U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Rochester Gas and Electric Corporation (RG&E)
Facility:	R. E. Ginna Nuclear Power Plant
Location:	1503 Lake Road Ontario, New York 14519
Dates:	May 5 - June 15, 1996
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EXECUTIVE SUMMARY

R. E. Ginna Nuclear Power Plant

Inspection Report No. 50-244/96-05

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a four week period of resident inspection. In addition, it includes the results of announced inspections by a regional reactor engineer and operations engineer, a NRR reactor systems engineer and a NMSS nuclear engineer.

Operations:

At the beginning of the inspection period, the plant was shut down with the reactor defueled and the reactor coolant system drained for steam generator replacement. The refueling was completed on May 23, 1996. After restoration of the containment access penetrations made for SG replacement, the licensee conducted a containment integrated leak rate test (ILRT) and a containment structural integrity test (SIT).

Reactor plant heatup was conducted on June 3, 1996; however, the plant was returned to Mode 5 the following day due to failure of a reactor coolant system (RCS) resistance temperature detector (RTD). Following completion of this repair, the plant entered Mode 3 on June 7, 1996.

Reactor startup was commenced on June 8, 1996. The plant entered Mode 2 early the following day, and criticality was achieved on June 9, 1996. The main generator was paralleled to the grid on June 10, 1996. Later that morning, operators manually tripped the main turbine from about 20 percent power due to a loss of main condenser vacuum while shifting the steam generator (SG) blowdown lineup. The main generator was paralleled back onto the grid on June 10, 1996. On June 11, 1996, the licensee commenced a plant shutdown to perform main turbine overspeed trip testing and to repair a leak from a high pressure turbine governor control valve.

The main generator was taken off line and the reactor trip breakers were opened on June 12, 1996. During the subsequent reactor startup, a rod control system abnormality aborted the startup. Later that day, the plant achieved criticality. The main generator was paralleled to the grid the following day. At the close of the inspection period, the plant was operating at approximately 99 percent power.

The licensee demonstrated good control during the plant startup activities. Operator communications were precise, although better coordination of the blowdown system realignment may have precluded a loss of main condenser vacuum that resulted in a manual turbine trip. Shift supervisors demonstrated strong command and control, and responded promptly and conservatively to the off-normal situations. The licensee's decision to shut down for a control valve repair was prudent, although it appeared closer examination of the valve prior to original reassembly should have identified the existing defect. Insertion of a manual trip in response to the rod control system abnormality demonstrated the licensee's conservative operating philosophy.

Training activities conducted in preparation for startup with the replacement steam generators and attendant procedure changes was well conducted both in the simulator and classroom. The nature of operating parameter changes, the reasons for them, and their effects were appropriately presented. The one operating crew observed had no problem operating the simulator with these changes.

An appropriate review of plant procedures was conducted to determine needed changes due to the steam generator replacement and other modifications. Although some of these changes were being made three days before the Mode in which they would be applicable, the changes were accomplished and the operating crews were informed. Also, the inspector determined that the facility operations department had performed an effective review of procedures to identify changes required by the steam generator replacement and was in the process of making those changes.

A lack of refueling integrity existed for more than three hours during the movement of irradiated fuel in containment. Fuel movement was immediately stopped. The immediate corrective actions to restore an open containment penetration were adequate to restore refueling integrity. Although the actual safety consequences of the incident are minimal, failure to properly implement the applicable procedures was a violation of 10 CFR 50, Appendix B, Criterion V. **(VIO 50-244/96-05-01)**

Operators made the auto start feature of the auxiliary feedwater (AFW) pumps inoperable with the reactor in Mode 2 at approximately 2% power. The on-shift operations personnel had not been adequately briefed on the purpose of a procedure change. Operator unfamiliarity with the Improved Technical Specifications (ITS) contributed to this event. The shift supervisor acted promptly and decisively when he determined that a problem existed with the AFW system alignment. It is not clear whether the motor drive auxiliary feedwater (MDAFW) pump automatic start feature is, or is not, assumed to be operable for any accident analysis or any analyzed condition while in Mode 2. RG&E considers that the ITS requirement to maintain this function operable in Mode 2 is not necessary, represents a potential hinderance to safe plant operation, and should be removed from their TS. This item remains unresolved **(URI 50-244/96-05-02)**

No safety-significant deficiencies were noted during a detailed walkdown of safety related systems. The material condition of the systems was good and the systems were properly aligned. All system component identification and labelling was consistent with controlled drawings.

The Nuclear Safety Audit Review Board (NSARB) QA/QC Subcommittee discussions were thorough and indepth. Presentations by the individual members and guests were very informative for senior management and NSARB members. The Subcommittee Chairman and the members were able to assess the effectiveness of both QA/QC activities and activities of the plant line organizations over the previous quarter.

Maintenance:

Observed maintenance activities were adequately controlled, personnel properly adhered to maintenance procedures, and the maintenance was accomplished in accordance with specified requirements. Surveillance activities were performed in accordance with procedures and problems were dealt with conservatively.

Omission of the B-RHR pump secondary shaft seal during maintenance received proper evaluation and disposition by engineering. Operability of the B-RHR pump was not affected by the omission of this seal. Management actions to reenforce lessons learned from this event to plant maintenance personnel were appropriate.

Engineering:

The containment dome was restored near the end of the refueling outage and the licensee ensured the structural integrity of the containment and the leak tightness of the containment liner.

Each sequential step in the structural restoration of containment and the leak tightness of the liner plate was implemented in an excellent manner by competent personnel. RG&E and Bechtel engineering provided good oversight and resolution of issues related to the SGRP project activities.

RG&E maintained good control of welding, rebar splicing, and nondestructive examinations of the liner, and ensured the adequacy of the liner's restoration. During the placement of new concrete, RG&E & its contractor displayed excellent corporate, project, and engineering management involvement. The containment dome concrete was restored to its specified compressive strength, and successfully passed the integrated leak rate test (ILRT) and the structural integrity test (SIT). RG&E and contract engineers demonstrated experience, technical know-how, and safety responsibility prior to and during the ILRT and the SIT.

The licensee's search for, and response to, actual or suspected containment leaks during the ILRT was commendable. The test director's performance was excellent and the contractor's supervisor demonstrated considerable knowledge and expertise. The test was successful and all acceptance criteria were met. The licensee needs to update the test procedure and the UFSAR in accordance with their recent license amendment regarding Appendix J.

The containment structural integrity test (SIT) was performed in an excellent manner and in conformance with regulatory requirements, the updated final safety analysis report (UFSAR), and the approved SIT procedure.

Control rod drag testing conducted by RG&E adequately demonstrated that the rods currently used in the reactor do not experience the high drag conditions reported in Bulletin 96-01. The rod testing in the spent fuel pool was well controlled and the drag data was

captured with accurate instrumentation. The licensee's test methodology and data review were generally adequate, and the results were reported to Westinghouse and the NRC in a timely fashion.

Disposition of the service water pump fastener thread engagement analysis was adequate. A difficulty with addressing the potential existence of a nonconforming condition could not be fully resolved because applicable design documents did not have any specifications, or because original design requirements were not available to RG&E Mechanical Engineering. Lack of QA reviews could allow a nonconforming condition to go unidentified and unreviewed by the licensee.

Very good and effective engineering support of operations was noted by eliminating nearly all operator workarounds prior to completing the refueling outage. The remaining workarounds do not impose a significant burden on operators.

<u>Plant Support</u>:

RG&E's efforts for preparation of the original steam generators (OSGs) are consistent with the revisions to the NRC and DOT regulations. The licensee was cognizant of the important regulatory revisions which will affect OSG shipments, and has identified the relevant technical issues.

The licensee fully and effectively restored the proper vital area access controls for the containment building prior to conducting refueling operations. All visible portions of plant systems inside containment were properly evaluated for integrity and the vital area was properly restored.

The licensee took prompt and adequate corrective actions after discovering an inattentive security officer. A check for unauthorized containment entries was immediately undertaken. Adequate administrative controls were in place to avoid further incidents.

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ATTACHMENT

Report Details

Summary of Plant Status

At the beginning of the inspection period, the plant was shut down with the reactor defueled and the reactor coolant system (RCS) drained for steam generator (SG) replacement. The licensee commenced reactor refueling (entered Mode 6) at 5:37 a.m., May 21, 1996. Refueling was completed at 3:20 a.m., May 23, 1996, and reactor vessel head tensioning was completed (entered Mode 5) at 7:20 p.m., May 26, 1996. Following restoration of the containment access penetrations that had been made for SG replacement, the licensee conducted a containment integrated leak rate test (ILRT) on May 29-31, 1996, and a containment structural integrity test (SIT) on May 31, 1996.

Reactor plant heatup to greater than (>) 200 degrees Fahrenheit (°F) and less than (<) 350°F (Mode 4) was conducted on June 3, 1996; however, the plant was returned to Mode 5 the following day due to failure of an RCS emersion resistance temperature detector (RTD). Replacement of the failed RTD required that the RCS be drained to mid-loop level, which was performed on June 5, 1996. Following completion of this repair, RCS heatup in preparation for plant startup was again commenced, with the plant entering Mode 3 (RCS temperature $\geq$350°F) on June 7, 1996.

Reactor startup was commenced on June 8, 1996. The plant entered Mode 2 early the following day, and criticality was achieved at 4:36 a.m., June 9, 1996. Following the completion of zero-power core physics testing, power was escalated and the main generator was paralleled to the grid at 10:01 a.m., June 10, 1996. Later that morning, at 11:37 a.m., operators manually tripped the main turbine from about 20 percent power due to a loss of main condenser vacuum that occurred due to inadequate coordination of procedural steps while shifting the SG blowdown lineup. Plant response to this transient was normal and the reactor was maintained critical. The main generator was paralleled back onto the grid at 1:23 p.m., June 10, 1996. On June 11, 1996, the licensee commenced a controlled plant shutdown from about 45 percent power to perform main turbine overspeed trip testing and to repair a body-to-bonnet leak from the high pressure turbine number one governor control valve. The main generator was taken off line at 12:23 a.m. and the reactor trip breakers were opened at 1:03 a.m., June 12, 1996.

During the subsequent reactor startup on June 12, 1996, a rod control system abnormality caused the startup to be aborted. The rod control system problem was determined to have been caused by a faulty firing circuit card. Later on June 12, 1996, the licensee again commenced a reactor startup, and achieved criticality at 9:48 p.m. The main generator was paralleled to the grid the following day at 6:01 a.m. At the close of the inspection period, the plant was operating at approximately 99 percent power.

I. Operations

O1 Conduct of Operations[1]

O1.1 General Comments (Inspection Procedure 71707)

The inspectors observed plant operations to verify that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. This review included tours of the accessible areas of the facility, verification of engineered safeguards features (ESF) system operability, verification of proper control room and shift staffing, verification that the plant was operated in conformance with technical specifications and appropriate action statements for out-of-service equipment were implemented, and verification that logs and records were accurate and identified equipment status or deficiencies. The inspectors noted the following conditions:

- On May 21, 1996, the inspector noted that the auto voltage control rheostats for the two emergency diesel generators (EDGs) were set higher than normal. The scales on these rheostats are not specific to voltage, since the required settings vary with loading conditions. They are normally set for 480 VAC at no-load, which corresponds to a setting of approximately 4.0 on the 10-division rheostat scale. On this occasion, the A-EDG was set at just under 5.0 and the B-EDG was set at just under 7.0. The inspector questioned the on-shift operators concerning the rheostat settings, and none knew of any reason for them being different than normal. When the EDGs were started to determine what voltages they were set for, both were found to be high. The A-EDG operated at just under 500 VAC and the B-EDG operated at 515 VAC. Both EDGs were readjusted to 480 VAC. The licensee considered that the misadjustment was most likely due to the rheostats being inadvertently bumped during equipment setup in the immediate vicinity of the EDG control panel. The licensee performed an operability assessment of the EDG for the as-found voltage conditions. The licensee concluded that the A-EDG had been operable, but that operability of the B-EDG could not be positively established without additional testing. No additional testing was performed because the plant was in Mode 6 (refueling) at the time of this event, and only one EDG was required to be operable.

