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RA-19-0253 10 CFR 50.90

August 28, 2019

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

Subject: Duke Energy Carolinas, LLC
Oconee Nuclear Station
Renewed Facility Operating License Numbers DPR-38, DPR-47, and DPR-55

Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Breaks Outside of the Containment Building.

References:

1. Letter from A. Giambusso (Atomic Energy Commission) to A. C. Thies (Duke Power Company), "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment," dated December 15, 1972.
2. Letter from A. Schwencer (Atomic Energy Commission) to A. C. Thies (Duke Power Company), "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment, Clarification Letter," dated January 17, 1973.
3. MDS Report No. OS-73.2, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, & 3, prepared by Duke Power Company, dated April 25, 1973.
4. MDS Report No. OS-73.2, Supplement 1, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, & 3, prepared by Duke Power Company, dated June 22, 1973.
5. MDS Report No. OS-73.2, Supplement 2, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, & 3, prepared by Duke Power Company, dated March 12, 1974.
6. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, "Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events Outside of the Containment Buildings; License Amendment Request No. 2008-005," dated June 26, 2008.

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Attachment 4 of this letter contains ~~proprietary information. Withhold from Public Disclosure Under 10 CFR 2.390. Upon removal of Attachment 4,~~ this letter is uncontrolled.

7. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events Outside of the Containment Building – Unit 2; License Amendment Request No. 2008-006,” dated December 22,2008.
8. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events Outside of the Containment Building; License Amendment Request No. 2008-007,” dated June 29, 2009.
9. Letter to the U.S. Nuclear Regulatory Commission from T. Preston Gillespie, Jr., Vice President, Oconee Site, “Tornado and High Energy Line Break (HELB) Mitigation License Amendment Requests (LARs) – Responses to Request for Additional Information,” dated December 16, 2011.
10. Letter to the U. S. Nuclear Regulatory Commission from Thomas Ray, Vice President, Oconee Nuclear Station, Duke Energy Carolinas, LLC, “Revision to Tornado/HELB Mitigation Strategies and Regulatory Commitments,” dated November 15, 2017.

In accordance with 10 CFR 50.90, Duke Energy Carolinas, LLC (Duke Energy) proposes to amend Renewed Facility Operating License Numbers DPR-38, DPR-47, and DPR-55 to revise the Oconee Nuclear Station (ONS) current licensing basis (CLB) with regard to High Energy Line Breaks (HELBs) outside of the containment building. The license amendment request (LAR) includes revisions to the Updated Final Safety Analysis Report (UFSAR) in support of the revised HELB licensing basis (LB).

The purpose of this LAR is to establish normal plant systems, protected service water (PSW), and/or the standby shutdown facility (SSF) as the assured mitigation path following a HELB. Nuclear Regulatory Commission (NRC) approval is requested for specific details of the new strategy discussed in section 2.4 and evaluated in section 3 including associated attachments.

In parallel with the review and approval of this LAR, ONS is implementing a number of conforming modifications to the plant under 10 CFR 50.59. A description of these changes is included in Attachment 1 and provided for your information. These modifications either enhance the ability of structures, systems, or components (SSC) to withstand the effects of the HELB or improves the response of the mitigating systems in responding to a HELB. The descriptions and conclusions provided in this LAR credit these modifications. These modifications will be completed prior to implementation of the LAR.

The analysis of the dynamic effects resulting from postulated piping breaks outside of the containment building was originally documented in Duke Energy mechanical design study (MDS) Report No. OS-73.2 (reference 3) and corresponding supplements (references 4 and 5). The existing HELB report (references 3, 4, and 5) will remain as the HELB LB pending the approval and implementation of this LAR.

This LAR and supporting attachments provide a re-evaluation of postulated HELBs and describes the ‘as modified’ station configuration for the identified HELBs. This LAR is a LB reconstitution effort that reflects extensive analysis. The proposed changes, once approved by the NRC staff, will supersede the existing HELB LB documentation, MDS Report No. OS-73.2 (reference 3) and corresponding supplements (reference 4 and 5).

The enclosure to this LAR provides a description and assessment of the proposed change. Attachment 1 contains the list of conforming modifications to be installed as a result of this LAR. Attachments 2 and 3 contain the UFSAR red marked changes and retypes, respectively. Attachments 4 and 5 describe the Thermal Hydraulic (T-H) models used to perform analysis of mitigated HELB scenarios in support of this LAR. Within Attachment 4, proprietary information is identified by brackets. In accordance with 10 CFR 2.390, Duke Energy requests that this information be withheld from public disclosure. Attachment 5 contains the non-proprietary (redacted) version of this content. Attachments 7 and 8 contain affidavits attesting to the proprietary nature of the information in Attachment 4. The proprietary information that is owned by Duke Energy and Framatome is annotated, respectively. The annotated information has substantial commercial value that provides a competitive advantage. Attachment 6 contains the T-H Transient Analyses performed to evaluate HELB effects. Attachment 9 provides how ONS meets the regulatory requirements from the Giambusso/Schwencer letters with exclusions and deviations (references 1 and 2). Attachment 10 provides HELB definitions. Attachments 11 and 12 provide the time critical operator actions and feasibility assessment associated with the prescribed HELB mitigation strategies, respectively.

In accordance with Duke Energy administrative procedures that implement the Quality Assurance Program Topical Report, these proposed changes have been reviewed and approved by the On-Site Review Committee. A copy of this LAR is being sent to the State of South Carolina in accordance with 10 CFR 50.91 requirements.

Duke Energy requests approval of this amendment request by August 2021 with an implementation period in accordance with completion dates identified in Attachment 1. Note that Duke Energy plans to implement the revised HELB licensing basis in a staggered fashion on a per unit basis. The UFSAR changes will also be issued on a per unit basis. For the intent of this LAR and sake of review, the proposed changes are treated like all modifications have been completed for all three units. Inquiries on this proposed amendment request should be directed to Timothy D. Brown of the ONS Regulatory Projects Group at (864) 873-3952

I declare under penalty of perjury that the foregoing is true and correct. Executed on August 28, 2019.

Sincerely,

J Ed Burchfield Jr

J. Ed Burchfield, Jr.
Vice President
Oconee Nuclear Station

Enclosure: Evaluation of Proposed Changes

Attachment 1 Conforming Actions
Attachment 2 UFSAR Red-Marked Changes
Attachment 3 UFSAR Retyped Changes
Attachment 4 Thermal-Hydraulic Models for High Energy Line Break Transient Analysis [Proprietary]
Attachment 5 Thermal-Hydraulic Models for High Energy Line Break Transient Analysis [Non-Proprietary]

Attachment 6 Thermal-Hydraulic Transient Analysis for Evaluation of High Energy Line Breaks
Attachment 7 Duke Energy Affidavit
Attachment 8 Framatome Affidavit
Attachment 9 Regulatory Requirements
Attachment 10 Definitions
Attachment 11 Time Critical Operator Actions
Attachment 12 Feasibility Assessment for New Proposed Time Critical Operator Actions

cc w/enclosure and attachments:

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ENCLOSURE

EVALUATION OF PROPOSED CHANGES
LICENSE AMENDMENT REQUEST

Subject: Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Breaks Outside of the Containment Building.

1. SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, Duke Energy Carolinas, LLC (Duke Energy) proposes to amend Renewed Facility Operating License Numbers DPR-38, DPR-47, and DPR-55 to revise the Oconee Nuclear Station (ONS) current licensing basis (CLB) with regard to high energy line breaks (HELBs) outside of the containment building. The license amendment request (LAR) includes revisions to the Updated Final Safety Analysis Report (UFSAR) in support of the revised HELB licensing basis (LB).

The purpose of this LAR is to establish normal plant systems, protected service water (PSW), and/or the standby shutdown facility (SSF) as the assured mitigation path following a HELB. Nuclear Regulatory Commission (NRC) approval is requested for specific details of the new strategy discussed in section 2.4 and evaluated in section 3 including associated attachments.

The LAR also proposes to credit a number of plant modifications to enhance the station's capability to withstand the dynamic effects of a damaging HELB. Implementation of the proposed HELB LB and the related activities will clarify and, in some cases, revise the station's LB to collectively enhance the overall design and safety margin. Note that the modifications are being performed under 10 CFR 50.59 and their approval is not a part of this LAR even though they are discussed.

The analysis of the dynamic effects resulting from postulated piping breaks outside of the containment building was originally documented in Duke Energy mechanical design study (MDS) Report No. OS-73.2 (reference 3) and corresponding supplements (references 4 and 5). The existing HELB report (references 3, 4, and 5) will remain as the HELB LB pending the approval and implementation of this LAR.

This LAR and supporting attachments provide a re-evaluation of postulated HELBs and describes the 'as modified' station configuration for the identified HELBs. This LAR is an HELB LB reconstitution effort that reflects extensive analysis. The proposed changes, once approved by the NRC, will supersede the existing HELB LB documentation, MDS Report No. OS-73.2 (reference 3) and corresponding supplements (reference 4 and 5).

The current commitments for HELB can be found in the letter dated November 15, 2017 (reference 39). HELB commitment 24H addresses submittal of the subject LAR and is considered met with submittal of this LAR. Commitments 31H and 32H have been addressed by the HELB re-analysis and are considered met and closed. The remaining commitments specific to HELB are incorporated into this LAR as conforming actions within Attachment 1 to be completed and tracked accordingly.

This LAR will supersede, in its entirety, previous HELB documentation and responses to request for additional information (RAI). These were provided in letters to the NRC dated November 30, 2006 (reference 8), June 26, 2008 (reference 14), December 22, 2008 (reference 15), September 2, 2009 (HELB related RAI 10) (reference 33), June 29, 2009 (reference 16), October 23, 2009 (reference 26), June 24, 2010 (HELB related RAIs 2-37 and 2-38) (reference 27), August 31, 2010 (HELB related RAI 2-36) (reference 28), December 7, 2010 (reference 29), December 16, 2011 (reference 30), January 20, 2012 (reference 31), and March 1, 2012 (reference 32).

This enclosure provides a description and assessment of the proposed change. Attachment 1 contains the list of conforming actions to be implemented as a result of this LAR. Attachments 2 and 3 contain the UFSAR red marked changes and retypes, respectively. Attachments 4 and 5 describe the Thermal Hydraulic (T-H) models used to perform analysis of mitigated HELB scenarios in support of this LAR. Within Attachment 4, proprietary information is identified by brackets. In accordance with 10 CFR 2.390, Duke Energy requests that this information be withheld from public disclosure. Attachment 5 contains the non-proprietary (redacted) version of this content. Attachments 7 and 8 contain affidavits attesting to the proprietary nature of the information in Attachment 4. The proprietary information that is owned by Duke Energy and Framatome is annotated, respectively. The annotated information has substantial commercial value that provides a competitive advantage. Attachment 6 contains the T-H Transient Analyses performed to evaluate HELB effects. Attachment 9 provides how ONS meets the regulatory requirements from the Giambusso/Schwencer letters with exclusions and deviations (references 1 and 2). Attachment 10 provides HELB definitions. Attachments 11 and 12 provide the time critical operator actions and feasibility assessment associated with the prescribed HELB mitigation strategies, respectively. Note that references and acronyms provided in sections 6 and 7 of this enclosure are used throughout the attachments.

Each step of this HELB LB reconstitution process and the results have been documented in station calculations. These documents are controlled and owned by the station, and they form the basis of the information contained in this document. They will be posted to a designated sharepoint upon request to support NRC review and approval of this LAR.

2. DETAILED DESCRIPTION

2.1 System Design and Operation

2.1.1 Protected Service Water System

The PSW system is designed as a standby system for use under emergency conditions. The PSW system provides added “defense-in-depth” protection by serving as a backup to existing safety systems and as such, the system is not required to comply with single failure criteria. The PSW system is provided as an alternate means to achieve and maintain safe shutdown (SSD) conditions for one, two, or three units following postulated scenarios that damage essential systems and components normally used for SSD. The PSW System requires manual activation and can be activated if normal emergency systems are unavailable.

The function of the PSW System is to provide a diverse means to achieve and maintain SSD by providing secondary side decay heat removal (DHR), reactor coolant system (RCS) pump seal cooling, RCS primary inventory control, and RCS boration for reactivity management following plant scenarios that disable the 4160 volts alternating current (VAC) essential electrical power distribution system. The PSW System is not an Engineered Safety Feature Actuation System and is not credited to mitigate design basis events (DBEs) as analyzed in UFSAR Chapters 6 and 15. No credit is taken in the safety analyses for PSW system operation following DBEs.

The PSW pumping system utilizes the inventory of lake water contained in the Unit 2 Condenser Circulating Water (CCW) piping. The PSW primary and booster pumps are located in the auxiliary building (AB) at elevation 771’ and take suction from the Unit 2 CCW piping and discharge into the steam generators (SGs) of each unit via the emergency feedwater (EFW) system headers. The raw water is vaporized in the SGs, removing residual heat, and is dumped to atmosphere via the Main Steam Relief Valves (MSRVs) or Atmospheric Dump Valves (ADVs). For extended operation, the PSW portable pump with a flow path capable of taking suction from the intake canal and discharging into the Unit 2 CCW piping is designed to provide a backup supply of water to the PSW system in the event of loss of CCW and subsequent loss of CCW siphon flow. The PSW portable pump is stored onsite.

The PSW system is designed to support cool down of the RCS and maintain SSD conditions. The PSW system is designed to promote natural circulation DHR using the SGs for an extended period of time during which time other plant systems required to cool the RCS to Mode 5 conditions will be restored and brought into service. In addition, the PSW system, in combination with the high pressure injection (HPI) system, provides borated water for reactor coolant pump (RCP) seal cooling, RCS makeup, and reactivity management.

The mechanical portion of the PSW system provides DHR by feeding Lake Keowee water to the secondary side of the SGs. In addition, the PSW pumping system supplies Keowee lake water to the HPI pump motor coolers. The PSW pumping system consists of a booster pump, a primary pump, and a portable pump.

The PSW primary and booster pumps, motor operated valves, and solenoid valves required to bring the system into service, are controlled from the main control rooms (CRs). Check valves and manual handwheel operated valves are used to prevent back-flow, accommodate testing, or are used for system isolation.

The PSW electrical system is designed to provide power to PSW mechanical and electrical components as well as other system components (i.e., RCS vent valves, select groups of pressurizer heaters, one HPI pump, etc.) needed to establish and maintain an SSD condition. Normal power is provided by a transformer connected to a 100 kilovolt (kV) overhead transmission line that receives power from the Central Tie Switchyard located approximately eight (8) miles from the plant. Standby power is provided from the Keowee Hydroelectric Station via an underground path. The Keowee Hydro Unit (KHU) aligned to the overhead emergency power path can automatically provide power to Keowee Hydroelectric Station in-house loads.

These external power sources provide power to transformers, switchgear, breakers, load centers (LCs), batteries, and battery chargers located in the PSW electrical equipment structure. There are two (2) batteries inside the PSW building. Either battery is sized to supply PSW direct current (DC) loads. The battery banks are located in different rooms separated by fire rated walls. A separate room within the PSW building is provided for major PSW electrical equipment.

PSW building heating, ventilation, and air conditioning (HVAC) is designed to maintain transformer and battery rooms within their design temperature range. The HVAC system consists of two (2) systems; a non-QA-1/non-credited system designed to maintain the PSW transformer and battery rooms environmental profile and a QA-1/credited system designed to actuate whenever the non-QA-1 system is not able to meet its design function.

2.1.2 Standby Shutdown Facility

The SSF is designed as a standby system for use under certain emergency conditions. The system provides additional “defense-in-depth” protection for the health and safety of the public by serving as a backup to existing safety systems. It provides an alternate means to achieve and maintain the unit(s) in Mode 3 with average RCS temperature ≥ 525°F (unless the initiating event causes the unit(s) to be driven to a lower temperature) following a fire, turbine building (TB) flood, and station blackout (SBO) events. The SSF is designed for the criteria associated with these events. The SSF Auxiliary Service Water (ASW) system is credited as a backup to EFW to address EFW system equipment vulnerabilities associated with single failures, tornado missiles, and seismic design. The SSF may also be activated as necessary in response to events associated with plant security. The single failure criterion is not required. Failures in the SSF system will not cause failures or inadvertent operations in other plant systems. The SSF requires manual activation and can be activated if emergency systems are not available.

The SSF is designed to maintain the reactor(s) in an SSD condition for a period of 72 hours following a fire or TB flood, and for a period of 4 hours following an SBO. The capability of the SSF to maintain the reactor(s) in an SSD condition is also credited for certain security related events. The design criteria associated with each of these events is described in UFSAR Section 9.6.2. The main components of the SSF are the SSF ASW system, SSF Portable Pumping system, SSF Reactor Coolant Makeup (RCMU) system, SSF Power system, and SSF instrumentation.

The SSF ASW system is a high head, high volume system designed to provide sufficient SG inventory for adequate DHR for three units during a loss of normal alternating current power in conjunction with the loss of the Main Feedwater (MFDW) and EFW systems. One motor driven SSF ASW pump, located in the SSF, serves all three units. The SSF ASW pump utilizes a suction supply of lake water from the embedded Unit 2 CCW piping.

The SSF ASW system is used to provide adequate cooling to maintain single phase RCS natural circulation flow in Mode 3 with an average RCS temperature ≥ 525°F (unless the initiating event causes the unit(s) to be driven to a lower temperature). In order to maintain single phase RCS natural circulation flow, an adequate number of Bank 2, Group B and C pressurizer heaters are needed to compensate for ambient heat loss from the pressurizer. As long as the temperature in the pressurizer is maintained, RCS pressure will also be maintained. This will preclude hot leg voiding and ensure adequate natural circulation cooling.

Portions of the SSF ASW system are credited to meet the Extensive Damage Mitigation Strategies commitments per Nuclear Energy Institute (NEI) 06-12 (B.5.b) and the SSF is fully credited to meet the Extensive Damage Mitigation Strategies commitments per NEI 12-06 (FLEX).

The SSF Portable Pumping system, which includes a submersible pump and a flow path capable of taking suction from the intake canal and discharging into the Unit 2 CCW line, is designed to provide a backup supply of water to the SSF in the event of loss of CCW and subsequent loss of CCW siphon flow. The SSF Portable Pumping system is installed manually in accordance with procedures.

The SSF RCMU system is designed to supply makeup to the RCS and RCP seal cooling in the event that normal makeup systems are unavailable. An SSF RCMU pump located in the reactor building (RB) of each unit supplies makeup to the RCS should the normal makeup system flow and seal cooling become unavailable. The system is designed to ensure that sufficient borated water is provided from the spent fuel pool (SFP) to allow the SSF to maintain all three units in Mode 3 with average RCS temperature ≥ 525°F (unless the initiating event causes the unit(s) to be driven to a lower temperature) for up to 72 hours. An SSF RCMU pump is capable of delivering borated water from the SFP to the RCP seal injection lines. A portion of this seal injection flow is used to makeup for RCP seal leakage while the remainder flows into the RCS to makeup for other normal RCS leakage.

When normal and emergency systems are not available, RCS inventory and reactor shutdown margin are maintained from the SSF CR by the SSF RCMU pump taking suction from the SFP. Primary system pressure can be maintained by the pressurizer heaters or by use of charging combined with letdown. The SSF reactor coolant (RC) letdown is also used to maintain the desired level in the pressurizer if the seal injection flow exceeds the RCP seal leakage plus other RCS leakage once adequate makeup flow has been provided for allowable RCS volume shrinkage.

The SSF Power system includes 4160 VAC, 600 VAC, 208 VAC, 120 VAC and 125 volts direct current (VDC) power. It consists of switchgear, a LC, motor control centers (MCCs), panelboards, remote starters, batteries, battery chargers, inverters, a diesel generator (DG), relays, control devices, and interconnecting cable supplying the appropriate loads. The SSF Power system provides electrical isolation of SSF equipment from non-SSF equipment. The SSF 125 VDC Power system provides a reliable source of power for DC loads needed to black start the DG. The DC power system consists of two 125 VDC batteries and associated chargers, two 125 VDC distribution centers (DCSF, DCSF-1), and a DC power panelboard (DCSF). The SSF Power system is provided with standby power from a dedicated DG. The SSF DG and support systems consist of the DG, fuel oil transfer system, air start system, diesel engine service water system, as well as associated controls and instrumentation. This SSF DG is rated for continuous operation at 3500 kilowatt, 0.8 power factor, and 4160 VAC. The SSF electrical design load does not exceed the continuous rating of the DG. The auxiliaries required to assure proper operation of the SSF DG are supplied entirely from the SSF Power system. The SSF DG is provided with manual start capability from the SSF only. It uses a compressed air starting system with four air storage tanks. An independent fuel system, complete with a separate underground storage tank, duplex filter arrangement, a fuel oil transfer pump, and a day tank, is supplied for the DG.

