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

Subject: Oconee Nuclear Station
Docket Nos. 50-269
Licensee Event Report 269/2004-01, Revision 0
Problem Investigation Process No.: O-04-0101

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report 269/2004-01, Revision 0, regarding completion of a unit shutdown required by Technical Specifications due to Reactor Coolant System leakage in excess of the Technical Specification limit.

This report is being submitted in accordance with 10 CFR 50.73 (a)(2)(i)(A). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

R. A. Jones

Attachment

IE22

cc: Mr. Luis A. Reyes
Administrator, Region II
U.S. Nuclear Regulatory Commission
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Mr. L. N. Olshan
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Mr. M. C. Shannon
NRC Senior Resident Inspector
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INPO (via E-mail)

NRC FORM 366 (7-2001)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 7-31-2004

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Oconee Nuclear Station, Unit 1	050- 0269	1 OF 9

4. TITLE

Unit Shutdown due to Reactor Coolant Leak Above Technical Specification Limits

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME: None	DOCKET NUMBER
01	08	04	2004	– 01	– 01	03	08	2004	FACILITY NAME	DOCKET NUMBER

9. OPERATING MODE	1
10. POWER LEVEL	26

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

	20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
	20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
	20.2203(a)(1)		50.36(c)(1)(i)(A)		50.73(a)(2)(iv)(A)		73.71(a)(4)
	20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
	20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		
	20.2203(a)(2)(iv)	X	50.73(a)(2)(i)(A)		50.73(a)(2)(v)(D)		
	20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
	20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
	20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
B.G. Davenport, Regulatory Compliance Manager	(864) 885-3044

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

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	AB	TBG	Unknown	Yes					

14. SUPPLEMENTAL REPORT EXPECTED				15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On 1/8/2004 Oconee Unit 1 was at approximately 26% RTP, with an increasing leak rate trend from an unidentified location in the Reactor Coolant System (RCS). At 1312 hours a power reduction was initiated to reduce dose inside containment to facilitate a search for the leak source.

At 1502 hours, Operations personnel conservatively estimated the leakage to be approximately one gpm. Technical Specification (TS) 3.4.13 Condition A was entered. At 1902 hours Operations personnel declared Unit 1 in TS 3.4.13 Condition B, which required that the unit be placed in Mode 3 within 12 hours.

At 1912 hours an ENS notification was made per 10CFR 50.72 (b)(2) for initiation of a TS required shutdown. The NRC assigned event number 40433. At 1925 hours Operators completed the shutdown by entering Mode 3. The leak was subsequently identified as a crack in 3/8 inch diameter tubing at a fitting on a Reactor Vessel Level Instrument line. The cracked section was cut out and a new fitting installed.

A cause evaluation concluded that the crack was vibration induced and had propagated over time.

This event is considered to have no significance with respect to the health and safety of the public.

EVALUATION:

BACKGROUND

This event is reportable per 10CFR 50.73 (a)(2)(i)(A) as completion of a shutdown required by Technical Specifications.

Technical Specification (TS) 3.4.13 provides the following limits on RCS operational leakage in Modes 1 through 4:

a. no RCS pressure boundary leakage

b. 1 gpm unidentified leakage

c. 10 gpm identified leakage.

The Reactor Coolant System (RCS) [EIIS:AB] has two steam generators [EIIS:HX] with associated pumps, piping, and instrumentation. These are designated Loop A and Loop B.

The Reactor Vessel Level Indicating System (RVLIS) [EIIS:XT] was installed on all three Oconee Units during outages in 1986 and 1987. This modification added Reg. Guide 1.97 level instruments and associated instrument impulse lines to existing taps on the reactor vessel head, both A and B steam generators, and two taps on the decay heat drop line.

The RVLIS tubing [EIIS: TBG] on Unit 1 which was involved in the event being reported was installed during an outage in May 1992 as part of a corrective action after a 1991 Unit 3 RVLIS tubing fitting failure, reference LER 387/1991-08, dated 12-23-1991, and NRC Information Notice No. 92-15, dated 2-24-92.

Prior to the current event, Unit 1 was operating at 26% Rated Thermal Power (RTP), with no safety systems or components out of service that would have contributed to this event.

