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U. S. Nuclear Regulatory Commission
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Attention: Document Control Desk

Subject: Oconee Nuclear Station
Docket Numbers 50-269, 270, and 287
Preliminary Accident Sequence Precursor (ASP) of Operational Condition - Postulated High Energy Line Breaks in Turbine Building Leading to Failure of Safety-Related 4 kV Switchgear

In a letter dated March 28, 2001, the Nuclear Regulatory Commission (NRC) provided a copy of the preliminary Accident Sequence Precursor (ASP) analysis of an operational condition that was reported in License Event Report (LER) No. 269/1999-001-01. Duke Energy Generation Services (Duke) appreciates this opportunity and has reviewed the preliminary analysis as requested. Duke agrees with the NRC concerning the importance of technical adequacy. It is very important that specific plant features and responses be characterized correctly for various accident sequence initiators.

From a broad perspective, Duke is concerned that the characterization of this scenario is inaccurate and misleading. The subject scenario is not an event, rather it is an approved design feature of Oconee. The ASP analysis, Event Summary, incorrectly states that LER No. 269/1999-001-01 reports this condition as outside design basis. The LER did not report this event, but mentioned it in the background section as a result of High Energy Line Break (HELB) Analysis submittals provided to the NRC in April, 1973 and June, 1973. The NRC evaluated and approved Duke's HELB analysis in a

IE22

Safety Evaluation dated July 7, 1973. This condition is considered to be part of Oconee's licensing and design basis. Mitigation of this scenario has been factored into plant operations, procedures, training, and modifications since inclusion in the ONS design and licensing basis in 1973. Therefore, the basis used to subject this scenario to a precursor analysis is not apparent.

Notwithstanding, Duke has reviewed the ASP report and we conclude that the analysis has included several conservative assumptions that cause the significance of the issue to be significantly overstated. If more realistic assumptions were used, we believe that the core damage frequency for Units 2 and 3 would have been calculated to be below the precursor threshold of 1E-6 and that Unit 1 would have only slightly exceeded this threshold. It should be noted that as a result of recent modifications, the current Unit 1 configuration would reduce the significance to the same level as Units 2 and 3. This response addresses plant configuration and practices as they were in the 1999 timeframe when the LER was written.

Attachment 1 contains Duke's response to the ASP analysis with specific comments to support our position on the risk significance of the scenario. Attachment 2 contains a summary of the thermal hydraulic analysis related to recovering and maintaining High Pressure Injection. This information supports Duke's conclusions in Attachment 1.

If there are any questions or further information is needed, please contact Reene' Gambrell at (864) 885-3364 or Duncan Brewer at (704) 382-7409.

Very truly yours,

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Attachment 1

Preliminary ASP Analysis of Operational Condition

Postulated High Energy Line Break in Turbine Building Leading To Failure of Safety-Related 4 kV Switchgear

Review

Attachment 1

Preliminary Accident Sequence Precursor Analysis of Operational Condition Review of Postulated High Energy Line Break in Turbine Building Leading To Failure of Safety-Related 4 kV Switchgear

Overview:

This attachment provides specific comments on the draft Accident Sequence Precursor (ASP) report. The cumulative impact of these comments on the Core Damage Frequency (CDF) for the subject scenario is characterized in the cover letter.

Comments on the Event Summary:

The event summary incorrectly states that the postulated High Energy Line Breaks (HELB) in turbine building leading to failure of safety related 4kV switchgear was reported as a condition in License Event Report (LER) 269-99-01 dated 2/24/99. The background section of the LER states that this was a condition identified to the Nuclear Regulatory Commission (NRC) in the HELB Analysis submittals dated 4/25/73 and 6/22/73. Thus, the subject of this ASP evaluation is a design feature of the plant approved by the NRC in the original licensing of the facility and is not a new condition identified by LER 269-99-01.

It also appears that the event summary is stating that the LER is reporting this condition as outside the design basis. Again, this is not an event that the LER is identifying. It was actually provided to the NRC in the HELB analysis, which was submitted in 1973. The NRC evaluated and approved the HELB analysis in a Safety Evaluation dated 7/6/73. Therefore, this is not a condition outside the design basis of the facility.

