U.S. NUCLEAR REGULATORY COMMISSION

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Region I

Report No. 50-244/82-15

Docket No. 50-244

License No. DPR-18 Priority -- Category C

Licensee: Rochester Gas and Electric Corporation
89 East Avenue
Rochester, New York 14649

Facility Name: R. E. Ginna Nuclear Power Plant

Inspection at: Ontario, New York

Inspection conducted: August 1-31, 1982

Inspectors: R P Zimmerman — 9/9/82
R. P. Zimmerman, Senior Resident Inspector — date signed

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Approved by: HB Kister — 9/10/82
H. B. Kister, Chief, Reactor Projects Section 1C, Division of Projects & Resident Programs — date signed

Inspection Summary:
Inspection on August 1-31, 1982 (Report No. 50-244/82-15)
Areas Inspected: Routine, onsite, regular and backshift, inspection by the resident inspector (97 hours). Areas inspected included: plant operations; surveillance testing; Licensee Event Reports; followup of IE Bulletins; followup of licensee actions on previous inspection findings; followup of implementation of Three Mile Island Lessons Learned; periodic and special reports; and accessible portions of the facility during plant tours. Results: Of the 8 areas inspected, one violation was identified in one area (Failure to submit a required Thirty Day Written Report-Paragraph 3).

Region I Form 12
(Rev. April 77)

DETAILS

1. Persons Contacted

The below listed technical and supervisory level personnel were among those contacted:

E. Beatty, Operations Supervisor
J. Bodine, QC Engineer
L. Boutwell, Maintenance Supervisor
C. Edgar, I & C Supervisor
D. Filkins, Supervisor Health Physics and Chemistry
D. Gent, Results and Test Supervisor
G. Larizza, Operations Engineer
T. Meyer, Technical Engineer
R. Morrill, Training Coordinator
B. Quinn, Health Physicist
T. Schuler, Maintenance Engineer
B. A. Snow. Plant Superintendent
S. M. Spector, Assistant Plant Superintendent
J. Straight, Fire Protection and Safety Coordinator
R. Wood, Supervisor of Nuclear Security

The inspector also interviewed and talked with other licensee personnel during the course of the inspection.

2. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (244/77-18-01): Realignment of the emergency plan training program to be consistent with the functional areas, requirements and structure of the emergency organization will be reviewed during followup of significant finding #4 documented in NRC Region I Inspection Report 81-22. This item is administratively closed.

(Closed) Unresolved Item (244/77-18-02): Administrative Procedure (A)-103.8, Emergency Plan Training Program, Revision 2, dated July 30, 1982 and A-103.9, Fire Brigade Training, Revision 0, dated December 22, 1981 have been revised to describe the scope, frequency and degree of offsite agency participation for emergency drills.

(CLosed) Unresolved Item (244/77-18-03): Site Contingency Procedure (SC)-1, Radiation Emergency Plan, Revision 18, May 22, 1982, requires that a radiation emergency exercise be conducted annually. A-103.9, Emergency Plan Training Program, which states that an emergency exercise must be conducted each calender year, will be revised to conform to SC-1 and 10 CFR 50, Appendix E.

(Closed) Inspector Follow Item (244/82-06-01): Licensee letter dated August 24, 1982, J. Maier (RG&E) to R. Haynes (NRC) submitted a corrected 1981 report of personnel exposure by exposure groups.

3. Review of Plant Operations

a. Throughout the reporting period, the inspector reviewed plant operations. Activities in progress included routine, full power operation with the exception of a reactor trip on August 6 and a 5% turbine runback on August 17. The trip on August 6 occurred while venting the reference leg of pressurizer level transmitter LT-428, which also serves as the sensing location for two pressurizer pressure transmitters. During the venting operation, a low pressure condition was generated in the reference leg and a low pressure reactor trip signal resulted. The unit returned to power operation on August 7. On August 17, a turbine runback to 95% power occurred during routine surveillance testing of Power Range Channel 44, due to an operator inadvetently returning the dropped rod bypass switch to "normal" while simulating a dropped rod-runback condition. Full power was restored within approximately one hour.

b. Shift Logs and Operating Records

Operating logs and records were reviewed against Technical Specification and administrative procedure requirements. Included in the review were:

Control Room Log	-	daily during control room surveillance
Daily Surveillance Log	-	daily during control room surveillance
RCS Leakage Surveillance	-	daily during control room surveillance
Shift Supervisor's Log	-	daily during control room surveillance
Plant Recorder Traces	-	daily during control room surveillance
Plant Process Computer Printouts	-	daily during control room surveillance
Jumper/Bypass Log	-	August 24, 1982
Station Event Reports	-	all issued between 8/1-31/82
Maintenance Work Orders and Trouble Cards	-	all issued between 8/1-31/82

The logs and records were reviewed to verify that entries were being properly made; entries involving abnormal conditions provided sufficient detail to communicate equipment status, deficiencies, corrective action restoration and testing; records were being reviewed by management; operating orders did not conflict with the Technical Specification or reporting requirements; logs and records were maintained in accordance with Technical Specification and administrative procedure requirements.

