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FACIL:50-287 Oconee Nuclear Station, Unit 3, Duke Power Co. 05000287

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SUBJECT: LER 91-008-00:on 911123,operators observed symptoms of excessive RCS leakage.Caused by mgt deficiencies & equipment failure.Operators controlled unit shutdown.W/911223 ltr.

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TITLE: 50.73/50.9 Licensee Event Report (LER), Incident Rpt, etc.

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DUKE POWER

December 23, 1991

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

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
LER 287/91-08

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report (LER) 287/91-08, concerning a reactor coolant leak.

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,

Joe M. Davis
for J. W. Hampton
Vice President

/ftr

Attachment

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NRC FORM 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WTH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit 3	0 5 0 0 0 2 8 7	1 OF 2 4

TITLE (4) Excessive Reactor Coolant Leak, Reactor Trip, And Inadvertent Protective System Actuation Result From Management Deficiencies and Equipment Failure

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)
1 1	2 3	9 1	9 1	— 0 0 8 —	0 0	1 2	2 3	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

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)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[X] OTHER *(Specify in Abstract below and in Text, NRC Form 366A)*
[ ] 20.405(a)(1)(iii)	[X] 50.73(a)(2)(i) (A)	[ ] 50.73(a)(2)(viii)(A)	50.72 (A)(2)(i)
[ ] 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	
Steve Benesole, Safety Review Group	8 0 3	8 8 5 - 3 5 1 8

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
B	A B	P S P	P 0 7 0	Yes					

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 November 23, 1991, Oconee Unit 3 was operating at 100% Full Power (FP) when the Control Room Operators (CROs) received several alarms at 0141 hours which indicated failed instruments inside the reactor building (RB). At 0143 hours, the CROs observed symptoms of excessive Reactor Coolant System (RCS) leakage and began assessing the leak rate. At 0203 hours, they started a rapid controlled shutdown. At 0214 hours, the Shift Supervisor concluded that leakage was approximately 60 to 70 gpm, and declared an ALERT. At 0327 hours, the unit tripped from 33% FP due to a control oscillation while the CROs were attempting to secure a feedwater pump. At 0641 hours, an additional unanticipated Reactor Protective System actuation occurred due to operator error. At 1720 hours the unit reached cold shutdown and the ALERT was terminated. The leak was determined to be a failed fitting on an instrument line at the top of a steam generator. A total of approximately 87,000 gallons of RCS leakage was confined within the RB. The instrument line was replaced, and additional fittings inspected. The root causes are Management Deficiency and Equipment Failure.

BACKGROUND

The Reactor Protective System (RPS) [EIIS:JC] is a safety related system which monitors parameters related to the safe operation of the plant. The RPS provides a two-out-of-four logic for tripping the reactor when a predetermined setpoint is exceeded. One parameter which will cause an RPS actuation is low Feedwater [EIIS:SJ] Pump discharge pressure. The RPS logic requires that pressure switches for both pumps must actuate in at least two-of-four channels to initiate a trip. Another parameter which will cause a trip is RCS pressure being either too high or too low. During cooldown and depressurization to cold shutdown, the RPS normal RCS pressure trips can be can be bypassed and a lower high pressure trip setpoint imposed to limit pressure excursions.

The Integrated Control System (ICS) [EIIS:JA] provides automatic control of both primary and secondary system components. Reactor control rod positions, feedwater flow rates, and throttle valve positions are adjusted by the ICS as needed to maintain the principal control parameters: average reactor coolant temperature (Tave), feedwater throttle valve pressure drop, and main turbine [EIIS:TA] header pressure.

The Control Rod Drive (CRD) [EIIS:AA] system receives a reactor power demand signal from the ICS through a hand/automatic selector station known as the "Reactor/Bailey" station. The power demand signal is further processed and is input to the CRD control station, known as the "Diamond" panel. The control rods are divided into safety, regulating, and power shaping groups. Groups one through four are safety rods, used to provide shutdown capacity, and must be fully withdrawn from the core before the reactor is permitted to go critical. Groups five through seven are regulating rods, used to regulate power level. Group eight is a special group of partial length rods, and is used to control power distribution along the core axis.

Control Rod [EIIS:ROD] position indication is provided by a series of position indication switches located along the length of the drive mechanism. A faulty switch can result in an inaccurate indication. Also, the group out limit is activated when the first rod in a group reaches its out limit switch.

The High Pressure Injection (HPI) System [EIIS:BQ] controls the Reactor Coolant System (RCS) [EIIS:AB] inventory, provides the seal water for the Reactor Coolant Pumps [EIIS:P], and recirculates RCS letdown for water quality maintenance and reactor coolant boric acid concentration control. The HPI System is also a part of the Emergency Core Cooling System (ECCS) which mitigates the consequences of loss of coolant accidents (LOCA).

The Reactor Coolant System (RCS) has two steam generators [EIIS:HX] with associated pumps, piping, and instrumentation. These are designated Loop A and Loop B. The flow indications for each loop are provided by one flow element with one pair of impulse lines which act as headers and are connected to several differential pressure transmitters. Four of these transmitters are connected to the four redundant channels of the RPS. A fifth transmitter provides the normal input to the ICS.

The Reactor Vessel Level Indicating System (RVLIS) [EIIS:XT] was installed on Unit 3 during an outage that concluded in March, 1987. This modification added 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.

EVENT DESCRIPTION

On November 23, 1991, Oconee Unit 3 was operating at 100 % Full Power (FP). All safety systems were operable. The unit was known to have a higher than normal level of Reactor Coolant System (RCS) activity due to an estimated 8 fuel cladding pinhole leaks.

At 0120 hours, the Control Room Operators (CROs) completed an RCS leakage periodic test which indicated 0.18 gpm total system leakage.

A. RCS Leak

At 0141 hours, the CROs received alarms which indicated failure of "ICCM Train A", which includes the Reactor Vessel Level Indication System (RVLIS) and an RCS wide range pressure transmitter. At approximately the same time, they received a fire alarm from a detector [EIIS:IC] located inside the reactor containment building (RB) [EIIS:NH]. CRO A checked for a spurious alarm by resetting the fire alarm and observed that it alarmed again. The CROs notified the Unit Supervisor and Control Room Senior Reactor Operator (CRSRO) that a problem existed. CRO A also attempted to visually inspect the RB using a video camera installed inside the RB at one end of the refueling canal and a monitor adjacent to the control room. However, the image was so foggy that CRO A assumed that the camera was either not working properly or was badly out of adjustment.