The SSF air conditioning, which includes the HVAC service water system and air conditioning equipment (fan motors, compressors, condensers, and coils), must be operable to support the SSF power system operability.

2.1.3 Normal Plant Systems

Normal plant systems and related support systems may remain available for HELB mitigation. These systems can be used for plant cooldown and the establishment of cold shutdown (CSD). For conciseness, only the HPI and EFW systems are discussed below based on their significance to the safety analysis performed for HELB mitigation scenarios.

2.1.3.1 High Pressure Injection

The HPI system consists of two independent trains, each of which splits to discharge into two RCS cold legs, so that there is a total of four HPI injection lines. Each train takes suction from the borated water storage tank (BWST) and has an automatic suction valve and discharge valve which open upon receipt of an Engineered Safeguards (ES) Protective System (ESPS) signal. The two HPI trains are designed and aligned such that they are not both susceptible to any single active failure (SAF) including the failure of any power operating component to operate or any single failure of electrical equipment.

There are three ESPS actuated HPI pumps; the discharge flow paths for two of the pumps are normally aligned to automatically support HPI train “A” and the discharge flow path for the third pump is normally aligned to automatically support HPI train “B”. The discharge flow paths can be manually aligned such that each of the HPI pumps can provide flow to either train. At least one pump is normally running to provide RCS makeup and seal injection to the RCPs. Suction header cross-connect valves are normally open, cross-connecting the HPI suction headers during normal operation. The discharge crossover valves (HP-409 and HP-410) are normally closed; these valves can be used to bypass the normal discharge valves and assure the ability to feed either train’s injection lines via HPI pump “B”. For each discharge valve and discharge crossover valve, a safety grade flow indication is provided to enable the operator to throttle flow to assure that runout limits are not exceeded.

A suction header supplies water from the BWST to the HPI pumps. HPI discharges into each of the four RCS cold legs between the RCP and the reactor vessel (RV). There is one flow limiting orifice in each of the four injection headers that connect to the RCS cold legs. If a pipe break were to occur in an HPI line between the last check valve and the RCS, the orifice in the broken line would limit HPI flow lost through the break and maximize the flow supplied to the RV via the other line supplied by the HPI header. The HPI pumps are capable of discharging to the RCS at an RCS pressure above the operating setpoint of the pressurizer safety valves (PSVs). The HPI system also functions to supply borated water to the reactor core following increased heat removal events, such as main steam line breaks (MSLBs).

2.1.3.2 Emergency Feedwater

The EFW System automatically supplies feedwater (FDW) to the SGs to remove decay heat from the RCS upon the loss of normal FDW supply. The EFW pumps take suction through suction lines from the upper surge tank (UST) and condenser hotwell and pump to the SG secondary side through the EFW nozzles. The SGs function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the SGs via the MSRVs or ADVs. If the main condenser is available, steam may be released via the turbine bypass system and recirculated to the condenser hotwell.

The EFW System consists of two motor-driven EFW pumps and one turbine-driven EFW pump, any one of which can provide the required heat removal capability. Thus, the requirements for diversity in motive power sources for the EFW System are met. The steam turbine driven EFW pump receives steam from either of the two main steam (MS) headers, upstream of the main turbine stop valves, or from the auxiliary steam system which can be supplied from the other two unit's MS system. The EFW System supplies a common header capable of feeding either or both SGs. The EFW System normally receives a supply of water from the UST. The EFW system can also be aligned to the condenser hotwell.

The EFW System is capable of supplying FDW to the SGs during normal unit startup, shutdown, and hot standby conditions. The discharge header of each EFW system can be cross-connected making each system capable of supplying any unit.

The three EFW pumps are started automatically upon a loss of both MFDW pumps or a signal from the anticipated transient without scram mitigation system actuation circuitry. The two motor driven EFW pumps are also started automatically upon a low SG level that exists for at least 30 seconds.

2.2 Current Technical Specifications Requirements

There are no technical specification (TS) requirements for HELB.

2.3 Reason for the Proposed Change

In December 1972, the Atomic Energy Commission (AEC) sent to Duke Power Company a request for information (references 1 and 2) concerning postulated piping breaks on high energy (HE) lines outside of the containment building at ONS. It was issued by A. Giambusso, the Deputy Director for Reactor Projects Directorate of Licensing, and is referred to as the "Giambusso Letter" (reference 1) throughout this LAR. The "Giambusso Letter" was amended by an errata sheet provided in a letter from A. Schwencer (AEC), Chief Pressurized Water Reactors Branch No. 4 Directorate of Licensing in January 1973 (reference 2). In response to the "Giambusso Letter", a summary of the analysis of the HE line configuration was provided to the AEC. This analysis was documented in MDS Report No. OS-73.2 (reference 3) and supplements 1 and 2 (references 4 and 5). The 1973 document included the HELB criteria, station design methodologies, and protection requirements for mitigating postulated HELBs outside of the containment building. Based upon the information provided in the 1973 document and the supplements, an ONS Unit 2 and 3 Safety Evaluation Report (SER) was received from the AEC on July 6, 1973, in which the AEC evaluated the assessment performed by Duke Power Company and concluded that ONS had been analyzed in a manner consistent with the intent of the criteria and guidelines provided by the AEC (reference 6).

The MDS report was incorporated into the ONS license application by reference. SER Section 7.1.11 "High-energy Line Rupture External to the Reactor Building" addressed the MDS report, and Attachment E of the SER repeated the NRC HELB criteria, as amended by the Schwencer letter (reference 2). The basic criteria require that:

1. Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from all effects resulting from ruptures in pipes carrying high-energy fluid, up to and including a double-ended rupture of such pipes, where the temperature and pressure conditions of the fluid exceed 200°F and 275 psig. Breaks should be assumed to occur in those locations specified in the "pipe whip criteria." The rupture effects on equipment to be considered include pipe whip, structural (including the effects of jet impingement) and environmental.
2. Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from the environmental and structural effects (including the effects of jet impingement) resulting from a single open crack at the most adverse location in pipes carrying high-energy fluid routed in the vicinity of this equipment, where the temperature and pressure conditions of the fluid exceed 200°F and 275 psig. The size of the cracks should be assumed to be ½ the pipe diameter in length and ½ the wall thickness in width.

   <u>*Staff Evaluation and Conclusion*</u>
   The staff has evaluated the assessment performed by the applicant and has concluded that the applicant has analyzed the facilities in a manner consistent with the intent of the criteria and guidelines provided by the staff. The staff agrees with the applicant's selection of pipe failure locations and concludes that all required accident situations have been addressed appropriately by the applicant.

   Furthermore the staff has evaluated the analytical methods and assumptions used in the applicant's analyses and find them acceptable and concurs with the proposed plant modifications and the criteria to be used in their designs.

Many years after approval of the MDS report and initial licensing of ONS, the SSF was built. The SSF provides additional defense-in-depth protection to achieve and maintain Mode 3 with an average RCS temperature ≥ 525°F (unless the initiating event causes the unit(s) to be driven to a lower temperature) following postulated fire, sabotage, SBOs, or flooding events.

The SSF RCMU system is the SSF sub-system designed and credited to supply RCP seal injection flow in the event that the HPI, the normal makeup system, becomes unavailable when a Unit's RCS temperature is > 250°F during Modes 1, 2, and 3. It can recover RCS volume shrinkage caused by cooling the RCS to Mode 3 with an average RC temperature ≥ 525°F (unless the initiating event causes the unit(s) to be driven to a lower temperature). However, the SSF RCMU System is not credited for UFSAR Chapter 6 and 15 events, such as Loss of Coolant Accident (LOCA), which result in significant loss of RCS inventory. The SSF ASW system is the SSF sub-system credited as the backup to the FDW and EFW systems.

In 1998, Duke Energy performed an assessment (reference 7) that identified gaps in documentation with the original HELB analysis performed in 1973. As a result, Duke Energy initiated a project to update the original HELB work. This initiative was communicated to the NRC Region II management during a January 26, 1999 management meeting. The primary objective of this initiative was to revalidate and update the original HELB design basis for the present station configuration.

To further reduce plant risk and improve the quality of ONS LB documentation, Duke Energy initiated a risk reduction initiative in 2004. The goal of this initiative was to further clarify the LB and produce a set of design, program, and procedure changes that would reduce SSF vulnerability concerns. Duke Energy believed that this integrated approach was more beneficial than recommending changes that targeted individual design issues.

The risk reduction initiative report was completed in May 2005 and recommended a number of modifications to resolve old design issues that included HELB. The proposed modifications would result in a significant improvement in overall core damage frequency.

In light of the risk reduction team's recommendations and as a result of continued communications with the NRC regarding resolution of HELB outstanding issues, a combined tornado and HELB mitigation strategies letter was submitted on November 30, 2006 (reference 8). The submittal contained a number of regulatory commitments as well as responses to key issues identified by the NRC related to the HELB LB.

In 2007, there were additional communications between Duke Energy and the NRC regarding the mitigation strategies in the November 2006 submittal (reference 8). The result of this effort is documented in an NRC letter to Duke Energy dated March 28, 2007 (reference 9). Finally, as concluded in a May 15, 2007 NRC letter (reference 10) to Duke Energy,

> *"…as a result of the extensive dialogue that we have had concerning your proposed modifications and mitigation strategies, we believe that the future LARs based on this approach could be found acceptable."*

Duke Energy submitted follow-up letters (references 11 and 12) to refine and adjust implementation schedules of several of the commitments made in the November 30, 2006, letter (reference 8).

Supplemental letters dated September 2 (reference 33), October 23, 2009 (reference 26); June 10 (reference 40), June 24 (reference 27), August 31 (reference 28), and December 7, 2010 (reference 29) were provided to address requests for additional information (RAI). RAIs dated December 16, 2011 (reference 30); January 20 (reference 31), March 1 (reference 32), March 16 (reference 41), June 11 (reference 42), July 20 (reference 43), August 31 (reference 60), November 2, 2012 (reference 44); April 5 (reference 23), June 28 (reference 45), August 7 (reference 46), December 18, 2013 (reference 47); February 14 (reference 17), April 3 (reference 61), April 11 (reference 25), and July 24, 2014 (reference 24) were credited for PSW review and approval, but also had information regarding HELB.

During this timeframe, PSW was also being implemented and reviewed as part of the National Fire Protection Association 805 and HELB LB reconstitution work. Each LAR credited PSW for varying types of mitigation. The NRC realized that PSW required final approval before they could continue review of HELB. As a result, the NRC suspended their review of the HELB LARs and separated the PSW review from it as stated in the issuance of PSW License Amendments 386, 388, and 387 dated August 13, 2014 (reference 13).

This document is the result of the initiatives and history provided above. It provides the completed analysis for HELBs at ONS. Included in the document are the descriptions of the station modifications that have been made or will be made as a result of performing this comprehensive HELB analysis. It will be used as the HELB LB for ONS and will supersede the configuration and strategy provided in the 1973 ONS HELB Report, OS-73.2 (references 3, 4, and 5) and more recent HELB LARs submitted in 2008 and 2009 (references 14, 15, and 16) and later combined in 2011 (reference 30) along with supporting documentation.

2.4 Description of the Proposed Change

The purpose of this LAR is to establish normal plant systems, PSW, and/or SSF as the assured mitigation path following a HELB. Specifically, NRC approval is requested for:

1. Crediting the PSW system or SSF for HELB mitigation when a HELB results in the loss of plant systems needed for SSD inside the TB.
2. Crediting normal plant systems (i.e., HPI and EFW) or the SSF for HELB mitigation when a HELB results in the loss of plant systems needed for SSD inside the AB.
3. Crediting normal plant systems for HELB mitigation when a HELB occurs outside of the TB and AB.
4. UFSAR revisions that will incorporate the HELB strategy into the LB.
5. Time critical operator actions (TCAs) associated with the prescribed HELB mitigation strategies.
6. Exclusion of systems whose operating time at high energy (HE) conditions is less than 1% of the total unit operating time.
7. Exclusion of systems whose operating time at HE conditions is less than approximately 2% of the total system operating time.
8. Elimination of arbitrary intermediate breaks in ASME B & PV Section III-Class 2 and Class 3 equivalent piping. Intermediate breaks are postulated where calculated longitudinal stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.8(S_a + S_h)$.
9. Intermediate breaks in non-rigorously analyzed piping are postulated in accordance with Branch Technical Position (BTP) Mechanical Engineering Branch (MEB) 3-1, Section B.1.c(2)(b)(i).
10. Elimination of critical cracks at the most adverse location in ASME Boiler and Pressure Vessel (B&PV) Section III-Class 2 and Class 3 equivalent piping. Critical cracks are postulated at axial locations where the calculated stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.4(S_a + S_h)$. Critical cracks are not postulated at locations of terminal ends.
11. The effects of the postulated intermediate breaks bound the effects from critical cracks; therefore, critical cracks are eliminated from evaluation in non-rigorously analyzed piping.
12. Determination of the effective length of jets from a break or critical crack in accordance with NUREG/CR-2913.
13. Strategies to achieve and maintain CSD conditions.
14. Elimination of the TCA to cross-connect EFW.
15. Elimination of the TCA to manually start the turbine driven EFW pump locally.
16. RCS Acceptance criteria as specified in Attachment 6.

Implementation of the proposed HELB LB and the conforming actions will clarify and, in some cases, revise the station's CLB to collectively enhance the overall design and safety margin. The LAR describes plant modifications to enhance the station's capability to withstand effects of a HELB. These modifications, included in Attachment 1, are being performed under 10 CFR 50.59 and their approval for installation is not part of this LAR even though they are discussed.

2.5 UFSAR Changes

Duke Energy proposes to modify the UFSAR, as follows below, to describe the ONS HELB mitigation strategy and update other applicable sections to reflect normal plant systems, PSW, and/or the SSF as the HELB mitigation strategy. Duke Energy plans to implement the UFSAR on a per unit basis. When all modifications are complete on a unit, the proposed changes described below will be issued for that unit through normal station processes. For the intent of this LAR and sake of review, the proposed changes are treated like all modifications have been completed for all three units. The UFSAR marked-up and retyped pages are provided in Attachments 2 and 3, respectively.

Currently, the analysis of effects resulting from postulated piping breaks outside of the containment building is contained in Duke Energy's MDS Report No. OS-73.2 dated April 25, 1973 including revisions through supplement 2 (references 3 – 6) and incorporated by reference in UFSAR section 3.6.1.4. UFSAR Section 3.6.1.3 will be deleted and new section 3.6.2, Postulated Piping Failures in Fluid Systems Outside Containment, will be added to generally describe the revised HELB methodology and results. Section 3.6.2 will contain the following:

The purpose and methodology associated with evaluating HELBs outside of the containment building to include the following:

- Identification of HE lines.
- HELB location methodology.
- Identification of HELB types.
- Shutdown sequence evaluation criteria.
- Interaction evaluation criteria.
- Determination of SSD systems to include the following:
  - HELB mitigation strategy.
  - Shutdown objectives.
  - Functions to meet SSD objectives.

Also, section 3.6.1.4 will become section 3.6.3 and will reflect the HELB safety analysis performed in support of the LAR. References will be renumbered from 3.6.3 to 3.6.4. UFSAR Sections 5.1.2.4, Natural Circulation, 9.6, SSF and 9.7, PSW will be revised to reflect the HELB mitigation strategies. UFSAR Section 10.4.7.3.2, EFW Response Following a HELB, will be revised to reference the new HELB strategy.

3. TECHNICAL EVALUATION

3.1 Purpose and Methodology

The purpose of this LAR and the descriptions of the evaluations and analyses contained within are to document the HELB configuration for ONS and to provide a comprehensive, updated strategy for mitigating the potential adverse interactions caused by these postulated HELBs. Since this document provides a re-evaluation of the postulated HELBs in ONS and credits the as-modified ONS configuration for the identified HELBs, it supersedes the analysis provided in the original 1973 ONS HELB analysis (references 3, 4, and 5) and establishes a new basis for future HELB considerations. The original HELB report, OS-73.2 (references 3, 4, and 5) will still be used as a reference for definitions and historical information.

The analyses in this evaluation have been accomplished by using a systematic, step-by-step program of identification, evaluation, and documentation. The steps in the HELB program for ONS are as follows:

1. Identification of the HE systems, the HE lines, and the boundaries of the HE lines on each of those systems.
2. Identification of the postulated HELB locations and break types on each of the HE lines.
3. Determination of the equipment and systems in the ONS units, which could be utilized to mitigate the postulated HELBs.
4. Identification of the targets (structures, systems, or components (SSCs)) of each postulated HELB based upon the results of field inspections.
5. Determination of the shutdown equipment that is undamaged by the postulated HELB and can be used for the HELB mitigation and the shutdown of the station. This step is based upon the identification of the targets and the impact of the postulated HELBs on those targets.

6. Identification and recommendation of station physical and/or procedural changes to support the HELB mitigation strategy.

The details for the methodology have been documented in Attachment 9.

3.2 HELB Strategy

The revised HELB Mitigation Strategy addresses the level of protection provided to SSCs necessary to reach SSD from the direct effects (pipe whip and jet impingement) and indirect effects (environmental and flooding) of a given HELB outside of the containment building. The major points of the updated strategy are as follows:

- Required SSCs located in the TB are not impacted by HELBs postulated to occur in the AB or in the yard.
- Required SSCs located in the AB are not impacted by HELBs postulated to occur in the TB.
- SAFs are imposed for those components required for initial mitigation.
- SAFs are not imposed for those components required to initiate a cooldown of the plant.
- HELBs resulting in the loss of plant systems inside the TB needed for SSD are mitigated by the PSW system.
- Should the PSW system be unavailable, the SSF is credited as an alternate means of achieving and maintaining SSD following HELBs that disable plant systems inside the TB.
- HELBs resulting in the loss of plant systems inside the AB needed for SSD are mitigated by normal plant systems or the SSF.
- As applicable, NUREG/CR-2913 is used for the determination of jet impingement effects following breaks and critical cracks.
- Exclusion of systems whose operating time at HE conditions is less than 1% of the total unit operating time.
- Exclusion of systems whose operating time at HE conditions is less than approximately 2% of the total system operating time.
- Elimination of arbitrary intermediate breaks in ASME B & PV Section III-Class 2 and Class 3 equivalent piping. Intermediate breaks are postulated where calculated longitudinal stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.8(S_a + S_h)$.
- Intermediate breaks in non-rigorously analyzed piping are postulated in accordance with BTP MEB 3-1, Section B.1.c(2)(b)(i).
- Elimination of critical cracks at the most adverse location in ASME B&PV Section III-Class 2 and Class 3 equivalent piping. Critical cracks are postulated at axial locations where the calculated stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.4(S_a + S_h)$. Critical cracks are not postulated at locations of terminal ends.
- The effects of the postulated intermediate breaks bound the effects from critical cracks; therefore, critical cracks are eliminated from evaluation in non-rigorously analyzed piping.
- HELBs occurring outside of the TB and AB are mitigated by normal plant systems.
- Repairs are made to any system/components required for CSD.
- Elimination of the TCA to cross-connect EFW.
- Elimination of the TCA to manually start the turbine driven EFW pump locally.
- RCS Acceptance criteria as specified in Attachment 6.

3.3 Regulatory Requirements

The regulatory requirements for ONS are defined in the Implementation Section of the Standard Review Plan (SRP) 3.6.2, revision 1 (reference 18). Specific guidance is provided in Section B.4 of the BTP Auxiliary Systems Branch (ASB) 3-1, in which it is stated that for plants with operating licenses issued before July 1, 1975, the requirements of the Giambusso/Schwencer Letters (references 1 and 2) applied. The ONS Units were licensed to operate before the July 1, 1975 date, and the Unit 2 and 3 SER was issued on July 6, 1973 (reference 6). Hence the regulatory requirements for the ONS are contained within the Giambusso/Schwencer Letters (references 1 and 2).

