Florida Power
CORPORATION
Crystal River Unit 3
Docket No. 50-302

April 26, 1996
3F0496-37

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

Subject: Licensee Event Report (LER) 96-009-00

Dear Sir:

Please find the enclosed Licensee Event Report (LER) 96-009-00. This report is submitted by Florida Power Corporation in accordance with 10 CFR 50.73.

Sincerely,

BJ Hickle

B. J. Hickle, Director
Nuclear Plant Operations

TWC:ff

Attachment

xc: Regional Administrator, Region II
Project Manager, NRR
Senior Resident Inspector

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CRYSTAL RIVER ENERGY COMPLEX: 15760 W Power Line St • Crystal River, Florida 34428-6708 • (352) 795-6486
A Florida Progress Company

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104

EXPIRES 5/31/95

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	1 OF 0 7

TITLE (4)

Failure to Re-attach Instrument Tubing to Seismic Supports After Modification Leads to Operation Outside Design Basis

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)
									N/A	0 5 0 0 0
0 3	2 7	9 6	9 6	0 0 9	0 0	0 4	2 6	9 6	N/A	0 5 0 0 0

OPERATING MODE (9): 6

POWER LEVEL (10): 0 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)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)	X	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)
T.W. Catchpole, Sr. Nuclear Licensing Engineer	3 5 2 5 6 3 - 4 6 0 1

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On March 27, 1996, Florida Power Corporation's Crystal River Unit 3 (CR-3) was in MODE 6 (REFUELING) when engineering personnel confirmed an approximately 17 foot section of 1/2-inch instrument tubing in the Reactor Building had been removed from its seismic supports. The condition had been questioned earlier by a work supervisor performing an unrelated activity. The tubing provides the upper tap for safety related Emergency Feedwater Initiation and Control high range level transmitters for the "B" Steam Generator. In addition, non-Class 1E startup level and operating range transmitters share the same tubing. The tubing had been removed from its supports in 1992 to allow for installation of a work platform and had inadvertently not been re-attached due to interference with structural members associated with the platform. A one-hour report was made on March 28, 1996 as a condition outside CR-3's design basis. The cause of the event was personnel error and inattention to detail in failing to re-attach the instrument tubing. A contributing cause was an inadequate walkdown by the work supervisor of the work platform installation. The instrument tubing has been properly supported using modified supports to facilitate re-attachment. Other corrective actions include "lessons learned" discussions with project management personnel and maintenance supervision.

EVENT DESCRIPTION

On March 27, 1996, Florida Power Corporation's (FPC) Crystal River Unit 3 (CR-3) was in MODE 6 (REFUELING). A question had been raised regarding the seismic adequacy of instrument tubing in the Reactor Building [NH] (RB) via a Precursor Card by a work supervisor who was performing an unrelated activity. The instrument tubing is located between Main Steam (MS) Instrument Block Valves [SB,ISV] MSV-171 and MSV-85 below a work platform at elevation 135 feet in the RB inside the "D-ring". The Once Through Steam Generators [AB,SG] (OTSG) are surrounded by shielded cubicles called "D-rings" because of their shape. Engineering personnel investigating the condition confirmed that a section of 1/2-inch instrument tubing downstream of MSV-171 had been removed from its seismic supports leading to an unsupported length of approximately 17 feet. CR-3's seismic support criteria for instrument tubing requires the maximum seismic support spacing for 1/2-inch stainless steel tubing to be 80 inches (6 feet, 8 inches). The instrument tubing provides the upper tap for safety related Emergency Feedwater Initiation and Control [JB] (EFIC) high range level transmitters [JB,LT] associated with Channels "B" and "D" for the "B" OTSG. The EFIC High Range level transmitters affected by this event are identified as SP-022-LT and SP-024-LT on Figure 1. Additionally, the instrument tubing serves the same purpose for the "B" OTSG non-Class 1E Startup Level transmitter [SJ,LT] and Operating Range Transmitter. The transmitters in this category affected by this event are identified as SP-1B-LT4 and SP-1B-LT3 on Figure 1. The tubing had been removed from its seismic supports in 1992 to allow installation of a crossover work platform between Reactor Coolant (RC) Pumps [AB,P] RCP-1C and RCP-1D. The investigating engineer determined the design of the work platform did not provide sufficient clearance to allow the tubing to be re-attached to its previous points.

