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U. S. Nuclear Regulatory Commission
Washington, DC 20555

Attention: Document Control Desk

Subject: Oconee Nuclear Station
Docket Nos. 50-269, 270, and 287
High-Energy Line Break Outside Reactor Building Methodology

Significant technical and regulatory advances in pipe rupture postulation and protection requirements have taken place since ONS was designed and built in the early 1970's. Duke Energy Corporation (Duke) has chosen to update the existing pipe rupture criteria for Oconee Nuclear Station (ONS) to include the advances that have been made.

Duke submitted ONS's methodology for "Analysis of Effects Resulting From Postulated Piping Breaks Outside Containment For Oconee Nuclear Station, Units 1, 2 & 3" for NRC review and concurrence on October 15, 2001. The NRC reviewed the methodology and submitted questions for additional information to Duke during January, 2002. Duke initiated conference calls, as well as a meeting on March 20, 2002, with the NRC. Another response, dated July 3, 2002 was submitted to document the common understanding reached between the NRC and Duke as a result of the conference calls and meeting. This response superceded the original letter dated October 15, 2001. On August 5, 2003, a conference call between Duke and the NRC occurred. As stated in the conference call, Duke provided the list of assumptions as general information to the HELB licensing basis. Duke understands that all changes must be identified and processed in accordance with 10 CFR 50.90 and 10 CFR 50.59. Attachment 1 contains the following: a restatement of the deviations, including an error correction related to deviation 2; and a restatement of the assumptions.

Duke has a significant, self-initiated project underway to re-constitute HELB design and licensing basis. The purpose of this letter is to obtain NRC concurrence with the planned

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project approach. Based on Duke's HELB project schedule, staff concurrence on the proposed methodology is requested by September 30, 2003. Duke will submit a revision to the licensing basis upon completion of the HELB project to reflect a new HELB licensing basis for the facility.

If there are any additional questions, please contact Reene' Gambrell at (864) 885-3364.

Very Truly Yours,

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Attachments

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ATTACHMENT 1

High Energy Line Break Methodology

Attachment 1

High Energy Line Break Methodology

Duke Energy Corporation (Duke) performed an assessment in 1998 that identified issues with the original High Energy Line Break (HELB) analysis. As a result of this assessment, Duke initiated a project to update the original HELB work. This initiative was communicated to Region II management during a January 26, 1999, management meeting. The primary objective of this project is to revalidate and update the Oconee Nuclear Station (ONS) HELB study originally completed in 1973 for the present day plant configuration. In the initial phase of the project, Duke created the methodology used to identify the postulated break locations and then generated a list of break locations with their associated interactions. In the next phase, the interactions developed in the initial phase will be evaluated from a plant shutdown perspective. To support implementation of the second phase, Duke seeks concurrence from the NRC regarding the methodology used to determine break locations in the initial phase.

Criteria for postulating rupture locations and providing protection methods for piping inside containment are not within the scope of this submittal. The original HELB criteria outside containment for ONS are documented in MDS Report No. OS-73.2 dated April 25, 1973 and Supplement 1 to MDS Report No. OS-73.2 dated June 22, 1973. Design methods and protection requirements were based on standard practice and approved criteria at that time (1973). The rules and guidelines to address HELBs provided in Appendix A to 10CFR50, General Design Criteria (GDC) 4, "Environmental and Missile Design Bases" were in the developmental stage during that time frame and were therefore not included in the initial ONS HELB licensing position. However, Duke responded positively and adequately to the analysis requested in the Atomic Energy Commission (AEC) letter authored by A. Giambusso dated December 15, 1972. This is documented in the ONS Unit 2 and 3 Safety Evaluation Report received from the AEC dated July 6, 1973.

Significant technical and regulatory advances in pipe rupture postulation and protection requirements have taken place since ONS was designed and built in the early 1970's. Duke has chosen to update the existing pipe rupture criteria for ONS to include the advances that have been made.

This attachment documents Duke's updated position on the various issues pertaining to pipe rupture requirements outside containment. The position has been established considering the technical and regulatory requirements at the time of plant design and construction, current NRC Standard Review Plan (SRP) guidance, and Generic Letter 87-11, to be compatible with existing design bases methods for ONS. The purpose of the updated criteria is to provide acceptable pipe rupture postulation and protection methods for the plant that meet the intent of current NRC requirements.

