U. S. NUCLEAR REGULATORY COMMISSION

REGION I

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE
Baltimore Gas and Electric Company

CALVERT CLIFFS NUCLEAR POWER PLANT

Board Meeting: November 29, 1982

Presentation to Licensee: December 14, 1982

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1.1 Purpose and Overview

The Systematic Assessment of Licensee Performance (SALP) is an effort to collect NRC staff observations annually and evaluate licensee performance based on those observations with the objectives of improving the NRC Regulatory Program and Licensee performance.

This SALP period is October 1, 1981 through September 30, 1982. The SALP also contains significant prior and subsequent information which has a bearing on the findings.

Evaluation criteria used are discussed in Section III below. Each criterion was applied using "Attributes for Assessment of Licensee Performance" contained in NRC Manual Chapter 0516.

1.2 SALP Board Members

R. W. Starostecki, Director, Division of Project and Resident Programs (DPRP)
R. J. Bores, Acting Chief, Radiological Protection Branch, Division of Engineering and Technical Programs, (DETP)
J. H. Joyner, III, Chief, Nuclear Materials and Safeguards Branch, DETP
R. R. Keimig, Chief, Reactor Projects Branch No. 2, DPRP
E. C. McCabe, Jr., Chief, Reactor Projects Section 2B, DPRP
D. H. Jaffe, Project Manager, Operating Reactors Branch #3, NRR
R. E. Architzel, Senior Resident Inspector, Calvert Cliffs

1.3 Background

1.3.1 Licensee Activities

Unit 1

The unit was shutdown on 10/24/81 to repair tube leaks on #15B feedwater heater, and the outage was extended to 11/1/81 to replace seals on the #11 Main Steam Isolation Valve Hydraulic Accumulator. On 11/24/81, the unit was tripped due to a steam leak on the High Pressure Turbine third stage extraction line. Return to power was on 11/26/81.

On 4/17/82, the unit began its fifth refueling outage. Major activities included condenser rimcut. Inservice Inspections, TMI Action Plan items, and steam generator rimcut. Power operation resumed on 7/5/82.

From 10/81 through refueling outage commencement, the unit experienced numerous condenser tube saltwater leaks, forcing power reductions for tube plugging.

The unit was shutdown on 8/14/82 when Reactor Coolant System leakage approached the limit allowed by Technical Specifications. Power operation was resumed on 8/17/82.

The unit was shutdown from 9/17-27/82 to replace the #12B Reactor Coolant Pump shaft seal.

There were four additional shutdowns of about one day or less.

Unit 2

On 2/12/82 the unit was manually tripped due to low steam generator level following the loss of #22 Main Feed Pump. The outage was extended to 2/24/82 to correct problems associated with #21 Main Steam Isolation Valve, a sticking Control Element Assembly, and the Containment Purge Valves (failed to meet leak tightness criteria).

On 8/23/82 the reactor tripped on low steam generator water level after loss of #22 Main Feed Pump. Startup was delayed until 8/25/82 for repairs to a leaking primary System hot leg sample valve.

The unit experienced numerous condenser tube saltwater leaks forcing power reductions for tube plugging. Condenser retubing was scheduled for the October-December 1982 refueling outage.

There were five additional unit shutdowns of about one day or less.

1.3.2. Inspection Activities

One NRC resident inspector was assigned during the entire assessment period. A second resident was assigned in February 1982. The total NRC inspection hours for the period was 2687 hours (resident and region-based), with a distribution in the appraisal functional areas as shown on Table 2.

Violations and NRC inspections during the period are tabulated in Tables 3 and 4, respectively.

The new Emergency Response Plan was appraised during this period. Teams of NRC inspectors observed two full scale emergency exercises in November 1981 and September 1982.

II. SUMMARY OF RESULTS

CALVERT CLIFFS NUCLEAR POWER PLANT

FUNCTIONAL AREAS	CATEGORY 1	CATEGORY 2	CATEGORY 3
1. Plant Operations		X	
2. Radiological Controls	X		
3. Maintenance		X	
4. Surveillance (Including Inservice Testing)	X		
5. The Change Control Process			X
6. Fire Protection and Housekeeping	X		
7. Emergency Preparedness	X		
8. Security and Safeguards		X	
9. Refueling	X		
10. Licensing Activities		X	

III. CRITERIA

The following performance aspects were reviewed in each area:

1. Management involvement in assuring quality.
2. Resolving technical issues from a safety viewpoint.
3. Responsiveness to NRC initiatives.
4. Enforcement history.
5. Reporting and analysis of reportable events.
6. Staffing (including management).
7. Training effectiveness and qualification.

To provide a consistent evaluation, attributes relating each aspect to Category 1, 2, and 3 performance were applied as discussed in NRC Manual Chapter 0516, Part II and Table I.

The SALP Board conclusions were categorized as follows:

Category 1: Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety is being achieved.

Category 2: NRC attention should be maintained at normal levels. Licensee management attention and involvement in nuclear safety are evident; licensee resources are adequate and reasonably effective such that satisfactory performance with respect to operational safety is being achieved.

Category 3: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appear strained or not effectively used such that minimally satisfactory performance with respect to operational safety is being achieved.

IV. PERFORMANCE ANALYSIS

1. Plant Operations (31%)

This area was routinely reviewed by the resident inspectors. Three inspections were made by region-based specialists. In addition, an in-depth examination was performed in January and February, 1982 by the NRC Performance Appraisal Section (PAS), with emphasis on committee activities, training, organization, and audits.

Operational strengths found by PAS were a well written program, a strong effort in communicating with the plant staff, and positive staff attitude. Weaknesses included a shortage of licensed operators and lack of independent inspection/surveillance of plant operations (administrative functions, startups, mode changes, etc.). Both the Off-Site Safety Review Committee (OSSRC) and Plant Operations and Safety Review Committee (POSRC) exhibited many strengths. Their charters were comprehensive. Both committees kept detailed meeting minutes and effective tickler systems. Meeting frequency and member attendance were high for both. The POSRC had a particularly significant strength in their use of the POEAC (Plant Operations Experience Assessment Committee), a valuable resource for safe operation. A weakness common to both committees was their limited involvement in the review of QA audits and corrective action systems, particularly Nonconformance Reports (NCR's). Committee weakness was also found in review of changes. That concern is assessed in Area 5, the Change Control Process.

Operations Division management was strong. This management maintained a conservative attitude toward safe operations and is cooperative when NRC concerns are addressed. Procedure reviews were thorough and timely; quality assurance in particular was strong; there was an ample staff; audits were excellent; reporting was timely; management review was good; policies were adequately stated and understood; action on bulletins was timely and thorough; and work backlog and overtime were well controlled. A strong feature implemented during the evaluation period was a Special Licensee Event Report and evaluation program for events that result in plant shutdown or trips, unplanned radioactive releases, and other significant events. The purpose of the reports is to identify equipment modifications, procedure revisions, and training which can be implemented to reduce recurrence. This more comprehensive review system has been effective.

A long standing problem has been high operator turnover and a relatively inexperienced operations staff. There are 12 Control Room Operators (CRO's) on shift (4 shifts). Eight more took and passed the October 1982 examination. Four CRO's took and passed the October 1982

examination for Senior licenses. Fifty-three Plant Operators were hired in 1981 and 26 were hired in 1982. There are 10 Plant Operators in the 10 month Licensed Operator Training Program and 8 more in the next class. The General Supervisor-Operations initiated weekly section meetings to identify problems and establish better communications. An Operator Advisory Committee was created to address grievances and try to improve the working environment. Licensed staffing remains an NRC concern: the licensee's hiring and training program is substantial, but it remains to be seen whether the turnover rate will remain low enough to maintain a strong cadre of experienced licensed operators. At present, operating staff stability and experience are improving. The aspect of increased operator advancement potential from operator transfers to other parts of the organization is career enhancing for the operators. Also, there has been a beneficial aspect to transfers of operators to other parts of the facility staff: those operators have increased the operational knowledge of the groups to which they were transferred.

Operator response to plant transients was typically timely and in accordance with approved procedures. Examples observed included a loss of Salt Water cooling to the Service Water Subsystems, several plant trips, and a Safety Injection System actuation (without injection) caused by technician error.

An event of concern was the 16 minute, July 1982 loss of all emergency diesel generators because of reactive load imbalance. This was the second diesel loss event. (The previous event, in 1980, was due to shutting down the diesels with a start signal present.) This indicates a need for better operator training on diesel characteristics. In another event, an inexperienced Turbine Building Operator opened a disconnect on a running Service Water Pump, ruining the disconnect and tripping the plant. The operator had been trained on the 4-KV System in the month before the event, including a walk through of the disconnect procedure. Control Room Operators contributed by directing a power transfer on a running piece of machinery. This event also indicates a training deficiency because the newly trained individual did not follow the applicable procedure.