  As a result of this occurrence, the licensee placed covers over the rheostats to prevent inadvertent movement. Additionally, the 480 VAC no-load settings on the auto voltage control rheostats have been marked, and verification of proper setting has been added to operations procedure O-6.13, "Daily Surveillance Log."

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[1]Topical headings such as 01, M1, etc., are used in accordance with the NRC standardized reactor inspection report outline found in MC 0610. Individual reports are not expected to address all outline topics.

The inspector considered that the licensee's response to this condition was prompt and that the corrective actions were thorough. The inspector considered that a positive determination of B-EDG operability was unnecessary, given that only one EDG was required to have been operable.

- During plant startup on June 10, 1996, one channel of steam flow indication, FI-475, was slow to indicate steam flow. The licensee believed this to be due to the condensing pot for the detector requiring a long time to fill. As power was escalated, the inspector noted that the indicator for the associated engineered safety feature actuation system (ESFAS) high steam flow channel on the relay status panel was not lit, whereas the other three channels were lit. Although the licensee considered that the instrument was not malfunctioning, the inspector considered that the channel should be considered inoperable based on the missing ESFAS input. After discussion, the licensee declared the steam flow channel inoperable and placed it in trip as required by TS. Subsequent investigation found that the instrument calibration was out of tolerance.

  Although the licensee initially considered that the slow response of the steam flow instrument would correct itself as the startup progressed and the associated condensing pot filled, operability of the ESFAS feature was not considered until the inspector raised the issue.

O1.2 Failure to Establish Containment Refueling Integrity Prior to Reactor Refueling

a. Inspection Scope (71707)

On May 21, 1996, the licensee commenced refueling operations to return the full core from the spent fuel pool to the reactor vessel. After approximately 3-1/2 hours of fuel movement, the licensee discovered that complete containment closure had not been established, and suspended fuel movement inside containment to seal an open containment penetration. The inspector reviewed the circumstances surrounding this event.

b. Observations and Findings

Penetration "P-2" is a permanently installed 8 inch in diameter containment penetration that is normally closed and sealed during reactor operations. During refueling outages, the penetration is opened and used to pass communications cables and equipment service lines through the containment wall. The Ginna technical specifications (TS) allow for the use of a dense foam rubber to seal the areas around the cables inside the penetration sleeve to maintain the containment closure requirements defined by TS 3.9.3.c during the movement of irradiated fuel.

During the recent refueling outage, the P-2 penetration was used to pass communications cables, an auxiliary 3-1/2 inch service air line, and a 1-1/2 inch argon line through the containment wall to support steam generator replacement project (SGRP) work inside containment. Foam rubber was used to seal the areas around these lines. The service air line contained a manual isolation valve just on the inside and outside of the containment boundary. The service air and argon lines were both installed and removed under Station Modification procedure SM-10034-10.01, "Temporary Service Air System For SGRP." This procedure contained a requirement to maintain the temporary service air line pressurized, or to maintain its isolation valves closed during fuel movement in containment. The Work Plan and Instruction Record (P-SAX-01) that implemented procedure SM-10034-10.10 contained the same requirement. However, the removal instructions in P-SAX-01 did not explicitly refer to the requirement that integrity of the service lines must be maintained for containment closure during refueling operations. The service air line isolation valves not under RG&E control, but were under Bechtel's equipment configuration controls.

On May 20, 1996, RG&E and Bechtel held an interface planning meeting in which explicit discussions were held emphasizing the requirement to keep both the service air and argon lines in place for refueling integrity. Also, in accordance with RG&E procedure O-15.2, "Valve Alignment for Reactor Head Lift, Core Component Movement, and Periodic Status Checks," two plant operators independently verified that penetration P-2 was adequately sealed. However, due to an apparent breakdown in configuration and work controls, and inadequate procedure adherence, both services lines were removed from penetration P-2 before refueling operations commenced the following morning. These openings could not have controlled the release of radioactivity from containment that could have resulted from a postulated fuel handling accident. Without an adequate seal, penetration P-2 did not satisfy the containment closure conditions required by TS section 3.9.3.c for refueling operations.

Approximately 3-1/2 hours after refueling operations began on the morning of May 21, a radiation protection (RP) contractor technician working outside containment near penetration P-2 discovered that it was not properly sealed. The technician performed a smoke test at the penetration and noted that a relative negative pressure inside containment caused a continuous airflow into the penetration opening from outside. He then informed the licensee, who immediately suspended refueling operations and inspected the configuration of the penetration. The licensee confirmed that the penetration did not satisfy the containment closure requirements for refueling operations as contained the TS. The licensee subsequently removed all of the cables in the penetration and sealed each end of its sleeve with bolted flanges. Refueling operations were resumed after an adequate seal was verified.

The Ginna TS require an adequate seal in containment penetrations to prevent the release of radioactivity during a postulated fuel handling accident. However, the fuel handling accident analysis in the UFSAR does not take credit for the containment pressure boundary, or for a relative negative pressure inside containment. An analysis supporting a recent TS amendment (No.62) assumed that a fuel handling accident occurring 100 hours after plant shutdown, with a 1.83 ft^2 opening in the containment equipment hatch door and with a relative positive pressure, would result in a release at the site boundary that is well within the

10 CFR 100 limits. In this incident, the penetration opening was approximately 0.05 ft^2 and the inside of containment was at a relative negative pressure. Also, the incident occurred 60 days after plant shutdown.

The licensee opened an ACTION Report for this incident (AR 96-0517). Also, a Human Performance Enhancement System (HPES) investigation was initiated to examine the root cause(s) in depth, and to make recommendations for corrective actions to prevent a recurrence. The licensee could not confirm whether the operator verifications occurred prior to removal of the service lines; however, procedure O-15.2 did not contain explicit acceptance criteria for penetration P-2. Consequently, the operators may not have recognized a proper seal. At the conclusion of this inspection period, the HPES investigation was still in progress.

c. Conclusions

The licensee self-identified the lack of refueling integrity that existed for more than three hours during the movement of irradiated fuel in containment. They immediately stopped fuel movement and investigated the configuration of penetration P-2. The licensee's immediate corrective actions to remove the remaining cables and seal the penetration were adequate. Although the actual safety consequences of the incident are minimal, failure to properly implement procedures O-15.2 and SM-10034-10.01, is a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." **(VIO 50-244/96-05-01)**

O1.3 Plant Startup Activities

a. Inspection Scope (71707)

The inspector observed various aspects of plant operations from the initial reactor startup following outage completion through escalation of power to 100 percent.

b. Observations and Findings

- Initial Criticality and Zero Power Core Physics Testing

The predicted core physics parameters were verified through the performance of PT-34.0, "Startup Physics Test Program." This procedure provides overall direction for achieving initial criticality, performance of zero power (reactor critical but energy output too low to change RCS temperature) physics testing, and performance of physics testing during power escalation to full power. Parameters measured during the zero power phase of testing include all rods out boron concentration, moderator temperature coefficient, differential and integral control rod worths, and differential boron worth.

The zero power physics test program was performed on June 9, 1996, with initial criticality being achieved at 4:36 a.m. The inspector observed portions of PT-34.3, "RCC Bank Worth Measurement," and noted that the testing was very well controlled. The inspector verified that the measured values of the all rods out boron

concentration and moderator temperature coefficient were within acceptable limits of the predicted values.

- Manual Turbine Trip Due To High Condenser Backpressure

After completion of zero power physics testing, the main generator was paralleled to the grid at 10:01 a.m., June 10, 1996. Later that morning, operators were realigning the steam generator blowdown system to direct blowdown flow to the discharge canal. Transition to this lineup has the potential for creating a flowpath between the main condensers and atmosphere as the blowdown flash tank is placed in service. On this occasion, control room operators were alerted to a problem by a high main turbine backpressure alarm and rapidly lowering main condenser vacuum. Within seconds of the alarm, main condenser vacuum had decreased to below the operating limit for the main turbines. At 11:37 a.m., operators manually tripped the main turbine from about 20 percent power. Plant response to this transient was normal and the reactor was maintained critical. The main generator was paralleled back onto the grid at 1:23 p.m., June 10, 1996.

The inspector was in the control room during this event and noted that operator response to the lowering condenser vacuum was very good. However, given that the steam generator blowdown system had been modified during the outage, the inspector considered that a more deliberate approach to shifting the blowdown lineup may have prevented this event.

- Shutdown For High Pressure Turbine Control Valve Steam Leak Repair

During the plant startup, the licensee identified a body-to-bonnet steam leak on the high pressure turbine number one control valve, V-3464. On June 11, 1996, the licensee commenced a controlled plant shutdown from about 45 percent power to repair this leak. The shutdown was also utilized to perform main turbine overspeed trip testing that was required as a retest for outage maintenance but which first required a run-in period. The main generator was taken off line at 12:23 a.m. and the reactor trip breakers were opened at 1:03 a.m., June 12, 1996. A steam cut on the body-to-bonnet union of V-3464 was repaired by weld buildup.

During the subsequent reactor startup on June 12, 1996, with the plant in Mode 2, but still subcritical, the startup was temporarily suspended due to the inoperability of the auxiliary feedwater pump auto start function (refer to paragraph O1.4 below). At the time, both shutdown control rod banks A and B were fully withdrawn, control bank C was at 140 steps, and control bank D was at 10 steps. After the auto start function was returned to operability, the startup was resumed. As operators began to further withdraw bank D rods, a control rod sequence/deviation alarm occurred. A mismatch condition existed between the microprocessor rod position indication (MRPI) and the rod control step counters for the bank D, group 1 rods. Control rods C-7 and D-7 did not transition off the bottom of their indicated MRPI positions when the step counters reached 12 steps. Operators immediately stopped all further rod movement and entered abnormal operating procedure AP-RCC.2, "RCC/RPI Malfunction," in response to the alarm.

Instrument and Control (I&C) technicians performed troubleshooting in the power cabinet for rods C-7 and D-7, but no obvious indications of faults or blown fuses were evident. Since more extensive troubleshooting efforts would be time consuming and not desirable in such close proximity to criticality (K_{eff}>0.99), station management decided all control rods should be manually inserted to perform additional troubleshooting. However, after rods were inserted 16 steps, another rod sequence/deviation alarm occurred. At this time, bank D rods were in motion, bank C rods were stationary at 126/125 steps, and bank B rods had started to move too soon off the top of their indicated MRPI positions. Operators immediately stopped all rod motion and again entered AP-RCC.2. Since the rod control problems appeared potentially extensive, the shift supervisor ordered a manual reactor trip. Operators performed the immediate actions required by emergency procedure E-0, "Rector Trip or Safety Injection," and then transitioned to procedure ES-0.1, "Reactor Trip Response." The plant responded normally to the reactor trip and was subsequently stabilized in operating Mode 3.

While in Mode 3, I&C technicians performed extensive troubleshooting of the rod control system and discovered a faulty firing card in the rod control multiplexing logic circuitry. After the firing card was replaced, the licensee performed surveillance test PT-1, "Rod Control System," and verified that the correct rod movement and sequencing resulted from operator commands.

Later on June 12, 1996, the licensee recommenced a reactor startup and reached Mode 2 at 9:13 p.m. Criticality was achieved at 9:48 p.m., and the plant was in Mode 1 and online at 6:01 a.m. the following morning. The startup sequence was normal and without further rod control anomalies. At the close of the inspection period, the plant was operating at approximately 99 percent power.

- Plant Startup and Power Escalation

Later on June 12, 1996, the licensee again commenced a reactor startup, and achieved criticality at 9:48 p.m. The main generator was paralleled to the grid the following day at 6:01 a.m. The three percent per hour power escalation included holds at approximately 25, 45, and 75 percent power for core flux mapping. Steam generator transient response testing was also performed during the power escalation; preliminary indications during the tests were that the new steam generators were more stable than predicted. The shrink and swell responses of the generators were very small after feedwater flow perturbations were introduced by manually changing the feedwater regulating valve positions by plus and minus 5%. Full power operation (approximately 100 percent) was achieved on June 15, 1996.

c. Conclusions

The inspector considered that the licensee demonstrated overall good control during the plant startup activities. Operator communications were precise, although better coordination of a blowdown system realignment may have precluded a loss of main condenser vacuum that resulted in a manual turbine trip. Shift supervisors demonstrated strong command and control, and responded promptly and conservatively to the off-normal situations. The licensee's decision to shut down for repair of V-3464 was prudent, although it appeared closer examination of the valve prior to original reassembly should have identified the existing defect. Insertion of a manual trip in response to the rod control system abnormality demonstrated the licensee's conservative operating philosophy. A problem that occurred during the aborted startup of June 12, 1996, involving operation of the auxiliary feedwater system, is discussed in section O1.4 below.

