ATTACHMENT 5

THERMAL-HYDRAULIC MODELS FOR HIGH ENERGY LINE BREAK TRANSIENT ANALYSIS [NON-PROPRIETARY]

Attachment 5

Thermal-Hydraulic Models for High Energy Line Break Transient Analysis [Non-Proprietary]

Note: Text that is within brackets is proprietary to Duke Energy or Framatome. The subscripts D or F, respectively, are used to identify the appropriate company.

The T-H analyses for HELB scenarios described in the LAR enclosure have been performed using either Duke Energy's RELAP5/MOD2-B&W ONS T-H model, or Duke Energy's RETRAN-3D ONS model. The RCS T-H analyses evaluate the ability to mitigate HELBs in the TB or EPR for the ONS using SSF, PSW, or normal plant equipment mitigation. The methods associated with each model are described below.

1.0 ONS T-H Models

1.1 ONS RELAP5/MOD2-B&W T-H Model

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 RELAP5/MOD2-B&W model and analysis methods are described in Duke Energy's NRC approved methodology report DPC-NE-3003-PA (reference 22). The ONS RELAP5 model is designed primarily for use with small and large break LOCA applications. This model has been modified to include additional detail and features required to perform the analyses described in Attachment 6.

RELAP5/MOD2-B&W is derived from RELAP5/MOD2 Cycle 36.05, which is an advanced T-H computer code developed by EG&G Idaho for the NRC. The code was originally developed to provide the NRC with a tool for auditing licensing analyses of both large and small break LOCAs. Babcock & Wilcox (B&W) (now Framatome) modified RELAP5/MOD2 by including the evaluation model correlations and methods required by 10 CFR 50 Appendix K. This NRC approved code is described in reference 22 and in BAW-10164P-A, Revision 4 (reference 54).

RELAP5/MOD2 is selected for these analyses based on the potential for sustained two-phase conditions in the RCS piping. The MS HELB analysis can result in sufficient overcooling that leads to two-phase conditions in the RCS piping which can potentially interrupt natural circulation. To accurately predict this phenomenon the RELAP5/MOD2 code was selected to perform this analysis. The FDW HELB analyses can also result in sustained two phase conditions, indicating that RELAP 5 based methods are more appropriate to perform the analysis. RETRAN based methods are selected for analyses where sustained two phase conditions are not expected.

1.2 ONS RETRAN-3D T/H Model

The ONS RETRAN-3D model has previously been approved for use in the ONS UFSAR Chapter 6 steam line break and Chapter 15 accident 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). This model has been modified to include additional detail and features required to perform the analyses described in Attachment 6.

2.0 Analysis Description

Analyses have been performed for each of the scenarios to evaluate the ONS RCS response to a HELB using normal plant, SSF, and PSW equipment for establishing SG heat removal to the unit experiencing the 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

the scenario. The results of the analyses met the acceptance criteria. Details of the overheating and overcooling analyses are contained in Attachment 6.

2.1 Overheating Analysis Description

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 FDW HELB.

Three scenarios, described below, are evaluated for establishing SG heat removal to the unit experiencing the FDW HELB. EFW is credited for cases where 4160 VAC power remains available. For scenarios where 4160 VAC power is lost due to the HELB, two alternatives are evaluated for mitigation strategies using either PSW or SSF equipment.

2.1.1 4160 VAC Power Available

For scenarios where 4160 VAC power remains available, ES equipment is credited for mitigation. These scenarios include FDW HELBs in the EPR and TB.

2.1.1.1 4160 VAC Power Available - TB FDW HELB

The initiating event from hot full power (HFP) conditions causes an immediate and complete loss of MFDW resulting in a reactor trip on high RCS pressure 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, or 3 minutes after a loss of RCP seal cooling, or through established procedural guidance. Normal plant equipment is available to mitigate the overheating transient. The primary objective of the analysis is to demonstrate the ability to satisfy the proposed HELB mitigation acceptance criteria for a limiting overheating scenario.

For performing the overheating analysis for a FDW HELB scenario with 4160 VAC power available, the RELAP5/MOD2-B&W ONS T-H model has been modified to: 1) include ambient heat losses from the pressurizer after the time of peak RCS pressure, 2) improve its capability to model thermal stratification of fluid in the pressurizer region, and 3) add loop high point vents and RV head vent modeling.

2.1.1.2 4160 VAC Power Available – EPR FDW HELB

The initiating event from HFP conditions causes an immediate loss of MFDW resulting in a reactor trip on high RCS pressure 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, or 3 minutes after a loss of RCP seal cooling, or through established procedural guidance. Two break locations are considered. The only breaks postulated upstream of the check valve are critical cracks. Critical cracks are defined as equivalent to half the pipe OD by half the pipe thickness, or 0.05 ft^2 for the FDW pipe. Downstream of the check valve the break area is limited to 0.54 ft^2 by a guard pipe.

The break location downstream of the check valve allows the affected SG to completely depressurize resulting in an AFIS actuation on low steam line pressure and high rate that trips the MFDW pumps, closes MDFW valves to the affected SG, and blocks the auto start of the turbine driven EFW pump and the motor driven EFW pump on the affected loop. AFIS actuation to trip the MFDW pumps actuates the remaining motor driven EFW pump. The primary objective of the analysis is to demonstrate the ability to satisfy the proposed HELB mitigation acceptance criteria for a limiting overheating scenario.

AFIS is modeled for this scenario since its actuation limits the available heat sink and represents a penalty in the analysis.

For performing the overheating analysis for a FDW HELB scenario with 4160 VAC power available, the RELAP5/MOD2-B&W ONS T-H model has been modified to: 1) include ambient heat losses from the pressurizer after the time of peak RCS pressure, 2) improve its capability to model thermal stratification of fluid in the pressurizer region, 3) add portions of the condensate and FDW system piping to represent the fluid volumes, and 4) add loop high point vents and RV head vent modeling.

2.1.2 4160 VAC Power Unavailable - SSF Mitigation

For scenarios where 4160 VAC power is lost due to a FDW HELB in the TB, mitigation with SSF equipment is credited. The initiating event from HFP conditions causes an immediate loss of 4160 VAC power, and an immediate and complete loss of MFDW 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, or 3 minutes after loss of RCP seal cooling. The primary objective of the analysis is to demonstrate the SSF is capable of meeting the proposed HELB mitigation acceptance criteria for a limiting overheating scenario.

For performing the overheating analysis for an SSF mitigated FDW HELB scenario, the RELAP5/MOD2-B&W ONS T-H model has been modified to: 1) include ambient heat losses from the pressurizer after the time of peak RCS pressure, 2) improve its capability to model thermal stratification of fluid in the pressurizer region, 3) eliminate the MFDW piping to conservatively minimize liquid added to the SGs, and 4) add the modeling for the SSF letdown line.

2.1.3 4160 VAC Power Unavailable - PSW Mitigation

For scenarios where 4160 VAC power is lost due to a FDW HELB in the TB, mitigation with PSW equipment is credited with providing a means of establishing SG heat removal to the unit experiencing the FDW HELB. The initiating event from HFP conditions causes an immediate loss of 4160 VAC power, and an immediate and complete loss of MFDW 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, or 3 minutes after a loss of RCP seal cooling. The primary objective of the analysis is to demonstrate that PSW equipment is capable of meeting the proposed HELB mitigation acceptance criteria for a limiting overheating scenario.

For performing the overheating analysis for a PSW mitigated FDW HELB scenario, the RELAP5/MOD2-B&W ONS T-H model has been modified to: 1) include ambient heat losses from the pressurizer after the time of peak RCS pressure, 2) improve its capability to model thermal stratification of fluid in the pressurizer region, 3) eliminate the MFDW piping to conservatively minimize liquid added to the SGs, and 4) add loop high point vents and RV head vent modeling.

2.2 Overcooling Analysis Description

Postulated MS system piping failures are analyzed for their effects on the ability to achieve and maintain SSD of the affected unit following a MS 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 scenarios, described below, are evaluated for establishing SG heat removal to the unit experiencing the MS HELB. EFW is credited for cases where 4160 VAC power remains available. For scenarios where 4160 VAC power is lost due to the HELB, two alternatives are evaluated for mitigation strategies using either PSW or SSF equipment.

2.2.1 4160 VAC Power Available

For scenarios where 4160 VAC power remains available, ES equipment is credited for mitigation. These scenarios include MS HELBs in the EPR and TB.

2.2.1.1 4160 VAC Power Available – Single MS HELB

For scenarios where 4160 VAC power remains available, ES equipment is credited for mitigation. These scenarios include MS HELBs in the EPR and TB. The core response for these HELB scenarios are bounded by the UFSAR Chapter 15.13 large steam line break and UFSAR Chapter 15.17 small steam line break analyses. EFW is available to provide a heat sink, and HPI flow is available to ensure adequate RCS inventory.

For scenarios where 6900 VAC power is maintained, 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.

Small MSLBs are analyzed in UFSAR Section 15.17. A limiting break size was determined in the analysis that resulted in a maximum power excursion, which occurs by avoiding a RPS trip function. The analysis assumes that the electrical distribution system as well as the secondary systems remain in operation such that the reactor does not automatically trip. Should the 230 kV red and yellow buses, both main feeder buses, or the 6900 VAC buses be lost, the reactor will automatically trip. A loss of the condensate and MFDW systems would also result in an automatic trip of the reactor on high RC pressure. Any of these direct effects on plant equipment would result in less limiting consequences than that already analyzed in UFSAR Section 15.17.

The methods for these scenarios are previously approved.

2.2.1.2 4160 VAC Power Available – Double MS HELB

For scenarios where 4160 VAC power remains available, ES equipment is credited for mitigation. These scenarios evaluate double MS HELBs in the TB, with a break located on each steam line. The condensate and MFDW pumps remain available to feed the SGs. With 6900 VAC power available, the RCPs remain in operation until operator action is taken to trip the RCPs 2 minutes after a loss of indicated subcooled margin. Although both MS lines are assumed to be lost, the turbine driven EFW pump is assumed to operate to ensure a conservative overcooling response is obtained. EFW is available to provide a heat sink, and HPI flow is available to ensure adequate RCS inventory and boration.

For performing the overcooling analysis for this HELB scenario, the RETRAN-3D ONS T-H model has been modified to include an additional break location. The remainder of the model is the same as that described in the UFSAR 15.13 analyses.

2.2.2 4160 VAC Power Unavailable – SSF Mitigation

For scenarios where 4160 VAC power is lost due to a MS HELB in the TB, mitigation with SSF equipment is credited with providing a means of establishing SG heat removal to the unit experiencing the HELB.

This analysis evaluates the plant transient response to a single or double MS HELB and loss of the 4160 VAC ES switchgear due to a HELB that results in damage to the switchgear and other equipment in the TB. The HELB 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 primary

objective of the analysis is to demonstrate the SSF is capable of meeting the proposed HELB mitigation acceptance criteria for a limiting overcooling scenario.

For performing the overcooling analysis for an SSF mitigated HELB scenario, the RELAP5/MOD2-B&W ONS T-H model has been modified to: 1) include ambient heat losses from the pressurizer, 2) improve its capability to model thermal stratification of fluid in the pressurizer region, 3) add portions of the condensate and FDW system piping to represent the fluid volumes anticipated to flash and contribute mass to the SGs, and 4) add detailed steam line modeling to capture the effects of liquid entrainment.

2.2.3 4160 VAC Power Unavailable - PSW Mitigation

For scenarios where 4160 VAC power is lost due to the HELB, mitigation with PSW equipment is credited with providing a means of establishing SG heat removal to the unit experiencing the HELB.

This analysis evaluates the plant transient response to a single or double MS HELB and loss of the 4160 VAC ES switchgear due to a HELB that results in damage to the switchgear and other equipment in the TB. The HELB 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 loss of RCP seal cooling. The primary objective of the analysis is to demonstrate that PSW is capable of meeting the proposed HELB mitigation acceptance criteria for a limiting overcooling scenario.

For performing the overcooling analysis for a PSW mitigated HELB scenario, the RELAP5/MOD2-B&W ONS T-H model has been modified to: 1) include ambient heat losses from the pressurizer, 2) improve its capability to model thermal stratification of fluid in the pressurizer region, 3) add portions of the condensate and FDW system piping to represent the fluid volumes anticipated to flash and contribute mass to the SGs, and 4) add detailed steam line modeling to capture the effects of liquid entrainment.

3.0 RELAP5 Model Modifications

The aforementioned modifications to Duke Energy's RELAP5/MOD2-B&W ONS T-H models are described in more detail below. The modified RELAP5/MOD2-B&W ONS T-H models have been developed specifically for performing overheating and overcooling transient analyses of HELB scenarios mitigated using either normal plant, SSF, or PSW equipment. Duke Energy does not intend to apply these models or modifications to the ONS UFSAR Chapter 6 accident analyses. Therefore, a revision to Duke Energy's NRC approved methodology report, DPC-NE-3003-PA (reference 22), will not be made. Should the need arise, Duke Energy intends to use the modified RELAP5/MOD2-B&W ONS T-H models in future HELB analyses to evaluate changes to the plant and operator guidance.

While these modifications have been developed and applied for the analysis of a HELB scenario mitigated using either normal plant, SSF, or PSW equipment, Duke Energy considers the modifications to be equally suitable for use in analysis of other similarly mitigated scenarios.

3.1 Ambient Heat Losses

The existing RELAP5/MOD2-B&W ONS T-H model exterior heat structures (or conductors) on the RCS and pressurizer components are modeled with [ ]$_D^{a,c}$ The heat structure inputs are selected to [ ]$_D^{a,c}$ To model ambient heat losses from a region of the RCS, the associated heat structures are converted to [

]$_{D}^{a,c}$

Within the RELAP5/MOD2-B&W ONS models used for the overheating and overcooling analysis for a HELB scenario mitigated by normal plant equipment, SSF, or PSW, ambient heat losses are [

]$_{D}^{a,c}$ This change is considered an enhancement to the existing models since it allows more accurate modeling of the impact of real phenomena on the pressurizer response for longer duration scenarios associated with the SSF or PSW. Ambient heat losses from the pressurizer are modeled in the overheating (after the peak RCS pressure occurs) and overcooling analyses. Ambient heat losses from the other RCS structures are not modeled in the overheating and overcooling analyses. This is conservative for overheating analyses, and consistent with the approach described in references 21, 22 and 53. Ambient heat losses from the RCS do not play a significant role during relatively short duration overcooling scenarios.

3.2 RV Head Axial Conduction

For the RELAP5/MOD2-B&W ONS T-H model described in reference 22, the RV upper head region is divided into [ ]$_{D}^{a,c}$ Due to nodalization limitations, the top-most RV upper head node is effectively a dead-ended volume. During a transient, the fluid conditions in this node can be affected by the nodalization. This is non-physical since buoyancy effects would cause circulation and mixing of the RCS fluid in this region. If the dead-ended node were to become voided due to depressurization, the dead-ended volume effect would impact the nature of subsequent condensation and refill. In the overcooling analysis, to mitigate this non-physical behavior [

]$_{D}^{a,c}$ The RV upper head includes numerous axial structures, a portion of which are modeled to allow heat transfer across node boundaries.

3.3 Pressurizer Nodalization for Thermal Stratification of Pressurizer Fluid

As described in the Enclosure section 3.7, the HELB scenarios can be generically classified as RCS overheating or overcooling transients. The pressurizer plays a significant role in regulating RCS pressure during these transients, and experiences several important phenomena for both overcooling and overheating conditions.

In general, for overheating scenarios, there is an initial insurge of subcooled liquid into the pressurizer from thermal expansion of the RCS inventory. If the overheating transient is short lived, the presence of subcooled liquid in the pressurizer has little impact on the immediate response. This is because there is little mixing in the fluid region under these conditions and buoyancy (density) effects cause the colder liquid in the pressurizer to remain near the bottom of the vessel, while the hotter (originally saturated) liquid remains near the top of the water column and in contact with the vapor space. Thermal stratification of the pressurizer liquid helps limit the amount of steam condensation that occurs at the steam-liquid interface during these pressure excursions.

For RCS overcooling transients, saturated liquid in the pressurizer flashes to steam, expands, and limits the depressurization rate of the RCS. Subsequently when the pressurizer refills, insurges of subcooled liquid to the pressurizer can limit the ability of the pressurizer to regulate subsequent depressurizations of the RCS. For more severe overcooling scenarios, the

pressurizer may empty as a result of the initial overcooling, but subcooled liquid will refill the pressurizer once operators restore RCS pressure or pressurizer level to the specified operating range. In the longer term recovery phase, operator actions to stabilize pressurizer level and energize pressurizer heaters allows the fluid in the pressurizer to resaturate and restore RCS pressure to a desired range.

For scenarios mitigated with limited pressurizer heater capacity, the ability to re-saturate the subcooled liquid in the pressurizer is greatly diminished. Additionally, pressurizer ambient heat losses can cause condensation of the vapor space on internal structural surfaces. Continued condensation of the vapor space leads to a reduction in RCS pressure and increases in pressurizer level. As the vapor space collapses, the continual insurge of subcooled liquid challenges the ability of the pressurizer heaters to re-saturate the fluid. Should the pressurizer eventually refill to a water-solid condition, RCS pressure control is provided by balancing makeup and letdown flow with either the SSF letdown line, pressurizer PORV or loop high point vents.

In order to evaluate longer duration transients, it is important that the T-H models be capable of capturing the effects from thermal stratification and ambient heat losses in the pressurizer. Modifications for modeling ambient heat losses are described above. To improve the modeling capability for thermal stratification of fluid in the pressurizer region, a finer nodalization is required.

Section 2.1 of reference 22 describes the original pressurizer modeling approach in the RELAP5/MOD2-B&W ONS model. The RELAP5/MOD2-B&W pressurizer is modeled with [$]_D^{a,c}$ In order to increase the spatial resolution of axial temperature gradients that can establish in longer duration SSF scenarios, [$]_D^{a,c}$ as well as improved predictions of thermal stratification of the liquid region during insurges, outsurges, and large pressure drops.

3.4 Main Feedwater and Condensate System Nodalization

Section 2.1 of reference 22 describes the MFDW piping included in the RELAP5/MOD2-B&W ONS T-H base model. The ONS model nodalization includes the MFDW piping between the last check valve and the SG. This enables modeling flashing of the MFDW in the piping if the SG pressure decreases low enough for the flashing to occur. Should this occur additional hot water would be expelled into the SG with the potential to increase secondary to primary heat transfer, which is conservative for LOCA mass and energy release calculations. This modeling detail is necessary to accurately model the MFDW boundary condition.

For overheating scenarios, it is conservative to minimize the amount of FDW that can enter the SGs. For the HELB overheating analysis of pipe breaks located upstream of the last check valve, the MFDW piping included in the ONS RELAP5 base model is removed to conservatively minimize liquid added to the SGs. For the EFW mitigated HELB overheating analysis of a break downstream of the last check valve in the EPR, the portions of the MFDW piping required to appropriately model the flow and break location boundary conditions are added to the model.

For overcooling scenarios, it is conservative to maximize the amount of FDW that can enter the SGs. For the HELB overcooling analysis, the portions of the condensate and FDW system piping that are anticipated to flash due to the depressurization and contribute mass to the SGs

are included in the model. The MFDW control valves are assumed to remain open to allow the maximum amount of FDW to enter the SG.

3.5 Main Steam System Nodalization

The RELAP5/MOD2-B&W ONS T-H model described in Section 2.1 of reference 22 represents the MS piping from the SG to the turbine with a single volume for each loop. This level of nodalization is acceptable for performing mass and energy release calculations where the turbine stop valves are assumed to close immediately without delay upon break initiation and the turbine bypass valves (TBVs) are assumed to be unavailable, and other MS branch lines (2nd stage reheat, etc.) are also assumed to be isolated. Therefore, the secondary coolant is isolated in the SGs and steam lines and is available to transfer energy from the primary fluid. The secondary steam release is accomplished via the MSRVs.

For overheating scenarios, the nodalization included in the RELAP5/MOD2-B&W ONS T-H base model is conservative to represent the heat transfer and steam release from the SGs.

For overcooling scenarios, additional phenomena are present that potentially impact the ability to remove heat from the SGs. These phenomena are associated with the rapid depressurization due to postulated MS piping breaks. The rapid depressurization will initially cause a liquid level swell and entrainment due to high steam velocities. The SG outlet nozzles installed in the Replacement Once Through Steam Generators (OTSGs) serve to limit the blowdown mass flow rate. Entrained liquid droplets in the steam flow may become de-entrained in the vertical portions of the steam line piping downstream of the SGs. Modeling the vertical piping enables a liquid level in this section of steam line that could impact conditions within the SG. Additional detail that preserves flow area and elevation change is included in the steam line nodalization used for the HELB overcooling analysis to allow the analysis to capture these effects.

3.6 Steam Generator Modeling

Section 2.1 of reference 22 describes the SG modeling approach in the RELAP5/MOD2-B&W ONS base model. This approach provides conservative modeling of primary to secondary heat transfer for small and large break LOCA applications.

The RELAP5/MOD2-B&W EFW heat transfer model described in reference 54 is used to model flow through the SG upper nozzles for the overheating and overcooling analysis; this model has been approved for use in licensing calculations for OTSG designs (reference 22 and reference 54). The upper nozzles are used by a variety of SG feed sources including SSF ASW, PSW, EFW, B5b, and Flex pumps, and MFDW after the integrated control system (ICS) realigns valves to direct FDW to the upper nozzles if all four RCPs trip. The RELAP5/MOD2-B&W ONS EFW model consists of [

]F To use this model, the OTSG tubes are modeled with [

]F

Reference 22 includes a conservative modeling approach based on the experimental results referenced in reference 56. The SER for the Babcock and Wilcox Owners Group CRAFT2 small break LOCA evaluation model (reference 55), includes a re-evaluation of the effectiveness of EFW, the technical bases for the SG level requirements during small break LOCA conditions, and a review of the appropriate operating guidelines and utility operating procedures.

Reference 56 describes the SG model included in reference 55. Reference 56 discusses EFW modeling and benchmarks, and provides [ ]$_{D}^{a,c,e}{}_{,F}$ This supports the [ ]$_{D}^{a,c}$ assumed in reference 22 for performing LOCA mass and energy release calculations, as appropriate for minimizing SG heat transfer.

Reference 56 also indicates [ ]$_{D}^{a,c,e}{}_{,F}$

For overheating scenarios, the limiting peak RCS pressure occurs prior to SSF ASW or PSW being aligned to the SGs for cooling. The RELAP5/MOD2-B&W ONS T-H model is modified [ ]$_{D}^{a,c}$ This selection conservatively represents SG heat transfer and is appropriate for representing the cooldown phase of the transient.

For overcooling scenarios, the wetted tube fraction is increased to maximize the high-elevation heat transfer. The RELAP5/MOD2-B&W ONS T-H model is modified [ ]$_{D}^{a,c}$

3.7 Boundary Condition Modeling

The overheating and overcooling analyses for HELB scenarios include several boundary conditions that are not described in reference 22. These boundary conditions require additional modeling features to be included in the RELAP5/MOD2-B&W ONS model to facilitate the analyses. These modeling features include the steam line ADVs, SSF ASW, PSW, turbine driven EFW, secondary steam loads, loop high point vents, the RV head vent and the SSF letdown line. The modeling approach for several of these features considers the impact of asymmetric loop conditions on the performance of the individual boundary condition. These modeling features are applied in a manner to ensure appropriate boundary conditions are specified for each analysis.

SSF ASW is generally available at 14 minutes for SSF mitigated analyses. SSF ASW is assumed to be available at 14 minutes in the overcooling analysis, but is not delivering flow to the SGs at this time due to the overcooling. In the overheating analysis where SSF mitigation is credited, SSF ASW is assumed to be available at 14 minutes. In overheating analysis cases designed to bound either SSF or PSW mitigation, SSF ASW is assumed to be available at 15 minutes. For cases where 4160 VAC power is available, EFW is credited using typical Chapter 15 response times.

Certain T-H analyses assume SSF ASW flow to be available at 14 minutes in the HELB overheating analysis to prevent liquid relief through the PSVs or PORV. The supporting analyses assume a time of 15 minutes for PSW flow, consistent with the current PSW licensing basis. Since SSF and PSW are modeled using the same flow rate, the results of SSF cases that assume flow is available at 14 minutes are used to support this LAR. Crediting PSW with providing a heat sink at an earlier point in time does not adversely impact the analytical results.

The peak RCS pressure in the overheating analysis is defined by the pressurizer safety relief valve characteristics as the PORV is assumed to not be available. With an immediate reactor trip, the rate of RCS pressurization is such that pressurization does not continue after the PSVs begin to lift. Thus, the peak RCS pressure results obtained are not contingent on the timing of SSF or PSW flow. The peak RCS pressure is not limiting for cases where the pressurizer PORV or loop high point vents are available.