EVENT DESCRIPTION

At 05:25 on 1/7/2004, following Unit 1 start-up from a refueling outage, the Control Room operators received initial indications of a small leak in the RCS. Operations calculated a leak rate at 0.30 gpm, entered OP/0/B/1106/033 "Primary Leak Check", and began planning activities to identify the leak.

On 1/8/2004 at 1225 hours, with reactor power at approximately 26% RTP, leakage had increased to approximately 0.8 gpm. Personnel

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entered containment but were unable to identify the leak location. At 1312 hours a power reduction to 17% RTP was initiated to reduce dose sufficiently to allow entry into the steam generator cavities in an attempt to identify the exact leak source.

The RCS leakage calculation involves calculation of the changes over time of a number of inputs; this time dependence results in the potential for the calculated value to lag actual leakage. Therefore, at 1502 hours, after the calculated leakage reached 0.91 gpm, Operations personnel conservatively estimated the leakage to be approximately one gpm. TS 3.4.13 Condition A and AP/1/A/1700/002 "Excessive RCS Leakage" were entered and Operations personnel began preparations to continue the shutdown.

At 1902 hours the four hour action statement of TS 3.4.13 Condition A expired and Operations personnel declared Unit 1 in Condition B, which required that the unit be placed in Mode 3 within 12 hours.

At 1912 hours an ENS notification was made per 10CFR 50.72 (b)(2) for initiation of a TS required shutdown. The NRC assigned event number 40433. The NRC resident inspector was also notified.

Per OP/1/A/1102/10 "Controlling Procedure for Unit Shutdown" Operators manually tripped the reactor when a power level reached less than 3 %RTP at 1925 hours. The trip placed Unit 1 in Mode 3, completing the initial phase of the shutdown required by TS 3.4.13 Condition B. A manual trip from this power level is a routine step of the shutdown procedure and was NOT performed to compensate for the leak condition.

At 2040 hours, personnel inside the containment building identified the leak location as a tubing joint down stream from 1RC IV0090, the first isolation valve off the RCS on an impulse line to a RVLIS instrument in the B steam generator cavity. Additional details related to the tubing leak are described below.

At 2114 hours 1RC IV0090 was closed, which terminated the RCS leak, but made the RVLIS instrument inoperable. Operations exited TS 3.4.13 Condition A on RCS leakage and entered TS 3.3.8 Condition A for Function 3 (RCS Hot leg level) due to the inoperable RVLIS instrument.

Initial inspection revealed that there was a crack in the tubing adjacent to the ferrule of the compression fitting. Because this tubing is normally in service and directly subject to RCS pressure, this must be considered an RCS pressure boundary leak.

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Approximately 2" of the tubing was removed and saved for analysis. On 1/9/04 at 0430 hours the tubing repair was completed. At 1050 hours an evaluation of the condition was completed, the affected RVLIS instrument line was declared operable, and unit restart was authorized with respect to this issue.

At 1200 hours an RCS leakage calculation measured leakage to be 0.028 gpm, which provides further evidence that the observed tubing leak was the significant contributor to this event.

The configuration of the instrumentation is as follows:

The RVLIS hot leg level instrument is connected to one inch vent piping located at the high point of the hot leg. Valve 1RC IV0090 is a one inch valve and is the first instrument isolation valve off the RCS. The downstream side of the valve has welded fittings to reduce from the one inch pipe to a 3/8 inch tubing connection. Stainless steel tubing is connected to this fitting by use of a standard compression fitting (two pieced ferrule compressed into the tubing by tightening of the nut). The tubing then extends several feet to two horizontal 90 degree bends, making a U shape, and returns parallel on its way to the level instrument. The total length of the 3/8 inch tubing is 13 feet. The tubing is self supporting between the valve and the level instrument.

In this case, the tubing itself was observed to be slightly bent near the fitting. The leak had been observed spraying from a portion of the gap where the tubing passes through the hole in the fitting nut. As a repair, the tubing was cut approximately two inches from the end, behind the nut. A new nut and ferrule were installed on the remaining tubing and the tubing was reconnected to the reducer, thus restoring the integrity of the RCS and instrument system. During the investigation of the leak, it was identified that the wall thickness of the installed tubing is 0.035", which is less than the 0.049" wall thickness described in the applicable Oconee Pipe Specification. Some construction drawings indicate that 0.035" tubing was installed in this application on all three units. An operability evaluation was performed which concluded that this difference is acceptable for continued operation.