At 0143 hours, CRO B noted that the Letdown Storage Tank (LDST) and Pressurizer levels were decreasing and that High Pressure Injection (HPI) make-up flow had increased significantly. The RB normal sump also showed an increase in level. The operators concluded that the problem was an RCS leak rather than a fire and entered AP/3/A/1700/02, "Excessive RCS Leakage."

The Shift Supervisor and the Shift Manager, who performs the Shift Technical Advisor function, were notified at this time. They both reached the Unit 3 control room shortly after notification.

At 0155 hours, an RB particulate radiation monitor [EIIS:IL] alarmed momentarily.

At 0203 hours, the leakage was estimated to be 70 gpm and the Shift Supervisor ordered a rapid controlled shutdown. The CROs set the Integrated Control System (ICS) for a load reduction at 15 MW/min. They isolated RCS letdown at 0211 hours to eliminate that loss from the system.

At 0214 hours, the Shift Supervisor officially declared the unit to be in an ALERT Emergency Classification and began making the necessary notifications to establish the Technical Support Center (TSC), and Operational Support Center (OSC) as required by the Site Emergency Plan.

At 0217 hours, during the power reduction, an ICS Asymmetric Rod signal generated a rapid load limit runback of the ICS from 77% to 55% FP. The operators diagnosed the CRD indication as spurious and, at the Unit Supervisor's direction, placed the ICS Feedwater and Reactor control stations in manual to stop the automatic runback at 60% FP.

Throughout the event, the CROs made additions to the LDST from the Bleed Holdup Tanks and Concentrated Boric Acid Storage Tank (CBAST) to maintain adequate inventory to compensate for the leak.

At 0305 hours, the TSC, adjacent to the Unit 1&2 control room, and OSC, adjacent to the Unit 3 control room, were manned and the Station Manager assumed the position of Emergency Coordinator. One of the first TSC actions was to have the operators re-establish letdown flow at 20 gpm to facilitate collection of RCS liquid samples to be analyzed for boron concentration and for indications of failed fuel. Other immediate actions included initiation of Radiation Protection surveys of areas outside the Reactor Building, and outside the Site Protected area to assure that no radioactive materials were being released from the RB as a result of the event. The Crisis Management Center (CMC) was activated in accordance with the emergency plan.

At 0320 hours, the leak was still estimated to be approximately 60 to 70 gpm.

B. Reactor Trip

The power reduction was stopped at approximately 33% FP in order to shutdown one of the two main feedwater pumps from a stable power level. At 0320 hours, the ICS Feedwater control station was returned to Automatic. This resulted in a slight increase in the magnitude of the normal oscillation of the control system. At 0324 hours, CRO A placed the "B" Main Feedwater Pump (MFWP B) in manual and began to reduce its demand. Apparently, FDWP B discharge pressure reached the Reactor Protective System (RPS) trip setpoint for two or more pressure switches and the contact buffers for that portion of the logic sealed in. As MFWP B output was reduced, FDWP A output momentarily increased but a divergent oscillation began. When the magnitude of the oscillation became apparent to CRO A, he increased the output of MFWP B. As he brought the demand for MFWP B up,

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
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ESTIMATED BURDEN PER RESPONSE TO COMPLY WTH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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)

the control system reacted to match total feedwater flow to total feedwater demand by reducing MFWP A demand and output. The oscillation also resulted in feedwater header low pressure alarms, low Main Steam pressure alarms, and opening of turbine by-pass valves (TBVs) due to high Main Steam pressure. MFWP A suction flow went to zero and the MFWP A minimum flow valve cycled open. Other system parameters such as reactor power, generated power, RCS pressure and RCS temperature were also oscillating.

The low discharge pressure on MFWP A apparently reached the trip setpoint and the second pump's contact buffers actuated. This satisfied the RPS logic and, at 0327:55 hours, RPS channels A and D tripped on low Main Feedwater Pump discharge pressure, which requires detection of low discharge pressure (800 psi) on both pumps. At the time of the trip, the oscillation had raised power to approximately 37% FP.

The immediate post trip response of the plant was normal. All CRD breakers opened and all control rod groups were inserted into the core. The turbine generator tripped, and both 4kv and 7kv electrical power supplies [EIIS:EA] transferred to the start-up source. Unit 3 stabilized at hot shutdown conditions with the operators safely controlling the reactor after the trip. No Engineered Safeguards System or pressurizer relief valve actuations occurred.

The RCS system response was normal. RCS pressure ranged between a low of 1988 psig and a high of 2141 psig. RCS average temperature dropped from 578 F. at the time of the trip to 551 F. Pressurizer level dropped from approximately 220 inches to between 135 and 144 inches. Letdown was isolated by the CROs in accordance with the trip procedure.

On the secondary side, the post trip reduction in feedwater demand proceeded as normal, and the steam generator level was maintained between 20 and 28 inches. The turbine stop valves closed and the TBVs opened. At least some of the main steam relief valve setpoints were reached and some of the valves opened. Main steam pressure varied between 973 psig and 1044 psig, according to the Transient Monitor [EIIS:IQ]. The operators momentarily reduced turbine header pressure to 970 psig in order to reseat one of the main steam relief valves, then returned to the normal post-trip pressure of 1010 psig. The Main Feedwater pumps do not trip due to low discharge pressure, so both pumps continued to run until CRO A manually tripped MFWP A. The emergency feedwater system [EIIS:BA] was not actuated after the trip.

At 0340 hours, letdown was re-established at 20 gpm.

By 0348 hours, the unit was considered to be at stable hot shutdown. The leak was then estimated to be approximately 130 gpm. RB sample results indicated that the RB atmosphere contained radioactive Iodine at 2 times maximum permissible concentration (MPC) and Noble gases at 407 MPC.

At about 0400 hours, the video camera in containment was used to examine the area. It showed a significant amount of steam rising from the "A" Steam Generator cavity. The steam was condensing on virtually all visible walls, hand rails, and equipment. The camera was panned to view the reactor vessel head, which showed significant amounts of water, but no steam leak, on the head. The top of the "B" Steam Generator cavity was also checked, but showed no steam source.

At 0406 hours, Chemistry samples showed an RCS boron concentration of 579 ppm. At 0445 hours, the operators began to cool the RCS down to 532 F. Plans were made to initiate boron addition to raise boron concentration for long term shutdown margin considerations.

At 0520 hours, the Engineered Safeguards (ES) [EIIS:JE] system was bypassed, per procedure, before lowering RCS pressure below the ES high pressure setpoint of 1750 psig.