Many good training programs are being developed by the licensee. An extensive effort was undertaken to completely revise the system descriptions and these have become a valuable training tool. An onsite simulator is being constructed. The training staff is being expanded, and appropriate emphasis is being placed on non-licensed operator training and maintenance/technical training. Individual Operations staff member knowledge is increasing.

Unit 1 operated throughout Cycle 5 with the Hydrogen Analyzers inoperable (Enforcement Conference held on 7/7/82) due in part to inadequate Operating Instruction (OI) valve position information and inaccurate as-built status on plant drawings. Corrective action progress has been acceptable: a task force reporting directly to the Plant Superintendent was established in February 1982 to walk down all

piping systems and assure as-built drawing correctness, proper and permanent valve identification, and valve list correctness. This full time task force represents a considerable licensee investment in improving operational safety and, in effect, pre-addressed the cause of hydrogen analyzer inoperability.

The licensee has also committed to change its method for locking valves by using keyed locks. Previously, valves were locked by easily removed clips on the locking chains. The use of keyed locks provides a stronger safeguard against improper valve manipulation.

Several Operating Instructions and Alarm Response Procedures were inadequate. The biggest problem was that the Operating Instruction for the Spent Fuel Pool Cooling System did not address closure of a drain valve, and that cracked open valve interrupted the CILRT. Corrective actions have been acceptable.

Two safety tagging violations were identified. The licensee has been upgrading their tagout system. The Senior Control Room Operator now maintains a file of the current tagouts (previously maintained only by the tagging authority) and revisions to tagouts are performed in a manner similar to the original tagout, including approval by the Shift Supervisor. Adequate corrective action has been taken.

Identifying the root causes of problems is an NRC concern. For example, Unit 2 was manually tripped from 100% power following the loss of a Main Feedwater Pump (MFWP). Without finding and correcting the pump trip cause, Unit 2 was restarted and power operation resumed. A week later, the same feed pump tripped under the same initial conditions, causing a second manual reactor trip. After the resident inspector expressed concern, the licensee initiated a thorough investigation. The MFWP was run (off-line), a leaking control oil diaphragm was found and replaced, and the problem did not recur.

Operator awareness of Control Room indications and/or action taken on equipment problems has been a weakness. Auxiliary Feedwater Actuation was in pull-to-lock when required to be operable; monitors, indicators, and recorders have been found inoperable, and a Component Cooling Water valve was passing sufficient flow for cooling loads when fully closed, all with no action having been initiated. Acceptance of deficient equipment conditions is still a potential problem. The General Supervisor-Operations has stated that he reviews the highlights of each NRC Inspection Report with each Operations shift and places the reports in the Operator Required Reading File. In the course of these reviews, he has emphasized to the operators the need for increased awareness of equipment deficiencies and prompt initiation of repair requests. Stronger managerial action such as upgraded training and better operational checks may be necessary to assure correction. Stronger supervisory overview may be appropriate until knowledge and experience improvements correct the problem. Another problem identified

was that some systems, such as Spent Fuel Pool Cooling and Control Room Ventilation, were not checked on a periodic basis (The Spent Fuel Pool Cooling System had last been checked in 1976. The lineup, when examined by the NRC, was not consistent with OI requirements). In the future, the licensee plans lineup checks at least every 18 months. Considerable additional benefit could accrue through aggressive supervisor and STA spot checks of system lineups and other plant conditions.

Overall, operations is strong and improving, with deficient areas receiving attention. The most significant problem area is operating staff stability and experience.

Conclusion: Category 2

Board Recommendations:

Continue to emphasize (under Module 92701) licensed operator staffing, the results of the task force effort on piping systems, and operator awareness of equipment and corrective action status.

2. Radiological Controls (5%)

Analysis

Radiation Protection had 3 region-based specialist inspections. Radwaste, Effluent Control/Monitoring, and Transportation/Burial had no region-based inspection. Radiological Controls received routine resident inspector coverage.

Spent resin was spilled on April 13, 1982 and July 13, 1982 during transfer from the spent resin metering tank to a shipping cask liner. The first event was caused by level probe inoperability in the cask liner and no level indication being provided for the spent resin metering tank. (A "bubbler indication" on that tank had been inoperable since the plant was licensed.) Resin spillage was detected when the transfer evolution was completed. This event was a minor cask overfill and the spilled resin did not spread off the top of the cask liner. The second spill was more serious. The liner level probe was inoperable again. Lack of spent resin metering tank level indication was also a factor. Transfer air blew resin out of the cask liner when the metering tank emptied. Resin spread into the cask and the surrounding pit area. Two months before the second event, the licensee's investigator recommended reviewing the possibility of replacing the bubbler indicator with a new level indicating device, verifying cask liner level probe accuracy and operability before each resin transfer, and improving chemistry, rad-safety, and operations interdepartmental operations. Prompt compensation for these factors could have prevented the second event. The second event also involved inoperability of the TV camera used to observe the cask liner and failure to use the specified alternate vantage point above the cask, restricting the ability of the operators to observe the progress of the evolution. These circumstances are evidence of radiological events occurring because of inattention to material conditions and procedural requirements. Proposed corrective actions include using radwaste operators for spent resin transfers instead of plant operators (scheduled for 12/1/82 implementation), installation of spent resin metering tank level indication (a longer term corrective action proposal), repair of the installed TV camera (still inoperable) or use of the specified alternate vantage point or of a temporary TV camera (implemented), verification of cask liner probe operability before each transfer (implemented), and use of a lower normal transfer pressure (implemented). The two subsequent resin transfers occurred without spills. The two spill incidents did not involve above limit radiation exposures.

Events and occurrences during the reporting period are not indicative of substantive radiological problems. However, in February 1981, before the assessment period, two workers accidently raised an in-core instrument wire from the Spent Fuel Pool and received exposures of 1500 mrem and 660 mrem. A similar event on September 30, 1981 resulted in two workers receiving 180 mrem and 140 mrem. Subsequent corrective actions have thus far prevented recurrence. These

events, the failure to record a fuel pin serial number during its transfer within the Spent Fuel Pool on September 15, 1982, and the spent resin spills collectively indicate a possible weakness in the interface between health physics and the other licensee groups involved in handling highly radioactive materials. Licensee management initiated a review of highly radioactive materials handling in October 1982; that study is expected to be completed in 60 days.

The NRC found, at the close of the period, that the licensee had non-conservatively specified the limit for particulates with half-lives greater than 8 days in its Gaseous Waste Release Permit procedure; no releases above Technical Specification limits were identified. The licensee has completed acceptable procedural modifications.

Background counts on the Liquid and Gaseous Waste Effluent Monitors obscured the expected increase from radioactive material passing through the monitor (unless the release magnitude was near the monitor's trip setpoint). The licensee committed to establish measures to control the background counts of effluent radiation monitors and to correlate monitor responses to actual release rates. This event is an example of an NRC concern over reliable performance of radiation monitoring equipment. Another possible example was the 3 separate failures of the Containment Atmosphere Particulate Monitor, with no common cause evident but overall reliability nonetheless suspect. The licensee has established a working group to evaluate radiation monitor performance, and preliminary indications are that this group will be effective if their efforts are given sufficiently high priority. Although the NRC identification of such items does indicate a need for better licensee self-overview, the licensee's responsiveness has shown management attention to radiological control concerns.

Several years ago, perceived over-reliance on contractor health physicists resulted in development of a BG&E Health Physicist (HP) training program. This program has been effective as evidenced by the good professional knowledge of its product.

The licensee is participating in an INPO developed pilot program for radiation worker training. A failure rate of about 30% is being experienced on the examination. Workers failing the exam are being retrained. This program, undertaken on the licensee's initiative, is an example of licensee management commitment to radiation protection.

There were seven Radiation Protection Violations. Effluent monitoring had one Violation. No Transportation/Burial violations were found. No significant radiological problems are indicated by these conditions.

Man-rem exposures reported for 1981 were 10.3% below those reported for 1980 and relatively low per unit compared with other PWR's; there were no above-limit radiation exposures; and radiation protection has been functionally effective with no major problems identified.

Conclusion: Category 1

Recommendations:

1. Reallocate NRC inspection resources to radwaste handling and other uninspected areas.

2. That the licensee address improving the coordination between the HP staff and other onsite groups.

3. Maintenance (5%)

Analysis

Maintenance was observed during regular resident inspections, three region-based inspections, and a Performance Appraisal Section (PAS) inspection. The licensee's program was found adequate to control corrective and preventive safety-related maintenance.

A significant strength noted by the Performance Appraisal Section and the resident inspectors was the licensee's extensive use of QC inspectors to observe safety-related work. QC coverage was almost 100 percent and was found effective. Interviews with QC inspectors showed that they were knowledgeable of work inspected. Many of them had previously worked as mechanics, electricians, or instrument technicians.

