NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Calvert Cliffs, Unit One	0 5 0 0 0 3 1 7	1 OF 0 7

TITLE (4) Saltwater System Graphitic Corrosion

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 5	0 3	8 4	8 4	0 0 5	0 1	0 7	0 3	8 4	Calvert Cliffs, Unit 2	0 5 0 0 0 3 1 8
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OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check one or more of the following)* (11)

[ ] 20.402(b)	[ ] 20.405(c)	[ ] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[X] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[X] 50.73(a)(2)(vii)	[ ] OTHER *(Specify in Abstract below and in Text, NRC Form 366A)*
[ ] 20.405(a)(1)(iii)	[X] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
R. W. L'Heureux, Engineer	3 0 1	2 6 0 - 4 0 0 3

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	C C	H X	5 4 4 5	Y	B	B S	P	F 0 1 9	Y
B	B I	H X	F 1 7 5	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES *(If yes, complete EXPECTED SUBMISSION DATE)* [X] NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT *(Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines)* (16)

On 5/2/84, during Unit 2 refueling outage a through wall hole occurred during removal of the graphite layer on one #22 component cooling heat exchanger (CCHX) channel head. The graphite layer was being removed in preparation for coal tar epoxy application. On 5/3/84, a second hole was created during graphite removal, prompting notification to the Nuclear Regulatory Commission. A visual examination was subsequently conducted on the operating #11, #12, and #21 (CCHX) and service water heat exchanger (SRW HX) channel heads. The #11 and #12 CCHX outlet channel heads had three areas with apparent through wall weepage. On 5/6/84, Unit 1 shutdown and all Unit 1 and Unit 2 CCHX and SRW HX were opened as conditions permitted. Due to the size, location, and number of below minimum wall areas found on the channel heads several repairs were pursued. Encapsulations were installed on #12 and #22 CCHX channel heads, while new channel heads were installed on #11 and #21 CCHX. Bolted plate patches were installed on #12 and #22 SRW HX to correct the deficiencies. Numbers 11 and 21 SRW HX did not need any repairs. However, all CCHX and SRW HX channel heads were coated with coal tar epoxy to prevent future corrosion. New channel heads for all CCHX and SRW HX will be installed during the next outage of sufficient duration. An expanded surveillance program for cast iron components in the saltwater system is being developed.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

During the Fall, 1983 Unit 1 Refueling Outage, some localized graphitization had been noted in the saltwater (BS) channel heads of #11 and #12 Component Cooling (CC) Heat Exchangers (HX). Some nominal graphitization of the 2% nickel cast iron (SA-278CL30) channel heads was expected from this type of material and service. Plans were made to design and install a new cathodic protection system for the component cooling and service water (BI) heat exchangers (HX) during the spring, 1984 Unit 2 Refueling Outage and spring, 1985 Unit 1 Refueling Outage.

On May 2, 1984, at 1600, during the Unit 2 Refueling Outage (MODE 6), severe localized graphitization was noted and a through wall hole was created during removal of the graphite layer on #22 component cooling heat exchanger (Manufactured by Struthers Wells, Type 35-30NY11-6H) outlet channel head with air operated needle guns and chisels. The graphite layer was being removed in preparation for application of coal tar epoxy to prevent further corrosion.

On May 3, 1984, a second hole was created during graphite layer removal, prompting notification to the Nuclear Regulatory Commission at 1700, due to potential generic implication on the Unit 2 Saltwater System.

On May 5, 1984, after removal of insulation (asbestos) a visual examination was then conducted on #11, #12, and #21 component cooling and service water (Foster Wheeler, Serial No. 58-888) heat exchanger channel heads at service pressure. The #11 and #12 CCHX outlet channel heads were found to have a total of three areas where apparent weepage through the wall was occurring. The remaining heat exchanger channel heads did not display any signs of weepage.

On May 6, 1984 at 0310, shutdown of Unit 1 began because of the inability with the information existing at the time to definitely demonstrate that the channel heads on #11 and #12 component cooling heat exchangers were operable (Tech. Spec. 3.7.3.1). Besides detailed ultrasonic mapping and visual inspections on all component cooling and service water heat exchanger channel heads, ultrasonic inspections of a representative sample of other gray cast iron components was begun.