O1.4 Auxiliary Feedwater System Automatic Initiation Function Inoperable in Mode 2.

a. Inspection Scope (71707)

The inspector reviewed the events surrounding an occurrence on June 12, 1996, where an automatic initiation function for the auxiliary feedwater (AFW) system was inoperable during transition of the plant into a Mode where the function was required by TS to be operable.

b. Observations and Findings

The auxiliary feedwater system includes two motor driven (MD) pumps and one steam turbine driven pump. The safety function of the AFW system is to provide feedwater to the steam generators for residual heat removal from the reactor in the event that the main feedwater (MFW) system becomes unavailable. One of the initiation features that accomplishes this function is the automatic start of the MDAFW pumps if both of the MFW pump breakers are opened. A bypass switch for each MDAFW pump allows this feature to be defeated when MFW and/or MDAFW pump operation is not required, such as when the plant is shut down. The AFW system is also used as the normal feedwater supply during low power operations (<5%), prior to startup of the MFW system.

Improved technical specifications (ITS) were implemented at Ginna in February 1996. The ITS contained a new requirement for operation of the AFW system; specifically, Table 3.3.2-1 requires that the automatic start of the MDAFW pumps when both MFW pump breakers are open be operable in Mode 1 (reactor power >5%) and Mode 2 ($K_{eff} \geq 0.99$). Table 3.3.2-1 also requires the MDAFW pumps automatic actuation logic and actuation relays to be operable in Modes 1, 2, and 3. Prior to implementation of the ITS, the MDAFW pumps were operated during plant startup with the bypass switches in the defeat position. This allowed operators to control operation of the MDAFW pumps, as well as providing finer control of AFW flow by enabling the AFW flow bypass valves (a second function of the bypass switches).

To satisfy the ITS requirement for operability of the MDAFW pump automatic start feature during plant startup, the licensee modified the plant startup procedure to place one MFW pump breaker in the test position prior to commencing startup. This allowed the breaker to be closed without starting the MFW pump, but keep the protective functions associated with the breaker still energized. Thus, with one MFP in simulated operation, the MDAFW pump bypass switches could be placed in normal to enable the automatic start feature. Operators could then maintain manual control of one MDAFW pump, with the other pump idle, but available for automatic start if necessary. This change was accomplished by a temporary procedure change (PCN 96-T-0429) to Operations Procedure O-1.2, "Plant Startup From Hot Shutdown to Full Load," revision 133, which included applicable portions of an existing test procedure (SEV-1065) as an attachment to O-1.2.

In preparation for plant startup on June 12, 1996, the B-MFP breaker was racked out to the test position in accordance with PCN 96-T-0429. One of the concluding steps of this procedure attachment stated, "Operations to restore MDAFW pumps as desired." The on-shift operators interpreted this step as authorization to place the MDAFW pump bypass switches in the defeat position. Although the procedure had specifically placed the bypass switches in the normal position, operation in the bypass mode was desired due to the finer control of feedwater flow that the AFW flow bypass valves provided. Therefore, operators placed the MDAFW pump bypass switches in defeat and continued with the plant startup. This action made the MDAFW pump automatic start feature inoperable. At the time, rod withdrawal to criticality was in progress, the A-MDAFW pump was operating, and the B-MDAFW pump was idle.

Coincident with the startup, instrument and controls (I&C) technicians were performing testing on the main turbine electrohydraulic control (EHC) system. The Control Room Foreman (CRF) became concerned that this testing might generate a turbine trip signal which could cause the engineered safety feature actuation system (ESFAS) to automatically start the idle MDAFW pump. Therefore, the CRF directed that the B-MDAFW pump control switch be placed in pull-stop. This action made the B-MDAFW pump inoperable.

The shift supervisor had been attending to plant activities outside the immediate area of the main control boards. When he returned and noted the condition of the AFW system, he directed that rod withdrawal be stopped until the situation had been evaluated. The B-MDAFW pump control switch was taken out of pull-stop and the MDAFW pump bypass switches were placed in normal. A review of the "1/M" plot revealed that the plant had transitioned from Mode 3 to Mode 2 with the MDAFW pump bypass switches in defeat. Placing the plant in a lower number Mode without first satisfying all requirements for being in that Mode is contrary to TS 3.0.4. However, the licensee considered that the TS table 3.3.2-1 requirement for the MDAFW pump automatic start feature to be operable in Mode 2 was in error, and therefore considered that the occurrence did not represent an operational problem. It was further determined that the B-MDAFW pump control switch had been placed in pull-stop after the plant had entered Mode 2. Operation in Modes 2 or 1 with one MDAFW pump inoperable is allowed by TS 3.7.5.b for a maximum of seven days; however, this LCO was not formally entered and was not noted into the operators log. The licensee concluded that conditions were acceptable for continued operation and proceeded with the plant startup.

c. Conclusions

The inspector concluded that the on-shift operations personnel had not been adequately briefed on the purpose of the procedure change to operations procedure O-1.2. Based on interviews with operations department personnel, the inspector determined that unfamiliarity with the ITS also contributed to this event. The CRF indicated that he had been thinking in terms of the old TS in directing alignment of the AFW system. The shift supervisor acted promptly and decisively when he determined that a problem existed with the AFW system alignment. Based on discussions with the licensee, it is not clear whether the MDAFW pump automatic start feature is, or is not, assumed to be operable for any accident analysis or any analyzed condition while in Mode 2. RG&E considers that the ITS requirement to maintain this function operable in Mode 2 is not necessary, represents a potential hinderance to safe plant operation, and should be removed from their TS. This item remains unresolved pending NRC review of the licensee's basis for this assertion. **(URI 50-244/96-05-02)**

O1.5 Auxiliary Operator Accompaniments and Procedure Verification

a. Inspection Scope (71707)

On June 4, 1996 and June 5, 1996, the inspector accompanied auxiliary operators (AOs) on their rounds, including primary and secondary plant tours. The inspector independently reviewed the licensee's procedures for AO tour guidelines (P-13), and AO rounds and logsheets (O-6.1). The inspector also performed an independent review of procedure S-30.9, "Component Cooling Water Flow Path Verification."

b. Observations and Findings

The AO rounds were thoroughly performed, consistent with procedures, and plant data readings required for log-sheets were complete and within normal ranges. The component cooling water (CCW) flow was above its normal range due to operation of the residual heat removal (RHR) system. AO actions performed during the tours included boric acid batching, CCW flow adjustment to the RHR system, and repressurization of the safety injection system accumulators.

The inspector reviewed and independently completed procedure S-30.9. The procedure consists of a monthly surveillance and verification of the open position of eight valves and the locked open position of a ninth. It also serves to verify flow paths through both CCW pumps and heat exchangers, to the CCW surge tank, and to several other safety-related systems. The review included a check of the procedure for consistency, for completeness in implementing technical specifications surveillance requirement (SR) 3.7.7.1, and evaluating the adequacy of the procedure to verify the necessary flowpaths to safety-related systems.

c. Conclusions

The inspector concluded that AO rounds were thorough, and that the recorded data was accurate. Procedure P-13 provided adequate guidelines for AO tours. AO rounds were properly performed and plant system data was accurately recorded in procedure O-6.1 logsheets. Procedure S-30.9 adequately implemented the TS surveillance requirement for flow path verifications, and no concerns were identified.

O1.6 Engineered Safety Features - System Walkdowns

a. Inspection Scope (71707)

During the pre-operational heatup of the reactor plant, the inspector conducted an independent, detailed walkdown of the accessible portions of safety-related systems including auxiliary feedwater (AFW), both A & B emergency diesel generators (A-EDG and B-EDG), component cooling water (CCW), containment spray (CS), safety injection (SI), and the boric acid addition and charging subsystems of the chemical and volume control system (CVCS).

b. Observations and Findings

During the walkdown and visual observation of each system, the inspector focused on a detailed verification that system lineups and descriptions were consistent with current plant piping and instrumentation diagrams (P&IDs). The inspector verified that all system components were properly labelled and that the labelling was consistent with the P&IDs. The P&ID for the AFW system did not show 4 valves that were installed during the recent refueling outage; however, the inspector verified that a drawing change request (DCR-96-0179) had been performed and was pending for the next P&ID revision. Selected local system instruments were observed and found to be functional and calibrated. All valves observed in these systems were in their correct position for the plant operating Mode, and locking devices were properly installed on applicable valves. Overall, the inspector observed a good material condition for these systems and good general housekeeping in the plant areas around these systems.

The inspector called the CVCS system engineer's attention to an air-operated valve (AOV-105) on the discharge of the "B" boric acid transfer pump, which showed a significant buildup of crystallized boron on its exterior surfaces. This condition had not been previously identified for maintenance. The system engineer evaluated the situation and concluded that the buildup was not an immediate concern for operability of the valve, as the valve is frequently cycled and has not experienced problems when stroked. However, he submitted a trouble card to initiate a work order to remove the boron and tighten the valve packing.

c. Conclusions

No safety-significant deficiencies were noted. The material condition of the inspected portions of safety-related systems within the inspection scope was good and the systems were properly aligned. All system component identification and labelling was consistent with controlled drawings. One minor discrepant condition was noted for maintenance follow-up.

O3 Operations Procedures and Documentation

O3.1 Operations Procedure Changes

a. Inspection Scope

The inspector reviewed operating procedures needed after the steam generator replacement, to evaluate if appropriate procedure changes were being made. The following plant parameters changed as a result of the steam generator replacement.

- T-avg control program (T-avg reduction).
- Pressurizer level control program.
- Steam generator level control program (changed to a fixed setpoint).
- Seam generator high level trip setpoint.

The inspector reviewed major plant operating procedures and the Emergency Operating Procedures (EOP) setpoint document, to evaluate whether the licensee had made appropriate changes.

b. Observations and Findings

The Plant Operating Procedures set had been updated the week prior to this inspection. The inspector found only one setpoint to be in question; however it was later shown to be correct.

Emergency Operating Procedures (EOPs) had not been updated at the time of this review. The licensee had previously reviewed the procedures and the identified changes were being made. The inspector compiled a list of necessary setpoint changes and compared it to the changes planned by the licensee. No discrepancies were found. The licensee had also added additional setpoints based on plant modifications and their review.

The inspector reviewed the methodology used to identify which procedures contained setpoints that needed to be changed. The methods used were keyword searches, number searches, and direct review of procedures. The licensee used procedure maintenance software, but in a transition to a Windows version they had lost the ability to generate a complete setpoint list that would be used to search for the procedures that contained these setpoints. It was still possible to look up a known setpoint alphanumerical identifier to determine what the parameter was, and then search procedures for that parameter. The inspector and the EOP Coordinator

used this capability to determine procedures affected by a sample of eight setpoint changes and verified these changes had been identified.

The EOP coordinator had been in the position for two weeks and was unfamiliar with the "Modes of Applicability" listing for EOPs in the Emergency Response Guidelines Executive volume. This was because numbered Modes to identify plant operating status was new to Ginna with their new technical specifications. There is no requirement associated with this listing; it simply states in which operating Modes particular EOPs may provide guidance in mitigating an event. The licensee stated they would review this listing and make changes to identified procedures before entering a given Mode.

c. Conclusions

The operations department performed an effective review of procedures to identify changes required by the steam generator replacement, and was in the process of making those changes prior to the end of the refueling outage.

