50317 810614	50317 810613	50317 810716	50318 810604	50318 790328
50317 810618	50317 810701	50317 810721	50318 810619	
50317 810617	50317 810702	50317 810707	50318 810704	
50317 810624	50317 810613		50318 810709	

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report Nos. 50-317/81-15 50-318/81-14

Docket Nos. 50-317 50-318

License Nos. DPR-53 DPR-69 Priority -- Category C C

Licensee: Baltimore Gas and Electric Company

P.O. Box 1475

Baltimore, Maryland 21203

Facility Name: Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Inspection At: Lusby, Maryland

Inspection Conducted: July 6-August 18, 1981

Inspector: E.C. McCabe, Jr., for — 9/15/81
R.E. Architzel, Senior Resident Reactor Inspector — date signed

Approved By: E.C. McCabe, Jr., for — 9/15/81
E.C. McCabe, Jr., Chief, Reactor Projects Section 2B — date signed

Inspection Summary:
Inspection on July 6-August 18, 1981 (Combined Report Nos. 50-317/81-15 and 50-318/81-14)
Areas Inspected: Routine, onsite regular and backshift inspection by the resident inspector (37 hours, Unit 1; 35 hours, Unit 2). Areas inspected included the control room and accessible portions of the auxiliary, turbine, service, and intake buildings; radiation protection; physical security; fire protection; plant operating records; plant maintenance; surveillance testing; TMI Action Plan Items and reporting to the NRC.
Noncompliances: One (Failure to adequately investigate security barrier, paragraph 9).

THE INFORMATION ON THIS PAGE IS DEEMED TO BE APPROPRIATE FOR PUBLIC DISCLOSURE PURSUANT TO 10 CFR 2.790

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~~THE REPORT DETAILS CONTAIN~~ 10 CFR 2.790 INFORMATION
(Pages 16 & 17 only)

DETAILS

1. Persons Contacted

The following technical and supervisory level personnel were contacted:

G.E. Brobst, General Supervisor, Chemistry
J.T. Carroll, General Supervisor, Operations
R.E. Denton, General Supervisor, Training/Technical Services
C.L. Dunkerly, Shift Supervisor
W.S. Gibson, General Supervisor, Electrical and Controls
J.E. Gilbert, Shift Supervisor
R.P. Heibel, Principal Engineer, Technical Support
J.R. Hill, Shift Supervisor
D.W. Latham, Principal Engineer, Plant Engineering Nuclear
J.F. Lohr, Shift Supervisor
R.O. Mathews, Assistant General Supervisor, Nuclear Security
J.E. Rivera, Shift Supervisor
L.B. Russell, Plant Superintendent
J.A. Snyder, Supervisor Instrument Maintenance
T.L. Sydnor, General Supervisor, Operations QA
J.A. Tiernan, Manager, Nuclear Power Department
D. Zyriek, Shift Supervisor

Other licensee employees were also contacted.

2. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (317/81-11-03; 318/81-11-03): Status of Reserve Battery. The licensee has submitted (letter dated July 20, 1981) a request for amendment to the Technical Specifications to NRR. This request addresses the nature of the modification to the licensee's 125 Volt DC Vital System. Future use of the reserve battery will be in accordance with Technical Specifications upon approval.

(Closed) Noncompliance (317/80-16-01; 318/18-15-01): Qualification of facility staff to ANSI N18.1, 1971. The licensee responded to this item in a letter dated February 9, 1981. A memorandum initiated by the Nuclear Power Department Manager cautioned managers to observe the requirements of the standards to which the licensee is committed when making promotions. In addition, a Technical Specification change was requested (BG&E letter dated February 18, 1981). The change was not approved by the NRC, however, the licensee was invited to submit specific exemption requests for certain individuals (NRC letter dated April 9, 1981). The licensee sent a letter (July 10, 1981) requesting such exemptions for two individuals on the plant staff not meeting the literal educational requirements of the ANSI standard. Further action in this area will be based upon disposition of the specific exemption requests.