On May 14, 1984, at 1915, all Unit 1 and 2 saltwater pumps (P) were considered inoperable, due to several thin wall areas found on a single saltwater pump during ultrasonic inspections. This placed both units in several Action Statements. Pertaining to Unit 2, Technical Specification 3.8.2.2 Action Statement required that CONTAINMENT (NH) INTEGRITY be established. This condition had already been met prior to conducting core alterations and moving irradiated fuel within the Containment. As a result of the assumed inoperability of the saltwater pumps, the diesel generators (EK) also had to be assumed inoperable. This results from the fact that the service water system (which is cooled via saltwater) is needed for cooling of the diesel generators. Therefore, Tech. Spec. 3.8.1.2 prevented further core alterations or positive reactivity changes until a saltwater header, and thereby diesel was declared operable. Fuel movement on Unit 2 was, therefore, suspended on May 14, 1984 at 1920. On May 19, 1984 at 1000, #23 saltwater pump and all piping and valves in #22 saltwater subsystem were declared operable after numerous ultrasonic thickness readings revealed no areas below the minimum wall requirement.

On May 22, 1984, at 0025, #21 service water heat exchanger was declared operable, in that no thickness readings were found to be below minimum wall. This made #21 diesel generator operable thereby permitting refueling to continue. On May 22, 1984, at 2300, #12 component cooling and service water heat exchangers were returned to service (after being out of service for 16 days). Due to the size, location, and number of below minimum wall areas on the different channel heads several repairs were performed to make the heat exchangers operable. Carbon steel encapsulations were installed on #12 component cooling heat exchanger channel heads, with patches and a belly band installed on #12 service water heat exchanger channel heads. In addition, the channel head interior surfaces were coated with coal tar epoxy to prevent further corrosion.

On May 23, 1984, at 0400 and 1700, respectively, #22 component cooling and service water heat exchangers were returned to service (after being out of service for 21 days) and #11 component cooling and service water heat exchangers channel heads were opened. Carbon steel encapsulations were installed on #22 component cooling heat exchanger channel heads, and patches were installed on #22 service water heat exchanger channel heads. Both heat exchangers were coated with coal tar epoxy to prevent further corrosion.

On May 24, 1984, at 1200, #21 component cooling and service water heat exchanger channel heads were opened. On May 27, 1984, at 0300, #11 component cooling heat exchanger was returned to service with new channel heads coated with coal tar epoxy, (after being assumed inoperable for 16 days and actually out of service for four days). On May 28, 1984, at 0300, #11 service water heat exchanger was returned to service after being out service for five days. No minimum wall deficiencies were found, but in order to prevent future corrosion, coal tar epoxy was applied to channel head internals.

On May 29, 1984, at 0800 and 1200, respectively, #21 component cooling and service water heat exchangers were returned to service. Number 21 component cooling heat exchanger was assumed inoperable for 10 days and actually out of service for five days. Number 21 service water heat exchanger was out of service for five days. New carbon steel channel heads lined with coal tar epoxy were installed on #21 component cooling heat exchanger. No minimum wall deficiencies were found with the channel heads of #21 service water heat exchanger, but in order to prevent future corrosion, coal tar epoxy was applied to its internals. As of May 31, 1984, all saltwater trains in both units had been returned to service.

A summary of the inspections and repairs of Unit 1 and 2's saltwater system is as follows:

1. Heat Exchanger Channel Heads

   Numbers 11 and 21 component cooling heat exchangers have new channel heads. Numbers 12 and 22 component cooling heat exchangers have encapsulations. Numbers 12 and 22 service water heat exchangers have bolted plate patches. All of the component cooling and service water heat exchanger channel heads have been coated with coal tar epoxy to prevent further corrosion. It is planned to have new channel heads installed on the remaining heat exchangers during the next outage of sufficient duration.

2. ECCS Room Air Coolers (HX) and Strainers (STR)

   All components were inspected. No significant wall loss was found. The internals were coated with coal tar epoxy.

3. Cast Iron Bodied Valves (V)

   A representative sample (40%) of the check valves and butterfly valves (FCV) on both units were visually and ultrasonically inspected. No significant wall loss was found.

