closed. This inspection report will be listed as supporting documentation on the closeout of this item.

6. Inspection of Open Items (92700) (90712) (92701)

The following items were reviewed using licensee reports, inspection, record review, and discussions with licensee personnel, as appropriate:

- a. (Closed) URI 321,366/89-20-01: Timeliness of NRC Physicals for Licensed Operators. This URI addressed the licensee's practice of tracking operator physical exam dates by the license expiration date as opposed to the previous physical exam date. This practice resulted in several licensed operators receiving their physicals at

a time in excess of two years from their previous physical exam. At the time of this inspection, all operator physical exams had been performed within the last two years.

On August 31, 1989, licensee policy with respect to operator physicals was changed to be that all future NRC physical exams would be completed biennially on or before the date of the previous physical exam. Subsequent to these findings and corrective actions, the NRC staff evaluated this issue and interpreted 10 CFR Part 55.21 as follows: The medical examination shall be completed by the end of the calendar month during which the previous examination was completed two years earlier. On October 15, 1990, the licensee issued Rev. 3 to procedure 72TR-TRN-002-05, "License Requalification Training Program," which conforms to the NRC interpretation of 10 CFR Part 55.21. Based on these actions this item is closed.

- b. (Open) LER 50-366/90-07: Personnel Error Results in Inadequate Procedure and Missed TS Surveillance. This LER was issued by the licensee in correspondence dated October 12, 1990. It addressed the issue of inadequate surveillance testing of the emergency diesel generators and time response testing. Specifically, response time testing was not properly performed. Paragraph 3b of this report discusses the inspectors review of this issue. NCV 50-366/90-20-02: Inadequate Isolation System Response Time/Diesel Generator Surveillance Procedures will also be utilized to follow this issue. This LER remains open.

7. Evaluation of Licensee Quality Assurance Program Implementation (35502)

A mid-SALP review was conducted during the September 18, 1990, QPPR meeting. Each SALP category was evaluated by reviewing inspection reports, LERs, past SALP findings, the OIL, licensee corrective actions to NRC findings, and the input from the resident inspector staff.

No significant trends were identified in any of the SALP categories that would require a change to the current Master Inspection Plan. The completion of all core inspection modules appeared to be on schedule. No additional inspection activities were identified as needing to be performed within this SALP period.

8. Exit Interview (30703)

The inspection scope and findings were summarized on October 22, 1990, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection

findings. The licensee did not identify as proprietary any of the material provided to, or reviewed by, the inspectors during this inspection.

Item Number	Status	Description and Reference
50-321/90-20-01	Opened	VIOLATION - Improperly Set Main Steam Line Radiation Monitors (paragraph 2c)
50-366/90-20-02	Opened and Closed	NCV - Inadequate Isolation System Response Time/Diesel Generator Surveillance Procedures (paragraph 3b)
50-321,366-89-20-01	Closed	URI - Timeliness of NRC Physicals for Licensed Operators (paragraph 6a)

8. Acronyms and Abbreviations

A/E - Architect Engineer
 AOP - Abnormal Operating Procedure
 ARP - Annunciator Response Procedure
 BOP - Balance of Plant
 BWR - Boiling Water Reactor
 CFR - Code of Federal Regulations
 DCR - Design Change Request
 ECCS - Emergency Core Cooling System
 EDG - Emergency Diesel Generator
 EOP - Emergency Operating Procedure
 ERT - Event Review Team
 ESF - Engineered Safety Feature
 FSAR - Final Safety Analysis Report
 GMWe - Generator Megawatt Electric Output
 HELB - High Energy Line Break
 HPCI - High Pressure Coolant Injection
 I&C - Instrumentation and Controls
 ICA - Item Control Area
 IFI - Inspector Followup Item
 IGSCC - Intergranular Stress Corrosion Cracking
 LCO - Limiting Condition for Operation
 LER - Licensee Event Report
 LOCA - Loss of Coolant Accident
 LOSP - Loss of Offsite Power
 LPRM - Local Power Range Monitor
 MSIV - Main Steam Isolation Valve
 MSL - Main Steam Line
 MSLRM - Main Steam Line Radiation Monitor
 MSR - Moisture Separator Reheater

MWO - Maintenance Work Order
NCV - Non-cited Violation
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
NSSS - Nuclear Steam Supply System
PCIS - Primary Containment Isolation System
PRB - Plant Review Board
QA - Quality Assurance
RCIC - Reactor Core Isolation Cooling
RHR - Residual Heat Removal System
RHRSW - Residual Heat Removal Service Water System
RSSV - Reheater Steam Source Valve
RTP - Rated Thermal Power
SAER - Safety Audit and Engineering Review
SCFM - Standard Cubic Feet Per Minute
SIMS - Safety Issue Management System
SNM - Special Nuclear Material
SOR - Significant Occurrence Report
SOS - Superintendent On Shift (Operations)
SRO - Senior Reactor Operator
TMI - Three Mile Island
TS - Technical Specifications
URI - Unresolved Item