The steam line ADVs (or other steam flow paths) are included in the overcooling analysis for examining long term recovery actions for single MS HELB cases, and are not credited in the mitigation phase of the analysis.

4.0 RELAP5/S3K Reactivity Evaluation

The RELAP5 core response is determined with a point kinetics model which is generally recognized as providing a conservative power response relative to the response obtained using 3D methods. To ensure that an appropriate transient reactivity is calculated for the overcooling analysis, SIMULATE-3K (S3K) 3D core models are used to assess the RELAP5 reactivity calculation. A comparison is performed between RELAP5 and S3K to ensure a conservative (i.e., higher return to power) power response is obtained. The process used is based on the MSLB methodology described in Duke Energy's NRC approved methodology report DPC-NE-3005-PA "UFSAR Chapter 15 Transient Analysis Methodology" (reference 53) with exceptions as discussed below.

The process begins by selecting bounding reactivity parameters as inputs to the RELAP5 point kinetics reactivity calculation. Time dependent T-H parameters from the RELAP5 calculation are provided for input to S3K for a cycle-specific calculation using consistent thermal/hydraulic forcing functions. Then, to remove excess conservatism in the predicted reactivity, an input parameter to the RELAP5 point kinetics model is adjusted that impacts the magnitude of the reactivity, without altering the overall response shape. In the HELB overcooling analysis, the parameter selected for adjustment is the trippable rod worth.

The objective of the S3K calculation is to demonstrate that the RELAP5 reactivity calculation remains conservative for a specific ONS core, and the RELAP5 power response bounds (is greater than) that obtained by S3K.

The MSLB methodology described in DPC-NE-3005-PA (reference 53) uses SIMULATE-3P to demonstrate the RETRAN reactivity calculation is conservative. For the overcooling analysis performed with RELAP5, S3K is selected instead of SIMULATE-3P based on the anticipation of nodal voiding at the limiting return to power statepoint. S3K incorporates T-H models capable of calculating nodal voiding and its impact on reactivity and power distributions which are not included in the PWR version of SIMULATE-3P. However, the limiting case with a return to power included highly subcooled fluid conditions in the core at the statepoint. As an additional check, SIMULATE-3P is used to confirm the RELAP5 reactivity at the limiting statepoint. The use of this code is acceptable because of the slow progression of the transient and subcooled core conditions. The results confirmed the S3K calculation that the reactivity inserted by RELAP5 was conservative (i.e. greater than that produced by either SIMULATE-3P or S3K).

S3K was approved to model the very fast control rod ejection transient (< 10 seconds) in reference 53, DPC-NE-3005-PA "UFSAR Chapter 15 Transient Analysis Methodology". S3K was used here to model the much slower MSLB transient (40+ minutes). Both transients model a control rod scram, with the most reactive rod stuck fully withdrawn, with the MSLB scram initiated from HFP conditions at time zero. The MSLB transient models time-dependent input moderator temperature & inlet moderator flow rate, along with time-dependent boron

concentration and core pressure. Trippable control rod worth was conservatively reduced by a 10% uncertainty in rod worth, an allowance for control rod depletion, and by assuming control bank rods were initially at their rod insertion limit. The fission product distribution during the course of the transient is modeled to account for its impact on core reactivity and power distribution. However, modeling the time dependent fission product distribution had no noticeable effect on the parameters of interest (i.e. core power, k-effective, reactivity), except for an increase of < 10% in xenon concentration during the modeled time. The only other S3K-specific feature exercised for the MSLB transient that was not exercised in reference 53 was the modeling of the four time-dependent parameters listed above.

The results of this comparison demonstrate the RELAP5 calculation is conservative relative to the S3K calculation performed for the selected core design. The S3K calculation follows the guidance described in references 53 and 57 for assumptions such as 10% rod worth uncertainty and most reactive single stuck rod. This comparison is incorporated as a reload check into future ONS core designs.

Two alternate methods are provided by means of either PSW or the SSF for mitigating TB HELB overcooling scenarios. The alternate methods ensure the HELB mitigation with the postulation of a SAF. The reactivity response for both systems is independently reviewed considering the postulation of the most reactive rod stuck fully withdrawn.

A DNBR evaluation performed using VIPRE demonstrates a large amount of departure from nucleate boiling (DNB) margin exists for the statepoint at the peak heat flux. The VIPRE methodology used is described in the Duke Energy NRC approved methodology report DPC-NE-3000-PA (reference 21).

5.0 RETRAN-3D Model Modifications

The overheating and overcooling analyses for HELB scenarios include several boundary conditions that are not described in DPC-NE-3000-PA (reference 21) or DPC-NE-3005-PA (reference 53). These boundary conditions require additional modeling features to be included in the RETRAN-3D ONS model to facilitate the analyses. These modeling features include additional break junctions, turbine driven EFW, secondary steam loads, additional steam line nodes to facilitate turbine control modeling, and the normal letdown line. The modeling approach for several of these features considers the impact of asymmetric loop conditions on the performance of the individual boundary condition. These modeling features are applied in a manner to ensure appropriate boundary conditions are specified for each analysis.

The modified RETRAN-3D ONS T-H models have been developed specifically for performing overheating and overcooling transient analysis of a HELB scenarios mitigated using either normal plant equipment.

To facilitate future HELB analyses using RETRAN-3D, additional modeling would be required for the associated boundary condition. These boundary conditions include using SSF ASW or PSW equipment, loop high point vents, the RV head vent, and the SSF letdown line. The modeling would be similar to that described for similar RELAP5 analyses.

Duke Energy does not intend to apply these models or modifications to the ONS UFSAR Chapter 6 or 15 accident analyses. Therefore, a revision to the Duke Energy's NRC approved methodology reports, DPC-NE-3000-PA (reference 21), DPC-NE-3003-PA (reference 22), or DPC-NE-3005-PA (reference 53), will not be made. Should the need arise, Duke Energy intends to use the modified RETRAN-3D ONS T-H models in future HELB scenario analyses to evaluate changes to the plant and operator guidance.

While these modifications have been developed and applied for the analysis of a HELB scenario using normal plant, SSF or PSW equipment, Duke Energy considers the modifications to be equally suitable for use in analysis of other similarly mitigated scenarios.

6.0 RETRAN Reactivity Evaluation

The RETRAN core response is determined with a point kinetics model which is generally recognized as providing a conservative power response relative to the response obtained using 3D methods. To ensure that an appropriate transient reactivity is calculated for the overcooling analysis, SIMULATE-3P core models are used to assess the RETRAN reactivity calculation. A comparison is performed between RETRAN and SIMULATE to ensure a conservative (i.e., higher return to power or less subcritical) reactivity response is obtained. The process used is described in the MSLB methodology described in Duke Energy's NRC approved methodology report DPC-NE-3005-PA "UFSAR Chapter 15 Transient Analysis Methodology" (reference 53).

7.0 Conditions and Limitations of the RETRAN-3D Safety Evaluation Report

Appendix C of DPC-NE-3000-PA (reference 21) evaluates the conditions and limitations in the generic RETRAN-3D SER (reference 58) for the application of RETRAN-3D to the ONS with replacement OTSGs. The evaluation demonstrates that Duke Energy's RETRAN-3D ONS thermal-hydraulic model, as described in reference 21, is appropriately justified and within the RETRAN-3D SER conditions and limitations.

The application of the modified ONS RETRAN-3D model for analyzing HELB scenarios using normal plant equipment is considered consistent with the NRC-approved use of the RETRAN model in reference 21, and complies with the conditions and limitations in reference 58.

While these modifications have been developed and applied for the analysis of a HELB scenario using normal plant equipment, Duke Energy considers the modifications to be equally suitable for use in analysis of other similarly mitigated scenarios.

ATTACHMENT 6

Thermal-Hydraulic Transient Analysis for Evaluation of High Energy Line Breaks

ATTACHMENT 6

Thermal-Hydraulic Transient Analysis for Evaluation of High Energy Line Breaks

Background

Reference is made in this document to previous analysis completed to support MSLB evaluations in Section 15.13 and 15.17 of the ONS UFSAR. The analyses and the treatment of MSLB as described in UFSAR Section 15.13 were required as part of the initial licensing of the ONS units. The UFSAR Section 15.17 analyses and methods were introduced following the initial approval of DPC-NE-3005-PA (reference 53). The analyses were completed to gauge the reactor core response to the resulting overcooling following the MSLB. The locations of the MSLBs described in Chapter 15 were not specified, and as such, damage from the MSLB was not considered. The Giambusso/Schwencer letters 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. Therefore, MSLBs are not synonymous with MS HELBs. They 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.

The T-H analyses for HELB scenarios described in the LAR enclosure have been performed using either Duke Energy's RELAP5/MOD2-B&W ONS T-H model, or Duke Energy's RETRAN-3D ONS model. These methods are discussed further, below.

The RCS T-H analysis evaluates the ability to mitigate HELBs in the TB or EPR for the ONS using SSF, PSW, and normal plant equipment mitigation. The initiating event for these HELB scenarios may not cause an immediate loss of 4160 VAC power. For scenarios where 4160 VAC power is lost, an immediate reactor trip, turbine trip, and loss of the condensate and MFDW systems will occur. For scenarios where 6900 VAC power is maintained, 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.

1.0 HELB Mitigation - Methods

For HELBs that are postulated to create a MS HELB or FDW HELB, 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 RELAP5/MOD2-B&W ONS models and analysis methods are described in Duke Energy's NRC approved methodology report DPC-NE-3003-PA (reference 22) and have been modified to include additional detail and features required to perform these analyses, as described in Attachment 4.

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 to include additional detail and features required to perform these analyses, as described in Attachment 4.

Attachment 4 includes information that is proprietary to Duke Energy and Framatome, 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.

RELAP5/MOD2 is selected for the HELB analyses based on the potential for sustained two phase conditions in the RCS piping. The MS HELB analysis results in sufficient overcooling to produce two phase conditions in the RCS piping. The FDW HELB analysis also results in sustained two phase conditions, indicating that RELAP5 based methods are more appropriate to perform the analysis. RETRAN based methods are selected for analyses where sustained two phase conditions are not expected. The methods selected are discussed further in Attachment 4.

2.0 HELB Mitigation - Analysis 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 analysis to demonstrate acceptable results.

- The core must remain intact and in a coolable core.
- Minimum 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 overcooling analysis to demonstrate acceptable results.

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

3.0 HELB Mitigation - Overheating Analysis

Three sets of overheating analyses are described in this section; HELB mitigation with 4160 VAC power available, HELBs mitigated using SSF equipment, and HELBs mitigated using PSW equipment.

3.1 4160 VAC Power Available

Three sets of overheating analysis scenarios with 4160 VAC power available are described in this section. The first set describes FDW HELBs in the TB, and includes scenarios where 4160 VAC is maintained throughout the transient, and for scenarios where offsite power is lost and 4160 VAC power restored by Keowee. The second and third sets of scenarios describe FDW HELBs in the EPR, upstream and downstream of the check valve.

3.1.1 FDW HELB in the TB

The majority of the postulated FDW HELBs are located inside the TB. These postulated FDW HELBs do not impact the status of 4160 VAC power. These analyses assume an initial core power level of 102% of 2568 MW and HFP conditions. The postulated break location produces a transient that evolves as a complete loss of MFDW and leads to an overheating condition for the RCS. Due to the MFDW line check valves, SG pressure is unaffected by the pipe break. The RPS will trip the reactor following the loss of MFDW on high RCS pressure. The pressurizer code safety valves are credited to relieve pressure to maintain RCS pressure below the safety limit. The MS lines are assumed to remain intact with only the MSRVs lifting and controlling MS pressure to maximize the RCS heatup. With the EFW system available to feed both SGs, long term heat transfer is assured and tube stress issues are mitigated.

The transient evolves rapidly into an overheating scenario with two motor driven EFW pumps and all 4 RCPs operating. The procedural response in this analysis uses existing guidance to secure one RCP in each loop, and proposes guidance to open the loop high point vents as

necessary to maintain a desired RCS pressure range. Pressurizer heaters not impacted by the TB HELB are available to maintain RCS pressure control. Pressurizer spray is not required to mitigate the transient response.

3.1.2 EPR FDW HELB Upstream of Check Valve

The only breaks postulated on this section of FDW piping are critical cracks. The effects of these breaks would be similar to the loss of MFDW transient described in section 3.1.1, above. The RPS will trip the reactor on high RCS pressure. Since the critical cracks are upstream of the MFDW check valves, there is no loss of the SG pressure boundary. The EFW system is available to feed both SGs. The HPI system is available for normal makeup and RCP seal cooling. The RPS, EFW, and HPI are sufficient to achieve and maintain a SSD condition. The pressurizer heater capacity is limited to one group of heaters. Should the available heater capacity be insufficient to accommodate heat losses from the pressurizer, a plant cooldown would be initiated. The ADVs, in addition to HPI and EFW, are credited to cool the plant down to LPI entry conditions. The LPI and LPSW Systems are available to cool the plant down to the CSD condition.

3.1.3 EPR FDW HELB Downstream of Check Valve

The FDW HELB break area downstream of the check valve in the EPR is limited to 0.54 ft^2 by a guard pipe. Due to the break location, 4160 VAC and 6900 VAC switchgear are not affected by the HELB, enabling normal plant equipment to be available to mitigate the consequences of the scenario. This analysis assumes an initial core power level of 102% of 2568 MW and HFP conditions. The EPR FDW HELB is assumed to damage the instrument air (IA) header in the EPR resulting in a loss of IA. The loss of IA results in a loss of normal letdown as the letdown isolation valve HP-5 fails closed, and causes the normal charging control valve (HP-120) to fail closed, and the seal injection throttle valve (HP-31) to fail open. The loss of IA also causes the CC isolation valve CC-8 to fail closed isolating the RCP thermal barrier cooling, CRD mechanism motor coolers, and the letdown coolers, TBVs to fail closed, and the main and startup FDW control valves to fail in their current position. The FDW HELB reduces the MFDW flow to the SGs resulting in a rapid heatup of the RCS and a reactor trip on high RCS pressure. Due to the break location, the affected SG will completely depressurize following the reactor trip resulting in an AFIS actuation.

On low steam line pressure AFIS will trip both MFDW pumps, trip or block the turbine-driven EFW pump, and close the following valves on the affected loop; MFDW control valve, MFDW block valve, MFDW startup control valve, and MFDW startup block valve. With a loss of IA, the main and startup FDW control valves fail in their current position. AFIS on low steam line pressure with a high depressurization rate will trip or block the auto start of the motor driven EFW pump on the affected loop. The motor driven EFW pump on the intact loop will auto start on the loss of both MFDW pumps. AFIS is modeled for this scenario since its actuation limits that available heat sink and represents a penalty in the analysis.

The transient evolves rapidly in to an overheating scenario with one motor driven EFW aligned to one SG, and all 4 RCPs operating. The procedural response in this analysis uses existing guidance to secure one RCP in each loop, and proposes guidance to open the loop high point vents as necessary to maintain a desired RCS pressure range. Pressurizer heaters not impacted by the EPR HELB are available to maintain RCS pressure control. Pressurizer spray is not required to mitigate the transient response.

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 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 transient.

3.2 4160 VAC Power Unavailable - SSF Mitigation

SSF ASW is credited with providing an alternate means of establishing SG heat removal should EFW be lost. This analysis evaluates the RCS response to a rupture in the MFDW piping with a loss of the 4160 VAC ES switchgear due to a TB HELB. This break location is upstream of the MFDW line check valves such that a break in this location results in a complete loss of MFDW to both SGs.

An analysis has been performed to evaluate the RCS response to a loss of MFDW and the 4160 VAC ES switchgear due to a HELB that also damages the switchgear and other equipment in the TB. The primary objective of the analysis is to demonstrate the SSF is capable of meeting the proposed HELB mitigation acceptance criteria for a limiting overheating scenario.

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 motor driven EFW pumps are powered from the 4160 VAC switchgear and are not available due to the loss of power. The turbine driven EFW pump is assumed to be unavailable.

Since portions of the ICS are unprotected from HELB damage, the pressurizer PORV is assumed to be unavailable. SG pressure increases rapidly to the MSRV lift setting following turbine trip. SG pressure cycles on the lowest lifting MSRV bank until the SG liquid inventory has boiled away. At this point, SG pressures stabilize just below the lift setpoint of the lowest lifting MSRV bank until the operators establish SSF ASW flow to the SGs.

The combination of high end of cycle decay heat (ANS-79 with uncertainty) and delayed SSF 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 pressurizer PORV lift setting (if available), or the PSV lift setting, and the PORV or 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 if 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.

Pressurizer level increases with increasing RCS temperatures and goes off-scale high. The pressurizer does not become water-solid prior to SSF ASW being aligned to the SGs at 14 minutes, and liquid relief is not predicted through the PSVs or PORV. Maintaining a steam space in the pressurizer is dependent on the timing of providing a heat sink. SSF ASW flow is controlled by procedure to maintain an RCS pressure of about 2100 psig. With the SSF RC makeup pump supplying seal cooling, a slow increase in RCS liquid mass is accommodated through a slow RCS cooldown, accomplished by SSF ASW being controlled to maintain a constant RCS pressure. This slow cooldown returns the RCS to a condition where the RCS cold

leg temperatures are limited by the SG saturation temperature defined by the lowest lifting MSRVs. As cold leg temperatures stabilize at the secondary side temperature, the operator will increase ASW flow to maintain the desired RCS pressure. This action increases SG liquid levels to the natural circulation setpoint. In the longer term response, operators use SSF ASW to maintain SG levels that promote sustained natural circulation flow in the RCS, and use the SSF controlled pressurizer heaters and SSF letdown line to control RCS pressure and pressurizer level, respectively.

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.

3.3 4160 VAC Power Unavailable - PSW Mitigation

The PSW system is credited with providing an alternate means of establishing SG heat removal when both EFW and SSF ASW are unavailable. This analysis evaluates the RCS response to a rupture in the MFDW piping with a loss of the 4160 VAC ES switchgear due to a TB HELB. This break location is upstream of the MFDW line check valves such that a break in this location results in a complete loss of MFDW to both SGs.

An analysis has been performed to evaluate the RCS response to a loss of MFDW and the 4160 VAC ES switchgear due to a HELB that also damages the switchgear and other equipment in the TB. The primary objective of the analysis is to demonstrate the PSW system is capable of meeting the proposed HELB mitigation acceptance criteria for a limiting overheating scenario.

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 a loss of RCP seal cooling. The motor driven EFW pumps are powered from the 4160 VAC switchgear and are not available. The turbine driven EFW pump is assumed to be unavailable.

Since portions of the ICS are unprotected from HELB damage, the pressurizer PORV is assumed to be unavailable. SG pressure increases rapidly to the MSRV lift setting following turbine trip. SG pressure cycles on the lowest lifting MSRV bank until the SG liquid inventory has boiled away. At this point, SG pressures stabilize just below the lift setpoint of the lowest lifting MSRV bank until the operators establish PSW flow.

The combination of high end of cycle decay heat (ANS-79 with uncertainty) 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 PORV lift setting (if available), or the PSV lift setting, and the PORV or 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 or PORV. The peak RCS pressure in the overheating analysis is defined by the pressurizer safety relief valve

characteristics if 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.

Certain T-H analyses assume SSF ASW flow to be available at 14 minutes in the HELB overheating analysis to prevent liquid relief through the PSVs or PORV. The supporting analyses assume a time of 15 minutes for PSW flow, consistent with the current PSW licensing basis. Since SSF and PSW are modeled using the same flow rate, the results of SSF cases that assume flow is available at 14 minutes are used to support this LAR. Crediting PSW with providing a heat sink at an earlier point in time does not adversely impact the analytical results.

Pressurizer level increases with increasing RCS temperatures and goes off-scale high. The pressurizer does not become water solid prior to PSW being aligned to the SGs, and liquid relief is not predicted through the PSVs or PORV when PSW is started within 14 minutes. Maintaining a steam space in the pressurizer is dependent on the timing of providing a heat sink. PSW flow is controlled to maintain an RCS pressure of about 2100 psig. This pressure setpoint results in a temporary loss of subcooling until RCS temperatures decrease. With an HPI pump supplying seal cooling and RCS makeup flow, a slow increase in RCS liquid mass is accommodated through a slow RCS cooldown, accomplished by PSW being controlled to maintain a constant RCS pressure. This slow cooldown returns the RCS to a condition where the RCS cold leg temperatures are limited by the SG saturation temperature defined by the lowest lifting MSRVs. As cold leg temperatures stabilize at the secondary side temperature, the operator will increase PSW flow to maintain the desired RCS pressure. This action increases SG liquid levels to the natural circulation setpoint. In the longer term response, operators use PSW to maintain SG levels that promote sustained natural circulation flow in the RCS, and use the PSW powered pressurizer heaters and loop high point vents to control RCS pressure and pressurizer level, respectively.

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 DHR and primary coolant makeup to keep the core covered and maintain the RCS in Mode 3 for the duration of the scenario.

4.0 HELB Mitigation - Overcooling Analysis

Three sets of overcooling analyses are described in this section; HELB mitigation with 4160 VAC power available, and for scenarios where 4160 VAC power is lost due to the HELB, HELBs mitigated using SSF equipment and HELBs mitigated using PSW equipment.

4.1 4160 VAC Power Available

4.1.1 Single MS HELB with 4160 VAC Available

MS HELBs that do not impact the status of 4160 VAC power are analyzed as part of the MSLB analyses described in UFSAR Chapter 15.13 and UFSAR Section 15.17. These analyses are performed assuming an initial core power of 102% of 2568 MW and HFP conditions.

Small MSLBs are analyzed in UFSAR Section 15.17. A limiting break size is determined in the analysis that results in a maximum power excursion, which occurs by avoiding a RPS trip function. The analysis assumes that the electrical distribution system as well as the secondary systems remain in operation such that the reactor does not automatically trip. Should the 230 kV red and yellow buses, both main feeder buses, or the 6900 VAC buses be lost, the reactor will automatically trip. A loss of the condensate and MFDW systems would also result in an automatic trip of the reactor. Any of these direct effects on normal plant equipment would result in less limiting consequences than that already analyzed in UFSAR Section 15.17.

These scenarios do not require further discussion.

MSLB analyses are performed to determine the limiting SG tube stress. These analyses assume an initial core power level of 102% of 2568 MW and HFP conditions. RCS integrity is demonstrated by determining the limiting SG tube compressive and tensile stresses remain within design limits, and that the RCS pressure and temperature remains within the acceptable cooldown limits during the transient evolution. The maximum tensile stress resulting from a single MSLB is significantly less than the limiting tensile stress that results from a large break LOCA. With 4160 VAC power available, normal plant equipment is able to maintain the plant within limits during the cooldown.

4.1.2 Double MS HELB with 4160 VAC Available

In this scenario, both 4160 VAC and 6900 VAC power remain available. The 4160 VAC essential power remains available to power safety systems as well as non-safety systems. With 6900 VAC power available, the RCPs remain in operation until operator action is taken to trip the RCPs 2 minutes after a loss of indicated subcooled margin. The initial RCS overcooling is similar to the MSLB with offsite power available case analyzed in UFSAR Section 15.13. Although both MS lines are assumed to be lost, the turbine-driven EFW pump is assumed to operate to ensure a conservative overcooling is obtained.

Borated water injection is available from the CFTs and HPI pumps. In addition, the condensate and FDW pumps remain available to feed the SGs. The boundary conditions for this scenario are identical to the UFSAR Section 15.13 MSLB analysis "with offsite power available" case, with a guillotine break of both steam lines. The primary difference is that both SGs experience an uncontrolled depressurization. Cases are analyzed to evaluate the effects of various additional failures, operation of the ICS, and operation of the RCPs. The cases considered the following:

- Uncontrolled MFDW addition (with tripping RCPs on loss of subcooled margin at 2 minutes and not tripping RCPs)
- Uncontrolled MFDW addition with a failed open EFW flow control valve (with tripping RCPs on loss of subcooled margin at 2 minutes and not tripping RCPs)
- ICS controlling MFDW to various SG water level setpoints

A reactor power level of 102% of 2568 MW is assumed to account for instrument uncertainty. An immediate reactor trip is conservatively assumed to maximize the overcooling effects for this scenario. No credit is taken for automatic isolation of MFDW or EFW during this scenario. The condensate and FDW systems are assumed to continue feeding the SGs until the condensate inventory is depleted.

It has been determined that there is no return to criticality for all cases evaluated. The limiting overcooling case that challenges a return to criticality is a double MS HELB with the 4160 VAC equipment available and the RCPs left on (similar to the UFSAR Section 15.13 analysis). The case also assumed uncontrolled MFDW addition with the additional failure to the 4160 VAC system resulting in a loss of the HPI train A. Since the RCPs continue to operate in this case,

the DNBR is bounded by the double MS HELB without offsite power case where RCPs are lost immediately.