This response documents important deviations or changes from the original MDS Reports dated April 25, 1973 and June 22, 1973, respectively. A list of assumptions is being provided as general information. To facilitate a revision to the HELB licensing basis, Duke understands that NRC review and approval is required in accordance with 10 CFR 50.90 and 10 CFR 50.59.

Duke's proposed methodology is very similar to the following plants:

Florida Power Corporation's methodology and submittal for Crystal River 3 dated December 18, 1989. The submittal was approved by the NRC on April 11, 1990.

Watts Bar, NRC SSER 6, section 3.6, "Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping" which was reviewed and approved by the NRC in April, 1991.

Comanche Peak Steam Electric Station, Units 1 and 2 submittal on "Jet Impingement Analysis," dated March 28, 1988 and the NRC's response dated September 30, 1988.

D. C. Cook's methodology and submittals dated April 6, 2000 and November 13, 2000. The submittal was approved by the NRC on November 21, 2000.

DEVIATIONS:

Deviation 1: Criteria established in the AEC letter dated December 15, 1972 stated that systems (or portions of system) be identified for which protection against pipe whip is required. ONS has deviated from this requirement in that certain systems are excluded based on operating time.

No HELB protection requirements are needed if total system operation time is less than 1% total plant operating time or time as a High Energy Line (HEL) is less than 2% system operating time. Piping which operates at pressures and temperatures meeting high energy requirements is not considered high energy if the total time spent in operation at high energy conditions is less than either of the following: a)1% of the normal operating life of the plant or, b)2% of the time required to accomplish its system design function. For these systems, no breaks are postulated. This is justified based on the very low probability of a HELB occurring during the limited operability time for these systems.

In accordance with BTP MEB 3-1 B.2.e, piping systems or portions of systems that qualify for the 1% or 2% rule will be evaluated as moderate energy systems.

Deviation 2: The AEC letter dated December 15, 1972, as supplemented on January 17, 1973, stated that criteria used to determine the pipe break locations in the piping systems should be equivalent to the following: "Design basis break locations should be selected in accordance with the following pipe whip protection criteria; however, where pipes carrying high energy fluid are routed in the vicinity of structures and systems necessary for safe shutdown of the nuclear plant, supplemental protection of those structures and systems shall be provided to cope with the environmental effects (including the effects of jet impingement) of a single postulated open crack at the most adverse location(s) with regard to those essential structures and systems, the length of the crack being chosen not to exceed the critical crack size. The critical crack size is taken to be ½ the pipe diameter in length and ½ the wall thickness in width."

Duke submits a partial deviation from the postulation of critical cracks:

A. For piping that is seismically analyzed (i.e. stress analysis information is available), critical cracks shall be postulated in Class 2 or 3 piping at axial locations where the calculated stress for the applicable load cases exceeds $0.4(S_A + S_h)$. For Class 2 or 3 piping, applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (defined as operational basis earthquake, OBE).

Actual stresses used for comparison to the threshold shall be calculated in accordance with the ONS Power Pipe Code of Record, USAS B31.1.0, 1967 Edition, "Code For Pressure Piping." Allowable stress values S_h and S_A shall be taken from the applicable appendices of USAS B31.1.0, or USAS B31.7, February 1968 Edition including Errata of June 1968, as appropriate.

B. For non-seismically analyzed or unanalyzed piping, cracks will be postulated in accordance with BTP MEB 3-1 section B.1.e.

Rules for postulation of cracks in Class I piping are not defined, since there is no Class I piping located outside of containment at ONS.

Deviation 3: Criteria established in the AEC letter dated December 15, 1972 state that ASME Section III Code Class 2 and 3 piping breaks should be postulated to occur at the following locations in each piping run or branch run:

Any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with seismic events and operational plant conditions exceed $0.8\ (S_h + S_A)$ or the expansion stresses exceed $0.8\ S_A$.

Duke seeks deviation from this criterion in that breaks are not being postulated based on stresses exceeding 0.8 S_A. Thermal stresses are secondary in nature, and taken in absence of other stresses, do not cause rupture in pipes. This complies with BTP MEB 3-1 requirements for postulating intermediate breaks, based on stress, for Class II piping systems.