The licensee effectively used mockups (e.g. reactor coolant pump seals and steam generator tubesheets) for training to ensure proper work performance, reduce work time, and reduce radiation exposure. Morale within the maintenance sections is high. There was open and effective communication between management and craft personnel.

Consumables have been a long standing NRC concern at Calvert Cliffs. During this evaluation period, after fifty-five gallons of poor quality lubricating oil were added to the Lube Oil Day Tank for Diesel Generator #21, the licensee implemented an analytical testing program to assure use of required quality lubricating oils, hydraulic fluids, and bulk chemicals (all of which are commercial grade) used in safety-related or important plant systems. The licensee also committed to evaluate the need for testing of bulk gases and to implement testing if appropriate. This reflects a substantive upgrading of control of consumables used in safety- significant applications.

Generally, maintenance activities were conducted using approved written procedures, and tools were properly calibrated. NRC inspections identified no failure to have proper documentation during maintenance. Maintenance work quality is high. Maintenance Requests (MR's) are the principal method for reporting maintenance problems and initiating necessary repairs. Generally, the plant staff used the system properly by filling out MR's routinely upon finding equipment deficiencies. (Operator initiation of MR's is assessed in the Operations section.) The use of locally posted MR tags describing the nature of equipment problems was effective in warning personnel of equipment deficiencies and preventing multiple reports of a single problem.

Repetitive problems (five event reports) involved improper adjustment or breakage of the Unit 2 Containment Personnel Lock inner and outer door operating mechanism. The licensee, during the current refueling outage, plans to upgrade the material used in the door mechanism and make necessary adjustments in door alignment and closure tightness.

Control Rod drops are a problem at Calvert Cliffs and other Combustion Engineering facilities. The licensee has been working with the vendor to reduce the number of control rod drops. However, they still continue to be a problem. Over the evaluation period, four Control Element Assembly (CEA) drops occurred on Unit 1 and two on Unit 2. A satisfactory solution to this longstanding problem does not appear to have been identified, but the licensee's approach (through the vendor) is satisfactory and the number of rod drops is decreasing.

Maintenance induced two plant trips and 8 ESFAS actuations (no injections). Because large numbers of unnecessary challenges to and initiations of safety systems leads to reduced safety, such events are significant.

In the procurement area, a new licensee Procurement and Storage Manual provides very good administrative controls over its subject areas: interfaces between organizational units are well understood; vendor audits are thorough and effective; staffing and training are adequate; records are well maintained and complete; and corrective action is prompt and effective.

Maintenance weaknesses noted by the Performance Appraisal Section included no equipment failure trending program and no independent verification of instrument valve lineups. The licensee has committed to trend nonconformance reports, QA Audit findings, Licensee Event Reports, and to do independent verifications of instrument valve lineups following maintenance. Careful adherence to these commitments should significantly improve these weak aspects.

Installed equipment which is not specifically required to be operable for conformance to Technical Specification action statements has been found to be inoperable for protracted periods. For example, an installed spare HPSI pump failed and was not replaced for about 3 years. The CVCS failed fuel radiation monitors have been inoperable for at least three years and the associated FCR for their replacement will not be funded until 1983. The boronometers have been, at best, intermittently operable. The Unit 2 Condenser Off-Gas Radiation Monitor has been inoperable since 6/1/82 when the NRC noted that it was not working. Because such equipment is a part of the facility design, it should either be kept operable or modified by an appropriate FCR.

Four maintenance violations were identified but not considered indicative of serious maintenance problems. Overall, Maintenance is an effective program at Calvert Cliffs.

Conclusion: Category 2

Board Recommendation:

That the licensee increase emphasis on eliminating unnecessary protective or safeguards system actuations/challenges.

4. Surveillance (5%)

Four inspections were conducted by region-based inspectors and routine inspection was provided by the resident inspectors.

Surveillance work groups track requirements and accomplish the required surveillance competently. Region-based NRC inspections covered Inservice Testing of pumps and valves, Inservice Testing required by ASME Section XI and Technical Specifications (other than pumps and valves), Eddy Current Testing on Unit 1 during the refueling outage, and Containment Integrated Leak Rate Testing. The licensee's program is well defined; records and audits were complete, well maintained and available; usually, surveillance test results review was thorough and timely; corrective action was prompt and effective for a violation; and staffing was adequate and training good (including technician training).

A surveillance program strength noted by PAS is the requirement that technicians be qualified on the specific surveillance test being performed. Another is the comprehensive and centralized Pump and Valve Testing Program. The licensee's Inservice Testing (NDE, Special Processes) inspection program is well staffed with seasoned, experienced technicians and supervision. A separate shop has been set up for testing safety-related snubbers by a special work force which performs onsite testing of most snubbers. One problem identified by the licensee concerned the boundary between safety-related and non-safety-related portions of the Main Steam, Auxiliary, and Main Feedwater Systems. As a result, 27 snubbers were upgraded to safety-related status; many of these had to be repaired or replaced. Although this shows improper initial classification of snubbers, it also shows good licensee self-monitoring and corrective action.

An installed gage not included in the licensee's calibration program was used for a pressure drop surveillance test. An installed manometer for measuring main vent flow was also not calibrated or included in the calibration program. Licensee control of installed gage calibrations is therefore deficient. Calibration control for portable measuring equipment is acceptable.

Although the licensee reports missed surveillance on reactor protection and engineered safeguards systems, missed surveillance tests on other equipment covered by the Technical Specifications has not been reported. Because failure to perform required surveillance constitutes equipment inoperability (TS 4.0.3) and an LER should be submitted on conditions leading to a degraded mode permitted by a limiting condition for operation (LCO) or plant shutdown required by an LCO (TS 6.9.1.9.6), LER's should also be submitted on missed surveillances of equipment covered by LCO's. The licensee is reassessing his practices in this area.

A violation was identified for not checking shutdown margin after a CEA stuck on a trip. Though significant, that was not a major problem.

An improper CILRT surveillance procedure change is assessed in Section 5, The Change Control Process.

Overall, surveillance has been an effective program.

Conclusion: Category: 1

Board Recommendations:

None.

5. The Change Control Process (7%)

Analysis

Because significant weaknesses were noted in the change control process, it has been selected for specific SALP analysis. One inspection of this area was conducted by the Performance Appraisal Section (PAS) and one inspection was conducted by a region-based inspector. Routine inspection was provided by the resident inspectors.

PAS found and resident inspection confirmed that 10 CFR 50.59 evaluations for Facility Change Requests (FCR's) were too often simple statements of conclusion without a stated supporting basis. An example was a temporary location of halon nozzles (FCR 79-1024). Another was fire barrier modifications (FCR 81-1011). Resident inspection found that LPSI alternate core flush valves were added as a part of a shielding change package without a 10 CFR 50.59 evaluation of the LPSI piping and valve changes involved. Also, a blind flange installed inside containment disabled the Hydrogen Purge System. POSRC had reviewed the associated procedure change and concluded that no unreviewed safety question (USQ) existed. Later resident inspection found that the margin of safety as described in the FSAR was lowered because the system was inoperable (an USQ), and that 10 CFR 50.59 was thereby violated. The licensee's November 16, 1982 violation response noted, correctly, that use of this system in a post accident condition is doubtful and then stated their corrective action would be to delete the system from the FSAR. (The system backs up the recombiners added to the design after the purge system was installed.) Failure to identify the USQ involved was not addressed in the response and does not appear to be a problem recognized by the licensee.

The Offsite Safety Review Committee (OSSRC) is required to review 10 CFR 50.59 safety evaluations by the Technical Specifications. PAS found that a one person subcommittee filtered those evaluations without overview, presented only selected ones to the OSSRC, and that the required OSSRC review was not being accomplished. Such inadequate OSSRC review of Facility Change Request safety evaluations was the most significant OSSRC weakness. The licensee revised his criteria for 10 CFR 50.59 and OSSRC reviews, appointed a 2 person OSSRC subcommittee to verify safety evaluation adequacy and assure OSSRC review requirements are met, gave additional training to individuals developing or processing FCR's or screening evaluations, committed to audit the 10 CFR 50.59 evaluation review process annually, and committed to better document the actual reviews accomplished.

Overall, as evidenced by the preceding paragraphs, 10 CFR 50.59 has not been properly implemented in the licensee's change control process.

Other FCR inadequacies found by the resident and the licensee were 16 Intake Wall penetrations and a conduit penetration into the Main Steam Penetration Room being accomplished and not meeting water tightness and high energy line break criteria. Also, the Containment Integrated Leak Rate Test procedure was revised to allow leakage which exceeded the limits of the Technical Specifications. POSRC review is a required part of the implementation of such procedure changes and did not identify these problems. Overall, these circumstances are evidence of inadequate consideration of design bases in the change control process.