Since the 4160 VAC essential power system is available, the unit can be brought to the CSD condition immediately following the event. Operator actions are necessary to realign the LPI system from the emergency injection mode to the normal DHR mode of operation. The SGs would be relied upon for DHR until the change in LPI alignment has been completed. A number of water sources could be utilized for feeding the SGs. The affected unit's EFW source is from the UST (only) since the condensate in the hotwell has been depleted. EFW can be supplied from an alternate unit should the inventory in the UST on the affected unit be lost. PSW or SSF ASW could also be utilized to supply water to the SGs until normal DHR via the LPI system is achieved.

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 maximum tensile stress resulting from a double MSLB is significantly less than the limiting tensile stress that results from a large break LOCA. With 4160 VAC power available, normal plant equipment is able to maintain the plant within limits during the cooldown.

4.1.3 Double MS HELB – LOOP With 4160 Available

This scenario assumes that the LOOP is coincident with the double MS HELB. This scenario is similar to the description provided in UFSAR Section 15.13.4 MSLB analysis with respect to the initial conditions and boundary conditions for the "without offsite power available" case. The primary difference is both SGs experience an uncontrolled depressurization. The transient RCS conditions encompassing the time frame during which minimum DNBR occurs for the MS HELB without offsite power are utilized in the analysis for evaluating the DNBR. The minimum DNBR for this analysis occurs during the first few seconds of the event. This transient is considered to be bounded by the double MS HELB with 4160 VAC available cases previously discussed for effects on core reactivity and a potential return to criticality condition. Therefore, the 5 second duration of the analysis immediately after reactor trip is sufficient to determine the minimum DNBR for this case. The analysis shows that the minimum DNBR is within acceptable limits.

After 4160 VAC power is restored from Keowee, EFW would be available to provide a heat sink. The HPI system is available to provide normal makeup and RCP seal cooling, and ECCS flow as necessary. The operation of RPS, EFW, and HPI are sufficient to achieve and maintain a SSD condition.

MSLB analyses are performed to determine the limiting SG tube stress. These analyses assume an initial core power level of 102% of 2568 MW. RCS integrity is demonstrated by determining the limiting SG tube compressive and tensile stresses remain within design limits, and that the RCS pressure and temperature remains within the acceptable cooldown limits during the transient evolution. The maximum tensile stress resulting from a double MSLB is significantly less than the limiting tensile stress that results from a large break LOCA. With 4160 VAC power available, normal plant equipment is able to maintain the plant within limits during the cooldown.

4.2 SSF Mitigation with 4160 VAC Power Unavailable

The primary objective of this scenario is to demonstrate adequate core cooling and establish a basis for mitigation strategies using the SSF for establishing and maintaining SSD conditions for MS HELBs.

This analysis evaluates the plant transient response to a single or double MS HELB and loss of the 4160 VAC ES switchgear due to a HELB that results in damage to the switchgear and other equipment in the TB.

This analysis determines the plant transient response to a 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 motor driven EFW pumps are not available due to the loss of 4160 VAC power. The turbine driven EFW pump is assumed to be available which is conservative for maximizing the overcooling. 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 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.

Upon initiation of the single or double MS HELB, RCS pressure, hot and cold leg temperature, SG pressures and pressurizer level rapidly decrease due to the overcooling and contraction of the RCS. The RCS saturates and pressurizer level goes off scale low. The turbine driven EFW pump is assumed to automatically start and run without being throttled until the contents of the UST are delivered to the SGs. 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.

4.2.1 Single MS HELB - SSF

The minimum RCS pressure reached is a function of the number of broken steam lines. After the RCPs coast down following a single MS HELB, RCS flow in the intact loop stagnates and allows primary coolant in the intact loop to flash, limiting the RCS depressurization. This void formation in the intact loop allows the affected RCS loop to remain full and circulating. For the single MS HELB cases, RCS pressure remains above 600 psig, preventing boron from the CFT from entering the RCS. The sustained overcooling in the affected loop is sufficient to result in a minimal return to power (<<0.1% power). The core remains covered and subcooled during the return to power, with adequate DNB margin. The overcooling continues until shortly after the turbine driven EFW pump depletes the UST and stops feeding the SGs.

The limiting core response is obtained with a single MS HELB with an immediate RCP trip. This case is evaluated further by a sensitivity case that does not credit boron added by the SSF RCMU pump. The maximum core power level reached in this sensitivity case is 2.4% power at 1501 seconds. The indicated core exit subcooling between 1200 and 1800 seconds is greater than 120°F, and consistently greater than 60°F subcooled during the return to power.

The RELAP5 core response is determined with a point kinetics model which is generally recognized as providing a conservative power response relative to the response obtained using 3D reactor core physics methods. To ensure that the appropriate transient reactivity is calculated, a SIMULATE-3K (S3K) 3D core model is used to assess the RELAP5 reactivity calculation. The results of this comparison demonstrate the RELAP5 calculation is conservative (i.e., higher return to power) relative to the S3K calculation performed for the selected core

design. The S3K calculation follows the guidance described in the NRC approved methodology defined in reference 59, DPC-NE-1006-PA “Oconee Nuclear Design Methodology Using CASMO-4 / SIMULATE-3”, reference 53, DPC-NE-3005-PA “UFSAR Chapter 15 Transient Analysis Methodology”, and reference 57, NFS-1001-A “ONS Reload Design Methodology”. This comparison is incorporated as a reload check in future ONS core designs.

A DNBR evaluation performed using VIPRE and the EPRI and Modified Barnett CHF correlations demonstrates a large amount of DNB margin exists for the statepoint at the peak heat flux during the return to critical portion of the transient. The DNBR immediately following reactor trip is covered by the Chapter 15 MSLB DNBR analyses and the double MS HELB with LOOP analyses previously discussed. The VIPRE methodology used is described in the Duke Energy NRC approved methodology report DPC-NE-3000-PA (reference 21).

The EPRI CHF correlation is used to identify the limiting critical heat flux and DNBR statepoints. The Modified Barnett CHF correlation is then used to evaluate the limiting statepoints identified with the EPRI correlation and the peak heat flux statepoint. The Modified Barnett correlation is the current licensed correlation used for low pressure (steam line break) analyses for ONS and B-HTP fuel. Acceptable minimum DNBR results are obtained.

4.2.2 Double MS HELB - SSF

For a double MS HELB, the RCS depressurization and shrinkage causes a RV head void that expands into the hot legs. This interrupts RCS loop flow to the SGs, and limits the cooldown of the core. While hot leg flow is interrupted, recirculating liquid flow through the RV internal vent valves ensures the core remains cooled. When primary loop flow stagnates, heat transfer to the SGs is interrupted. RCS pressure increases as the liquid in the RV absorbs the core decay heat and expands, raising the liquid level in the hot legs until liquid spillover occurs. Each spillover transfers hot liquid into the SG tubes and returns cool fluid from the bottom of the SG to the cold legs. Spillovers cause the liquid circulating in the RV to cool, and results in a decrease in RCS pressure. As RCS pressure decreases below 600 psig, the two CFTs inject additional borated inventory into the RCS. The core remains covered throughout the overcooling transient. While a brief recriticality is indicated by the RELAP5 point kinetics model for cases with an immediate RCP trip, the resulting fission power obtained is not significant (less than one watt). The overcooling continues until shortly after the turbine driven EFW pump stops feeding the SGs.

After the overcooling has terminated, the RCS begins to slowly reheat and swell, and pressurizer level returns on scale. The SSF powered pressurizer heaters are manually energized when level in the pressurizer exceeds 90 inches. SSF ASW flow is established to the SGs to stabilize pressurizer level in order to limit the volume of water in the pressurizer that must be heated to saturated conditions. Saturated conditions are established in the pressurizer approximately three to four hours into the transient at which point the addition of steam to the steam bubble in the pressurizer begins to increase RCS pressure. Pressurizer heaters are then cycled to maintain RCS pressure stable. Stable subcooled natural circulation conditions are also achieved approximately three hours into the transient.

The overcooling T-H analyses is used to inform operator guidance for the SSF. The analysis assumes operators initially control SSF ASW flow to stabilize pressurizer level, which effectively precludes the pressurizer from developing into a water solid condition. SSF ASW flow is controlled by the operator to prevent the RCS from re-heating and pressurizing to the nominal hot zero power set of conditions maintained in the overheating analysis. By controlling SSF ASW to stabilize either RCS pressure or pressurizer level, the operator manages the liquid insurge to the pressurizer and allows the pressurizer liquid to become saturated. A minor RCS temperature reduction is required to accommodate the continued RCMU flow rate.

The goal of the operator guidance assumed in the analysis is to stabilize the plant to between 325°F - 350°F and 650 - 700 psig. Operationally, there are several advantages to this set of conditions:

- The RCS would be in natural circulation with a subcooled margin consistent with the normal natural circulation guidance (150°F indicated subcooling).
- SSF ASW would be controlled to maintain a constant cold leg temperature with pressurizer heaters and SSF letdown available to control RCS pressure.
- Below 350°F, RCP seal integrity would not be readily challenged should seal injection flow be interrupted.
- Remaining above 600 psi allows time to isolate the CFTs and prevent nitrogen injection.
- Should the pressurizer become water solid at these conditions, there is a significant amount of margin to lifting the pressurizer code safety valves (2500 psig setpoint).
- The compressive tube stress analytical limit is defined by the RCS at 550°F and the SG shell at 212°F. The cooldown to below 350°F will provide margin to prevent tube deformation.
- During the cooldown, sufficient boron is added to ensure the core remains subcritical down to 200°F without credit for Xenon.

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 described above.

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 350°F 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 single or double MS HELB can be mitigated using SSF equipment. In summary, the overcooling analysis demonstrates that for either a single or 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.

4.3 PSW Mitigation with 4160 VAC Power Unavailable

The primary objective of this scenario is to demonstrate adequate core cooling and establish a basis for mitigation strategies using PSW equipment for establishing and maintaining SSD conditions for MS HELBs.

This analysis evaluates the plant transient response to a single or double MS HELB and loss of the 4160 VAC ES switchgear due to a HELB that results in damage to the switchgear and other equipment in the TB.

This analysis determines the plant transient response to a MS HELB mitigated with PSW 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 motor driven EFW pumps are not available due to the loss of 4160 VAC power. The turbine driven EFW pump is assumed to be available which is conservative for maximizing the overcooling. 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 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.

Upon initiation of the single or double MS HELB, RCS pressure, hot and cold leg temperature, SG pressures and pressurizer level rapidly decrease due to the overcooling and contraction of the RCS. The RCS saturates and pressurizer level goes off scale low. The turbine driven EFW pump is assumed to automatically start and run without being throttled until the contents of the UST are delivered to the SGs. The RCPs remain operating until tripped by operator action either 2 minutes after the loss of indicated subcooled margin, or 3 minutes after a loss of RCP seal cooling. 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.

4.3.1 Single MS HELB - PSW

The minimum RCS pressure reached is a function of the number of broken steam lines. After the RCPs coast down following a single MS HELB, RCS flow in the intact loop stagnates and allows primary coolant in the intact loop to flash, limiting the RCS depressurization. This void formation in the intact loop allows the affected RCS loop to remain full and circulating. For the single MS HELB cases, RCS pressure remains above 600 psig, preventing boron from the CFT from entering the RCS. 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 overcooling continues until shortly after the turbine driven EFW pump depletes the UST and stops feeding the SGs.

The core response for the HELB analyses with PSW mitigation is bounded by the core response previously described for HELB analyses with SSF mitigation. The limiting core response for the SSF mitigation is evaluated by a sensitivity case that does not credit boron added by the SSF RCMU pump. For the PSW mitigation analyses, an HPI pump is providing RCS makeup flow and RCP seal injection flow from the BWST.

4.3.2 Double MS HELB - PSW

For a double MS HELB, the RCS depressurization and shrinkage causes a RV head void that expands into the hot legs. This interrupts RCS loop flow to the SGs, and limits the cooldown of the core. While hot leg flow is interrupted, recirculating liquid flow through the RV internal vent valves ensures the core remains cooled. When primary loop flow stagnates, heat transfer to the SGs is interrupted. RCS pressure increases as the liquid in the RV absorbs the core decay heat

and expands, raising the liquid level in the hot legs until liquid spillover occurs. Each spillover transfers hot liquid into the SG tubes and returns cool fluid from the bottom of the SG to the cold legs. Spillovers cause the liquid circulating in the RV to cool, and results in a decrease in RCS pressure. As RCS pressure decreases below 600 psig, 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 overcooling continues until shortly after the turbine driven EFW pump stops feeding the SGs.

After the overcooling has terminated, the RCS begins to slowly reheat and swell, and pressurizer level returns on scale. The PSW powered pressurizer heaters are manually energized when level in the pressurizer exceeds 85 inches. PSW flow is established to the SGs to stabilize pressurizer level in order to limit the volume of water in the pressurizer that must be heated to saturated conditions. Saturated conditions are established in the pressurizer approximately three to four hours into the transient at which point the addition of steam to the steam bubble in the pressurizer begins to increase RCS pressure. Pressurizer heaters are then cycled to maintain RCS pressure stable. Stable subcooled natural circulation conditions are also achieved approximately three hours into the transient.

The overcooling T-H analyses is used to develop operator guidance for mitigating MS HELB scenarios using PSW equipment. The analysis assumes operators initially control PSW flow to stabilize core exit temperatures (CET). HPI flow is throttled to maintain 150°F CET subcooling until pressurizer level recovers to 100”. Afterwards HPI flow is throttled to maintain 100” pressurizer level, although due to continued RCP seal injection pressurizer level continues to increase. Loop high point vents are used to control pressurizer level between 180” and 200”. The level setpoints are selected to accommodate adverse containment condition effects on the level indication. The pressurizer heaters are used to maintain 150°F CET subcooling.

The goal of the operator guidance assumed in the HELB PSW analyses is to stabilize the plant to between 325°F - 350°F and 650 - 700 psig. Operationally, there are several advantages to this set of conditions:

- The RCS would be in natural circulation with a subcooled margin consistent with the normal natural circulation guidance (150°F indicated subcooling).
- PSW would be controlled to maintain a constant cold leg temperature with pressurizer heaters, and RCS head and loop vent valves available to control RCS pressure.
- Below 350°F, RCP seal integrity would not be readily challenged should seal injection flow be interrupted.
- Remaining above 600 psi allows time to isolate the CFTs and prevent nitrogen injection.
- Should the pressurizer become water solid at these conditions, there is a significant amount of margin to lifting the pressurizer code safety valves (2500 psig setpoint).
- The compressive tube stress analytical limit is defined by the RCS at 550°F and the SG shell at 212°F. The cooldown to below 350°F will provide margin to prevent tube deformation.
- During the cooldown, sufficient boron is added to ensure the core remains subcritical down to 200°F without credit for Xenon.

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 as described above using SSF mitigation.

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 350°F 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 transient.

This analysis demonstrates that a single or double MS HELB can be mitigated using PSW equipment. In summary, the overcooling analysis demonstrates that for either a single or 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.

ATTACHMENT 7

DUKE ENERGY AFFIDAVIT

AFFIDAVIT of Steve Snider

1. I am Vice President of Nuclear Engineering, Duke Energy Carolinas, and as such have the responsibility of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear plant licensing and am authorized to apply for its withholding on behalf of Duke Energy.

2. I am making this affidavit in conformance with the provisions of 10 CFR 2.390 of the regulations of the Nuclear Regulatory Commission (NRC) and in conjunction with Duke Energy's application for withholding which accompanies this affidavit.

3. I have knowledge of the criteria used by Duke Energy in designating information as proprietary or confidential. I am familiar with the Duke Energy information contained in Attachment 4 of the Oconee License Amendment request for High Energy Line Breaks (HELB) Outside of the Containment Building (correspondence no. RA-19-0253) which proposes to update the Updated Final Safety Analysis Report (UFSAR) regarding the HELB licensing basis.

4. Pursuant to the provisions of paragraph (b) (4) of 10 CFR 2.390, the following is furnished for consideration by the NRC in determining whether the information sought to be withheld from public disclosure should be withheld.

   (i) The information sought to be withheld from public disclosure is owned by Duke Energy and has been held in confidence by Duke Energy and its consultants.

   (ii) The information is of a type that would customarily be held in confidence by Duke Energy. Information is held in confidence if it falls in one or more of the following categories.

      (a) The information requested to be withheld reveals distinguishing aspects of a process (or component, structure, tool, method, etc.) whose use by a vendor or consultant, without a license from Duke Energy, would constitute a competitive economic advantage to that vendor or consultant.

      (b) The information requested to be withheld consist of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), and the application of the data secures a competitive economic advantage for example by requiring the vendor or consultant to perform test measurements, and process and analyze the measured test data.

      (c) Use by a competitor of the information requested to be withheld would reduce the competitor's expenditure of resources, or improve its competitive position, in the design, manufacture, shipment, installation assurance of quality or licensing of a similar product.

      (d) The information requested to be withheld reveals cost or price information, production capacities, budget levels or commercial strategies of Duke Energy or its customers or suppliers.

(e) The information requested to be withheld reveals aspects of the Duke Energy funded (either wholly or as part of a consortium) development plans or programs of commercial value to Duke Energy.

(f) The information requested to be withheld consists of patentable ideas.

The information in this submittal is held in confidence for the reasons set forth in paragraphs 4(ii)(a), 4(ii)(c), and 4(ii)(e) above. Rationale for this declaration is the use of this information by Duke Energy provides a competitive advantage to Duke Energy over vendors and consultants, its public disclosure would diminish the information's marketability, and its use by a vendor or consultant would reduce their expenses to duplicate similar information. The information consists of analysis methodology details that provides a competitive advantage to Duke Energy.

(iii) The information was transmitted to the NRC in confidence and under the provisions of 10 CFR 2.390, it is to be received in confidence by the NRC.

(iv) The information sought to be protected is not available in public to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld is that which is marked in Attachment 4 of Oconee License Amendment request for HELBs Outside of the Containment Building (correspondence no. RA-19-0253) which proposes to update the UFSAR regarding the HELB licensing basis. This information is consistent with marked proprietary information in the NRC-approved Duke Energy methodology report DPC-NE-3003-PA. This information enables Duke Energy to:

(a) Support license amendment requests for its Oconee reactors.

(b) Perform transient and accident analysis calculations for Oconee.

(vi) The proprietary information sought to be withheld from public disclosure has substantial commercial value to Duke Energy.

(a) Duke Energy uses this information to reduce vendor and consultant expenses associated with supporting the operation and licensing of nuclear power plants.

(b) Duke Energy can sell the information to nuclear utilities, vendors, and consultants for the purpose of supporting the operation and licensing of nuclear power plants.

(c) The subject information could only be duplicated by competitors at similar expense to that incurred by Duke Energy.

5. Public disclosure of this information is likely to cause harm to Duke Energy because it would allow competitors in the nuclear industry to benefit from the results of a significant development program without requiring a commensurate expense or allowing Duke Energy to recoup a portion of its expenditures or benefit from the sale of the information.

Steve Snider affirms that he is the person who subscribed his name to the foregoing statement, and that all the matters and facts set forth herein are true and correct to the best of his knowledge.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 31, 2019.

Steve Snider

ATTACHMENT 8

FRAMATOME AFFIDAVIT

A F F I D A V I T

COMMONWEALTH OF VIRGINIA)
) ss.
CITY OF LYNCHBURG)

1. My name is Philip A. Opsal. I am Manager, Product Licensing, for Framatome Inc., (formally known as AREVA Inc.), and as such I am authorized to execute this Affidavit.

2. I am familiar with the criteria applied by Framatome Inc., to determine whether certain Framatome Inc. information is proprietary. I am familiar with the policies established by Framatome Inc. to ensure the proper application of these criteria.

3. I am familiar with the Framatome Inc. information contained in the following document: Duke Energy Document No. RA-19-0253, 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", Attachment 4 "Thermal-Hydraulic Models for High Energy Line Break Transient Analysis", referred to herein as "Document." Information contained in this Document has been classified by Framatome Inc. as proprietary in accordance with the policies established by Framatome Inc. for the control and protection of proprietary and confidential information.

4. This Document contains information of a proprietary and confidential nature and is of the type customarily held in confidence by Framatome Inc. and not made available to the public. Based on my experience, I am aware that other companies regard information of the kind contained in this Document as proprietary and confidential.

5. This Document has been made available to the U.S. Nuclear Regulatory Commission in confidence with the request that the information contained in this Document be withheld from public disclosure. The request for withholding of proprietary information is made in accordance with 10 CFR 2.390. The information for which withholding from disclosure is requested qualifies under 10 CFR 2.390(a)(4) "Trade secrets and commercial or financial information."

6. The following criteria are customarily applied by Framatome Inc. to determine whether information should be classified as proprietary:

(a) The information reveals details of Framatome Inc.'s research and development plans and programs or their results.

(b) Use of the information by a competitor would permit the competitor to significantly reduce its expenditures, in time or resources, to design, produce, or market a similar product or service.

(c) The information includes test data or analytical techniques concerning a process, methodology, or component, the application of which results in a competitive advantage for Framatome Inc.

(d) The information reveals certain distinguishing aspects of a process, methodology, or component, the exclusive use of which provides a competitive advantage for Framatome Inc. in product optimization or marketability.

(e) The information is vital to a competitive advantage held by Framatome Inc., would be helpful to competitors to Framatome Inc., and would likely cause substantial harm to the competitive position of Framatome Inc.

The information in this Document is considered proprietary for the reasons set forth in paragraphs 6(b), 6(c), 6(d) and 6(e) above.

7. In accordance with Framatome Inc.'s policies governing the protection and control of information, proprietary information contained in this Document has been made available, on a limited basis, to others outside Framatome Inc. only as required and under suitable agreement providing for nondisclosure and limited use of the information.

8. Framatome Inc.'s policy requires that proprietary information be kept in a secured file or area and distributed on a need-to-know basis.

9. The foregoing statements are true and correct to the best of my knowledge, information, and belief.

SUBSCRIBED before me this 31st
day of July, 2019.

Heidi Hamilton Elder

Heidi Hamilton Elder
NOTARY PUBLIC, COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES: 12/31/2022
Reg. # 7777873

HEIDI HAMILTON ELDER NOTARY PUBLIC COMMONWEALTH OF VIRGINIA REGISTRATION NO 7777873 MY COMM. EXPIRES 12/31/2022

ATTACHMENT 9

REGULATORY REQUIREMENTS

Attachment 9
Regulatory Requirements

The regulatory requirements for HELBs outside of the containment building at ONS are based on the requirements contained in a request from the AEC dated 12/15/1972 (Giambusso Letter) and the errata sheet contained in a letter from the AEC dated 1/17/1973 (Schwencer Letter – references 1 and 2).

The HELB requirements can be summarized as follows:

1. The reactor can be shutdown and maintained in a SSD condition and subsequently cooled to the CSD condition in the event of a postulated rupture, outside 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 a SSD condition should be protected or designed to withstand the effects of such a postulated pipe failure.

The commission requested the following information from the licensee to assist them in their review to verify that the above HELB requirements could be met.

Shutdown Sequence Evaluation Criteria

In order to establish the list of targets for postulated HELBs, it is necessary to know which SSCs are required to mitigate the consequences of the postulated HELBs and safely bring the unit to a CSD condition. This list of SSCs can be determined by establishing the shutdown sequence for ONS. The following criteria are used to identify the systems and components necessary for HELB mitigation and/or unit shutdown to CSD 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
    - RB (Boundary) Integrity
    - CR 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 SAFs. They are, however, HELB targets.
- A SAF is postulated in systems used to mitigate the consequences of the postulated breaks 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 CSD 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 CSD, 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 CSD.

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 CSD 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 CSD condition.
- SSD, CSD, 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 HE 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 126°F 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 (Revision 2).
- Systems and components, whose only function is to support the cooldown of the unit from an RCS temperature of approximately 250°F to the CSD condition, need not be protected from postulated HELBs.
- A 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 LC or 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.

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 EFW pump, 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 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 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.

3. Initiation of RCS cooldown to approx. 250^{o}F

   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 250^{o}F. 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 CSD condition (RCS temperature < 200^{o}F)

   The objective of this phase of post-HELB operations is to transition from DHR using the SGs to removing core decay heat using the LPI system. The LPI system, in conjunction with the LPSW system, is utilized to cool the RCS from approximately 250^{o}F to less than 200^{o}F.

Functions to meet SSD 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 FDW), those that result in excessive heat transfer (loss of MS pressure boundary control), and those that result in loss of RC 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 RC 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
- RB (Boundary) Integrity
- CR Habitability (long term)
- Plant Cooldown
- Process Monitoring
- Support Functions

Requirement 1:

Requirement 1 in the Giambusso letter requested that pipe whip protection be provided to those systems that normally operate at temperatures greater than or equal to 200°F or have design pressures greater than or equal to 275 psig. Pipe whip protection would not be required if certain conditions could be met.