A Problem Report was generated on March 27, 1996 and evaluated by the Shift Supervisor on Duty (SSOD) at 1155 hours on March 28, 1996 as a reportable condition outside the design basis of CR-3. The EFIC high level transmitters did not meet seismic requirements and could not be relied upon to provide information to assess the performance and status of the "B" OTSG high level indication following a design basis seismic event. A one-hour notification was made to the Nuclear Regulatory Commission (NRC) at 1204 hours in accordance with 10CFR50.72(b)(1)(ii)(B) and Event Number 30189 was assigned. There were no Improved Technical Specification (ITS) requirements applicable in the MODE in which the problem was discovered and no immediate actions were taken other than to note the transmitters would be required prior to entering MODE FOUR (HOT SHUTDOWN) from the current refueling outage.

This written report is being submitted in accordance with 10CFR50.73 (a)(2)(ii)(B).

EVENT EVALUATION

SP-1B-LT4 is one of four transmitters required to provide signals for Steam Generator Startup level monitoring and selectable control signals to the Integrated Control [JA] System (ICS). SP-1B-LT3 is one of four transmitters required to provide signals for Steam Generator Operating Range level monitoring and control signals to the ICS for feedwater control. Full range non-Class 1E level measurement is provided for indication of each steam generator level but does not provide safety related protective actuation functions. Loss of these instruments during a seismic event would have no impact on the ability to mitigate a design basis accident.

EFIC System components essential to safe shutdown are designed as Seismic Category I in order to maintain system functional integrity during an earthquake. Shortly after the reporting of this event, engineering personnel evaluated the as-found condition of the unsupported section of tubing and noted it was stressed above code (Power Piping Code USAS B31.1) allowables due to deadweight. The evaluation determined that under seismic loading, the tubing would have been stressed above the ultimate tensile capacity of the tubing material, ASTM A213, TP304. As a result, it was concluded that the affected section of tubing would not have been capable of performing its design function during a design basis seismic event. As a minimum, the tubing would have crimped and resulted in inaccurate instrument reading. It is also possible this section of tubing would have ruptured, causing a breach in the secondary side of the OTSG pressure boundary. Although the analysis conservatively indicated the section of tubing was at yield stress under normal loading, no permanent deformation of the tubing was noted on field observation of the as-found condition. It is reasonable to conclude that a more rigorous analysis would demonstrate the tubing did not yield. It is Engineering's conclusion that no permanent damage or degradation was experienced by this section of tubing as a result of this event.

EFIC activates Emergency Feedwater [BA] (EF) System components to supply a dedicated source of feedwater to the steam generators in the event one of several initiating conditions is met. The EF System is considered safety grade because it is the only source of water to the OTSG's for decay heat [BP] removal when the main feedwater system becomes inoperable and, therefore, must be designed to operate when needed. The EFIC System also controls the atmospheric steam dump valves [SB,PCV] and isolates the affected OTSG in event of a high energy line break.

EFIC level instrumentation providing Regulatory Guide 1.97 Type A/Category 1 indication of steam generator level is required to be OPERABLE per Improved Technical Specification Limiting Condition for Operation (LCO) 3.3.17 "Post Accident Monitoring (PAM) Instrumentation". The combined steam generator level instrument ranges (low and high range) cover a span of 6 to 394 inches above the lower tubesheet as noted in Figure 1. Redundant monitoring capability is provided by two channels ("A" and "B") of each range of instrumentation per OTSG. The level signals for Channels "A" and "B" are displayed on control room indicators. One "A" Channel high range level transmitter and one low range level transmitter also inputs to a recorder in the control room. The signal from the EFIC high range level transmitters is used for detection of high OTSG level conditions (overfill) and for level control when the system is controlling at the natural circulation or emergency core cooling system (ECCS) setpoints.