O5 Operator Training and Qualification

O5.1 Plant Startup Training

a. Inspection Scope (71707)

On May 9, 1996, the inspector observed one day of simulator startup training with the simulator plant modelling updated to reflect anticipated performance with the new steam generators. The inspector also observed one day of classroom training concerning plant modifications and their anticipated effects on plant performance. Documentation of training on changes to Emergency Operating Procedures resulting from these plant modifications was also reviewed.

b. Observations and Findings

b.1 Simulator Training

The inspector observed two scenarios involving reactor startups and reactor trips. The conduct of the scenarios by the instructors was very good. The instructor began by briefing the crew on plant modifications, control band changes, and industry events involving rod control problems and inadequate control of plant parameters by an operating crew. As the scenario proceeded, the instructor paused frequently to highlight procedure and technical specification changes, where plant modifications affected plant response or where a modification was not reflected in the simulator, as in the specifics of automatic boration controls.

The crews were observed to have no difficulty operating with control band changes, modified procedures, or any differences in plant response.

b.2 Classroom Training

Classroom training expanded upon the event and modification briefings given in the simulator. The same instructor conducted both training sessions and integrated them effectively. The classroom session included more detailed discussion of industry events such as the following:

- Improper reactor trip setpoints.
- Response to multiple rod insertion failures.
- Failure to take effective action to control plant parameters resulting in an improper mode change.

These discussions were conducted in a manner which held student interest.

Additional instruction was provided on plant modification and control band changes, including the reasons for the changes and why certain procedure changes were made. The inspector considered the presentation of how the changed T-ave band affected nuclear instrumentation and the resulting changes to calorimetric requirements to have been particularly well conducted.

b.3 Late Procedure Changes

Changes to Emergency Operating Procedure and Abnormal Operating Procedure Setpoints were still being made less than one week before the scheduled startup. The inspector verified that the facility intended to inform shift personnel of these changes prior to startup. This was accomplished via the "read and sign" method by routing a package stating the setpoint changes, listing affected procedures, and providing examples. The inspector considered this acceptable.

c. Conclusions

The simulator and classroom training were both conducted in an effective manner for preparing the crews for startup and operation following the outage. The "read and.sign" package was acceptable training for last-minute procedure updates.

07 Quality Assurance in Operations

07.1 QA/QC Subcommittee Meeting

a. Inspection Scope (40500)

On June 11, 1996, the Nuclear Safety Audit Review Board (NSARB) QA/QC Subcommittee met at the RG&E corporate offices for a regularly scheduled review of QA/QA activities within the Nuclear Operations Group over the past calendar

quarter. The inspector attended this meeting and reviewed the committee's deliberations.

b. Observations and Findings

The areas reviewed by the QA/QC Subcommittee included the status of all existing Open and Action Items before the Subcommittee, the status of the Corrective Actions Program, an assessment of the ACTION Report (AR) Program, a summary of the outage audit results, a presentation of the most recent Nuclear Assessment (Quarterly) Report, and the planned 1996 Cooperative Management Audit.

The committee discussed recent issues and problems experienced with tracking and trending of ARs and the computer database information associated with their closeout status. The committee considered a proposal to transfer complete ownership of the AR system from the Nuclear Assessment Group to the Plant line organization as an effort to better control AR processing and maintaining the AR database accurate and current. A review of AR cause codes revealed that procedure adherence problems have a relatively high incidence, as do equipment aging problems. The committee will evaluate these findings and pursue refinements to the AR database for improved trending capability.

As a result of the Subcommittee's discussions, the Chairman assigned ten new Action Items to department managers to pursue the committee's concerns and to make recommendations for their resolution. One new Open Item was identified over the concern for the adequacy and use of procedures. A lead self assessment in the maintenance department will be performed to address the open item and the results will be presented at the next Subcommittee meeting. All Subcommittee members participated in a complete review of the current Open and Action Items before the committee to assure that they all understood their purpose and scope. The committee also performed a post-meeting self assessment, and several opportunities for improvement were identified.

c. Conclusions

The inspector considered that the QA/QC Subcommittee members were well prepared for the meeting, and that the discussions were thorough and indepth. Presentations by the individual members and guests were very informative to senior management and to NSARB members. The presentations enabled the Subcommittee Chairman and members to assess the effectiveness of both QA/QC activities and activities of the plant line organizations over the previous quarter. Appropriate followup actions were identified based on the information presented to the committee. The post-meeting critique was an effective vehicle for the committee to identify improvement areas.

O8 Miscellaneous Operations Issues

O8.1 <u>(Closed) LER 50-244/96-002:</u> Secondary Transient, Caused by Loss of "B" Condenser Circulating Water Pump, Results in Manual Reactor Trip.

On March 7, 1996, prior to the past refueling outage, the B-condenser circulating water (CCW) pump tripped when the reactor was in steady state operation at approximately 97% power. A resulting reduction in heat removal capability and an increase in condenser backpressure above the safe limit for turbine operation, caused the licensee to manually trip the reactor. The licensee and the reactor responded appropriately to the trip and the plant was stabilized in hot shutdown (Mode 3).

It was subsequently determined that the B-CCW pump motor tripped out on a high power factor condition. The licensee's troubleshooting identified high resistance in the variable auto transformer associated with the power factor protection circuitry. The equipment was repaired and the resistance restored to an acceptable value. The licensee also found discrepancies in the abnormal operating procedure for a CCW pump trip and in maintenance procedures for the power factor circuitry.

The inspector reviewed the LER and determined that all details were clearly supported, the root cause was properly determined, and that the corrective actions were thorough and complete. The potential safety consequences were properly evaluated and that the requirements of 10 CFR 50.73 were met for reporting this event. LER 96-002 is closed.

O8.2 <u>(Open) LER 50-244/96-003:</u> Both Pressurizer Relief Valves Inoperable, Results in Condition That Could Have Prevented Fulfillment of a Safety Function.

During the March 7-10 forced outage, the licensee performed maintenance on the pressurizer power operated relief valves (PORVs) to make adjustments to the valves in preparation for placing the low temperature overprotection (LTOP) system in service during the upcoming refueling outage. An inadvertent result of this work caused both PORVs to be made simultaneously inoperable. This condition is contrary to the technical specifications. The unavailability of both PORVs represented the loss of the available vent path safety function and invalidated other assumptions in the accident analysis for a steam generator tube rupture. This event was previously reviewed and discussed in Inspection Report 50-244/96-01.

The licensee determined that the causes of this event were both the physical disabling of both PORVs, and inadequate procedure guidance and adherence. A Human Performance Enhancement System (HPES) evaluation was initiated and further ongoing corrective actions are in progress. The inspector reviewed the LER and found it to have clearly reported the known details surrounding this event. The immediate and intermediate causes were correctly identified and the safety consequences were properly evaluated. The requirements of 10 CFR 50.73 were fulfilled in the LER.

At the end of the inspection period, the HPES report, and a supplement to the LER were still in progress. On June 7, 1996, the licensee responded to a violation for this occurrence; however, long term corrective actions were not yet completed. Pending completion of those corrective actions and submittal of the LER supplement, this LER remains open.

O8.3 (Closed) LER 50-244/96-004: Decrease in Steam Generator Level, Caused by Failed Open Atmospheric Relief Valve, Results in Automatic Start of Auxiliary Feedwater Pump on Lo-Lo Level.

During the March 7-10 forced outage, when restoring from AFW pump maintenance, operators attempted to establish steam flow in the header and slightly opened the A-SG atmospheric relief valve (ARV) to assist in opening the A-MSIV. However, the ARV failed open. Controls on the main control board had no further affect on valve position. RCS temperature and pressure, and SG water levels, all began to lower. Level in the A-SG was initially low (22 percent).and reached the 17 percent low level ESF setpoint approximately three minutes into the event. This generated a reactor trip signal (all rods were already fully inserted) and caused an automatic start of the non-operating AFW pump. Operators shut the A-MSIV and manually isolated the A-ARV. All safeguards equipment functioned properly.

The cause of the ARV failure was a failed air system volume booster relay that translates the control air signal into operating air for the valve. The relay was replaced, and the ARV was returned to service. A four-hour non-emergency report was made to the NRC as required by 10 CFR 50.72 and was subsequently reported in this LER 96-004. The inspector reviewed the LER and concluded that the details surrounding the event were clearly evaluated and understood by the licensee, who considered the event to be a maintenance preventable functional failure. A buildup of particulate matter was observed in the volume buildup relay in the ARV pilot valve. Eight specific corrective actions were identified in the LER mostly to improve maintenance on the ARVs and the instrument air system. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Outage Overview

During this inspection period, the major outage maintenance activities included reactor refueling (full core reloaded from the spent fuel pool); full restoration of two steam generator access holes in the containment dome; steam generator piping restoration; a containment integrated leak rate test (ILRT) and structural integrity test (SIT); Class 1E electrical bus outages for maintenance and inspection (busses 16 and 18), overhaul of both pressurizer power operated relief valves; and full disassembly, inspection, and repair of the high pressure turbine.

M1.2 Maintenance Observations

a. Inspection Scope (62703)

The inspectors observed portions of plant maintenance activities to verify that the correct parts and tools were utilized, the applicable industry code and technical specification requirements were satisfied, adequate measures were in place to ensure personnel safety and prevent damage to plant structures, systems, and components, and to ensure that equipment operability was verified upon completion of post maintenance testing.

b. Observations and Findings

The inspectors observed all or portions of the following maintenance activities:

- Number 18 transformer repair

-- Outage inspection revealed several loose insulators which had worn through insulation on the transformer core due to vibration.

- Reactor refueling

-- Observed activities in the control room, at the spent fuel pool, and in containment via the control room video monitor. Fuel movements were deliberate and fuel placement tracking was precise. A problem with preparations for refueling concerning containment integrity is discussed in section 01.2 of this report.

- TE-402B RCS cold leg immersion RTD replacement (post-maintenance)

-- This RTD had been replaced earlier in the outage; second replacement required plant cooldown and RCS drain down to mid-loop. Troubleshooting prior to removal indicated that an open circuit had occurred in the detector. The RTD had been tested prior to installation and had operated satisfactorily once connected to its associated temperature instrument.

The inspector observed the work site following the replacement and noted no impediments to installation (such as would have required flexure or undue force to achieve installation). The RTD probe showed no significant abrasions or deformations. Although it has not been positively established, the suspected cause of failure was separation of one or more of the detector leads at the connection to the RTD element.

c. Conclusions

The inspector concluded that the observed maintenance activities were adequately controlled, personnel properly adhered to maintenance procedures, and the maintenance was accomplished in accordance with the specified requirements.

M1.3 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed portions of surveillances to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting conditions for operation (LCOs), and correct post-test system restoration.

b. Observations and Findings

The inspectors observed all or portions of the following surveillance tests:

- RSSP 2.1, "Safety Injection Functional Test," observed May 10, 1996

-- A portion of the test related to the C-safety injection pump logic circuitry could not be performed due to plant conditions at the time of the test. This was not identified prior to the test, but was noted as an apparent improper indication during A-train testing. When the cause of the problem was understood, a procedure change (PCN 96-T-0277) to RSSP-2.1 was developed prior to testing the B-train. The affected A-train circuitry was subsequently tested satisfactorily during a different test (RSSP-2.2).

- PT-12.1, "Emergency Diesel Generator A," observed May 22, 1996

-- No problems were noted.

- PT-16Q-B, "Auxiliary Feedwater Pump B - Quarterly," observed June 4, 1996

-- No problems were noted.

- PT-12.2, "Emergency Diesel Generator B," observed June 6, 1996

-- Fuel oil pressure was initially low; adjustment of the oil pressure regulator initially produced too much pressure increase, second adjustment was satisfactory. Based on having made these adjustments during the test, PT-12.2 was reperformed later that day, satisfactorily.

- PT-34.3, "RCC Bank Worth Measurement," observed June 9, 1996

-- Part of zero power physics testing, as discussed in section O.1.3 of this report.

c. Conclusions

The inspector concluded that the observed surveillance activities were performed in accordance with the applicable procedures and that problems were dealt with conservatively.

M1.4 Residual Heat Removal System Pump Maintenance

a. Inspection Scope (62703)

The inspector reviewed the events surrounding the licensee's discovery that a secondary shaft seal had intentionally not been installed during maintenance on the B-residual heat removal (RHR) pump.

b. Observations and Findings

The A- and B-RHR pump shaft seals were repacked as a part of outage maintenance on the system. During acceptance testing, the A-RHR pump packing overheated after a short period of operation. While investigating this event, the licensee discovered that a related component, the secondary shaft seal, had intentionally not been installed on the B-RHR pump. The decision not to install the secondary seal had been made by the mechanics and planner who were directly involved with the B-RHR pump outage maintenance, and had not received engineering review or concurrence.