The inspector noted on August 31, 1982, that a Thirty Day Written Report had not been generated from the Station Event Report (A-25.1) previously

issued and reviewed on July 12, 1982. Specifically, all fire detection instruments listed in Technical Specification (TS) Table 3.14-1 had been declared inoperable on July 12 as a result of exceeding the TS surveillance frequency. In addition to initiating a fire watch patrol within one hour, TS 3.14.1 requires that if a fire detection instrument(s) is inoperable for greater than fourteen days, a Thirty Day Written Report must be submitted outlining the cause of the inoperability and plan for restoring the instrument(s) to operable status. Although an hourly fire watch patrol was established as required, several fire detection instruments were not returned to operable status within fourteen days. Failure to submit a written report is contrary to TS 3.14.1 and is considered a violation (82-15-01).

During review of the Jumper/Bypass Log, the inspector noted that jumper 81-21 was installed on June 5, 1981 to remove alarm indication in the Control Room when the fire suppression supply valve (V5208) to the Cable Tunnel was in the closed position (tamper alarm). Investigation by the licensee determined that the jumper had been installed during modification/upgrade of the fire protection system to prevent receiving numerous annoyance alarms in the Control Room from the existing tamper alarm circuitry. It was further determined that the jumper had no effect on the current upgraded system as new tamper alarm circuitry was installed during the system upgrade. The licensee removed the jumper after reviewing the above circumstances. The inspector stated that more frequent, detailed review of the Jumper/Bypass Log appeared necessary to ensure that: 1) the function of all jumpers and their effects are understood, considering that plant conditions may have changed since their installation, and 2) jumpers are removed promptly when no longer performing an originally intended purpose. The inspector will observe licensee actions to improve Jumper/Bypass Log review.

Trouble Card 82-2336 documented that prior to plant startup on August 6, surveillance testing of Intermediate Range (IR) Channel N-36 indicated a discrepancy with the high flux reactor trip setpoint. Periodic Test Procedure (PT)-6.2, NIS Intermediate Range Channels, Revision 10, October 14, 1981 requires verifying the trip setpoint in units of detector output current corresponding to 25% power. No specific amperage range or value is given in the procedure. The trip setpoint determined by testing was 3.2×10^{-4} amps. Based on correlations between 25% power and corresponding IR detector current during previous normal reactor shutdowns and startups (2.7×10^{-4} amps), the operator considered the setpoint to be high and submitted a Trouble Card. Review of the Trouble Card by Instrument and Control supervision considered the trip setpoint acceptable based on 1) the current reading was within several percent power of the administrative limit of 25%; no Technical Specification limit exists, and 2) the differance between 3.2×10^{-4} and 2.7×10^{-4} amps is difficult to distinguish on the meter face. Inspector review of the Final Safety Analysis Report (FSAR) verified that the IR high flux setpoint had not been taken credit for in analyzing potential reactivity accidents during startup. The low flux

Power Range trip setpoint of 25% power was used in the accident analyses and is incorporated in the Technical Specifications. The licensee has agreed to revise Procedure 6.2 to provide an IR high flux setpoint in units of current output with appropriate upper and lower limits.

c. Plant Tour

1. During the course of the inspection, tours of the following areas were conducted:

   -- Control Room

   -- Auxiliary Building

   -- Intermediate Building (including control point)

   -- Service Building

   -- Turbine Building

   -- Diesel Generator Rooms

   -- Battery Rooms

   -- Screenhouse

   -- Yard Area and Perimeter

2. The following observations resulted from the tours:

   a. Monitoring instrumentation. Process instruments were observed for correlation between channels and for conformance with Technical Specification requirements. Early in the inspection period, deviation of up to 5% was experienced between the three narrow range pressurizer level channels. Licensee investigation determined that a small leak existed at the reference leg fitting to pressurizer level transmitter LT-433. Venting of the reference leg, which is also common with LT-428, determined that gases were trapped in that line. The licensee replaced the fitting on August 6, and instituted a six hour venting program from the Pressurizer steam space to the Volume Control Tank on an every-other-day frequency. No further deviations in level indication have occurred. The licensee intends on stopping the venting early in September and observing the level channels for any further problems.