Comments on Modeling Details and Key Assumptions:

In 1999, the Reactor Coolant Pumps (RCPs) for Oconee units 2 and 3 had Sulzer seal packages. Duke believes that application of the Rhodes model to these seal packages is overly conservative. Oconee is participating in the

Combustion Engineering Owners Group (CEOG) project that provides a specific seal Loss Of Coolant Accident (LOCA) model for Sulzer seals. This model has been submitted to the NRC for review. Application of this model to the Oconee plant substantially reduces (two orders of magnitude) the likelihood of a seal LOCA. It should be noted that the Westinghouse RCP seals were replaced on Unit 1 in 2000 with Sulzer seal packages. Thus, the current seal failure probability for all three units is substantially less than predicted by the Rhodes model.

Comments on Attachment 1, Section 4 Main Feedwater Line Breaks:

A review of the data and methods used in the calculation of the HELB initiating events was performed. This included a review of both the large Main Feedwater (MFW) line break, and the Auxiliary Steam (AS) line break initiating events.

The data and methods used for the large MFW line break were reasonable. The analyst used methods that used a plant specific estimate of the length of piping that could affect critical equipment, and used generic historical data for the type of break of concern. This provides a reasonable estimate for the generic historical failure rate. However, a more detailed review of the operating experience, based on stress levels in piping and actual plant conditions associated with the failures, may reduce the estimated failure probability.

Comments on Attachment 1, Section 6 AS Line Breaks:

The analyst again used a plant specific estimate for the length of piping and historical data for the calculation of AS line breaks capable of failing the 4kV switchgear. This results in a plant specific failure rate that is close in value to that calculated by using pipe length break frequencies, such as those described in EPRI TR-102266, "Pipe Failure Study Update." This results in a reasonable estimate for the overall AS line break initiating event frequency.

However, a review of the LERs used for the initiating event data shows several of the LERs listed are not applicable to the calculation. The report should be modified to remove these failures from the initiating event calculation. The

LERs considered not applicable for the AS line break initiating event calculation include:

1) LER 280/87-027 - The leak described in the LER was from a condenser access manway, not from piping. The leak caused water to be released from the condenser resulting in a short in a flood panel. This leak was not an HELB event, and is not applicable to piping failure scenarios.

2) LER 280/90-003 - Per the LER, Section 2.0, Safety Consequences and Implications, "In this case, the leak was small,…" Small leaks should not be added to failure data used to calculate the AS line break initiating event. The final initiating event is assumed to cause major equipment damage, which was not possible with this leak.

3) LER 318/92-001 - The steam leak was from a ¾ inch feedwater heater relief valve. There are two issues that make this failure not applicable; a)the failure was through a relief valve, and not through failed piping, and b)the release was from a ¾ inch line, which is insufficient to cause the type of damage assumed for the AS line break initiating event.

Additionally, since there is data for the initiating event, the use of a 0.5 factor is inappropriate. This type of factor is used when there is little or no prior/industry data available. As discussed in NUREG/CR-5750, Appendix E, Page E-10, the Jeffreys noninformative prior distribution is "appropriate when very few events have occurred." Since we have more than a few events (at least 7) for this study, the noninformative prior distribution is not appropriate. The AS line break estimate should be based solely on the historical data. If a Basyesian approach is desired, the Oconee and non-Oconee data can be separated, with the non-Oconee data used as a prior. However, this would yield a similar result.

If the AS line break initiating event is recalculated with these three events removed, and the 0.5 factor removed, the following initiating event frequency is determined:

7/810 critical-years = 8.6E-03/critical-year

With a 1.8% factor applied for AS line breaks capable of failing 4kV switchgear, the result is:

$$= 0.018 * 8.6E-03 = 1.5E-04/year$$

Section 7, Comments on probability of failing to recover seal cooling capability within 10 minutes:

Operator Failure Probability Comment

For the Standby Shutdown Facility (SSF), Reactor Coolant Makeup (RCMU) is established in less than 10 minutes for Oconee Unit 1 and 20 minutes for Oconee Units 2 and 3 and Auxiliary Service Water (ASW) in less than 14 minutes. Due to the high Probabilistic Risk Assessment (PRA) significance and time constraints for this task, Operations performs quarterly time verifications for all licensed operators. In 1999, data from one hundred verifications was reviewed and showed a 100% pass rate. From the verifications reviewed, the average time for injecting into the Reactor Coolant System (RCS) with the SSF RCMU System was 7.29 minutes. For the SSF ASW System, the average time to feed the steam generators was 9.38 minutes. Because of the significant training, the failure probabilities for these activities are too conservative.