3. Review of Plant Operations

a. Areas Toured

Facility tours included the Control Room, Auxiliary Building (all levels, no High Radiation Areas), Turbine Building, Outside Peripheral Area, Security Buildings, Health Physics Control Points, Diesel Generator Rooms, Service Building and Intake Structure.

b. Instrumentation

Control room process instruments were observed for correlation between channels and for conformance with Technical Specification requirements.

c. Annunciator Alarms

Alarm conditions which had been received and acknowledged were observed. These conditions were discussed with shift personnel, who were knowledgeable of the alarms and actions required. During plant tours, the inspector observed the conditions of equipment associated with various alarms.

d. Shift Manning

The operating shifts were observed to be staffed to meet the operating requirements of Technical Specifications, Section 6, both to the number and type of licenses. Control room and shift manning was observed to be in conformance with Technical Specifications and site administrative procedures.

e. Radiation Protection

Radiation protection control areas were examined. Radiation Work Permits in use were reviewed, and compliance with those documents (as to protective clothing and required monitoring instruments) was inspected. Proper posting of radiation and high radiation areas was reviewed in addition to verifying requirements for wearing of appropriate personal monitoring devices.

f. Housekeeping

Housekeeping, including storage of materials and components, was observed with respect to prevention of fire and safety hazards.

Plant housekeeping was also evaluated with respect to controlling the spread of surface and airborne contamination.

g. Fire Protection/Prevention

Selected pieces of fire fighting equipment were examined. Combustible materials were not found near vital areas. Selected cable penetrations were examined and fire barriers were found intact. Cable trays were clear of debris.

h. Control of Equipment

Selected equipment under safety tag control was examined. Equipment conditions were consistent with information in plant control logs.

i. Instrument Channels

Instrument channel check logs were reviewed. An independent comparison was made of selected instruments.

j. Equipment Lineups

Breaker positions on accessible switchgear and motor control centers were examined. Equipment conditions, including valve lineups, were reviewed for conformance with Technical Specifications and operating requirements.

k. Review of Operating Logs, Records

Logs and records were reviewed to identify significant changes and trends, to assure required entries were being made, to verify Operating Orders conform to the Technical Specifications, to verify proper identification of abnormal conditions, and to verify conformance to reporting requirements and Limiting Conditions for Operation. The following records were reviewed for the report period:

-- Shift Supervisor's Log;

-- Unit 1 Control Room Operator's Log;

-- Unit 2 Control Room Operator's Log;

-- Nuclear Plant Engineer - Operations Notes and Instructions

-- Unit 1 and 2's Control Room Daily Operating Logs (sampling review);

-- Radiation Control Smooth Log (sampling review);

-- Chemistry Smooth Log (sampling review).

l. Blue Crab Impingement

During a tour of the water front area on July 20, the inspector noted a large number of blue crabs impinged on the intake structure's trash racks. The inspector asked the licensee about the numbers of blue crabs impinged and whether an unusual event had occurred. The licensee stated that the conditions had been caused by a prolonged (over 10 hour) southwesterly wind, coupled with high summer temperatures. Such conditions have historically resulted in stagnation of bay water and low dissolved oxygen levels. The licensee stated that dissolved oxygen was measured at below 0.5 ppm at up to 0.5 miles from the plant, and that the general condition of large numbers of crabs on the surface existed near the western shore of the bay. The licensee, using the professional judgement of its contractor (Benedict Laboratory of the Academy of Natural Sciences of Philadelphia) as input to whether an obviously unusual event occurred with regard to either the number of a fish species or blue crabs being impinged or their survival (Environmental TS 3.1.2.6 refers), concluded that an unusual event had not occurred. The impingement was attributed to meteorologic and hydrologic causes. No unacceptable conditions were identified.

m. Bay Water Intrusion Incident

During plant startup on July 14, 1981, Unit 1 secondary chemistry was found to be outside specifications due to condenser in-leakage. The plant was taken to cold shutdown to minimize the effects, facilitate cleanup, and restore chemistry to acceptable limits prior to operation. The licensee informed the resident inspector of the incident during the afternoon of July 14, and initiated an investigation into the cause(s). The inspector reviewed the licensee's actions and investigation results and independently verified selected findings.