Following discussions with the pump vendor, engineering determined that elimination of the secondary shaft seal was desirable. A Plant Change Request (PCR 96-052) was completed, and the secondary shaft seal was removed from the A-RHR pump during the shaft seal repack.

Personnel involved in the decision not to install the secondary shaft seal on the B-RHR pump were counselled by licensee management. Management's expectations for procedural compliance and use of proper channels to affect changes were re-enforced during meetings with maintenance personnel.

c. Conclusions

Omission of the B-RHR pump secondary shaft seal received proper evaluation and disposition by licensee engineering. Operability of the B-RHR pump was not affected by the omission of this seal. Management actions to re-enforce lessons learned from this event to plant maintenance personnel were appropriate.

III. Engineering

E1 Conduct of Engineering

E1.1 Steam Generator Replacement Project (SGRP) Overview

During this inspection period, the licensee completed all SGRP activities. This included: complete restoration of the containment building dome liner, rebar, and concrete; all SG piping restoration; installation and testing of new SG instrumentation; modification of the feedwater regulating valves, and necessary adjustments to the advanced digital feedwater control system (ADFCS). The inspectors observed these activities and reviewed associated documents.

E1.2 Containment Dome Restoration

a. Inspection Scope (50001)

The inspector observed engineering and work activities associated with the containment dome restoration and reviewed the technical documentation associated with this work. The inspectors evaluated the restoration work to ensure the dome was restored in conformance with NRC regulatory requirements, the updated final safety analysis report (UFSAR), industry standards, and approved structural procedures.

b. Observations and Findings

The inspector performed direct observation, witnessed quality control (QC) holdpoints, and reviewed construction records and procedures related to the containment dome restoration after the steam generators were replaced.

b.1 Restoration and Test of the Liner Plate

The liner plate sections for both dome openings were reinstalled, fitted, and welded. The inspector observed a portion of the welding of the dome liner plate. During welding of the liner plate, the contractor was effective in detecting flaws and promptly repairing them. The radiographic examination in the Bechtel special processes manual contained the appropriate acceptance criteria as required by the ASME Boiler and Pressure Vessel Code, Section VIII, 1965 Edition.

The inspector verified that nondestructive examination of the selected sample of liner plate welds was performed in accordance with the Bechtel special processes manual, which included external surface magnetic particle test and a volumetric examination with a radiographic test.

The inspector reviewed the final acceptance documentation of the liner plate field welds and for both the "A" and "B" openings of the liner plate. The welds were accepted by two level III radiographers (Bechtel and RG&E), and certified acceptable through inter-office correspondence, dated May 14, 1996, from RG&E's Level III radiographer to RG&E Engineering. The inspector also interviewed the RG&E Level III radiographer and verified the adequacy of the records showing the acceptability of the welds.

b.2 Pneumatic Pressure Test of the Liner Plate's Leak Chase Channel

A leak chase channel was installed on the welded perimeter of the two restored openings. The leak chase channel was welded to the dome liner and was pneumatically tested in accordance with a Bechtel approved procedure. The results of the test were properly documented in Attachment "S" of the work plan and inspection record (WP&IR). The test gauge used in the pneumatic pressure test was calibrated with an expiration date of

May 16, 1996 (the test was performed May 11, 1996).

The effective use of the leak chase channel detected a few leaks that were promptly repaired. Upon completion of these repairs, the welds were successfully retested in accordance with the approved procedure using a currently calibrated test gauge.

b.3 Conclusions on the Restoration and Test of the Liner Plate

The results of the licensee's efforts effectively demonstrated that the leak tightness of the liner was restored. The licensee maintained the proper controls for welding and nondestructive examinations. The pneumatic test performed on the chase leak channel was effective. The leak chase installation enabled the licensee to detect a few leaks, but they were repaired in an effective and efficient manner.

b.4 Production of Rebar Splicing

To restore the rebar in both containment dome openings "A" and "B," the licensee spliced each section of the replaced rebar utilizing the "Cadweld" process. The production splices were performed by qualified and experienced craft personnel, and there were first-level supervisors available during the splicing to provide guidance and assistance to the craft. The installation of all rebar splices was performed in accordance with the splicing specification 22225-C-309(Q).

The inspector reviewed a sample of the rebar splice quality control (QC) records, WP&IR #C-DOB-01, Attachment M, dated May 8, 1996. The sample consisted of a night shift inspection performed on production splices CL144W, CL143W, CL142W, and CL113E. The QC acceptance records of these production splices were properly documented and were kept current by experienced supervisors assigned to maintain them.

To assure the adequacy of the production splices, the licensee implemented an installation and test program (referred to as "sister" test splices) to determine the tensile strength of samples of rebar spliced in each of three positions (horizontal, vertical, and diagonal). They were installed next to production splices, under the same conditions as the production splices, and were made by the same crew that made the production splices. The inspector verified that the sister splices were installed in accordance with the test splice procedure. The sister splices were removed from the dome and sent to a testing facility.

The tested splices were fractured under tension forces ranging from 105,000 to 135,000 PSI, which is above the standard ultimate tensile strength (90,000 psi) of the rebar material, and its standard yield strength (60,000 psi). These tests demonstrated that the rebar splices were stronger than the base rebar material. These results gave sufficient assurance of the structural

integrity of the cadweld splices. The inspector considered that the tests were performed by capable personnel in accordance with the approved test procedure.

b.5 Conclusions on Rebar Splicing

Based on direct observations of the production and test (sister) splices, the splicing operation was performed by qualified and experienced craft personnel. First-level supervisors were available during the rebar splicing and provided guidance and assistance to the craft. QC inspections were properly documented, and were kept current by experienced supervisors.

b.6 Concrete Placement, Pour, and Cure

The licensee evaluated the liner plate for the strains imposed by concrete placement, and for direct membrane forces and moments applied to bare liner sections by the removal and placement of new concrete. Calculation C-0402-13, Rev. 3, concluded that the add-on liner plate stiffeners were adequately designed to support the wet concrete and safe shutdown earthquake (SSE) loading. The angle beams welded to the liner plate were shown by the calculation to be capable of resisting the significant loads imposed on the liner plate during dome restoration.

Prior to the placement of new concrete, the pipeline for the concrete pumping system was securely installed, and a backup system for concrete placement was made available (e.g., pouring concrete with buckets). Anchor bolt installations for the concrete pipeline supports were completed and the results were properly documented in a WI&PR. Prior to the arrival of the first concrete truck, all commodities required for a successful concrete pour were installed and accepted per design documents. This was evidenced by the signing of the WI&PR quality control hold points prior to the arrival of the first concrete truck.

The inspector reviewed the concrete batch tickets and the official laboratory reports included in Attachment "Q" of the WI&PR for concrete placement. The concrete placement card indicated that the test results showed a minimum compressive strength of 5000 psi within 7 days as required.

b.7 Conclusions on Concrete Placement and Cure

The inspector concluded that there were no concerns with regard to the ability of the liner to withstand the load(s) imposed by the placement of new wet concrete or by a SSE.

In addition, at the receiving end, or ground elevation adjacent to the equipment hatch, the inspector concluded that:

- The licensee displayed excellent corporate, project, and engineering management involvement in the coordination and actual execution of the different steps of the concrete placement.

- The receiving controls for the concrete trucks, including the temperature and the slump test, were performed in a systematic, orderly manner and showed a precise control.

- Prior to actually pumping the concrete, the receiving and testing were closely monitored by Bechtel, RG&E engineering, and QC personnel.

- All the temperature and slump tests performed on each truck were within the acceptable ranges established in the concrete placement procedure.

- Security personnel performed their role in an excellent manner with a guard assigned to each truck.

- The lead contractor (Bechtel Power Corp.) displayed extensive experience and efficiency in their handling of assigned duties.

At the pouring end (top of the dome), the inspector concluded that:

- The slump and temperature test taken at the top of the dome were within the acceptable range established by the concrete placement procedure.

- Although a tedious operation, the placement was performed in a very efficient manner with the effective use of form openings and with the aid of high revolution vibrators.

Overall, the placement of concrete to restore the containment dome was performed effectively and efficiently by qualified personnel. The containment dome concrete was restored to its specified compressive strength, and it was properly prepared for testing to verify its structural integrity.

c. <u>Overall Conclusions</u>

Each sequential step in the structural restoration of containment and the leak tightness of the liner plate was implemented in an excellent manner by competent personnel, and in conformance with NRC regulatory requirements, the updated final safety analysis report (UFSAR), industry standards, and approved structural procedures. RG&E and Bechtel engineering provided good oversight and resolution of issues related to the SGRP project activities.

E1.3 Integrated Leak Rate Testing (ILRT) of the Containment, Post-Restoration

a. Inspection Scope (70307, 70313)

The scope of this inspection was to verify that the ILRT was performed in conformance with regulatory requirements, the updated final safety analysis report (UFSAR), approved ILRT procedures and specific containment design bases. The inspector performed direct observations and witnessed QC holdpoints at different phases of the ILRT.

b. Observations and Findings

The ILRT was conducted in accordance with Option B, "Performance-Based Requirements," of Appendix J to 10 CFR Part 50. Appendix J is entitled "Primary Reactor Containment Leakage Testing For Water-Cooled Power Reactors." Additional requirements for conducting the test are found in Technical Specifications 3.6.1 and 5.5.15, which in part require testing in accordance with the guidelines contained in Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995. RG 1.163 states that NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," provides methods acceptable to the NRC staff for complying with Option B, with four exceptions described in the RG. Option B of Appendix J was published in the Federal Register on September 26, 1995, and became effective on October 26, 1995. The test at Ginna was the first CILRT performed anywhere in the United States under Option B.

b.1 Procedure

The inspector reviewed Procedure No. RSSP-6.0, Rev. 21, and made the following observations:

Section 2.4 of the procedure states that the pre-test stabilization criteria may be as defined in ANSI/ANS-56.8-1987, ANSI/ANS-56.8-1994, or BN-TOP-1. Sections 2.3, 2.5, and 6.11.14 also contain references to the 1987 ANS standard. These references are inappropriate. NEI 94-01 states in section 8.0 that CILRTs should be performed using the technical methods and techniques specified in ANSI/ANS-56.8-1994 or other alternative testing methods that have been approved by the NRC. BN-TOP-1, Rev. 1, has been approved by the NRC (refer to NRC memorandum to NRR Project Managers, "10 CFR Part 50, Appendix J, Option B; Technical Specifications Amendments," dated March 13, 1996; available in PDR), but the 1987 ANSI standard has not.

When questioned, test personnel stated that Option A of Appendix J approved the 1987 standard, in section III.A.3.(a). To the contrary, that section states, in part: "In addition to the Total Time and Point-to-Point methods..., the Mass Point Method...is an acceptable method to use to

calculate leakage rates. A typical description of the Mass Point method can be found in the American National Standard ANSI/ANS 56.8-1987."

This passage did not approve the 1987 standard, but instead approved the Mass Point Method, a well-known method which had been described in many documents, including the 1987 standard. This point is further substantiated by the Federal Register notice which added the above words to Appendix J on November 15, 1988, and which states: "The intent of this limited amendment is not to endorse ANS 56.8..."

The intent under Appendix J, Option B, and RG 1.163 is that the 1994 edition of the standard be used, not the 1987 edition. As it turned out, the licensee did not make use of the 1987 standard during the test, so there was no violation. However, the procedure should be revised to remove references to the 1987 standard.

b.2 Pressurization and Stabilization Period

Several occurrences during the containment pressurization and stabilization period are noteworthy. They involved the search for, and response to, actual or suspected containment leaks. After the test pressure of approximately 60 psig was reached, the containment leakage rate remained higher than the as-left test acceptance criterion (0.15% by weight of containment air per day) for most of the stabilization period. Ultimately, the licensee determined that the pressurization process had perturbed the containment air more than expected and, after a long stabilization period (approximately 24 hr instead of the planned 4-8 hr), the leakage rate settled into an acceptable range. The test personnel pro-actively searched for leaks during this period, as described below.

b.3 Air Lock Door Leak

A CILRT is generally run with all of the containment isolation barriers closed, so if either one of two redundant barriers in a containment penetration is leak-tight, it will stop or limit leakage regardless of the leakage through the other barrier. This so-called "Minimum Pathway Leakage Rate" (MNPLR) is acceptable for a CILRT.