A weakness exists in the maintenance of an up-to-date record of facility conditions on facility drawings. This was evidenced by: a schematic for a Containment Penetration Valve did not agree with the as-built configuration; a drawing for the Salt Water System did not show two drain valves; a Wiring Diagram for a Reactor Control System Control Board did not reflect seven FCR changes; a drawing used by Control Room operators did not show the Containment water level instruments installed under the TMI Action Plan; a Fire Protection System Alarm Annunciator Panel Drawing did not agree in window labeling with the as-built configuration; Seventeen Control Room drawings did not have a proper control stamp; and drawing revisions were not timely. The licensee appointed a Document Control Task Force to review FCR and drawing control. That task force developed a "bubbling" or mark-up process for plant drawings which would temporarily indicate FCR changes until a print revision could be issued. It is also preparing a revision to the plant procedure for drawing control. The licensee has placed increased priority on the closeout of FCR's. Additionally, the licensee has been conducting a drawing review and system walk-down program which compares plant drawings to "as built" configurations. (That effort is discussed in the Plant Operations Section.) These proposed corrective actions were acceptable.

The licensee has made relatively good progress in the installation of TMI Action Plan modifications. In two instances, (Post Accident Sampling; Noble Gas Monitor and Iodine/Particulate Sampling) though, the licensee reported to the NRC that new systems were operable when hardware installation was complete but successful operation would be difficult due to deficiencies such as unavailability of a final operating procedure, lack of training on system use, inoperable indicating recorders, and incomplete system calibration. After these deficiencies were identified by the NRC to plant personnel (after the commitment dates), the licensee acknowledged the incomplete system status and stated that they would send a letter restating system completion dates based upon true system operability. A BG&E letter sent as an integrated status update on TMI Action Plan Requirements, several months after the deficiencies were brought out, did not refer to the Noble Gas Effluent Monitor and Iodine/Particulate Sampling Systems which were still inoperable. The potential consequences of such reporting could be premature incorporation of system operability requirements in the

Technical Specifications and confusion about the operability of the systems within the licensee and NRC organizations. This situation is evidence of inadequate internal licensee communication of system status.

NRR has found licensee safety evaluations for his self-initiated Technical Specification changes to be inadequate when such evaluations are performed by the licensee (but not when the evaluations are accomplished by the NSSS vendor). This is further evidence of problems in the change control process.

Six violations were identified: three associated with an improper failure mode of a Component Cooling Water Containment Isolation Valve, failure to complete a 10 CFR 50.59 safety evaluation for a design change, failure to control drawing changes, and improper change of the CILRT test acceptance limits. These are consistent with other problem indicators in the Change Control area. Of particular concern was the CILRT procedure change violation which involved changing the Technical Specification (TS) limit on total containment isolation valve and containment penetration leakage to an administrative limit. POSRC review did not identify this error. Later testing was followed by improper acceptance of measured (but not actual) leakage above the TS limit. This is evidence of the potential for modifying the facility design basis through inadequate development and review of procedure changes, and this consideration was discussed during a July 1982 enforcement conference. Proposed corrective actions include specific POSRC training and are acceptable.

Overall, the items discussed in this section show a common thread of a lack of sufficiently careful control of changes. However, no facility events have resulted from this programmatic weakness. Corrective actions have been initiated, but this problem area is a broad one which crosses many organizational lines, and much better performance by and interaction between organizational groups is needed to resolve it.

Conclusion: Category 3

Board Recommendation:

Perform Design Change and Modification Modules 37700 and 37702B within the next six months.

6. Fire Protection (2%)

Analysis

One region-based and one PAS inspection were conducted. The resident inspectors monitored these areas throughout the period. No violations were identified. The fire protection program was found to be well implemented and maintained. An effective housekeeping program was evident.

Fire brigade response to two fires (a security diesel generator room fire and a fire in a temporary structure being constructed inside the protected area) were observed by the NRC and found to be rapid and effective.

Licensee management is attentive to fire protection: the licensee has a full time staff of three people devoted to fire protection and a request for three additional people is being considered.

Copies of the Fire Fighting Strategies Manual were not controlled to ensure that changes would be incorporated. The station fire protection plan was modified to provide administrative controls for these manuals, including a biennial Fire Protection Inspector review to assure that personnel holding manuals are receiving necessary updates. There were no requirements for fire brigade training lesson plans, written exams, or student feedback on training quality. However, lesson plans were used, testing was done quarterly, and critiques were solicited and received after lectures. This administrative discrepancy was quickly corrected by the licensee.

Testing and evaluation of the halon system in the summer and fall of 1981 was extensive and thorough.

Significant resources have been devoted to and progress made in cleanup and painting in the Auxiliary Building. Cleanup has been particularly effective in the boric acid storage tank rooms. Generally good housekeeping conditions exist in the protected area.

Fire Protection at Calvert Cliffs has been effective, and aggressively pursued by the licensee.

Conclusion: Category 1

Board Recommendation: None

I. Emergency Preparedness (34%)

Analysis

Two full scale emergency exercises were evaluated during the appraisal period (11/17/81 and 9/28/82). Each evaluation concluded that the licensee had demonstrated the ability to adequately protect public health and safety. FEMA found that the objectives of both exercises were generally achieved by the State and local agency response.

Significant improvements over the 1981 exercise were made in the licensee's preparation, scenario and critique for the 1982 exercise: the licensee conducted four workup drills using varying scenarios and involving senior management and the major portion of plant personnel; each drill was extensively critiqued; and the scenario for the 1982 exercise was thoroughly prepared, with all components of the emergency response team more realistically exercised.

During the 1982 exercise, a patient with a hypothesized broken leg did not receive first aid for an extended period. The cause was radiation exposure taking unwarranted precedence over injury treatment. That portion of the exercise is to be redone.

In October 1981, an Emergency Preparedness Implementation Appraisal (EPIA) produced findings representative of EPIA's. The licensee committed to correct the more significant findings in November 1981.

Twice during the evaluation period, the licensee did not classify actual unplanned releases of radioactivity as "Radiological Events" when such action was required by the Emergency Plan. As a consequence, the events were not reported and evaluated as required. Neither release was radiologically significant. Proposed corrective actions have been acceptable.

In general, the licensee has been responsive to NRC initiatives and has proposed acceptable resolution. In April 1982, the licensee significantly upgraded Emergency Planning by creating an Emergency Planning Unit with a full time staff of 8 people. This group is a part of the Training Department and can receive assistance from Training Staff personnel.

Emergency Preparedness, overall, has been effective and significantly upgraded. Emergency Facilities are not yet complete, and some administrative deficiencies remain to be corrected.

Conclusion: Category 1

Board Recommendation:

Reduce the size of the NRC observation team for the next full scale emergency exercise.

8. Security and Safeguards (8%)

Analysis:

Two inspections were conducted by region-based security inspectors, one by MC&A inspectors (violation addressed in Refueling Section) and routine inspection was provided by resident inspectors. The licensee was generally prompt in initiating acceptable corrective action for violations, other NRC identified problems, and security incidents.

Incidents have been properly reported to the NRC.

Licensee Security Management anticipated and planned for circumstances such as the construction of additional administrative buildings requiring temporary changes in the security perimeter, the temporary storage of new fuel received ahead of schedule, and the threatened strike of a subcontractor. Inspectors noted a serious and professional attitude by the security force. However, the operations unit of the security organization did not adequately plan for an outage by timely procurement of additional key cards, and did not adequately limit access to packages between security examination and later introduction into the protected area, and did not properly provide for changeout of locks when required. This reflects a significant lack of planning for conditions which should have been anticipated. Further, in the case of package security, the planned corrective actions were unacceptably modified by warehousemen. This was not detected by other licensee personnel and shows a lack of control of corrective actions.

Corporate involvement in security was evident. Onsite security units were established, with each made responsible for administering a part of the program (i.e. training, screening, administrative, and operations units). The Annual Corporate Security Audit was a comprehensive and thorough review of security plan requirements. Correction of audit items was timely and effective.

Key security positions are identified, with duties and responsibilities defined. The licensee's security force was amply staffed. Supplementary security by contract watchmen (Globe Security) was used primarily outside the PA, and was used within the PA for compensatory measures. Management resources, onsite and corporate, were adequate.

Security personnel are knowledgeable. Progress toward implementing the Security Training and Qualification Plan was on schedule.

Some security equipment has a poor performance history (e.g.microwave alarm zones 30-37). Cardreaders on watertight doors either performed poorly or were not completely installed. Consequently, watchmen were used extensively for compensatory measures. Such usage has lasted for an extended period but has been in compliance with NRC requirements.

However, these circumstances are evidence that BG&E has not effectively pursued correction of poor security material performance.

Overall, major issues are well addressed, with lack of correction of poor material performance and deficient security operations unit performance being problem areas.

Conclusion: Category 2

Board Recommendation: None

However, these circumstances are evidence that BG&E has not effectively pursued correction of poor security material performance.

Overall, major issues are well addressed, with slow correction of poor material performance and the noted security operations deficiencies being problem areas.