During an outage to replace the 11B Reactor Coolant Pump seals, the licensee had removed 29 tubes from the Unit 1 Condenser. The licensee has been experiencing numerous tube leaks in the copper-nickel, condenser tubes and planned metallurgical examinations of selected, recently plugged tubes. The tube sheet holes were to be filled with dummy plugs rolled into the inlet and outlet water boxes. One of the inlet (11B water box) dummy tubes was not installed (required maintenance action). Failure to plug this tube hole caused the incident and initiated contamination of the condensate system about 00:45 a.m., July 14, when the water level was raised in the water box preparatory to starting a circulator. This allowed brackish water to enter the condenser. The leakage rate was estimated to be 25 gpm.

The following chemistry conditions were sampled following the event:

Condensate Storage Tank (CST)	11	12	21
pH	3.3	5.6	4.2
Conductivity (umhos/cm)	2900	20	700

Steam Generators	11	12
Na^+ (ppm)	340	415
Cl^- (ppm)	325	276
Conductivity (umhos/cm)	2400	2600

Unit 2 Condensate Storage Tank 21 was contaminated due to a normal startup cross connection. (During Unit 1 startup, sealing steam was supplied from Unit 2. The condensate was returned to 11 CST, and the overflow was returned via a hose connection to the source - Unit 2 CST 21.) Unit 2 chemistry was maintained within limits by the full flow demineralizers and connection (by hoses) of a Demineralized Water Tank for condensate makeup.

The inspector reviewed the following procedures regarding required licensee actions to prevent a chemistry incident of this nature:

-- OP1 - Plant Startup from Cold Shutdown, Revision 14;

-- OP6 - Pre-Startup Check Off, Revision 19;

-- OI 14 - Circulating Water System, Revision 7;

-- OP2 - Plant Startup from Hot Shutdown to Minimum Load, Revision 9;

-- OI 11 A - Condensate System, Revision 9;

-- OI 11 B - Precoat Filter System, Revision 7;

-- OI 11 C - Condensate Demineralizer System, Revision 9;

-- OI 11 D - Condensate and Feed System Layup and Layup Recovery, Revision 1;

-- RCP 1-211 - Specifications and Surveillance of Condensate, Feedwater and Main Steam Generators, Revision 8.

Various procedural inadequacies were identified by the inspector. These inadequacies, and others, were identified by the licensee as follows:

-- OP1 requires verification of proper steam generator chemistry as an initial condition, but the OP6 Pre-Startup checklist does not require verification of this check. This did not contribute to the event because samples taken July 7, 1981, were used to verify adequate chemistry and the steam generators had not been fed after that date.

-- The GSO Notes and Instructions entry on July 10, 1981, was not followed. The note cautioned operators to be wary of salt water leaks upon pulling water up in each water box (due to the possibility of a leaking roll on a dummy tube). Indications of a salt water leak following pulling up water were to be followed up by freon testing the rolled joints. During the actual drawing up of water boxes on 7/14 between midnight and about 3:00 a.m., the on-shift chemistry technician, busy investigating Unit 2 salt water leaks and Unit 2 primary chemistry, did not monitor Unit 1 for salt water leaks upon drawing up water in the water boxes.

