U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report Nos. 50-272/85-09
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Docket Nos. 50-272
50-311

License Nos. DPR-70
DPR-75

Licensee: Public Service Electric and Gas Company
80 Park Plaza
Newark, New Jersey 07101

Facility Name: Salem Nuclear Generating Station - Units 1 and 2

Inspection At: Hancocks Bridge, New Jersey

Inspection Conducted: April 6, 1985 - May 6, 1985

Inspectors: T. J. Kenny, Senior Resident Inspector
R. J. Summers, Resident Inspector

Reviewed by: D. F. Limroth — 5.16.85
D. F. Limroth, Project Engineer — date
Reactor Projects Section No. 1, DRP

Approved By: L. J. Norrholm — 5/16/85
L. J. Norrholm, Chief, Reactor Projects — date
Section No. 2B, DRP

Inspection Summary:
Inspections on April 6, 1985 - May 6, 1985 (Combined Report Numbers 50-272/85-09 and 50-311/85-11

Areas Inspected: Routine inspections of plant operations including: operational safety verification, maintenance observations, surveillance observations, review of special reports, NRC senior inspector, licensee event report followup and survey of licensees response to selected safety issues. The inspection involved 82 inspector hours by the resident NRC inspectors.

Results: There were no violations in this report. A concern with regard to operations and lack of supervisory oversight has been addressed by the inspector and the licensee and is described in section 2.c.2.c of this report.

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DETAILS

1. Persons Contacted

   Within this report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activity.

2. Operational Safety Verification

   a. - Selected Operators' Logs
      - Senior Watch Supervisors (SWS) Log
      - Jumper Log
      - Radioactive Waste Release Permits (liquid & gaseous)
      - Selected Radiation Work Permits (RWP's)
      - Selected Chemistry Logs
      - Selected Tagouts
      - Health Physics Watch Log

   b. The inspectors conducted routine entries into the protected areas of the plants, including the control rooms, Auxiliary Building, fuel buildings, and containments (when access is possible.) During the inspection activities, discussions were held with operators, technicians (HP & I&C), mechanics, foremen, supervisors, and plant management. The purpose of the inspection was to affirm the licensee's commitments and compliance with 10 CFR, Technical Specifications, and Administrative Procedures.

      (1) On a daily basis, particular attention was directed in the following areas:

         - Instrumentation and recorder traces for abnormalities;

         - Adherence to LCO's directly observable from the control room;

         - Proper control room, shift manning and access control;

         - Verification of the status of control room annunciators that are in alarm;

         - Proper use of procedures;

         - Review of logs to obtain plant conditions; and,

         - Verification of surveillance testing for timely completion.

(2) On a weekly basis, the inspectors confirmed the operability of selected ESF trains by:

- Verifying that accessible valves in the flow path were in the correct positions;

- Verifying that power supplies and breakers were in the correct positions;

- Verifying that de-energized portions of these systems were de-energized as identified by Technical Specifications;

- Visually inspecting major components for leakage, lubrication, vibration, cooling water supply, and general operable conditions; and,

- Visually inspecting instrumentation, where possible, for proper operability.

Systems Inspected:

- Safety Injection (Unit 1)

- Diesel Generators (Unit 1)

- Hydrogen Recombiners (Unit 2)

- Containment Spray (Unit 2)

(3) On a biweekly basis, the inspectors:

- Verified the correct application of a tagout to a safety-related system;

- Observed a shift turnover;

- Reviewed the sampling program including the liquid and gaseous effluents;

- Verified that radiation protection and controls were properly established;

- Verified that the physical security plan was being implemented;

- Reviewed licensee-identified problem areas; and,

- Verified selected portions of containment isolation lineup.

c. Inspector Comments/Findings:

The inspectors selected phases of the units' operation to determine compliance with the NRC's regulations. The inspectors determined that the areas inspected and the licensee's actions did not constitute a health and safety hazard to the public or plant personnel. The following are noteworthy areas the inspector researched in depth:

1. Unit 1 operated at 100% power throughout this report period, with the exception of minor power reductions to perform surveillance testing.

2. Unit 2 began this report period in Mode 3 with Tavg at 458 degrees F and a heatup in progress. When the unit reached operating temperature, the licensee began experiencing difficulties with the steam generator code safeties. The safeties were lifting too early on #22 Steam Generator. Subsequently, the licensee determined that they were probably set too early in the heatup and not given a chance to equalize in temperature.

   a. The licensee closed the reactor trip breaker April 10 and the physics testing program was started on April 11. The unit was brought critical and physics testing continued until April 13.

   b. Shortly after synchronizing to the bus on April 13, the unit tripped due to low steam generator level with steam flow/feed flow mismatch. The trip was caused by maintenance work being performed on the steam flow instruments. After completing the necessary maintenance, the unit was returned to service.

