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ACCESSION NBR:9705120319 DOC.DATE: 97/05/02 NOTARIZED: NO DOCKET #
FACIL:50-269 Oconee Nuclear Station, Unit 1, Duke Power Co. 05000269
50-270 Oconee Nuclear Station, Unit 2, Duke Power Co. 05000270
50-287 Oconee Nuclear Station, Unit 3, Duke Power Co. 05000287

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SUBJECT: Special rept:on 970428,Oconee submitted justification for continued operation of Units 1 & 3.Oconee continually reviewing impact on safe operation of Unit 1.Oconee will continue to keep staff informed of ongoing investigation.

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May 2, 1997

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

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
Justification for Continued Operation (JCO) of Oconee Unit 1 Based On Oconee Unit 2 HPI Line Leak
NRC TAC No. M98454

Oconee Unit 2 was shutdown on April 22, 1997 as a result of a leak in the Reactor Coolant System (RCS). The leak was caused by a crack in the weld for the pipe to safe end connection at the RCS nozzle for the High Pressure Injection (HPI) System A1 injection line. Duke Power has a formal process, referred to as the Failure Investigation Process, to methodically determine the root cause of an equipment failure. A FIP team was initiated on April 22, 1997, to determine the root cause of the crack in the Unit 2 A1 injection line weld.

Oconee Nuclear Station has been continuously assessing the impact of the potential causes for the Unit 2 HPI line crack on the continued safe operation of Oconee Units 1 and 3. Several conference calls have been held with the staff over the last ten days to discuss the status of the ongoing investigation of the Unit 2 A1 injection line weld crack. On April 28, 1997, Oconee submitted a JCO of Units 1 and 3. This JCO reflected the technical judgment of the Oconee staff based on the information available at that time.

The investigation has been progressing rapidly and newly acquired information has altered Oconee's JCO position as described in the April 28, 1997 submittal. The most significant piece of new information was the determination that the thermal sleeve on the Unit 2 A1 injection line was damaged. As a result of this finding, Oconee focused its attention on past operating experience related to thermal sleeve failures. Information Notice 82-09, "Cracking in

IE22

Piping of Makeup Coolant Lines at B&W Plants", was issued on March 31, 1982 as a result of a RCS leak in an injection line at Crystal River-3 and subsequent inspections at other B&W plants, including Oconee. This information notice describes thermal fatigue induced cracking in the normal makeup lines. All of the past experience with cracks have also involved loose thermal sleeves. As a result of this operating experience, the B&WOG formed a High Pressure Injection/Makeup (HPI/MU) Nozzle Safe End Task Force on March 16, 1982. In a February 15, 1983 letter to the staff, Duke Power submitted the Task Force Report and indicated that the recommended ISI program in the report would be implemented for Oconee Units 2 and 3. Although not specifically addressed in the Task Force recommendations due to the unique double thermal sleeve design, Duke Power also indicated that an augmented ISI program would be implemented for Oconee Unit 1.

Oconee reviewed our performance of the recommended ISI program in the Task Force report with respect to past radiographic tests (RTs) for the three Oconee units. As a result of this review, it was determined that RTs performed in 1996 applicable to Units 2 and 3 were not appropriately analyzed. The 1996 RT for the Unit 2 A1 injection line safe end/thermal sleeve indicated that a gap existed between the thermal sleeve and the safe end. Based on this information, and the belief that loose thermal sleeves are an indicator of potential thermal fatigue concerns in normal makeup lines, a Level III inspector reviewed past safe end/thermal sleeve RTs for Units 1 and 3. This review was completed on May 1, 1997, and concluded that a gap existed between the thermal sleeve and safe end for the Unit 3 A1 nozzle. The Level III inspector briefed station management on his findings during a meeting at 1430 hours on May 1, 1997. Based on the uncertainty regarding the status of the Unit 3 A1 injection line introduced by this new information, station management decided to initiate an orderly shutdown of Oconee Unit 3. Based on the information we have at this time, it appears the augmented RT inspection program for Unit 1 was appropriately followed.

The decision to shut down Unit 3 was communicated to the staff during a conference call that was held at 1500 hours on May 1, 1997. During this call, Oconee management stated that a revision to the April 28, 1997 JCO would be submitted to the staff. Attachment 1 provides a JCO of Oconee Unit 1. This JCO reflects the current technical judgment of the Oconee staff regarding the continued safe operation of Unit 1. It should be recognized that, as new information from the investigation becomes available, the management team at

Oconee is continually reviewing its impact on the safe operation of Oconee Unit 1.