The licensee found during the pressurization period that the personnel air lock inner door was leaking. If the outer door were leak-tight, the test could pass, but the inner door leak would register on the CILRT measurement system as a real leak until the space between the inner and outer doors (i.e., the air lock barrel) pressurized to 60 psig. The inner door leak alone could have taken many hours to pressurize the air lock, so the licensee speeded up the process by quickly pressurizing the space with compressed air. Although the outer door was then found to have a small leak, it was too small to fail the test. The licensee's action shortened the test without affecting the result.

b.4 Inspecting the Containment Dome For Leaks

The licensee searched for possible leaks in the re-patched areas of the containment dome, using soap solution ("Snoop") and an ultrasonic detector. No leaks were found.

b.5 Pressurizing Steam Generator Secondary Side

The licensee investigated the possibility of a containment air leak into the steam generator secondary side through pipe fittings, past manhole or handhole covers, etc., that could have leaked out to the environment through an MSIV, steam dump valve, or relief valve. The SG secondary side was pressurized to approximately 50 psig to see if this would noticeably reduce the measured containment leakage rate. It did not, indicating that there was not a significant leak in this area. The secondary side remained pressurized for approximately two hours, and then was depressurized.

This was a legitimate diagnostic tool for finding leaks, but should not be used to block leaks during a CILRT. In this case, the secondary side remained pressurized into the early part of the actual test (after stabilization was complete). This was acceptable only because there was no significant leak through the secondary side.

b.6 Test Results

After the extended stabilization period, the test itself was completed in 8 hours, the minimum duration allowed under ANSI/ANS-56.8-1994. This was followed by a successful 5 hour verification test. The calculated 95% Upper Confidence Limit (UCL) on the containment integrated leakage rate was 0.11967% by weight of containment air per day (%/day) using the Mass Point Method. After small additions for leaks isolated before or during the test, and for leakage reductions from repairs or adjustments before the test (for the as-found calculation), the test acceptance criteria of 0.15%/day for the as-left leakage rate and 0.2%/day for the as-found leakage rate were satisfied. The test was performed in compliance with the requirements and guidelines of Option B of Appendix J, RG 1.163, NEI 94-01, ANSI/ANS-56.8-1994, and the plant's Technical Specifications.

b.7 Review of UFSAR Commitments

While performing the inspections discussed above, the inspectors reviewed the applicable portions of the UFSAR. The following inconsistencies were noted:

A number of inconsistencies were found in section 6.2.6, "Containment Leakage Testing," between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors. All were due to the fact that the UFSAR has not undergone its periodic update

since the plant switched over to Option B of Appendix J, and that the Technical Specifications were revised via License Amendment No. 61, on February 13, 1996. The licensee stated that the next UFSAR update will correct these inconsistencies.

c. Conclusions on the ILRT

The inspector concluded that the ILRT test procedure was deficient in that it referred to ANSI/ANS-56.8-1987. The procedure should be revised to remove references to this 1987 standard. The licensee's search for, and response to, actual or suspected containment leaks was commendable. The test director's performance was excellent and the contractor's supervisor demonstrated considerable knowledge and expertise. The test was successful and all acceptance criteria were met. The licensee needs to update the UFSAR in accordance with their recent license amendment regarding Appendix J.

E1.4 Post-Restoration Structural Integrity Test of the Containment

a. Inspection Scope (50001)

The scope of this inspection was to verify that the structural integrity test (SIT) was performed in conformance with regulatory requirements, the UFSAR, approved SIT procedures and specific containment design bases. The inspector performed direct observations and witnessed QC holdpoints at different phases of the SIT.

b. Observations and Findings

The objective of the SIT was to demonstrate that the reconstruction of the primary containment was adequate to withstand internal design basis accident pressure loads, after closure of two temporary construction openings that were made to accommodate the steam generator replacement. SIT test equipment was installed in areas affected by the temporary construction openings to monitor structural displacements, rebar strain, and concrete cracking during pressurization and depressurization of the primary containment structure.

b.1. Observations and Walkdown Prior to the SIT

SIT Procedure RSSP-6.0, "Integrated Leak Test," stated that all components inside containment not able to withstand a pressure of 72 psig were to be removed from containment or protected from damage by other means. The inspector reviewed control records which certified that all the necessary items were listed in Procedure RSSP 6.0, and were protected and/or removed from containment prior to the pressurization of the containment.

SIT Procedure RSSP-6.0 required inspection of all accessible interior and exterior surfaces of the containment structure prior to pressurization. The final report prepared by the licensee summarized this walkdown, and indicated that the containment insulation inspection (RSSP 6.5) and the

exterior inspection of the containment (RSSP 6.5) were properly documented.

b.2 Conclusion

All sensitive equipment inside containment was either protected or removed by the licensee as evidenced in the records. This precluded any damage on the safety-related equipment during pressurization of the containment. The walkdown performed by the licensee was thorough and complete. The initial conditions of the containment prior to the SIT were properly recorded for the "base line" SIT.

b.3 Personnel Performance During the SIT and Review of the SIT Results

During the containment pressure increase, the licensee's test coordinator and crew exercised proactive measures to identify possible leak paths out of containment. These proactive actions consisted of snoop checks, ultrasonic detection of the dome repair areas, and balloons used to detect valve leaks. The leak checks helped to ensure the success of the SIT.

The structural engineers supporting the SIT crews demonstrated a high level of experience, technical know-how, and safety responsibility by actively participating in eliminating possible leak paths and ensuring that containment temperature and pressure stabilized prior to proceeding with the various steps of the tests.

Based on a comparison of the actual measurements of the containment's behavior relative to the acceptance criteria in the SIT procedure, the containment demonstrated a higher level of structural integrity than was predicted. For example:

- The maximum measured containment vertical displacement at V1 was 0.116 inches at the maximum pressure of 72 psig, which is much less than the predicted 0.608 inches.

- Displacement and strain data was collected prior to pressurization, at various intervals throughout the test, and after depressurization. The maximum measured increase of the width of a crack in the outside surface of the containment during the test was 0.047 inch, which is less than the 0.060 inch allowed by the SIT.

b.4 Conclusions

The personnel involved in the SIT demonstrated a high level of technical competence during the test. The SIT demonstrated the structural integrity of the containment.

c. Overall SIT Conclusion

The inspector concluded that each individual step of the SIT was performed in an excellent manner and in conformance with regulatory requirements, the updated final safety analysis report (UFSAR), and the approved SIT procedure.

E2 Engineering Support of Facilities and Equipment

E2.1 Response to NRC Bulletin 96-01, "Control Rod Insertion Problems"

a. Inspection Scope (37551)

The inspector reviewed the licensee's response and follow-up actions to NRC Bulletin 96-01, issued on March 8, 1996, which reported recent control rod insertion problems experienced at several Westinghouse designed pressurized water reactors (PWRs).

b. Observations and Findings

Bulletin 96-01 alerted PWR licensee's to recent failures where full control rod insertion was not achieved upon a scram signal. Operators of Westinghouse PWRs were required to respond to the Bulletin because the specific rod insertion incidents all occurred at Westinghouse design plants in high burnup fuel assemblies (>42,000 MWD/MTU). One of the Bulletin's requested actions included measuring and evaluating drag forces for all rodded fuel assemblies.

On April 10 & 11, 1996, the inspector witnessed the control rod drag tests performed by the licensee in the spent fuel pool. The tests were performed as part of the normal outage activity that rearranges the control rods into those fuel assemblies designated for control rod positions for the next operating core. The test apparatus consisted of the normal control rod lifting and transfer tool, with a load cell connected to an instrument recorder and a strip chart record accurate to within one pound (lb). Each control rod was fully withdrawn and inserted in the same assembly it was in during the past operating cycle.

RG&E reported their rod drag data to Westinghouse and the NRC indicating that only two of the control rods showed drag levels in the guide thimble region that exceeded the Westinghouse limit of 40 lbs. in that region. None of the control rods exceeded the drag limit in the dash pot region. The inspector reviewed the licensee's submitted data and performed an independent measurement of selected strip chart data records for the withdrawal and insertion tests in the guide thimble region. The following results were obtained.

Rod Drag Data in the Guide Thimble Region

	RG&E Strip Chart Measurement		NRC Independent Measurement	
Rod Number	Withdrawal Drag- lbs	Insertion Drag - lbs	Withdrawal Drag - lbs	Insertion Drag - lbs
A65	33	39	33	39
C52	41	29	41	28
C51	40	35	40	35
E80	40	27	43	25
D72	28	38	26	38
D69	40	25	40	25

The inspector noted that one additional fuel assembly (E80) exceeded the drag limit during the withdrawal test in the guide thimble region. The fuels system engineer concurred with this measurement and contacted Westinghouse for an assessment. It was noted that the high withdrawal value of 43 lbs. occurred as a momentary peak that was not sustained for a long period. Westinghouse and the licensee considered that the peak represented a short duration reaction force combined by the fuel assembly, the control rod, and the lifting tool. The peak did not appear to represent a concern that a high drag condition existed with the E80 control rod or its associated fuel. The inspector reviewed this conclusion with an NRR technical specialist who also concurred. The licensee considered that all the rod drag data had a small positive bias due to additional drag forces present in the rod lifting tool itself.

c. Conclusions

The inspector concluded that the control rod drag testing conducted by RG&E adequately demonstrated that the rods currently used in the reactor do not experience the high drag conditions reported in Bulletin 96-01. The rod testing in the spent fuel pool was well controlled and the drag data was captured with accurate instrumentation. The licensee's test methodology and data review were accurate, and the results were reported to Westinghouse and the NRC in a timely fashion.

E2.2 Service Water Pump Discharge Piping Fasteners

a. Inspection Scope (37551)

The inspector identified a condition where 3 safety-related service water pumps did not have full thread engagement on fasteners installed in the pump discharge flange. RG&E's system engineer and corporate engineering departments evaluated this condition for acceptability. The inspector reviewed the results of the licensee's evaluation.

b. Observations and Findings

During a walkdown inspection of the Ginna Station screenhouse equipment on May 29, 1996, the inspector identified that all 12 fasteners on 3 of the 4 service water pump discharge flanges lacked approximately 1/2 inch of full thread engagement in their 1-1/4 inch tapped flanges. The inspector contacted the service water system engineer to discuss this condition and to determine if it was in accordance with the service water piping design requirements. The system engineer in turn contacted an RG&E corporate mechanical design engineering supervisor who initiated an ACTION Report (AR 96-0622) to complete an analysis (DA-ME-96-061) of the design piping loads at these connections.

The analysis evaluated the piping loads under maximum accident and seismic conditions, and concluded that the mechanical strength of these joints would not be jeopardized. This was because of the near proximity of a flexible expansion joint, the number and size of the fasteners, and because the amount of actual thread engagement was equal to at least one thread diameter. These results were presented to the plant operations review committee (PORC) for closeout of the ACTION report, However, it was also reported to the PORC that this did not represent a "nonconforming condition." As such the ACTION Report did not have to be reviewed by the QA organization before closeout.

The inspector questioned the engineering supervisor about the basis for the conclusion that this did not represent a nonconformance. He indicated that a review of the design basis requirements contained in the original engineering specifications for these pipe joints was not accomplished. He further indicated that the question of a nonconformance was intended to refer only to the strength of these joints under maximum pipe loading conditions. However, he stated that a review of the design basis and piping design specifications would be made in order to determine what engineering assumptions were made regarding the amount of thread engagement for fasteners in these flanges.