-- During repeated questioning of chemistry technicians on July 13 and 14 about secondary chemistry, operations personnel were informed it was satisfactory. Samples were not taken each time but the answers were based upon results of a 9:00 a.m., July 13, set of samples. These samples were, in fact, outside the abnormal limits, although not grossly so due to the fact the plant had been shutdown with saltwater leaks (procedural limits: 9 pH, 5 ppb Na^+; actual 9.4 pH, 35 ppb Na^+). About 3 a.m., July 24, the Shift Supervisor questioned whether the condensate demineralizers should be placed on line prior to feeding the generators with main feed. Plant Chemistry said no. (Standard practice is to allow the resin in the precoat filters to clean up the feed and condensate and "save" the full flow demineralizers for later in the power escalation.) The condensate demineralizers were placed on line sequentially about 6 a.m. when the Shift Supervisor noted that condensate cleanup was not progressing as desired. The demineralizers were quickly exhausted. Feedwater pH rapidly dropped. The chemistry technician began trying to correct pH by ammonia addition. Chemistry personnel did not promptly follow RCP 1-211, regarding the action to be taken if a decrease in pH occurs (an indication of a condenser tube leak). In addition, RCP 1-211 directs that, for abnormal feedwater chemistry, plant shutdown should be begun within four hours.

-- Although the secondary sample system was not placed on line when cleanup was begun during the morning of July 13, the Turbine Building Operator placed the system in operation about 1:30 a.m., July 14 (shortly after the water was drawn up in 11B water box). The operator did not consider the fact that the conductivity recorder was pegged high unusual for plant startup conditions.

-- About 10 a.m., July 14, the Shift Supervisor questioned the General Supervisor-Chemistry about the secondary pH and conductivity recorder indications. A decision was made to secure main feedwater and use the Auxiliary Feedwater System (from No. 12 CST). By about 11 a.m., July 14, the licensee concluded from samples of hotwells and steam generators, that a gross saltwater in leakage had occurred. The startup was aborted (the reactor had not been critical) and the plant taken to cold shutdown. The licensee's corrective actions and analysis of the event are described in paragraphs 3.n. and 3.o. following.

n. Licensee Evaluation of the July 14, 1981, Bay Water Intrusion Incident

The inspector requested that the licensee evaluate the possible detrimental consequences of the salt water intrusion incident. The Plant Operations and Safety Review Committee (POSRC) reviewed such an evaluation during meeting 81-96 held on July 17, 1981 (memorandum to the POSRC of same day). The licensee concluded that an unreviewed safety question did not exist. Two corrosion phenomena were evaluated; the bulk water effects of pitting corrosion and potential damage to the tube to tube support plate annuli. The licensee concluded that for their Inconel 600 tubed Steam Generators, corrosion results of Type 304 stainless steel could be used for comparison due to similar chromium contents. These tests included 2550 day immersions in sea water with only 1 mil pits developing and pot boilers operated for 73 days in brackish water with a maximum pit depth of 7 mils observed. The licensee concluded that the Inconel tubes (nominal 48 mils thick) were satisfactorily resistant to significant pitting in the circumstances which occurred.

Regarding tube support plate-tube annuli corrosion, generally credited as causing steam generator tube "denting", a similar determination was reached. This was based upon the necessary significant concentration of feedwater impurities in the crevice regions. With no heat flux present, this concentration was not possible, and the region would be subjected to bulk water chemistry (approximately 120 ppm salinity). The licensee stated that EPRI studies indicated that the normal operating crevice chemistry is substantially worse than the bulk water chemistry associated with this event.

o. Licensee Corrective Actions for the July 14, 1981 Bay Water Intrusion

Unit 1 was taken to cold shutdown. Both steam generators were drained and refilled several times to obtain proper chemistry. CSTs 11 and 21 were also drained and refilled. CST 12 was restored to adequate chemistry by portable demineralizers. Main feed and condensate systems were drained, flushed, and cleaned. Portable demineralizers were brought to the site to assist in making demineralized water for the plant. The unit was restarted on July 21, 1981, following restoration of adequate chemistry. The Plant Operations and Safety Review Committee directed the Plant Operational Experience Assessment Committee (POEAC) to investigate the incident and propose corrective actions. A POEAC sub-committee was formed on July 23, 1981 to perform the review. The inspector reviewed the results of the investigation. Selected licensee actions to prevent recurrence include the following:

(1) Revise Radiation Chemistry Procedure (RCP-1-211) to include start-up conditions.