Conclusion: Category 2

Board Recommendation: None

9. Refueling/Outage Activities (4%)

Analysis

There was a major refueling/modification outage at Unit 1 (April-July, 1982) and several short outages for equipment repairs at both units. Outage planning, scheduling, and sequencing were well controlled and staffed, contributing toward Calvert Cliffs being the highest CY 1981 capacity multi-unit plant (2nd year running). Twice daily outage meetings and periodic Newsletters effectively disseminate outage information.

Refueling and outage activities observed by the resident inspectors included actual refueling, steam generator eddy current testing, steam generator tube rim cutting, startup tests, leak rate tests, MSIV hydraulic operator repair, reactor vessel stud hole repairs, and new fuel receipt. Region-based inspection activities included observation of refueling, major maintenance, special nuclear material control and accountability, the Containment Integrated Leak Rate Test, and refueling Health Physics practices (see Radiation Protection).

Two minor (Severity V) violations were identified: Not inventorying fission chambers within required period, and not verifying spent fuel pin serial numbers during Fuel Handling.

A heavy load (polar crane load block) was taken over the reactor vessel unnecessarily while the head was off. All crane operators were retrained to prevent recurrence. This corrective action is acceptable.

Overall, refueling and outage activities have been effectively and efficiently accomplished by the licensee.

Conclusion: Category 1

Board Recommendation:

None.

10. Licensing Activities

The evaluation was based on: General conduct of licensing activities; containment tendon Technical Specifications (TS); operator licensing; snubber TS; cycle 6 reload; TMI item II.E.1.2, Auxiliary Feedwater; Appendix I (ALARA) TS; Appendix R, Fire Protection; Inservice Testing; and Pressurized Thermal Shock Audit.

The licensee has multiple contact points for licensing, with 2 BG&E Departments involved. One Department, reporting to the Vice President for Supply , is at Calvert Cliffs and is principally responsible for operational considerations including TS changes. The second Department, reporting to the Vice President for Engineering and Construction, is located at the corporate offices in Baltimore, Maryland, and is responsible for assessing safety issues involving engineering, construction, or extensive analysis. In one case, the Appendix I TS, extensive negotiations and agreement with the corporate headquarters staff were refuted by the plant staff. Such inefficiency should be corrected.

The licensee has provided the leadership necessary to resolve a number of difficult licensing issues including inservice testing, long-term containment purge and vent, and fire protection. In addition, the licensee's management has provided assistance to NRC in addressing issues that are presently not required for all licensees. These include: integrated licensing schedules; unresolved safety issue (USI) A-49 (pressurized thermal shock); and USI A-47 (safety implications of control systems). This aspect has been a significant strength and is direct evidence of licensee management involvement in the licensing process.

The BG&E organization has shown considerable expertise in addressing safety issues when responding to specific questions from the NRC staff. When dealing with self-initiated issues (i.e., plant specific TS changes), the licensee's evaluation is often insufficient. When submittals to NRR have incorporated safety evaluations performed by the NSSS vendor, the safety evaluations have been found sufficient, indicating that the problem is with the BG&E ability to perform safety evaluations without outside assistance. The need to produce a comprehensive safety analysis (quantitative and/or qualitative) for every proposed change to the TS has been discussed with the licensee. Thus far, he has not provided complete safety analyses on his own initiative. This aspect is assessed under Area 5, Change Control.

The licensee has made a considerable effort to maintain schedules on regulatory deadlines. On several occasions, the licensee has not been able to meet self-imposed written commitments for the submittal of information.

The licensee has met with the Operating Reactors Project Manager informally on almost a monthly basis to discuss schedule problems and has been working on a computer-based commitment control system to improve schedule control. These actions also show management involvement in the licensing process.

The licensee has a staff of sufficient size and quality to address licensing issues initiated by the NRC and licensee-initiated topics. The licensee used consultants on occasion and carefully reviews their work.

A defined training program is implemented for the plant staff. During the assessment period an audit was conducted at the plant site to assess the effectiveness of training and procedural measures to deal with pressurized thermal shock (PTS). A September 13, 1982 NRR letter to the licensee suggested improvements in PTS training.

During the review period, two sets of operator examinations were given at Calvert Cliffs. Overall, six out of fourteen reactor operators and one out of two senior reactor operators passed the examination. Calvert Cliffs management took steps to identify and correct training deficiencies. These steps were outlined in a meeting held with the Operations Licensing Branch at the licensee's request. The proposed course of action was found adequate. Subsequent to the assessment period, BG&E licensed operator candidates performance was much improved, with all 12 candidates (4 SRO, 8 RO) passing the examinations.

Conclusion: Category 2

Board Recommendations:

(1) That BG&E re-evaluate the effectiveness of their control over licensing activities.

(2) That BG&E produce more complete and comprehensive safety analyses to support TS changes.

(3) That BG&E initiate their commitment control system at the earliest practical date.

V. SUPPORTING DATA AND SUMMARIES

1. Licensee Event Report (LERs)

Tabular Listing

Type of Events:

A.	Personnel Error	15
B.	Design/Man./Constr./Install	9
C.	External Cause	0
D.	Defective Procedure	11
E.	Component Failure	57
X.	Other	39
	Total	131

Licensee Event Reports Reviewed:

Report Nos. 317/81-71 through 82/57, 82/60, 82/61, and 82/62; and 318/81-45 through 82/44

Causal Analysis October 1, 1981 - September 30, 1982

Chains Identified

Seven chains were identified:

(a) LER's 318/82-23, 318/82-40, 317/81-75, 317/82-37, 317/82-50, and 317/82-24 describe Unit 1 and 2 pressurizer level deviations greater than 5% from a program value. The licensee has submitted a Technical Specification Change Request which would provide a wider allowable range for pressurizer level.

(b) LER's 318/82-01, 318/82-08, 318/82-37, 318/82-41, and 318/82-42 involved improper adjustment or breakage of the Unit 2 containment personnel lock inner and outer door operating mechanism. The licensee, during the current refueling outage, will upgrade the material used in the door mechanism (Facility Change Request 82-24) and will make necessary adjustments in door alignment and closure tightness.

(c) LER's 318/81-57 and 317/82-01 involved Unit 1 and 2 seal leakages on outer containment personnel lock door handwheels. The licensee plans , in its refueling preventative maintenance program, to perform steps to ensure seal integrity.

(d) LER's 318/81-54, 318/82-26, 317/82-11, 317/82-36, and 317/82-45 involved Unit 1 and 2 Control Element Assembly drops. The cause was identified and corrected in one case only (317/82-45). The licensee is working with the NSSS vendor to resolve the problem. LER's 317/82-55 and 318/81-51 involved leaking Unit 1 and 2 Reactor Coolant Pump seal pressure sensing lines. The licensee has initiated an Engineering review of sensing line design.

(e) LER 317/82-40 reported out of calibration conditions on the four Unit 1 safety channel pressurizer pressure transmitters and the Steam Generator pressure transmitters. All transmitters were manufactured by Barton Instrument Co. (Model 763) and do not meet specifications for thermal sensitivity.

(f) In 1981, prior to the evaluation period, the licensee had reported Unit 1 Charging Pump inoperability due to discharge relief valve liftings (CER's 317/81-12, 317/81-21, and 317/81-46). During the evaluation period a similar event occurred and was reported in LER's 317/82-12 and 317/82-13.

(g) LER's 318/82-05 and 318/82-30 involved failures to maintain high energy line break or main steam jet impingement barrier integrity following maintenance and facility change activities.

Note: No conclusions were drawn from the total number of LER's because that is perceived to be a function of Technical Specifications and licensee reporting practices.

2. Investigation Activities

One investigation of allegations of poor Quality Control in the fabrication of Spent Fuel racks. The allegations were not substantiated.

3. Escalated Enforcement Actions - none

3.1 Civil Penalties - none

3.2 Orders - none

3.3 Confirmatory Action Letters

Confirmatory letter dated November 19, 1981 (clarification letter dated November 19, 1981) regarding planned corrective action on significant findings identified in the Emergency Preparedness Team (NRC) inspection on October 5 through 16, 1981.

4. Management Conferences

July 7, 1982 Enforcement Conference held in the NRC Region 1 Office to address Containment Integrated Leak Rate Testing (results and procedures) and inoperability of the Hydrogen Monitors (Violations on Unit 1 only).