Loss of SP-022-LT and SP-024-LT during a postulated seismic event would result in loss of these level control and overfill protection functions. A tubing rupture would result in high level indication because the transmitters would detect a low differential pressure which translates to high level in the circuit. This in itself would not cause an EFW actuation; however, if there was an EFW actuation from some other initiating event, the EFW control valves [BA,FCV] controlled by the "B" Channel and the EFW block valves [BA,ISV] controlled by the "D" Channel would isolate EFW to the "B" OTSG on a false overfill indication. A sufficient heat sink would be available in the remaining unaffected OTSG to remove decay heat and regulate RCS cooldown. For a tubing pinch failure, because of static pressure in the line, the affected high level transmitters would not respond to changing conditions in the OTSG. However, by comparing "A" Channel and "B" Channel indication on the Main Control Board [MCBD], operators would be able to diagnose the false indication and take manual control of EFIC, thereby feeding the OTSG's using the good instrumentation.

Even though the subject instrument tubing was outside its intended design basis, it continued to perform its intended function in meeting ITS Surveillance Requirements and did not present a safety risk to the general public.

CAUSE

The cause of this event was personnel error/inattention to detail. The crossover platform between RCP-1C and RCP-1D was one of several work platforms installed in the Reactor Building (RB) in 1992 (Refuel 8R). The platforms were installed for required maintenance and access to valves located throughout the RB for inspection and line-up. A review of the work package reveals there are no instructions that address the need to detach instrument tubing. Consequently, there are no instructions that address the need to re-attach the tubing which was removed from its supports. There is no record of anyone notifying field engineering personnel that supports for this tubing were not long enough to mount the clamp that supported the tubing. The original supports were 8 inches long and needed to be at least 11 inches long to provide sufficient clearance around a structural member associated with the work platform. See Figure 2. The tubing would have required bending in order to re-attach to the original supports.

A contributing cause was an inadequate walkdown and modification package closeout in that, although there was a "Walkdown and System Acceptance (WSA)" form completed for the 1992 modification, it only indicated the platform was installed per the work package. There was no independent walkdown of the work beyond that of the work supervisor.

IMMEDIATE CORRECTIVE ACTION

None

ADDITIONAL CORRECTIVE ACTION

1. A modification was installed to modify the original instrument tubing supports on both side of MSV-85 to facilitate re-attaching the instrument tubing, thereby returning the instrumentation to full qualification.

2. A memorandum has been issued to Maintenance Department supervision including a copy of this LER as an attachment. Maintenance supervision will be requested to convey the information to responsible department personnel as a "lessons learned".

3. Discussions have been held using this LER as a basis, with Project Managers who are responsible for closing out modification packages. These discussions served to raise the sensitivity of the Project Managers to this issue and promoted a questioning attitude with respect to those modifications that may not require an independent walkdown of the work activity.

ACTION TO PREVENT RECURRENCE

Additional lighting has been installed in the D-rings during Refuel 10 which will improve the ability to identify discrepancies during inspections of the Reactor Building prior to startup after major outages in accordance with procedures AI-1305 "Administrative Inspection of Reactor Containment" and SP-324 "Containment Inspection".

In addition to the "lessons learned" discussions as described above, a review of the applicable engineering procedures will be conducted by May 31, 1996 to determine if enhancements are warranted to preclude recurrence of this event.