At 0530 hours, the RCS pressure had been reduced to 1735 psig and temperature was 535 F. Permission was given by the TSC to begin cooling down to 450 F. at a rate of 45 degrees per 30 minutes. However, the operators had several procedures in progress and took some time to assure that all appropriate requirements were met and steps documented prior to continuing the cooldown.

C. Inadvertent RPS Actuation

Step 2.3 of Enclosure 4.2 in the shutdown procedure specified that the turbine bypass valves (TBVs) [EIIS:SO] were to be placed in Manual. The TBVs are used to control main steam pressure and, therefore, the saturation temperature in the steam generator, which, in turn, controls the RCS temperature. However, CRO A had been controlling pressure by using the ICS turbine header pressure setpoint control. He wished to continue in that mode to minimize the number of ICS stations in Manual and, therefore, limit operator burden. This was discussed with CRSRO A, who gave verbal approval for CRO A to keep the TBVs in Automatic and to perform the transfer to Manual out of sequence at a later time. The exact point in the procedure where this would be accomplished was not discussed.

At 0606 hours, the AMSAC/DSS (ATWS mitigation system) was bypassed. At 0613 hours, the Emergency Feedwater pumps were placed in Manual.

At 0622 hours, RCS pressure was 1660 psig and temperature was 526 F. At 0633 hours, the RPS was placed in "Shutdown Bypass", which allows the system to be reset below the normal low pressure trip setpoint. This also instates an over-pressure trip setpoint of 1710 psig to prevent inadvertent re-pressurization. CRO B announced to the other Operations personnel in the control room that he was about to "reset the reactor" and, at 0638 hours, the control rod drive breakers were reset. This was done in preparation for partially withdrawing one group of control rods as a standby source of negative reactivity.

However, when the breakers were reset, the ICS removed an automatic bias which is applied to the turbine header pressure setpoint after a trip. (This bias automatically increases the setpoint by 125 psig to raise the saturation temperature after a trip to limit the RCS cooldown and control RCS temperature at 555 F.) As a result of removing the bias, the ICS sensed a 125 psi pressure error and opened the bypass valves in an attempt to achieve the new setpoint. This created a cooling transient on the RCS and RCS pressure dropped to approximately 1620 psig.

CRO A responded by placing the TBVs into Manual at 0638 hours and driving them closed. This response resulted in RCS temperature and pressure increasing again. CRO A stated that he concentrated on RCS temperature and turbine header pressure while trying to match the setpoint to demand in order to smoothly return to automatic. At approximately 0640 hours, CRO A returned the TBVs to Auto but RCS pressure was still increasing rapidly. At 0641 hours, RCS pressure reached the overpressure set point and tripped the RPS. The CRD breakers opened but, since all control rods were already fully inserted, no other consequences occurred. RCS pressure continued to increase to approximately 1720 psig until CRO A took the TBVs back into manual at 0642 hours and reopened them to stabilize pressure.

D. Subsequent Actions

The operators subsequently reset the control rod drive breakers and withdrew one group of control rods to 50% withdrawn in accordance with procedure. The cooldown continued.

At 1717 hours, the RCS reached 200 F. and 293 psig (cold shutdown). At this point the event emergency classification was terminated.

At 2115 hours, samples of RB atmosphere indicated that airborne iodine activity was 1382 MPC.

Between 0002 and 0450 hours on the morning of November 24, 1991, Operations pumped part of the water from the RB normal sump into waste tanks for processing.

At 0800 hours, it was estimated that approximately 5 to 10 gpm was still leaking out of the RCS due to the fact that the pressurizer was still at saturation temperature and was maintaining a 30 psig system pressure. The normal cooldown process requires that personnel enter the RB to align manual valves to establish a flow through the pressurizer to cool it. However, due to the level of airborne contamination this was not possible and a less effective flow path had to be used. Additionally, a special method of venting the pressurizer and steam generators was incorporated into the shutdown procedure to reduce level in Steam Generator A hot leg below the leak. By 1700 hours on November 24, 1991, the unit was completely de-pressurized and the leak stopped.

At 2200 hours, airborne iodine activity inside the RB was 731 MPC.

On November 25, at 0100 hours, the Reactor Building Purge System [EIIS:VA] was started to clean up the RB atmosphere for building entry.

At 1300 hours, airborne iodine activity was 27 MPC. An inspection team entered the RB and located the source of the leak. It was found to be due to a 3/4 inch diameter instrument line which had pulled out of a compression fitting downstream of a root valve. The line was located at the top of the RCS hot leg pipe where it entered the "A" Steam Generator (SG A).

The tubing configuration is shown as Attachment A. The same configuration was used on both steam generators and the reactor vessel head on all three Oconee units when RVLIS was installed. Note that a series of tubing reducers were used to transition from a 3/4 inch root valve to 3/8 inch tubing. This configuration resulted in a total of six compression joints per instrument line.

The root valve, fittings, and affected tubing from SG A were subsequently removed from the system for inspection and analysis. The equivalent impulse lines on the "B" Steam Generator and the reactor vessel head were inspected and found to be intact. It was subsequently decided to replace these lines with a new configuration which used welded fittings to reduce to 3/8 inch tubing. The new configuration has only two compression joints per line.

Parker Hannifin Company (Parker), manufacturer of the fitting, was contacted and provided a range of "nominal" values for the makeup gap between the hex on the fitting and the end of the nut. The Parker spokesperson stated that these nominal values did not constitute acceptance tolerances or specifications. The inspections showed that the gap was 0.182 inch versus a nominal 0.153 inch. The degree of crimping of the tube was determined by comparing the internal diameter (ID) reduction of the failed fitting to the reduction due to the fitting at the other end of the tube, which did not fail. The ID reduction at the failed end was only 0.002 inch compared to 0.007 inch at the "good" end.

Both Oconee Engineering personnel and the Babcock and Wilcox Lynchburg Research Center (B&W) concluded that the inspections indicated that the fitting had not been fully crimped onto the instrument line during initial fitup and installation in 1987.

It was decided to inspect a sample of compression fittings located in the RB, which included both Parker and Swagelock fittings. Vernier calipers were used to measure the gap on Parker fittings for comparison against the nominal values supplied by Parker. Swagelock fittings were checked with Swagelock go/no go gauges.