TABLE 1

TABULAR LISTING OF LERs BY FUNCTIONAL AREA

CALVERT CLIFFS NUCLEAR POWER PLANT

AREA	Total-Number/Cause Codes					
1. Plant Operations	12/A	2/B	0/C	8/D	44/E	33/X
2. Radiological Controls	2/A	2/B	0/C	0/D	7/E	4/X
3. Maintenance	1/A	2/B	0/C	1/D	4/E	0/X
4. Surveillance	0/A	3/B	0/C	1/D	1/E	1/X
5. Control Changes	1/A					
6. Fire Protection	None					
7. Emergency Preparedness	None					
8. Security & Safeguards	0/A	0/B	0/C	1/D	0/E	0/X
9. Refueling	0/A	0/B	0/C	0/D	0/E	1/X
10. Licensing Activities	None					

		U1	U2	Combined
Cause Codes:	A. Personnel Error	9	6	15
	B. Design/Man./Const./Install	5	4	9
	C. External Cause	0	0	0
	D. Defective Procedure	6	5	11
	E. Component Failure	32	25	57
	X. Other	22	17	39
	Totals	74	57	131

TABLE 2

INSPECTION HOURS SUMMARY (10/1/81-9/30/82)

CALVERT CLIFFS NUCLEAR POWER PLANT

		HOURS	% OF TIME
1.	Plant Operations	834	31%
2.	Radiological Controls	141	5%
3.	Maintenance	111	4%
4.	Surveillance	138	5%
5.	Design Control/Quality Assurance	184	7%
6.	Fire Protection/Housekeeping	57	2%
7.	Emergency Preparedness	900	34%
8.	Security and Safeguards	208	8%
9.	Refueling	114	4%
10.	Licensing Activities	No Data	0
	Total	2687	100%

TABLE 3

VIOLATIONS (10/1/81-9/30/82)

CALVERT CLIFFS NUCLEAR POWER PLANT

A. Number and Severity of Violations

(1) Interim NRC Policy Severity Level (10/1/81-3/9/82)

Severity Level I	0
Severity Level II	0
Severity Level III	0
Severity Level IV	5
Severity Level V	8
Severity Level VI	2

(2) NRC Policy Severity Levels (3/10/82-9/30/82)

Severity Level I	0
Severity Level II	0
Severity Level III	0
Severity Level IV	14
Severity Level V	7

Total = 36

B. Violations vs. Functional Areas

(1) October 1, 1981- March 9, 1982

FUNCTIONAL AREAS	Severity Level I	II	III	IV	V	VI
1. Plant Operations					3	1
2. Radiological Controls				1	1	
3. Maintenance					2	1
4. Surveillance				1		
5. Facility Changes				2	1	
6. Fire Protection						
7. Emergency Preparedness						
8. Security and Safeguards				1		
9. Refueling					1	
10. Licensing Activities						
Totals	0	0	0	5	8	2

(2) March 10 - September 30, 1982

	Severity Level				
FUNCTIONAL AREAS	I	II	III	IV	V
1. Plant Operations				4	2
2. Radiological Controls				3	2
3. Maintenance				3	1
4. Surveillance				1	
5. Change Control Procedures				2	
6. Fire Protection					
7. Emergency Preparedness					1
8. Security and Safeguards				1	
9. Refueling					1
10. Licensing Activities					
Totals	0	0	0	14	7

C. Summary (* = Violations common to both Units)

Insp. No.	Insp. Date	S	A	Requirement	Subject
UNIT 1					
81-21	10/6-11/3/81	4	8	Phy.Sec.Plan	Failure to maintain visitor escort
81-22	10/22-10/30/81	4	5	10CF50App.B	Known deficiency in Component Cooling Water System not corrected to fail-shut per FCR-1089 of 9/2/76 until 10/22/81.
		4	5	10CF50App.B	Failure to prevent recurrence of wrong valve failure mode for CCW Containment Supply Valves *
		5	5	10CFR50App.B	Electric schematics with false Containment Isolation Valve failure mode.
81-24	11/3-12/1/81	5	3	10CFR50App.B	Failure to adequately control maintenance on a safety-related system *
81-25	11/18-11/20/81	5	9	10CFR50App.B	Failure to provide receipt verification and accounting of SNM in fission chambers within 10 days *
81-27	12/0-1/5/82	5	2	TS	Technician entered a radiation area without signing in on Radiation Work Permit, failed to check with Radiation Control Point or obtain survey instrument, and exited without monitoring for contamination
82-02	1/6-2/2/82	6	1	ETS	Failure to ensure regenerative waste was properly neutralized prior to discharge *

NRC Policy Severity Level Change

Insp. No.	Insp. Date	S A Requirement	Subject
82-05	3/2-4/13/82	4 5 10CFR50App.B	Failure to conduct required safety reviews for facility changes *
82-06	3/15-3/19/82	4 2 TS	Detailed work procedure did not provide necessary directions to assure adequate radiation protection was implemented for work on ICI components in Spent Fuel Pool*
		4 2 TS	Surveys not made to support work being performed on ICI wire spool in Spent Fuel Pool*
		4 2 TS	Work in Spent Fuel Pool performed beyond scope of RWP without prior approval*
82-07	4/13-5/11/82	4 4 TS	Measured containment leakage rate greater than allowed
		4 1 TS	Failure to have operable hydrogen analyzer during Cycle 5
82-15	6/16-6/18/82	4 3 10CF50App.B	Failure to control activity affecting quality of work performed on safety related containment pressure sensing lines
		4 1 TS	Failure to establish adequate procedures to maintain containment integrity

Insp. No.	Insp. Date	S A Requirement	Subject
82-16	6/15-7/1/82	4 1 TS	Inoperability of Auxiliary Feedwater System in Mode 3
82-18	7/13-7/23/82	4 3 TS	Inadequate maintenance instructions for calibration of RPS/ESFAS
82-20	7/19-7/23/82	5 1 TS	Several operating procedures contained technically incorrect information; no procedure for alarm annunciator; no abnormal operating procedure for Saltwater System flow blockage and records not maintained *
82-22	7/26-7/30/82	4 8 TS	Failure to change locks/locksets in accordance with security plan requirements *
82-23	8/10-9/14/82	5 1 TS	Failure to properly implement OI-24; Spent Fuel Pool Cooling System valve lineup improper *
82-24	9/13-9/17/82	5 2 TS	Failure to follow procedures regarding posting radioactive materials and entry into a radiation area
82-26	9/14-10/12/82	5 9 TS	Failure to follow fuel pin serial number verification
		4 1 10CFR50.59	Inoperability of Hydrogen Purge System

Unit 2

Insp. No.	Insp. Date	S A Requirement	Subject
81-20	10/6-11/3/81	5 1	Failure to isolate air supply to Unit 2 Containment Purge Exhaust
81-23	11/3-12/1/82	4 2 TS	Radioactive release above TS instantaneous limits
81-25	12/1-1/5/82	5 1 TS	Failure to lock Service Water Valves
		5 3 10CFR50	Failure to maintain high concentration boric acid piping insulation
82-02	1/6-2/2/82	6 3 10CFR50	Failure to adequately control the special processes associated with the repair of Salt Water System Piping
82-04	2/3-3/2/82	5 1 TS	Failure to properly lock valves
		4 4 TS	Failure to check shutdown margin when CEA was found stuck following reactor trip
NRC Policy Severity Level Change			
82-05	3/2-4/13/82	5 2 10CFR20	Failure to post a radiation area
		4 5 10CFR50	Failure to control drawing changes
82-07	4/13-5/11/82	4 3 TS	Failure to follow tagouts requirements

Insp. No.	Insp. Date	S A Requirement	Subject
82-16	7/13/-8/10/82	5 3 TS	Failure to properly clear tagout
82-19	8/10-9/14/82	5 7 TS	Failure to declare radiological event

TABLE 4

INSPECTION REPORT ACTIVITIES

REPORT NOs.	INSPECTOR	AREAS INSPECTED
81-19/81-18	Specialist	Emergency Preparedness Implementation
81-21/81-22	Resident	Routine inspection
81-22/81-21	Resident/ Specialist	Valve failure mode
81-23/81-24	Specialist/ Resident	Emergency preparedness inspection and the annual emergency exercise.
81-24/81-23	Resident	Routine inspection.
81-25/81-24	Specialist	Organization and Operation; Measurement and Controls; Shipping and Receiving; Storage and Internal Controls; Inventory; Records and Reports; and Material Control System Management.
81-26	Specialist	Investigation of allegations that the quality of the welds on the spent fuel storage racks was unacceptable because of poor inspection practices and the use of defective test equipment.
81-27/81-25	Resident	Routine inspection.
82-01/82-01	Specialist	Controls over Committee Activities, Quality Assurance Audits, Design Changes and Modifications, Maintenance, Plant Operations, Corrective Action Systems, Licensed Training, and Non-Licensed Training.
82-02/82-02	Resident	Routine inspection.
82-03/82-03	Specialist	Previous inspection findings and NRC Bulletins.
82-04/82-04	Resident	Routine inspection.
82-06/82-06	Specialist	Radiation Protection including followup on previously identified items, radiation safety practices, and preparations for a refueling and maintenance outage.