SSF Support Systems Failure Probability Comment

The failure probabilities used for the SSF ASW system and for the RCMU System include many failures that would occur later in the accident. This type of "run" failure would provide additional time for the operators to successfully align alternate systems.

For example, the dominant failure of the SSF RCMU pump is a run failure of the SSF diesel generator. If the SSF diesel generator initially works but then fails after several hours of operation, significant additional time would be available for the station personnel to restore seal cooling and if necessary, RCS makeup by aligning a High Pressure Injection (HPI) pump to the Station ASW Switchgear. Since nearly all sequences are dominated by high human error failure probabilities which result from the Performance Shaping Factor (PSF) associated with time available, then changing the time available would have a significant effect on the overall frequency of these sequences.

This issue is also important for the loss of steam generator cooling sequences. If the SSF ASW systems work for even a short time, then the operators will use the SSF ASW pump to increase steam generator levels. As discussed in section 9, HPI Recovery Capability, Oconee specific RELAP analyses show that this would change the time available to restore a means of Secondary Side Heat Removal (SSHR) from 40 minutes to many hours.

To be more realistic, it is suggested that the SSF failures be separated into a "fails-to-start" failure mode and a "fails-to-run" failure mode. Then different human error probabilities can be determined for these different sequences.

Based on the most recent Oconee PRA SSF model, the following would be the recommended values for the two functions and two failure modes of the SSF.

SSF ASW Fails to Start	0.07
SSF ASW Fails to Run	0.17
SSF RCMU Pump Fails to Start	0.08
SSF RCMU Pump Fails to Run	0.17

The above values include all equipment failures associated with the main system and all its support systems. However, the post initiator human errors have been excluded from the model so that the ASP human errors can be used instead. Tables 1 through 4 provide the basis for the above values.

Table 1
SSF ASW Cutset Report, Start Failures Only

#	Inputs	Description	Event Prob
1	NSSFSYSTRM	SSF Is In Maintenance	3.80E-02
2	NACSFDGDGS	SSF Diesel Generator Fails To Start	7.20E-03
3	NACDJPUGPS	Diesel Service Water Pump Fails To Start	3.18E-03
4	NSFASWZLHE	SSF ASW System Left Unavailable After Test Or Maintenance	3.00E-03

Table 1 (continued)

#	Inputs	Description	Event Prob
5	NACSFDGLHE	SSF Diesel Generator Is Left Unavailable After Test Or Maintenance	3.00E-03
6	NSFPU02APS	SSF ASW Pump Fails to Start on Demand	2.87E-03
7	NCW0287MVO	MOV 3CCW-287 Fails To Open On Demand	2.59E-03
8	NCW0268MVO	MOV 3CCW-268 Fails To Open On Demand	2.59E-03
9	NAC3X3ACLC	SSF 600 V ac MCC 3XSF Breaker 3A Fails To Close (From OXSF)	1.96E-03
10	NDCDCSFBYF	Battery DCSF Fails	1.83E-03
11	NSFCON2VCS	SSF Ventilation Chiller 2 Fails To Start	1.77E-03
12	NSFAHUFFNS	HVAC Air Handling Unit Fan Fails To Start On Demand	1.14E-03
13	NAC3X5ACLO	600 V ac SSF MCC 3XSF Breaker 5A Fails To Open (From 3XB)	1.09E-03
14	NCW0125VVT	Manual Valve CCW-125 Transfers Closed	6.66E-04
15	NACOTS4C4C	4160 V ac Switchgear OTS1 Breaker 4 Fails To Close (From Diesel)	4.06E-04
16	NACOTS2C4C	4160 V ac SSF Switchgear OTS1 Breaker 2 Fails To Close (SSF ASW Pump)	4.06E-04
17	FEF0442CVO	Check Valve 3FDW-442 Fails To Open	2.36E-04
18	NCW0284CVO	Check Valve CCW-284 Fails To Open	2.36E-04
19	NCW0289CVO	Check Valve CCW-289 Fails To Open	2.36E-04
20	FEF0346CVO	Check Valve FDW-346 Fails To Open	2.36E-04
21	NACDJ02HXF	Diesel Jacket Heat Exchanger 2 Fails	1.79E-04
22	NACDJ01HXF	Diesel Jacket Heat Exchanger 1 Fails	1.79E-04
23	NDC0CSFBCF	Battery Charger CSF Fails	1.54E-04
24	NDCSF4BCDT	125 V dc Distribution Center DCSF Breaker 4B Transfers Open	9.98E-05
25	NCWFL01FLF	SSF HVAC Service Water Filter Fl-1 Clogs	6.88E-05
Total			7.33E-02