<u>ONS Methodology</u>

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

- The HE (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 200°F.
  2. A normal operating pressure greater than 275 psig.
- The HE section of any piping run shall extend from component to component. The HE 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 HE boundary for a HE piping run, is not postulated to be HE due to potential leakage across the closed valve.
- HE line boundaries are based upon the normal operating configuration of the system with the unit operating at a 100% rated thermal power level (full power).
- Gas Systems (e.g. Nitrogen) and oil systems (e.g. EHC) are not identified as HE systems because those systems possess limited energy.

Breaks and critical cracks (as applicable) have been postulated in each HE system and mitigation strategies developed. In general, for pipe whip protection, separation of mitigation system(s) from the initiating HELB or critical crack was applied. For example, the mitigation systems (PSW and SSF) for HELBs postulated to occur in the TB are located outside of and protected from those TB HELBs. For HELBs postulated to occur within rooms of the AB, mitigation systems are either (a) located in other rooms/buildings separated and physically protected from those AB HELBs, (b) evaluated to be acceptable within the AB room the HELB is postulated to occur, or (c) protected by an installed pipe whip restraint.

Discussion

ONS excluded some systems from consideration of the protection requirement based on the small amount of time the system operates at HE conditions. No HELB protection was provided if the operating time of a system at HE conditions was less than 1% of the total unit operating time (e.g. EFW, RB spray), or if the operating time of a system at HE conditions was less than approximately 2% of the total system operating time (e.g. LPI). For systems meeting these limitations, no breaks or cracks are postulated. This was justified based on the very low probability of a HELB occurring during the limited operating time of these systems at HE conditions. In addition, gas systems (e.g. nitrogen) and oil systems (e.g. electrohydraulic control) have been excluded, since these systems possess limited energy.

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 to a lesser extent, precedent established in other licensee submittals. This issue was previously addressed in the March 5, 2007 meeting between the NRC and Duke Energy and a common understanding reached (reference 9: Matrix item H3).

The probability that HE piping would fail in a given year is on the order of 1×10^{-4}. Should the HE system or subsystem operate less than 1% of the time in a given year, then the probability that the piping would fail in a given year is approximately 1×10^{-6}. The overall objective of the break and crack postulation criteria is to identify those locations that have a higher probability of failure and determine the mitigation strategies necessary to reach SSD. Other locations such as those contained within systems that operate at HE conditions for short periods of time have a lower probability of failure and as such should be discounted.

The exclusion of the postulation of breaks for those HE systems or portions of systems that operate at HE conditions for short periods of time was also based on pipe rupture LB information reviewed from other licensees. Specifically, Final Safety Analysis Report Appendix 3.6A of Tennessee Valley Authority's Watts Bar Nuclear Plant 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."

Giambusso/Schwencer does not require the postulation of critical cracks in moderate energy systems.

The 1% time exclusion has been applied to certain HE systems that are provided for emergency situations. Note the PSW system has been previously excluded. These systems are not normally in operation. However, the systems are routinely tested to verify their capability to perform their accident mitigation functions. The interval of time in which the system is pressurized is limited in duration (well below the 1% plant operating time). Combining the low probability of the HELB with the limited duration of the system being in a HE state, the probability of a line break is sufficiently low to exclude the system from the postulation of a HELB. The 1% exclusion was applied to the following emergency systems:

- RB spray (entire system)
- "B" Train of HPI ("C" HPI pump discharge to RB penetration)
- EFW system (entire system)
- SSF ASW system (entire system)

When these systems are operating, they always operate in the HE state. Therefore, normal plant startup and shutdown sequences and the associated times spent in the different modes do not determine the time the emergency systems are exposed to HE conditions. A historical review of these systems was performed to validate operating times of the above systems in accordance with the common understanding reached (reference 9: Matrix item H3).

Plant data was reviewed from January 1, 2005 to May 1, 2009 (a period of 1581 days) to provide a representative historical period for review of the various systems. The time interval was judged to be of sufficient duration to reflect typical HE operating times.

1% Exclusions - Time Spent in HE (1/1/2005 to 5/1/2009)

	Unit 1 (days)	Unit 2 (days)	Unit 3 (days)
'A' motor driven EFW pump discharge	2.9	1.8	1.1
'B' motor driven EFW pump discharge	2.6	1.3	1.2
Turbine driven EFW pump discharge	2.5	2.9	3.1
'A' RB spray pump discharge	0.9	0.8	0.7
'B' RB spray pump discharge	0.8	0.7	0.7
'C' HPI pump discharge	1.9	1.5	0.9

SSF ASW is an emergency system that supports all three units. The SSF ASW pump discharge was operated in a HE condition for approximately 3.2 days during the same time interval of 1581 days (from 1/1/2005 thru 5/1/2009).

The total operating time spent in Modes 1 through 4 for each unit within the time interval from 1/1/2005 to 5/1/2009 is provided below:

- Unit 1 total operating time in Modes 1 through 4 was approximately 1440 days.
- Unit 2 total operating time in Modes 1 through 4 was approximately 1480 days.
- Unit 3 total operating time in Modes 1 through 4 was approximately 1500 days.

A similar exclusion was applied for those systems or portions of systems that operate at HE conditions for less than approximately 2% of the total time the particular system or portions of systems operate.

The following systems (and portions of systems) are downgraded from HE systems and excluded from HELB postulation based on the 2% exclusion:

1. LPI system (entire system)
2. Condensate recirculation piping to the UST
3. MFDW pump recirculation piping to the main condenser
4. MFDW cleanup piping to the UST
5. MFDW to the SG auxiliary FDW nozzles
6. SG hot blowdown/drain piping
7. Turbine bypass valve discharge piping to the main condenser

A historical review of the systems being downgraded from HE was performed to validate operating times at HE conditions in accordance with the common understanding reached (reference 9: Matrix item H3). Plant startup and shutdown data was reviewed for the following periods:

1. For unit 1: From 7/8/1999 to 6/1/2008
2. For unit 2: From 12/16/1999 to 12/12/2008
3. For unit 3: From 5/21/2000 to 11/11/2008

1. LPI System (entire system)

This system is normally isolated from the RCS by closed motor-operated valves. The system is charged from the BWST by two normally open motor-operated valves. The system is normally pressurized by the head of the BWST. Both the pressure from the BWST and the temperature in the system are below the threshold for HE conditions. During the latter stages of plant cool-down, the system is placed into service by isolating the system from the BWST and opening the isolation valves from the RCS. The RCS is aligned to the LPI system after RCS pressure has been reduced to approximately 300 psig and RCS temperature has been reduced below 250°F. This subjects the LPI system to HE conditions until the RCS is cooled to 200°F (or below) and depressurized to 275 psig (or below). Likewise, during the initial stages of RCS heat-up and pressurization for unit startup activities, the LPI system is aligned to the RCS where conditions subject the LPI system to HE conditions. The total time the LPI spends in HE conditions is typically short in duration. A historical review was performed for startup/shutdown evolutions on all three units using operator aid computer (OAC) data to quantify the "short periods of time" while subjected to HE conditions. The historical review period for Unit 1 was from 7/8/1999 to 6/1/2008. The historical review period for Unit 2 was from 12/16/1999 to 12/12/2008. The historical review period for Unit 3 was from 5/21/2000 to 12/18/2007. The LPI system experienced HE conditions for approximately 32 [24 hour] days on Unit 1, approximately 17 days on Unit 2, and approximately 14 days on Unit 3 for the time period reviewed.

2. Condensate Recirculation Piping to the UST

This section of piping is normally isolated from the HE portion of the condensate system by a closed motor-operated valve. The valve is opened for short periods of time during unit startup to establish cleanup of the condensate system. A historical review was performed for startup evolutions on all 3 units using OAC data to quantify the “short periods of time” while subjected to HE conditions. The condensate recirculation piping on each unit was subjected to HE conditions for less than 1% of the time for the period reviewed.

3. MFDW Pump Recirculation Piping to the Main Condenser

Each MFDW pump is equipped with a minimum recirculation line that directs flow to the main condenser. There are two lines per unit routed to separate condenser sections. Both of the recirculation lines are normally isolated from the HE portion of the FDW system by a closed air-operated valve. The piping is under vacuum conditions during normal operation while the valve is closed. The valve is throttled open for short periods of time during unit startup and shutdown when required flow to the SGs is below the minimum required flow for an operating MFDW pump. The total time the recirculation piping spends in HE conditions is typically short in duration. A historical review was performed for startup and shutdown evolutions on all 3 units using OAC data to quantify the “short periods of time” while subjected to HE conditions. The total time the MFDW pump recirculation lines to the condenser was subjected to HE conditions was approximately 2% of the time period reviewed for each unit.

4. MFDW Cleanup Piping to the UST

Each MFDW header is equipped with a recirculation line that directs flow to a single line to the UST to aid in cleanup of the system. Each of the recirculation lines is normally isolated from the HE portion of the FDW system by two closed motor-operated valves. The valves are opened for short periods of time during unit startup and shutdown when FDW cleanup is desired. The total time the FDW cleanup piping spends in HE conditions is typically short in duration. A historical review was performed for startup evolutions on all 3 units using OAC data to quantify the “short periods of time” while subjected to HE conditions. The total time the FDW cleanup line to the

UST was subjected to HE conditions was approximately 2% of the time period reviewed for each unit.

5. MFDW to the SG Auxiliary FDW Nozzles

Each MFDW header is equipped with a line that directs flow to the auxiliary nozzles of the associated SG. These lines are normally isolated from the HE portion of the FDW system by a closed motor-operated valve. The valves are equipped with an automatic signal to open the valves on a loss of all four RCPs or a loss of both MFDW pumps. In addition, the valves may be opened during startup and shutdown evolutions. The total time the FDW piping to the auxiliary nozzles spends in HE conditions is typically short in duration. A historical review was performed for startup and shutdown evolutions on all 3 units using OAC data to quantify the “short periods of time” while subjected to HE conditions. The total time the MFDW lines to the auxiliary nozzles are subjected to HE conditions is less than 1% of the time period reviewed for each unit.

6. SG Hot Blowdown/Drain Piping

Each SG is equipped with a blowdown line that directs flow to the main condenser. Both of the blowdown lines are normally isolated from the HE portion of the SGs by closed manually operated valves located inside the RB. During unit startup, it is desired to establish SG blowdown to control the water chemistry inside the SGs. The total time the SG blowdown piping spends in HE conditions is typically short in duration. A historical review was performed for startup and shutdown evolutions on all three units using OAC data to quantify the "short periods of time" while subjected to HE conditions. The historical review period for Unit 1 was from 7/8/1999 to 6/1/2008. The historical review period for Unit 2 was from 12/16/1999 to 12/12/2008. The historical review period for Unit 3 was from 5/21/2000 to 12/18/2007. The SG hot blowdown piping experienced HE conditions for approximately 35 days on Unit 1, approximately 32 days on Unit 2, and approximately 35 days on Unit 3 for the time period reviewed.

7. Turbine Bypass Valve Discharge Piping to the Main Condenser

There are four TBVs (two per SG) that are normally closed. The discharge of each TBV is connected to a common discharge header. The common discharge header is then divided into three lines that are directed to the main condenser (one line per condenser). During normal operation, these lines are subjected to vacuum conditions. Following a main turbine trip or planned shutdown of the main turbine, the TBVs open as necessary to control MS pressure at the desired setpoint. The TBVs are utilized to cool the RCS down to LPI entry conditions. During startup evolutions, the TBVs are initially opened to pull a vacuum on the SGs. Once RCS heat-up is commenced, the TBVs would be closed to allow the heat-up to continue. The TBVs may be throttled open during periods of startup where the heat-up process is placed on hold. The TBVs are also throttled open during reactor power increases until the main turbine is placed online. A historical review was performed for startup and shutdown evolutions on all 3 units using OAC data to quantify the “short periods of time” while subjected to HE conditions. The total time the TBV discharge lines are subjected to HE conditions is approximately 2% of the time period reviewed for each unit.

No through-wall leakage cracks have been postulated for HE systems (or portions of HE systems) that have been downgraded using the 1% of the total unit operating time or less than approximately 2% operating time at HE conditions.

Normal operating temperature and pressure in systems was based on operation at 100% rated power. A calculation, OSC-8385, was created to document these normal operating conditions. The normal operating configuration at 100% rated power was established by reviewing the system operating procedures. Pressure and temperature instrumentation was selected where appropriate to define the conditions existing in the piping section of interest. Plant operating

history was reviewed to determine a period of time when the units were operating at a steady state of 100% rated power. Plant data was obtained from the OAC for the pressure and temperature instruments of interest during the selected operating period and documented in the attachments to the calculation. Average values were selected to define the normal operating conditions. The review of piping systems was limited to water and steam systems. Utilizing the data from OSC-8385, any systems or portions of systems, whose temperature exceeds 200°F, but operate at atmospheric pressure or below were excluded from damage assessments. The basis for the exclusion is that piping systems at or below atmospheric pressure possess insufficient energy to create pipe whips or jet impingement. This exclusion principle was applied to the “E” extraction steam piping and the steam seal header return piping.

In addition, gas systems (e.g. nitrogen) and oil systems (e.g. electrohydraulic control) have been excluded, since these systems possess limited energy. The gas systems are within the original scope of HELB postulation. However, there are no breaks postulated that could impact SSCs that could adversely affect the operation of the RCS. These systems are excluded from the HELB reconstitution project due to the limited energy of the piping. This was based primarily on the small diameter piping in these systems. The nitrogen system consists of a high pressure portion and a low pressure portion. The low pressure portion is not considered to be HE due to the pressure being below 275 psig. The high pressure portion is normally pressurized to approximately 625 psig. However, most of the piping is 1-inch or less excluding it from break postulation. A small section of 1.5-inch (outer diameter (OD)) piping is routed inside the TB basement. Any break in this section of piping is judged to have insufficient energy to damage adjacent piping systems or structural components. There are two locations inside the AB on the 2nd floor hallway (one at the north end and one at the south end) where the high pressure nitrogen piping increases in size from 1-inch (OD) to 2-inches (OD) to accommodate a pressure reducing valve. A break in this section of piping is judged to have insufficient energy to damage adjacent piping systems or structural components. The electrohydraulic control system also consists of a HE portion and low energy portion. The low pressure portion is not considered to be HE due to the pressure being below 275 psig. The high pressure portion is normally pressurized to approximately 1600 psig. The HE portion contains piping that is 1-inch and 1.5-inch nominal pipe size. Again, due to the small diameter piping, it is judged that there would be insufficient energy to damage adjacent piping systems or structural components

Air or other gases do not have the density or the phase change that subcooled or saturated water conditions have during depressurization. They also do not have the wetting and flooding concerns. The nitrogen and hydrogen lines at ONS do not exceed temperatures of 200°F. The air systems in the ABs and TBs all have operating temperatures less than 425°F (backup IA) and some (service and breathing) air systems have aftercoolers that limit actual air temperatures to a maximum of 30°F above ambient. Therefore, with low density and no phase change, the identification and protection from the effects of low pressure and low temperature air and gas lines are not included in the ONS HELB criteria.

The following systems (portions of which normally operate at temperatures greater than or equal to 200°F or have design pressures greater than or equal to 275 psig) are determined to be HE:

- Auxiliary Steam
- Condensate
- Extraction Steam
- MFDW
- MS
- Heater Drain
- Heater Vent

- HPI
- Moisture Separator Reheater Drain
- Plant Heating (PH)
- Reverse Osmosis
- Steam Drain
- Steam Seal Header

For the systems above, the evaluation conclusions reached relative to pipe whip protection are discussed in later requirements.

Requirements 2 and 3:

The Giambusso letter, as modified by Schwencer letter, provided guidance on the selection of break locations based on a set of criteria. In addition, a single critical crack was required to be postulated at the most adverse location(s) with regard to those essential structures and systems. The critical crack size area was taken to be ½ the pipe diameter in length and ½ the wall thickness in width.

ONS Methodology

The following criteria were used to identify the HE piping break locations:

- HELBs of any type are not postulated on HE piping that has a nominal size of 1" or less.
- Breaks and critical cracks are not postulated on HE lines that operate at HE conditions less than approximately 2% of the total system operating time.
- Breaks and critical cracks are not postulated on HE lines that operate at HE conditions less than 1% of the total plant (unit) operating time (normal plant conditions).
- HELBs are postulated at the terminal ends of HE piping runs.
- There is no ASME 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 ends.
- 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 (references 1 and 2). The requirements contained therein do not include postulation of moderate energy line breaks.
- HE 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 MFDW 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.

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

- Circumferential Breaks are to be postulated in HE lines that exceed one (1) inch nominal pipe size.
- Only circumferential breaks are postulated at terminal ends of HE piping runs. (Longitudinal breaks are not postulated at terminal ends.)
- Longitudinal Breaks are to be postulated in HE piping 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 to be postulated on seismically analyzed HE piping that exceeds one (1) inch in nominal pipe size.

Discussion

ONS has modified the break selection criteria using GL 87-11 (reference 19) and portions of BTP MEB 3-1. Duke has postulated circumferential and longitudinal break locations as follows:

A. For piping that is seismically analyzed, i.e. stress analysis information is available and the analysis includes seismic loading, intermediate breaks are postulated in Class 2 or 3 equivalent piping at axial locations where the calculated longitudinal stress for the applicable load cases exceed $0.8(S_a + S_h)$. Applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (OBE). Intermediate breaks are not postulated at locations where the only stress is the expansion stress and this stress exceeds $0.8S_A$. Thermal stress is a secondary stress, and taken in absence of other stresses, does not cause ruptures in pipe.

   In the absence of primary stress, secondary stress, such as thermal, is a poor predictor of potential pipe failure locations. Primary stress is needed to cause a potential pipe failure. The ASME Code Section NB-3213.8 (1977 edition) defines primary stress as follows: "Any normal or a shear stress developed by an imposed loading which is necessary to satisfy the laws of equilibrium of external and internal forces and moments. The basic characteristic of a primary stress is that it is not self-limiting. Primary stresses which considerably exceed the yield stress will result in failure or, at least, in gross distortion."

   ASME Code NB-3213.13 defines thermal stress as follows: "Thermal stress is a self balancing stress produced by a non-uniform distribution of temperature or by differing thermal coefficients of expansion. Thermal stress is developed in a solid body whenever a volume of material is prevented from assuming the size and shape that it normally should under a change in temperature."

   In section NB-3213.13(b), the Code notes: "Local thermal stress is associated with almost complete suppression of the differential expansion and thus produces no significant distortion. Such stresses shall be considered only from the fatigue standpoint and are therefore classified as local stresses in Table NB-3217-1." Since thermal stress is self-balancing, thermal stress which exceeds the yield stress will not result in failure. Repeating cycles of thermal stress exceeding the yield stress may result in cracking due to fatigue, however, the potential for critical crack formation is addressed by the postulation of critical cracks where the actual stress exceeds the crack stress threshold of $0.4 \times (S_a + S_h)$.

   Giambusso/Schwencer included the requirement to postulate break locations where the actual stress exceeded $0.8S_A$. However, BTP MES 3-1 includes no such requirement. Duke Energy concluded that the omission of the thermal stress threshold in BTP MES 3-1 is recognition by the regulatory authorities that thermal stress, in the absence of primary stress, cannot cause pipe rupture failures.

B. For piping that is not rigorously analyzed or does not include seismic loadings, intermediate breaks are postulated in accordance with BTP MEB 3-1 (Section B.1.c(2)(b)(i)). The ONS UFSAR Section 3.7.3.9 notes that “seismic/non-seismic lines are physically separated insofar as possible such that failure of a non-seismic line has no effect on safety related piping.” However, in certain cases a postulated break location of a non-seismic system or subsystem may interact with and possibly cause failure of a seismically supported system. These potential interactions were discovered in the TB. These postulated interactions were based on field surveys of the plant, using experienced engineers. Conservative concepts were employed during the field surveys, with the resulting worst case assessment of potential interactions. The overall mitigation strategy is predicated on separation of essential systems (e.g., those systems and components necessary to reach a SSD condition) from

the postulated HELB. For breaks postulated to occur in the TB, systems and components located in the AB or the SSF would be available for mitigation of the effects from the break. Therefore, any possible interactions between non-seismic piping and seismic piping located in the TB can be adequately mitigated with available equipment in either the AB or the SSF.

The identified potential interactions between non-seismic and seismic piping are located in the TB, between the various secondary side HE systems and portions of the following systems:

- EFW system
- MS branch lines
- Siphon seal water system
- CCW
- LPSW system

C. Terminal ends are vessel/pump nozzles, building penetrations, in-line anchors, and branch to run connections that act as essentially rigid constraints to piping thermal expansion. A branch appropriately modeled in a rigorous stress analysis with the run flexibility and applied branch line movements included and where the branch connections stress is accurately known, the stress criteria noted above in (A) is used for postulating breaks locations. In order for the branch connection stress to be accurately assessed, the branch line must be included in the stress model of the main run. This is not incompatible with BTP MEB 3-1 Rev. 2 Section B.1.c.(1)(a) footnote 3. In those cases where the branch line is included in the stress model of the main run, the branch line is classified as part of the main run and by its inclusion, has a significant effect on the main run behavior. For those cases where the branch line is not included in the stress model of the main run, terminal end breaks are postulated on the branch side of the connection. For unanalyzed branch connections or where the stress at the branch connection is not accurately known, break locations are postulated in accordance with BTP MEB 3-1 (Section B.1.c(2)(b)(i)).

Thermal analysis of the decoupled branch line included thermal movements of the run pipe applied as anchor movements to the branch line. Similarly, seismic analysis of the decoupled branch line included inertial displacements and/or seismic anchor motion displacements of the run pipe applied as anchor movements to the branch line.

The terminal end definition discrepancy was previously discussed in the March 5, 2007 meeting between the NRC and Duke Energy. It was agreed during the meeting that a common understanding had been reached and that no further action was required by Duke Energy (reference 9: Matrix Item H4).

The Giambusso/Schwencer letters do not directly address the postulation of terminal end breaks in Class 2 and 3 equivalent piping at isolation valves that separate HE systems or subsystems from non-HE systems or subsystems. However, Giambusso/ Schwencer does address the postulation of terminal end breaks at isolation valves for Class 1 piping. Footnote 3 under Giambusso 2(a) notes the following:

> *"A piping run interconnects components such as pressure vessels, pumps, and rigidly fixed valves that may act to restrain pipe movement beyond that required for design thermal displacement. A branch run differs from a piping run only in that it originates at a piping intersection, as a branch of the main pipe run."*

As noted before, ONS is not licensed to the SRP or BTP MEB 3-1, and does not seek to be licensed as such in the future. However, for purposes of discussion, Footnote 3 of Section B.1.c.(1)(a) of BTP MEB 3-1 Revision 2 notes the following:

> *"Extremities of piping runs that connect to structures, components (e.g., vessels, pumps, valves), or pipe anchors that act as rigid constraints to piping motion and thermal expansion. A branch connection of a main piping run is a terminal end of the branch run, except where the branch run is classified as part of the main run in the stress analysis and is shown to have a significant effect on the main run behavior. In piping runs which are maintained pressurized during normal plant conditions for only a portion of the run (i.e., up to the first normally closed valve) a terminal end of such runs is the piping connection to this closed valve."*

Note that the first part of the footnotes is similar in that both define terminal ends as structures (including pipe anchors) and components that act to restrain pipe motion and thermal expansion.

However, the BTP MEB 3-1 Revision 2 footnote expands the definition beyond that provided in Giambusso/Schwencer to include isolation valves that separate piping that is normally maintained at HE conditions from other piping that is not normally maintained at HE conditions.

The HELB evaluation fully meets the requirements of Giambusso/Schwencer in this regard. Giambusso/ Schwenccer required the postulation of terminal end breaks at rigidly fixed valves that may act to restrain thermal movement. There are no such rigidly fixed isolation valves that serve as the boundary between HE systems or subsystems and the non-HE systems or subsystems at ONS. All isolation valves that serve in this manner are in line valves that are not independently supported or supported in a way that would prohibit piping motion and thermal movement.

The applicable HE piping systems at ONS are denoted as those systems or subsystems that are rigorously analyzed for applicable design loads, including seismic, those systems or subsystems that are not rigorously analyzed, and those systems or subsystems that are rigorously analyzed, but are not analyzed for seismic loads. For those systems or subsystems that are rigorously analyzed for the applicable design loads, including seismic, and the analyses are continuous across the subject isolation valves such that accurate stress information is available, breaks are postulated at locations where the actual calculated primary stress (longitudinal pressure + gravity + OBE) + secondary stress (thermal movement, anchor motions, etc.) exceeds the stress threshold given in BTP MEB 3-1 Rev. 2 Section B.1.c(2). For all other systems or subsystems, breaks are postulated to occur at all welds and fittings.