The HELB requirements can be summarized as follows:

1. The reactor can be shut down and maintained in an SSD condition and subsequently cooled to the CSD condition in the event of a postulated rupture, outside of the containment building, of a pipe containing a HE fluid, including the double ended rupture of the largest pipe in the MS and FDW systems.
2. Plant SSCs required to safely shutdown the reactor and maintain it in an SSD condition should be protected or designed to withstand the effects of such a postulated pipe failure.

In addition to the Giambusso/Schwencer Letters (references 1 and 2), SRP 3.6.2 (reference 18) is used to provide guidance by supplementing and clarifying the requirements in the Giambusso/Schwencer letters. This includes adopting portions of Generic Letter (GL) 87-11 (reference 19). In that GL, those portions that eliminated the arbitrary intermediate breaks and critical cracks are used for establishing pipe break and critical crack locations on the seismically analyzed HE piping lines in the station. Specific mitigation strategies, regulatory commitments, and responses were provided to the NRC in the November 30, 2006 letter (reference 8) and the January 25, 2008 letter (reference 12) from Duke Energy, and the information in these letters form the basis for this document.

Attachment 9 provides the detailed information pertaining to how ONS meets the Giambusso/ Schwencer requirements (references 1 and 2).

3.4 Arbitrary Intermediate Breaks and Critical Cracks

There are two areas where BTP MEB 3-1 (reference 19) provides more clarity than given by the Giambusso/Schwencer letters: (1) Relaxation in Arbitrary Intermediate Pipe Rupture Requirements; and (2) Postulation of Critical Cracks. In general, these are the two subjects where a deviation to the Giambusso/Schwencer requirements are sought. These topics are addressed below.

3.4.1 Arbitrary Intermediate HELBs

Giambusso/Schwencer required for American Society of Mechanical Engineers (ASME) Code Class 2 and 3 equivalent piping that intermediate break locations should be postulated as follows:

1) *At 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 .8 x (S_H + S_A) or the expansion stresses exceed .8 S_A.*
2) *Intermediate locations in addition to those determined by (1) above, selected on a reasonable basis as necessary to provide protection. At a minimum, there should be two intermediate locations for each piping run or branch run.*

GL 87-11 allowed licensees to eliminate postulated arbitrary intermediate pipe breaks in Class 1 piping and Class 2 and 3 equivalent piping in areas of the plant outside the containment penetration areas without prior NRC approval insofar as the change did not conflict with the plant's license or the TSs. The GL implemented the relaxation by revising portions of the BTP MEB 3-1, "Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment" (reference 19).

ONS proposes to adopt this provision to use stress criteria to postulate intermediate break locations for Class 2 and 3 equivalent piping and eliminate arbitrary intermediate breaks. Intermediate break locations would be determined based on the calculated circumferential or longitudinal stresses derived on an elastically calculated basis using the loadings associated with seismic events and operational plant conditions that exceed 0.8 x (S_H + S_a). Intermediate break locations would not be postulated where the expansion stress exceeds 0.8 S_a. Thermal stresses are classified as secondary, and taken in absence of other stresses, do not cause ruptures in pipes. Actual stresses used for comparison to the break thresholds are calculated in accordance with the ONS piping code of record, USAS B31.1.0 (reference 48). Allowable stress values S_a and S_H shall be determined in accordance with the USAS B31.1.0 code or the USAS B31.7 code (reference 49). The scope of piping effected by this proposal is seismically analyzed lines within the TB and AB including the containment penetration rooms.

This approach was first communicated in a letter to the NRC dated July 3, 2002 (reference 52). This provision is similar to that given in the BTP MEB 3-1 Rev. 2 Section B.1.c (2) (reference 19). The approach to eliminate arbitrary intermediate breaks by the adoption of GL 87-11, and by reference BTP MEB 3-1 Revision 2 Section B.1.c (2) (reference 19) has been previously approved for portions of the low pressure injection (LPI) system at ONS as part of the Passive LPI Cross Connection Modifications (reference 50).

Although adoption of GL 87-11 implies a reduction in the number of break locations, the re-evaluation and inclusion of the proposed portions of BTP MEB 3-1 revision 2 in the ONS HELB design and LB results in an actual increase in the number of postulated HELB locations outside of the containment building when compared to the number postulated in the original HELB MDS OS-73.2 report. Each of these new locations require that ONS formulate a mitigation strategy. These actions enhance the ability of the plant to mitigate any break that could possibly occur. In doing this, the overall safety of the plant is improved.

As noted above, ONS plans to adopt the provisions of BTP MEB 3-1 regarding the elimination of arbitrary intermediate breaks for analyzed lines that include seismic loading. Adoption of this provision allows ONS to focus attention to those high stress areas that have a higher potential for catastrophic pipe failure. Breaks for analyzed lines that do not contain seismic loading and breaks for non-analyzed lines are postulated at every piping weld and fitting. The inclusion of this approach provides a comprehensive break scenario for which mitigation strategies are determined. These actions enhance the overall safety of the plant.

3.4.2 Determination of Jet Impingement Effects

NUREG/CR-2913 describes the method for determination of jet impingement effects following a HELB. However, Duke Energy requests NRC approval to use the NUREG for determination of the effects from breaks and critical cracks.

Giambusso/Schwencer does not provide any direction on the methodology to be used to determine potential impingement effects from critical cracks. The NUREG provides an analytical model for predicting two-phase, water jet loadings on axisymmetric targets. Input to the model includes the initial system pressure, temperature (or alternatively steam quality), diameter of the break opening, distance to the target, and radius from the centerline of the target. The model ranges in application from 60 bars (870 psi) to 170 bars (2465 psig) pressure and 70 degrees Centigrade (158 degrees Fahrenheit) subcooled liquid to 0.75 (or greater) steam quality.

Since no guidance for the determination of the zone of influence (ZOI) for critical cracks was promulgated in Giambusso/Schwencer and there is no description of the methodology used for the determination of the ZOI for critical cracks in the original HELB report MDS OS-73.2, the use of the NUREG in the manner described represents a change to the ONS LB for HELB. In absence of definitive studies of the ZOI for critical cracks, the NUREG provides a reasonable methodology that can be adapted for critical cracks.

The MS and MFDW systems are the only two HE systems which had calculated stresses that exceeded the crack threshold, and thus are the only two systems in which critical cracks are postulated. For the MS system the locations where the stresses exceeded the crack threshold are limited to the TB of all three units. For the MFDW system the locations where the stresses exceeded the crack threshold are in both the TB and the EPR of the AB of all three units. The operating pressure and temperatures for the MS and MFDW systems fall within the pressure and temperature ranges described in the NUREG/CR-2913.

3.4.3 Postulation of Critical Cracks

Giambusso/Schwencer defines critical cracks as ½ the pipe diameter in length and ½ the wall thickness in width. Giambusso/Schwencer notes that the critical crack needs to be postulated at the 'most adverse location'. ONS seeks to modify this requirement by incorporating the stress criteria from MEB BTP 3-1 1.e(2) for postulation of leakage cracks for piping that is seismically analyzed (i.e., stress analysis information is available, and the analysis includes seismic loading). Critical cracks would be postulated in Class 2 and Class 3 equivalent piping at axial locations where the calculated stress for the applicable load cases exceed $0.4(S_a + S_h)$. Applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (defined as Operational Basis Earthquake (OBE)). Critical cracks are not postulated at locations of terminal ends. For non-seismically analyzed piping, critical cracks are not postulated, since breaks are postulated at each weld location, which would bound the effect from a critical crack.

3.5 Excluded Systems

ONS has excluded some systems from HELB consideration due to the short time these systems operate at HE conditions. No HELB protection is provided if the operating time of a system at HE conditions is less than 1% of the total unit operating time (e.g. EFW, RB spray). For systems meeting this limitation, no breaks or cracks are postulated. This is justified based on the very low probability of a HELB occurring during the limited operating time of these systems at HE conditions.

In addition, ONS has excluded some systems from HELB consideration if the operating time of a system at HE conditions is less than approximately 2% of the total system operating time (e.g. LPI). This is justified based on the very low probability of a HELB occurring during the limited operating time of these systems at HE conditions.

The 1% or 2% criterion is not contained in Giambusso/Schwencer or the SRP. The proposal to exclude consideration of breaks in HE systems or subsystems that operate for short periods of time at HE conditions is based on the probability of a pipe break actually occurring during this short operational period and precedent established in other licensee submittals. This issue was previously discussed in the March 5, 2007 meeting between Duke Energy and the NRC and a common understanding reached (reference 9: Matrix item H3) (ADAMS Accession Nos. ML070670206 and ML070670203).

An example in this regard is located in a SER dated January 4, 1991 (section 4.2.2 of this enclosure) for Tennessee Valley Authority's Watts Bar Nuclear Plant. The NRC reviewed and approved Appendix 3.6A Definition 6 which notes in part:

> *"Systems may be classified as moderate energy if the total time that the above conditions are exceeded is less than either of the following:*
>
> *a. One percent of the normal operating life span of the plant*
> *b. Two percent of the time period required for the system to accomplish its design function."*

In addition, gas systems (e.g. Nitrogen) and oil systems (e.g. Electrohydraulic Control) have been excluded, since these systems possess limited energy (reference 51).

3.6 Operations Response, Training and Procedures

All of the postulated HELBs outside of the containment building are described in calculation entitled, "Analysis of Postulated HELBs Outside of Containment."

HELB mitigation is dependent on the location and magnitude of the HELB as well as its interactions with SSD equipment. The consequences of the HELB interactions were reviewed to determine if one HELB could be found that was bounding with respect to operator actions, necessary repairs, manpower requirements and the associated time limits for performing these actions. It was found that HELBs occurring inside the TB have the potential to create the most bounding scenario involving required operator actions, manpower requirements and damage repairs.

The expected actions are described in the discussion below and are based on approval of the revised HELB mitigation strategy, subsequent completion of committed modifications, and revisions to the mitigation and recovery procedures.

3.6.1 Overheating Scenarios

3.6.1.1 FDW HELBs in the TB

FDW HELBs that can cause a loss of AC power to all three units coupled with failures to CCW piping resulting in TB flooding will create the bounding overheating scenario for activities necessary to place the units in Mode 5. Such HELBs result in a loss of MFDW and EFW on all three units. No un-isolable breaks occur in either of the MS lines for these HELBs. The plant transient and acceptance criteria are described in section 3.7 of this enclosure and Attachment 6.

Mitigation of these postulated HELBs is divided into four distinct phases. Phase 1 is reactor shutdown and the stabilization of the affected unit(s) in Mode 3 with RC average temperature ≥ 525°F. Phase 2 is the plant cooldown from Mode 3 to Mode 4 (< 250°F). Phase 3 is the assessment and repair of SSCs required to transition the unit from Mode 4 (< 250°F) to Mode 5 (< 200°F). Phase 4 is the plant cooldown to Mode 5 (< 200°F).

Phase 1: Reactor Shutdown

The postulated MFDW HELB leads to an overheating condition for the RCS. The reactor protective system (RPS) will trip the reactor on the loss of MFDW pumps or on high RCS pressure. The pressurizer code safety valves are credited to relieve pressure to maintain RCS pressure below the acceptance limits. The MSRVs are the only credited means of steam release for DHR during this phase.

Operator actions are needed to restore secondary side DHR and RCP seal cooling to establish a SSD Condition. The SSF and the PSW systems would remain available to establish and maintain SSD for these MFDW HELBs. Emergency procedures direct the operators to initiate both pathways in parallel. The actions taken by the operators have been segregated by the different pathways in which SSD would be achieved and maintained.

Pathway 1: SSD Using PSW Systems

1. The offsite or onsite power source is aligned to the PSW electrical system.
2. The PSW pumps are started and aligned to the affected unit.
3. PSW power is aligned to the ‘A’ train of HPI and the RCS vent valves.
4. PSW is established to the SGs. This is a new TCA that must be completed within 14 minutes.
5. A PSW powered HPI pump is started and aligned to provide RCP seal cooling. This is an existing TCA that must be completed within 20 minutes.
6. RCS vent valves are opened to establish RCS letdown as required to maintain pressurizer level.
7. RCS boundary valves are closed to isolate potential diversion flow paths (e.g., RCP seal return and normal RCS letdown). These are existing TCAs that must be completed within 15 minutes for RCP seal return isolation and 20 minutes for RCS letdown.
8. PSW power is locally aligned to selected pressurizer heaters and the pressurizer heaters are cycled as required to control RCS pressure.
9. Local actions are taken to prevent flooding of the HPI pump room due to boiloff from the SFP. This is an existing TCA that must be completed between 4 hours and 6 hours depending upon the amount of decay heat present in the SFP.
10. Control complex and AB cooling is locally restored via the PSW powered alternate chilled water (AWC) system. This is an existing TCA that must be completed between 12 hours and 72 hours depending upon the area(s) requiring cooling.
11. RBC is locally restored via a diesel powered Alternate RBC pump and a PSW powered RBC unit. This is an existing TCA that must be completed within 30 hours.
12. The unit is placed in Mode 4 within 36 hours. This is an existing TCA.

Pathway 2: SSD Using SSF Systems

1. Operators are dispatched to the SSF upon recognition of the loss of RCP seal cooling.
2. A breaker transfer is performed at the SSF 600 VAC MCCs to transfer control of selected RCS boundary isolation valves, selected pressurizer heaters and selected RCS instrumentation from the main CR to the SSF.
3. The SSF DG is emergency started and aligned to the SSF electrical system, and the SSF ASW pump is started.
4. The SSF RCMU pump is started to restore RCP seal cooling. This is an existing TCA that must be completed within 20 minutes.
5. RCS boundary valves are closed to isolate potential diversion flow paths (e.g., normal RCS letdown and RCP seal return). These are existing TCAs that must be completed within 15 minutes for RCP seal return isolation and 20 minutes for other RCS isolations.
6. SSF ASW is established to the SGs. This is an existing TCA that must be completed within 14 minutes.
7. Sufficient SSF ASW flow is provided to the SGs to reduce and maintain RCS pressure ≤ 2250 psig. This is an existing TCA that must be completed within 20 minutes.
8. SSF powered pressurizer heaters are energized. This is an existing TCA that must be completed within 20 minutes. Once the pressurizer is saturated, the heaters are cycled as required to control RCS pressure.
9. RCS letdown to the SFP is established to control pressurizer level.

While the operators are placing the affected unit(s) in Mode 3 with an RC temperature of ≥ 525°F, the Operations Shift Manager initiates the Emergency Plan and activates the Technical Support Center and the Operations Support Center. Emergency Preparedness implementing procedures provide guidance to augment staff resources and initiate site damage assessment/repair procedures.

Operators will terminate the TB flooding by tripping all four CCW pumps on all three units within 45 minutes. This action reduces the rate of TB flooding to a flow rate that can be accommodated by the TB drain. This is a new TCA that will be added to the TB HELB mitigation procedure.

Operators monitor the water temperature and water level in the SFP due to the loss of spent fuel cooling as directed by existing emergency procedures. Refill of the SFP is performed using existing site damage repair procedures.

A SSD condition can be maintained from either the Main CR using the PSW and HPI Systems or from the SSF CR using the SSF ASW and SSF RCMU Systems. There are no required repairs from these postulated HELBs to achieve SSD using either the PSW or SSF systems. However, if makeup to the CCW piping from the CCW intake or discharge via gravity induced flow is not available, a portable pump would need to be installed at the CCW intake to provide replenishment of the water being used by the PSW or SSF systems. Electrical power can be supplied from either the PSW electrical system or the SSF electrical system. Placement of the portable pump in operation must be completed within 3 hours and 20 minutes of a loss of forced and gravity CCW system flow. This is an existing TCA.

Phase 2: Plant Cooldown to Mode 4 (< 250°F)

Plant cooldown requires one PSW powered HPI pump to provide sufficient makeup capability. PSW is used to feed the SGs during the plant cooldown. A natural circulation cooldown would be required.

If the unit is being maintained in a SSD condition from the SSF, the RCS inventory control, RCP seal cooling and SG feed functions are transferred from the SSF to the PSW system prior to initiating a cooldown.

Plant Cooldown Sequence to Mode 4:

1. The RV head vents are opened and the RCS loop high point vents are cycled as necessary.
2. The manually operated ADVs are throttled open to establish a cooldown to Mode 4 (< 250°F).
3. PSW flow to the SGs is throttled as required to control SG levels.
4. The ‘A’ train HPI header discharge valve is throttled open as required to control pressurizer level.
5. The pressurizer power operated relief valve (PORV) is cycled as required to decrease RCS pressure while maintaining RCS subcooling margin during plant cooldown.
6. When RCS pressure is approximately 700 psig, the core flood tank isolation valves are remotely closed from the portable valve control panel. The actions taken to restore power to the CFT isolation valves is contained in the site damage repair procedures.
7. RCS pressure is stabilized at approximately 300 psig by cycling the pressurizer heaters with RCS temperature maintained < 250°F.
8. The RV head vent valves and RCS loop high point vents are closed, and the operating HPI pump is secured as RCP seal cooling is no longer required.

In this configuration long term subcooled natural circulation DHR conditions are maintained with RC pressure being controlled by the cycling of the pressurizer heaters and RC temperature being maintained < 250˚F by natural circulation.

Phase 3: Damage Assessment and Repairs Required to Achieve Mode 5 (< 200°F)

HELB damage assessment is initiated to assess, and repair systems needed to allow plant cooldown from Mode 4 (< 250°F) to Mode 5 (< 200°F). Although the assessment may begin in Phase 1, the systems needed to achieve CSD are not required to be repaired prior to initiating a cooldown of the RCS from Mode 4 to Mode 5. The scope of the assessment determines the availability of the CCW system, the LPSW system, the LPI system, and the associated electrical power to these systems.

The postulated loss of AC power to all three units would require restoring power to one CCW pump motor, two LPSW pump motors (one shared by Units 1 and 2, and one for Unit 3), three LPI pump motors (one for each unit), and the decay heat drop line isolation valves for each unit. The actions taken to restore power to the pump motors and valves needed for CSD are contained in the site damage repair procedures. The necessary electrical equipment has been identified in these procedures and is available to enable the restoration of power to these motors. Power to the pump motors is provided by 4160 VAC breakers mounted on a portable trailer. Power to the 4160 VAC breaker trailer is provided by a KHU via the CT4 transformer. In addition, two LPSW pump motors would need to be replaced due to the effects of TB Flooding. There are two spare LPSW pump motors that can be installed using existing station procedures. The manpower requirements to execute the repairs have been defined in the procedures.

Phase 4: Plant Cooldown to Mode 5 (< 200°F)

Following assessment and repair, the following sequence is used to achieve Mode 5:

1. The CCW system, LPSW systems and LPI systems are locally aligned for operation.
2. One CCW pump is locally started at the 4160 VAC breaker trailer to supply suction to the LPSW pumps.
3. The two LPSW pumps are locally started at the 4160 VAC breaker trailer to provide cooling water to the Unit 1, Unit 2, and Unit 3 LPI coolers.
4. The decay heat drop line valves are remotely opened from the portable valve control panel. The actions taken to restore power to the drop line valves is contained in the site damage repair procedures.
5. One LPI pump is locally started at the 4160 VAC breaker trailer for each unit.
6. LPSW flow is locally throttled to the LPI coolers to establish the desired cooldown rate.

The guidance to cooldown the plant to Mode 5 is contained in site operating procedures.

3.6.1.2 FDW HELB in the EPR

The postulated FDW HELB occurs downstream of the check valve in the EPR of the AB. The station electrical system is not affected by the HELB, and normal plant equipment is used for mitigation. The RPS will trip the reactor on high RCS pressure. The affected SG will completely depressurize following reactor trip resulting in an automatic feedwater isolation system (AFIS) actuation which trips the MFDW pumps and isolates main and emergency FDW to the affected SG. The motor driven EFW pump aligned to the intact SG will auto start on the loss of both MFDW pumps. The transient evolves rapidly to an overheating scenario with one motor driven EFW pump supplying the unaffected SG and all 4 RCPs operating. The bounding scenario assumes that the pressurizer PORV is unavailable to provide RCS pressure control.