(2) Write a Radiation Chemistry Procedure to place the secondary sample station in service.

(3) Define in Operating Procedure (OP-6) and in a new Radiation Chemistry Procedure when the secondary sample station should be placed in service.

(4) Include a sign-off in OP-6 to verify the acceptability of chemistry prior to initiating main feedwater flow.

(5) Train appropriate personnel regarding the new procedures and changes to existing procedures as noted above.

(6) Review mechanical maintenance work practices to determine if additional quality control measures should be implemented.*

*The licensee has historically dye checked condensers following major outages involving tube replacements. Due to the limited number of tubes replaced (29) and the about one day required for a dye check, a decision was made not to perform these checks during the July outage.

(7) Provide more supervisory and staff involvement in plant start-ups by requiring their presence on site per the guidelines of the Manager of the Nuclear Power Department, as an interim measure until other programs are in place.

(8) Install hi-hi conductivity alarm at the secondary sample stations.

The inspector concluded that the circumstances surrounding this event constituted a combination of inadequate procedures and failure to follow procedures. The situation was licensee identified and corrected. Measures to prevent recurrence were assessed as comprehensive. Further NRC review of the event will be conducted (317/81-15-04).

4. Review of Events Requiring One Hour Notification to the NRC

The circumstances surrounding the following events requiring prompt NRC (one hour) notification via the dedicated telephone (ENS-line) were reviewed.

-- At 00:18 a.m., July 7, Unit 1 tripped due to loss of load. The reactor was being shutdown to investigate the status of 11B Reactor Coolant Pump seals. (About 7:15 p.m., July 6, the licensee discovered that the second of three seals had apparently failed.) The exact cause of the turbine trip was not determined, but, the licensee speculated that feedwater heater water level caused the trip. Power was below 10% and preparations being made to take the turbine off-line at the time. Due to the unstable nature of the feedwater system at this low a power level, the licensee concluded that further investigation was not warranted.

-- Pressurizer Level Deviations. Unit 1 was restarted on July 21 following an outage begun on July 6 to replace 11B Reactor Coolant Pump seals. Pressurizer level oscillations during normal restart were reported via the ENS. Pressurizer level oscillations are an unresolved item addressed in Combined NRC Inspection 317/81-13; 318/81-13.

5. Plant Maintenance

During the inspection period, the inspector observed maintenance and problem investigation activities for: compliance with regulatory requirements; compliance with administrative and maintenance procedures; compliance with applicable codes and standards; required QA/QC involvement; proper use of safety tags; proper equipment alignment and use of jumpers; personnel qualifications; radiological controls for worker protection; fire protection; retest requirements; and reportability as required by Technical Specifications. The following activities were observed.

-- MR E-81-55, 11 Emergency Diesel Generator: Repair or Replace Cable/Sleeve between Governor and first Condulet, observed on 7/20/81.

-- PMS 1-36-M-M-1, 11 Auxiliary Feedwater Pump, Oil Samples, Change Oil, observed on 8/14/81.

-- MR 0-81-2908, Ground Isolation on 21 Volt DC Vital Bus, observed on 7/6/81.

-- MR-0-81-864, Reactor Coolant Pump 11B Seal Replacement, observed on 7/10/81.

No unacceptable conditions were identified.

6. Review of Licensee Event Reports (LERs)

a. LERs submitted to NRC:RI were reviewed to verify that the details of the event were clearly reported, including the accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LERs were reviewed.