Oconee will continue to keep the staff informed of its ongoing investigation associated with this issue.

Please address any questions to J. E. Burchfield, Jr. at (864) 885-3292.

Very Truly Yours,

J. W. Hampton

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Site Vice President

xc: L. A. Reyes, Region II
Regional Administrator

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Project Manager

Attachment 1
Oconee Unit 1 JCO

Status of FIP Investigation

The section of piping containing the cracked weld on the Unit 2 A1 injection line was shipped to the Framatome Technologies Incorporated (FTI) metallurgical laboratory in Lynchburg, VA on April 28, 1997. Test results thus far indicate that the crack is due to high cycle low amplitude fatigue. Oxide film formation on the crack surface indicates that the crack was present for several years. Oconee has removed the safe end and thermal sleeve on the A1 nozzle. This specimen has been shipped to Lynchburg, VA for metallurgical tests. Ultrasonic tests (UTs) have been performed this past week on the other three HPI injection lines on Unit 2. The UTs did not identify any cracks on these lines or the safe ends. Video inspections were completed for the three remaining thermal sleeves and indicated that these sleeves were intact. Additionally, the thermal sleeves were radiographed to assure their position and verify tightness of the rolled joint. The FIP team is continuing to evaluate this data.

Additional inspections will be performed over the next several days on Oconee Unit 3. Of particular interest are the UTs planned for the normal injection lines. This data may provide further insights regarding the forcing functions for the crack that developed on Unit 2. As new information becomes available, Oconee will continue to assess the impact of this information on the continued safe operation of Oconee Unit 1. This JCO summarizes the current technical judgment of the Oconee staff regarding the continued safe operation of Oconee Unit 1.

Differences Between Oconee Unit 1 and Oconee Units 2 and 3

Oconee Unit 1 has Westinghouse reactor coolant pumps while Units 2 and 3 have Bingham reactor coolant pumps. Seal injection for the Bingham reactor coolant pumps is approximately 40 gpm. Of this 40 gpm, approximately 36 gpm results in makeup to the RCS. Seal injection for the Westinghouse reactor coolant pumps is approximately 32 gpm. Of this 32 gpm, approximately 20 gpm results in makeup to the RCS. All three units operate at about the same letdown flow; typically about 60-70 gpm. Since letdown flow equals makeup flow plus seal injection, flow through each Unit 1 normal injection line is approximately 8 gpm more on Unit 1 than on Units 2 and 3. Assuming a letdown flow of 60 gpm, makeup flow through each injection line on Unit 1 is about

20 gpm. Of this 20 gpm, 3 gpm is the flow through the bypass line. For Units 2 and 3, the makeup flow through each injection line would be about 12 gpm. The higher flow rate would tend to reduce the significance of thermal cycles by minimizing the effects of turbulent penetration of RCS fluid on the RCS end of the thermal sleeve.

Oconee Unit 1 is the only B&W reactor with a double thermal sleeve design for its HPI nozzles. During original construction, the thermal sleeves on Oconee Unit 1 did not penetrate into the free volume of the cold legs. An inner sleeve which penetrates about two inches into the free volume of the cold legs was rolled into the outer sleeve during construction. This change was made to divert the colder HPI makeup from the stainless steel cladding on the RCS nozzle. The double thermal sleeve has four characteristics that are considered an improvement over the single sleeve design.

1. The roll expansion of the inner sleeve improves the contact between the outer sleeve and nozzle wall. This prevents cold water from leaking past the rolled joint and contacting the hot nozzle. In addition, the improved contact makes the sleeve stiffer and thus increases its natural frequency. This produces additional margin by increasing the separation between the sleeve natural frequency and a forcing function frequency.

2. The thermal resistance of the two sleeve design is greater than that for the single sleeve design. This reduces thermal stresses in the nozzle. In addition, the temperature differential across the inner sleeve of the two sleeve design will be less than across the single sleeve design resulting in increased life for the inner sleeve.

3. The thermal shock imposed on the inner sleeve must fail that sleeve before the outer sleeve would be exposed to this type of thermal load. Thus, the nozzle would be protected longer (by the life of the inner sleeve) by using two sleeves rather than one.