The plant transient and acceptance criteria are described in section 3.7 of this enclosure and Attachment 6.

The guidance to place the affected unit in a SSD condition following a FDW HELB in the EPR is contained in existing emergency procedures. However, the procedures will need to be revised to utilize the RCS high point vent valves, e.g.:

1. Proper actuation of AFIS is verified.
2. Proper operation of the EFW system is verified.
3. One RCP per SG is secured to limit heat input into the RCS. This is an existing procedural action, but is now a new TCA that must be completed within 15 minutes.
4. One set of RCS high point vent valves is cycled as required to maintain an alternate RCS letdown flow path. This is a new procedural action and a new TCA that must be completed within 30 minutes.

Once the affected unit has restored a steam bubble in the pressurizer and RC letdown has been restored, the RCS high point vent valves are closed, and the unit is cooled down to Mode 5 using normal plant systems and procedures.

FDW will collect on the floor of the EPR and when the level exceeds the top of the curb around the flood outlet device, the water will flow out of the AB to the west yard.

If a SAF prevents the HPI system from providing RCP seal cooling, the SSF RCMU system is used to provide RCP seal cooling and RCS inventory control. If a SAF prevents the EFW system from supplying the unaffected SG, HPI forced cooling (e.g., HPI feed and bleed) is utilized to provide core cooling until SSF ASW feed is established to the unaffected SG. If a SAF results in a failure of the control complex (CR, cable spreading room (CSR), equipment room) cooling, the affected unit is maintained in an SSD condition using the SSF RCMU system and the SSF ASW system.

3.6.2 Overcooling Scenarios

The bounding scenario is a double MS HELB in the TB resulting in a loss of all AC power and reactor trip (Note: If scenario does not result in a loss of all AC power, the RPS will trip the reactor on a low or variable low RCS pressure). The postulated double MS HELB leads to an overcooling condition for the RCS. The affected unit is stabilized in Mode 3 with RC temperature of approximately 325°F - 350°F.

Mitigation of these postulated overcooling HELBs is also divided into the same four distinct phases as described in section 3.6.1. However, the sequence and timing of certain actions differs due to overcooling and shrinkage of the RCS.

The plant transient and acceptance criteria are described in section 3.7 of this enclosure and Attachment 6.

Phase 1: Reactor Shutdown

Operator actions are needed to restore secondary side DHR and RCP seal cooling to establish a SSD Condition. The SSF and the PSW systems would remain available to establish and maintain SSD for these double MS HELBs. Emergency procedures direct the operators to initiate both pathways in parallel. The actions taken by the operators have been segregated by the different pathways in which SSD would be achieved and maintained. Note that the scenario progression times are approximate based on the analyses described in section 3.7 of this enclosure.

Pathway 1: SSD Using PSW Systems

1. The offsite or onsite power source is aligned to the PSW electrical system.
2. The PSW pumps are started and aligned to the affected unit.
3. PSW power is aligned to the ‘A’ train of HPI and the RCS vent valves.

4. A PSW powered HPI pump is started and aligned to provide RCP seal cooling. This is an existing TCA that must be completed within 20 minutes
5. Flow is established in the ‘A’ train HPI header to refill the RCS, restore SCM and recover pressurizer level to ≥ 100 inches. This occurs approximately 28 minutes following start of the HPI pump.
6. RCS boundary valves are closed to isolate potential diversion flow paths (e.g., normal RCS letdown and RCP seal return). These are existing TCAs that must be completed within 15 minutes for RCP seal return isolation and 20 minutes for RCS letdown.
7. PSW power is locally aligned to selected pressurizer heaters and the pressurizer heaters are energized as required to establish and maintain RCS pressure at approximately 700 psig. It may take approximately 8 hours to establish saturated conditions in the pressurizer and increase RCS pressure to 700 psig.
8. RCS vent valves are opened to establish RCS letdown as required to control pressurizer level.
9. Once the overcooling has been terminated and the RCS has refilled, PSW is established to the SGs to control RCS temperature at approximately 350°F. This activity may not be initiated until approximately 2 hours into the scenario.
10. Local actions are taken to prevent flooding of the HPI pump room due to boiloff from the SFP. This is an existing TCA that must be completed between 4 hours and 6 hours depending upon the amount of decay heat present in the SFP.
11. Control complex and AB cooling is locally restored via the PSW powered AWC system. This is an existing TCA that must be completed between 12 hours and 72 hours depending upon the area(s) requiring cooling.
12. RBC is locally restored via the PSW powered Alternate RBC system. This is an existing TCA that must be completed within 30 hours.
13. The unit is placed in Mode 4 within 36 hours. This is an existing TCA.

Pathway 2: SSD Using SSF Systems

1. Operators are dispatched to the SSF upon recognition of the loss of RCP seal cooling.
2. A breaker transfer is performed at the SSF 600 VAC MCCs to transfer control of selected RCS boundary isolation valves, selected pressurizer heaters and selected RCS instrumentation from the main CR to the SSF.
3. The SSF DG is emergency started and aligned to the SSF electrical system, and the SSF ASW pump is started.
4. The SSF RCMU pump is started to restore RCP seal cooling. This is an existing TCA that must be completed within 20 minutes.
5. RCS boundary valves are closed to isolate potential diversion flow paths (e.g., normal RCS letdown and RCP seal return). These are existing TCAs that must be completed within 15 minutes for RCP seal return isolation and 20 minutes for other RCS isolations.
6. The SSF pressurizer heaters are energized to establish and maintain a ≥ 100°F subcooling margin. It may take approximately 3.5 hours for saturated conditions to be established in the pressurizer and approximately 5 hours for 100°F subcooling margin to be established.
7. Once the overcooling has been terminated and the RCS has refilled, SSF ASW is established to the SGs at a rate necessary to maintain a stable pressurizer level. This activity may not be initiated until approximately 2 hours into the scenario.
8. Once ASW flow has been throttled to maintain an RCS temperature of approximately 300°F, pressurizer level will continue to increase due to RCP seal injection. RCS letdown to the SFP is established to control pressurizer level. This activity may not be initiated until approximately 7 hours into the scenario.

The activities required to cooldown the plant to Mode 4 (< 250ºF), perform damage assessment and repairs required to achieve Mode 5 (< 200ºF), and cooldown the plant to Mode 5 (< 200ºF) are the same as those previously described in section 3.6.1 for the overheating scenario.

3.6.3 Letdown Line Break

There is a postulated terminal end break at the letdown line containment penetration #6 in the EPR. This break does not interact with any other SSD equipment but the detection and isolation of the letdown line is important since the isolation of the letdown line terminates the loss of RCS inventory.

The letdown line break results in depressurization of the RCS as primary inventory is lost through the break and a reactor trip is initiated on either the low RCS pressure or on variable low pressure trip function. Continued RCS depressurization results in the RCS pressure decreasing to the ES actuation point. The ES system actuation isolates the break by closing valves HP-3 (A letdown cooler outlet and containment isolation valve) and HP-4 (B letdown cooler outlet and containment isolation valve). If a SAF of either HP-3 or HP-4 occurs (failure to close), procedural guidance directs the operators to close HP-1 (A letdown cooler inlet isolation valve) or HP-2 (B letdown cooler inlet isolation valve) to isolate the break. The HPI system has adequate capacity to compensate for the leak rate as RCS pressure and pressurizer level recover, RCS subcooling is not lost and the RCPs remain in operation. Following the isolation of the letdown line, unit shutdown would be conducted using the normal shutdown systems.

The following TCAs are identified for timely isolation of primary leakage outside of the containment building, with consideration for providing margin to potential radiological effluent release:

1. Isolate the letdown line break within 20 minutes following ES actuation. This is a new TCA.
2. Start the control room ventilation system (CRVS) Booster Fans within 30 minutes of ES actuation. This is an existing TCA.

3.6.4 HPI Pump Discharge Line Break

The postulated terminal end break at the discharge nozzle of the 1,2,3A or 1,2,3B HPI pump will result in flooding of the HPI pump room if not isolated.

The HPI pump provides RCS makeup and RCP seal cooling. A HELB at the discharge nozzle of an operating HPI pump can be quickly diagnosed and isolated. The CR operator will immediately receive the HPI pump discharge pressure low annunciator and the RCP seal header flow low annunciator, the standby HPI pump will auto start, and LDST level will rapidly decrease. Once the break location has been identified, the affected HPI pump will be tripped by the CR operator. A non-licensed operator than locally isolates the leak by closing the remote-operated manual suction valve on the affected HPI pump. Operation of the isolation valve does not require entry into the HPI pump room.

This scenario identified the need for the following TCA:

1. Isolate HPI pump discharge nozzle break within 39 minutes. This is a new TCA.

3.6.5 HPI HELBs in the Penetration Rooms

3.6.5.1 HPI HELBs in the EPR

In addition to the RCS letdown line break described above, there are three (3) additional postulated HPI HELBs in the EPR:

1. A terminal end break on the train ‘A’ HPI line at containment penetration #9.

2. A terminal end break on the RCP seal injection line at containment penetration #23A.

3. A terminal end break on the RCP seal injection line at containment penetration #23B.

If either one or both seal injection lines break, the operators in the CR will be alerted to the break by RCP seal flow annunciators. The break(s) will then be isolated by closing HP-31 (RCP seal flow control valve) from the CR. If HP-31 fails to close, operators can isolate the break by closing manually operated valves, which are located outside of the break area. The component cooling (CC) system remains available and RCP seal cooling will not be lost. If the CC system fails due to a SAF, RCP seal cooling will be restored by the SSF RCMU system. If this leak is not isolated within approximately 1 hour and 40 minutes, the flood level will exceed the top of the curb around the flood outlet device and the water will flow out of the AB to the west yard. The radiological consequences of the flooding will be insignificant as the water being released to the EPR is from the BWST/LDST. Unit shutdown to the CSD condition would be performed using normal plant systems.

If a break occurs on the train ‘A’ HPI line, the operators in the CR will be alerted to the break by decreasing LDST level, decreasing pressurizer level, and low HPI header discharge pressure. The break will then be isolated by closing HP-120 (RC volume control valve) from the CR. If HP-120 fails to close, the operator will align RC makeup to the train ‘B’ HPI line from the CR. An operator can then isolate the break by closing a manually operated valve on the train ‘A’ HPI line upstream of the break. The break on the injection line can also whip into the two (2) RCP seal injection lines in the EPR and rupture both lines. The CC system remains available and RCP seal cooling will not be lost. Isolation of these breaks is described above. If the CC system fails due to a SAF, RCP seal cooling will be restored by the SSF RCMU system as described above. If this leak is not isolated in approximately 10 minutes, the flood level will exceed the top of the curb around the flood outlet device and the water will flow out of the AB to the west yard. The radiological consequences of the flooding will be insignificant as the water being released to the EPR is from the BWST/LDST. Unit shutdown to the CSD condition would be performed using normal plant systems. No T-H analyses were performed for these breaks in the EPR.

3.6.5.2 HPI HELBs in the West Penetration Room

There are two (2) postulated HPI HELBs in the west penetration room (WPR):

1. A terminal end break on the RCP seal injection line at containment penetration #10A.

2. A terminal end break on the RCP seal injection line at containment penetration #10B.

These breaks would be isolated as described above for the seal injection line breaks in the EPR. The CC system remains available and RCP seal cooling will not be lost. If the CC system fails due to a SAF, RCP seal cooling will be restored by the SSF RCMU system. If this leak is not isolated within approximately 1 hour and 4 minutes, the flood level will exceed the top of the flood barrier located in front of the exit door from the WPR to the west yard and the water will flow out of the AB to the west yard. The radiological consequences of the flooding will be insignificant as the water being released to the WPR is from the

BWST/LDST. Unit shutdown to the CSD condition would be performed using normal plant systems. No T-H analyses were performed for these breaks in the WPR.

3.6.6 Training

Operators receive classroom, simulator (including the SSF simulator) and on-the-job training for the emergency procedures and abnormal procedures (APs) during the initial licensed operator training program. Licensed operators maintain their proficiency with these procedures and their skill in placing the plant in a SSD condition using the simulator through participation in the licensed operator continuing training program. Non-licensed operators receive training on their emergency procedure and AP related tasks through participation in the non-licensed operator initial and continuing training programs. Also, licensed and non-licensed operators may be evaluated on SSF time critical tasks using job performance measures during their annual operating exam that is part of the operator requalification program.

For implementation of this LAR, both shift licensed operators and non-licensed operators will receive applicable training on the modifications associated with the new HELB strategy. Emergency procedures and APs will be revised to reflect the change in HELB mitigation strategy. Licensed operators and non-licensed operators will be trained on the revised procedures. These changes and training will be completed as part of implementation of this license amendment.

3.6.7 Procedures and Verification

The emergency procedures will be revised to provide the guidance required to place the HELB affected unit in an SSD condition.

All ONS emergency operating procedures (EOPs) and APs changes go through a rigorous verification and validation process governed by operations administrative procedures. The purpose of the verification and validation process is to ensure that the procedures used to mitigate, and correct abnormal and emergency conditions meet certain criteria. These criteria include written correctness, accurate technical content, usability, and operational correctness. Procedure validation provides assurance that the procedure contains sufficient and understandable operator information and is compatible with plant response, equipment accessibility, plant hardware, and shift manpower. Procedures are validated using a table top setting, in the field, and/or on the training simulator, including the SSF simulator for the SSF procedure. Procedure validation also ensures that TCAs can be completed within the required time.

The new proposed TCAs included in Attachment 11 to this LAR have been reviewed by the SRO responsible for managing the operations TCA program and the previously licensed SRO responsible for maintaining the APs and EOPs. This qualitative assessment included a review of the impact of the TCA to the applicable operating procedure, the time available before the action is required, the time required to complete the action, the required staffing, the complexity/feasibility of the action, the plant condition at the time the action is required, and the adequacy of existing operator skill and knowledge to perform the TCA. These reviews provide additional assurance that these TCAs can be successfully performed within the prescribed times. The assessment of these new proposed TCAs is provided in Attachment 12.

Approved TCAs are managed in accordance with an administrative procedure that provides guidance on how to identify TCAs and control these actions to assure the required times can be met. TCAs without excess margin are re-validated approximately every five years to verify the ability to accomplish the actions with margin.

Unless noted, all TCAs described in this section are existing TCAs that have been previously reviewed and approved as documented in OSS 0254.00-00-4005, Design Basis Specification for the DBEs. The HELB credited TCAs are summarized in Attachment 11.

3.7 Thermal Hydraulic Analysis

The analyses assess the new LB of the PSW system, the SSF, and normal plant systems as the assured mitigation paths following a HELB outside of the containment building. The HELBs considered in these analyses are MS HELBs and FDW HELBs outside of the containment building.

Direct effects from some HELBs inside the TB can impact the electrical distribution system that provides power to both safety related and non-safety related equipment. In addition, some HELBs can result in the loss of secondary systems needed for continued plant operation. The effects can result in any combination of the following:

- Loss of the 230 kV red and yellow buses (similar to a loss of offsite power (LOOP))
- Loss of the standby buses
- Loss of the 4160 VAC main feeder buses
- Loss of the 6900 VAC buses
- Loss of condensate/MFDW system

Any interaction on the above equipment due to consequential effects from postulated HELBs is assumed to result in its immediate loss at the time of the break. If there are no consequential effects on the above equipment, the equipment is assumed to remain in operation during the transient analyses.

The HELB analyses consider the possibility that either the condensate, MFDW or MS piping located outside of the containment building in either the TB or EPR could be faulted. The overheating analysis considers a faulted MFDW line while assuming the MS lines remain intact to maximize the overheating. The overcooling analysis considers a faulted MS line while assuming the MFDW lines remain intact to maximize the overcooling. Both the overheating and overcooling analyses consider the possibility that the HELB causes damage that may result in the loss of onsite emergency power sources.

The RCS T-H analyses evaluate the ability to mitigate HELBs in the TB for the ONS using normal plant equipment, SSF, and PSW mitigation. The initiating event for the HELB scenario is either a MS HELB or FDW HELB in the TB that causes an immediate loss of 4160 VAC power, resulting in an immediate reactor trip and turbine trip. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, 3 minutes after a loss of RCP seal cooling, or through established procedural guidance. Offsite power or Keowee may be available for this scenario, enabling PSW equipment to be available to mitigate the plant transient.

The RCS T-H analyses also evaluates the ability to mitigate HELBs in the EPR for the ONS using normal plant equipment mitigation. The initiating event for these HELB scenarios does not cause an immediate loss of 4160 VAC power. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, 3 minutes after loss of RCP seal cooling, or through established procedural guidance.

The T-H analyses are performed using either Duke Energy's RELAP5/MOD2-B&W ONS T-H model or Duke Energy's RETRAN-3D ONS model. The ONS RETRAN-3D model has previously been approved for use in the ONS UFSAR Chapter 6 and Chapter 15 accident analyses. Duke Energy's RELAP5/MOD2-B&W model has previously been approved for use in the ONS UFSAR Chapter 6 LOCA mass and energy release analyses.

The ONS RETRAN-3D model and analysis methods are described in Duke Energy's NRC approved methodology reports DPC-NE-3000-PA (reference 21), DPC-NE-3003-PA (reference 22), and DPC-NE-3005-PA (reference 53), and have been modified as described in Attachment 4, to include additional detail and features required to perform these analyses.

The ONS RELAP5/MOD2-B&W model and analysis methods are described in Duke Energy's NRC approved methodology report DPC-NE-3003-PA (reference 22) and have been modified, as described in Attachment 4, to include additional detail and features required to perform these analyses.

3.7.1 HELB Mitigation – Acceptance Criteria.

The acceptance criteria are as follows:

> Successful mitigation of a HELB condition at ONS shall be defined as meeting the following criteria to ensure that the integrity of the fuel and RCS remains unchallenged.
>
> The following criteria are validated for the overheating analyses to demonstrate acceptable results.
>
> - The core must remain intact and in a coolable core geometry.
> - Minimum Departure from Nucleate Boiling Ratio (DNBR) meets specified acceptable fuel design limits.
> - RCS pressure must not exceed 2750 psig (110% of design).
>
> In addition to the criteria specified above, the following criteria are validated for the most limiting overcooling analyses to demonstrate acceptable results.
>
> - The SG tubes remain intact.
> - RCS remains within acceptable pressure and temperature limits.
>
> The two additional criteria validated in the overcooling analysis recognize the thermal stress induced on the RCS and SG materials during the transient evolution. These criteria ensure the thermal stress induced on the RCS materials during the transient evolution does not challenge the integrity of the RCS pressure boundary. The first criteria is required by the OTSG design. The second criteria is validated to ensure the transient response remains within analyzed limits.

3.7.2 HELB Mitigation - Overheating Analysis

The postulated condensate and MFDW system piping failures are analyzed for their effects on the ability to achieve and maintain SSD of the affected unit following a HELB. It is assumed that a loss of 4160 VAC power to the affected unit may occur as a result of a HELB located in the TB.

Three sets of overheating analyses scenarios are evaluated for establishing SG heat removal to the unit experiencing the FDW HELB; one with 4160 VAC power available, and two where 4160 VAC power is lost. EFW is credited for cases where 4160 VAC power remains available. For scenarios where 4160 VAC power is lost, two alternatives are evaluated for mitigation strategies using either PSW or SSF equipment.

Analyses have been performed for each of these scenarios, using normal plant, SSF and PSW equipment to evaluate the ONS RCS response to a FDW HELB. The primary objective of the analyses is to demonstrate that the credited systems are capable of meeting the proposed HELB mitigation acceptance criteria for an overheating scenario. The results of the analyses met the acceptance criteria. Details of the overheating analyses are contained in Attachment 6.

3.7.3 HELB Mitigation - Overcooling Analysis

The postulated MS system piping failures are analyzed for their effects on the ability to achieve and maintain SSD of the affected unit following a HELB. It is assumed that a loss of 4160 VAC power to the affected unit may occur as a result of a HELB located in the TB.