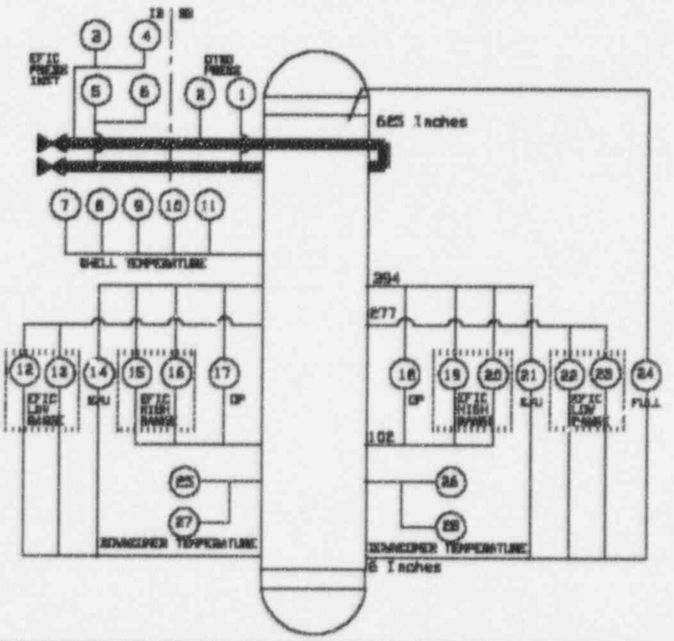
PREVIOUS SIMILAR EVENTS

LER 88-013 reported low pressure control air [LD] (AH) tubing was not supported in accordance with Seismic Class 1 criteria. The tubing had been installed by a subcontractor to the original ventilation contractor who failed to submit necessary design calculation and detailed installation documents. The action to prevent recurrence assumed credit for more thorough reviews of modification packages and more comprehensive controls in place within nuclear engineering procedures. LER 89-015 reported discovery of a solenoid valve whose mounting bracket and associated tubing did not meet seismic requirements. No documentation could be found to support the original installation or later removal of the mounting arrangement. This problem was determined to be an isolated case.

ATTACHMENT

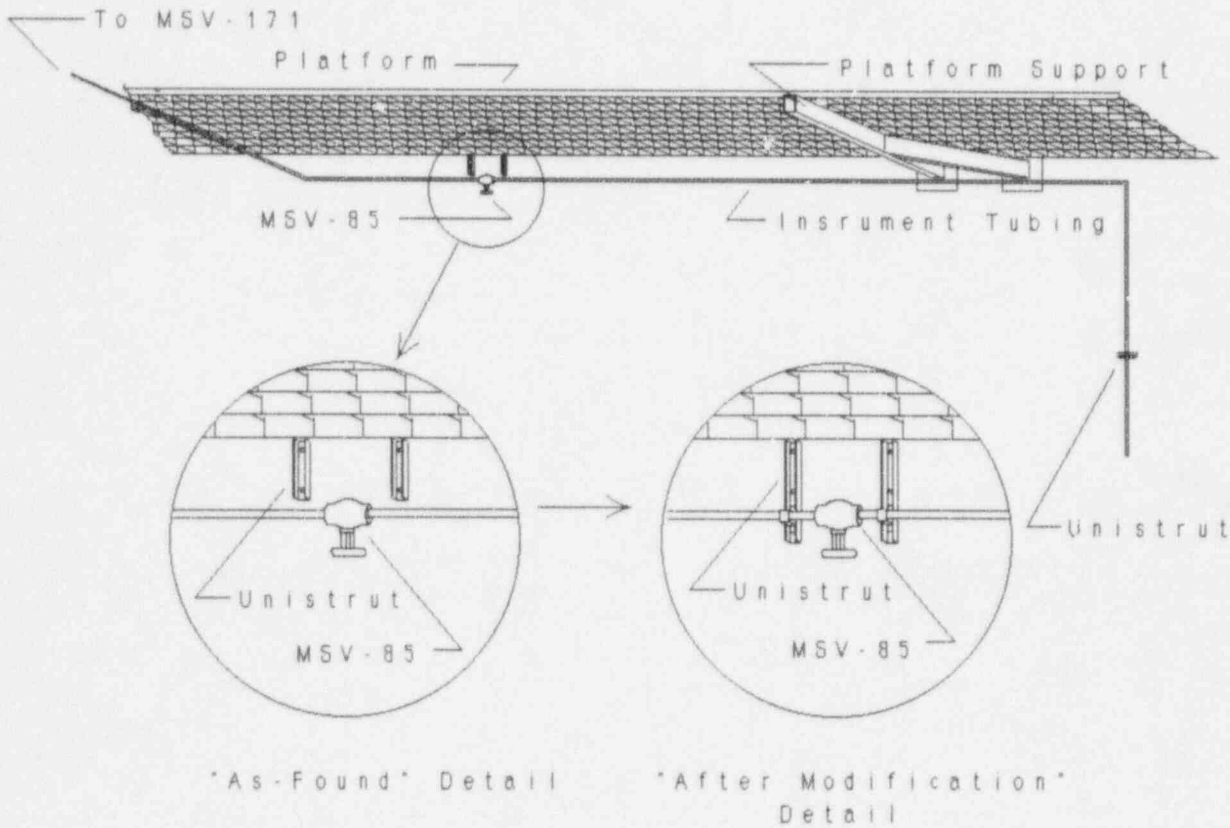
Figure 1 - Steam Generator Instrumentation
Figure 2 - Unsupported Instrument Tubing