The justification for not postulating breaks at isolation valves between HE piping and non-HE piping for those systems or subsystems that are rigorously analyzed for the applicable design loads, including seismic, is based on the similarities between a branch connection that is appropriately analyzed in the stress analysis and a closed isolation valve that is appropriately analyzed in the stress analysis. As noted in the footnote, the branch side of a connection is a terminal end unless it is classified as part of the main run in the stress analysis and is shown to have a significant effect on the main run behavior. Applying that rationale to a closed valve that represents the boundary between HE piping and non-HE piping would lead one to conclude that if such a valve was classified as part of the main run in the stress analysis and shown to have a significant effect on the main run behavior, then the valve would not represent a terminal end. In the stress analysis, the appropriate design parameters are applied such that the lower pressure is applied to the non-HE piping and the higher pressure to HE piping. Given these facts, Duke Energy concludes that these valves do not represent a terminal end.

The NRC has previously approved this interpretation at ONS for the passive LPI cross connection modifications.

Other licensees have reached the same conclusion. Two examples are included below:

Florida Power Corporation (now part of Duke Energy) submitted a revised pipe rupture analysis criteria for Crystal River Unit 3 by letter dated March 31,1989 and later revised by letter dated December 18, 1989. Page 7 of the pipe rupture analysis criteria report defines a terminal end as:

> *"Extremities of piping runs that connect structures, large components (e.g., vessels, pumps) or pipe anchors that act as essentially rigid constraints to piping thermal expansion including rotational movement from static or dynamic loading. In line fittings such as valves, adequately modeled and not anchored in the piping stress analysis, are not terminal ends."*

The NRC accepted the new LB for pipe rupture for Crystal River Unit 3 by letter dated April 11,1999.

In Tennessee Valley Authority's Watts Bar final safety analysis report Section 3.6.A.2, "Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping," Subsection 3.6.A.2.1.2.3, "High/Moderate Energy Interfaces," reads as follows:

> *"Line supported valves sometimes form the interface between high energy lines and moderate energy lines. In this case, the fixity as implied in the word terminal does not exist at the line supported valve. This condition is treated as if there were no terminal (end)."*

D. The Giambusso letter provides criteria to determine pipe break orientation at break locations and specifies that longitudinal breaks in piping runs and branch runs be postulated for nominal pipe sizes greater than or equal to 4 inches. Circumferential breaks are postulated at all terminal ends. The design of existing and potentially new rupture restraints may be used to mitigate the results from such breaks, including prevention of pipe whip and alteration of the break flow. Longitudinal breaks are not postulated at terminal ends. This is consistent with the requirements of BTP MEB 3-1.

E. For the postulation of critical cracks, the following applies:

For piping that is seismically analyzed (i.e. stress analysis information is available and the analysis includes seismic loading), critical cracks are postulated in Class 2 or 3 equivalent piping at axial locations where the calculated longitudinal 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).

For non-seismically analyzed piping, critical cracks are not postulated, since the effects of postulated circumferential and longitudinal breaks at these locations will bound the effects from critical cracks (see Item B above).

Actual stresses used for comparison to the break and crack thresholds noted above 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 the USAS B31.1.0 code or the USAS B31.7 (February 1968 Draft Edition with Errata) code as appropriate.

Requirement 4:

Giambusso Letter requested that a summary be provided for the dynamic analysis applicable to the design of Category 1 piping and associated supports which determine the resulting loadings, including:

a. **The locations and number of design basis breaks on which the dynamic analyses are based.**
b. **The postulated rupture orientation for each design basis break location.**
c. **A description of the forcing functions used for the pipe whip dynamic analyses including the direction, rise time, magnitude, duration and initial conditions that adequately represent the jet stream dynamics and the system pressure difference.**
d. **Diagrams of mathematical models used for the dynamic analysis.**
e. **A summary of the analyses which demonstrates that unrestrained motion of ruptured lines will not damage to an unacceptable degree, structure, systems, or components important to safety, such as the control room.**

ONS Methodology

Dynamic analyses were performed for ASME B&PV, Section III-Class 2 equivalent piping (MFDW and MS) postulated HELBs in the EPR to determine the internal pressurization of the room. Dynamic analyses were also performed for postulated PH HELBs in the ventilation equipment rooms in the AB to determine internal pressurization of those rooms. The software GOTHIC was used to determine the internal pressurization. For the MFDW and MS postulated HELBs in the EPR, mass and energy release associated with the SG blowdown was predicted using the software RETRAN. This information was used as input to the GOTHIC analyses. Other dynamic analyses of ASME B&PV, Section III-Class 2 and 3 equivalent piping postulated HELBs and the effect on associated supports were not performed at ONS. Except for two MFDW rupture restraints, located in the EPR, evaluations of the effects of whip and jet impingement associated with postulated HELB locations assumed unrestrained lines.

Dynamic analyses were performed for the break scenarios that warranted a dynamic analysis. Dynamic analyses were not required for breaks postulated to occur in the TB to determine internal pressurization, since the volume of the building is large and contains numerous openings, such that internal pressurization of the building is insignificant. Furthermore, systems were credited with mitigation outside of the TB for breaks within the TB. However, where the room is small and contain no significant openings, as is the case for the EPR and the ventilation equipment rooms of the AB, dynamic analyses were performed to determine the internal pressurization of the room.

Discussion

Giambusso/Schwencer does not define the meaning of HE category 1 piping. If HE category 1 piping means class 1 piping, no dynamic analysis is required since there is no class 1 piping outside of the containment building at ONS. Should HE category 1 piping mean piping that is indirectly connected to the primary system (RCS), such as MFDW and MS, or if HE category 1 piping means safety related piping, then the dynamic analyses were performed for postulated FDW and MS HELBs in the EPR to determine the internal pressurization of the room. Additional dynamic analyses were performed for several postulated plant heat HELBs.

The Giambusso letter attachment 1, “General Information Required for Consideration of the Effects of a Piping System Break outside Containment” noted on page 1 the following:

"Since piping layouts are substantially different from plant to plant, applicants and licensees should determine on an individual plant basis the applicability of each of the following items for inclusion in their submittals."

Dynamic analysis of HE category 1 piping postulated HELBs and the effect on associated supports was not accomplished at ONS. With the exception of two MFDW rupture restraints, located in the EPR, evaluations of the effects of whip and jet impingement associated with postulated HELBs assumed unrestrained lines. As such, there was no need to determine the dynamic response for these HELBs since no supports in the lines were designed to absorb these loads. Rather, the SSD equipment located in the ZOI of these breaks were assumed failed and rendered non-operational. The design of the MFDW rupture restraints are described in the response to requirement 5 below.

For the postulated HELBs, jet impingement forces were determined in accordance with ANSI/ANS 58.2 -1988, "Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture". Once the jet impingement forces were determined, plastic hinges were postulated, and whip interaction zones established. Following that, surveys were made of the interaction zones to identify any SSD equipment. Identified SSD equipment located within the interaction zones were considered to be damaged and rendered non-functional.

The overall mitigation strategy for postulated HELBs is the availability of other equipment remote from the postulated HELB location that could be used to bring the affected unit to a SSD state.

Requirement 5:

Requirement 5 in the Giambusso Letter requested that a description be provided for the measures, as applicable, to protect against pipe whip, blowdown jet and reactive forces including:

a. **Pipe restraint design to prevent pipe whip impact.**
b. **Protective provisions for SSCs required for safety against pipe whip, blowdown jet and reactive forces.**
c. **Separation of redundant features.**
d. **Provisions to physically separate piping and other components of redundant features.**
e. **A description of the typical pipe whip restraints and a summary of number and locations of all restraints in each system.**

<u>ONS Methodology</u>

There are two rupture restraints per each unit designed to mitigate a postulated HELB. Each MFDW train contains a rupture restraint, located in the EPR, adjacent to the respective containment penetration. The rupture restraint consists of eight threaded rods that are attached at one end via clevises to vane plates that are in turn attached to the structure of the MFDW structural anchor. This anchor is attached directly to the exterior of the containment wall. The structural anchor is a terminal end. The other end(s) of the threaded rods are attached to the MFDW pipe by welded attachments. At the welded attachments, the rods penetrate through holes in the welded attachments. Heavy hex nuts are threaded onto the rods. Gaps are provided between the heavy hex nuts and the welded attachments to allow thermal growth.

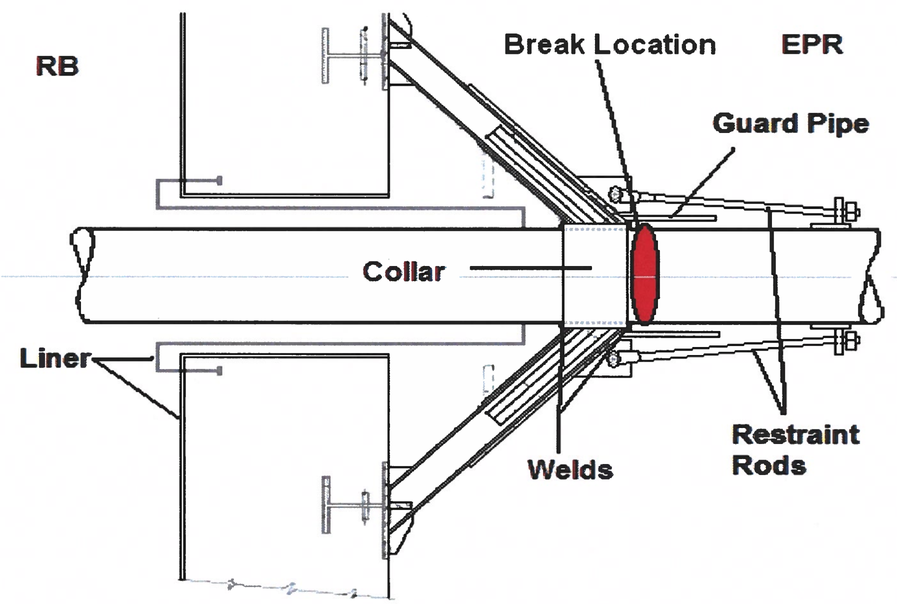
The MFDW rupture restraints are designed to prevent pipe whip of the lines into the EPR following a postulated double ended guillotine break just upstream of the structural anchor. The design limits the break gap to 0 inches insofar as possible based on the thermal expansion

tolerances, and the physical properties of the restraint rods. A guard pipe is provided as part of the rupture restraint. The guard pipe limits jet impingement resulting from the postulated break. The guard pipe also directs flow of the leakage away from vulnerable mechanical and electrical equipment located in the EPR.

The guard pipe is designed for full system design pressure and temperature, 1275 psig, and 475°F. All load bearing members are designed to an allowable of 0.9 F_y for primary stresses, where F_y is the yield stress of the applicable material. A dynamic load factor of 3.0 is used for applicable load bearing members of the restraint.

Note that the postulated break location at the MFDW rupture restraint remains unchanged from the original MDS Report No. OS-73.2. The AEC previously accepted the report with the break location at the MFDW rupture restraint as shown on Figure 2.1-4.c of the MDS report. Below is a detailed sketch showing the rupture restraint and the postulated break location.

Main Feedwater Rupture Restraint



Discussion

The intent of the original MDS Report (OS 73.2) was to address HELBs occurring outside of the containment building. The postulated terminal end breaks at containment penetrations given in this report were located on the AB side of the penetration. All of the containment penetrations at ONS are of the fixed design, and as such, act as terminal ends. So, any postulated break at the containment penetrations (at the terminal end) would result, by definition, in a loss of the containment building integrity. Any of these breaks would be similar to a break inside of the containment building. Similarly, a postulated break location downstream of the MFDW rupture restraint would be similar to a MFDW break inside of the containment building, except that a localized failure of the containment building would also occur. The design basis of containment penetrations is given in UFSAR section 3.6.1.1. The section states the following:

"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."*

The statements of interest are numbers 2 and 4 above. Statement 2 means that the MFDW rupture restraint can withstand the associated rupture forces associated with a break on either side of the restraint. Statement 4 means that should the FDW line break downstream of the rupture restraint or inside the containment building, a primary line will not be affected.

The design pressure and temperature of the piping systems penetrating the containment building are used to determine the line rupture forces and moments caused by their own rupture in the design of the containment penetration(s). The normal operating pressure and temperature of the HE systems are used to determine the line rupture forces and moments caused by the postulation of break locations. Since the design pressure and temperatures are greater than the normal operating pressure and temperatures, the containment penetrations are adequately designed to absorb without failure, the forces and moments associated with a postulated HELB of the line passing through each penetration.

This issue was previously discussed during the March 5, 2007 meeting between the NRC and Duke Energy and a common understanding reached (reference 9: Matrix item H7)

Requirement 6:

Requirement 6 in the Giambusso Letter requested procedures be provided that will be used to evaluate the structural adequacy of Category 1 structures and to design new seismic Category 1 structures, including:

a. **The method of evaluating stresses, e.g., the working stress method and/or the ultimate strength method that will be used.**
b. **The allowable design stresses and/or strains.**
c. **The load factors and the load combinations.**

ONS Methodology

AB

Unreinforced Block and Brick Walls:

Method of Evaluating Stresses: Arch Method

Allowable Design Stress:

Flexure:

Brick: $0.85\ f_m$ = 935 psi

Block: $0.85\ f_m$ = 850 psi

Shear:

Brick: 48.5 psi

Block: 48.5 psi

Strain: $\varepsilon_c = 0.00085$

Where: f'_m is the compressive strength of the brick or block, as appropriate.

Loading Combination:

Dead Load + Internal Pressure Load

Reinforced Concrete:

Method of Evaluating Stresses: Ultimate Strength and Yield Line/Plastic Hinge

Allowable Design Stress:

Compression:	$f'_c = 5,400$ psi
Flexure:	$0.85\ f'_c = 4,590$ psi
Shear:	$1.33 \times 1.1\ (f'_c)^{1/2} = 107.5$ psi
Bond:	$1.33 \times 3.4\ (f'_c)^{1/2} / D$ (for top bars)
Bond:	$1.33 \times 4.8\ (f'_c)^{1/2} / D$ (for other bars, not top bars)
Steel reinforcement:	$f_y = 40,000$ psi

Where: f'_c is the compressive strength of the concrete.

f_y is the yield stress of the steel reinforcement.

D is the diameter of the reinforcing bars (in.)

In cases where the components could not be qualified by the ultimate strength methodology, a yield line/plastic hinge methodology was used. This method used a yield line collapse mechanism approach to obtain the ultimate load of the component. Ductility and hinge rotation were then checked to ensure that the component could withstand the deformation(s). The following ductility limits were imposed:

Flexure (concrete beams):	$0.10 / \rho - \rho' \leq 10$
Flexure (slabs):	$0.10 / \rho - \rho' \leq 30$
Compression (walls and Columns):	1.3
Shear (beams and slabs)	
carried by concrete only	1.0
carried by concrete & stirrups	1.3
carried completely by stirrups	3.0

Where: ρ is the tension reinforcement ratio

ρ' is the compression reinforcement ratio

In addition, the following concrete plastic rotational limits must be satisfied:

$r_\theta \leq 0.0065$ d/c

and

$r_\theta \leq 0.07$

Where: r_θ is the actual rotational of plastic hinge, radians.

d is the effective depth of the section (distance from extreme compressive fiber to centroid of tensile reinforcement), in.

c is the distance from the extreme compressive fiber to neutral axis at ultimate strength, in.

Loading Combination:

Dead Load + Internal Pressure Load

$$Y = \left(1/_{\Phi}\right)[1.05D + P]$$

Dead Load + Internal Flooding Load

$$Y = \left(1/_{\Phi}\right)[1.05D + F]$$

Where: Y = Required strength of structure
D = Dead loads of the structure and equipment, plus any other permanent loads.
P = Design Accident Pressure
F = Design Flood Pressure
ϕ = Concrete capacity reduction factor
= 0.9 for concrete flexure
= 0.85 for tension, shear, bond, and anchorage in concrete

Steel Reinforced Masonry Walls:

Flexure (Steel members):	$F_b = F_y = 36{,}000$ psi
Shear (Steel members):	$F_v = 0.6\ F_y = 21{,}600$ psi
Shear (7/8" Anchor Bolts):	V = 18,800 psi, factor of safety = 2.0

Dynamic Increase Factor (DIF): 1.2 (All analyses)

<u>TB</u>

Steel Beams and Columns

Method of Evaluating Stresses: Linear Elastic

Allowable Design Stress:

Bending:	$F_y = 36{,}000$ psi
Shear:	$0.6\ F_y = 21{,}600$ psi
Web Crippling:	$F_y = 36{,}000$ psi

Loading Combination:

1.0 D + 1.0 T

Where D = the dead load of the structure and equipment

T = the HELB thrust load

Dynamic Increase Factor (DIF): 1.2 (All analyses)

Discussion

Analysis of AB structural components was performed for the internal pressurization of the EPR following either a MFDW or MS HELB postulated to occur in the room. Blow-out panels installed on the north wall of the Unit 1 EPR and the south side of the Units 2 & 3 EPRs were credited in the pressurization analyses. The analysis results indicate that although minor damage to unreinforced block and brick walls may occur following the postulated HELB, the overall structure of the AB remains intact.

Analysis of TB steel columns and beams was performed for pipe whip loads associated with postulated HELBs located in the TB. The analysis results indicate that although damage to columns and beams may occur, the overall structure of the TB remains intact.

Requirement 7

The Giambusso letter, as modified by the Schwencer letter, requested information regarding the structural design loads, including the pressure and temperature transients, the dead, live and equipment loads; and the pipe and equipment static, thermal and dynamic reactions.

ONS Methodology

The design loads utilized in the analysis for the AB are as follows:

1.	Concrete	150 lbs. per cu. ft.
2.	Block Walls	125 lbs. per cu. ft.
3.	Structural Steel	490 lbs. per cu. ft.
4.	Pressure and Temperature Transients	as defined in the MFDW and MS pressurization analysis.

The design loads utilized in the analysis for the TB are as follows:

1.	Roof	25 lbs. per sq. ft. (psf)
2.	Operating Floor (Total)	370 psf
	Dead Load (Concrete Slab):	145 psf
	Dead Load (Steel)	25 psf
	Equipment Load	200 psf
3.	Mezzanine Floor (Total)	240 psf
	Dead Load (Concrete Slab):	100 psf
	Dead Load (Steel)	15 psf
	Equipment Load	125 psf
4.	Pressure and Temperature Transients	Negligible
5.	Dynamic pipe reactions are HELB specific.	

Requirement 8:

The Giambusso letter requested that Seismic Category 1 structural elements such as floors, interior walls, exterior walls, building penetrations and the buildings as a whole for eventual reversal of loads due to the postulated accident be analyzed.

ONS Methodology

The only areas of the plant outside of the containment building subjected to reversal of load are the EPR and WPR ceilings. The ceiling structures are normally loaded with equipment and dead loads. Pressurization of the EPR and WPR due to postulated MFDW and MS HELBs located in the EPR will exert an upward load on the ceiling structure followed by a reestablishment of the equipment and dead loads. The evaluation shows that the results are within the acceptable limits.

Requirement 9:

The Giambusso letter requested that if new openings are to be provided in existing structures, demonstrate the capabilities of the modified structures to carry the design loads.

ONS Methodology

The north facing exterior block walls were removed from the Unit 1 EPR and replaced by lightweight panels in 1974. These panels were designed to relieve the internal pressure in the EPR, following either a MFDW or MS break. Analysis to determine the pressure blowout capability of each panel, has been completed, considering their as-built configuration. Similar panels were installed and analyses completed for Units 2 and 3.

Discussion

The computer code GOTHIC was used to model the EPR and WPR, and determine the resulting pressurization following either a MFDW break or a MS break. The pressure blowout capability (failure pressure) of each of the panels was assigned to the appropriate “quick open” valves in the GOTHIC model to represent the failure of the panels following the pipe rupture. Pressure time histories were obtained for each junction. The structural components that comprise the EPR and WPR were then evaluated for the appropriate pressure time history.

Requirement 10:

The Giambusso letter requested that failure of any structure, including non-seismic Category 1 structures, caused by the accident, will not cause failure of any other structure in a manner to adversely affect:

a. mitigation of the consequences of the accident
b. capability to bring the unit(s) to a Cold Shutdown Condition

ONS Methodology

There is no damage postulated to the AB structure. Postulated MFDW HELBs are limited to the terminal ends at the RB wall, inside the EPR. Whip restraints were installed to protect against the resultant pipe whips from the MFDW HELBs. There were no interactions with the AB structure due to pipe whips or jet impingement from the postulated MS HELB inside the EPR. A postulated pipe rupture in the MS line or either of the MFDW lines could result in pressurization of the penetration room. Blowout panels were installed in the exterior walls of the EPR to relieve the steam to outside to prevent excessive pressurization of the room. The peak pressure inside the penetration room was determined to be between 3.6 and 4.3 psig, and occurs between 0.1 and 0.2 seconds. The peak pressure was based on the double-ended MS HELB. The pressure

response for the MS HELB bounds the other postulated HELBs inside the penetration room. The resulting pressure spike does not result in a failure of the penetration room structure. However, several unreinforced masonry walls are expected to crack and potentially fail. The CR and CSR are protected by a structural reinforced wall between it and the penetration room. In addition, the control battery room is protected by a reinforced wall between it and the penetration room.

Localized structural damage is postulated inside the TB for TB HELBs. Although postulated pipe ruptures inside the TB will not result in any significant pressurization effect, pipe whip and jet impingement may result in interactions with structural components.

Some localized structural damage to the TB is caused by specific breaks on the condensate, extraction steam, MFDW, heater drain, MS, and moisture separator reheater drain systems. For the columns that may fail as a result of the interactions, modifications are being implemented to strengthen these columns, such that the structural damage does not prevent achieving and maintaining a SSD condition and the subsequent cooldown to CSD condition.

Requirement 11:

Item 11 in the Giambusso Letter, as modified by the Schwencer letter, required that rupture of a pipe carrying HE fluid will not directly or indirectly result in either:

a. **Loss of required redundancy in any portion of the protection system, Class 1E electrical system, ES equipment, cable penetrations, or their interconnecting cables required to mitigate the consequences of that accident and place the reactor(s) in a CSD Condition.**

OR

b. **Environmental induced failures caused by a leak or rupture of the pipe which would not of itself result in protective action but does disable protection functions. In this regard, a loss of redundancy is permitted but a loss of function is not permitted. For such situations plant shutdown is required.**

<u>ONS Methodology</u>

The core protection systems at ONS consist of the RPS and ES systems. The RPS trips the reactor to prevent exceeding acceptable fuel damage limits. The ES system automatically initiates the HPI and LPI Systems on either a low RCS pressure or high containment pressure. The cabinets for the RPS and ES systems are physically located inside the control complex. The cabinets are protected from the effects of postulated HELBs outside of the containment building. HELBs outside of the containment building can lead to either inadequate heat transfer or excessive heat transfer in the RCS. Inadequate heat transfer results in high RCS pressure conditions. Excessive heat transfer results in low RCS pressure conditions. The RPS trip on high RCS pressure is credited for inadequate heat transfer. The RPS trip on low RCS pressure or variable low RCS pressure is credited for excessive heat transfer. The ES system is expected to be actuated following excessive heat transfer or letdown line breaks. There are RCS pressure and temperature instruments that feed the RPS. These instruments are located inside of the containment building. The containment pressure instruments are not required for HELBs outside of the containment building. There are RCS pressure transmitters that feed into the ES system. These instruments are also located inside of the containment building. The cabling from these instruments for RPS and ES systems are routed through the penetration rooms to the CSR. The electrical penetrations and the associated cabling for the instruments are qualified for the environmental conditions inside the penetration room, and these cables are not directly impacted by any postulated HELBs in the penetration room. Therefore, there is no expected

loss of required redundancy due to the effects of postulated HELBs outside of the containment building.

The class 1E electrical system may be damaged by postulated HELBs inside the TB. The direct effects (pipe whip and jet impingement) from some HELBs may result in damage to the 4160 VAC switchgears, 4160 VAC main feeder buses, or associated cabling that may result in loss of the power sources to the 4160 VAC/6900 VAC electrical distribution systems. The effect would be similar to a SBO. To address the loss of these power sources, two alternate means of achieving a SSD condition are available through the PSW system and the SSF. Two alternate means of achieving and maintaining a SSD condition are provided to address SAFs.