The two inch portion of the tubing with the compressed ferrule and nut was sent to the Duke Energy Materials Engineering Laboratory for metallurgical analysis of the crack.

CAUSAL FACTORS

The root cause of this event is equipment failure due to vibrational fatigue, with possible contributing factors being a) the relatively long run of self supported tubing, b) the installation of a thinner wall tubing than specified in the design specification, and c) additional stresses due to a slight bend near the fitting. This conclusion is based on the following supporting information:

Initial examination of the two inch long piece revealed a straight, flat crack which extended 0.06" in axial distance beyond the backing ferrule, slanted approximately 30 degrees from the ferrule edge, then turned and ran axially back toward the backing ferrule at its tip. The ferrules were cut from the tubing. The tubing contained two distinct crimp sites, at the front and backing ferrules. The crack was found to extend approximately 270 degrees around the circumference of the tube under the backing ferrule. When the crack was separated for examination, more than 50 % of the cross-section was darkly oxidized, indicating that this portion of the crack was old.

Much of the crack length was covered by the ferrules on the fitting, which prevented leakage prior to this event, and the crack ran circumferentially along the crimp mark for the backing ferrule. The cracking did not follow the minimum wall thickness at this crimp; instead, the backing ferrule was likely a point of restraint where the bending moment was maximized.

In addition there was a slight bend (estimated as approximately 20 degrees or less) within a few inches of the fitting nut. Although there was no evidence that the bend in the tubing overloaded it to the point that it introduced a flaw - that is, there was no "tear" at the crack origin - the bend almost certainly resulted in an increased level of bending stress at the restraint point (the backing ferrule).

Thermal fatigue was excluded as a probable cause due to the absence of any known mechanism for producing a high number of thermal fluctuations at this location. There is no monitoring of system induced vibrations at this location but it appears reasonable to for this tubing to be subjected to some mechanical vibrations. The tubing runs in a "U' shape, with a total length of 11 feet, and is attached only by the fittings at the two ends, so that it is self supporting.

The cracking mode which formed the pre-existing crack appeared to be high-cycle fatigue.

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A localized high stress condition due to crimping the ferrule, combined with possible additional stress due to the slight bend, and the fact that the tubing wall thickness was less than that called for in the design specification apparently resulted in a stress concentration such that the ambient vibration was sufficient to initiate and propagate a high-cycle fatigue crack. Microscopic examination indicated that it originated on the outer diameter surface at the top of the tube as installed, near where the ferrule was crimped into the tubing. The microscopic examination did NOT indicate any signs of any initiating flaw (e.g. due to stress corrosion or overstress). There was some evidence of higher-stress cyclic loading in the newer cracked area at the crack ends; the crack clearly began to grow more quickly than it had previously. No gross tearing was seen in the newest part of the primary crack, so it did not appear that an overstress event during the previous outage furthered the cracking. The accelerated growth was more likely due to a change in stress intensity at the crack tip, as opposed to an increase in applied stress. The stress intensity would be expected to increase significantly when the crack reached an unstable point, with the remaining ligament too small to support the weight of the tubing run. A few short parallel cracks in the same crimp mark were not darkly oxidized and appeared to be the most recent high-cycle fatigue areas on the tubing.

A representative of the fitting vendor stated that on make-up of any two ferrule fitting, the rear ferrule "bites" into the tubing to create a leak free seal. There is a stress concentration in front of the rear ferrule's bite into the tube. Exposure to system vibration can lead to fatigue failure. This vendor representative reviewed photographs of the failure and confirmed that they have seen this type of failure in the past where vibration in the system was identified as the root cause. A search of the INPO Equipment Performance and Information Exchange (EPIX) Data Base, which includes data from industry reported events, revealed a number of reported tubing failures of this type.

It appears that the tubing and associated fitting have been in service since installation in May 1992 when the configuration of the impulse line was revised as a corrective action from the 1991 event on Unit 3 as referenced in the Background section above.