In a follow-up letter to the PORC, RG&E Mechanical Engineering indicated that the original design information available to RG&E for the service water piping did not make specific reference to minimum thread engagement requirements. Also, the pump manufacturer's drawing did not refer to a bolt length or to the amount of thread engagement. An RG&E mechanical engineering technical specification (ME-320) provided guidance indicating that bolts in general should be fully engaged with a nut, and that this was consistent with the current conditions on the pumps with one full thread diameter of engagement. The letter further noted that a modification to the service water pump seismic supports was made in 1984 that specified the use of 2-1/2 in long fasteners at this location. The above information was incorporated into the initial design analysis through a revision and the PORC accepted the ACTION Report for closure.

c. Conclusions

The licensee's disposition of the service water pump fastener thread engagement analysis was adequate. The initial difficulty with addressing the potential existence of a nonconforming condition could not be fully resolved either because the applicable design documents did not have any specifications on thread engagement, or because original design requirements that may have specified thread engagement were not available to RG&E Mechanical Engineering. The inspector considered that the this ACTION Report exhibited a potential for a nonconforming condition. The lack of a QA review could allow a true nonconforming condition in a similar circumstance to go unidentified and unreviewed by the licensee.

E2.3 Operator Workaround Controls

a. Inspection Scope (37551)

The inspector reviewed the operator workaround controls and the specific workarounds dispositioned by engineering during the past refueling outage.

b. Observations and Findings

Administrative procedure A-52.16, "Operator Workaround Control," defines an operator workaround as a long term equipment deficiency that requires additional operator action to compensate for the condition. The procedure requires that the operations manager perform a quarterly assessment of the aggregate impact of existing workarounds to ensure that impact will not challenge the operators ability to respond to transients or abnormal events. The manager of operations presents his quarterly reviews to the PORC to ensure that the appropriate level of safety review for each workaround is performed, and that actions are initiated to correct or modify plant equipment to remove the workaround conditions. Engineering participates in these reviews and provides the status of the ongoing engineering actions for resolution of the workarounds. The workarounds inplace prior to the last refueling outage and the associated engineering actions are listed below.

1) EM-877 must be performed for MOV-871A & 871B if SI Pump A or B breaker is racked out (TSR 94-210).

2) Manual service water alignment is required for the TDAFW pump oil cooler (TSR 95-134).

3) Reactor compartment cooling fan dampers fail closed and fans trip on loss of instrument air (TSR 94-229).

4) MOV-4615 and 4616 must be locally throttled open when restoring SW isolation to the turbine building (TSR 95-169).

5) No direct position indication of the pressurizer spray valves is available, complicating diagnosis of a stuck valve (EWR-5105).

6) MOV-515 (PORV block valve) closed due to PORV-431C leakage.

7) MOV-516 (PORV block valve) closed due to PORV-430 leakage.

8) Manual Reactor trip required with loss of safeguards buses (EWR-10199).

9) Cannot determine internal position of condensate pump discharge valve V-3920, could cause system pressure transients with pump starts and stops. (WO 19504420).

10) Intermittent A-train core exit thermocouple scanning failures are affecting plant computer indications (WO19601036).

At the end of the refueling outage, only two workarounds still remained in the Ginna plant. No. 4) above requires completion of TSR 95-169, and no. 8) above only requires completion of the Ginna PSA report.

c. Conclusions

The inspector considered that the definition of operator workarounds in A-52.16 closely matches the NRC definition. Very good and effective engineering support of operations was noted by eliminating nearly all operator workarounds prior to completing the refueling outage. The remaining workarounds do not impose a significant burden on operators since 1) manual restoration of SW isolation to the turbine building is a long term activity in a post-accident scenario, and 2) a manual reactor trip is an immediate action easily performed by operators upon loss of the safeguards buses.

E8 Miscellaneous Engineering Issues

E8.1 Spent Fuel Pool Cooling and Refueling Activities

A review of the current licensing basis, design basis and refueling practices was conducted by the NRR Project Manager to determine if the spent fuel pool design and refueling practices at Ginna were consistent with the current licensing basis as documented in the UFSAR.

No new issues, open items or commitments were identified during this review. Two discrepancies identified during an assessment in 1995 were resolved. The results of this review are included as Attachment 1 to this inspection report.

IV. Plant Support

R2 Status of RP&C Facilities and Equipment

R2.1 Preparation of Original Steam Generators for Shipment

a. Inspection Scope (86740)

A Nuclear Materials Safety and Safeguards (NMSS) staff member met with the licensee at the Ginna Station to discuss their preparations for shipment of the original steam generators (OSGs) that were removed during the 1996 refueling outage. The purpose of the meeting was to review RG&E's efforts to-date to determine if they are in accordance with the revised regulations, and if licensee interpretations of certain regulations were consistent with recent NRC and Department of Transportation (DOT) activities.

b. Observations and Findings

Revisions to NRC and U.S. Department of Transportation (DOT) regulations, which became effective April 1, 1996, impacted the regulatory considerations necessary for shipment of the Ginna Station OSGs, and are different from the regulatory considerations in effect for previous OSG shipments by other utilities. Items discussed with the licensee included: 1) the planned shipping method and technique (i.e., by barge, not with internal grout, shipment to the HAKE Company for destructive decontamination); 2) cost estimates; 3) physical characterization of the OSGs (e.g., possible liquid content); 4) characterization of the source term and distribution, including the importance (based on past SG shipments) of transuranic nuclides to the total normal form activity fraction; 5) the need for and means of adding shielding or other packaging to the OSGs; and 6) the potential impacts of three specific provisions of the regulations. These include the (new) definition for surface contaminated objects (49 CFR 173.403), the dose rate limit at three meters from the unshielded contents (49 CFR 173.427(a)(1) and 10 CFR 71.10(b), and the conveyance activity limit (49 CFR 173.427(f)). The NMSS staff member informed the licensee of pending guidance from NRC on the topic of shipment of large components such as OSGs.

c. Conclusions

RG&E's efforts to-date for preparation of the OSGs are consistent with the revisions to the NRC and DOT regulations. The licensee was cognizant of the important regulatory revisions which will affect OSG shipments, and has identified the relevant technical issues.

S2 Status of Security Facilities and Equipment

S2.1 Containment Reestablished as a Vital Area

a. Inspection Scope (71750)

The inspectors reviewed the licensee's process for "revitalizing" the containment building after the steam generator replacement project and prior to refueling the reactor.

b. Observations and Findings

The licensee "devitalized" the containment building at the beginning of the refueling outage in order to facilitate more efficient movement of personnel, equipment, and material in and out of containment for the steam generator replacement project. The reduced access controls applied only to the containment building and they remained in effect only during the time period when no fuel was in the reactor. On May 20, 1996, prior to commencing refueling operations inside the containment, the licensee performed a detailed walkdown inspection of all accessible containment areas in accordance with a new security procedure that was specifically written to reestablish the vital area.

The inspector reviewed the revitalization procedure and found it to contain a detailed inspection process with specific search and inspection points throughout the containment building. The procedure prescribed an organized and systematic walkdown, simultaneously performed under the direction of a search coordinator by the security force, the operations department, and the radiation protection organization. The walkdown inspection was performed by two separate teams, and consisted of a well controlled, point-by-point surveillance throughout all containment spaces.

After the vital area controls were reestablished, the inspectors performed a walkdown of all containment areas. The licensee had restored all containment access restrictions and controls by reinstalling the equipment hatch, removing and closing off the temporary access route used during the outage, providing security guard posts at the personnel and equipment hatches, and performing a general systems walkdown to assure that system integrity had been maintained or restored from the outage.

c. Conclusions

The inspectors concluded that the licensee fully and effectively restored the proper vital area access controls for the containment building prior to conducting refueling operations. All visible portions of plant systems inside containment were properly evaluated for integrity and the vital area was properly restored.

S4 Security and Safeguards Staff Knowledge and Performance

S4.1 Security Officer Found Inattentive While on Duty

a. Inspection Scope (71750)

The inspector reviewed the circumstances surrounding an incident the licensee identified where a security officer was inattentive to his duties. The licensee's follow-up actions were evaluated for their effectiveness in preventing a recurrence.

b. Observations and Findings

On May 28, 1996, a security supervisor discovered a security officer inattentive to his duties while posted at the equipment hatch entrance to the containment building with the plant in Mode 5. His assigned duty at the time was to control access to the containment building through the unlocked equipment hatch door and to prevent any unauthorized exit or entry. The supervisor immediately relieved the officer and remained at the post until being subsequently relieved by another officer. Also, the security organization immediately conducted a search of the containment building and determined that no unauthorized entries had been made. The licensee reported this incident to the NRC within one hour, as required by 10 CFR 73.71.

The inspector noted that the officer was inattentive only for a short time based on the fact that he had properly responded to a radio call check only a few minutes earlier. The inspector reviewed the licensee's administrative controls for security officers to remain alert on duty, and found them to be adequate. This incident appeared to be only a matter of one individual's performance. The inspector also noted that the officer did not exceed any of the licensee's administrative limits on overtime. The inspector found the licensee's response to this event and the corrective actions were appropriate.

c. Conclusions

The licensee took prompt and adequate corrective actions after discovering the inattentive security officer by immediately relieving the individual and by performing a check for unauthorized containment entries. The licensee has adequate administrative controls in place to avoid further incidents of this nature. Prompt notification to the NRC was made following the incident.

S8 Miscellaneous Security and Safeguards Issues

S8.1 (Closed) LER 96-S01: Secondary Review of Access Authorization Files Results in Discovery of a Contractor Employee with Improper Unescorted Access Authorization.

On March 15, 1996, during a secondary review of employee access authorization files, the licensee discovered that an unacceptable entry was made on a contractor employee's initial processing for unescorted access into vital areas. The individual

was granted access on February 20, 1996. His access authorization was immediately revoked, and the licensee subsequently reviewed all of his activities in vital areas. It was determined that there was no indication of any suspicious or unusual activity on his part.

The inspector reviewed the LER and found it to be thorough and complete. The reporting requirements of 10 CFR 73.71 were fulfilled both in substance and timeliness of the report. The licensee promptly corrected the conditions and identified long term corrective actions to prevent a recurrence. This LER is Closed.

S8.2 (Closed) LER 96-S02: Contractor Employee with Temporary Unescorted Access Authorization Falsified the Reason for Termination from a Previous Employer.

On March 25, 1996, the licensee discovered that a contractor employee with temporary unescorted access to vital areas had falsified the reasons for termination from a previous employer. Since this employment was before the one year employment verification process for access authorization (per 10 CFR 73.56), the falsification was not discovered before unescorted access was granted on March 12, 1996. The licensee also discovered another falsification documented in a previous employment period at the Ginna Station. The individual's unescorted access authorization was immediately suspended. The licensee considered that all administrative controls for granting unescorted access were in full accordance with 10 CFR 73.56.

The inspector reviewed this LER and found it to be well documented with all factual information well supported. All reporting requirements of 10 CFR 73.71 were satisfied. This LER is closed.

V. Management Meetings

X1 Exit Meeting Summary

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of the inspection. The exit meeting for the current resident inspection report 50-244/96-05 was held on June 17, 1996. The operator training aspects of this inspection were discussed with the licensee at the exit for an initial license retake examination, Report Number 50-244/96-04(OL).

L1 Review of UFSAR Commitments

A recent discovery of a licensee operating its facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected to verify that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. An inconsistency was noted concerning the Integrated Leak Rate Test as discussed in Section E1.3.b.7.

ATTACHMENT 1

A. SYSTEM DESIGN:

SUMMARY OF SPENT FUEL POOL (SFP) RERACKING/STATION MODIFICATIONS/SYSTEMATIC EVALUATION PROGRAM (SEP)

The original Ginna Station SFP cooling system consists of a single permanently installed cooling loop containing one stainless steel horizontal centrifugal circulating pump, one shell-and-tube heat exchanger and associated piping, valves and instrumentation. A small purification loop, and a loop-surface skimmer loop, were also provided.

The spent fuel assembly storage arrangement was modified in 1977. The original spent fuel racks were replaced with higher density flux trap type racks. The increased storage capacity from 210 to 595 fuel assemblies.

In 1979, a skid-mounted back-up system, designed and procured in the previous year, was installed. It was comparable in capacity to the original SFP cooling system. The designs of the pump, heat exchanger, were similar to the original. The skid-mounted back-up system used heavy-duty hoses to interconnect the components and to interface with existing plant systems.