This initial sample found approximately 10% of the fittings to be out of the nominal range, although all of the fittings checked had been in service with no signs of leakage. The decision was made to perform a full inspection of fittings attached to the Reactor Coolant System and primary support systems such as the High Pressure Injection Systems. This inspection included 455 fittings (264 Parker and 191 Swagelock) of which 126 (27.7%) were found out of the nominal range. Of these, one had boron on it, indicating that it had leaked, and another had a loose nut. The technicians attempted to tighten all of these fittings into the nominal range. However, 27 Parker fittings (5.7%) could not be tightened into the nominal range without use of excessive force in the opinion of the technicians. Maintenance Engineering selected one of these Parker fittings, which had been the most out of the nominal range after re-tightening, to be replaced and inspected. Maintenance Engineering concluded from their inspection that the ferrule was installed properly and was adequately crimped on the tube despite being out of the nominal range provided by Parker. Three more fittings were subsequently tightened into the nominal range. The remaining 23 fittings, of which 16 are 1/2 inch and 7 are 1/4 inch, were left out of range after an engineering evaluation concluded that it was acceptable to do so. Portions of that evaluation are addressed in the Safety Evaluation section of this report.

Other equipment inside the RB was inspected due to exposure to the extremely humid atmosphere during the event. These components and the results are listed on Attachment B.

Because a divergent control oscillation developed in the Integrated Control System and appeared to cause the unit trip, a team of consultants was brought in to analyze available data in accordance with the B&W Owners Group Transient Assessment Program. The results of that assessment are included in the Conclusions section below.

E. Radiological Consequences

The RCS water that leaked into the RB overflowed the Normal and Emergency Sumps and covered the RB basement floor. It was contained there until it was transferred to waste storage tanks for treatment. A total of 87,183 gallons was treated and released.

The Reactor Building Purge System was used to lower airborne activity inside the RB. The Purge System is a once through ventilation system which filters RB air through High Efficiency Particulate Air and Carbon Adsorber filters prior to release through the Unit vent. Radiation Protection personnel calculated the dose to the public due to releases via the Purge using two different filter efficiencies. The Projected Dose was calculated using an assumed carbon filter efficiency of 90%. An Estimated Dose was calculated using actual filter efficiencies from the latest surveillance tests. Both methods use annualized average meteorological data rather than actual conditions at the time of the release.

The release data is summarized on Attachment C. Final calculations will be included in the Semi-annual Effluent Report.

Monitoring in accordance with the Fuel Reliability Program indicated that, prior to the leak, there was an estimated 8 leaking fuel pins. Unit 3 activity levels shortly before the leak were approximately 0.15 microcuries/milliliter dose equivalent Iodine, compared to Unit 1 levels of approximately 0.01 microcuries/milliliter dose equivalent Iodine.

As a result, the leak produced high contamination levels throughout the RB. Some of the results of smear surveys are shown on Attachment D. The decision was made early in the outage to perform minimum decontamination at this time. The intent was to allow the contamination to decay until the next scheduled refueling outage and minimize the amount of dose due to decontamination activities. However, additional items were found which required maintenance and extended the outage beyond the initial scope. The total dose to personnel performing outage activities through 0600 hours, December 17, 1991, was 30.70 person-rem. No personnel have received doses in excess of Duke Power administrative limits.

CONCLUSIONS

A. RCS Leak

It is concluded, based on the investigation performed by Oconee Engineering and Babcock and Wilcox, that the initiating cause of the leak in this event was improper installation of the fitting. Specifically, the fitting nut was not fully tightened. Therefore, a contributing cause of Inappropriate Action, (Improper Action, Action chosen was proper but execution failed because an action was performed with insufficient precision), is assigned. However, the root cause of this event is determined to be Management Deficiency, for less than adequate policy, directive, or task specific procedure, as explained below.

A review of procedures, Quality Control (QC) manuals, and personnel interviews indicated that procedures provided less than adequate guidance and/or documentation of installation or inspection of tubing fittings. The procedure for installation of the RVLIS instruments included one signoff step for each impulse line being installed which covered installation of all associated fittings and instrument tubing. It did not contain specific instructions on how to makeup fittings. Each step had provision for the initials of one craft person as installer, one person as independent verifier, and one QC inspector. The reference section of the procedure refers to a design specification on installation standards for instruments, which specifies that tubing fittings be installed in accordance with the manufacturer's instructions.

Both Swagelock and Parker provide installation instructions which specify that their fittings should be installed "finger tight," then tightened 1 and 1/4 turns (3/4 turns on tubing 3/16 inch or less). This process has been considered "skill of the craft" and has been included in technician training. Both vendors recommend that one face of the nut be marked while finger tight to facilitate counting the turns, but training documents do not include this recommendation. The technicians were aware of the recommendation to mark the nut, but they did not interpret it as a requirement, and they did not, as a general practice, mark the nut. Swagelock manufactures go/no go gauges for inspecting their fittings, but, prior to this event, no program or procedure required that they be used and they were not in general use at Oconee. No similar device or inspection criteria was referenced in Parker installation instructions.

According to the craft technician who signed the step for the "A" Steam Generator line, the valve, 3/4 inch and 1/2 inch tubing, and associated fittings had been made up in the shop area and transported as an assembly into the Reactor Building. No one signed for the individual fitting connections and it is unknown who performed the fitup and tightening on them. The independent verification sign off was based on the fact that the line was installed, rather than that the individual fittings were properly tightened. The QC inspector stated that the line was inspected in accordance with the QC manual which specified a general inspection of the tubing. It did include a requirement to "verify that all fittings are tight," but no method to check fitting tightness was included. The inspector stated that he typically checks to see that fittings cannot be loosened by hand and that the tubing cannot be pulled out of the fitting.

The impulse line was subjected to a pressure test of the entire RCS at 2200 psig as required by Technical Specifications during startup following refueling outages (or any other opening of the RCS). This test includes walk down of the system and any leakage at the fitting should have been detected prior to operation after it was installed. The fitting subsequently held for 4 and 1/2 years, and the line has been subject to inspection during three subsequent refueling outages without any indication of leakage. It is apparent that the fitting, if not tightened exactly in accordance with the manufacturer's instructions, was tightened to an extent that the deficiency could not be discovered by routine observation without some specific inspection criteria (such as a go/no go gauge or disassembly to visually verify proper compression of the tubing).

No system transient was detected immediately prior to or simultaneously with the initiation of the leak which might have explained why the fitting failed at this particular time.

The inspection performed on existing fittings on Unit 3 after the event found that approximately 28 % of the fittings inspected did not meet the manufacturer's guidelines. This indicates that "skill of the craft" was not adequate to assure that the manufacturer's guidelines were met.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

B. Reactor Trip

The root cause for the reactor trip was found to be an unanticipated interaction of control signals with plant parameters steam pressure and feedwater flow at low power conditions after placing a Main Feedwater pump (MFWP B) in manual to shutdown the pump. This root cause is classed as a Equipment Failure, due to ICS components being slightly out of tune.