4. Pumps

   All saltwater pump (Fairbanks-Morse, 24x30, Fig. 5712) front heads, back heads and volutes were inspected. Backheads on #13 and #21 saltwater pumps had to be replaced. Number 22 saltwater pump volute had some low ultrasonic wall thickness measurements. The operability of this pump is still being evaluated.

5. Piping (BSP)

   Portions of Unit 1 and 2's class LC cement lined ductile cast iron piping were visually and ultrasonically tested. All wall thickness measurements were found to be above minimum wall requirements with the exception of one elbow which was replaced. It was later determined that the localized low ultrasonic test reading area was a result of casting porosities.

An expanded surveillance program to monitor the performance of cast iron components in the saltwater system will be developed.

The maximum non-accident heat load on the Unit 1 saltwater system exists during Full Power, **MODE** 1 operation. Since Unit 1 was at 100% power in **MODE** 1 at the start of this event, there are no reasonable or credible alternative circumstances for which this event would be more severe. In the unlikely event of a design basis earthquake, the saltwater system may have been further degraded sufficiently to raise doubt as to its capability to perform its design function. However, a design basis earthquake in conjunction with another design basis event, is considered to be beyond the scope of reasonable and credible alternative circumstances. Nonetheless, prompt action was taken to minimize the amount of time the plant was exposed to the **OPERATION MODES** where a seismic event would be most severe, i.e., **MODES** 1 through 4.

The weepage from the Unit 1 component cooling water heat exchanger channel heads would not have prevented satisfying the safety function of the Unit 1 saltwater cooling systems. The quantity of water weeping was insignificantly small when compared to the capacity of the saltwater pumps. In addition, system heat loads were being maintained in spite of the weepage.

In the event of a design basis earthquake and a subsequent loss of offsite power, one or more of the degraded service water or component cooling heat exchanger channel heads Unit 1 may have ruptured. It should be noted, however, that engineering review of operating and seismic stresses on the saltwater pumps showed that rupture of any of these pumps would not be credible during a design basis earthquake, even though some pumps were below minimum code wall thickness. The operator would have been alerted to any flooding due to the high room level alarms in the component cooling water rooms and the service water rooms, which contain the affected heat exchangers. To minimize the extent of the flooding, the operator would have remotely isolated the affected components. Once the affected components were remotely isolated and the saltwater pump(s) secured to minimize the flooding, the affected Unit would have been shutdown.

The steam driven train of the auxiliary feedwater system (BA) would be used to provide makeup water to the steam generators with the atmospheric dump valves (JI) used to remove decay heat. The Unit 1 diesel generator (EK) would have been declared inoperable due to the loss of saltwater to Unit 1. Since #21 service water heat exchanger and #23 saltwater pump were **OPERABLE** throughout this event, cooling to one Unit 1 diesel generator could have been provided by cross-connecting the Unit 1 and 2 service water systems and cooling the service water by Unit 2 saltwater system, #21 header. This would have established long term electrical power to maintain the affected Unit in **HOT STANDBY**, using auxiliary feedwater and atmospheric steam dump valves, as described above.

In the event of a Loss of Coolant Accident (design basis accident), Unit 1 could have mitigated the Loss of Coolant Accident as described in the Unit 2 evaluation below.

Since Unit 2 was in **MODE** 6 at the time of the event, the heat loads on the Unit 2 saltwater system were small. However, the heat loads existing were being removed by the operating subsystem. The removal of the graphitization layer was being conducted as a planned refueling outage evolution and would not have been normally conducted during reactor operation. Therefore, it is not considered credible that the through wall holes would have occurred during **MODE** 1 operation although weepage did occur on the Unit 1 Heat Exchangers in **MODE** 1. Nonetheless, had Unit 2 been in **MODE** 1 operation, the system non-accident heat loads would have been at a maximum.

A design basis Loss of Coolant Accident could have been mitigated. Since only the component cooling water heat exchangers had developed the through wall holes the service heat exchangers and ECCS pump room heat exchangers would have been available to provide the needed post-Loss of Coolant Accident cooling. The Updated Final Safety Analysis Report addresses a complete loss of the Component Cooling Water System in Chapter 9, Section 9.5.5. This section states that in the event of complete loss of the Component Cooling Water System, the containment coolers (BK) (cooled by service water) would be available to provide the containment heat removal function in lieu of the containment spray (BE)/shutdown heat exchangers (cooled by component cooling water).