Improvements were made to the portion of the Auxiliary Building ventilation system serving the SFP in 1981. This modification installed a set of fire dampers in the ventilation system ductwork.

Also in 1981, to accommodate future SFP storage needs, and to address NRC staff concerns regarding the Integrated Plant Safety Assessment Systematic Evaluation Program (SEP) Topic IX-1, "Fuel Storage" a new, larger, fully-qualified SFP cooling loop was proposed. The proposed system, which was designed to ASME Code class and Seismic Category I criteria, was installed in 1988. It consisted of another permanently installed cooling loop containing one stainless steel horizontal centrifugal circulating pump, one shell-and-tube type heat exchanger and associated piping, valves and instrumentation. The new system was installed in parallel with the original SFP cooling system. This new SFP cooling system (loop 2), together with the combination of the original SFP cooling system (loop 1), and the skid -mounted SFP cooling system (loop 3), continues to provide the Ginna plant with two trains of 100% capacity SFP cooling.

In 1985, six of the flux trap type spent fuel racks were replaced with new higher density fixed poison type spent fuel racks. This further expanded the storage capacity from 595 to 1016 fuel assemblies.

In 1986, the fuel rods from 16 assemblies were consolidated into eight canisters (two additional canisters were filled with non-fuel-bearing hardware resulting from disassembly).

GINNA NUCLEAR POWER PLANT

B. SUMMARY OF CURRENT LICENSING BASIS (CLB) REQUIREMENTS/LIMITS/COMMITMENTS

RE: SPENT FUEL POOL (SFP) DECAY HEAT REMOVAL/REFUELING OFFLOAD PRACTICES

1. TS 3.9.11: Water level at least 23 feet above top of stored irradiated fuel.

   TS 3.9.12: Spent fuel pool boron concentration.

   TS 3.9.13: Storage Region II burnup/enrichment restrictions.

2. The "normal" basis heat load for an inventory of fuel assemblies from annual refueling discharges through 1998 and offload of one-third core in 1999 under refueling conditions is 7.9 x 106 BTU/hr (FSAR 9.1.3). The corresponding temperature limit for this scenario is 120 °F based on operator comfort. Operating time, decay time, and other parameters important to heat load calculation are not identified in the FSAR or other CLB documents.

3. The "safety" basis heat load for an inventory of fuel assemblies from annual refueling discharges through 1998 and offload of a full core in 1999 under refueling conditions is 16 x 106 BTU/hr (FSAR 9.1.3). The corresponding temperature limit for this scenario is 150 °F based on providing alternate cooling before temperature exceeds 180 °F following a loss of the primary cooling loop (loop 1). Full core offloads are described as occurring on 10 year intervals to support inservice inspection and "on other occasions when it is deemed necessary" (FSAR 9.1.3.1). Again, operating time, decay time, and other parameters important to heat load calculation are not identified in the FSAR or other CLB documents,

4. The loop 2 (primary loop) spent fuel heat exchanger B is sized to remove the safety basis and normal basis heat loads using service water at 80°F with the service water temperature rise constrained to 20°F and 15°F respectively.

5. Adequate redundancy is provided to address a single failure. Loop 2 (the primary loop) can handle the safety basis heat load alone with a maximum temperature of 150°F. Loops 1 and 3 (the skid mounted loop) together can handle the safety basis heat load with a maximum temperature of 150°F. Each of Loops 1 or 3 can alone handle the normal basis heat loads alone with a maximum temperature of 120°F. Normally, either Loop 1 or Loop 2 is operated alone to maintain the desired pool temperature. Loop 3 is connected and operated only when high heat loads are expected.

6. Pool structural analysis based on bulk pool temperature of 180°F.

GINNA NUCLEAR POWER PLANT

B.1 SUMMARY OF CURRENT LICENSING BASIS (CLB) DISCREPANCIES/RESOLUTIONS

CLB COMPLIANCE REVIEW

Discrepancy:

1. The NRC staff's assessment of spent fuel pool storage in 1995 determined that the licensee lacked administrative controls regarding verification that actual decay heat load is below the appropriate level for the type of offload. Determine what corrective actions the licensee has taken prior to refueling.

Resolution:

Full-core offloads are not a regular practice. The licensee has accomplished full core offloads during refueling outages in the spring of 1971, 1979, 1981, 1989, 1990, 1993, and 1994. The licensee will perform a full-core offload during the spring 1996 refueling outage to accommodate steam generator replacement. The licensee has offloaded a full-core 7 times in 26 years. Not including the 1996 refueling outage the licensee will have offloaded a full core twice in five years.

All full-core offloads at Ginna were in support of major inspection and maintenance activities. Therefore the "normal" basis heat load will continue to be 7.9 MBTU/hr and the "safety" basis heat load will continue to be 16 MBTU/hr.

Full-Core Offloads:

Year	Major Inspection/Maintenance Activity
1971	Fuel cladding inspection
1979	10-year inservice inspection (ISI)
1981	Reactor coolant pump bowl inspection
1989	10-year ISI
1990	Fuel inspection
1993	Service water system (SWS) valve refurbishment
1995	SWS valve refurbishment
1996	Steam Generator replacement

The licensee has no formal procedures which require an annual SFP heat load analysis to be performed. Beyond the 100-hr minimum in-vessel decay time required by the Ginna Technical Specifications, there are no formal procedural requirements which restrict the timing of fuel movement from the vessel to the SFP.

The SFP cooling system heat load capacities are given in Table C.1 for the full-core offload of spring 1996. Table C.1 demonstrates adequate redundancy with all three cooling loop availability during a full-core offload.

Discrepancy:

2. Because the last 5 refuelings have involved full core offloads and a full core offload is planned this year to support steam generator replacement, determine whether the licensee plans to alter the description of "normal" basis heat load.

Resolution:

It is the staff's understanding that the licensee does not plan to alter the description of "normal" basis heat load.

The licensee has accomplished full-core offloads during refueling outages in the spring of 1971, 1979, 1981, 1989, 1990, 1993, and 1994. The licensee will perform a full-core offload during the spring 1996 refueling outage to accommodate steam generator replacement. The licensee has offloaded a full-core 7 times in 26 years. Not including the 1996 refueling outage the licensee will have offloaded a full-core twice in five years.

The licensee has established a "normal" basis heat load of 7.9 MBTU/hr, and a "safety" basis heat load of 16 MBTU/hr for the SFP. The licensee has based the heat load on projected spent fuel assembly inventory from normal refueling operations through 1998 combined with one-third core discharge at the end of 1999 (date at which the SFP will be filled). By letter to the NRC, June 9, 1981, the licensee responded to the staff's request for information regarding modification of the SFP cooling system and the licensee's projected heat loads for full-core discharges. These projections indicate that the "safety" basis heat load limit would be satisfied by progressively extending the irradiated fuel decay time in the reactor vessel prior to initiation of fuel movement from 8 days in 1981 to 14 days in 2009 (end of life). The progressively increasing decay time reduces the decay heat from the full-core discharge to accommodate the increasing decay heat load from earlier refueling outage discharges. During a SFP storage assessment, performed by the NRC staff from June 19-23, 1995, the team reviewed a spring 1994 fuel cycle-specific SFP decay heat analysis that demonstrated the decay heat load would be below the "safety" basis value of 16 MBTU/hr after a 10-day in-vessel delay.

All full-core offloads at Ginna were in support of major inspection and maintenance activities (see item 1 above). Therefore the "normal" basis heat load will continue to be 7.9 MBTU/hr and the "safety" basis heat load will continue to be 16 MBTU/hr.

The SFP cooling system heat load capacities are given in Table C.1 for the full-core offload of spring 1996. Table C.1 demonstrates adequate redundancy with all three cooling loop availability during a full-core offload.

C. SUMMARY OF COMPLIANCE WITH CURRENT LICENSING BASIS (CLB) REQUIREMENTS

(1) A sustained loss of spent fuel pool (SFP) cooling or a significant loss of SFP coolant inventory is a remote event at Ginna due to certain design features and procedural controls, listed below:

(a) The availability of multiple loops for the SFP cooling.

(b) The extended period available to recover from a loss of SFP cooling to the onset of bulk boiling conditions in the SFP when the reactor is at full power.

(c) The procedural controls that govern the SFP cooling and support systems when a full core offload to the SFP is accomplished.

(d) The anti-siphon protection provides for flow-paths capable of draining SFP coolant levels below the top of stored fuel.

(2) Administrative requirements control the water level at least 23 feet above the top of the stored irradiated fuel by Section 5.2.4 of Operating Practices Procedure No. O-15.1, "Administrative Requirements for Reactor Head Lift, Core Component Movement and Periodic Status Checks," Revision 4 (February 24, 1996).

(3) Administrative requirements control the SFP boron concentration as outlined in Section 5.1 of Operating Practices Procedure No. O-15.1, Rev 4. The SFP boron concentration is also controlled by the Core Operating Limits Report (COLR) located in the plant Technical Requirements Manual.

(4) Administrative requirements control the SFP storage Region II burnup/enrichment restrictions outlined in Sections 3.9, 3.10, and 3.11 of Refueling Procedure No. RF-8.4,"Fuel and Core Component Movement in the Spent Fuel Pit," Revision 44 (February 22, 1996).

(5) Table C.1 below summarizes SFP cooling system heat load and capacities for the current 1996 refueling outage during a full-core offload.

(6) Possible SFP leakage reported at Ginna Station:

The licensee has identified contaminated water leakage into the residual heat removal (RHR) pump room potentially due to leakage from the SFP (NRC Region I Inspection Report No.s 50-244/95-15, 50-244/95-17, 50-244/95-20 and Draft 50-244/96-01). The RHR pump room is located on the southwest side of the plant adjacent to the SFP. The licensee, based on sample analysis, estimates possibly one cup of water per day. The licensee is pursuing onsite environmental well sampling to confirm any contamination from the SFP.

The licensee's action plan to address the potential leakage into the RHR pump room include:

(a) Continued cleaning of the RHR pump room walls and divert all in-leakage to a leakage collection system.

(b) Installation of a sensitive water level indicator in the SFP to quantify water losses.

(c) Quantification of evaporative losses from the SFP with consideration of total pool makeup to establish the net water loss due to SFP leakage.

(d) Continued water sampling of the intermediate building subbasement and environmental monitoring wells on at least a monthly basis.

(e) The licensee has employed a consultant to further investigate the plant hydrology/geology (includes other groundwater leakage in other areas).

GINNA NUCLEAR POWER PLANT

SUMMARY OF SFP COOLING HEAT LOAD AND CAPACITIES

1996 REFUELING OUTAGE

Date	Heat Load (Mbtu/hr)	Lake Temp Assumed (deg F)	"B" Sys Capacity (Mbtu/hr)	"A" Sys Capacity (Mbtu/hr)	Modified Skid Capacity (Mbtu/hr)	Available Backup Capacity (Mbtu/hr)	Comments
4/9	16.3	50	21.0	13.5	17.1	30.6	Earliest offload
4/10	16.0	50	21.0	13.5	17.1	17.1	Lampson rotated
4/11	15.46	50	21.0	Not available	17.1	17.1	MCC C Outage
4/23	11.96	50	Not available	13.5	17.1	17.1	Bus 16 Outage
5/1	10.64	60	19.0	12.0	15.0	27.0	Lake temp. assump. change to 60 deg
5/4 - 5/6	<10.64	60	19.0	12.0	15.0	12/15	MOV static testing
5/15	<10.64	80	16	8	>8	>16	Lake Temp Change to 80 deg

D. SINGLE FAILURE CRITERION EVALUATION

RE: NUREG 0800, "STANDARD REVIEW PLAN FOR THE REVIEW OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS (SRP)."

The Ginna Nuclear Power Plant CLB does not require conformance to SRP 9.1.3. However, the Ginna Station SFP cooling and cleanup systems compare with most of the SRP areas. The latest upgrades to the SFP cooling system (Loop 2, Pump B), although not active failure proof, is designed to seismic Category I and Appendix B requirements. The original non-seismic SFP cooling system (Loop 1, Pump A) remains in place as a fully functional backup to Loop 2, Pump B.

The licensee has no plans to backfit SFP cooling system requirements into the CLB.