The resolution of the problem is to "tune" the turbine header pressure control to make it more stable in this configuration. The Oconee philosophy on tuning the ICS is to calibrate individual components periodically (typically during refueling outages), review operating data to evaluate system performance, and perform system tuning only when necessary to resolve a problem. This is based on the fact that tuning activities require that small transients be intentionally imposed on the system, which increases the possibility of a unit trip.

The investigation of plant and ICS performance data recorded immediately prior to the trip revealed that steam pressure and feedwater demand were out of phase and limit cycling before MFWP B was placed in manual. After switching the pump to manual, the amplitude of the steam pressure and feedwater flow oscillations increased exponentially in a classic unstable manner.

Specifically, one component of the oscillation was caused by the response of the turbine header pressure control portion of the system. This portion of the system has been recognized by assigned ICS technical support personnel as being marginally stable when the reactor is in manual. With the ICS SG/Reactor Master station in Automatic, the feedwater demand was modified by the turbine header pressure error signal, which was oscillating within stable limits due to the response time of the various components. A second contribution to the oscillation was the response of the feedwater pump control portion of the system. With both feedwater pumps in automatic, the response time of the feedwater pumps to the changes in demand was fast enough to keep the oscillations stable. However, when the operator took one pump to manual, only one pump could respond. Therefore, that pump speed had to change more to produce the same flow change. That meant that the pump turbine throttle valve had to move further, and, due to proportional control, the error signals had to be larger to cause the change. This shifted the response time of the pump control system such that the oscillations became divergent.

One difference between this event and other shutdowns was that the reactor was in manual control at the time. This caused the Tave control to modify the feedwater control signal, and prevented the reactor from contributing to the overall response to the control signals. Therefore, the feedwater pump control system response time was affected by the Tave control and the turbine header pressure response time was affected by the lack of reactor response, thus neither sub-system was experiencing the response times seen in a normal shutdown.

The period of oscillations (approx. 36 seconds) and time from initiating event to reactor trip was too short for the operators to adequately evaluate and react to the situation.

Given sufficient time for diagnosis, the operator could have stabilized the oscillation by taking other stations to Manual. The first preference would be for him to have taken turbine control to manual. The second preference would be for the SG/Reactor master control station to have been left in, or returned, to manual, as this would have blocked the steam pressure affect on feedwater control.

It is noted that the Oconee training simulator does not model the ICS and response of individual secondary components in sufficient detail to exhibit this type of control oscillation during training.

An initial question was raised after the trip as to why the Emergency Feedwater pumps were not started if the unit tripped on low MFWP discharge pressure, as indicated by the Unit 3 Events Recorder, because the initiating pressure switches have the same nominal setpoint as the RPS switches. This was subsequently explained as follows:

First, the RPS logic contact buffers require manual reset. The contact buffers on MFWP B were apparently actuated when CRO A manually ran back the demand for that pump which caused discharge pressure to drop. A control room alarm should have alerted the operator to the actuated buffer, but it was apparently overlooked due to the large number of alarms resulting from the leak and the sudden appearance of the divergent oscillation. When CRO A reacted by increasing manual demand on MFWP B, the system responded by reducing demand for MFWP A, which was still in Automatic. When MFWP A discharge pressure reached the setpoint, the associated contact buffers actuated and satisfied the logic in the RPS. The Emergency Feedwater pumps are also actuated by indicated low discharge pressure on both MFWPs, but that logic does not seal in if only one pump discharge pressure is low. The system will only actuate if both MFWPs are low simultaneously.

Second, the pressure switch calibrations were verified after the trip. These checks found that one switch in each actuation channel of the Emergency Feedwater actuation logic was slightly out of the procedure calibration tolerance on the low side. Therefore, MFWP discharge pressure could fall low enough to actuate the RPS switches, which were all within tolerance, and still be above the actual setpoint of the Emergency Feedwater pump logic.

Because of the continuing divergent secondary plant oscillation, it is believed that the reactor would have tripped even if the operator had not increased MFWP B speed.

C. Inadvertent RPS Actuation

It is concluded that the root cause of the inadvertent actuation of the Reactor Protective System (RPS) is Management Deficiency, Deficient Supervision, by CRSRO A.

CRO A was operating with the ICS turbine header pressure control in Automatic after the procedure directed the operator to manually control header pressure by placing the Turbine Bypass Valves in Manual. However, both CRSRO A and CRO A state that they had discussed this deviation from the procedure and reviewed portions of the procedure in an attempt to identify any adverse affects. Neither CRSRO A nor CRO A either recalled from training or reviewed the procedure adequately to identify the reason for the requirement that Turbine Bypass Valves be in manual. This inappropriate action of less than adequate attention to detail contributed to the event.

CRSRO A granted verbal approval for CRO A to stay in Automatic control for the time being. Station directives allow performance of steps out of sequence with the supervisor's approval but require that the approval be documented in the procedure. Additionally, Operations management has a more restrictive Operations Management Procedure which directs that the Shift Supervisor's approval, rather than the CRSRO's, is required prior to performing steps out of sequence. Although the existing operating conditions were unusual, this deviation could not be justified as being necessary to mitigate an emergency situation. Therefore, it was inappropriate for CRSRO A to grant such approval. CRSRO A did so in his role as supervisor, therefore this act is classified as deficient supervision.

It is noted that the procedures in use, OP/3/A/1102/10, "Unit Shutdown", Enclosure 4.2, and OP/0/A/1105/09, "Control Rod Drive System", did not provide any Note, Caution, or verification step immediately prior to resetting the CRD breakers to indicate that the turbine bypass valves should be in Manual or that resetting the CRD breakers would result in a change in pressure if the bypass valves were in automatic.

Recurrence and Other Conclusions

The RCS leak is not considered to be a recurring event. Oconee has not had a history of leaks due to leaking compression fittings. The reactor trip is considered recurring. On April 26, 1990, Oconee Unit 1 tripped due to an unexpected control interaction when an operator stopped the second of four reactor coolant pumps during shutdown. Following a Technical Specification change which prohibited operation with only two running pumps, the RPS had been calibrated to trip the unit if only two pumps were running and power was greater than zero. It was not anticipated that, during the shutdown, the power level indicated by the neutron detectors was small but greater than zero. That event was reported as LER 269/90-06.