Deviation 4: Criteria established in the AEC letter dated December 15, 1972 state that ASME Section III Code Class 2 and 3 piping breaks should be postulated to occur at the following locations in each piping run or branch run:

Intermediate locations in addition to those determined by Deviation 3, selected on reasonable basis as necessary to provide protection. As a minimum, there should be two intermediate locations for each piping run or branch run.

Consistent with GL 87-11, Duke plans to deviate from the postulation of Arbitrary Intermediate Breaks provided in the AEC's December 15, 1972 letter:

A. For piping that is seismically analyzed (i.e. stress analysis information is available), intermediate breaks shall be postulated in Class 2, 3 piping at axial locations where the calculated stress for the applicable load cases exceed $0.8(S_A + S_h)$. Applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (defined as operational basis earthquake, OBE).

B. For piping that is non-seismically analyzed or unanalyzed piping, intermediate breaks shall be postulated in accordance with BTP MEB 3-1, section B.1.c.(3).

Rules for postulation of breaks in Class I piping are not relevant in this submittal, since there is no Class I piping located outside of containment at ONS.

Actual stresses used for comparison to the threshold shall be calculated in accordance with the ONS Power Pipe Code of Record, USAS B31.1.0, 1967 Edition, "Code For Pressure Piping." Allowable stress values S_h and S_A shall be taken from the applicable appendices of USAS B31.1.0, or USAS B31.7, February 1968 Edition including Errata of June 1968, as appropriate.

Structural HELB Terminal Ends

Terminal Ends are vessel/pump nozzles, penetrations, in-line anchors and branch-to-run connections that act as essentially rigid constraints to piping thermal expansion. A branch connection appropriately modeled with the run (flexibility and movements) and where the branch connection stress is accurately known uses the stress criteria for postulating breaks. For unanalyzed branch connections or connections where the stress is not accurately known, break locations will be postulated in accordance with BTP MEB 3-1, section B.1.c.(3).

Deviation 5: The AEC letter dated December 15, 1972 provides criteria to determine pipe break orientation at break locations and specifies that longitudinal breaks in piping runs and branch runs be postulated for 4 inches nominal pipe size and larger.

Circumferential breaks are postulated at all terminal ends. Longitudinal breaks are not postulated at terminal ends, unless the piping at the terminal end is of a seamed design. This is consistent with specifications in B.3.b.(2) of BTP MEB 3-1.

ASSUMPTIONS FOR METHODOLOGY:

The following are key assumptions applied in the ONS Methodology:

1. The ONS initial plant state used for postulating break locations is nominal full power conditions. Mitigation capabilities are analyzed assuming 102% full power operation.

2. The Jet Impingement Cone Geometry and Jet Impingement Effective Length are postulated in accordance with NUREG/CR-2913, "Two Phase Jet Loads", subject to the pressure and temperature limitations given in the NUREG (i.e. stagnation pressures from 870 psig to 2465 psig, 158°F subcooling to 75% steam quality). For jets consisting of steam or subcooled liquid falling outside of the NUREG limitations, the effective length of the jet will be 10 pipe diameters (ID). NUREG/CR-2913 will be used to determine jet lengths from breaks subject to the 10 pipe diameter requirement. Similarly, spray lengths from cracks will be limited by 10 pipe diameters.

3. Safe shutdown for ONS is defined as Mode 3 with an average reactor coolant temperature $\geq$ 525°F. Overcooling events can lead to reactor coolant temperatures < 525°F. Safe shutdown for these events includes reestablishing and maintaining shutdown margin > 1%$\Delta k/k$ with RCS temperatures and pressures being controlled in accordance with plant emergency procedures.

   The original HELB described plant cooldown to cold shutdown conditions. It did not specify safe shutdown conditions. It was recognized that certain events create vulnerabilities in certain plant systems during cooldown to cold shutdown. The assumed safe end state for each HELB is safe shutdown as defined in (3) above.

4. Non-safety related equipment may be credited for HELB mitigation.

The use of non-safety related equipment for accident mitigation is within Oconee's licensing basis. The plant's licensing basis for safety-related equipment was reviewed and approved by the NRC in a Safety Evaluation of Dukes Response to Generic Letter 83-28, dated August 3, 1995.