The PSW system is capable of maintaining the SSD condition from the unit CR. Electrical power to the PSW system is provided from either the 100 kV power line or from a Keowee Hydro outside the TB. The PSW pump can be started from the CR to feed either or both SGs to maintain secondary side heat removal. The PSW pump also supplies cooling water to the HPI pump motors. Power for one HPI pump can be restored from the PSW electrical system as well as selected motor-operated valves to align pump suction to the BWST and control flow to the RCS via the ‘A’ injection header and RCP seal injection. RCS pressure can be controlled by using pressurizer heaters powered from the PSW electrical system. Finally, the control batteries serving the 125 VDC and 125 VAC Vital I&C systems can be recharged from the battery chargers powered from the PSW electrical system.

The SSF is capable of maintaining the SSD condition from the SSF CR. The SSF Power system includes 4160 VAC, 600 VAC, 208 VAC, 120 VAC and 125 VDC power. It consists of switchgear, a LC, MCCs, panelboards, remote starters, batteries, battery chargers, inverters, a 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.

With the unit(s) being maintained in a SSD condition, there is no immediate need for plant cooldown. Damage repair guidelines will continue to be credited to restore power to systems and components needed for plant cooldown to CSD conditions. As part of the damage repair procedures a portable valve control panel would be installed and wired to allow closure of the core flood outlet valves (CF-1 & CF-2) when conditions permit their closure. In addition, the portable valve control panel would allow the opening of the decay heat drop line isolation valves (LP-1 & LP-2) when entry conditions for normal DHR are established.

Some ES equipment may be lost due to possible flooding inside the TB basement, specifically the LPSW pumps. The LPSW pumps for all three units are located in the TB basement. Some postulated HELBs inside the TB may result in ruptures to the CCW piping. ES equipment (HPI and LPI) located inside the AB are protected from the effects of flooding inside the TB by the existing flood protection measures/barriers and the TB drain located at the south end of the TB. The EFW pumps, although not classified as ES equipment, are also located in the TB basement. TB flooding can result in the loss of LPSW and EFW on all three units. Damage repair guidelines are credited to restore the LPSW Systems once the source of flooding has been isolated to enable a plant cooldown to CSD conditions. Replacement motors and associated cabling for the LPSW pumps are stored in a protected warehouse.

SAFs are not postulated in establishing plant cooldown and the establishment of CSD.

Requirement 12:

The Giambusso Letter requested that assurance be provided that the control room will be habitable and its equipment functional after a steam line or feedwater line break or that the capability for shutdown and cooldown of the unit(s) will be available in another habitable area.

ONS Methodology

Postulated MS and FDW line breaks inside the EPR do not result in a direct loss of CR habitability. The integrity of the CR is protected by a reinforced concrete wall between it and the EPR. However, there is a potential interaction with the CR HVAC system. Ductwork serving the Unit 1/2 CR is partially located inside a duct shaft adjacent to the EPR. The unreinforced masonry walls of the duct shaft may crack and potentially fail due to the compartmental pressurization effects following either a MS or FDW HELB postulated inside the EPR. Potential damage to the ductwork could not be ruled out. Modifications are to be installed to address potential interactions with the CR HVAC system.

The CSR is also protected by a combination of HELB blast walls and doors, as well as a reinforced concrete wall between it and the EPR. However, the HVAC duct work serving the CSR has a discharge register into the stairwell adjacent to the EPR. The unreinforced masonry wall separating the stairwell from the EPR may crack and potentially fail due to the compartmental pressurization effects following either a MS or FDW HELB postulated inside the EPR. A failure of this wall could fill the stairwell with steam from the postulated HELBs inside the EPR. The discharge register from the CSR to the stairwell is equipped with a fire damper and should close if it were subjected to a steam environment. Modifications are to be installed to address potential interactions with the CSR HVAC system.

The electrical equipment room is located directly beneath the CSR. For Units 1 and 2, the HVAC system serving this room uses the same duct shaft that is adjacent to the EPR above. Since the unreinforced masonry walls of the duct shaft above may crack and potentially fail, potential damage to the HVAC system and its associated duct work could not be ruled out. Modifications are to be installed to address potential interactions with the electrical equipment room HVAC system.

The 125 VDC and 120 VAC Vital I&C power system supports the continued operation of the systems and components needed for achieving and maintaining a SSD condition. The associated unit's control batteries provide power to the 125 VDC Vital I&C system. The control battery room is located adjacent to the EPR. The battery room is protected by a blast wall and doors between it and the EPR.

The CRs, CSRs, and electrical equipment rooms are provided with air conditioning systems, described in UFSAR Section 9.4.1, to maintain a suitable environment for personnel and equipment. Chilled water is supplied to the HVAC systems from the CR ventilation chilled water system as described in UFSAR Section 9.2.5. Electrical power to the HVAC systems as well as the chilled water system itself is vulnerable to the effects of HELBs inside the TB. Following a HELB in the TB that results in a loss of cooling to the CRs, CSRs and electrical equipment rooms, the AWC system is placed in operation to ensure that these areas remain habitable. The AWC system is located outside the TB and remains free of HELB damage.

Requirement 13:

The Giambusso Letter, as modified by the Schwencer letter, requested that environmental qualifications be demonstrated by test for that electrical equipment

required to function in the steam-air environment resulting from a HE fluid line break. The information required includes:

a. **Identify all electrical equipment necessary to mitigate the consequences of the break and to bring the reactor to a CSD condition. Provide the time after the accident in which they are required to operate.**

b. **The test conditions and the results of test data showing that the systems will perform their intended function in the environment resulting from the postulated accident and the time interval of the accident. Environmental conditions used for the tests should be selected from a conservative evaluation of accident conditions.**

c. **The results of a study of steam systems identifying locations where barriers will be required to prevent steam jet impingement from disabling a protection system. The design criteria for the barriers should be stated and the capability of the equipment to survive within the protected environment should be described.**

d. **An evaluation of the capability for safety related electrical equipment in the CR to function in the environment that may exist following a pipe break accident should be provided. Environmental conditions used for the evaluation should be selected from conservative calculation of accident conditions.**

e. **An evaluation to assure that the onsite power distribution system and onsite sources (diesels and batteries) will remain operable throughout the event.**

ONS Methodology

The areas of the plant considered to be a harsh environment following a postulated HELB outside of the containment building are the EPR, WPR, and CDTR. The breaks of concern are the MS HELB and the FDW HELBs. This is consistent with the original MDS Report No. OS-73.2. The worst case environmental profile created by these breaks has been documented in the Equipment Qualification Criteria Manual. The equipment credited to mitigate the consequences of these breaks has been qualified for the resultant environment profile. Equipment located inside the TB will not be adversely affected by postulated HELBs inside the EPR.

With the consideration of a SAF, the SSF is being used for the mitigation of EPR HELBs. Therefore, the SSF electrical equipment that could potentially be affected by the EPR HELBs is being added to the environmental qualification program to demonstrate its capability to operate in the analyzed steam air environment.

Discussion

In relation to the evaluation of environmental effects, HELBs are postulated in the TB and in the AB. Within the TB, electrical equipment is assumed to fail due to effects of postulated HELBs. As such, the qualification of this electrical equipment is not necessary. This alternate methodology, which does not rely on any equipment in the TB, would be utilized if the electrical equipment in the TB failed as a result of adverse environmental conditions. The two alternate means of achieving and maintaining a SSD condition have been established. Power and control for these systems are transferred from outside of the TB and do not rely on any electrical equipment located inside the TB.

Within the AB, environmental profiles were recalculated for the MFDW and MS HELBs postulated to occur in the EPR. The following components were evaluated for the new environmental profiles inside the EPR, WPR, and cask decontamination tank room. The below components existed prior to the LAR. None of these components needed to be added to the equipment qualification program as a result of the LAR. The temperature and pressure profile

for components located inside the EPR and WPR was changed as a result of new analysis for the postulated MS HELB and MFDW HELBs located inside the EPR. The below components were reviewed for the new pressure and temperature profiles and found to be qualified.

Equipment ID	Equipment Type	Manufacturer/Model Number
xBS VA0001	Motor-operated valve	Limitorque
xBS VA0002	Motor-operated valve	Limitorque
xFDWVA0103	Motor-operated valve	Limitorque
xFDWVA0104	Motor-operated valve	Limitorque
xFDWIP0315	Signal Converter	Fisher 546NS
xFDWIP0316	Signal Converter	Fisher 546NS
xGWDSV0003	Solenoid Valve	ASCO NP206
xHPISV0090	Solenoid Valve	ASCO NP8316
xHPISV0095	Solenoid Valve	ASCO NP8321
xHP VA0026	Motor-operated valve	Limitorque
xHP VA0027	Motor-operated valve	Limitorque
xHP VA0409	Motor-operated valve	Limitorque
xHP VA0410	Motor-operated valve	Limitorque
xHPIFT0159	Flow Transmitter	Rosemount 1154
xHPIFT0160	Flow Transmitter	Rosemount 1154
1LP VA0003	Motor-operated valve	Limitorque
xLP VA0017	Motor-operated valve	Rotork
xLP VA0018	Motor-operated valve	Rotork
xLPIFT0004P	Flow Transmitter	Rosemount 1153B
xLPIFT0005P	Flow Transmitter	Rosemount 1153B
xLPITE0209	Thermocouple	Conax 7S22
3LPITE0210	Thermocouple	Conax 7S22
xLPSPT0010	Pressure Transmitter	Rosemount 1154
xLPSPT0011	Pressure Transmitter	Rosemount 1154
xLPSPT0012	Pressure Transmitter	Rosemount 1154
xLPSPT0013	Pressure Transmitter	Rosemount 1154
xLPSSV1054	Solenoid Valve	Valcor V70900-65
xLPSSV1055	Solenoid Valve	Valcor V70900-65
xLPSSV1061	Solenoid Valve	Valcor V70900-65
xLPSSV1062	Solenoid Valve	Valcor V70900-65
xLPSVA0016	Motor-operated Valve	Limitorque
xLPSVA0018	Motor-operated Valve	Limitorque
xLPSVA0019	Motor-operated Valve	Limitorque
xLPSVA0021	Motor-operated Valve	Limitorque
xLPSVA0022	Motor-operated Valve	Limitorque
xLPSVA0024	Motor-operated Valve	Limitorque
xPR SV0075	Solenoid Valve	ASCO NP8316
xPR SV0076	Solenoid Valve	ASCO NP8316
xRC PS0453	Pressure Switch	Barton 581
xRC PS0454	Pressure Switch	Barton 581
xRC PS0455	Pressure Switch	Barton 581
xRC PS0456	Pressure Switch	Barton 581
xRC PS0457	Pressure Switch	Barton 581

Equipment ID	Equipment Type	Manufacturer/Model Number
xRC PS0458	Pressure Switch	Barton 581
xRC SV0036	Solenoid Valve	Valcor V70900-65
	Electrical Penetration Assemblies	Conax
	Electrical Penetration Assemblies	D. G. Obrien
	Electrical Penetration Assemblies	Viking
	States Terminal Blocks	
	Cabling	

The SSF electrical equipment that could potentially be affected by the EPR HELBs is being added to the environmental qualification program to demonstrate its capability to operate in the analyzed steam air environment.

For postulated HELBs in other areas of the AB, equipment qualification is not required. Either the loss of any shutdown components in these areas would not preclude achieving and maintaining a SSD condition, or adverse environmental conditions are not generated. Aside from the MFDW and MS systems, there are two (2) additional systems with postulated HELBs inside the AB. These systems are the HPI system and the PH system. The HPI System has HELBs postulated in the EPR, the WPR, and the HPI pump room of each unit. The postulated HPI HELBs in these rooms may create a flooding hazard, but no adverse temperature and pressure environments are generated due to the low temperature (< 110°F) of the BWST and/or the LDST water. The postulated HELBs on the PH system are located in various areas of the AB, including the ventilation equipment rooms (505, 520, & 565) and storage room 408B. The evaluation of these postulated HELBs in the ventilation equipment rooms and the storage room 408B are documented in calculations. These evaluations show that no revisions to the ONS environmental qualification program are required. The postulated PH system HELBs in the other areas of the AB do not adversely affect shutdown components and do not require any changes to the station configuration.

Requirement 14:

Requirement 14 in the Giambusso Letter requested design diagrams and drawings of the steam and feedwater lines including branch lines showing the routing from containment to the Turbine Building. The drawings should show elevations and include the location relative to the piping runs of safety related equipment including ventilation equipment, intakes, and ducts.

ONS Methodology

Given below is a description of the MS and MFDW systems at ONS. Drawings of the respective systems showing elevations and their proximity to safety related equipment are available on request.

The purpose of the MS System is to provide steam at specified thermodynamic conditions and at specified flow rates to the main turbine. The MS system is also used to remove heat from the RCS and to supply steam to the MFDW and turbine Driven EFW pumps, condenser air ejectors, steam seal header, the 2nd stage of the moisture separator reheaters, and miscellaneous auxiliary equipment.

The HE portions of the MS System include essentially all of the MS System piping that exceeds 1” nominal pipe size. Most of the MS System HE piping is located in the TB. A section of the MS

piping line from containment penetration #28 is routed through the yard outside of any building before entering the TB. The other MS piping line exits the containment building from containment penetration #26 into the EPR in the AB. It is then routed out of the AB through the yard and into the TB. The major boundaries to the MS System include containment penetrations #26 and #28 and the connections to the main turbine, the turbine driven EFW pump, the MFDW pump turbines, the 2nd stage moisture separator reheaters, the steam separators, steam drains and safety valves for the condenser steam air ejectors, and the emergency steam air ejector.

The purpose of the MFDW system is to increase the temperature and pressure of the water received from the condensate system, so that the water can be used on the shell side of the SGs. The MFDW System also controls the flow rate of the water, which is supplied to the shell side of the SG.

The HE portions of the MFDW system include essentially all of the MFDW system piping that exceeds 1” nominal pipe size. Most of the MFDW System HE piping is located in the TB. The two (2) MFDW piping lines are routed out of the TB into the AB, and these piping lines are routed to containment penetrations #25 and #27 in the EPR. The major boundaries of the HE sections of the MFDW system include the discharge nozzles of the MFDW pumps “A” and “B,” the connections to the “A” & “B” high pressure heaters, and containment penetrations #25 and #27.

Requirement 15:

Requirement 15 in the Giambusso Letter requested that a discussion be provided of the potential for flooding of safety related equipment in the event of failure of a feedwater line or any other line carrying high energy fluid.

<u>ONS Methodology</u>

Postulated pipe failures in the MFDW system can lead to flooding inside the EPR. Flood protection modifications have been installed in these rooms. Flood outlet devices have been installed inside each EPR. The design assures that flood water from the FDW line breaks are released to the outside at a rate sufficient to prevent submergence of the electrical penetrations in the EPR. The resulting water level inside of the EPR is limited to two (2) feet. The AB floor structure can sustain a 2 foot flood height without failure. Flood impoundment walls were installed in each EPR to limit flood water from being released to other areas of the AB. Any water released to other areas of the AB could eventually reach the HPI pump rooms. The flood impoundment walls protect the HPI pump rooms from flooding caused by line breaks inside the EPR.

Postulated pipe ruptures on the discharge of the ‘A’ or ‘B’ HPI pumps could lead to flooding of the HPI pump rooms. Each ONS unit has three (3) HPI pumps and two HPI injection flow paths to the RCS. Sufficient time exists for the operators to diagnose and isolate the break to preclude the loss of all HPI pumps due to flooding. However, the current methods for isolation of the break could result in one HPI pump and one flow path remaining available. To address SAFs, modifications are to be implemented to support isolation of the faulted pump discharge while keeping two HPI pumps and two HPI flow paths available for achieving and maintaining a SSD condition.

Postulated HELBs in the TB can result in a loss of 4160 VAC power. A loss of 4160 VAC power results in a loss of spent fuel cooling with boiling eventually occurring in the SFP. Condensed steam from boiling in the SFP will drain to the first floor of the AB and flood the safety related HPI pumps. Procedures are in place to vent steam from the spent fuel building and to block the spent fuel building floor drains to prevent HPI pump flooding from occurring.

Certain HELBs inside the TB can result in a rupture to the CCW piping. Floods in the TB can be identified by a flood detection system, which provides CR alarms of a flood. No flood protection is provided for systems and components located in the TB basement. Achieving and maintaining a SSD condition can be assured from either of the two alternate methods (PSW or SSF). Existing flood protection measures that prevent TB flooding from causing AB flooding are credited. Damage repair guidelines are credited to terminate the source of flooding and repair those systems and components necessary to reach CSD (ex: LPSW).

There are no postulated piping failures that need to be repaired to support operation of the PSW system in maintaining SSD. The PSW system and its associated electrical distribution system will also provide for a plant cooldown to approximately 250°F. Mode 4 must be achieved within 36 hours of PSW operation. Mode 4 can be maintained with PSW for an extended period of time. Some piping necessary for the achievement of CSD may be damaged from postulated HELBs inside the TB. Should PSW be unavailable, SSD can be maintained utilizing the SSF while PSW is restored.

Requirement 16:

Requirement 16 in the Giambusso letter requested a description be provided of the quality control and inspection programs that will be required or have been utilized for piping systems outside containment.

<u>ONS Methodology</u>

ONS has instituted an inspection program that ensures that the AB MS and MFDW girth and accessible attachment welds are inspected, at least once, during each 10 year ASME Section XI in-service inspection interval. Girth welds are inspected for internal weld flaws and weld thickness. Attachment welds are inspected for surface indications. Initial inspections of the MS and MFDW girth and attachment welds located in the AB have been completed.

<u>Unit 1</u>

There are three (3) girth welds and one (1) attachment weld, located on the ‘A’ MS line in the EPR:

Weld ID	Weld Type	Inspection Type
1-MS9A-A	Girth (Shop)	Ultrasonic Testing (UT)
1-MS-0070-2BD	Girth (Field)	UT
1-MS10A-A	Girth (Shop)	UT
1-01A-0-550-H1	Attachment	Magnetic Particle Testing (MT) or Penetrant Testing (PT)

The straight piping of the MS system in the EPR contains a longitudinal seam weld. This weld was made in the shop prior to installation. A one time inspection of this seam weld was conducted in 2008 for Unit 1.

For the MFDW System, there are fifteen (15) girth welds and three (3) attachment welds, located on both the ‘A’ and ‘B’ lines in the EPR:

Weld ID	Weld Type	Header	Inspection Type
1FWD-64-A	Girth (Shop)	A	UT
1-03-3-3 x 4	Girth (Field)	A	UT
1FWD-64-C	Girth (Shop)	A	UT
1-03-3-25C	Girth (Field)	A	UT
1-03-3-25D	Girth (Field)	A	UT

Weld ID	Weld Type	Header	Inspection Type
1-03-3-26C	Girth (Field)	A	UT
1-03-4-23B	Girth (Field)	A	UT
1-03-4-23G	Girth (Shop)	A	UT
1-FPA-27	Attachment (Rupture Restraint)	A	MT or PT
1-03-3-35C	Girth (Field)	B	UT
1-03-3-34C	Girth (Field)	B	UT
1-03-3-34G	Girth (Shop)	B	UT
1-03-3-33B	Girth (Field)	B	UT
1-03-3-32B	Girth (Field)	B	UT
1-03-3-32G	Girth (Shop)	B	UT
1-03-3-33G	Girth (Shop)	B	UT
1-FPA-25	Attachment (Rupture Restraint)	B	MT or PT
1-03-0-439A-H63	Attachment	B	MT or PT

In addition, the accessible terminal end welds inside the respective rupture restraint guard pipe on the ‘A’ and ‘B’ MFDW trains have received an initial inspection. A program has been initiated to inspect these terminal end welds during each 10 year ASME Section XI in-service inspection interval.

Inspections of the piping base metal downstream of the respective MFDW isolation valves have been included within the weld inspection program noted above or included as part of the station’s flow accelerated corrosion (FAC) inspection program. The table given below provides the scope of those inspections:

Weld ID or FAC ID	Weld / FAC Location	Header	Inspection Type
1FWD-64-C	Weld	A	UT
1-03-3-3 x 4	Weld	A	UT
1FWD-64-A	Weld	A	UT
1FDW076	FAC	A	UT
1-03-3-26C	Weld	A	UT
1FDW067	FAC	A	UT
1-03-3-25D	Weld	A	UT
1FDW068	FAC	B	UT
1-03-3-35C	Weld	B	UT

ONS has committed to implement an inspection program that ensures that critical cracks located at welds and in the base metal away from welds, for other HE lines located in the AB, would receive an inspection, at least once, during each 10 year ASME Section XI in-service inspection interval. ONS has determined that no critical crack locations at welds or at base metal locations away from welds for other HE lines exist in the AB. As such an inspection program is not needed at this time.

Unit 2

There are three (3) girth welds and one (1) attachment weld, located on the ‘A’ MS line in the EPR:

Weld ID	Weld Type	Inspection Type
2-MS9A-A	Girth (Shop)	UT

Weld ID	Weld Type	Inspection Type
2-MS-0103-39	Girth (Field)	UT
2-MS10A-A	Girth (Shop)	UT
2-01A-0-1441-H1	Attachment	MT or PT

The straight piping of the MS System in the EPR contains a longitudinal seam weld. This weld was made in the shop prior to installation. A one-time inspection of this seam weld was conducted in 2008 for Unit 2.

For the MFDW system, there are seventeen (17) girth welds and five (5) attachment welds, located on both the 'A' and 'B' lines in the EPR:

Weld ID	Weld Type	Header	Inspection Type
2-03-18-43A	Girth (Field)	A	UT
2-FWD60-A	Girth (Shop)	A	UT
2-FWD-60A-B	Girth (Shop)	A	UT
2-03-18-44AA	Girth (Field)	A	UT
2-03-18-43AA	Girth (Field)	A	UT
2-03-18-45	Girth (Field)	A	UT
2-03-18-44AB	Girth (Field)	A	UT
2-03-18-46G	Girth (Shop)	A	UT
2-03-18-46	Girth (Field)	A	UT
2-FPA-27	Attachment (Rupture Restraint)	A	MT or PT
2-03-0-1439B-H62	Attachment	A	MT or PT
2FDW-225-22B	Girth (Field)	B	UT
2-03-18-22C	Girth (Field)	B	UT
2-03-18-23A	Girth (Field)	B	UT
2-03-18-23G	Girth (Shop)	B	UT
2-03-18-24	Girth (Field)	B	UT
2-03-18-24G	Girth (Shop)	B	UT
2-03-18-25	Girth (Field)	B	UT
2-03-18-25G	Girth (Shop)	B	UT
2-FPA-25	Attachment (Rupture Restraint)	B	MT or PT
2-03-0-1439A-H63	Attachment	B	MT or PT
2-03-0-1439A-H61	Attachment	B	MT or PT

In addition, the accessible terminal end welds inside the respective rupture restraint guard pipe on the 'A' and 'B' MFDW trains have received an initial inspection. A program has been initiated to inspect these terminal end welds during each 10 year ASME Section XI in-service inspection interval.

Inspections of the piping base metal downstream of the respective MFDW isolation valves have been included within the weld inspection program noted above or included as part of the station's FAC inspection program. The table given below provides the scope of those inspections:

Weld ID or FAC ID	Weld / FAC Location	Header	Inspection Type
2-FWD-60A-B	Weld	A	UT
2-03-18-43A	Weld	A	UT

Weld ID or FAC ID	Weld / FAC Location	Header	Inspection Type
2-FWD60-A	Weld	A	UT
2FDW043	FAC	A	UT
2-03-18-43AA	Weld	A	UT
2-03-18-45	Weld	A	UT
2FDW036	FAC	A	UT
2-03-18-44AA	Weld	A	UT
2FDW-225-22B	Weld	B	UT
2FDW037	FAC	B	UT

ONS has committed to implement an inspection program that ensures that critical cracks located at welds and in the base metal away from welds, for other HE lines located in the AB, would receive an inspection, at least once, during each 10 year ASME Section XI in-service inspection interval. ONS has determined that no critical crack locations at welds or at base metal locations away from welds for other HE lines exist in the AB. As such an inspection program is not needed at this time.

Unit 3

There are three (3) girth welds and one (1) attachment weld, located on the 'A' MS line in the EPR:

Weld ID	Weld Type	Inspection Type
3-MS9B-A	Girth (Shop)	UT
3-01A-13-01	Girth (Field)	UT
3-MS10B-A	Girth (Shop)	UT
3-01A-0-2441-H1	Attachment	MT or PT

The straight piping of the MS system in the EPR contains a longitudinal seam weld. This weld was made in the shop prior to installation. A one-time inspection of this seam weld was conducted in 2007 for Unit 3.