The unplanned actuation of the RPS is also considered recurring. On April 1, 1991, Unit 3 had two inadvertent actuations of the Diversified Scram System (an ATWS mitigation system which provides a back up to the RPS) which resulted in an reactor trip and a subsequent scram of a partially withdrawn group of control rods. The subsequent scram occurred during troubleshooting when involved personnel failed to anticipate that the control rods would be affected by their actions. That event was reported as LER 287/91-05. In the RPS actuation portion of this event, CRSRO A and CRO A failed to anticipate the effect of leaving header pressure control in automatic.

There were no personnel injuries or excessive personnel exposures associated with this event. Releases of radioactive materials were controlled and within normal limits. The failure of the fitting, a Parker Hannifin Company model 12-3/4 ZHBW2-SS, has been determined to be NPRDS reportable.

CORRECTIVE ACTIONS

Immediate

1. Operators began a controlled unit shutdown.

2. An Emergency Classification of "Alert" was declared and notifications made to initiate activation of the Technical Support Center and Operational Support Center in accordance with the Site Emergency Plan.

3. Following the Unit trip, Operations stabilized the unit and continued shutting down to cold shutdown.

Subsequent

1. The root valve, tubing, and associated fittings on both the "A" and "B" Steam Generator RVLIS impulse lines were replaced with new components.

2. All compression fittings on tubing connected to the Reactor Coolant System and related high pressure systems (High Pressure Injection and Core Flood) were inspected, and tightened if necessary.

3. An operability evaluation was performed to document the engineering justification for returning Unit 3 to service with the gap on several fittings remaining outside the manufacturer's nominal range. This also documented the justification for continuing operation of Units 1 and 2 without shutting down to inspect for similar defects.

4. Appropriate calibration procedures were revised to change the tuning of the Integrated Control System with the intent to minimize the control oscillation which caused the unit trip.

5. The calibration of the Main Feedwater Pump low discharge pressure RPS and Emergency Feedwater pressure switches were checked. Two Emergency Feedwater pressure switches were slightly out of tolerance low (785 versus 793 psig) and were recalibrated.

Planned

1. The RVLIS instrument line on the Unit 3 reactor vessel head will be replaced prior to startup.

2. The equivalent RVLIS instrument lines on Units 1 and 2 will be replaced with a configuration using fewer compression fittings during the next outage of sufficient duration.

3. All compression fittings on tubing connected to the Reactor Coolant System and related high pressure systems on Units 1 and 2 will be performed during the next outage of sufficient duration.

4. Policy, directive and/or procedure enhancements shall be implemented to assure proper installation and inspection of compression fittings.

5. All personnel who inspect, install, makeup or remake tubing fittings will receive additional training to assure that the manufacturer's instructions are understood and complied with.

6. During unit startup following this outage, a pressure test and walkdown inspection of the RCS will be performed as required by Technical Specifications.

7. During unit startup following this outage, the ICS shall be operated in manual with one Feedwater pump in service long enough to verify that the control oscillation which caused the unit trip is more stable after the tuning adjustment.

8. Operators involved in the inappropriate action and less than adequate supervision will be counselled.

9. Operations procedures will be evaluated for enhancements. Specifically, additional "condition oriented" guidance on ICS controls will be reviewed and implemented as deemed appropriate.

SAFETY ANALYSIS

FSAR Section 15.14.4.3, "Small Break LOCA", defines the minimum area for a small break LOCA to be 0.007 sq. ft. This corresponds to a circular opening approximately 1.13 inches in diameter. The tubing/fitting which failed resulted in an opening of approximately 0.75 inch diameter, or 0.003 sq. ft. area. Therefore, by definition, this event was not a LOCA. All identified consequences were bounded by FSAR analyses for a Small Break LOCA. The leak rate was calculated to average approximately 80 gpm while the Reactor Coolant System (RCS) was at operating pressure. One High Pressure Injection (HPI) pump was capable of maintaining RCS pressure and inventory at this leak rate. No Engineered Safeguards actuations were necessary as a result of the leak. The unit trip which occurred was not caused by the leak.

As shown in Attachment C, radiological releases made as a result of this event were very small percentages of NRC annual limits. All releases were made in a controlled manner after processing the effluent appropriately to minimize the release. The total releases were increased due to the relatively high amount of failed fuel (estimated at 8 rods) which existed in the core prior to the event. Since there are 177 fuel assemblies and each assembly has 208 rods, eight leaks represents only 0.022 %, well less than the FSAR LOCA analysis, which assumes failure of 1% of the fuel rods. The FSAR Maximum Hypothetical Accident analysis further assumes failure of all fuel rods, and shows that 10CFR100 limits would still be met.

As discussed previously, the unit trip response was well within normal post trip response guidelines. No Engineered Safeguards or Emergency Feedwater actuations were required due to the trip. The trip was caused by an Integrated Control System (ICS) oscillation while in an infrequent but normal activity, i.e. taking one feedwater pump out of service at low power level while shutting down. The principle difference in this event from routine shutdowns was the combination of power level and control configuration, i.e. which ICS stations were in manual. The ICS will be tuned to minimize the probability of recurrence, but the worst case scenario would be for the ICS to fail in a similar divergent oscillation while at full power. Should such a failure occur, the Reactor Protective System (RPS) is designed to trip the unit prior to any safety limits being exceeded. In this case the RPS functioned as designed.

The inadvertent actuation of the RPS after resetting the Control Rod Drive (CRD) breakers had minor safety significance. Again, the RPS functioned as designed to assure that safety limits were not exceeded. If a similar event occurred at a higher RCS pressure and temperature (CRD breakers are normally reset at hot shutdown conditions in preparation for restarting the reactor after a trip), the sudden removal of the Turbine Header Pressure post-trip bias of 125 psig would result in a quick cooldown of the RCS from approximately 555 F to 532 F. Such a cooldown could affect RCS apparent inventory due to contraction of the RCS water. This would reduce system pressure and the RPS would trip on low pressure. The HPI system would provide additional makeup flow, but, if the pressurizer was at or near minimum post-trip levels, the pressurizer level could go off scale low momentarily. If the operator reacted similarly to CRO A and closed the Turbine Bypass Valves, RCS pressure would increase. If the operator failed to control pressure properly, the operator could possibly challenge the Pressure Operated Relief Valve (PORV), but the PORV should still assure that no safety limits were exceeded.

Oconee Engineering performed an evaluation of the 23 Parker fittings left out of the manufacturer's nominal range for fitting makeup. This evaluation concluded that Unit 3 could safely restart with these fittings in place. This conclusion was based on the facts that:

1) Parker does not consider the gap dimension to be a critical parameter,

2) the fittings were all tightened as much as appeared feasible to highly experienced instrument technicians,

3) these fittings have been in place for years without leaking, and

4) one of the fittings most out of the nominal range was removed from service, inspected, and verified to have adequate swaging of the ferrule onto the tubing.