   c. The unit reached 25% power when a power reduction was initiated because of increasing temperatures on the thrust bearing of #22 Steam Generator feedwater pump. The turbine was manually tripped with the unit below P-10, and the unit remained critical. Due to the rapid load change and the steam dumps cycling, steam generator water levels began to cycle. The operator placed the steam dump in the pressure control mode and began to increase reactor power to stabilize the steam generator water level transients. At this time, steam generator atmospheric relief valves began to open but steam generator pressure continued to rise, and the steam generator code safeties lifted. The operator began to ramp down the setpoint of the steam dumps while another operator was manipulating control rods to control Tavg. The results, due to the delay in interaction between steam generator pressures and the primary temperature effect caused by the movement of control rods, caused

the pressure transients that lifted the relief valves. During the event the automatic pressurizer spray valve failed to operate causing the Primary Pressure Operated Relief Valve to lift. The primary pressure transient, was terminated by the operator taking manual control of the pressurizer spray valve. The noteworthy contributions to this event that caused transients of both primary and secondary system are:

- Lack of coordination between the operator who was operating the steam plant and the operator adjusting control rods in the reactor. (No positive supervisory oversight)

- Failure of automatic spray system.

The licensee has taken corrective action as follows:

- The senior licensed operators on duty have been counseled as to their role during operations with more than one board operator.

- The licensed operators who were manipulating controls have been counseled as to better communications between themselves while performing simultaneous operations.

- The entire scenario has been entered into the training system (simulator) for all shifts to experience.

- The automatic spray controller was repaired and returned to service.

d. The unit was returned to service on April 17. At 17% power the unit automatically tripped due to low-low water level in #24 Steam Generator. Feedwater controls were in automatic and #21 Steam Generator feedwater pump began to lose speed due to water entering the steam generator feedwater pump turbine as a result of a plugged steam trap on the steam supply line. The main generator breaker failed to open within the 30 seconds as designed and the operators opened them manually. The cause of the main generator breaker failure was attributed to a failed relay in the exciter field circuitry. After repairs, the unit was returned to service on April 18.

e. On April 23 the unit tripped due to "Turbine trip and P-7". The cause of the turbine trip was low auto stop oil pressure which occurred while shifting main lube oil coolers. At first the licensee could not determine the

cause of the low auto stop oil pressure because the transfer of lube oil coolers is continuous and no interruption of pressure should occur. It was subsequently discovered, with the introduction of a small amount of air into the cooler to be placed in service, that the momentary low auto stop oil pressure can be duplicated. This has been demonstrated by the licensee. On April 24 the unit was returned to service.

f. The licensee had been experiencing alignment problems on #22 Steam Generator feedwater pump until May 2 when alignment problems had been corrected and the unit began escalation of power to continue post refueling physics testing. On May 2 the unit tripped automatically as a result of a turbine trip on "generator loss of voltage/loss of field." This turbine trip is initiated by the activation of two relays in series. The first, a "loss of field relay," was determined by the licensee to have been wired improperly during the recent generator replacement. The second relay, "loss of voltage," was energized as a result of a loose wire causing the relay to see an artificial low voltage. The licensee is continuing to investigate the reasons for the relay problems.

g. The report period ends with the unit at 100% power and the physics testing completed.

No violations were identified.

3. Maintenance Observations

The inspectors observed portions of various safety-related maintenance activities to determine that redundant components were operable, these activities did not violate the limiting conditions for operation, required administrative approvals and tagouts were obtained prior to initiating the work, approved procedures were used or the activity was within the "skills of the trade," appropriate radiological controls were properly implemented, ignition/fire prevention controls were properly implemented, and equipment was properly tested prior to returning it to service.

4. Surveillance Observations

During this inspection period, the inspector reviewed in-progress surveillance as well as completed surveillance packages. The inspector verified that the surveillances were performed in accordance with licensee-approved procedures and NRC regulations. The inspector also verified that the instruments used were within calibration tolerances and that qualified technicians performed the surveillances.

The inspector paid particular attention to the review of the surveillances which were performed to return Unit 2 to service following the refueling outage. The inspector concluded that all surveillances were performed in accordance with approved procedures.

No violations were identified.

5. Review of Periodic and Special Reports

Upon receipt, the inspectors reviewed periodic and special reports. The review included the following: inclusion of information required by the NRC; test results and/or supporting information consistent with design predictions and performance specifications; planned corrective action for resolution of problems, and reportability and validity of report information. The following periodic reports were reviewed:

-- Unit 1 Monthly Operating Report - March 1985

-- Unit 2 Monthly Operating Report - March 1985

6. NRC Senior Resident Inspector

On April 21, 1985 the new Senior Resident Inspector Mr. Thomas J. Kenny assumed the duties, pursuant to the title. Mr. Kenny was the Senior Resident at Indian Point Units 2 and 3.