4. The double sleeve results in a nominal inside diameter of 1.235 inches compared to the 1.5 inch inside diameter for the single sleeves on Units 2 and 3. The reduced diameter of the double sleeve design results in a reduction in the flow area. For the same makeup flow rate, this correlates to a flow velocity in the double sleeve design that is 48% greater than in the single sleeve design. The higher velocity is more favorable

from a turbulent penetration makeup flow interaction aspect.

5. Units 2 and 3 have implemented modifications to the HPI check valves for the HPI System injection lines. This modification is planned on Unit 1 during the upcoming refueling outage. The FIP team reviewed this modification and concluded it did not contribute to the Unit 2 failure.

Inspection History

A summary of inspections of the Unit 1 HPI injection lines and nozzles was provided in the April 28, 1997, Duke Power submittal to the staff. The results of these inspections are summarized as follows:

1. RTs (taken in 1983, 1986, and 1989) were reviewed again this week by a Level III inspector. The inspector concluded that there are no gaps between the thermal sleeve and nozzle for the A1, A2, and B1 nozzles. However, a reduced contact area was identified in the B2 nozzle. The 1983 RT indicates the length of the contact area is reduced by 13/16 inch on this nozzle. The 1986 and 1989 RT inspections showed no relative change in the contact area from the 1983 inspection. Thus, these inspections indicate the reduced contact length and orientation did not change over this six year period. Even with a ¾ inch reduction in the contact length, about 1 inch of contact between the thermal sleeve and safe end remains. FTI indicates that this contact length is adequate for the sleeve to perform its intended function.

2. UT's of the normal makeup line safe ends were also performed in 1983,1986, and 1989. These inspections conclude that there are no cracks in the safe-end to nozzle weld.

3. UT's of the emergency lines (B injection lines) were performed per Duke's commitments in response to Bulletin 88-08. They include both safe-end welds, and adjacent welds in the injection line. These inspections, performed in 1989, 1991, and 1995, did not identify any cracks.

As a result of reviewing this inspection history, Oconee concludes that there is no evidence of cracks in the HPI lines and nozzles or damage to the thermal sleeves on Oconee Unit 1.

Evaluation of Forcing Functions

Metallurgical test results indicated that the crack in the HPI piping removed from Oconee Unit 2 was caused by a high cycle low amplitude stress field. This leads to the following possible causes for crack initiation and propagation:

1. Thermal Striping
2. Thermal Cycling
3. Thermal Stratification
4. Vibration

Experience shows that thermal striping has the ability to initiate a crack but is self limiting in nature and does not propagate through the pipe wall. Based on this, it is felt that the other loadings above could create a through wall crack such as that seen at Oconee Unit 2.

The only vibration seen at the HPI nozzles is caused by the adjacent reactor coolant pump (RCP). While the measured vibration on the 1A2 RCP is higher than normal, the stress level induced at the HPI nozzles from this loading is not expected to be significant. In addition, calculations demonstrate that the flow induced vibration frequency is much lower than the natural frequency of the thermal sleeve. Therefore, vibrational fatigue failures are a remote possibility. Therefore, it is considered that the only significant crack propagating loadings at the HPI nozzles are thermal in nature.

The impact of thermal fatigue is addressed by assessing both the emergency and normal makeup flow paths. There is no flow through the emergency injection line (B1 and B2) during normal operation. Oconee Unit 1 has had 19 thermal cycles associated with emergency injection flow through this path. No emergency injection flow cycles have occurred since the last augmented inspection. Oconee Unit 2 has had 18 such cycles. The design analyses assume 70 cycles. Thus, there is significant margin to the current design assumption. UTs of the Unit 2 B1 and B2 injection lines show no evidence of cracking. In addition, the emergency injection lines are inspected in accordance with Oconee's Bulletin 88-08 augmented inspection program and no concerns have been identified. The reduced contact area on the 1B2 thermal sleeve remained constant between 1983 and 1989. Since there is no flow through this line during normal operation, the high cycle low amplitude forcing function present on the

Unit 2 A1 injection line is not present on the emergency injection lines.