Because tubing failure has always been considered a possible failure mode, all of the affected instrument lines have been previously analyzed and evaluated, particularly with consideration of single failure criteria. However, the affect of failure of these 23 "problem" fittings was re-analyzed, including the affect on the connected instrumentation. A summary of the results of this analysis follows:

1. Problem fittings were found associated with three RPS Loop A RCS flow instruments and the ICS Loop A RCS Flow instrument. These all share common impulse lines and are always subject to being affected by any single failure of the impulse lines. Failure on the high pressure side would cause a low flow signal on all the RPS channels and would cause a reactor trip on Flux/Flow/Imbalance. A failure on the low pressure side would cause the flow indications to fail high, which would result in computer alarms to alert the operator. The low side failure would prevent an RPS Flux/Flow/Imbalance trip, but would not cause a trip condition to exist. If a real low flow condition occurred simultaneously with the tubing failure, the decreased heat transfer would result in a high RCS pressure condition which would trip the reactor using separate instruments.

2. Problem fittings were found which could affect pressure indication to Engineered Safeguards Channel B RCS pressure and RPS Channel B RCS pressure. A failure on this line could result in actuation of ES and

RPS Channels B. Neither system would actuate solely due to actuation of only one channel.

3. Problem fittings were found on one of two level control transmitters which control Emergency Feedwater flow into the "B" Steam Generator (SG B). The affected transmitter shares an impulse line with transmitters for Startup, Operate, and Full Range level indications on SG B. Redundant transmitters exist on all of these except Full Range, which provides indication only. The redundant Startup and Operate transmitters would be selected by the Smart Automatic Signal Selector system so that the failure would have no affect on normal operation.

   These instruments are located inside containment. If one of these fittings failed, one result would be a main steam leak inside containment. This would have no affect on the RCS, but, if a LOCA occurred after the instrument failure, the open tubing would provide a leak path out of containment.

4. Problem fittings were found associated with the Pressurizer (PZR) level transmitters. Several fittings are on impulse lines associated with one normal PZR level transmitter, a second level transmitter which provides indication in the Standby Shutdown Facility, and a PZR pressure transmitter. Other fittings are on a line connected to only one of the other two transmitters.

   A failure of a fitting on the high pressure leg could cause low PZR level and pressure indications which could result in the PZR heaters being turned off and increased makeup. The operator would receive low level and low pressure alarms to alert him of the failure. He would have to properly diagnose the failure and select an alternate PZR level transmitter. If the operator delayed this action too long, the increased makeup flow could fill the PZR and challenge the PORV. A failure on the low pressure leg would result in a high level indication, which would cause an alarm and stop RCS makeup flow. The operator would have to diagnose the failure and select an alternate transmitter. If the operator delayed this action too long, the loss of makeup would allow real PZR level and pressure to drop. This could lead to uncovering the PZR heaters while they were energized which could result in damage to the heaters. However, in each failure mode, the other two level instruments would be reading properly and the affected instrument would be off scale either low or high, making diagnosis easy. Also, PZR instrument failure scenarios are frequently used in Operator training, and the Operators are trained to recognize these failure modes.

5. One problem fitting was found on a transmitter for HPI Nozzle Warming Flow, which provides indication only.

The instruments connected to the RCS would result in system leakage, but, due to the size of the tubing, the leakage would remain within the capability of a single HPI pump to provide makeup. The HPI Nozzle Warming Flow instrument is located outside the Reactor Building (RB), but the makeup water is at low temperature and the associated instrument root valves would be accessible so that the leak could be isolated. The other instruments are located inside the RB and any leakage would be confined to the RB.

The evaluation also considered the possibility of similar fitting problems on Oconee Units 1 and 2. The conclusion reached was that the type and degree of problems found on Unit 3 do not warrant shutting down Units 1 or 2. Both Unit 1 and 2 will undergo similar tubing inspections during the next outage of sufficient duration. Unit 2 is currently scheduled to begin a refueling outage in January, 1992. There has been no history of tubing failures at Oconee prior to this event. Of the fittings found out of nominal range on Unit 3, only one showed any evidence of a slight leak. It was concluded that the probability of a fitting failure on either Unit 1 or 2 prior to the next outage is acceptably small. Furthermore, the tubing fittings on those units are of similar size to those on Unit 3, such that no fitting failure should be any worse than that on Unit 3.

In summary, the leak which occurred did not pose an immediate hazard to the public. The leakage was contained and all resulting effluents were treated prior to release to minimize dose to the public. All releases were within limits for normal operation. It is concluded that the health and safety of the public was not affected by this event.

NRC FORM 366A
(6-89)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WTH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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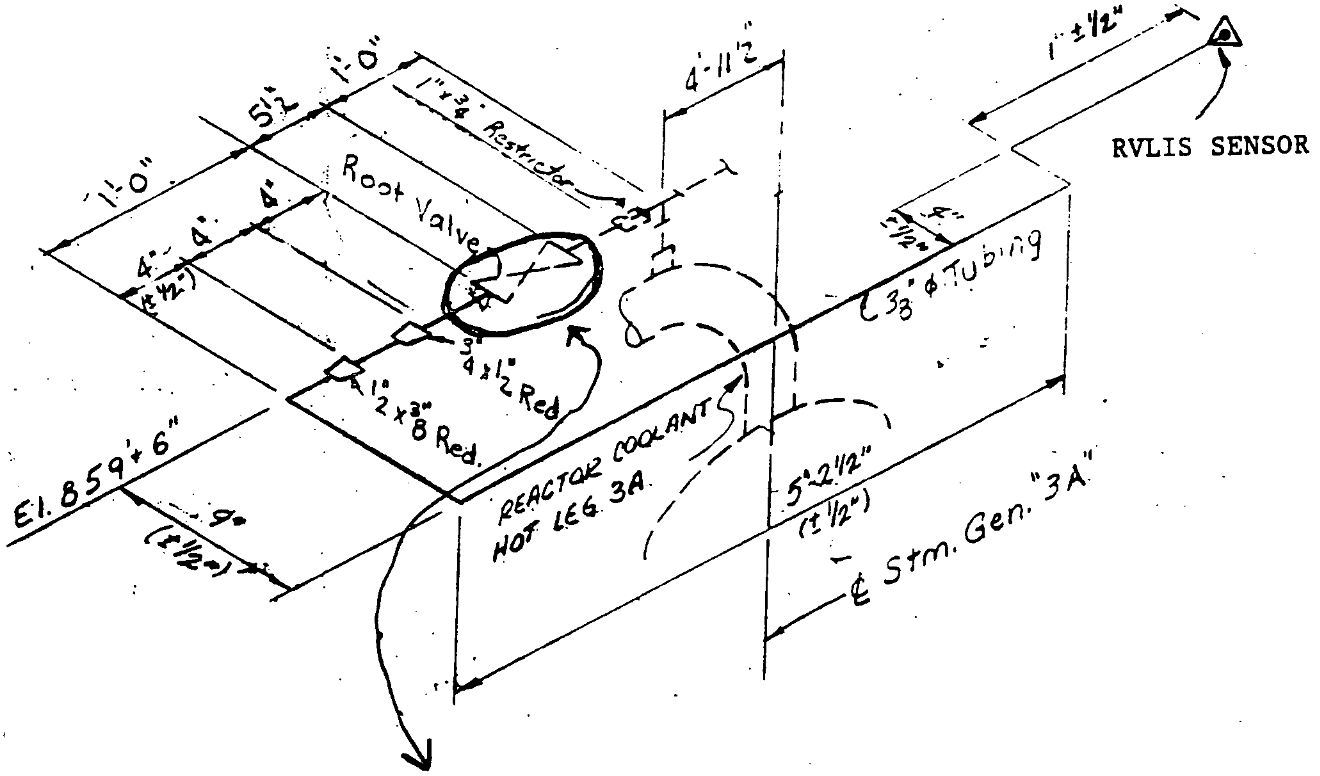
TEXT (If more space is required, use additional NRC Form 366A's) (17)