7. Licensee Event Report Followup

The inspector reviewed the following LER to determine that reportability requirements were fulfilled, immediate corrective action was taken, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications.

Unit 2

85-003 Pressurizer Overpressure Protection System Channel II Indications

This report detailed the actuation of the Pressurizer Overpressure Protection System Channel II, when a reactor coolant pump was started, while in Mode 5, with the reactor coolant pressure at 325 psig. The event occurred twice and both times the pressure of the reactor coolant system did not exceed 380 psig, but the relief valve lifted at 360 psig. Technical Specifications requires the relief setting of the channel to be equal to or less than 375 psig and the minimum pressure for starting reactor coolant pumps is 325 psig. This pressure channel is controlled by the 0-3000 psig transmitter of the reactor coolant system and the tolerance of 2% ± (15 psig) is within the tolerance of the equipment. Therefore the lift setpoint of 360 psig was within the tolerance of 375 psig setting. The operating procedures provide the operator with sufficient guidance for action during the filling and venting evolution.

However, the licensee has modified another procedure "Reactor Coolant Pump Operations" to caution operators to the increased likelihood of a Pressurizer Overprotection Protection System actuation during the starting of reactor coolant pumps.

No violations were identified.

8. Survey of Licensee's Response to Selected Safety Issues

The resident inspector conducted an inspection to accumulate the necessary information to complete Attachments I and II to this report. The subjects of the inspection were "Steam Binding of Auxiliary Feedwater Pumps" and "Mispositioned Control Rod." The inspector concluded that the licensee has taken the appropriate actions to these two events and no items of concern were identified.

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. An exit interview was held with licensee management at the end of the reporting period. The licensee did not identify 2.790 material.

Plant Name and Unit SALEM UNITS 1&2

Item 03.02a. Steam Binding of Auxiliary Feedwater Pumps

1. Is the discharge or the suction piping of the auxiliary feedwater pumps hot?

No

2. Is the licensee monitoring and recording the temperature of the auxiliary feedwater system piping once per shift to detect back leakage? If not, how frequently?

No

3a. Is temperature readout local or in control room?

No

3b. What is the method of monitoring AFW piping temperature? (For example: touching pipe, temperature sensing tape, or pyrometer)

TOUCHING

4. Is the licensee monitoring the temperature of the auxiliary feedwater system piping after each operation of a pump to detect back leakage?

No

5a. Did the licensee determine that procedural changes were needed to assure check valve seating when securing the auxiliary feedwater system?

Changes were made to examine the valves (check & Motor Stop)

5b. Have the changes been made?

Yes

6a. Have procedural guidance and training in identifying back leakage and returning the system to operability been provided?

Yes

6b. Provide a brief summary description of procedural corrective actions (For example, vent and flush).

~~N/A~~ X-ray of the valves to determine. Shut valves.

7a. Is the licensee performing periodic leakage tests of the check valves (or isolation valves if normally closed) in the auxiliary feedwater discharge line? How frequently?

Yes See below. Isolation valves normally closed.

7b. Is the licensee performing periodic inspections of the check valves (or isolation valves if normally closed) in the auxiliary feedwater discharge line? How frequently?

YES
- Stop check valves verfied shut every 92 days tested prior to entering mode 3
- Discharge valves verfied shut every 31 days in mode 1-3
- Check valves checked by audible sound every 31 days mode 1-4

8. For any items which are not implemented, does the licensee have an alternate reason or justification?

N/A

~~If so, provide a brief description.~~

The pipes at the discharge of the pumps are at ambment temperature as verified by the resident Inspector.

Plant Name and Unit SALEM UNITS 1 & 2

Item 03.02b Mispositioned Control Rod

1. (PWR) Do procedures define the steps necessary for recovery from a mispositioned rod?

   Yes

2. (PWR) Are procedures implemented for verifying rod position when one form of normal indications is lost?

   Yes

3. (BWR) Are procedural requirements implemented for written instructions, management concurrence, and briefing of operations personnel if a nuclear engineer is not required to be present during scheduled control rod movements?

   N/A

4. (BWR) Are procedures which identify the conditions under which the rod worth minimizer (RWM) may be bypassed implemented?

   N/A

5. (BWR) Do procedures prohibit the use of scram timing equipment except in testing and emergencies?

   N/A

6. (BWR) Do procedures contain guidelines on the appropriate use of the "emergency-in" mode of rod insertion and the notch override switch in continuous withdrawal?

   N/A

7. (ALL) Has training been provided for operators in the proper movement of control rods, the consequences of improper movement, and the consequences of operating with a mispositioned rod? [BWRs only] Has training been provided the operators on the function of the RWM, rod sequence control system, and the scram test switches?

   Yes

8. For any items which are not implemented, does the licensee have an alternate reason or justification?

N/A

If so, provide a brief description.