REPORT NOs.	INSPECTOR	AREAS INSPECTED
82-07/82-07	Resident	Routine inspection.
82-08/82-08	Specialist	Site Orientation; the Security Plan and Implementing Procedures; Security Organization (Management, Personnel, Response); Security Program Audit; Records and Reports; Testing and Maintenance; Locks, Keys, and Combinations; Access Controls (Packages) and Detection Aids (Vital Areas); and followup on previously identified items.
82-09/82-09	Specialist	Fire Protection/Prevention Program including implementation of administrative procedures; fire brigade training; observation of ignition source and combustible material control; review and observation of critical plant fire areas.
82-10	Specialist	Surveillance testing; maintenance; preparation for refueling; refueling activities; and followup on previous inspection items.
82-11/82-13	Specialist	Salt water intrusion into the steam generator and primary water leakage induced corrosion problems associated with the RCP suction elbow weld and closure studs.
82-12/82-10	Resident	Routine inspection.
82-14/82-12	Specialist	Previous inspection findings; receipt, handling, and storage; procurement; quality assurance; and document control.
82-15	Specialist	Containment penetration leak test program, containment integrated leak rate test, and previous inspection findings.
82-16/82-14	Resident	Routine inspection.
82-17/82-15	Specialist	Administrative controls for safety-related surveillance and Inservice Testing; Technical Specification required surveillance; Inservice Testing for pumps and valves; and previous inspection findings.

REPORT NOs.	INSPECTOR	AREAS INSPECTED
82-18/82-16	Resident	Routine inspection.
82-18/82-22	Specialist	Locks, Keys and Combinations, Physical Barriers (Protected and Vital Areas); Security System Power Supply; Assessment Aids; Access Controls (Personnel, Packages and Vehicles); Detection Aids; Alarm Stations and Communications; and previously identified items.
82-19	Specialist	Inservice inspection data and previous inspection findings.
82-20/82-17	Specialist	Administrative controls for facility procedures, and facility operating procedures.
82-21	RI Management/Resident	Enforcement Conference
82-23/82-19	Resident	Routine inspection.
82-24/82-20	Specialist	Health Physics
82-25/82-21	Specialist/ Resident	Emergency Drill

TABLE 5

CALVERT CLIFFS NUCLEAR POWER PLANT

LER SYNOPSIS
October 1, 1981 - September 30, 1982

LER Number	Type	Summary Description
Unit 1		
81-71	30 day	CEA #57 inserted further than other group 1 CEA's.
81-72	30 day	RPS Channel D Lo-Flow Trip bypassed for corrective maintenance.
81-73	30 day	RCS leakage increased to 1.23 GPM.
81-74	24 hour	Component Cooling Isolation Valve to Containment inoperable.
81-75	30 day	RCS temperature swing and PZR level exceeded programmed band by more than 5%.
81-76	30 day	Hydrogen Analyzer Sample Pump inoperable.
81-77	30 day	Ten solenoid valves rated for pressures less than normal operating conditions.
81-78	30 day	#12 Diesel Generator removed from service for corrective maintenance.
81-79	24 hour	Service Water Pump Room drain lines to Turbine Building lacked back flow protection.
81-80	30 day	Cracked weld on #12 Spent Fuel Cooling Pump discharge vent line.
81-81	30 day	Incore Detection System inoperable.
81-82	30 day	Incore Detection System inoperable.
81-83	30 day	Hydrogen Analyzer inoperable.
81-84	30 day	Incore Detection System inoperable.
81-85	30 day	Channel B Axial Shape Index Lower Setpoint failed.

LER Number	Type	Summary Description
82-01	30 day	Excessive leak rate past containment personnel air lock outer door.
82-02	30 day	Excessive leak rate past containment emergency escape hatch outer door.
82-03	30 day	#29 cell of 125 VDC Battery 12 was below minimum ICV.
82-04	ETS	Regenerative waste was not properly neutralized prior to discharge.
82-05	30 day	#12 Containment Room AC unit tripped and could not be reset.
82-06	30 day	#13 Containment Air Cooler Fan inoperable.
82-07	30 day	Auxiliary Feedwater flow indication inoperable.
82-08	30 day	#11 Component Cooling Heat Exchanger remained isolated for 13 hours after maintenance.
82-09	30 day	RPS Channel B HiPower, Thermal Margin/Low Pressure and Axial Shape Index TU'S bypassed.
82-10	30 day	CEA pulse counting system and incore detection system inoperable.
82-11	30 day	CEA #21 dropped into Core.
82-12	30 day	#11 and #12 Charging Pumps inoperable.
82-13	30 day	#12 charging Pump out-of-service.
82-14	30 day	RPS Channel C Pressurizer and Thermal Margin/Low Pressure TU'S bypassed; Channel C Pressure deviated high by 50 psi.
82-15	30 day	Pressurizer level exceeded the 5% program band.
82-16	30 day	ECCS Exhaust Filter Train inoperable.
82-17	30 day	#12 Control Room AC Unit failed to start.
82-18	30 day	#12 ECCS Pump Room Exhaust Fan removed from service for repair.
82-19	24 hour	Hydrogen Analyzer inoperable.

LER Number	Type	Summary Description
82-20	30 day	RCS indicated Iodine Dose Equivalent Value of 1.31 uCi/gm.
82-21	30 day	Main Steam Safety Valve inoperable.
82-22	24 hour	Operation above 200 degrees with combined Type B & C leakage above 0.60 La.
82-23	24 hour	Measured RCS dilution of 1.0% delta K/K in Mode 6 with refuel pool filled.
82-24	30 day	Pressurizer level deviated from program level by more than 5%.
82-25	30 day	Deficient pipe penetration welds in #11 Refueling Water Tank.
82-26	30 day	Loss of Shutdown Cooling flow during Mode 6.
82-27	24 hour	All three diesel generators inoperable.
82-28	30 day	Loss of redundant Shutdown Cooling loop and inoperable boration flow path.
82-29	24 hour	Automatic start for #11 & #12 AFW Pumps inhibited.
82-30	30 day	Auxiliary Feedwater Flow indication inoperable.
82-31	30 day	Auxiliary Feedwater Flow indication inoperable.
82-32	30 day	Salt Water System motor-operated isolation valve inoperable.
82-33	30 day	Leakage at 200 GPM into #11A Safety Injection Tank with High Pressure Safety Injection Pump operating.
82-34	30 day	12 snubbers in Main Steam Systems and 8 snubbers in Main/Auxiliary/Feedwater Systems not periodically tested.
82-35	24 hour	Safety Injection Tank Level below minimum.
82-36	30 day	CEA #55 dropped into Core.

LER Number	Type	Summary Description
82-37	30 day	Pressurizer level deviated from program level by more than 5% and pressurizer pressure decreased below 2225 psia.
82-38	30 day	Pressurizer level deviated from program by more than 5%.
82-39	30 day	#11B Safety Injection Tank level transmitter inoperable.
82-40	24 hour	Pressurizer pressure transmitters for four safety channels out of calibration.
82-41	30 day	Channel A hi-power, thermal margin/low pressure & axial shape index trip units bypassed for preventive maintenance.
82-42	30 day	#12 Charging Pump operating at reduced capacity with #13 Charging Pump out of service.
82-43	30 day	#12 ECCS Pump Room Exhaust Fan inoperable.
82-44	30 day	RPS Channel A Axial Shape Index setpoint out of specification.
82-45	30 day	CEA 33 dropped to core bottom.
82-46	30 day	Channel A RPS Axial Shape Index indication out of calibration.
82-47	30 day	Channel C RPS Low Flow Trip setpoint was nonconservative.
82-48	30 day	Wide Range Nuclear Instrument inoperable.
82-49	30 day	Containment Particulate Radiation Monitor inoperable.
82-50	30 day	Pressurizer level deviated from program level by more than 5% several times.
82-51	30 day	Plant Air Header isolation valve inside Containment was open vice locked shut.
82-52	30 day	#11 Diesel Generator inoperable.
82-53	30 day	Hydrogen Analyzer inoperable.

LER Number	Type	Summary Description
82-54	30 day	#12 Auxiliary Feedwater Pump inoperable.
82-55	30 day	RCS Leakage increased to 2 GPM.
82-56	30 day	Containment Particulate and Gaseous RMS sample pump tripped.
82-57	30 day	Channel A Th reading 11 degrees low.
82-60	ETS	Oyster samples collected per ETS showed Ag110-m to be 496+/-9 pCi/Kg
82-61	30 day	Pressurizer level deviated from program level by more than 5%
82-62	30 day	Pressurizer level deviated from program level by more than 5%.
Unit 2		
81-45	30 day	Component Cooling Isolation Valve inoperable.
81-46	30 day	Containment Sump level alarm inoperable.
81-47	24 hour	Service Water Pump Rooms drain lines had no backflow protection against Turbine Building flooding.
81-48	ETS	Main Vent flow monitoring instrument inoperable.
81-49	24 hour	Instantaneous radioactive release rate exceeded ETS.
81-50	30 day	Reactor Protective System Channel B Thermal Margin/Low Pressure trip unit bypassed.
81-51	30 day	#22A RCP Middle Seal Pressure Transmitter Sensing Line leaking.
81-52	30 day	Reactor Protective System Channel B trip units for high power thermal margin/low pressure and axial shape index bypassed.
81-53	30 day	Closure of Saltwater outlet valve caused degraded flow
81-54	30 day	CEA #37 dropped into Core.