For the normal injection lines (1A1 and 1A2), Oconee will be increasing makeup flow through the normal injection lines to eliminate the turbulent penetration effects that could contribute to thermal fatigue. Calculations by FTI for a 1.50 inch inner diameter thermal sleeve show that for injection line flow rates of 10 gpm, 30 gpm, and 60 gpm, the turbulent penetration depths (from the RCS end) are approximately 7.5, 4.5, and 0 inches, respectively. Thus, for an injection line flow rate of 60 gpm, thermal cycling due to turbulent penetration can be alleviated particularly as applied to the area of the safe end and the HPI pipe not protected by the thermal sleeve. With the Oconee Unit 1 double sleeve design, the required flow rate to mitigate the turbulent penetration is calculated to be $(60\ \text{gpm})*(1.235/1.5)^2 = 42$ gpm. This injection line flow rate can be accomplished by increasing letdown flow to 105 gpm.

Eliminating the turbulent penetration effects reduces one of the means of high cycle fatigue and thus reduces the potential for failure. This reduction should be applicable independent of the thermal sleeve roll joint integrity. If one hypothesizes that the safe end/thermal sleeve joint is loose, this may create a parallel flow path for the makeup flow. However, this flow path will be much more resistive than the thermal sleeve and the vast majority of the flow will be through the sleeve. Evaluations by FTI indicate the flow between the sleeve and the nozzle will be concurrent with the thermal sleeve flow and the sleeve will be cooled on both the inside and outside.

This conclusion that thermal cycles during steady-sate operation can be eliminated by increasing makeup flow would not be changed if damage to the thermal sleeves is postulated; such as displacement (which would cause gaps at the outboard end, cracking, or loss of part or all of the sleeve. FTI has concluded that damage to the thermal sleeve would cause high thermal peak stresses in the knuckle region of the nozzle, but, as stated above, these stresses are self limiting and will not cause failure of the nozzle.

The next refueling outage for Oconee Unit 1 is scheduled for early September 1997. As stated in the April 28, 1997 submittal to the staff, Oconee Operations has been instructed not to isolate makeup flow except in emergency conditions. In addition, Engineering requested that Operations limit variations in makeup flow as much as possible. These precautions, along with an increase in

letdown flow, will significantly reduce the potential for any further thermal cycling of the normal makeup nozzles.

Based on the above evaluation, additional administrative controls, and the fact that the Unit 1 refueling outage is in September of this year, Oconee believes it is extremely unlikely a leak will develop on Unit 1. As stated earlier, this conclusion is based on the information that is available at this time. As new information becomes available from the ongoing investigation of the Unit 2 leak, Oconee management will continue to reassess the continued safe operation of Oconee Unit 1.

Leakage Monitoring

As described in the April 28, 1997 Duke Power submittal, compensatory actions have been implemented by Operations to assure that the potential for RCS leakage on Oconee Units 1 is carefully monitored. These actions are documented on Operations turnover sheets and are discussed during shift turnover meetings. Operations has been instructed to take conservative actions if a leak develops on Oconee Unit 1. Any confirmed RCS leak greater than 1 gpm in the Reactor Building will be treated as a non-isolable leak and the reactor will be promptly shut down.

Operations has the ability to detect RCS leakage using several methods. These methods include:

- The Reactor Building air particulate monitor which is sensitive to low leakage rates. The rates of RCS leakage to which the instrument is sensitive are 0.1 gpm to greater than 30 gpm, assuming corrosion product activity and no fuel cladding leakage.

- Leakage is monitored by a level indicator in the reactor building normal sump. Changes in the normal sump level can indicate leakage from the RC system. The sump capacity is 15 gallons per inch of height and each graduation on the level indicates 0.5 inches of sump height. Thus, this indicator is capable of detecting changes on the order of 7.5 gallons of leakage into the sump. A 1 gpm leak can be detected within less than 10 minutes.

- Total RCS leakage is determined by indications of reactor power, coolant temperature, pressurizer water level and letdown storage tank level. All of these indications are recorded. Leakage calculations are performed once per

shift. As an interim measure until the root cause of the Unit 2 HPI line weld crack can be determined, Operations will be performing leakage calculations twice per shift.

- Since pressurizer level is held constant, RCS leakage is replaced from the letdown storage tank which would result in decreased letdown storage tank level. A 1 gpm leak can be detected within one half hour using letdown storage tank inventory monitoring. The need to carefully monitor LDST level for indications of potential RCS leakage has been stressed to the operators.