   b. Annunciator alarms. Various alarm conditions which had been received and acknowledged were observed. These were discussed with

shift personnel to verify that the reasons for the alarms were understood and corrective action, if required, was being taken.

c. Shift manning. Control room and shift manning were observed for conformance with 10 CFR 50.54 (K), Technical Specifications, and administrative procedures.

d. Radiation protection controls. Areas observed included control point operation, posting of radiation and high radiation areas, compliance with Radiation Work Permits (RWPs) and Special Work Permits (SWPs), personnel monitoring devices being properly worn, and personnel frisking practices.

e. Equipment lineups. Valve and electrical breakers were verified to be in the position or condition required by Technical Specifications and plant lineup procedures for the applicable plant mode. This verification included control board indications daily and field observations made during routine plant tours.

During a walkdown of valve lineups associated with various containment penetrations the inspector identified a fitting with two unlabeled valves, in series, originating from the local leak test connection upstream of the 'A' steam generator blowdown containment isolation valve. Attached to the valves were several inches of 3/8" stainless steel tubing followed by a short run of open-ended tygon hose. A similiar arrangement was observed upstream of the 'B' steam generator containment isolation valve. Review of system drawings and procedures did not depict the valve arrangement. Discussion with chemistry personnel indicated that the valves were installed to allow ease in sampling steam generators while in a cold shutdown condition, and the potential for violations of containment integrity were not specifically considered. Review of chemistry records from May/June startup did not identify any use of the valves after containment integrity was required. Local leak rate testing of the penetration performed during the recent refueling outage did include the unlabeled valves. Further, discussions with additional plant personnel indicated that the valves were probably added at least four years ago. The licensee has designated valve numbers, revised piping drawings and procedures, and instituted administrative controls over the valves. Additionally, an ongoing modification to install containment penetration test and drain connections will be revised, to include the above valves in the design criteria and safety analysis, portion of the modification package.

f. Equipment tagging. Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment in the condition specified.

g. Fire protection. Fire detection and fire fighting equipment and controls were observed for conformance with Technical Specifications and administrative procedures.

h. Security. Areas observed for conformance with regulatory requirements, and site security plan and administrative procedures, included vehicle and personnel access, protected and vital area integrity.

i. Plant housekeeping. Plant conditions were observed for conformance with administrative procedures. Storage of material and components was observed with respect to prevention of fire and safety hazards. Housekeeping was evaluated with respect to controlling the spread of surface and airborne contamination.

No violations were noted.

4. Inspector Witnessing of Surveillance Test

a. The inspector witnessed the performance of surveillance testing of selected components to verify that the surveillance test procedure was properly approved and in use; test instrumentation required by the procedure was calibrated and in use; Technical Specifications were satisfied prior to removal of the system from service; test was performed by qualified personnel; the procedure was adequately detailed to assure performance of a satisfactory surveillance; and test results satisfied the procedural acceptance criteria or were properly dispositioned.

b. The inspector witnessed the performance of:

-- Periodic Test (PT)-9.1, Undervoltage Protection-480 Volt Safeguard Bus, Revision 1, performed August 13, 1982. (witnessed Bus 17 test)

-- PT-16, Auxiliary Feedwater System, Revision 32, November 4, 1981, performed August 27, 1982. (witnessed 'A' Auxiliary Feedwater Pump test)

-- PT-13.7, Fire Hose Reel Assembly Inspection, Revision 5, February 27, 1982, performed August 30, 1982. (witnessed hydrostatic test of hose reel station #6)

No violations were identified.

5. Followup on IE Bulletins (IEB)

The inspector reviewed facility records, interviewed licensee personnel and observed facility equipment/components to verify that: licensee management received and reviewed the bulletins in accordance with administrative procedures; information discussed in the licensee's bulletin response was accurate; corrective action was taken as discussed in the reply; and the licensee's response was within the time period required.

IEB 80-12, Decay Heat Removal System Operability

The primary method for residual heat removal (RHR) during refueling or cold shutdown modes is through the RHR system. There are two RHR pumps with power supplied from separate safeguard buses. Two reactor coolant drain tank pumps are also available to aid in maintaining core cooling, if necessary.