LER Number	Type	Summary Description
81-55	30 day	#22 Charging Pump out of service.
81-56	30 day	Normal Containment Sump Isolation Valve partially opened.
81-57	30 day	Excessive leak rate past Containment Personnel Air Lock outer door.
82-01	30 day	Excessive leak rate past Containment Personnel Air Lock outer door.
82-02	30 day	21-KV Bus deenergized due to equipment failure while performing surveillance test.
82-03	30 day	CTMT atmosphere gaseous radioactivity monitor inoperable.
82-04	30 day	#22 Steam Generator pressure indication reading high by 44 psi.
82-05	30 day	Steam Jet impingement barrier in Main Steam Penetration Room not completely installed.
82-06	30 day	Leakage past CTMT purge supply & exhaust valves in excess of TS.
82-07	30 day	Auxiliary Feedwater flow indication to #22 Steam Generator indicated 70 gpm with no flow in line.
82-08	30 day	Containment inner door inoperable.
82-09	30 day	Pressurizer level deviated from program level by more than 5%.
82-10	30 day	CEA #19 stuck at about 8" withdrawn
82-11	30 day	Steam Generator Pressure indicator PI-1023A reading high.
82-12	30 day	Channel D Wide Range Nuclear Instrument spiking high.
82-13	30 day	Auxiliary Bldg. operator isolated #21 CTMT spray header.
82-14	30 day	Oil from #21 Diesel Generator contaminated with standing water.

LER Number	Type	Summary Description
82-15	30 day	Negative limit setpoint for Channel A of RPS Axial Shape Index out of specification.
82-16	30 day	Plant computer failed.
82-17	30 day	#23 Charging Pump removed from service while #22 Charging Pump out of service.
82-18	30 day	CEA #21 dropped into Core.
82-19	30 day	CEA #38 Reed Switch position indicator channel giving erroneous indication.
82-20	30 day	RPS Channel A trip units for low SG pressure and thermal margin/low pressure bypassed.
82-21	30 day	#22B Safety Injection Tank pressure decreased to 197 psig.
82-22	30 day	CEA #43 Reed Switch position Indicator Channel inoperable.
82-23	30 day	Pressurizer level deviated from program level by more than 5%.
82-24	30 day	Channel C Pressurizer Pressure failed low.
82-25	24 hour	All Diesel Generators inoperable.
82-26	30 day	CEA #64 dropped into Core.
82-27	30 day	Pressurizer level deviated from program by more than 5%.
82-28	30 day	Steam Generator Channel A level transmitter inoperable.
82-29	30 day	Containment Particulate Radiation Monitoring System inoperable.
82-30	30 day	4" diameter hole between 27 Switchgear Room and Main Steam Penetration Room
82-31	30 day	#12 Diesel speed control inoperable.
82-32	30 day	#21 Diesel Generator inoperable.

LER Number	Type	Summary Description
82-33	30 day	6 snubbers in Main Feedwater and Auxiliary Feedwater and Main Steam Systems were not periodically tested; 2 inaccessible snubbers on 22A RCS loop drain not tested.
82-34	24 hour	Service Water Heat Exchanger combined Saltwater outlet valve inoperable.
82-35	30 day	#21 Service Water Heat Exchanger Saltwater Discharge Line inoperable due to broken drain valve.
82-36	30 day	CTMT Particulate Radiation Monitor inoperable.
82-37	30 day	Outer personnel air lock door opening mechanism inoperable.
82-38	30 day	Hot leg sample valve inoperable.
82-39*	30 day	Outer door of air lock door not secured.
82-40	30 day	Pressurizer level deviated from program level by more than 5%.
82-41	30 day	Excessive leak rate past Containment Personnel Air Lock Outer Door gasket.
82-42	30 day	Inner door on normal personnel hatch to Containment would not shut completely.
82-43	30 day	Emergency Diesel Generator #12 inoperable.
82-44	30 day	Emergency Diesel Generator #21 inoperable.

TABLE 6

UNPLANNED ACTUATIONS OF REACTOR PROTECTIVE SYSTEMS AND ENGINEERING SAFEGUARDS FEATURES

Unit	Date	Trip	Nature
2	2/24/82	RPS	While troubleshooting automatic control circuit on #21 feedwater regulating valve, reactor tripped on low steam generator level.
1	7/05/82	RPS	Reactor tripped on high Steam Generator level after loss of #11 Feed Pump.
1	7/11/82	RPS	Reactor tripped while conducting power to load unbalance test.
1	8/04/82	RPS/	Reactor tripped due to undervoltage spike on reactor bus.
1	8/22/82	RPS	Reactor tripped on low steam generator level due to loading Main Turbine too rapidly.
2	11/09/81	ESF	Reactor tripped at 20% power due to low steam generator level.
1	11/23/81	ESF	Manual trip from full power due to a steam leak in High Pressure Turbine Extraction steam line.
1	12/23/81	ESF	Inadvertent actuation of Recirculation Actuation System.
2	2/05/82	ESF	Manual trip from 100% power after loss of Main Feed Pump #22.
2	2/12/82	ESF	Low steam generator level trip from 100% power after loss of Main Feed Pump #22.

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UNPLANNED ACTUATIONS OF REACTOR PROTECTIVE SYSTEMS AND ENGINEERING SAFEGUARDS FEATURES

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2	2/24/82	RPS	While troubleshooting automatic control circuit on #21 feedwater regulating valve, reactor tripped on low steam generator level.
1	7/05/82	RPS	Reactor tripped on high Steam Generator level after loss of #11 Feed Pump.
1	7/11/82	RPS/ ESF	Reactor tripped while conducting power to load unbalance test.
1	8/04/82	RPS/ ESF	Reactor tripped due to undervoltage spike on reactor bus when an electrical disconnect was opened on a running Service Water Pump.
1	8/22/82	RPS	Reactor tripped on low steam generator level due to loading Main Turbine too rapidly.
2	11/09/81	ESF	Reactor tripped at 20% power due to low steam generator level.
1	11/23/81	ESF	Manual trip from full power due to a steam leak in High Pressure Turbine Extraction steam line.
1	12/23/81	ESF	Inadvertent actuation of Recirculation Actuation System.
2	2/05/82	ESF	Manual trip from 100% power after loss of Main Feed Pump #22.
2	2/12/82	ESF	Low steam generator level trip from 100% power after loss of Main Feed Pump #22.
2	4/17/82	ESF	Manual trip occurred when a technician was directed to open individual CEA breakers for shutdown of U-1 and began to open U-2 CEA breakers instead.

Unit	Date	Trip	Nature
2	4/17/82	ESF	Manual trip occurred when a technician was directed to open individual CEA breakers for shutdown of U-1 and began to open U-2 CEA breakers instead.
1	6/07/82	ESF	Channel A Engineered Safeguards Logic actuated when power was lost to 4KV Vital Bus 11.
1	6/24/82	ESF	Inadvertant Safety Injection, Containment Isolation and Containment Spray System signal occurred. Plant was in cold shutdown; no injection or spray occurred.
1	7/11/82	ESF	Unit tripped during conduct of weekly preventive maintenance test of Main Turbine electro-hydraulic control system.
2	7/14/82	ESF	Unit tripped from 85% power when overspeed trip of Steam Generator Feed Pump #21 resulted in low steam generator water levels.
1	8/04/82	ESF	Unit tripped when an electrical disconnect was opened on a running Service Water pump.
2	8/23/82	ESF	Unit tripped from 83% power on low steam generator level.
1	8/23/82	ESF	Unit tripped on low steam generator level dueto operator error - too rapid pickup of turbine load.
1	8/25/82	ESF	Technician error caused partial ESFAS including starting one High Pressure Safety Injection Pump, one low pressure safety injection and one diesel generator. (No injection)

Unit	Date	Trip	Nature
1	6/07/82	ESF	Channel A Engineered Safeguards Logic actuated when power was lost to 4KV Vital Bus 11.
1	6/24/82	ESF	Inadvertant Safety Injection, Containment Isolation and Containment Spray System signal occurred. Plant was in cold shutdown; no injection or spray occurred.
2	7/14/82	ESF	Unit tripped from 85% power when overspeed trip of Steam Generator Feed Pump #21 resulted in low steam generator water levels.
1	8/23/82	ESF	Unit tripped on low steam generator level dueto operator error - too rapid pickup of turbine load.
1	8/25/82	ESF	Technician error caused partial ESFAS including starting one High Pressure Safety Injection Pump, one low pressure safety injection and one diesel generator. (No injection)