Attachment A

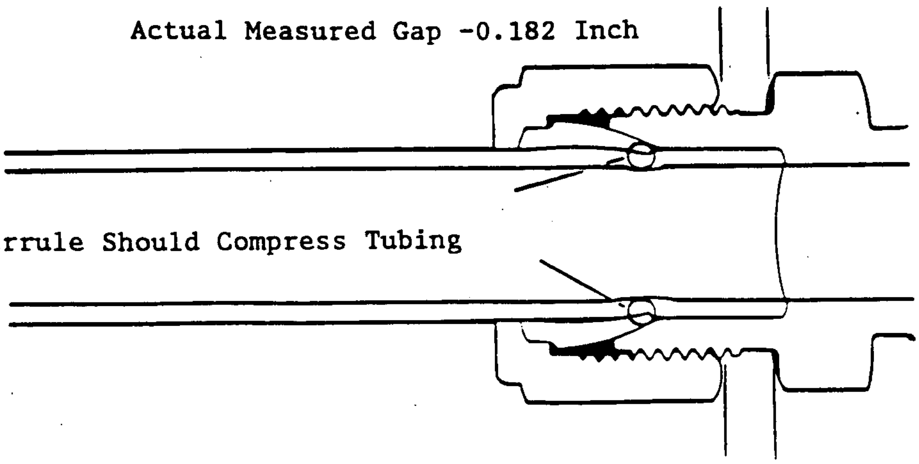
"A" STEAM GENERATOR TAP



"Nominal" Gap Expected - 0.153 to 0.165 Inch

Actual Measured Gap -0.182 Inch

Ferrule Should Compress Tubing



Attachment B

List of Equipment Inspected

Environmentally Qualified Transmitters- 4 of 11 opened and visually inspected. No evidence of water intrusion was found.

Environmentally Qualified Valves- 8 of 8 Target Rock solenoid valves were cycle tested successfully.

Valve Operators- Inspected 26 Limitorque limit switch housings for water.

Fire Detectors- 21 of 22 checked out good. Replaced bad one.

Electrical Penetrations- Opened 5 junction boxes, found no signs of moisture.

Control Rod Drives: Initially Megger tested 20 of 69, all good. Subsequently had one control rod stator fail during an attempted start-up. Later testing showed 29 of 69 to have some problems attributed to moisture. Four were replaced and the others were dried out.

Disconnected 2 control rod position indication tube cables, found no sign of moisture intrusion.

Pressurizer heaters- inspected two junction boxes and meggered 3 cables. No defects found.

Incore instruments- Performed TDR check on one of 7 detectors in each of 52 strings.

Resistance Temperature Detectors (RTDs)- Checked 5 RTDs on RCS.

Pressure Operated Relief Valve acoustic leak monitor- visual inspection

Reactor Coolant Pump Motors- performed High Pot Test on 2 of 4 pumps. Visually inspected instrument terminals on 2 of 4 pumps. Changed oil on 1A2 pump (both oil pots) after water found in upper oil pot.

Cranes- Visually inspected polar crane, Control Rod Drive crane, and fuel handling bridges.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

Attachment C

DOSE to Public Due To Releases

SOURCE	CURIES	WHOLE BODY	THYROID
Liquid	0.0305 Gross 0.0165 Tritium 0.293 Noble Gas	0.00139 mrem (0.0154 %)	0.0122 mrem (0.0407 %)
Noble Gas	672	0.00218 mrad (0.00727 %)	N/A
Iodine Gas	0.000126		0.0004 mrem (Estimated) 0.0513 mrem (Projected) (0.114 %)

NOTE: All % values above are % of maximum allowed dose per calendar year. Projected dose used 90 % carbon filter efficiency, Estimated dose used actual filter efficiency.

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Attachment D

Contamination Survey Results

AREA	CONTAMINATION		ISOTOPIC
A Steam Generator Cavity	24 K cpm	127 mrad	Co-58 71% Cr-51 11%
B Steam Generator Cavity	44 K cpm	42 mrad	Co-58 58% I-131 13% Cs-137 6% Cs-134 5%
Basement		(10,000 mrad)	
West Side		873 mrad	Co-58 36% I-131 36% Cr-51 8% Cs 6%
East Side		590 mrad	Co-58 47% I-131 20% Cr-51 11% Nb-95 4% Zr-95 2% Nb-97 2%
1st Floor	36 K cpm	10 mrad	Co-58 52% Cr-51 10% I-131 10% Cs 9%
2nd Floor	22 K cpm	68 mrad	Co-58 34% Cs-137 26% Cs-134 13% I-131 9%
3rd Floor	18 K cpm	156 mrad (1487 mrad)	Co-58 50% Cr-51 11% Nb-95 9% I-131 4% Cs-134 2% Cs-137 3%
4th Floor	20 K cpm	46 mrad	Co-58 48% I-131 13% Cs-137 9% Cs-134 8% Cr-51 8%
Polar Crane		90 mrad (182 mrad)	

NOTE: Readings indicate high "typical" readings in general area. Parentheses indicate readings at localized hot spots within general area.