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CORRECTIVE ACTIONS

Immediate:

1. Operations shutdown Unit 1 to Mode 3 in compliance with TS 3.4.13.

2. Instrument valve 1RCIV0090 was closed to isolate the leak. This action terminated the leak event.

Subsequent:

1. The portion of tubing containing the crack was removed for analysis and the tubing repaired.

2. Engineering performed an inspection of boron deposited inside containment due to the leak. There was no significant concern about corrosion due to this leak.

3. Reactor Building Auxiliary Cooling Units 1A, 1B, and 1C were cleaned to remove boron accumulation that had occurred during the RCS leak. Based on the amount of boron removed from the Auxiliary Cooling Units (which are not TS required), it was concluded that the Reactor Building Cooling Units [EIIS: BK] (which are TS required) did not require cleaning. Periodic Testing after the building reached stable operating temperatures confirmed that heat transfer capability had not been adversely affected.

Planned:

1. The following corrective actions will be performed on all three Oconee Units during the first outage which provides reasonable opportunity:

   - All 3/8 inch RVLIS instrument tubing subject to vibration will be replaced with new tubing with a wall thickness of 0.049 inches in order to re-zero any accumulation of stress due to vibration in the tubing.

   - The terminal ends of the removed RVLIS tubing subject to vibration will be sent to the Materials Laboratory to evaluate for evidence of cracking. Based on the results, appropriate actions will be taken to eliminate vibration or to control vibration induced cracking.

   - All additional 3/8 inch RVLIS tubing will be inspected and any installed 0.035 wall tubing will be replaced with new tubing with a wall thickness of 0.049 inches to conform to the design specification.

None of these corrective actions are considered NRC Commitment items. There are no NRC Commitment items contained in this LER.

SAFETY ANALYSIS

The leak rate during this event was approximately 1 gpm while the RCS was at operating pressure. The leaking water and any associated gaseous activity which came out of solution were confined to the Reactor Building and were processed by normal treatment systems. Associated releases and personnel exposures were considered routine and remained well within normal operating limits.

No Engineered Safeguards actuations were necessary as a result of the leak. The one gpm leakage was well within the capacity of the normal RCS make-up system, therefore, by definition, this event was not a Small Break LOCA. All identified consequences were bounded by UFSAR analyses for a small break LOCA. Entry into the emergency plan is not required unless the leakage is >= 10 gpm unidentified or >= 25 gpm identified. The actual leak in this event remained significantly below those limits.

Leaks of this size are not modeled in the Oconee Probabilistic Risk Assessment; therefore this event had no affect on the estimated core damage frequency.

The 1999 version of the Oconee Updated Final Safety Analysis Report (UFSAR) Section 15.14.4.3, "Small Break LOCA", defined the minimum area for a small break LOCA to be approximately 0.0008 square feet with letdown flow isolated or 0.0004 square feet assuming normal letdown. These areas correspond to circular openings of approximately 0.382 and 0.270 inches in diameter respectively. The tubing which cracked in this event resulted in a much smaller opening.

This event is NOT considered a Safety System Functional Failure.

Therefore, based on the discussions above, there was no actual impact on the health and safety of the public due to this event.

ADDITIONAL INFORMATION

On 1-2-2004, earlier in the startup from this refueling outage, an Unusual Event was declared due to an RCS leak of approximately 14 gpm. Reference NRC Event Number 40424. That leak had no

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relationship to the leak reported in this LER. The source of that leak was identified as a relief valve on a containment penetration. The root cause evaluation determined that there was a pressure pulse in the line that resulted in the relief valve lifting. Once it lifted, there was something (foreign material) that damaged the seat and resulted in the leak. The valve was isolated, and repaired within the applicable allowed action times such that no reactor shutdown was necessary.

A review of events within the last two years at Oconee did not reveal any similar events, therefore this event is not considered to be recurring.

There were no personnel injuries associated with this event.

This event is considered reportable under the Equipment Performance and Information Exchange (EPIX) program.

Component Information: Tubing, Stainless Steel (SA213), 3/8 inch diameter, 0.035" wall thickness
Manufacturer: Unknown