LER No.	Date of Event	Date of Report	Subject
50-317 81-38/3L	6/6/81	7/6/81	DURING PM TEST CEA #21 DROPPED INTO CORE.
81-43/3L	6/10/81	7/10/81	SFP EXHAUST FANS DID NOT MAINTAIN NEGATIVE PRESSURE IN SFP AREA.
*81-44/3L	6/14/81	7/13/81	#12 MSIV DID NOT SHUT IN REQUIRED TIME.
81-45/3L	6/18/81	7/1/81	CHANNEL A POWER RANGE INSTRUMENT INOPERABLE.
81-46/3L	6/17/81	7/17/81	#13 CHARGING PUMP IN-OPERABLE; RELIEF VALVE WAS OPEN.
81-47/3L	6/24/81	7/24/81	DURING STP, ESFAS DEGRADED ; VOLTAGE RELAY INOPERABLE.
81-48/3L	6/20/81	7/14/81	#12 COMPONENT COOLING HEAT EXCHANGER INOPERABLE.

81-49/3L	6/8/81	7/8/81	CONTAINMENT RADIATION MONITORING SYSTEM PUMP INOPERABLE.
*81-50/3L	6/13/81	7/13/81	RCS GROSS LEAKAGE RECORDED AT 16 GPM.
81-51/3L	7/1/81	7/31/81	RMS PUMP TRIPPED-GASEOUS AND PARTICULATE RADIATION MONITORS INOPERABLE.
81-52/3L	7/2/81	7/31/81	RMS PUMP TRIPPED-GASEOUS AND PARTICULATE RADIATION MONITORS INOPERABLE.
*81-53/3L	6/13/81	7/13/81	PRESSURIZER LEVEL DEVIATED FROM PROGRAM LEVEL BY MORE THAN 5% SEVERAL TIMES.
50-317			
*81-54/3L	6/26/81	7/24/81	PRESSURIZER LEVEL GREATER THAN 5% PROGRAMMED BAND.
81-55/3L	7/1/81	7/31/81	ESFAS PZR PRESSURE AND #11 SUBCOOLED MARGIN MONITOR INOPERABLE; 16 VOLT DEVIATION BE-TWEEN CHANNELS.
**81-56/3T	7/16/81	7/30/81	PROV INADVERTENTLY OPENED.
***81-57/3L	7/21/81	8/11/81	PRESSURIZER LEVEL DEVIATED FROM PROGRAM LEVEL BY MORE THAN +/-5% SEVERAL TIMES.
50-318			
81-27/3L	6/2/81	7/2/81	#23 HPSI INOPERABLE.
81-29/3L	6/9/81	7/9/81	RPS CHANNEL A TRIP UNIT FOR THERMAL MARGIN/LOW PRESSURE INOPERABLE.
81-30/3L	6/4/81	7/3/81	TEMPERATURE TRANSMITTER 122 HB OUT OF TOLERANCE IN NONCONSERVATIVE DIRECTION.

81-31/3L	6/19/81	7/17/81	ECCS PUMP ROOM EXHAUST FANS INOPERABLE.
81-32/3L	7/4/81	7/31/81	CRACKED SOCKED WELD ON 22A RCP.
*81-33/3L	7/4/81	7/15/81	PRESSURIZER LEVEL DEVIATED FROM PROGRAM LEVEL BY MORE THAN +/-5% FOR 30 MINUTES.
81-34/3L	7/9/81	8/7/81	RPS CHANNEL D HIPOWER, THERMAL MARGIN/LOW PRESSURE AND AXIAL SHAPE INDEX TRIP UNITS BYPASSED: T-HOT READING 2 DEGREES HIGH.
81-35/3L	7/3/81	7/31/81	LEAK ON REACTOR COOLANT CHARGING HEADER.

* These events are addressed in Combined Inspection 50-317/81-13, 50-318/81-13.

** See paragraph b below.

*** See paragraph 4.

b. For the LERs selected for onsite review (denoted by asteriks), the inspector verified that appropriate corrective action was taken or responsibility assigned, and that continued operation of the facility was conducted in accordance with Technical Specifications and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements, and applicability to other site systems and components were also reviewed.