For the MFDW System, there are seventeen (13) girth welds and six (6) attachment welds, located on both the 'A' and 'B' lines in the EPR:

Weld ID	Weld Type	Header	Inspection Type
3-03-31-8	Girth (Field)	A	UT
3-03-31-10	Girth (Field)	A	UT
3-03-31-10G	Girth (Shop)	A	UT
3-03-31-13	Girth (Field)	A	UT
3-03-31-13G	Girth (Shop)	A	UT
3-03-31-15A	Girth (Field)	A	UT
3-03-31-15G	Girth (Shop)	A	UT
3-03-31-16A	Girth (Field)	A	UT
3-FPA-27	Attachment (Rupture Restraint Lug Attachments)	A	MT or PT
3-03-0-2439B-H54	Attachment	A	MT or PT
3-PEN-27-WHIP	Attachment (Rupture Restraint Collar Weld)	A	Visual
3-03-31-3	Girth (Field)	B	UT

Weld ID	Weld Type	Header	Inspection Type
3-03-31-3G	Girth (Field)	B	UT
3-03-31-5A	Girth (Field)	B	UT
3-03-31-5G	Girth (Shop)	B	UT
3-03-31-6A	Girth (Shop)	B	UT
3-FPA-25	Attachment (Rupture Restraint Lug Attachments)	B	MT or PT
3-03-0-2439B-H64	Attachment	B	MT or PT
3-PEN-25-WHIP	Attachment (Rupture Restraint Collar Weld)	B	MT or PT

The weld IDs 3-PEN-27-WHIP and 3-PEN 25-WHIP are the accessible terminal end (collar) welds inside the respective rupture restraint guard pipe on the ‘A’ and ‘B’ MFDW trains. These welds have also received an initial visual inspection. A program has been initiated to visually inspect these terminal end welds during each 10 year ASME Section XI in-service inspection interval.

Inspections of the piping base metal downstream of the respective MFDW isolation valves have been included within the weld inspection program noted above or included as part of the station’s FAC inspection program. The table given below provides the scope of those inspections:

Weld ID or FAC ID	Weld / FAC Location	Header	Inspection Type
3-03-31-16A	Weld	A	UT
3-FDW-046	FAC	A	UT
3-FDW-047	FAC	B	UT

ONS has committed to implement an inspection program that ensures that critical cracks located at welds and in the base metal away from welds, for other HE lines located in the AB, would receive an inspection, at least once, during each 10 year ASME Section XI in-service inspection interval. ONS has determined that no critical crack locations at welds or at base metal locations away from welds for other HE lines exist in the AB. As such an inspection program is not needed at this time.

Inaccessible girth welds are enclosed by the MFDW guard pipes adjacent to the RB penetrations #25 and #27. The guard pipes form part of the MFDW rupture restraints as described in requirement 5 of this section. The inaccessible girth welds are present in Units 1 and 2, but not Unit 3. For Units 1 and 2, the MFDW A header(s) include an 18 degree elbow located just upstream of RB penetration #27 and the MFDW rupture restraint. While the upstream girth weld of the 18 degree elbow is accessible and volumetrically inspected once during each 10 year ASME Section XI in-service inspection interval, the downstream girth weld is enclosed by the aforementioned guard pipe. Similarly, the Units 1 and 2 MFDW B header(s) include a 32 degree elbow located just upstream of the RB penetration #25 and the MFDW rupture restraint. Again, the upstream girth weld of the elbow is accessible and volumetrically inspected once during each 10 year ASME Section XI in-service inspection interval, the downstream girth weld is enclosed by the aforementioned guard pipe. The Unit 3 headers contain no such elbows, and as such there are no girth welds enclosed by the MFDW rupture restraint guard pipe.

Each MFDW guard pipe encloses the postulated MFDW break location(s). Since these downstream elbow girth welds are adjacent to the postulated break location inside the guard pipe, assuming a break at the inaccessible weld(s) would result in no greater consequences than those that would occur for break(s) previously postulated inside the guard pipe.

Requirement 17:

Requirement 17 in the Giambusso Letter requested that if leak detection equipment is to be used in the proposed modifications, a discussion of its capabilities should be provided.

ONS Methodology

No leak detection equipment was used in the design of the EPR flow outlet device and flood impoundment features inside the EPR. No operator action is required to prevent unacceptable flooding inside the EPR.

A postulated break in the RCP seal injection line in the WPR can result in potential flooding inside the WPR. However, due to the small line size and the flow controls provided by the seal injection flow control valve upstream of the break, the flow rate into the room is limited to approximately 40 gpm. A break in this line would be initially detected by a decreasing LDST level. The break on a seal injection line would be identified by observing the individual seal injection flow gauges inside the CR.

HPI pump discharge breaks are detected by decreasing LDST levels and the standby HPI pump auto starting on low seal injection flow.

There are two LDST level instruments. The instruments are QA-1 and are powered from a battery-backed source of power. They have a range of 0 to 100 inches. The LDST has a high and a low level alarm inside the CR. The level instruments are not vulnerable to the effects of a postulated break in the HPI System.

There is one RCP seal injection flow indication for each individual seal injection line. The instruments and indicators are non-QA and are powered from a non-battery backed source of power. Each flow indication has a range of 0 to 15 gpm. The flow instruments are not vulnerable to postulated seal injection line breaks. A loss of station power is not postulated concurrent with the postulated breaks requiring these instruments. Therefore, these instruments are judged to be available to diagnose a postulated break in the seal injection lines.

Certain HELBs inside the TB can result in a rupture to the CCW piping. Floods in the TB can be identified by a flood detection system, which provides CR alarms of a TB flood.

The TB water level alarm system is an electrical logic system that provides a signal for two (2) independent annunciators in the Unit 2 CR and two (2) independent computer alarms in the Unit 3 CR. The system consists of a single control panel, level switches (float switches), and the associated power and instrumentation cables between the control panel and the level switches, power supplies, the Unit 2 CR, and the Unit 3 computer cabinet.

The control panel for the system is located in the TB at elevation 825' + 0" near the Unit 2 CR. The level switches for the system are located in four (4) different sumps in the basement of the TB (elevation 775' + 0"). The cables to these level switches are routed, in general, from the TB water level alarm system control panel down to the basement of the TB and then through the appropriate cable trays on this level to the identified sumps with the level switches.

The TB water level alarm system provides two (2) separate alarms:

- "Turbine Building Basement Water Level Alert," which alarms if the flood level has reached the 773' +0" Elevation.
- "Turbine Building Basement Water Emergency High Level," which alarms if the flood level has reached the 775'+6" Elevation.

Each alarm is generated by a 2-out-of-4 logic, and each alarm has its own set of level switches. The TB water level alarm system control panel also has amber and red test lights that verify that signals have been received from the level switches.

An evaluation of the interaction of the TB water level alarm system and HELBs in the TB was performed. The evaluation concluded that none of the TB water level alarm system components were adversely affected by those TB HELBs that could result in unrecoverable flooding of the TB without operator action. Therefore, the TB water level alarm system will remain available to alert the operator to take action to mitigate flooding of the TB before an unacceptable water level in the TB is reached.

Requirement 18:

Requirement 18 in the Giambusso Letter requested that a summary be provided of the emergency procedures that would be followed after a pipe break accident, including the automatic and manual operations required to place the reactor unit(s) in a Cold Shutdown Condition. The estimated time following the accident for all equipment and personnel operational actions should be included in the procedure summary.

<u>**ONS Methodology**</u>

For postulated HELBs in the TB, the affected unit(s) is placed and maintained in a SSD condition using the PSW System. If the PSW System is unavailable due to a SAF, the affected unit(s) is placed and maintained in a SSD condition using the SSF. The actions to place the SSF and PSW systems in service are contained in the station emergency procedures. No repairs are required in order to cooldown the unit to Mode 4 with the exception of local isolation of the CFTs and restoration of the PSW system (assuming SAF on the PSW system). In addition, an operator action is required to locally throttle open the MS ADVs to initiate the cooldown. Once the PSW system is placed in service, Mode 4 is achieved within 36 hours. A unit cooldown is not performed from the SSF. 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. The actions to cooldown the unit are contained in the station emergency procedures. With the unit in Mode 4, assessment and repair of those systems required to place the unit in Mode 5 (CSD) are completed using station damage assessment and repair procedures. Those systems required to place the unit in Mode 5 are then locally aligned and placed in operation using station emergency procedures.

For postulated HELBs in the AB, the affected unit(s) is placed and maintained in a SSD condition using normal plant systems. If the normal plant systems are unavailable due to a SAF, the affected unit(s) is placed and maintained in a SSD condition using the SSF. The actions to place the unit in SSD using normal plant systems are contained in the station emergency procedures. A unit cooldown to Mode 5 is then performed using normal plant systems after necessary repairs are completed. The actions to cooldown the unit are contained in the station emergency procedures. Operator actions and procedures are discussed in Section 3 and Attachment 11.

Requirement 19:

Requirement 19 in the Giambusso Letter requested a description be provided of the seismic and quality classifications of the high energy fluid piping systems including the steam and feedwater piping that run near structures, systems, or components important to safety.

ONS Methodology

Unit 1 Configuration

There are twelve (12) Unit 1 HE systems outside of the containment building identified for Unit 1. The HE Systems and the associated piping are located in the TB, AB, service (administration) building, and the yard. Only the MS system is located in the yard, and only the PH system is located in the service building. All of the HE systems except for the HPI system are located in the TB, and only the MS, MFDW, HPI, and PH systems are located in the AB. The description of the classification and seismic status of the HE systems in each building are discussed in the subsequent paragraphs.

Yard

The only HE system located in the yard is the MS system. The MS system in the yard is seismically analyzed and is classified as Duke Piping Class “F”. The MS system piping in the yard is not routed near any systems important to safety.

Service Building

The only HE system in the service building is the PH system. The PH system piping in the service building is non-seismically analyzed Duke Piping Class “G” piping. There are no SSCs important to safety located in the service building.

AB

There are four (4) HE systems located in the AB. These HE systems include:

- MS
- MFDW
- HPI charging section and letdown section
- PH

With the exception of the PH system piping and the HPI Pump “mini-flow” lines, all other HE piping in the AB is seismically analyzed.

The PH system piping is classified as Duke Piping Class “G,” non-seismic piping. One of these piping lines is routed just outside of the control complex. However, because of the low internal pressure in the piping, the ZOI for this line does not affect the control complex. This PH system piping line is also routed near the booster fans for the control complex HVAC system, but no credit is taken for the use of these fans for a break in this PH system piping. For the other two (2) PH system piping lines in the AB, one of the lines is isolated and is excluded as HE piping. The other PH system piping line is not routed near any equipment important to safety in the AB.

The HPI system HE piping is classified as Duke Piping Class “B” for the charging section (or HPI pump discharge) piping and Duke Piping Class “C” for the letdown section piping up to HP-5. The charging section of HPI piping, including the RCP seal injection piping, is routed through the EPR & WPR from the HPI pump rooms. These lines are seismically analyzed.

The MS and MFW system piping in the AB is classified as Duke Piping Class “F.” These piping lines are routed through the EPR of the AB. These lines are seismically analyzed in the AB.

<u>TB</u>

Except for the HPI system, all of the other identified HE systems are located in the TB. The only seismically analyzed HE piping in the TB is the MS system, its associated MS piping drains, and portions of the MFW system.

The MFDW system HE piping is seismically analyzed from the inlet valves 1FDW-26 & 1FDW-21, of the “A” HP FDW heaters to the containment penetrations. The seismically analyzed portions of the MFDW piping are Duke Piping Class “G” from these valves to valves 1FDW-41 and 1FDW-42 and 1FDW-32 and 1FDW-33. From there into the AB, and to the containment penetrations, the piping is Duke Piping Class “F.” Note that a portion of the Class “G” piping is seismically analyzed, and supported as part of the overlap/boundary conditions to assure that the Class G/F boundary is seismically protected. Thus, the stresses are considered accurate for use in the determination of intermediate break locations.

The two trains of the MS system HE piping in the TB to the high pressure turbine are seismically analyzed. In general, the MS branch lines are seismically analyzed up to and through the first isolation valve off each of the two trains. The main lines and branch lines up to the first isolation valve are classified as Duke Piping Class “F”. The piping downstream of the isolation valves is classified as Duke Piping Class “G” with the exception of the steam supplied to the turbine driven EFW pump which is Class “F”. Portions of the Class “G” piping on the branch lines are seismically analyzed and supported as part of the overlap/boundary conditions to assure that the class boundary is seismically protected.

<u>Unit 2 Configuration</u>

There are twelve (12) Unit 2 HE systems outside of the containment building identified for Unit 2. The HE systems and the associated piping are located in the TB, AB, and the yard. Only the MS system is located in the yard. All of the HE systems except for the HPI system are located in the TB, and only the MS, MFDW, HPI, and PH systems are located in the AB. The description of the classification and seismic status of the HE systems in each building are discussed in the subsequent paragraphs.

<u>Yard</u>

The only HE System located in the yard is the MS system. The MS system in the yard is seismically analyzed and is classified as Duke Piping Class “F”. The MS system piping in the yard is not routed near any systems important to safety.

<u>AB</u>

There are four (4) HE Systems located in the AB. These HE Systems include:

- MS
- MFDW
- HPI Charging Section and Letdown Section
- PH

With the exception of the PH system piping and the HPI pump “mini-flow” lines, all other HE piping in the AB is seismically analyzed.

The PH system piping is classified as Duke Piping Class “G,” non-seismic piping. There are three (3) PH system piping lines in the AB. One of these piping lines is routed to the Unit 2 RB purge heaters in the WPR. The second PH system piping line in the AB is routed to air handling unit (AHU) – 16 in the ventilation equipment room 520. This piping line is routed directly into Room 520 from the TB. The third piping line is routed from the TB into Storage Room 408B and then over to the package steam fired water heater within room 408B.

The HPI system HE piping is classified as Duke Piping Class “B” for the charging section (or HPI pump discharge) piping and Duke Piping Class “C” for the letdown section piping up to HP-5. The charging section of HPI piping, including the RCP seal injection piping, is routed through the EPR and WPR from the HPI pump rooms.

The MS and MFDW system piping in the AB is classified as Duke Piping Class “F.” One train of MS is routed within the EPR of the AB. Both MFDW trains are routed within the EPR.

TB

Except for the HPI system all of the other identified HE systems are located in the TB. The only seismically analyzed HE piping in the TB is associated with the MS system, MS piping drains, and portions of the MFDW system.

The MFDW system HE piping is seismically analyzed from the inlet valves 2FDW-26 and 2FDW-21, of the “A” high pressure FDW heaters to the containment penetrations. The seismically analyzed portions of the MFDW piping are Duke Piping Class “G” from these valves to the FDW valves 2FDW-41 and 2FDW-42 and 2FDW-32 and 2FDW-33. From there into the AB, and to the containment penetrations, the piping is Duke Piping Class “F.” Note that a portion of the Class “G” piping is seismically analyzed, and supported as part of the overlap/boundary conditions to assure that the Class G/F boundary is seismically protected. Thus, the stresses are considered accurate for use in the determination of intermediate break locations.

The two trains of the MS system HE piping in the TB to the high pressure turbine are seismically analyzed. In general, the MS branch lines are seismically analyzed up to and through the first isolation valve off each of the two trains. The main lines and branch lines up to the first isolation valve are classified as Duke Piping Class “F”. Downstream of the isolation valves, the piping is classified as Duke Piping Class “G” with the exception of the steam supplied to the turbine driven EFW pump which is Class “F”. Portions of the Class “G” piping on the branch lines are seismically analyzed and supported as part of the overlap/boundary conditions to assure that the class boundary is seismically protected.

Unit 3 Configuration

There are twelve (12) Unit 3 HE systems outside of the containment building identified for Unit 3. The HE systems and their HE piping are located in the TB, AB, and the yard. Only the MS system and the auxiliary steam system are located in the yard. All of the HE Systems except for the HPI system are located in the TB, and only the MS, MFDW, HPI, and PH systems are located in the AB. The description of the classification and seismic status of the HE Systems in each building are discussed in the subsequent paragraphs.

Yard

The only HE Systems located in the yard are the MS system and the AS system. The MS system in the yard is seismically analyzed and is classified as Duke Piping Class “F”. The MS system piping in the yard is not routed near any systems important to safety. The auxiliary steam system piping in the yard is non-seismic, Duke Piping Class “G”.

AB

There are four (4) HE systems located in the AB. These HE Systems include:

- MS
- MFDW
- HPI charging section and letdown section
- PH

With the exception of the PH system piping and the HPI pump “mini-flow” lines, all other HE piping is seismically analyzed.

The PH system piping is classified as Duke Piping Class “G,” non-seismic piping. There are two (2) PH system piping lines routed from the TB into the AB. One of these piping lines is routed to the Unit 3 RB purge heaters in room 669. The second PH system piping line is routed into the ventilation equipment room 565. This piping line then tees within room 565 with one branch routed to AHU 3-7 and AHU 3-8 within room 565. The other branch is routed out of room 565, through the Unit 3 EPR, and then up to AHU 3-9 and AHU 3-10 in room 651.

The HPI system HE piping is classified as Duke Piping Class “B” for the charging section (or HPI pump discharge) piping and Duke Piping Class “C” for the letdown section piping up to HP-5. The charging section of HPI piping, including the RCP seal injection piping, is routed through the EPR and WPR from the HPI pump rooms.

The MS and MFDW system piping in the AB is classified as Duke Piping Class “F.” One train of MS is routed within the EPR of the AB. Both MFDW trains are routed within the EPR.

<u>TB</u>

Except for the HPI system, all of the other identified HE systems are located in the TB. The only seismically analyzed HE piping in the TB is associated with the MS system, MS piping drains, and portions of the MFDW system.

The MFDW system HE piping is seismically analyzed from the inlet valves 3FDW-26 and 3FDW-21, of the “A” high pressure FDW heaters to the containment penetrations. The seismically analyzed portions of the MFDW piping are Duke Piping Class “G” from these valves to valves 3FDW-41 and 3FDW-42 and 3FDW-32 and 3FDW-33. From there into the AB, and to the containment penetrations, the piping is Duke Piping Class “F.”

The two trains of the MS System HE piping in the TB to the high pressure turbine are seismically analyzed. In general, the MS branch lines are seismically analyzed up to and through the first isolation valve off each of the two trains. The main lines and branch lines up to the first isolation valve are classified as Duke Piping Class “F”. Downstream of the isolation valves, the piping is classified as Duke Piping Class “G” with the exception of the steam supplied to the turbine driven EFW pump which is Class “F”. Portions of the Class “G” piping on the branch lines are seismically analyzed and supported as part of the overlap/boundary conditions to assure that the class boundary is seismically protected.

Requirement 20

Item 20 in the Giambusso Letter requested a description should be provided of the assumptions, methods, and results of analyses, including steam generator blowdown, used to calculate the pressure and temperature transients in compartments, pipe tunnels, intermediate buildings, and the Turbine Building following a pipe rupture in those areas. The equipment assumed to function in the analyses should be identified and the capability of systems required to function to meet a single active component failure should be described.

<u>ONS Methodology</u>

The only area of the plant analyzed for pressure and temperature transient was the EPR and WPR inside the AB. The analysis was performed using GOTHIC. The blowout panel strengths and the various blowdown data for MS HELBs and MFDW HELBs were used as inputs to the analysis. For MS HELBs, the analysis assumes that no operator action is taken within the first 10 minutes. The MFDW pumps are assumed to be tripped by AFIS when the actuation setpoint is reached, but the MFDW control valve is assumed to fail open. MFDW is assumed to continue

feeding the faulted SG via the condensate booster pumps until MFDW is isolated by the operator at 10 minutes. EFW is assumed to be automatically stopped by AFIS when the actuation setpoint is reached. For MFDW HELBs, the analysis assumes MFDW continues until the condensate inventory is depleted (i.e. no operator action assumed to isolate MFDW). The analysis is discussed in enclosure section 3 and Attachments 4, 5, and 6.

Requirement 21:

Item 21 in the Giambusso Letter requested that a description be provided of the methods or analyses performed to demonstrate that there will be no adverse effects on the primary and/or secondary containment structures due to a pipe rupture outside these structures.

ONS Methodology

In general, the RB penetrations represent terminal ends in the piping analyses. These RB penetrations are designed to withstand the forces and moments applied to the terminal end that could occur from postulated breaks located either inside or outside of the containment building.

The design of the MS and MFDW RB penetrations differ from the other RB penetrations. For these lines, structural anchors have been installed adjacent to the RB penetrations. The MS anchors are located inside the RB, while the MFDW anchors are located in the EPR. These anchors are designed to absorb the large forces and moments that could occur in the aftermath of either a postulated MS or MFDW break. The MS and MFDW anchors consist of a collar wrapped around the outside diameter of the piping. The collar is connected at both ends to the piping via two circumferential fillet welds. The collar is in turn welded to a series of structural wide flange members that span back to the RB wall. The wide flange members are then welded to embedded structural tees located in the RB wall. A simplified sketch of the MFDW anchor is shown in Requirement 5.

ATTACHMENT 10

DEFINITIONS

Attachment 10
Definitions

The following definitions apply to the analyses and evaluation described in this document.

Branch Line – A piping line where one of the terminal ends is at a piping intersection with a pipe of equal or larger size. A branch connection to a main piping line is a terminal end of a branch line, except where the branch line is classified as part of the main piping line in the stress analysis.

Branch Run – A piping run, where one of the extremities originates at a piping intersection and not at a component (See **Piping Run**).

Break – A complete circumferential pipe severance; or a longitudinal pipe split opening of an area equal to the pipe (cross-sectional) flow area, but without pipe severance.

Circumferential Breaks – HELBs that are perpendicular to the pipe axis and the break area is equivalent to the internal cross-sectional area of the pipe immediately upstream of the break location. The dynamic forces resulting from such breaks are assumed to separate the piping axially (initially) and cause the pipe ends to deflect in response to the discharging fluid.

Cold Shutdown (Condition) – The state of an ONS unit, when it is in a Mode 5 condition.

Collateral Damage – Damage to normal plant equipment, which results in an adverse condition, caused by the structural failures that are a result of postulated HELBs.

Compartmental Pressurization – The change in the internal pressure of a station room or enclosure, caused by a postulated HELB within or adjacent to the room or enclosure.

Containment (Reactor Building) – The enclosure that surrounds the RCS and acts as a leak tight barrier against the uncontrolled release of radioactivity from the RCS to the environment and serves as biological shield for the radioactivity contained therein.

Control Complex – The portion of the AB consisting of the CR (Room 510 – Unit 1 and 2, and Room 552 – Unit 3), CSR (Room 403 – Unit 1, Room 404 – Unit 2, and Room 450 – Unit 3), and the Electrical Equipment Room (Room 310 – Unit 1, Room 311 – Unit 2, and Room 354 – Unit 3).

Critical Crack (Through-Wall Crack) – A through wall crack in a HE pipe with a crack area equivalent to ½ the pipe (inner) diameter by ½ the pipe wall thickness. For flow purposes, the critical crack geometry is to be taken as a circular orifice.

Direct HELB Interaction – An adverse condition created by an HELB, where the impact on plant systems, components, or structures caused by pipe whip or jet impingement and results in the loss or damage to that equipment.

Environmental Qualification – A program of verifying that station equipment and components will function under the adverse environmental conditions (e.g. temperature, pressure, humidity, and radiation exposure) generated by postulated HELBs (and LOCAs).

Excluded Break – Those postulated breaks that are excluded from consideration of impacts to shutdown equipment. Breaks are excluded if any of the following are satisfied:

- Piping that does not exceed 200°F and 275 psig.
- Portions of HE system that are isolated during normal operating conditions.
- Piping operating at or below atmospheric pressure.

High Energy Line – Piping line where the fluid inside of the pipe during Initial Operating Conditions has either or both of the following conditions:

- A normal operating temperature greater than 200°F.
- A normal operating pressure greater than 275 psig.

High Energy Line Break – The instantaneous rupture of a HE line during normal plant conditions.

High Energy System – Any mechanical system outside of the containment building in the ONS containing HE lines.

Indirect HELB Interaction – An adverse condition created by a HELB that is not a result of a pipe whip or jet impingement on systems and components. Indirect HELB interactions are caused by flooding, environmental effects (temperature, pressure, and humidity), and collateral damage from HELB generated structural interactions.

Initial Operating Conditions (or "Normal Operating Conditions") – These conditions are the nominal parameters that would exist within an ONS Unit with the Unit operating at 100% rated thermal power level (full power). All plant systems are assumed to be aligned in their normal operating configuration for this power level. The Initial Operating Conditions are the conditions, upon which the HE lines and their boundaries are identified. The Initial Operating Conditions also aid in the identification of the HELB locations and define the operating parameters that exist at the beginning of an HELB sequence. (Note: For the purpose of conducting transient analysis, a power level of 102% of rated unit thermal power is identified as the Initial Operating Condition).

Intermediate Break Location – A postulated HELB location that is not at the connecting weld to a vessel, pump, or at a rigidly restrained pipe section (A postulated HELB that is not at a Terminal End – See definition of "Terminal End").

Jet Impingement – The hydraulic force generated by the HE fluid exiting the pipe break and impacting on other equipment or structures.