Three sets of overcooling analyses scenarios are evaluated for establishing SG heat removal to the unit experiencing the MS HELB; one with 4160 VAC power available, and two where 4160 VAC power is lost. EFW is credited for cases where 4160 VAC power remains available. For scenarios where 4160 VAC power is affected by the HELB, two alternatives are evaluated for mitigation strategies using either PSW or SSF equipment.

One objective of the overcooling analysis is to demonstrate adequate core cooling and establish a basis for mitigation strategies for establishing and maintaining SSD conditions following a MS HELB in the TB or EPR.

A second objective of the overcooling analysis is to demonstrate the SG tubes remain intact and the RCS remains within acceptable pressure and temperature limits.

Analyses have been performed for each of these scenarios using normal plant, SSF and PSW equipment to evaluate the ONS RCS response to a MS HELB. The primary objective of the analyses is to demonstrate that the credited systems are capable of meeting the proposed HELB mitigation acceptance criteria for an overcooling scenario. The results of the analyses met the acceptance criteria. Details of the overcooling analyses are contained in attachment 6.

4 REGULATORY EVALUATION

4.1 Applicable UFSAR

UFSAR Section 3.6.1 (Postulated Piping Failures in Fluid Systems Inside and Outside Containment), denotes that the analysis of effects resulting from postulated piping breaks outside of the containment building is contained in Duke Power MDS Report No. OS-73.2 dated April 25, 1973 including revision through Supplement 2. The proposed changes specified in Section 2.5 of the LAR will revise this section of the UFSAR. The proposed changes reflect a revised licensing strategy that credits normal plant equipment, the SSF, and the PSW system as assured SSD pathways for HELB mitigation.

UFSAR 3.11.1.2 (Environmental Conditions) - The postulated harsh environmental conditions resulting from a LOCA or HELB inside the RB and a HELB outside the RB are identified and discussed in the ONS Environmental Qualification Criteria Manual. The proposed changes will not affect this section of the UFSAR.

UFSAR 5.1.2.4 (Natural Circulation) – Natural circulation provides an acceptable method of energy removal from the core with transfer of energy to the secondary system through the SGs. The proposed changes will clarify that minor reductions in temperature to stabilize the plant do not constitute a natural circulation cooldown requiring the RCS head vents to be open.

UFSAR 5.4.8.6.1 (Replacement Steam Generator LOCA Analysis) – For the replacement SG RCS structural analysis, ten HELBs are identified and considered. The proposed changes will not affect this section of the UFSAR.

UFSAR 9.6, (Standby Shutdown Facility) - SSF houses stand-alone systems that are designed to maintain the plant in a safe and stable condition following postulated emergency events that are distinct from the design basis accidents and DBEs for which the plant systems were originally designed. The system provides additional "defense in-depth" protection for the health and safety of the public by serving as a backup to existing safety systems. The proposed changes will revise this section of the UFSAR as specified in Section 2.5 of the LAR. The proposed changes reflect a revised licensing strategy that credits the SSF as an assured SSD path for HELB mitigation.

UFSAR 9.7, (Protected Service Water) - PSW is designed as a standby system for use under emergency conditions. The PSW System provides added "defense-in-depth" protection by serving as a backup to existing safety systems and as such, the system is not required to comply with single failure criteria. The PSW System is provided as an alternate means to achieve and maintain SSD conditions for one, two or three units following certain postulated scenarios. The proposed changes will revise this section of the UFSAR as specified in Section 2.5 of the LAR. The proposed changes reflect a revised licensing strategy that credits the PSW system as an assured SSD path for HELB mitigation.

UFSAR 10.4.7.1 (EFW Design Bases) states that the effects of HELBs have been analyzed as addressed in UFSAR Section 3.6.1.3. The proposed change is editorial.

UFSAR 10.4.7.2.1 (Motor Driven EFW Pumps) states that the Motor Driven EFW Pumps are powered from the 4160 VAC switchgear TD and TE. The switchgear are located side by side on the ground floor of the TB and are not protected from HELBs. The proposed changes will not affect this section of the UFSAR.

UFSAR 10.4.7.3.2 (EFW Response Following a HELB) describes the mitigation strategies for HELBs resulting in a loss of TC, TD, and TE switchgear, FDW/MSLBs causing loss of SG pressure boundary, and other Condensate/FDW line breaks that result in a loss of condenser hotwell inventory. The proposed changes will revise this section of the UFSAR as specified in Section 2.5 of the LAR. The proposed changes reflect a revised licensing strategy that credits normal plant equipment, the SSF, and the PSW system as assured SSD pathways for HELB mitigation.

4.2 Precedent

The NRC has previously approved changes similar to the proposed changes in this LAR. The following plants submitted HELB methodology related LARs that have been reviewed and approved:

4.2.1 Donald C. Cook Units 1 and 2: Application dated April 6, 2000 (ADAMS Accession No. ML003702066); NRC Safety Evaluation dated November 21, 2000 (ADAMS Accession No. ML003770373).

4.2.2 Tennessee Valley Authority, Watts Bar Nuclear Plant, Units 1 and 2, Safety Evaluation Report Supplement 6 (SSER 6), Section 6, “Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping,” dated April 1991.

4.2.3 Florida Power Corporation (Now Duke Energy), submittal for Crystal River Unit 3, dated December 18, 1989. The submittal was approved by the NRC on April 11, 1990.

4.3 Significant Hazards Consideration

Duke Energy has evaluated whether a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, “Issuance of Amendment,” as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   Justification: A High Energy Line Break (HELB) does not constitute a previously-evaluated accident. HELB is a design criterion that is required to be considered in the design of structures, systems, or components and is not a design basis accident or design basis event. The possibility of HELBs is appropriately considered in the UFSAR and Duke Energy has concluded that the proposed changes do not increase the possibility that a HELB will occur or increase the consequences from a HELB. This LAR provides an overview of HELB reanalysis, descriptions of station modifications that will be made as a result of the HELB reanalysis, and the proposed mitigation strategies which now includes normal plant equipment, the protected service water (PSW) system, and the standby shutdown facility (SSF). The PSW and SSF Systems are designed as standby systems for use under emergency conditions. With the exception of testing, the systems are not normally pressurized. The duration of the test configuration is short as compared to the total plant (unit) operating time. Due to the combination of the infrequent testing and short duration of the test, pipe ruptures are not postulated or evaluated for these systems.

Other systems have also been excluded based on the infrequency of those systems operating at high energy conditions. Consideration of HELBs is excluded (both breaks and cracks) if a high energy system operates for less than 1% of total unit operating time such as emergency feedwater or reactor building spray or if the operating time of a system at high energy conditions is less than approximately 2% of total system operating time such as low pressure injection. This is acceptable based on the very low probability of a HELB occurring during the limited operating time of these systems at high energy conditions. Gas and oil systems have been excluded, since these systems also possess limited energy.

The modifications associated with the HELB licensing basis will be designed and installed in accordance with applicable quality standards to ensure that no new failure mechanisms, malfunctions, or accident initiators not already considered in the design and licensing basis are introduced. For Turbine Building HELBs that could adversely affect equipment needed to stabilize and cooldown the units, the PSW System or SSF provides assurance that safe shutdown can be established and maintained. For Auxiliary Building HELBs, normal plant systems or the SSF provides assurance that safe shutdown can be established and maintained.

As noted in Section 3.4, Oconee Nuclear Station plans to adopt the provisions of Branch Technical Position (BTP) Mechanical Engineering Branch (MEB) 3-1 regarding the elimination of arbitrary intermediate breaks for analyzed lines that include seismic loading. Guidance in the BTP MEB 3-1 is used to define crack locations in analyzed lines that include seismic loading. Adoption of this provision allows Oconee Nuclear Station to focus attention to those high stress areas that have a higher potential for catastrophic pipe failure. In absence of additional guidance, Duke Energy uses NUREG/CR-2913 to define the zone of influence for breaks and critical cracks that meet the range of operating parameters listed in NUREG/CR-2913. NUREG/CR-2913 provides an analytical model for predicting two-phase, water jet loadings on axisymmetric targets that did not exist prior in the Giambusso/Schwencer requirements.

In conclusion, the changes proposed will increase assurance that safe shutdown can be achieved following a HELB. The changes will also collectively enhance the station’s overall design, safety, and risk margin; therefore, the proposed change does not involve a significant increase in the probability or consequence of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

Justification: A HELB does not constitute a previously-evaluated accident. HELB is a design criterion that is required to be considered in the design of structures, systems, or components and is not a design basis accident or design basis event. The possibility of HELBs is appropriately considered in the UFSAR and Duke Energy has concluded that the proposed changes do not increase the possibility that a HELB will create a new or different kind of accident. This LAR provides an overview of HELB analysis, descriptions of station modifications that will be made as a result of the HELB reanalysis, and the proposed mitigation strategies which now include normal plant equipment, the PSW system, and the SSF.

In conclusion, the changes proposed will increase assurance that safe shutdown can be achieved following a HELB. The changes will also collectively enhance the station's overall design, safety, and risk margin; therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed amendment involve a significant reduction in a margin of safety?

Response: No.

Justification: A HELB does not constitute a previously-evaluated accident. HELB is a design criterion that is required to be considered in design of structures, systems, or components and is not a design basis accident or design basis event. The possibility of HELBs is appropriately considered in the UFSAR and Duke Energy has concluded that the proposed changes do not involve a reduction in the margin of safety. This LAR provides an overview of HELB analysis, descriptions of station modifications that will be made as a result of the HELB reanalysis, and the proposed mitigation strategies which now include normal plant equipment, the PSW system, and the SSF.

The changes described above provide a HELB licensing basis and have no effect on the plant safety margins that have been established through limiting conditions for operation, limiting safety system settings, and safety limits specified in the technical specifications. Therefore, the proposed change does not involve a reduction in the margin of safety.

Based on the above, Duke Energy concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significance hazards consideration" is justified.

Conclusion

Based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by the proposed revision to the wording in the UFSAR and operation of the unit in the proposed manner, (2) the proposed revision will be implemented in a manner consistent with the commission's regulations, and (3) the issuance of the amendment will not be adverse to the common defense and security or to the health and safety of the public.

5 ENVIRONMENTAL CONSIDERATION

Duke Energy has evaluated this LAR against the criteria for identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21. Duke Energy has determined that this LAR meets the criteria for a categorical exclusion as set forth in 10 CFR 51.22(c)(9). This determination is based on the fact that this change is being proposed as an amendment to a license issued pursuant to 10 CFR 50 that changes a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or that changes an inspection or a surveillance requirement, and the amendment meets the following specific criteria:

(i) The amendment involves no significant hazards consideration.

As demonstrated in Section 4.3, this proposed amendment does not involve a significant hazards consideration.

(ii) There is no significant change in the types or significant increase in the amounts of any effluent that may be released offsite.

The change proposed in this amendment request will enhance and clarify the overall HELB LB. Since the principal barriers to the release of radioactive materials are not modified or affected by this change, no significant increases in the amounts of any effluent that could be released offsite will occur as a result of this proposed change.

(iii) There is no significant increase in individual or cumulative occupational radiation exposure.

Because the principal barriers to the release of radioactive materials are not modified or affected by this change, there is no significant increase in individual or cumulative occupational radiation exposure resulting from this change.

Therefore, no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment pursuant to 10 CFR 51.22(b).

6 REFERENCES

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4. Letter from Duke Power Company to the AEC, MDS Report No. OS-73.2, Supplement 1, “Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2, & 3,” dated June 22, 1973.
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6. Letter from AEC to Duke Power Company, “Safety Evaluation Report for Oconee Units 2 & 3,” dated July 6, 1973.
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9. Letter from Leonard N. Olshan, Project Manager, Plant Licensing Branch II-1, Division of Operating Reactor Licensing, USNRC Office of Nuclear Reactor Regulation, to Duke Power

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11. Letter to the U. S. Nuclear Regulatory Commission from Bruce H. Hamilton, Vice President, Oconee Site, "Revision to Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated June 28, 2007.
12. Letter to the U. S. Nuclear Regulatory Commission from Henry B. Barron, Group Vice President and Chief Nuclear Officer, Nuclear Generation, Duke Energy Corporation, "Revision to Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated January 25, 2008.
13. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment Nos. 386, 388, and 387, Implementation of the Protected Service Water System, dated August 13, 2014 (Accession Number ML14206A790).
14. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events Outside of the Containment Buildings; License Amendment Request No. 2008-005,” dated June 26, 2008.
15. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events Outside of the Containment Building – Unit 2; License Amendment Request No. 2008-006,” dated December 22, 2008.
16. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Proposed License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for HELB Events Outside of the Containment Building; License Amendment Request No. 2008-007,” dated June 29, 2009.
17. Letter to the U.S. Nuclear Regulatory Commission from Scott Batson, Vice President, Oconee Site, “licensing Basis for the Protected Service Water System – Response to Request for Additional information (RAI) No. 190; Revised Responses to RAI Nos. 134 and 165; License Amendment Request (LAR) 2008-04 – Supplement 8,” dated February 14, 2014.
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26. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Responses to Request for Additional Information for the License Amendment Request to Revise the Oconee Nuclear Station Current Licensing Basis for High Energy Line Break Events Outside of the Containment Building; License Amendment Request No. 2008-007,” dated October 23, 2009.
27. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Tornado Mitigation License Amendment Request – Response to Request for Additional Information,” dated June 24, 2010.
28. Letter to the U. S. Nuclear Regulatory Commission from Dave Baxter, Vice President, Oconee Site, “Tornado Mitigation License Amendment Request – Response to Request for Additional Information,” dated August 31, 2010.
29. Letter to the U.S. Nuclear Regulatory Commission from T. Preston Gillespie, Jr., Vice President, Oconee Site, “High Energy Line Break License Amendment Request – Response to Request for Additional Information,” dated December 7, 2010.
30. Letter to the U.S. Nuclear Regulatory Commission from T. Preston Gillespie, Jr., Vice President, Oconee Site, “Tornado and High Energy Line Break (HELB) Mitigation License Amendment Requests (LARs) – Responses to Request for Additional Information,” dated December 16, 2011.
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39. Letter to the U. S. Nuclear Regulatory Commission from Thomas Ray, Vice President, Oconee Site, "Revision to Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated November 15, 2017.
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48. USAS B31.1.0, 1967 Edition, "Power Piping"
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55. Letter J. F. Stolz (NRC) to H. B. Tucker (Duke), Subject: NUREG-0737 ITEM II.K.3.30, SMALL BREAK LOCA METHODS, Re: Oconee Nuclear Station, Units 1, 2 and 3, Dated: July 29, 1985. (Safety Evaluation Report for the BABCOCK AND WILCOX OWNERS GROUP SMALL BREAK LOSS-OF-COOLANT ACCIDENT EVALUATION MODEL, CRAFT2 (REV. 3) (BAW-10092P, REV. 3 AND BAW-10154)).
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61. Letter to the U. S. Nuclear Regulatory Commission from Scott Batson, Vice President, Oconee Site, " Licensing Basis for the Protected Service Water (PSW) System – Response to Request for Additional Information (RAI) Nos. 191-194; License Amendment Request (LAR) 2008-07 – Supplement 9,” dated April 3, 2014.

7 ACRONYMS

AB	Auxiliary Building
ADV	Atmospheric Dump Valve
AEC	Atomic Energy Commission
AFIS	Automatic Feedwater Isolation System
AP	Abnormal Procedure
ASB	Auxiliary Systems Branch
ASME	American Society of Mechanical Engineers
ASW	Auxiliary Service Water
AWC	Alternate Chilled Water
B&PV	Boiler and Pressure Vessel
BTP	Branch Technical Position
BWST	Borated Water Storage Tank
CC	Component Cooling
CCW	Condenser Circulating Water
CET	Core Exit Temperatures

CLB	Current Licensing Basis
CR	Control Room
CRD	Control Rod Drive
CRVS	Control Room Ventilation System
CSD	Cold Shutdown
CSR	Cable Spreading Room
DBE	Design Basis Event
DC	Direct Current
DG	Diesel Generator
DHR	Decay Heat Removal
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio
Duke Energy	Duke Energy Carolinas, LLC
EFW	Emergency Feedwater
EPR	East Penetration Room
ES	Engineered Safeguards
ESPS	Engineered Safeguards Protective System
FAC	Flow Accelerated Corrosion
FDW	Feedwater
GL	Generic Letter
HE	High Energy
HELB	High Energy Line Break
HFP	Hot Full Power
HPI	High Pressure Injection
HVAC	Heating, Ventilation, and Air Conditioning
IA	Instrument Air
ICS	Integrated Control System
KHU	Keowee Hydro Unit
kV	Kilovolt
LAR	License Amendment Request
LB	Licensing Basis
LC	Load Center
LDST	Letdown Storage Tank
LOCA	Loss of Coolant Accident

LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MCC	Motor Control Center
MDS	Mechanical Design Study
MEB	Mechanical Engineering Branch
MFDW	Main Feedwater
MS	Main Steam
MSLB	Main Steam Line Break
MSRV	Main Steam Relief Valve
MT	Magnetic Particle Testing
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OAC	Operator Aid Computer
OBE	Operational Basis Earthquake
OD	Outer Diameter
ONS	Oconee Nuclear Station
OTSG	Once Through Steam Generator
PH	Plant Heating
PORV	Power Operated Relief Valve
PSV	Pressurizer Safety Valve
PSW	Protected Service Water
PT	Penetrant Testing
RAI	Request for Additional Information
RB	Reactor Building
RBC	Reactor Building Cooling
RC	Reactor Coolant
RCMU	Reactor Coolant Makeup
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RPS	Reactor Protective System
RV	Reactor Vessel
SAF	Single Active Failure
SBO	Station Blackout

SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SG	Steam Generator
SRP	Standard Review Plan
SSC	Structure, System, or Component
SSD	Safe Shutdown
SSF	Standby Shutdown Facility
T-H	Thermal Hydraulic
TB	Turbine Building
TBV	Turbine Bypass Valves
TCA	Time Critical Operator Action
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UST	Upper Surge Tank
UT	Ultrasonic Testing
VAC	Volts Alternating Current
VDC	Volts Direct Current
WPR	West Penetration Room
ZOI	Zone of Influence

ATTACHMENT 1

CONFORMING ACTIONS

Attachment 1
Conforming Actions

The following table identifies the conforming actions (previously commitments) that Duke Energy will take in implementing HELB. Any other statements in this submittal are provided for information purposes and are not considered to be conforming actions. Please direct questions regarding these conforming actions to Timothy Brown, ONS Regulatory Projects Group, at (864) 873-3952.

Previous Commitment #	Action	Completion Date
26H	In order to mitigate the postulated HELB on the letdown line, the inlet isolation valves to the Unit 1 letdown coolers on the letdown line (1HP-1 & 1HP-2) will be upgraded to permit their use following a postulated HELB on the letdown line at containment penetration #6. With these valves upgraded, the letdown flow path could be isolated if either of the inboard containment isolation valves (1HP-3 & 1HP-4) fail to close.	Two refueling outages after issuance of the SER.
27H	The Unit 1 control complex cooling is being upgraded to address the potential propagation of the HELB generated environment in the EPR to the Unit 1 control complex.	*Three refueling outages after issuance of the SER.
30H 44H	TB structural support columns D-24 (Unit 1), D-26 (Unit 1), and M-20 (Unit 1), will be modified to prevent potential failure of the column, when subjected to a pipe whip load. Upgrade of columns D-24 and D-26 prevent the loss of the routing to get temporary cabling to the LPI and LPSW pump motors.	*Three refueling outages after issuance of the SER.
35H	The Unit 2 control complex cooling is being upgraded to address the potential propagation of the HELB generated environment in the EPR to the Unit 2 control complex.	*Three refueling outages after issuance of the SER.
36H	The valves (2HP-103 & 2HP-107) on the individual suction lines to the Unit 2 "A" & "B" HPI pumps are being upgraded to allow the remote operation (operated outside the HPI pump room) of these valves. The remote operation of these valves allows the isolation of postulated HELBs on the discharge side of the HPI pumps without compromising the availability of the other HPI Pumps and the need to maintain the LDST aligned to the HPI pump suction piping. For a SAF of either valve 2HP-103 or 2HP-107 to close, a redundant, remotely operated valve is provided on each of the HPI Pumps "A" and "B" to assure HELB mitigation.	Two refueling outages after issuance of the SER.
38H 44H	TB structural support column D-29 (Unit 2), D-31 (Unit 2), and M-35 (Unit 2), will be modified to prevent potential failure of the column, when subjected to a pipe whip load.	*Three refueling outages after issuance of the SER.