5. Single active failures are postulated for accident mitigation, as well as achieving and maintaining safe shutdown. Once the plant has been stabilized in a safe shutdown condition, a plant cooldown may be initiated to bring the unit to a cold shutdown condition. No additional single active failures are postulated during the cooldown to a cold shutdown condition.

The single failure criterion has been applied to certain systems at ONS. Originally, the only systems required to be designed to protect against single failures were the Reactor Protection Systems (RPS) and the Engineered Safeguards (ES) Systems. Post-TMI action plans requested licensee's to upgrade the EFW systems to meet single failure criterion; therefore, single failure criterion will be applied to RPS, ES and EFW systems for achieving and maintaining safe shutdown. Single failures for the EFW system will be postulated in a manner consistent with the staff's June 11, 2002 Safety Evaluation on the EFW system.

HELBs outside containment may lead to design basis transients and accidents as described in Chapter 15 of ONS's Updated Final Safety Analysis Report (UFSAR). These accidents or transients include:

- Loss of Reactor Coolant Flow
- Turbine Trip
- Steam Line Break
- Small Steam Line Break
- Loss of Main Feedwater Transient

The methodology used to address each of the above accidents or transients is discussed in section 15.1 of the UFSAR. Single active failures are considered for RPS, ES and EFW systems only. In addition, the accident analysis only considers the single active failures for terminating the event and bringing the unit to a safe, stable condition. Plant cooldown is not considered to be a part of accident mitigation. In fact, additional systems may be required to cool the plant down that have not been designed to protect against single active failures. These systems include, but not limited to, the atmospheric steam dump valves and the reactor vessel head vents. In addition, establishing cold shutdown requires the alignment of the Low Pressure Injection system to the normal decay heat removal mode. This mode of operation is vulnerable to single active failures due to a single decay heat drop line.

6. A LOOP will be considered for Main Steam Line Breaks (MSLB) and Main Feedwater Line Breaks (MFLB).

   LOOP is only postulated for MSLB and MFLB in a manner consistent with the post-TMI EFW licensing basis. Other cases do not postulate a LOOP consistent with the MDS Report unless the initiating break directly causes a LOOP.

7. The Standby Shutdown Facility (SSF) is assumed to be available as a means of safe shutdown following events that lead to a loss of normal plant systems.

   The Standby Shutdown Facility (SSF) provides capability to shut down the nuclear reactors from outside the control room in the event of a fire, flood, or sabotage-related emergency. The SSF is also credited as the alternate AC (AAC) power source and the source of decay heat removal required to demonstrate safe shutdown during the required station blackout coping duration. It provides additional "defense-in-depth" by serving as a backup to safety-related systems. The SSF has the capability of maintaining Mode 3 (with Tave $\geq$ 250°F) in all three units for approximately three days following a loss of normal AC power. It is designed to maintain reactor coolant system (RCS) inventory, maintain RCS pressure, remove decay heat, and maintain shutdown margin.
   Should the SSF be used as a mitigative strategy for a particular HELB, increased surveillance on the SSF will be considered as appropriate.

8. Unaffected units' EFW systems are assumed to be available to mitigate a loss of EFW pumps/inventory on the affected unit.

   The original HELB report identified numerous secondary piping breaks which led to a loss of both main and emergency feedwater systems on a given unit. At the time of the report, the Station Auxiliary Service Water (ASW) pump was the only means of delivering water to the steam generators following the identified line breaks. A commitment was made to install new EFW piping with cross-connects between all three units to eliminate the single failure vulnerability of the Station ASW pump. This cross-connect capability exists today, but requires local manual operation to cross-connect the units. This will continue to be credited for events where personnel access to the areas can be demonstrated.

Post-TMI, the NRC questioned how EFW was able to mitigate the effects of a MSLB and Main Feedwater Line Break (MFLB) resulting in a ruptured SG pressure boundary coupled with a single active failure in the EFW system. These events did not require the use of the EFW cross-connects and therefore did not alter the requirements for the EFW cross-connects. The EFW cross-connects were installed for condensate and MFLB breaks inside the turbine building that could result in a complete loss of a unit's EFW system. The cross-connects are credited for these events. Post-TMI requirements did not alter these events. The EFW cross-connects are tested in accordance with the In-Service Testing program and also controlled by selected licensee commitment.