-- 81-56, Unit 1 PORV inadvertently opened. About 1 a.m., July 16, while in cold shutdown at 250 psia, Power Operated Relief Valve (PORV) RC-404-ERV opened. The operator immediately shut the PORV isolation valve. The PORV reshut in one minute and the blocking valve was reopened. The licensee determined the cause of the actuation to be a mechanic bumping the pressure transmitter while moving a deck grating. The licensee stated a mechanical stop would be installed to protect the transmitter from future bumping. The inspector reviewed recorder traces of pressurizer pressure (15 psi decrease) and level (no change) and determined that the PORV acoustic monitor and tailpipe temperature indication responded normally to the actuation. No unacceptable conditions were identified.

7. Radioactive Waste Releases

Records and sample results of the following liquid and/or gaseous radioactive waste releases were reviewed to verify conformance with regulatory requirements prior to release.

-- 12 RCWMT liquid release on 7/22/81; 7.837×10^{-3} Ci.

-- 11 Steam Generator liquid release on 7/14/81; less than 2.2×10^{-8} uC/cc.

-- 12 Steam Generator liquid release on 7/14/81; less than 2.2×10^{-8} uC/cc.

-- Decay Tank 12, released under permit G-046-81 on 8/6/81, completed filling on 7/26/81; Group I release rate 3.39×10^{-3} m^3/sec.*

-- Unit 1 Containment Purge, released under permit G-36-81 on 7/7/81; release rate, Group I: 3.55×10^4 m^3/sec, Group II: 7.06×10^{-1} m^3/sec.*

-- Decay Tank 13, released under permit G-043 on 7/27/81, completed filling 7/7/81; Group I release rate 4.82×10^3 m^3/sec.*

*Gaseous release numbers are pre-release estimates. Licensee's final calculations not completed at the time of inspector review.

No unacceptable conditions were identified.

8. Steam Generator Feedwater Ring Collapse at San Onofre Unit 2

On July 17, 1981, the inspector was informed of the results of water hammer tests on one Steam Generator at San Onofre Unit 2 on March 30, 1981. The test consisted of securing feed flow to the hot steam generator and drawing the water level to below the feed ring. After a two-hour hold, auxiliary feedwater flow (cold water) was initiated. The feed ring was inspected on July 14, 1981, and was found to be collapsed, with the attached "U" bolts torn loose. Originally, the feed ring was a 12-inch diameter schedule 40 pipe with 80 "J" tubes protruding from the top of the ring. The collapsed feed ring had a width of only four inches from top to bottom in the worst location. CE contracted other known licensees with "J" tube feed ring type steam generators (St. Lucie and Calvert Cliffs). The inspector reviewed portions of the event as they related to Calvert Cliffs. A previous Safety Evaluation Report (dated March 10, 1980) has been issued documenting the NRC's review of Steam Generator Water Hammer problems at Calvert

Cliffs. This analysis formed the basis for the inspector's review coupled with discussions with operators and procedure reviews.

Calvert Cliffs uses a separate feed ring for the Auxiliary Feedwater System (AFWS). The main feedwater sparger is similar and contains inverted "L" tubes (to discharge the feedwater horizontally inward) on the top of the spargers. The AFWS feed rings were found to have minimal potential for water hammer due to the high normal fluid velocity (9 ft/sec) and short horizontal run of pipe prior to the feed rings. To prevent water hammer in the main feed ring, the licensee installed the "L" tubes to keep water in the ring and prevent the steam voids which could cause water hammer by collapsing. Because there is some small leakage at the feedwater nozzle thermal sleeve, the ring could drain under no flow conditions if level is below the feed ring. To prevent water hammer, the licensee committed to develop procedures which will allow filling a steam generator with the AFWS (only) if main feedwater flow drops to 5% of full flow and a concurrent steam generator water level below the main feedwater ring (-50") exist. The inspector reviewed EOP-I, Reactor Trip, Feedwater System, and noted that such precautions are included. The inspector concluded that the San Onofre test was not applicable to Calvert Cliffs Steam Generators. No unacceptable conditions were identified.