Previous Commitment #	Action	Completion Date
41H	The Unit 3 control complex cooling is being upgraded to address the potential propagation of the HELB generated environment in the EPR to the Unit 3 control complex.	*Three refueling outages after issuance of the SER.
44H	TB structural support columns D-43 and D-45 (Unit 3), M-49 (Unit 3), and L-47 (Unit 3) will be modified to prevent potential failure of the column(s), when subjected to a pipe whip load.	*Three refueling outages after issuance of the SER.
New	Install new QA-1 instrumentation or upgrade existing instrumentation in the SSF CR for SG pressure, nuclear instrumentation, core exit thermocouples, pressurizer temperature, and temperature compensated pressurizer level. This will provide SSF CR operators with the enhanced ability to monitor and control the plant.	Three refueling outages after issuance of the SER.
New	Eliminate the cross-connection of power from a particular unit to another unit for the CRD. This will ensure immediate reactor trip following a postulated MFDW HELB that affects the ES switchgear.	Two refueling outages after issuance of the SER.
New	Install a new SSF letdown line in each unit to provide SSF CR operators with the ability to control the plant at lower-range RCS pressures.	Two refueling outages after issuance of the SER.
New	The SSF related components located in each unit's AB need to be either analyzed or replaced to qualify them for potential harsh environments created by AB HELBs, particularly HELBs within the EPR.	Three refueling outages after issuance of the SER.
New	LPSW system valves, 1,2,3LPSW-1119 and 1,2,3LPSW-1120 are vulnerable to damage by certain TB HELBs. A modification is needed to ensure the required LPSW system isolations can be made to enable operation of the Alternate RBC system.	Three refueling outages after issuance of the SER.
New	TCA Validations described in Attachment 12 of this LAR.	Three refueling outages after issuance of the SER.

*Note that the dates have changed from 2 refueling outages to 3 refueling outages due to the complex nature of the modifications.

ATTACHMENT 2
UPDATED FINAL SAFETY ANALYSIS REPORT
RED-MARKED CHANGES

3.6 Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping

Add INSERT 1a

3.6.1 Postulated Piping Failures in Fluid Systems Inside ~~and Outside~~ Containment

3.6.1.1 Design Bases

The basic design criteria for pipe whip protection is as follows:

1. All penetrations are designed to maintain containment integrity for any loss of coolant accident combination of containment pressures and temperatures.
2. All penetrations are designed to withstand line rupture forces and moments generated by their own rupture as based on their respective design pressures and temperatures.
3. All primary penetrations, and all secondary penetrations that would be damaged by a primary break, are designed to maintain containment integrity.
4. All secondary lines whose break could damage a primary line and also breach containment are designed to maintain containment integrity.

Pipe whip restraints, jet impingement shields and other protective devices do not have to be installed to protect against an instantaneous double ended rupture of a large RCS pipe based on LBB analyses and technology. Per References 4 and 5, the NRC has approved the use of the LBB approach to eliminate the need to protect against the dynamic effects of large bore pipe breaks, as established in previous topical report submittals in References 6, 7, and 8.

3.6.1.2 Description

The major components including reactor vessel, reactor coolant piping, reactor coolant pumps, steam generators, and the pressurizer are located within three shielded cubicles. Each of two cubicles contain one steam generator, two coolant pumps, and associated piping. One of the cubicles also contains the pressurizer. The reactor vessel is located within the third cubicle or primary shield. The reactor vessel head and control rod drives extend into the fuel transfer canal.

Openings are provided in the lower shield walls to provide vent area. Pipe lines carrying high pressure injection water are routed outside the shield walls entering only when connecting to the loop.

3.6.1.2.1 Core Flood/Low Pressure Injection System

After implementation of the passive Low Pressure Injection (LPI) cross connect modification on each Oconee Unit, the pipe rupture design basis of Core Flood (CF) / LPI system inside containment is based on the system function during full power operations. The CF section (defined as the "A" and "B" train piping downstream of LP-176 and LP-177 respectively) qualifies as high energy during full power operations. For this CF piping, up to but not including the CF / Reactor Vessel nozzles, Leak Before Break technology was employed to eliminate the dynamic effects associated with postulated breaks (Refer to Section 5.2.1.9). For the LPI section of the system (defined as the "A" and "B" train piping upstream of LP-176 and LP-177 to their respective Reactor Building penetrations, and including the cross connect piping between the "A" and "B" trains), USNRC Standard Review Plan Section 3.6.2 Branch Technical Position MEB 3-1 (Reference 3) was used for treatment of postulated pipe ruptures.

~~3.6.1.3 Protected Service Water (PSW) System~~

~~The PSW System is designed as a standby system for use under emergency conditions. With the exception of testing of the system, the system is not normally pressurized. Testing of the system is infrequent, typically every quarter. In addition, the duration of the test configuration is short, compared to the total plant (unit) operating time. Due to the combination of the infrequent testing and the short duration of the test, pipe ruptures are not postulated or evaluated for the PSW System.~~

2 Postulated Piping Failures in Fluid Systems Outside Containment

3.6.1.~~4~~ ~~Safety Evaluation~~

~~The analysis of effects resulting from postulated piping breaks outside containment is contained in Duke Power MDS Report No. OS-73.2, dated April 25, 1973 including revisions through supplement 2.~~

~~An evaluation of potential non-safety grade control system interactions during design basis high energy line break accidents is contained in the Duke Power/Babcock and Wilcox Report dated October 5, 1979.~~

~~An exception to report OS-73.2, extending the time allowed to align HPI after certain secondary piping breaks from 30 minutes to 1 hour, has been evaluated as acceptable.~~

~~The Reverse Osmosis Unit was added after MDS Report No. OS-73.2 was completed. It contains high energy piping that has been evaluated to have acceptable results.~~

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3.6.4

~~3.6.2~~ References

1. Duke Power MDS Report No. OS-73.2, dated April 25, 1973 including revisions through supplement 2.
2. ~~Duke Power/B&W Report, Oconee Nuclear Station, "Evaluation of Potentially Adverse Environmental Effects on Non-Safety Grade Control Systems", October 5, 1979.~~ USNRC Standard Review Plan (NUREG 0800) Section 3.6.1 Branch Technical Position ASB 3-1.
3. USNRC Standard Review Plan (NUREG 0800) Section 3.6.2 Branch Technical Position MEB 3-1.
4. NRC Safety Evaluation of B&W Owners Group Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops, dated December 12, 1985.
5. NRC Safety Evaluation Relating To Elimination of Dynamic Effects of Postulated Primary Loop Pipe Ruptures from Design Basis in Regard to TMI-1, dated November 5, 1987.
6. B&W Topical Report BAW-1847, Revision 1, "Leak-Before-Break Evaluation of Margin Against Full Break for RCS Primary Piping of B&W Designed NSS," September 1985.
7. B&W Topical Report BAW-1889P, "Piping Material Properties for Leak-Before-Break Analysis," October 1985.
8. B&W Topical Report BAW-1999, "TMI-1 Nuclear Power Plant Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping", April 1987.

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Main Steam High Energy Line Breaks (MS HELBs) are not synonymous with Main Steam Line Breaks (MSLBs). The analyses and the treatment of MSLBs as described in UFSAR Sections 15.13 and 15.17 were required as part of the initial licensing of the Oconee Nuclear Station (ONS) units. The analyses were completed to evaluate the reactor core response to the resulting overcooling following the MSLB. The postulated break locations for the MSLB analyses described in Chapter 15 were not specified, and as such, damage from the MSLB was not considered. The Giambusso/Schwencer letters (References 9 and 15) were released as construction of Unit 1 was nearing completion. These letters required that licensees consider damage following a postulated break, including those postulated in the MS system. These breaks were considered for different purposes using different assumptions and acceptance criteria. In cases where the potential damage postulated for a MS HELB was similar to the inputs and assumptions used in the MSLB analyses described in UFSAR Sections 15.13 and 15.17, those analyses were used as surrogates for the MS HELB analyses. In a similar manner, a Main Feedwater (MFDW) HELB is not synonymous with a Main Feedwater Line Break (MFLB). The analyses for a MFLB as discussed in UFSAR Section 10.4.7 were completed to evaluate the reactor core response to the overheating caused by the MFLB. The postulated break locations of the MFLBs described in Chapter 10 were not specified and damage from the MFLBs was not considered. However, for MFDW HELBs, the Giambusso/Schwencer letters required evaluation of specific locations and the potential damage.

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The purpose of this description is to provide a comprehensive strategy for mitigating the potential adverse interactions caused by the Oconee Nuclear Station (ONS) postulated HELBs. The strategy provides an evaluation of the ONS postulated HELBs and describes the (as modified) ONS configuration for the identified HELBs. It also supersedes the analysis provided in the original 1973 ONS HELB analysis (References 1 and 9). The strategy identifies and describes the pathway to a safe shutdown (SSD) condition for any postulated HELB in any unit. HELBs are only postulated to occur during the normal operating configuration of the system with the unit operating at 100% rated thermal power level (full power).

The revised HELB mitigation strategies will be implemented when the following conforming actions are completed: installation of new standby shutdown facility (SSF) letdown line, installation/upgrade of SSF control room QA-1 instrumentation, upgrade of inlet isolation valves to the Unit 1 letdown coolers, upgrade to the heating, ventilation, and air conditioning ducting impacting the control complex, upgrade of turbine building (TB) structural support columns, upgrade of suction valves to the Unit 2A & 2B High Pressure Injection (HPI) pumps, elimination of the Control Rod Drive (CRD) cross connect between units, environmentally qualify SSF related components located in each Unit's auxiliary building (AB), provide HELB protected isolation for Alternate Reactor Building Cooling (RBC) System return piping alignment, and Time Critical Operator Actions (TCA) validation.

3.6.2.1 Identification of High Energy Lines

The following criteria are used to identify the high energy piping and the boundaries of the high energy portions of the systems:

- The high energy (piping) lines are those lines that during initial operating conditions, the fluid inside of the pipe has either or both of the following conditions:
  1. A normal operating temperature greater than 200ºF.
  2. A normal operating pressure greater than 275 psig.
- The high energy section of any piping run shall extend from component to component. The high energy portion shall not terminate unless there is a termination at a vessel, a pump, a closed valve, or equivalent boundary.
- Piping downstream of a normally closed valve, that is the high energy boundary for a high energy piping run, is not postulated to be high energy due to potential leakage across the closed valve.
- High energy line boundaries are based upon the normal operating configuration of the system with the unit operating at 100% rated thermal power level (full power).
- Gas Systems (e.g. Nitrogen) and oil systems (e.g. Electro Hydraulic Control) are not identified as high energy systems because those systems possess limited energy.

3.6.2.2 Identification of High Energy Line Break Locations

The following criteria are used to identify the high energy piping break locations:

- HELBs of any type are not postulated on high energy piping that has a nominal size of (1) inch or less.
- HELBs and critical cracks are not postulated on high energy lines that operate at high energy conditions less than approximately 2% of the total system operating time.
- HELBs and critical cracks are not postulated on high energy lines that operate at high energy conditions less than 1% of the total plant (unit) operating time (Normal Plant Conditions).
- HELBs are postulated at the Terminal Ends of high energy piping runs.
- There is no American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section III, Division 1-Class 1 equivalent piping outside of the containment building.
- For ASME B&PV, Section III-Class 2 and Class 3 equivalent piping that is seismically analyzed, HELBs are postulated at axial locations, where the calculated longitudinal stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceeds $0.8(S_a + S_h)$.
- For ASME B&PV, Section III-Class 2 and Class 3 equivalent piping that is seismically analyzed, critical cracks are postulated at axial locations where the calculated stress for the applicable load cases exceed $0.4(S_a + S_h)$. Applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (OBE). Critical cracks are not postulated at locations of terminal end or intermediate breaks.
- For branch connections where the branch line is included in the seismic stress analysis of the run piping, the stress criteria for seismically analyzed piping lines is used to determine HELBs.

- Breaks and critical cracks at closed valves are postulated as follows. The postulation of terminal end breaks at the first normally closed valve(s) separating portions of a system maintained pressurized during normal operations and portions of a system not maintained pressurized depends on whether the system has a seismic analysis that is continuous across the valve. For systems or portions of systems that are not seismically analyzed, breaks are postulated to occur at all piping girth welds in the system including those that attach to normally closed valves. For systems or portions of systems that are seismically analyzed, and the analysis is continuous across the normally closed valve, such that stresses can be accurately determined, break and crack locations are determined based on comparison to the intermediate break and crack stress thresholds.
- For piping that is not rigorously analyzed or does not include seismic loadings, HELBs are postulated at intermediate break locations as provided in BTP MEB 3-1, Section B.1.c.(2)(b)(i).
- For branches where both the main and branch runs are unanalyzed or where the stress at the branch connection is not accurately known, break locations are postulated on the branch and run sides of the connection.
- For piping that is not rigorously analyzed or does not include seismic loadings, critical cracks are not postulated since the effects of postulated HELBs on these piping runs will bound the effects from critical cracks.
- Actual stresses used for comparison to the break and crack thresholds are calculated in accordance with the ONS piping code of record, USAS B31.1.0 (1967 Edition). Allowable stress values S_a and S_h are determined in accordance with USAS B31.1.0 or the USAS B31.7 (February 1968 draft edition with errata) code as appropriate.
- Moderate energy line breaks are not postulated. The HELB requirements for ONS only require compliance to the Giambusso/Schwencer letters. The requirements contained therein do not include postulation of moderate energy line breaks.
- High Energy Piping lines with an internal pressure at atmospheric or below (≤ 0 psig) are excluded from damage assessments due to insufficient energy to create pipe whip or jet impingement forces.
- For the MS penetrations into the containment structure, MS HELBs are postulated to occur at the outside face of the concrete containment structure.
- For the MFDW penetrations into the containment structure, MFDW HELBs are postulated to occur on the outside of the containment structure side of the Main Feedwater terminal/rupture/guard pipe restraint.
- For all other ASME B&PV, Section III-Class 2 equivalent piping penetrations into the containment structure, HELBs are postulated to occur at the outside face of the concrete containment structure.

3.6.2.3 Identification of High Energy Break Types

The following criteria are used to identify the high energy break types, required to be postulated at the identified break location in ONS. There are three (3) types of HELBs at ONS. They are circumferential breaks, longitudinal breaks, and critical cracks. The criteria for each break type are as follows:

- Circumferential Breaks are postulated in high energy lines that exceed one (1) inch nominal pipe size.

- Only circumferential breaks are postulated at terminal ends of high energy piping runs. (Longitudinal breaks are not postulated at terminal ends).
- Longitudinal breaks are postulated in high energy lines that have a nominal pipe size of four (4) inches or greater.
- Circumferential and longitudinal breaks are not postulated to occur concurrently.
- Longitudinal breaks are not postulated at branch connections.
- Longitudinal breaks are postulated only at intermediate break locations.
- Longitudinal breaks are postulated parallel to the pipe axis and orientated at all points on the pipe circumference.
- The break area of a longitudinal break is equal to the effective cross-sectional flow area of the pipe immediately upstream of the break location.
- Critical Cracks are postulated on seismically analyzed high energy piping that exceeds one (1) inch in nominal pipe size.

3.6.2.4 Shutdown Sequence Evaluation Criteria

The following criteria are used to identify the systems and components necessary for HELB mitigation and/or unit shutdown to the cold shutdown condition:

- Equipment used to mitigate postulated HELBs includes those systems and components that are used for detection and isolation of specified HELBs. Equipment that is used for the detection and isolation for an identified HELB is the only detection and isolation equipment required to be targets of that specific HELB.
- Equipment used to meet any of the following shutdown objectives are considered a target of postulated HELBs:
    - Reactivity Control
    - RCS Inventory Control
    - RCS Pressure Control
    - RCS Heat Removal Control
    - Reactor Building (Boundary) Integrity
    - Control Room Habitability (long term)
    - Plant Cooldown
- Both primary and back-up systems, used to achieve the shutdown objectives described above, are included as shutdown equipment and targets of the postulated HELBs.
- Piping, orifices, relief valves, and check valves, are considered passive type components in that they do not require an external power source or manual action to perform their intended function, and these components perform their intended function regardless of the environmental conditions. These components are not identified as required in the shutdown sequence, because they are not subject to single active failures (SAFs). They are, however, HELB targets.
- A SAF is postulated in systems used to mitigate the consequences of the postulated HELBs and Critical Cracks or those systems used to achieve a shutdown objective of the unit. The single active component failure is assumed to occur in addition to those components damaged by the postulated pipe break.

- No SAFs are postulated during the "Plant Cooldown" phase and the "Plant Cooldown to the Cold Shutdown Condition" phase.
- All available systems, including those actuated by operator actions, may be employed to mitigate the consequences of a postulated HELB or critical crack.
- In determining the systems and components available to mitigate the consequences of postulated HELBs, all Shutdown Equipment is assumed to be operable and available at the start of the postulated HELB sequence. It is not necessary to postulate that any systems or components are out of service for maintenance.
- Although a postulated HELB outside of the containment building may ultimately require a cold shutdown, holding at hot standby/shutdown is allowed in order that plant personnel assess the situation and make any necessary repairs to allow the unit to reach cold shutdown.

3.6.2.5 Interaction Evaluation Criteria

The following criteria are used to determine the interactions that occur as a result of postulated HELBs with shutdown equipment and the criteria for determining the pathway to cold shutdown for a given postulated HELB:

- The targets of the postulated HELBs are those systems and components required to mitigate the consequences of postulated HELBs and/or are used during the shutdown sequence to safely bring the unit to the cold shutdown condition.
- SSD, Cold Shutdown, and HELB mitigation systems and components directly impacted by a specific postulated HELB are considered to be unavailable to support the Shutdown Objectives for that specific HELB, unless documented otherwise.
- Movement of a ruptured high energy pipe (i.e. pipe whip) is considered for potential interactions. The pipe whip is assumed to occur in the plane defined by the piping geometry.
- The energy level in whipping pipes may be considered insufficient to rupture an impacted pipe of equal or greater nominal pipe size and equal or heavier wall thickness.
- No secondary pipe breaks are postulated due to jet impingement from the source pipe (pipe with postulated HELB).
- The Jet Impingement Forces, Jet Impingement Cone Geometry, and the Jet Impingement Effective Length are determined 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 psia to 2465 psia, 0 to 126ºF sub-cooling, and 0 to 75% steam quality). For jets consisting of steam or subcooled liquid water falling outside of the NUREG limitations, the effective length of the jet is 10 pipe diameters (ID). Similarly, jet lengths from Critical Cracks are limited to 5 pipe diameters (ID).
- Thrust loads for evaluating potential interactions between postulated HELBs and the TB structural components are determined in accordance with ANSI 58.2 (Rev. 2).
- Systems and components, whose only function is to support the cooldown of the unit from an RCS temperature of approximately 250ºF to the cold shutdown condition, need not be protected from postulated HELBs.

- A “Loss of Offsite Power” (LOOP) is not postulated unless the initiating break directly causes a LOOP.
- HELB interactions with cables result in the affected component(s) failing in the most undesired state or are evaluated for the effects of the interaction. However, the following exceptions apply. If an electric Load Center (LC) or Motor Control Center (MCC) is affected by interactions, the LC or MCC is considered to be de-energized. Components receiving power from this LC or MCC are considered de-energized and unable to function unless alternate power supplies are available. Valves directly powered from an affected MCC fail “as is” regardless of other interactions.
- The Reactor Trip Breakers and the CRD system can be excluded from the list of Shutdown Equipment components and potential HELB targets because the unit trip function can be considered to be completed prior to any potential degradation of the system due to any gradual adverse environmental effects caused by postulated HELBs.