Longitudinal Breaks – HELBs that are parallel to the pipe axis and orientated at any point around the pipe circumference. The break area is equal to the effective cross-sectional flow area upstream of the break location, and a longitudinal break does not result in pipe severance. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the directions normal to the pipe axis.

Loss of Offsite Power – The loss of the capability of the grid to provide auxiliary power to the three ONS Units. During a LOOP, the only auxiliary power available for the ONS units is from the Keowee Hydro-electric Units, supplied through the 230 kV switchyard or through transformer CT4.

MODE 1 (Power Operation) – Operation of an ONS unit with the following conditions: $k_{eff} \geq 0.99$ and the % Rated Thermal Power level > 5.

MODE 2 (Startup) – Operation of an ONS unit with the following conditions: $k_{eff} \geq 0.99$ and the % Rated Thermal Power level ≤ 5.

MODE 3 (Hot Standby) – Operation of an ONS unit with the following conditions: $k_{eff} < 0.99$ and the average RC Temperature is ≥ 250°F.

MODE 4 (Hot Shutdown) – Operation of an ONS unit with the following conditions: $k_{eff} < 0.99$ and the average RC Temperature (T) is 250°F > T > 200°F.

MODE 5 (Cold Shutdown) – Operation of an ONS unit with the following conditions: $k_{eff} < 0.99$ and the average RC Temperature is ≤ 200°F. To be in Mode 5, all RV Head closure bolts must be fully tensioned.

Normal Plant Conditions – An ONS unit operating in Mode 1, 2, 3, or 4. This definition is only used to exclude certain piping sections from the requirement of postulating HELBs on these sections.

Offsite Power – Electrical power used by ONS for station auxiliary needs that is not generated directly by the ONS units or the KHUs.

Pipe Whip – The movement of a ruptured pipe in response to the HE fluid exiting the pipe break.

Piping Run – A section of pipe that interconnects components such as pressure vessels, and pumps that may act to restrain pipe movements beyond that required for design thermal displacement.

Plant Cooldown – The transition of an ONS unit from a SSD condition to the Mode 4 condition, where the RCS temperature is approximately 250°F and further cooling of the RCS via the SGs is not practical.

Plant Cooldown to the Cold Shutdown Condition – The transition of an ONS unit from the Mode 4 condition, where the RCS temperature is approximately 250°F to the Cold Shutdown condition (Mode 5).

Return-to-Criticality – The reactor core returning to a value of $k_{eff} \geq 1.00$, following a unit shutdown (i.e. insertion of control rods into the core), as a result of the cooling of the RCS (water) inventory.

Running Break – The general designation for all of the individual break locations on a non-seismically analyzed piping run.

Safe Shutdown – The transition of an ONS unit from a Mode 1 or Mode 2 condition to a Hot Standby (Mode 3) state with stable RCS conditions while maintaining this state without adversely impacting the health and safety of the public.

Seismically Analyzed Piping Lines – Piping lines, where stress analysis information is available and where the analysis includes internal pressure, dead weight (gravity), thermal, and OBE loadings.

Shutdown Equipment – The systems and components used during the Shutdown Sequence to achieve the shutdown objectives. The terms “Shutdown System” and “Shutdown Component” can also be used, when “Shutdown Equipment” is too general.

Shutdown Sequence – The description of the sequence of events of an ONS unit from the Mode 1 state to the achievement of Mode 5 (Cold Shutdown Condition).

Single Active Failure – The failure on demand of an “Active Component” to perform its intended safety function. An “active component” is a component that is externally powered and a mechanical movement within the component is necessary to perform the safety function. Failure of additional components and/or systems that result from this failure is considered part of the SAF. Static electrical components such as cables, transformers, or conductors are not considered to be candidates for active failures. Self-actuated valves such as simple (not power operated) check valves, vacuum breaker valves, and safety/relief valves are not considered to be candidates for active failures.

Sub-Break – An individual HELB of one break type at one location on a Running Break. The terms "Sub-Break", "Discrete Break", and "Individual Break" are used interchangeably.

Subcritical – the condition of the reactor core, wherein $k_{eff} < 1.00$.

Terminal End – The interconnection point of a piping run with a plant component such as a pressure vessel, pump (nozzle), building penetration, in-line anchor, and decoupled branch to run connections that may act as point of maximum constraint to pipe thermal expansion movements.

Unit Blackout – The simultaneous loss of the Main Feeder Buses 1 and 2 (4160 VAC) in any unit. The terms "Unit Blackout" and "Loss of 4160 VAC Power Distribution System" is used interchangeably.

ATTACHMENT 11

TIME CRITICAL OPERATOR ACTIONS

Attachment 11
Time Critical Operator Actions

Reference	Action	TCA Status
LAR Attachment 6	RCPs tripped at 2 minutes following a loss of subcooled margin.	Existing TCA
LAR Attachment 6	RCPs tripped at 3 minutes based on activation of SSF.	Existing TCA
LAR Section 3.6.1.2*	Initiate HPI forced-cooling within 5 minutes of when HPI cooling initiation criteria are met.	Existing TCA
LAR Attachment 9 Requirement 20	MFDW is isolated from affected SG within 10 minutes.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 2	Establish secondary side DHR with SSF ASW pump within 14 minutes of loss of main and emergency FDW.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 1	Establish secondary side DHR with the PSW System within 14 minutes of loss of main and emergency FDW.	New TCA
LAR Section 3.6.1.2	Secure one RCP per SG within 15 minutes of loss of MFDW.	New TCA
LAR Section 3.6.1.1, Phase 1, Pathway 2 LAR Section 3.6.2, Phase 1, Pathway 2	Isolate 1,2,3HP-20, for applicable unit(s), within 15 minutes after a loss of HPI seal injection flow and CC flow to an RCP following a SSF mitigated HELB.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Isolate 1,2,3HP-21, for applicable unit(s), within 15 minutes after a loss of HPI seal injection flow and CC flow to an RCP following a PSW mitigated HELB.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 2 LAR Section 3.6.2, Phase 1, Pathway 2	Establish RCP seal cooling and RCS makeup with SSF RCMU pump within 20 minutes of loss of seal cooling.	Existing TCA

Reference	Action	TCA Status
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Establish RCP seal cooling and RCS makeup with PSW powered HPI train within 20 minutes of loss of seal cooling.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Isolate letdown flow during PSW events by closing 1,2,3HP-5 within 20 minutes after a loss of HPI flow to the RCS.	Existing TCA
LAR Section 3.6.3	Isolate a letdown line HELB within 20 minutes following failure of ES actuated valve to close (close 1,2,3HP-1 if 1,2,3HP-3 fails to close and close 1,2,3HP-2 if 1,2,3HP-4 fails to close).	New TCA
LAR Section 3.6.1.1, Phase 1, Pathway 2 LAR Section 3.6.2, Phase 1, Pathway 2	Isolate the following valves within 20 minutes after a loss of HPI flow to the RCS that requires operation of the SSF: 1,2,3HP-3 1,2,3HP-4 1,2,3RC-4 1,2,3RC-5 1,2,3RC-6	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 2	Energize SSF pressurizer heaters within 20 minutes of scenario initiation.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 2	Provide adequate SSF ASW flow to reduce and maintain RCS pressure ≤ 2250 psig within 20 minutes after a loss of FDW, EFW, and RCP seal cooling.	Existing TCA
LAR Section 3.6.1.2	Open the RCS high point vents within 30 minutes of a loss of MFDW to maintain RCS pressure below the pressurizer code safety valve lift setpoint.	New TCA
LAR Section 3.6.3	Initiate CR pressurization within 30 minutes after ES actuation.	Existing TCA
LAR Section 3.6.4	Isolate HPI pump discharge piping break by closing HPI pump suction valve within 39 minutes. (Close 1,2,3HP-98 or 1,2,3HP-103; 1,2,3HP-107 or 1,2,3HP-993).	New TCA

Reference	Action	TCA Status
LAR Section 3.6.1.1, Phase 1	Trip all CCW pumps on all three units within 45 minutes of HELB initiated flooding within the TB.	New TCA
LAR Section 3.6.1.1, Pathway 1* LAR Section 3.6.2, Pathway 1*	Open OAC room doors within 56 minutes and OAC is de-energized within 7 hours OR OAC room doors remain closed and OACs are de-energized within 56 minutes following scenario initiation.	Existing TCA
LAR Section 3.6.1.1, Pathway 2* LAR Section 3.6.2, Pathway 2*	Route SSF diesel engine service water discharge to yard drain after 105 minutes and before 120 minutes after the diesel emergency start pushbutton is pressed.	Existing TCA
LAR Section 3.6.1.1, Pathway 1* LAR Section 3.6.2, Pathway 1*	Secure the SSF RCMU to limit injection flow to the RCS within 2 hours if PSW/HPI pump operation is required.	Existing TCA
LAR Section 3.6.1.1, Phase 1	Replenish CCW embedded inventory within 3 hours and 20 minutes following loss of CCW forced flow and siphon flow (can be accomplished using either PSW portable or SSF submersible pump).	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Open SFP loading bay roll up door in affected unit (R-19 or R-22), and place tarps and sand bags over floor drains in SFP Loading Bays within 4 hours (SFP boiling < 12 hours) or 6 hours (SFP boiling ≥ 12 hours) following scenario initiation.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Restore cooling to Control Complex in support of PSW extended operation by means of AWC following scenario initiation. CR within 12 hours Cable Room within 18 hours Equipment Room within 18 hours	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Restore cooling to the containment building in support of PSW extended operation by means of the Alternate RBC system within 30 hours following scenario initiation.	Existing TCA

Reference	Action	TCA Status
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Achieve Mode 4 within 36 hours in support of PSW extended operation following PSW powered HPI initiation.	Existing TCA
LAR Section 3.6.1.1, Phase 1, Pathway 1 LAR Section 3.6.2, Phase 1, Pathway 1	Restore cooling to the main AB in support of PSW extended operation by means of AWC within 72 hours following scenario initiation.	Existing TCA

*Completion of this TCA is required for mitigation of the HELB scenario, but it has not been explicitly included in the Section 3.6 scenario mitigation summary.

ATTACHMENT 12

FEASIBILITY ASSESSMENT FOR NEW PROPOSED TIME CRITICAL OPERATOR ACTIONS

Attachment 12
Feasibility Assessment for New Proposed Time Critical Operator Actions

1. Trip All CCW Pumps on All Three Units Within 45 Minutes of HELB Initiated Flooding Within the TB.

Certain postulated HELBs in the TB can result in TB flooding as a result of the most limiting interaction which is with the CCW system. The AB/TB wall has been reinforced to a height of 20' as a TB flood protection measure. The CCW pumps on all three units must be secured within 45 minutes of HELB initiated TB flooding to prevent the maximum flood height from exceeding the 20-foot limit (the CCW intake piping is cross-connected between the three units). Securing the CCW pumps does not terminate the flooding but reduces the flow rate to a rate that can be accommodated by the TB drain.

Validation of this TCA will be completed during implementation. The licensee is confident that validation will be successful for the following reasons.

There is a similar existing TCA to control a design basis TB flood within 20 minutes by tripping the CCW pumps <u>and</u> closing the CCW pump discharge valves from the CR. This guidance is contained in the unit specific TB flood AP. The initiating cue to enter the TB flood AP is receipt of the turbine basement water emergency high level annunciator located in the Unit 2 CR. Unit 1 and Unit 2 share a combined CR and the Unit 1 and Unit 2 operators will immediately recognize that the entry conditions for the TB flood AP have been met. The Unit 3 CR operators receive a turbine basement water emergency high level computer alarm. In addition, the Unit 2 TB flood AP directs the Unit 2 CR operator to notify the Unit 1 and Unit 3 CR operators to enter the TB flood AP. The four CCW pump control switches are located on an auxiliary control board located immediately behind the main control board and within the main CR envelope (e.g., no intervening panels or walls that would impede access to the control switches). The pump switches are clearly labeled. There are no new skills or knowledge required to secure the CCW pumps following a HELB induced TB flood. Licensed operators receive periodic classroom and simulator training on the TB flood AP. During the most recent re-validation of the current TCA, the CCW pumps were tripped in 3 minutes.

Guidance to secure the CCW pumps will be added to the HELB mitigation procedure during implementation. The TCA to secure the CCW pumps within 45 minutes of a HELB induced TB flood will be validated in accordance with Operation's EOP/AP validation procedure to ensure that the TCA can be consistently accomplished with margin.

Licensed operators will receive (classroom and simulator) training on controlling a HELB induced TB flood during implementation.

2. Establish Secondary Side DHR With the PSW System Within 14 Minutes of Loss of MFDW and EFW.

Certain postulated FDW HELBs in the TB result in a loss of MFDW to both SGs. The FDW HELB also causes a loss of all 4 KV power and the turbine driven EFW pump resulting in a loss of secondary side DHR. Pressurizer level and RCS pressure increase as the RC expands. PSW flow must be established to the SGs within 14 minutes to prevent liquid relief through the pressurizer code safety valves. This new CR TCA replaces the current TCA that requires operators to locally start the turbine driven EFW pump and locally cross-connect EFW from an unaffected unit.

Validation of this TCA will be completed during implementation. The licensee is confident that validation will be successful for the following reasons.

There is an existing TCA to establish PSW flow to the SGs following a loss of secondary side DHR. Guidance to establish PSW flow to the SGs is provided in the unit specific EOP. Licensed operators receive periodic classroom and simulator training on this TCA. Licensed operators are periodically evaluated on their ability to successfully accomplish this TCA during periodic simulator evaluations. During the most recent re-validation of the current TCA, PSW flow was established to the SGs in 10 minutes.

This proposed TCA is identical to the existing TCA and there are no new skills or knowledge required to establish PSW flow to the SGs following a HELB induced loss of secondary side DHR.

The TCA to establish PSW to the SGs within 14 minutes of a HELB initiated loss of secondary side DHR will be validated in accordance with Operation’s EOP/AP validation procedure to ensure that the TCA can be consistently accomplished with margin.

Licensed operators will receive (classroom and simulator) training on the revised procedural guidance during implementation.

3. Secure One RCP Per SG Within 15 Minutes of Loss of MFDW.

A FDW HELB downstream of the check valve in the EPR of the AB does not result in a loss of the station electrical system. 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 AFIS actuation which isolates MFDW and EFW to the affected SG. The transient then evolves rapidly to an overheating scenario with one motor driven EFW pump supplying the unaffected SG and all 4 RCPs operating.

The overheating transient results in an increase in pressurizer level and RCS pressure as the RC expands. The T-H analysis that was performed for this scenario in support of the HELB LAR determined that one RCP per SG was required to be secured within 15 minutes to maintain RCS pressure below the pressurizer code safety valve lift setpoint. This bounding T-H analysis assumes that normal RCS letdown is lost and that the PORV is unavailable for pressure control.

Validation of this TCA will be completed during implementation. The licensee is confident that validation will be successful for the following reasons.

Guidance to secure one RCP per SG is provided in the unit specific EOP to reduce RCP heat to the RCS during mitigation of an overheating scenario, but this action is currently not a TCA. The RCP control switches are located on the auxiliary control board immediately adjacent to the front control board and are clearly labelled. Licensed operators receive periodic classroom and simulator training on the mitigation of overheating scenarios. Licensed operators are periodically evaluated on their ability to mitigate overheating scenarios during simulator evaluations.

There are no new skills or knowledge required to secure one RCP per SG for this TCA. During implementation, the TCA to secure one RCP per SG will be validated in accordance with Operation's EOP/AP validation procedure to ensure that the TCA can be consistently accomplished with margin. The procedure steps in the unit specific EOP will be rearranged as necessary to ensure that this TCA can be accomplished with margin.

Licensed operators will receive (classroom and simulator) training on the revised procedural guidance during implementation.

4. Open the RCS High Point Vents Within 30 Minutes of a Loss of MFDW to Maintain RCS Pressure Below the Pressurizer Code Safety Valve Lift Setpoint.

A FDW HELB downstream of the check valve in the EPR of the AB does not result in a loss of the station electrical system. 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 AFIS actuation which isolates MFDW and EFW to the affected SG. The transient then evolves rapidly to an overheating scenario with one motor driven EFW pump supplying the unaffected SG and all 4 RCPs operating.

The overheating transient results in an increase in pressurizer level and RCS pressure as the RC expands. The T-H analysis that was performed for this scenario in support of the HELB LAR determined that one set of RCS high point vent valves are required to be opened within 30 minutes to maintain RCS pressure below the pressurizer code safety valve lift setpoint. This bounding T-H analysis assumes that normal RCS letdown is lost and that the PORV is unavailable for pressure control.

Validation of this TCA will be completed during implementation. The licensee is confident that validation will be successful for the following reasons.

Guidance to open one set of RCS high point vent valves is provided in the unit specific EOP as an alternate RCS letdown flow path for PSW mitigated overheating events, but this guidance is currently not provided in the EOP for mitigating overheating events with normal plant systems. Licensed operators receive periodic classroom and simulator training operating RCS high point vent valves during the mitigation of overheating scenarios with PSW. Licensed operators are periodically evaluated on their ability to mitigate overheating scenarios with PSW during simulator evaluations.

There are no new skills or knowledge required to operate the RCS high point vent valves for this TCA. Each RCS hot leg (A and B) is equipped with two in-series solenoid operated high point vent valves. Both valves must be opened to establish flow. The control switches for the two sets of valves are located on the front control board (one switch per valve) and the control switches are clearly labelled.

During implementation, the TCA to open one set of RCS high point vent valves will be validated in accordance with Operation’s EOP/AP validation procedure to ensure that the TCA can be consistently accomplished with margin.

Licensed operators will receive (classroom and simulator) training on the revised procedural guidance during implementation.

5. Isolate a Letdown Line Break HELB Within 20 Minutes Following Failure of ES Actuated Valve to Close (Close 1,2,3HP-1 if 1,2,3HP-3 Fails to Close and Close 1,2,3HP-2 if 1,2,3HP-4 Fails to Close).

The HELB occurs at the letdown line containment penetration in the EPR upstream of the outside containment isolation valve. This break does not interact with any other SSD equipment and the HPI system has adequate capacity to compensate for the leak rate as RCS pressure and pressurizer level recover, RCS remains subcooled and the RCPs remain in operation. However, 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 leak results in an initial decrease in RCS pressure as primary inventory is lost through the break. The decrease in RCS pressure results in a reactor trip and actuation of the ES system. ES system actuation isolates the break by automatically closing valves HP-3 (A Letdown Cooler Outlet & Containment Isolation Valve) and HP-4 (B Letdown Cooler Outlet & Containment Isolation Valve). If a SAF prevents either HP-3 or HP-4 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. Isolating letdown within 20 minutes of ES actuation limits the radiological effluent release.

Validation of this TCA will be completed during implementation. The licensee is confident that validation will be successful for the following reasons.

The guidance to isolate the letdown line break with HP-1 or HP-2 is provided in the ES actuation verification enclosure of the unit specific EOP but is currently not a TCA. The control switches for HP-1,2, 3, and 4 are located on the front control board adjacent to the HPI pump control switches and are clearly labelled.

During implementation, the TCA to isolate the letdown line break with HP-1 or HP-2 will be validated in accordance with Operation’s EOP/AP validation procedure to ensure that the TCA can be consistently accomplished with margin. The procedure steps in the ES actuation verification enclosure of the unit specific EOP will be rearranged as necessary to ensure that this TCA can be accomplished with margin.

Licensed operators will receive training on the revised procedural guidance during implementation.

6. Isolate HPI Pump Discharge Piping Break by Closing HPI Pump Suction Valve Within 39 Minutes (Close 1,2,3HP-98 or 1,2,3HP-103; 1,2,3HP-107 or 1,2,3HP-993).

The HPI Pump provides RCS makeup and RCP seal cooling. Following a HELB at the discharge nozzle of the operating HPI Pump, the immediate response is the loss of discharge flow and the auto-start of the standby HPI Pump on low RCP seal flow. Upon start of the second HPI Pump, flow is restored to the RCS and the RCPs. The HELB at the discharge nozzle of an operating HPI Pump can be quickly detected and diagnosed. The CR operator will immediately receive the HPI pump discharge pressure low annunciator and the RCP seal header flow low annunciator. Subsequently, the CR operator will receive the LDST low level annunciator and the annunciator for when HPI suction is automatically transferred to the BWST. The CR operator will observe that both the in-service and standby HPI pumps are operating. In addition, the CR operators typically trend AB waste tank levels and containment sump levels on the OAC to assist in the quick identification of leaks in the AB or inside containment. Isolation of the HPI pump discharge piping break within 39 minutes is required to prevent flooding of the HPI pumps.

Validation of this TCA will be completed during implementation. The licensee is confident that validation will be successful for the following reasons.

There is a similar existing TCA to terminate flooding in the AB due to a pipe break on a raw service water system. This TCA is required to be completed within 45 minutes. During the most recent re-validation of the current TCA, the break was isolated in 33 minutes.

Guidance to identify and isolate RCS leaks is currently provided in the unit specific APs. The RCS leakage AP provides guidance to the operator on quickly identifying the location and source of the leak, including the trending of AB waste tank levels and containment sump levels on the OAC. Once the CR operators determine that the leak is on the HPI system, the RCS leakage AP directs the operators to perform the unit specific AP for loss of HPI makeup and RCP seal injection. This procedure, in turn, provides guidance to isolate HPI system leaks.

Specific guidance to isolate a HELB on the discharge nozzle of an HPI is currently not provided in the loss of HPI makeup and RCP seal injection procedure. This guidance will be added during implementation and is summarized as follows.

Based on the symptoms described above, the CR operators will recognize the need to perform the unit specific APs for RCS leakage and loss of HPI makeup and RCP seal injection. Once the break location is identified, the affected HPI Pump is tripped by the operator. The HPI pump on which the HELB occurred is the pump in the “ON” position, and this pump is manually tripped. The HPI pump that automatically starts on low RCP seal flow has its control switch in the “AUTO” position. Thus, the operator knows which pump to trip. Tripping the HPI pump significantly reduces the leak rate.

Each of the suction lines for the “A” and “B” HPI pumps has two isolation valves in series to address SAFs. For the “A” HPI pump suction line, the two isolation valves consist of an electric motor operated (EMO) valve and a remote-operated manual valve. For the “B” HPI pump suction line, the two isolation valves are both remote-operated manual valves. All of these isolation valves can be operated without entry into the HPI Pump Room. Closure of a remote-operated manual valve is performed by a non-licensed operator. Closure of an EMO valve is performed by the CR operator. The “A” and “B” HPI pump suction lines on Unit 1 and Unit 3 are already equipped with two isolation valves. Redundant suction isolation valves are to be installed on the “A” and “B” HPI pump suction lines in Unit 2 during implementation.

There are no new skills or knowledge required of the non-licensed/licensed operator. The control switches for the EMOs are located on the front control board adjacent to the HPI pump

control switches and are clearly labelled. The remote-operated manual valves are operated by a handwheel connected to a reach rod. The valve handwheels are located on the deck immediately above the HPI pump room in an open area that is easily accessible. No special tools or equipment is required to operate these valves. The CR is located on the 822' elevation of the AB and the HPI pump room is accessed from the 771' elevation of the AB. The Unit 1 and Unit 2 CRs are a combined CR. There is a stairwell located immediately north of the Unit 1 CR access door that provides direct access to the AB corridor at the 771' elevation. There is a stairwell located immediately south of the Unit 2 CR access door that provides direct access to the AB corridor at the 771' elevation. There is a stairwell located immediately south of the Unit 3 CR access door that provides direct access to the AB corridor at the 771' elevation. The stairwells, corridors and HPI pump room hatch area are well lighted and the valves are clearly labelled. No communications between the CR and the non-licensed operator are required during the performance of this TCA. However, a wall mounted telephone is located in the primary side sample hood area immediately adjacent to the HPI pump room hatch area and the operators are provided with portable radios. The site minimum staffing requirements Selected Licensing Commitment requires a minimum of 9 non-licensed operators to be on site with all three units in Modes 1-4. Operations management procedures require one fully qualified non-licensed operator responsible for implementing AP and EOP actions be assigned to each unit. The AP/EOP non-licensed operator will perform this TCA.

Guidance to identify and isolate a HELB at the discharge nozzle of the operating HPI pump will be added to the loss of HPI makeup and RCP seal injection procedure during implementation. Licensed operators will receive (classroom and simulator) training on identifying and isolating a HELB at the discharge nozzle of the operating HPI pump during implementation. Non-licensed operators will receive training on isolating the leak by locally closing the pump suction valve. The TCA to isolate a HELB at the discharge nozzle of the operating HPI pump will be validated in accordance with Operation's EOP/AP validation procedure to ensure that the TCA can be consistently accomplished with margin.

The task to locally isolate a HELB at the discharge nozzle of the operating HPI pump will be added to the non-licensed operator TCA qualification card.