OTSG INSTRUMENTATION LAYOUT



DRAWING #	STEAM GENERATOR A	STEAM GENERATOR B	RANGE
1	PT1-6A OTSG OUTLET PRESS (A-2)	PT1-6B OTSG OUTLET PRESS (B-1)	0-1800 PSI
2	PT2-6A OTSG OUTLET PRESS (A-1)	PT2-6B OTSG OUTLET PRESS (B-2)	0-1800 PSI
3	PT-106-A OTSG PRESS EFIC-A	PT-110-A OTSG PRESS EFIC-A	0-1200 PSI
4	PT-108-C OTSG PRESS EFIC-C	PT-112-C OTSG PRESS EFIC-C	0-1200 PSI
5	PT-107-B OTSG PRESS EFIC-B	PT-111-B OTSG PRESS EFIC-B	0-1200 PSI
6	PT-109-D OTSG PRESS EFIC-D	PT-113-D OTSG PRESS EFIC-D	0-1200 PSI
7	TE5-8A SHELL TEMP	TE5-8B SHELL TEMP	70-650 °F
8	TE4-8A SHELL TEMP	TE4-8B SHELL TEMP	70-650 °F
9	TE3-8A SHELL TEMP	TE3-8B SHELL TEMP	70-650 °F
10	TE2-8A SHELL TEMP	TE2-8B SHELL TEMP	70-650 °F
11	TE1-8A SHELL TEMP	TE1-8B SHELL TEMP	70-650 °F
12	SP026 LT LOW RANGE EFIC-B	SP030 LT LOW RANGE EFIC-B	0-150 INCHES
13	SP028 LT LOW RANGE EFIC-D	SP032 LT LOW RANGE EFIC-D	0-150 INCHES
14	LT5-1A STARTUP RANGE	LT4-1B STARTUP RANGE	0-250 INCHES
15	SP018 LT HI RANGE EFIC-B	SP022 LT HI RANGE EFIC-B	0-100%
16	SP020 LT HI RANGE EFIC-D	SP024 LT HI RANGE EFIC-D	0-100%
17	LT3-1A OPERATE RANGE	LT2-1B OPERATE RANGE	0-100%
18	LT2-1A OPERATE RANGE	LT3-1B OPERATE RANGE	0-100%
19	SP017 LT HI RANGE EFIC-A	SP021 LT HI RANGE EFIC-A	0-100%
20	SP019 LT HI RANGE EFIC-C	SP023 LT HI RANGE EFIC-C	0-100%
21	LT4-1A STARTUP RANGE	LT5-1B STARTUP RANGE	0-250 INCHES
22	SP025 LT LOW RANGE EFIC-A	SP029 LT LOW RANGE EFIC-A	0-150 INCHES
23	SP027 LT LOW RANGE EFIC-C	SP031 LT LOW RANGE EFIC-C	0-150 INCHES
24	LT1-1A FULL RANGE	LT1-1B FULL RANGE	0-600 INCHES
25	TE1-11A DOWNCOMER TEMP	TE1-11B DOWNCOMER TEMP	70-650 °F
26	TE2-11A DOWNCOMER TEMP	TE2-11B DOWNCOMER TEMP	70-650 °F
27	TE1-3A DOWNCOMER TEMP	TE1-3B DOWNCOMER TEMP	0-600 °F
28	TE2-3A DOWNCOMER TEMP	TE2-3B DOWNCOMER TEMP	0-600 °F

Figure 2



UNSUPPORTED INSTRUMENT TUBING

Figure 2