3.6.2.6 DETERMINATION OF SAFE SHUTDOWN SYSTEMS

3.6.2.6.1 HELB Mitigation Strategy

The HELB Mitigation Strategy addresses the level of protection provided to systems, structures, and components (SSCs) necessary to reach SSD from the direct effects (pipe whip and jet impingement) and indirect effects (environmental and flooding) of a given HELB outside of the containment building. The major points of the strategy are as follows:

- Required SSCs located in the TB are not impacted by HELBs postulated to occur in the AB or in the yard.
- Required SSCs located in the AB are not impacted by HELBs postulated to occur in the TB.
- SAFs are imposed for those components required for initial mitigation.
- SAFs are not imposed for those components required to initiate a cooldown of the plant.
- HELBs resulting in the loss of plant systems inside the TB needed for SSD are mitigated by the Protected Service Water (PSW) system (see UFSAR Section 9.7).
- Should the PSW system be unavailable, the SSF (see UFSAR Section 9.6) is credited as an alternate means of achieving and maintaining SSD following HELBs that disable plant systems inside the TB.
- HELBs resulting in the loss of plant systems inside the AB needed for SSD are mitigated by normal plant systems or the SSF.
- As applicable, NUREG/CR-2913 is used for the determination of jet impingement effects following HELBs and critical cracks.
- Exclusion of systems whose operating time at high energy conditions is less than 1% of the total unit operating time.
- Exclusion of systems whose operating time at high energy conditions is less than approximately 2% of the total system operating time.
- Elimination of arbitrary intermediate breaks in ASME B & PV Section III-Class 2 and Class 3 equivalent piping. Intermediate breaks are postulated where calculated longitudinal stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.8(S_a + S_h)$.
- Intermediate breaks in non-rigorously analyzed piping are postulated in accordance with BTP MEB 3-1, Section B.1.c(2)(b)(i).
- Elimination of critical cracks at the most adverse location in ASME B&PV Section III-Class 2 and Class 3 equivalent piping. Critical cracks are postulated at axial locations

where the calculated stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.4(S_a + S_h)$. Critical cracks are not postulated at locations of terminal ends.

- Elimination of critical cracks at the most adverse location in non-rigorously analyzed piping. The effects of the postulated intermediate breaks bound the effects from critical cracks.
- HELBs occurring outside of the TB and AB are mitigated by normal plant systems.

3.6.2.6.2 Shutdown Objectives

HELBs outside of the containment building may or may not result in consequences that require an automatic trip of the reactor and main turbine. The operator may elect to trip the reactor and main turbine for personnel and equipment protection. The objective for each shutdown interval is provided below.

The shutdown sequence is divided into four intervals:

1. Shutdown of the Reactor and Main Turbine

   The objective is to place the reactor in a subcritical state to protect the core. The main turbine must be tripped to prevent excessive RCS cooling. With the exception of the MS supply to the turbine driven emergency feedwater pump (TDEFWP), the tripping of the main turbine also separates the MS lines from one another by closure of the main turbine stop valves.

2. Establishment of stable RCS conditions

   The objective is to balance the heat generation in the RCS with the heat being removed by the Steam Generators (SGs) such that RCS temperatures can be controlled. This is accomplished by maintaining RCS inventory control and establishing RCS pressure control such that coupling with the SGs can be restored or maintained. Secondly, feeding and/or steaming of the SGs are controlled in a manner such that the amount of heat generated by core decay heat and Reactor Coolant Pump (RCP) heat (if still running) is balanced with the heat removal from the SGs. Finally, a source of borated water sufficient to maintain the reactor in a subcritical condition is aligned and used to supply the RCS. Depending on the extent of damage from the HELB and the strategy used for mitigation, stable RCS conditions may be maintained up to 72 hours before plant cooldown would be initiated.

3. Initiation of RCS cooldown to approx. 250ºF

   The objective of this phase is to initiate a plant cool-down from the point where RCS conditions are stabilized to LPI entry conditions. The SGs are utilized for plant cooldown from normal post reactor trip conditions to approximately 250ºF. Typically, plant cooldown would be via forced circulation using any RCP. If all of the RCPs are unavailable, procedures are provided to initiate a natural circulation cooldown.

4. Establishment of the cold shutdown condition (RCS temperature < 200ºF)

   The objective of this phase of post-HELB operations is to transition from decay heat removal using the SGs to removing core decay heat using the LPI system. The LPI system, in conjunction with the low pressure service water system, is utilized to cool the RCS from approximately 250ºF to less than 200ºF.

3.6.2.6.3 Functions to meet Safe Shutdown Objectives

This section describes the functions needed to satisfy the shutdown objectives following a postulated HELB outside of the containment building. HELBs outside of the containment building can be divided into three categories: those that result in a loss of heat transfer (loss of SG feedwater), those that result in excessive heat transfer (loss of MS pressure boundary control), and those that result in loss of reactor coolant inventory (letdown line break). Loss of heat transfer scenarios result in a mismatch where more heat is generated in the core than is removed by the secondary system. These scenarios lead to an increase in RCS temperature and pressure. Excessive heat transfer scenarios result in a mismatch where more heat is removed by the secondary system than is generated in the core. These scenarios lead to a decrease in RCS temperature, pressure, and water level (due to reactor coolant shrinkage). Loss of inventory scenarios have a minor effect on the RCS due to the insignificant amount of inventory lost. The systems necessary to reach SSD were selected based on meeting the following Shutdown functions for the categories of HELB:

- Reactivity Control
- RCS Inventory Control
- RCS Pressure Control
- RCS Heat Removal Control
- Reactor Building (Boundary) Integrity
- Control Room Habitability (long term)
- Plant Cooldown
- Process Monitoring
- Support Functions

3.6.3 Safety Evaluation

Normal plant systems, the PSW system, and the SSF are credited for the mitigation of HELBs outside containment. MFDW HELBs result in overheating transients. MS HELBs result in overcooling transients.

The safety analysis acceptance criteria for each HELB transient are as follows:

Overheating Analysis

- The core must remain intact and in a coolable geometry.
- Minimum departure from nucleate boiling ratio (DNBR) meets specified acceptable fuel design limits.
- RCS pressure must not exceed 2750 psig (110% of design).

Overcooling Analysis

In addition to the criteria specified above, the following criteria are applicable (validated) for the most limiting overcooling analyses:

- The SG tubes remain intact.
- RCS remains within acceptable pressure and temperature limits.

The bounding overheating transient is a MFDW HELB in the TB resulting in a loss of all 4160 VAC power to normal plant systems. The bounding overcooling transient is a double MS HELB in the TB resulting in a loss of all 4160 VAC power to normal plant systems.

The PSW system is credited for the mitigation of HELBs inside the TB when a HELB results in the loss of plant systems needed for SSD. The SSF is credited as an alternate means for mitigation of HELBs inside the TB when a HELB results in the loss of plant systems needed for SSD.

3.6.3.1 PSW Response Following a MFDW HELB in the TB

The transient begins with an immediate and complete loss of MFDW from hot full power (HFP) conditions with an initial core power level of 102% of 2568 MW, as well as a loss of the 4160 VAC switchgear. This causes an immediate reactor trip and turbine trip due to the loss of power. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, or 3 minutes after a loss of RCP seal cooling. The motor driven emergency feedwater pumps (MDEFWP) are powered from the 4160 VAC switchgear and are not available. The TDEFWP is assumed to be unavailable.

Since portions of the integrated control system (ICS) are unprotected from HELB damage, the pressurizer power operated relief valve (PORV) is assumed to be unavailable. The combination of high end of cycle decay heat and delayed PSW flow to the SGs causes a large overheating transient in the primary system and a rapid increase in RCS pressure. RCS pressure increases to the pressurizer safety valve (PSV) lift setting, and the PSVs cycle to control RCS pressure until operators establish PSW flow 14 minutes into the event. PSW is assumed to be available at 14 minutes in the overheating analysis to prevent liquid relief through the PSVs. The peak RCS pressure in the overheating analysis is defined by the pressurizer safety relief valve characteristics since the PORV is not available. With an immediate reactor trip, the rate of RCS pressurization is such that maximum pressure occurs during the first PSV lift. The maximum pressure observed remains below the 2750 psig limit. Thus, the peak RCS pressure results obtained are not contingent on the timing of PSW flow.

Successful mitigation of a HELB condition at ONS shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overheating analysis the fuel integrity is ensured by the reactivity added via control rod insertion and maintaining the core covered. A minimum DNBR evaluation is not required for this analysis since the transient does not include a return to power and the DNBR at reactor trip is bounded by the existing UFSAR Chapter 15 analyses. RCS integrity is demonstrated by verifying the RCS pressure remains below the 2750 psig limit.

In summary, the results of the analysis demonstrate that PSW is capable of ensuring peak RCS pressure remains below the 2750 psig limit. Additionally, the results demonstrate there is sufficient decay heat removal (DHR) and primary coolant makeup to keep the core covered and maintain the RCS in Mode 3 for the duration of the scenario.

3.6.3.2 SSF Response Following a MFDW HELB in the TB

The transient begins with an immediate and complete loss of MFDW from HFP conditions with an initial core power level of 102% of 2568 MW, as well as a loss of the 4160 VAC switchgear. This causes an immediate reactor trip and turbine trip due to the loss of power. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, or 3 minutes after loss of RCP seal cooling. The MDEFWPs are powered from the 4160 VAC switchgear and are not available due to the loss of power. The TDEFWP is assumed to be unavailable.

Since portions of the ICS are unprotected from HELB damage, the pressurizer PORV is assumed to be unavailable. The combination of high end of cycle decay heat and delayed SSF auxiliary service water (ASW) flow to the SGs cause a large overheating transient in the primary system and a rapid increase in RCS pressure. RCS pressure increases to the PSV lift setting, and the PSVs cycle to control RCS pressure until operators establish SSF ASW flow 14 minutes into the event. The peak RCS pressure in the overheating analysis is defined by the pressurizer safety relief valve characteristics since the PORV is not available. With an immediate reactor trip, the rate of RCS pressurization is such that the maximum pressure occurs during the first PSV lift. The maximum pressure observed remains below the 2750 psig limit. Thus, the peak RCS pressure results obtained are not contingent on the timing of SSF ASW flow.

Successful mitigation of a HELB shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overheating analysis the fuel integrity is ensured by the reactivity added via control rod insertion and maintaining the core covered. A minimum DNBR evaluation is not required for this analysis since the transient does not include a return to power and the DNBR at reactor trip is bounded by the existing UFSAR Chapter 15 analyses. RCS integrity is demonstrated by verifying the RCS pressure remains below the 2750 psig limit.

In summary, the results of the analysis demonstrate that the SSF is capable of ensuring peak RCS pressure remains below the 2750 psig limit. Additionally, the results demonstrate there is sufficient DHR and primary coolant makeup to keep the core covered and maintain the RCS in Mode 3 for the duration of the scenario.

3.6.3.3 PSW Response Following a Double MS HELB in the TB

This analysis determines the plant transient response to a double MS HELB mitigated with PSW equipment and without credit for the automatic feedwater isolation system (AFIS). This analysis assumes an initial core power level of 102% of 2568 MW at HFP conditions. The initiating event causes double MS HELB, an immediate loss of 4160 VAC power, a reactor trip, a turbine trip, and a trip of all condensate and MFDW pumps. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, or 3 minutes after a loss of RCP seal cooling. The MDEFWPs are not available due to the loss of 4160 VAC power. To maximize the overcooling, the TDEFWP is assumed to automatically start and run without being throttled until the contents of the upper surge tank (UST) are delivered to the SGs. This scenario is intended to bound the consequences resulting from a double MS HELB.

The primary objective of this analysis is to demonstrate that the minimum DNBR is acceptable and that the plant will achieve a steady state condition where the RCS is in natural circulation flow conditions with PSW providing a heat sink, a PSW powered HPI pump providing seal injection flow, RCS pressure being maintained with the PSW powered pressurizer heaters, and pressurizer level being controlled by operation of the loop high point vents and/or PSW flow. This assures that the core remains intact and in a coolable geometry.

The double MS HELB causes the RCS to depressurize and shrink. As RCS pressure decreases the two CFTs inject additional borated inventory into the RCS. The core remains covered throughout the overcooling transient. The sustained overcooling in the affected loop is not sufficient to result in a return to criticality. The core remains subcritical after the rods insert for the duration of the transient. The core remains covered and cooled for the duration of the transient. The PSW powered HPI pump is started to restore RCP seal cooling and makeup to the RCS. PSW flow is available at 14 minutes, but not delivering flow to the SGs at this time due to the overcooling. The overcooling continues until shortly after the TDEFWP stops feeding the SGs.

After the overcooling has terminated, the RCS begins to slowly reheat and swell, pressurizer level returns on scale, and the PSW powered pressurizer heaters are manually energized. PSW flow is established to the SGs to stabilize RCS temperature and pressurizer level. Saturated conditions are established in the pressurizer and pressurizer heaters are then cycled to maintain

RCS pressure stable. Stable subcooled natural circulation conditions are achieved approximately three hours into the transient.

Successful mitigation of a HELB condition at ONS shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overcooling analysis the fuel integrity is confirmed by the DNBR analysis.

RCS integrity is demonstrated by determining the limiting SG tube compressive and tensile stresses remain with design limits, and that the RCS pressure and temperature remains within the acceptable cooldown limits during the transient evolution. The time dependent SG tube and SG shell temperatures are determined using a linear average to determine if the temperature differences remain within the SG design limits. The results indicate the SG tube stress remains well within the established limits for the duration of the transient. The cooldown performed through operator control of PSW to below 350ºF will provide margin to prevent tube deformation.

This analysis demonstrates that a double MS HELB can be mitigated using PSW equipment. In summary, the overcooling analysis demonstrates that for a double MS HELB scenario, the following acceptance criteria are satisfied:

- The core remains intact and in a coolable geometry,
- Minimum DNBR meets specified acceptable fuel design limits,
- The SG tubes remain intact,
- RCS pressure does not exceed 2750 psig, and
- RCS remains within acceptable pressure and temperature limits.

3.6.3.4 SSF Response Following a Double MS HELB in the TB

This analysis determines the plant transient response to a double MS HELB mitigated with SSF equipment and without credit for AFIS. This analysis assumes an initial core power level of 102% of 2568 MW at HFP conditions. The initiating event causes either a single or double MS HELB, an immediate loss of 4160 VAC power, a reactor trip, a turbine trip, and a trip of all condensate and MFDW pumps. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, or 3 minutes after a loss of RCP seal cooling. The MDEFWP are not available due to the loss of 4160 VAC power. To maximize the overcooling, the TDEFWP is assumed to automatically start and run without being throttled until the contents of the UST are delivered to the SGs. This scenario is intended to bound the consequences resulting from a MS HELB.

The primary objective of this analysis is to demonstrate that the minimum DNBR is acceptable and that the plant will achieve a steady state condition where the RCS is in natural circulation flow conditions with SSF ASW providing a heat sink, SSF reactor coolant makeup (RCMU) flow providing seal injection flow, RCS pressure being maintained with the SSF powered pressurizer heaters, and pressurizer level being controlled by operation of the SSF letdown line and/or SSF ASW. This assures that the core remains intact and in a coolable geometry.

The double MS HELB causes the RCS to depressurize and shrink. As RCS pressure decreases, the two CFTs inject additional borated inventory into the RCS. The core remains covered throughout the overcooling transient. While a brief recriticality is indicated, the resulting fission power obtained is not significant (less than one watt). The SSF RCMU pump is started to restore RCP seal cooling and makeup to the RCS. SSF ASW flow is available at 14 minutes, but not delivering flow to the SGs at this time due to the overcooling. The overcooling continues until shortly after the TDEFWP stops feeding the SGs.

After the overcooling has terminated, the RCS begins to slowly reheat and swell, pressurizer level returns on scale, and the SSF powered pressurizer heaters are manually energized. SSF ASW flow is established to the SGs to stabilize RCS temperature and pressurizer level. Saturated conditions are established in the pressurizer and pressurizer heaters are then cycled to maintain RCS pressure stable. Stable subcooled natural circulation conditions are achieved approximately three hours into the transient.

Successful mitigation of a HELB condition at ONS shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overcooling analysis the fuel integrity is demonstrated by the DNBR analysis.

RCS integrity is demonstrated by determining the limiting SG tube compressive and tensile stresses remain with design limits, and that the RCS pressure and temperature remains within the acceptable cooldown limits during the transient evolution. The time dependent SG tube and SG shell temperatures are determined using a linear average to determine if the temperature differences remain within the SG design limits. The results indicate the SG tube stress remains well within the established limits for the duration of the scenario. The cooldown performed through operator control of SSF ASW to below 350ºF will provide margin to prevent tube deformation.

To validate that RCS pressure and temperature remain within limits, these parameters are plotted versus each other to examine the time dependent response. These results indicate significant margin is maintained to the acceptable cooldown limits during the scenario.

This analysis demonstrates that a double MS HELB can be mitigated using SSF equipment. In summary, the overcooling analysis demonstrates that for a double MS HELB scenario, the following acceptance criteria are satisfied:

- The core remains intact and in a coolable geometry,
- Minimum DNBR meets specified acceptable fuel design limits,
- The SG tubes remain intact,
- RCS pressure does not exceed 2750 psig, and
- RCS remains within acceptable pressure and temperature limits.

INSERT 2

3.6.4 References:

9. Clarification Letter (related to the 15 December 1972 letter), dated 17 January 1973, from A. Schwencer (AEC) to A. C. Thies (DPC).

10. HELB Outside Containment Walkdown Criteria & Requirements, ONS, Units 1, 2, & 3.

11. Calculation OSC-8385 – Normal Operating Conditions for High Energy Line Break (HELB) Analysis (ONS Units 1, 2, & 3).

12. OSS-0254.00-00-4017 - Design Basis Specification for the "Pipe Rupture" – ONS Units 1, 2, & 3.

13. NRC Generic Letter 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements (Rev. 2 of BTP MEB 3-1), June 19, 1987.

14. Duke Energy Calculation, OSC-11769, Analysis of Postulated HELBs Outside of Containment.

15. Letter from A. Giambusso (AEC) to A. C. Thies (Duke Power Company), "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment," dated December 15, 1972.

Natural circulation cooldown mode of operation is not expected to be undertaken at Oconee Nuclear Station except for SBLOCA events which do not allow continued operation of or restart of reactor coolant pumps. In all other situations, procedures recommend that MODE 3 with average Reactor Coolant temperature ≥525°F be maintained until those systems required for forced circulation are put back into service.

In response to Generic Letter 81-21, Duke has developed a procedure to continuously vent the reactor vessel head to containment during a natural circulation cooldown to Decay Heat Removal System conditions. Venting the upper head area will maintain a cooling water flow through the upper head area and prevent the formation of a steam void in this area. This procedure results in a single steam void in the RCS, i.e, in the pressurizer, and simplifies pressure control during cooldown. NRC Safety Evaluation Report (Reference 1) concurs with Duke that natural circulation cooldown is not a safety concern due to operator training and procedures.

The effects of a HELB may drive a unit to an average reactor coolant temperature less than 525°F. The subsequent minor reduction in RCS temperature required to compensate for the increase in RCS inventory by the SSF RCMU pump during plant stabilization does not constitute a natural circulation cooldown requiring use of the reactor vessel head vent. Refer to Reference 2 for additional information.

5.1.3 References

1. Letter from J. F. Stolz (NRC) to H. B. Tucker (Duke) dated June 5, 1985. Subject: NRC Safety Evaluation Report on Duke Response to Generic Letter 81-21 Natural Circulation Cooldown.

2. License Amendment No. XXX, XXX, and XXX (date of issuance - Month XX, 20XX); HELB Mitigation.

THIS IS THE LAST PAGE OF THE TEXT SECTION 5.1.

License Amendment Request
Attachment 2

9.6 Standby Shutdown Facility

9.6.1 General Description

The Standby Shutdown Facility (SSF) houses stand-alone systems that are designed to maintain the plant in a safe and stable condition following postulated emergency events that are distinct from the design basis accidents and design basis events for which the plant systems were originally designed. The system provides additional "defense in-depth" protection for the health and safety of the public by serving as a backup to existing safety systems. The original licensing basis of the SSF provided an alternate means to achieve and maintain mode 3 with an average Reactor Coolant temperature ≥ 525°F (RCS cold leg temperature ≤ 555°F and RCS pressure ~ 2155 psig) following postulated fire, security-related, or turbine building flood events, and is designed in accordance with criteria associated with these events.