10. Licensee Action on NUREG 0660, NRC Action Plan Developed as a Result of the TMI-2 Accident

The NRC's Office of Inspection and Enforcement has inspection responsibility for licensee implementation of selected action plan items. These items are numbered in enclosure 1 to NUREG 0737, Clarification of TMI Action Plan Items. Licensee letters containing commitments to the NRC were used as the basis for determining acceptability, as were NRC clarification letters and inspector judgement. The following action plan items were reviewed during this inspection.

-- I.A.1.3(2) - Minimum Crew Size. The licensee implemented the NRC guidance on the presence of a Senior Reactor Operator (SRO) in the Control Room during operation. The licensee included the Shift Supervisor's Office (adjacent to the Control Room, but visually, aurally, and physically isolated) within the surveillance area for the SRO. The NRC staff found that the licensee was not correctly implementing the position regarding presence of an SRO in the Control Room. The licensee stated that administrative procedures would be changed by September 15, 1981 to delete the Shift Supervisor's Office from the SRO's surveillance area. This item is unresolved (317/81-15-03; 318/81-14-02) pending procedure revision and NRC review.

11. Surveillance Testing

The inspector observed and reviewed testing to verify performance in accordance with approved procedures, limiting conditions for operation were satified, test results (if completed at time of observation) were satisfactory, removal and restoration of equipment were accomplished, and deficiencies identified were properly reviewed and resolved.

The following tests were involved.

-- NEP 4, Section 6.3, Reactivity Anomaly Surveillance, observed calculation on 7/9/81 for 6/16/81 (0.03% reactivity difference calculated).

-- NEP 4, Section 6.8, Total Planar Radial Peaking Factor Determination, observed calculations on 7/9/81 for 6/12/81 (1.4576 calculated).

-- NEP 4, Section 6.11, Incore Detector Channel Check, observed check on 7/9/81 of a day in June, 1981.

-- NEP 4, Section 6.7, Linear Heat Rate Incore Monitoring, observed checking on 7/9/81 for alarm setpoints calculated 6/12/81 (not completed during observation).

-- TSP 53, Revision 0, Cable Spreading Room Halon Operational Test, observed test gas discharge and monitoring on 8/12/81.

-- TSP 49, Revision 1, ESFAS Logic Test (STP 0-7-2 modified)--Reset Verified, observed on July 9, 1981.[1]

-- TSP 40, Revision 1, ESFAS Logic Test (STP 0-71-1, modified)--Reset Verified observed on July 7, 1981.[1]

No unacceptable conditions were identified.

12. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee pursuant to Technical Specification 6.9.1 and 6.9.2 were reviewed. The rev[illegible]luded the following: the report includes the information requir[illegible] be reported by NRC requirements; test results and/or supporting information are consistent with design predictions and performance specifications; planned corrective action is adequate for esolution of identified problems; determination of whether any information in the report should be classified as an abnormal occurrence; and the validity of reported information. Within the scope of the above, the following periodic reports were reviewed by the Inspector:

-- June, 1981-Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated July 15, 1981.

-- Calvert Cliffs Nuclear Power Plant, Units No. 1 ad 2, Docket Nos. 50-317 and 50-318 Report of Changes, Tests and Experiments, (10 CFR 50.59), Attachment to BG&E letter dated June 15, 1981.

-- July, 1981-Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated August 14, 1981.

13. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable, items of noncompliance, or deviations. Unresolved items addressed during this inspection are discussed in Paragraphs 3 and 9 of this report.

14. Exit Interview

Meetings were held periodically with senior facility management during the course of this inspection to discuss the inspection scope and findings. A summary of inspection findings was also provided to the licensee at the conclusion of the report period.

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1 TSP 49 and 50 were written to test selected Engineering Safeguards features reset logic per IE Bulletin 80-06. The test was performed in accordance with a licensee commitment documented in Combined Inspection Report 317/81-07; 318/81-07. IE Bulletin 80-06 will remain pending licensee submittal of a revised response and NRC review.