All of the above leakage indications were effective during the Unit 2 event and are operable on Unit 1. The above leakage detection systems provide a high level of confidence a leak in excess of 1 gpm will be promptly identified, as was the case in the Unit 2 event. FTI performed a leak before break analysis to support this JCO. The dead weight, thermal, and safe shutdown earthquake loads shown in Table 1 are the design loads for the HPI nozzle. The faulted loads calculated in that table ("Maximum moment" loads) are the absolute sum of deadweight plus thermal plus safe shutdown earthquake. Note that the externally applied axial forces are not tabulated as they are found to be negligible compared to the axial force due to pressure. The material properties used in the FTI analysis are listed in Table 2. Based on the fact that the leakage detection systems at Oconee can detect an RCS leak rate of 1 gpm, a leak rate of 10 gpm was used in the leak before break analysis. The leakage size crack and critical crack length determination for the Oconee HPI nozzle safe end to pipe juncture are performed in accordance with proposed SRP 3.6.3. The leakage size crack determination is performed in a two step process as described below.

In the circumferential crack opening area analysis, the normal operating loads (deadweight plus normal operating thermal plus pressure) and faulted loads (deadweight plus normal operating thermal plus safe shutdown earthquake plus pressure) tabulated in Table 1 are used to calculate the crack opening area for a range of hypothetical crack lengths.

The crack opening area calculated above is used to determine the crack length necessary to obtain a 10 gpm leak rate. As this location contains water that is approximately 100°F, single phase flow through the flaw is calculated considering parameters such as system pressure, temperature, flaw surface roughness, pipe dimensions and flaw area resulting from applied loads.

As described above, the leakage size crack is defined as the crack size resulting in a 10 gpm leak rate. The crack length at which the pipe will fail is the critical length. The results are as follows:

Loading Condition	Leakage Size Crack Length	Critical Crack Length	Margin Ratio
Normal Operating	1.9 in	3.19 in	1.68
Faulted	1.75 in	3.06 in	1.75

The results predicted from this analysis are consistent with the leak rates and crack size seen on Oconee Unit 2. The leak before break analysis indicates that there is a high level of confidence the plant can be safely shutdown in the unlikely event leakage is detected on Unit 1. Data from the Crystal River 3 leak and the Oconee Unit 2 leak indicate that growth of the crack and increases in leakage are gradual in nature and would not propagate to failure prior to the plant being safely shut down.

Conclusions

This JCO summarizes Oconee's technical judgment that the continued safe operation of Oconee Unit 1 is justified. Differences between Oconee Unit 1 and Oconee Units 2 and 3 indicate that Unit 1 should be less susceptible than the other two units to thermally induced fatigue failures. Administrative controls have been implemented to assure that the forcing functions for fatigue are minimized. In addition, the leak before break analysis indicates that, given the sensitivity of the leakage detection systems and the heightened awareness of the operators, the plant would be safely shut down in the unlikely event a leak in the injection line develops. Based on an assumed leak rate of 10 gpm, the leak before break analysis concludes that ample margin exists to pipe failure during a unit shutdown from a fatigue induced crack.

Oconee will continue to carefully assess the impact of new information from the ongoing investigation of the Unit 2 leak as it relates to the continued safe operation of Oconee Unit 1.

Table 1
Applied Loads at HPI Nozzle

Temperature	= 100 F
Pressure	= 2300 psi
Outside Diameter	= 2.875 in
Thickness	= 0.375 in
Material	= 316 Stainless Steel

Loading Connection	Ma (ft -lbs)	Mb (ft -lbs)	Mc (ft-lbs)	Mr (ft-lbs)
Weight	131	38	-59	
Thermal	2226	-914	-1043	
SSE	110	246	94	
Normal Operating (Min. Moment)	2357	-876	-1102	2745
Faulted (Max. Moment)	2467	1198	1196	2992

Table 2
Material Properties

Material	A-376 TP 316
Yield Stress	30 ksi (B31.7)
Ultimate Stress	75 ksi (B31.7)
Flow Stress	52.5 ksi ((Yield + Ultimate) / 2)
Young's Modulus	28.3E6 psi (B31.7)
Ramberg-Osgood Parameters	
alpha	3.46
n	5.68