TB Flood does not occur with any other concurrent event. The loss of all other non-SSF power is a design criteria applied to the SSF design to ensure that the SSF can independently mitigate the event over the long term. A loss of offsite power (LOOP) is not postulated to occur at event initiation, however it could occur as a consequence of the flooding event. (References 36 and 37)

In the time since the SSF was licensed and build, various new licensing issues have broadened and re-defined the SSF licensing requirements. In the early 1980's soon after the TMI event, NRC took steps to ensure the Emergency Feedwater System was adequately designed, GL 81-14 was issued to ensure the EFW System was designed seismically. When EFW vulnerabilities were identified, the SSF was credited as an acceptable alternate heat removal system with the required seismic design (Reference 34). Similarly, the ability of the EFW System to withstand tornado missiles was questioned by NRC. The SSF was credited as an acceptable heat removal system with adequate tornado missile protection (Reference 4). When the Station Blackout Rule was issued, the SSF was credited as the alternat[illegible] the source of decay heat removal required to demonstrate safe[illegible] station blackout coping duration (References 2 and 3). A June[illegible] credited the SSF as one of multiple, alternate paths that can be[illegible] single failure vulnerabilities (Reference 35). Adoption of the [illegible] licensing basis from what was originally committed for Fire [illegible] differences are the elimination of the "ten minute rule" and th[illegible] required time to be at cold shutdown (See Section 9.5.1.3.2). A high energy line break (HELB) licensing basis reconstitution effort that began in the early 2000s resulted in the SSF being credited as an alternate means to achieve and maintain safe shutdown following HELBs in the turbine building and auxiliary building.

The SSF had certain design criteria and rules that were appli[illegible] licensing action that apply to those events for which the SSF [illegible] scope of issues for which SSF was credited broadened, it is important to realize that original SSF design criteria may or may not apply to these new scenarios. It is necessary to review the specific licensing correspondence for the specific issue to determine the applicable design criteria and other requirements.

Per the licensing correspondence which documented the SSF design criteria, SSF-designated events are not postulated to simultaneously occur with standard design basis events such as an earthquake or LOCA; therefore, the single failure criterion is not applicable or required. However, SSF systems are required to be designed such that a failure of an SSF component would not result in failures or inadvertent operation of existing plant systems that would prevent existing plant systems from performing their intended function. SSF ties to the existing plant are such that no SSF failure will result in consequences more severe than those analyzed in the UFSAR. The SSF requires manual activation that would occur under adverse fire, flooding, HELB, or

250°F with a long term strategy for reactivity, decay heat removal and inventory/pressure control. Long-term subcooled natural circulation decay heat removal is provided by supplying lake water to the steam generators and steaming to atmosphere. The extended coping period at these conditions is based on the significant volume of water available for decay heat removal and reduced need for primary makeup to only match nominal system losses. A stuck rod is not required to be postulated for this event. Initial conditions are 100% power with sufficient decay heat such that natural circulation can be achieved. The hypothesized fire is to be considered an "event", and thus need not be postulated concurrent with non-fire-related failures in safety systems, other plant accidents, or the most severe natural phenomena (Reference 31).

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Deleted Paragraph(s) per 2012 update.

TURBINE BUILDING FLOOD EVENT

The Turbine Building Flood was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to maintain the reactor in a safe shutdown condition for a period of 72 hours following a TB Flood. No other concurrent event is assumed to occur. The success criteria for this event is to assure natural circulation and core cooling by maintaining the primary coolant system filled to a sufficient level in the pressurizer while maintaining sufficient secondary side cooling. The reactor shall be maintained at least 1% $\Delta k/k$ with the most reactive rod fully withdrawn. (Reference 1, 10)

SECURITY-RELATED EVENT

A Security Related Event was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to achieve and maintain a safe shutdown condition for this event. No other concurrent event is assumed to occur. (Reference 1) The success criteria for this event is to assure the core will not return to criticality, the active fuel will not be uncovered, and long-term natural circulation will not be halted. (Reference 41)

STATION BLACKOUT EVENT

This event was licensed after the design of the SSF was completed and approved by NRC. The SSF was credited as the method the plant would employ to mitigate a SBO event. (References 38 and 39) The success criteria is to maintain the core covered for 4 hours. No stuck rod is assumed for this event. Initial conditions are 100% power and 100 days of operation. (Reference 40)

SSF TORNADO DESIGN CRITERIA

This is a design criterion for the SSF that was committed to as part of the original SSF licensing correspondence. All parts of the SSF itself that are required for mitigation of the SSF events are required to be designed against tornado winds and associated tornado missiles. This requirement is satisfied through appropriate design of the SSF structure. This requirement does not exten
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HELB Design Criteria

As a result of a HELB licensing basis reconstitution performed in the early 2000s, the SSF is credited for meeting the design requirements of certain HELB locations. The SSF provides an alternate means to achieve and maintain safe shutdown following HELBs in the turbine building and auxiliary building. See Section 3.6 for more details on the design criteria of HELBs outside containment.

EFW SEISMIC DESIGN CRITERIA (GL 81-14)

During the seismic qualification review of the Oconee EFW system in the 1980s, the NRC postulated that a seismic event could break a pipe and potentially cause a flood of the turbine

1. Turbine Building Flood caused by a break in the non-seismic condenser circulating water (CCW) piping system.
2. Infiltration of normal groundwater.

The structure meets the requirements of GDC 2, and the guidelines of Regulatory Guide 1.102 with respect to protection against flooding.

9.6.5 Operation and Testing

/criterion

The SSF will be placed into operation to mitigate the consequences of the following events:

1. Flooding
2. Fire
3. Sabotage
4. Station Blackout

5. High Energy Line Break

For fire events that require activation of the SSF for the unit affected, following local confirmation of the fire, the operator will staff the SSF and perform the electrical isolation/control transfer of the 600VAC Motor Control Center in the SSF as promptly as possible after confirmation of the fire. Following the control transfer, the operator will establish continuous communications with the Control Room of the unit affected awaiting instructions regarding the need to start and utilize the available SSF Diesel Generator, RCMU system and establish SSF Auxiliary Service Water flow to the steam generators as needed and close all of the Reactor Coolant System isolation valves that are controlled from the SSF.

Additionally, for fire events where SSF activation is required, main steam boundary valves must also be promptly closed to maintain proper control of RCS parameters while the SSF is made operational.

, high energy line break

For flooding, sabotage, station blackout and those fire events where the SSF is credited for safe shutdown, operators will be sent to the SSF. When directed by the shift supervisor or procedure, the operator will start the RCM system and establish SSF Auxiliary Service Water flow to the steam generators as needed, as well as close SSF controlled Reactor Coolant System pressure boundary valves.

Deleted Paragraph(s) per 2012 update.

In-service testing of pumps and valves will be done in accordance with the provision of ASME OM Code except for the Submersible Pump which is used to supply makeup water to the Unit 2 embedded condenser circulating piping. This pump should be tested every other year to verify flow capability. A recirculation flow path with flow and pressure instrumentation is available for SSF ASW pump testing.

The electrical power system components will be tested consistent with Duke Power's Testing Philosophy as described in the nuclear station directives.

9.6.6 References

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Oconee Nuclear Station Standby Shutdown Facility, Docket Nos. 50-269, 50-270, and 50-287, April 28, 1983
2. Safety Evaluation for Station Blackout (10 CFR 50.63) - Oconee Nuclear Station, Units 1, 2, and 3 (TACS M68574/M68575/M68576), Docket Nos. 50-269, 50-270, 50-287, March 10, 1992

Facility (SSF) Electrical Distribution System should the normal and emergency power sources to the SSF be lost.

The PSW System does not provide the primary success path for core decay heat removal following design basis events and transients. The Emergency Feedwater (EFW) System serves as the primary success path for design basis events and transients in which the normally operating main feedwater system is lost and the steam generators are relied upon for core decay heat removal. The PSW System serves as a backup to the EFW System and adds a layer of defense-in-depth to the SSF Auxiliary Service Water (ASW) System, which also serves as a backup to the EFW System.

(For HELBs, see UFSAR Section 3.6)

The PSW System reduces fire risk by providing a diverse QA-1 power supply to power safe shutdown equipment thus enabling the use of plant equipment for mitigation of certain fires as defined by the Oconee Fire Protection Program. For certain scenarios inside the Turbine Building (TB) resulting in loss of 4160V essential power, either the SSF or PSW System is used for reaching safe shutdown. The PSW System can achieve and maintain safe shutdown conditions for all three units for an extended period of operation during which time other plant systems required to cool down to MODE 5 conditions will be restored and brought into service as required. Similar to the SSF, the PSW System is equipped with a portable pumping system that may be utilized as necessary to replenish water to the Unit 2 embedded Condenser Circulating Water (CCW) piping. The water in the Unit 2 embedded CCW piping is used as a suction source for the PSW System. Electrical power is supplied from the PSW electrical system. The PSW portable pump is located in an onsite storage location. The portable pumping system is not expected to be necessary unless there is a prolonged use of the PSW System to feed the steam generators. Should there be a prolonged use of the PSW System, the portable pumping system would be used to replenish the water in the CCW piping since the PSW System takes suction off the CCW pipe at its low point in the Unit 2 Auxiliary Building.

The PSW System consists of the following:

1. PSW Building and associated support systems.
2. Conduit duct bank from the Keowee Hydroelectric Station underground cable trench to the PSW Building.
3. Conduit duct bank and raceway from PSW Building to Unit 3 Auxiliary Building (AB).
4. Conduit duct bank from PSW Building to SSF trench and from SSF trench to SSF.
5. Electrical power distribution system from breakers at Keowee Hydro Units (KHUs) and from breakers connecting the PSW Building to the Central Tie Switchyard, and from there to the AB and SSF.
6. PSW booster pump, PSW primary pump, and mechanical piping taking suction from Unit 2 embedded CCW System to the EFW headers supplying cooling water to the respective unit's SGs and HPI pump motor bearing coolers.
7. PSW portable pumping system.
8. PSW pump room exhaust fan (in AB).

Portions of the PSW System are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H - Mitigation Strategy License Condition.

such that it would be expected to withstand the design basis earthquake. The piping from the hotwell to the MDEFWPs is seismically qualified.

Portions of the EFW System are vulnerable to tornado missiles. Thus, the plant relies upon diverse means to provide feedwater to the SGs in the event of a tornado. These diverse means include the SSF ASW System and the PSW System.

The Emergency Feedwater System was not designed to withstand the effects of internally generated missiles. If such an event were to occur and if main feedwater were unavailable, the single train SSF ASW System would provide an assured means of providing heat removal from the SGs. A detailed evaluation of the capability of the existing EFW System to withstand missiles was not considered necessary (Reference 2).

The effects of High Energy Line Breaks have been analyzed as addressed in UFSAR Section 3.6~~.1.3~~.

Provisions for water hammer events are considered unnecessary due to the use of Once Through Steam Generators (OTSG) (Reference 9).

Portions of the Emergency Feedwater system are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H - Mitigation Strategy License Condition.

10.4.7.1.1 Deleted Per 2002 Update

10.4.7.1.2 Deleted Per 2002 Update

10.4.7.1.3 Deleted Per 2002 Update

10.4.7.1.4 Deleted Per 2002 Update

10.4.7.1.5 Deleted Per 2002 Update

10.4.7.1.6 Deleted per 1996 Revision

10.4.7.1.7 Deleted Per 2002 Update

10.4.7.1.8 Deleted Per 2002 Update

26. FDW-315 Hand/Auto Station in Manual Mode
27. FDW-316 Hand/Auto Station in Manual Mode
28. FDW-315 Automatic Control on Primary Control
29. FDW-316 Automatic Control on Primary Control
30. FDW-315 Nitrogen Pressure A Low
31. FDW-316 Nitrogen Pressure A Low
32. FDW-315 Nitrogen Pressure B Low
33. FDW-316 Nitrogen Pressure B Low

10.4.7.3 Safety Evaluation

Feedwater inventory is maintained in the SGs following reactor shutdown by one of the following methods listed:

1. Either of the two main feedwater pumps in combination with a hotwell pump and a condensate booster pump are capable of supplying both SGs at full secondary system pressure.
2. The two MDEFWPs are capable of supplying their associated SG at full secondary system pressure.
3. The single TDEFWP is capable of supplying both SGs at full secondary system pressure.
4. An alternate EFW supply available from the EFW System of one of the other units, capable of supplying both SGs at full secondary system pressure.
5. The hotwell and condensate booster pump combination has a discharge shutoff head of approximately 620 psia. There are three hotwell pumps and three condensate booster pumps. If required, the Turbine Bypass System or the Atmospheric Dump Valves (ADVs) can be used to reduce secondary system pressure to the point where one hotwell and condensate booster pump combination can supply feedwater to both SGs.
6. The SSF Auxiliary Service Water System is capable of supplying both SGs of all three units at full secondary system pressure.
7. The Protected Service Water System is capable of supplying both SGs of all three units at full secondary system pressure.

A sufficient depth of backup measures is provided to allow SG water inventory to be maintained by any of the diverse methods listed above. Although redundancy and diversity is provided as listed above, the EFW System has been designed with special considerations to enable it to function when conventional means of feedwater makeup may be unavailable.

Section 10.4.7.3.2

Redundancy is provided with separate, full capacity, motor and turbine driven pump subsystems. Except as noted in ~~the subsections that follow~~, failure of either the MDEFWPs or the TDEFWP will not reduce the EFW System below minimum required capacity. Pump controls, instrumentation, and motive power are separate in design.

The transients that require EFW have been evaluated assuming only one MDEFWP is available to deliver the necessary feedwater. Except as noted in ~~the subsections that follow~~, no single failure in the three pump, two flowpath EFW System design will result in only one available MDEFWP (i.e., two EFW pumps will remain available). Therefore, the evaluation assuming only

The volumes maintained in the UST and the condenser hotwell satisfy the EFW inventory required to support a plant cooldown following a loss of main feedwater transient with or without offsite power available. Assuming automatic steam generator level control, the minimum Technical Specification required 30,000 gallon inventory in the UST will provide at least 40 minutes of EFW flow with all three EFW pumps operating simultaneously (Reference 10). This inventory requirement also assures that the plant operators have at least 20 minutes to act, following the UST low level alarm, before the UST is emptied. The EFW pumps will remain aligned to the UST as long as adequate inventory can be maintained. If the UST inventory cannot be maintained, EFW pump suction will be aligned to the hotwell. A combined inventory in the UST and condenser hotwell of 155,000 gallons is sufficient to permit cooldown of the primary coolant at a rate of 50°F per hour following a reactor trip to decay heat removal entry conditions assuming a maximum allowable UST and hotwell temperature of 130°F (see Section 10.4.7.2).

The non-safety hotwell is not designed to withstand a single active failure. The limiting single active failure ... renders the ho... measures is p... PSW or the SS...

Certain HELBs in conjunction with postulated single failure can disable all sources of emergency feedwater. These HELBs are evaluated in applicable analyses as addressed in UFSAR Section 3.6.2. For these cases in which EFW is not available (TDEFWP, MDEFWP, cross-connects), the PSW system and the SSF ASW system provide an additional source of secondary cooling water.

10.4.7.3.2

~~10.4.7.3.2.1 HELBs Resulting in Loss of TC, TD, TE Switchgear~~

~~HELBs in the vicinity of the TC, TD, TE switchgear could cause their failure. The consequence of the switchgear failure would cause a complete loss of the Condensate and Feedwater System (loss of pumps). This event is similar to a station blackout on the affected unit. This would also cause a loss of both MDEFWPs due to loss of power. In addition, the DC power supply to the auxiliary oil pump (AOP) for the TDEFWP could be lost due to its location being adjacent to the switchgear. Loss of the AOP results in an inability to start the TDEFWP from the Control Room. The TDEFWP could be locally started and has sufficient capacity to satisfy the flowrate requirements for this event. A single failure of the TDEFWP would lead to a complete loss of main and emergency feedwater. If the TDEFWP is the single failure, the SSF ASW System is credited to feed the SGs. In addition, alignment of an unaffected unit's EFW System could be performed to feed the SGs.~~

~~10.4.7.3.2.2 Feedwater/Main Steam Line Breaks Causing Loss of SG Pressure Boundary~~

~~Large line breaks in the Feedwater/Main Steam System that result in a depressurization of the steam generator will result in actuation of the Automatic Feedwater Isolation System (AFIS). Once actuated, all main feedwater will be automatically isolated to the faulted steam generator and the TDEFWP will be inhibited from automatically starting. The MDEFWPs will automatically start and feed both steam generators. If the AFIS rate of depressurization setpoint is exceeded coincident with low steam line pressure, the MDEFWP feeding the faulted steam generator will be tripped. For smaller break sizes that do not exceed the rate of depressurization setpoint, the operator is required to manually terminate EFW flow to the faulted steam generator by either closing the EFW flow control valve or by stopping the MDEFWP. These actions can be done from the Control Room. The operator has sufficient Control Room indication of SG level and pressure and would be aware of such a situation. Concurrently, the operator would monitor the intact SG to maintain adequate inventory and secondary heat removal via the EFW System.~~

~~In the event of a single active failure of the MDEFWP to the intact steam generator, manual operator action is required to start the TDEFWP to provide sufficient flow for adequate core cooling. AFIS would isolate main feedwater to the faulted steam generator, and inhibit the automatic start of the TDEFWP. The preferred method of mitigating this event, after having isolated flow to the affected SG, would be to restart the TDEFWP by manual operator action in the Control Room. However, if the TDEFWP is not available, the remaining MDEFWP could be aligned to the unaffected SG by manual operator action outside of the Control Room via the cross connect (FDW-313 and FDW-314).~~

~~In the event of a postulated failure of the EFW flow control valve to the intact steam generator, manual operator action would be required to align the MDEFWP through the main feedwater startup control valve. The AFIS circuitry must be disabled by the operator to allow EFW flow alignment through the non-safety MFW startup control valves. This alternate path through the main feedwater startup control valve relies on non-safety equipment and non-safety support systems (electrical power and instrument air). This alignment may not be available in LOOP events. The main feedwater startup block valves receive power from load shed power which may not be immediately available following a LOOP.~~

~~If the EFW control valve on the unaffected SG fails to open and the main feedwater startup path is unavailable, then the SSF ASW System would be required to feed the unaffected SG for heat removal. If the EFW flow control on the unaffected SG fails open (on a loss of compressed air and nitrogen), this could result in the SG overcooling and subsequent loss of EFW to the unaffected SG due to pump runout. The safety analyses assume both SGs are isolated within 10 minutes, with subsequent action outside the Control Room for local manual control of the EFW control valve if the valve failed open. The EFW flow control valves are located in the penetration rooms adjacent to the Control Room. Except in those cases where the break makes these valves inaccessible, an operator could manually adjust either valve. In the event this path were unavailable, the SSF ASW System provides an alternate means of establishing feedwater flow to the unaffected steam generator.~~

~~Certain breaks could deplete hotwell inventory. The impact of this loss of inventory is encompassed by the high energy line breaks described in Section 10.4.7.3.2.3.~~

~~10.4.7.3.2.3 Other Condensate/Feedwater Line Breaks that Result in a Loss of Condenser Hotwell Inventory~~

~~This class of condensate and feedwater line breaks could result in depletion of stored inventory in the hotwell due to continued operation of the hotwell and condensate booster pumps. These line breaks cause the hotwell makeup valves to open to control hotwell level. On a low UST level, automatic closure signals are sent to close the UST Riser Automatic Isolation valves to preserve the minimum required inventory of 30,000 gallons in the UST. The SSF ASW System would be available for feeding the SGs. HPI forced cooling also remains available. In addition, EFW could be aligned from an alternate unit using the unit cross connects.~~

10.4.7.3.3 EFW Response Following a SBLOCA

For certain size small break loss of coolant accidents, feedwater is required to remove the decay heat and reactor coolant pump heat which is not relieved through the break. The EFW flow rate demand requirements for a SBLOCA, with and without a loss of offsite power, are bounded by the LOMFW event in Section 10.4.7.3.1 in which a break in the primary system is not present to help remove system heat.