A licensee review of plant operating history indicated that a loss of RHR flow occurred in May, 1972, during steam generator work. At that time, the running pump lost suction due to low loop level. Flow was interrupted for about two hours while loop level was raised to a level satisfying net positive suction head considerations. Corrective action implemented following PORC review included: administratively limiting minimum loop level to ten inches above the loop centerline; installation of a tygon hose for level indication from a primary loop tap; procedural controls describing proper operation with low loop levels; and increased temporary monitoring of hot leg temperatures and RHR flow. No further instances of loss of decay heat removal capabilities have occurred to date.

Inspector review of the following procedures verified acceptable controls were in place for: 1) minimizing a loss of RHR flow, and 2) specifying required actions if a loss of cooling was to occur.

-- Operating Procedure (O)-2.3.1, Draining the Reactor Coolant System, Revision 15, October 14, 1981.

-- Emergency Procedure (E)-17, Loss of Residual Heat Removal, Revision 7, August 4, 1982.

-- System Procedure (S)-13B, RHR Pump Isolation, Revision 8, April 24, 1981.

-- E-17.1, Reactor Coolant Drain Tank Pump Operation for Core Cooling, Revision 3, December 2, 1981.

Currently, when entering low loop level operations, a tygon hose is connected to the 'B' loop sample tap to provide local level detection. In addition, normally isolated level transmitter LT-432 is placed in service to provide readout of loop level on the main control board. The level indicators are compared initially to assure proper indication and are then logged once per shift. Although LT-432 is

checked against the tygon hose the transmitter and control room indicator were noted to have been last calibrated in January, 1978. The licensee representative stated that the instrument loop would be calibrated before use in the upcoming fall outage and would be placed on a refueling calibration frequency, thereafter.

Administrative controls for assuring operability of redundant RHR components prior to removal of equipment from service have been effectively implemented. Further, operating precautions and corrective actions, implemented since 1972, have prevented any recent problems with operability of decay heat removal systems. This bulletin is closed.

6. Licensee Event Report (LER's)

The inspector reviewed the following LER's to verify that the details of the event were clearly reported, and to verify the accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required, and whether generic implications were involved. The inspector also verified that the reporting requirements of Technical Specifications and station administrative and operating procedure had been met; that appropriate corrective action had been taken; that the event was reviewed by the Plant Operations Review Committee; and that the continued operation of the facility was conducted within the Technical Specification limit.

82-16: Excessive Leakage Past Containment Spray Pump Discharge Check Valve (862B)-July 22, 1982. Review of this event is included in NRC Region I Inspection Report 82-14, paragraph 5.b. This is a repeat event.

On August 25, the clapper arm and pin were replaced; however, the valve failed to seat properly during subsequent surveillance testing. The cover-to-valve body alignment pin was found slightly loose and was driven further into place. The surveillance test was reperformed with acceptable results. The inspector will closely monitor future test results associated with V862B.

82-17: Residual Heat Removal (RHR) Pump Seal Leakage-August 3, 1982. During surveillance testing of the 'B' RHR pump, leakage from the mechanical seal was measured at 2.1 gallons per hour. The pump seal had approximately 3200 hours of running time, and failure was attributed to normal wear. The seal was replaced and the pump tested satisfactorily.

82-18: Inoperable Rod Position Indicator-July 30, 1982. While operating at 100% power, the individual rod position indication for Control Rod Bank 'A' Group 2 position H02 deviated from the respective group step counter by twelve steps. Investigation by Instrumentation & Control personnel resulted in adjustments for instrument drift.

7. Followup Inspection - Three Mile Island (TMI) Lessons Learned Implementation

II.E.4.2 Containment Isolation Dependability

Reference: NRC Inspection Report 81-04

The below listed procedures have been revised to require limiting purge times to ALARA;

-- Radioactive Discharge Procedure (RD)-2, Containment Purge Release, Revision 9, June 15, 1982;

-- Operating procedure (O)-11, Control of Containment Depressurization Valves While Reactor is Critical, Revision 1, January 29, 1981.

8. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee pursuant to Technical Specification 6.9.1 and 6.9.3 were reviewed by the inspector. This reveiw included the following considerations: the report contains the information required to be reported by NRC requirements; test results and/or supporting information were consistent with design predictions and performance specifications; planned corrective action was adequate for resolution of identified problems; determination whether any information in the report required classification as an abnormal occurrence; and the validity of the reported information. Within the scope of the above, the following periodic report was reviewed by the inspector.

-- Monthly Operating Report for July, 1982.

9. Exit Interview

At periodic intervals during the course of the inspection, meetings were held with senior facility management to discuss the inspection scope and findings.