The saltwater cooling to the component cooling water heat exchangers is isolated on a safety injection actuation signal (SIAS) (JE) and saltwater cooling is not reestablished to the coolers until a minimum of 36 minutes following a Design Basis Loss of Coolant Accident. Therefore, sufficient time would be available to isolate the affected saltwater/component cooling water heat exchangers and recover the remainder of the saltwater system. High room level alarm indication is provided in the control room to alert the operator in the event of flooding due to a rupture of the saltwater system within the component cooling water room.

The high pressure safety injection (BQ) pumps, whose seals are cooled by component cooling water, can operate for a minimum of two hours without cooling water. During this period, the operator can manually align one containment spray pump to provide the needed safety injection flow following a Loss of Coolant Accident. The containment spray pump seals are air cooled. Therefore, the loss of the component cooling water heat exchangers is bounded by the existing Updated Final Safety Analysis Report analyses. These evaluations would apply to both Units 1 and 2. System metallurgical evaluation revealed that propagation of the through-wall holes was not considered likely, due to the nature of the corrosion. Therefore, catastrophic failure of the heat exchanger channel heads is not considered likely.

In summary, because (1) Unit 2 was in a refueling outage at the onset of the event, (2) propagation of the through-wall holes was unlikely due to the nature of the graphitic corrosion, and (3) the service water heat exchangers and ECCS pump room heat exchangers were available, although potentially degraded, the overall safety significance of the event was minimal.

The normal shutdown cooling system was used to remove decay heat, with the steam generators as a backup means. The shutdown cooling heat exchangers are cooled by component cooling water, which is cooled by the saltwater system. Should shutdown cooling have failed, spent fuel pool cooling may be utilized to cool the core in **MODE** 6. The spent fuel pool cooling system may also be cross-connected between units, if necessary. Spent fuel pool cooling is provided by service water which is cooled by saltwater.

When the ultrasonic test measurements on #11 saltwater pump were found to be below minimum wall thickness, a conservative interpretation of the generic concern for the saltwater system components resulted in the Unit 2 saltwater system being declared inoperable. This placed the plant outside the provisions of Technical Specification 3.8.2.2, since the Unit 2 diesel generators (which are ultimately cooled by saltwater) were also declared inoperable. This condition is beyond the design basis of the plant, thus the provisions of the **ACTION** requirements of Technical Specification 3.8.2.2 were applied and containment integrity was established consistent with the plant conditions at the time (i.e., **MODE** 6). Although the saltwater pump #11 casing was degraded, saltwater pumps #12 and #13 casings were later verified to be acceptable and could have provided two **OPERABLE** saltwater subsystems on Unit 1. If the saltwater system for Unit 2 had failed, the spent fuel pool cooling system for Unit 1 would have been used to cool the Unit 2 reactor core, with heat dissipated through the Unit 1 containment atmosphere via the Unit 1 containment coolers. The Unit 1 spent fuel pool cooling system is cooled by the Unit 1 service water system, which is cooled by the Unit 1 saltwater system.

Obviously, if Unit 2 had been in **MODE** 1 when all saltwater pumps were declared inoperable, the reactor would have been shutdown and decay heat removed in **HOT STANDBY** from the Unit 2 reactor by natural circulation and atmospheric steam dump valves. The steam-driven auxiliary feedwater train would have been utilized to provide makeup water to the steam generators. The diesel-driven fire pump would have been available to provide additional makeup water to the suction of the steam-driven auxiliary feedwater pumps, if necessary.

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NUCLEAR POWER DEPARTMENT
CALVERT CLIFFS NUCLEAR POWER PLANT
LUSBY, MARYLAND 20657

July 3, 1984

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Docket No. 50-317
License No. DPR 53

Dear Sirs:

The attached revision to LER 84-05, Rev. 1 is being forwarded to you for your information.

Should you have any questions regarding this report, we would be pleased to discuss them with you.

Very truly yours,

L B Russell

L. B. Russell
Plant Superintendent

LBR:RWL:srm

Attachments

cc: Dr. Thomas E. Murley
Director, Office of Management Information
and Program Control
A. E. Lundvall, Jr.
J. A. Tiernan

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