Table 2
SSF ASW Cutset Report, Run Failures Only

#	Inputs	Description	Event Prob
1	NACSFDGDGR	SSF Diesel Generator Fails To Run	1.70E-01
2	NSFCON1VCR	SSF Ventilation Chiller 1 Fails To Run	1.25E-03
3	NSFCON2VCR	SSF Ventilation Chiller 2 Fails To Run	1.25E-03
4	NSFPU02APR	SSF ASW Pump Fails to Run	5.71E-04
5	NACDJPUGPR	Diesel Service Water Pump Fails To Run	2.64E-04
6	NSFAHUFFNR	HVAC Air Handling Unit Fan Fails To Run	9.86E-05
7	NSFAHU0FLF	HVAC Air Handling Unit Filter Fails	4.58E-05
8	NACOTS2C4T	4160 V ac SSF Switchgear OTS1 Breaker 2 Transfers Open (SSF ASW Pump)	2.52E-05
9	NACOTS4C4T	4160 V ac Switchgear OTS1 Breaker 4 Transfers Open (From Diesel)	2.52E-05
Total			1.74E-01

Table 3
SSF RCMP Cutset Report, Start Failures Only

#	Inputs	Description	Event Prob
1	NSSFSYSTRM	SSF Is In Maintenance	3.80E-02
2	NACSFDGDGS	SSF Diesel Generator Fails To Start	7.20E-03
3	NACDJPUGPS	Diesel Service Water Pump Fails To Start	3.18E-03
4	NSFRCMULHE	SSF RCM System Is Left Unavailable After Test Or Maintenance	3.00E-03
5	NACSFDGLHE	SSF Diesel Generator Is Left Unavailable After Test Or Maintenance	3.00E-03
6	NSF3097MVO	Motor-Operated Valve 3SF-97 Fails To Open	2.59E-03
7	NSF3082MVO	Motor-Operated Valve 3SF-82 Fails To Open	2.59E-03
8	NHP3398MVO	Motor-Operated Valve 3HP-398 Fails To Open	2.59E-03
9	NSF3PU1DPS	Unit 3 SSF RCM Pump Fails To Start	2.48E-03
10	NSF3FL2FLF	Unit 3 SSF Reactor Coolant Makeup Y Strainer Clogs	2.11E-03
11	NSF3F01FLF	SSF Unit 3 RCM Filter SSF-SF1 Clogs	2.11E-03
12	NAC3X3ACLC	SSF 600 V ac MCC 3XSF Breaker 3A Fails To Close (From OXSF)	1.96E-03
13	NDCDCSFBYF	Battery DCSF Fails	1.83E-03

Table 3 (continued)

#	Inputs	Description	Event Prob
14	NSFCON2VCS	SSF Ventilation Chiller 2 Fails To Start	1.77E-03
15	NSFAHUFFNS	HVAC Air Handling Unit Fan Fails To Start On Demand	1.14E-03
16	NAC3X5ACLO	600 V ac SSF MCC 3XSF Breaker 5A Fails To Open (From 3XB)	1.09E-03
17	NACOTS4C4C	4160 V ac Switchgear OTS1 Breaker 4 Fails To Close (From Diesel)	4.06E-04
18	NHP3401CVO	Check Valve 3HP-401 Fails To Open	2.36E-04
19	NCW0284CVO	Check Valve CCW-284 Fails To Open	2.36E-04
20	NHP3402CVO	Check Valve 3HP-402 Fails To Open	2.36E-04
21	NHP3400CVO	Check Valve 3HP-400 Fails To Open	2.36E-04
22	NHP3399CVO	Check Valve 3HP-399 Fails To Open	2.36E-04
23	NACDJ02HXF	Diesel Jacket Heat Exchanger 2 Fails	1.79E-04
24	NACDJ01HXF	Diesel Jacket Heat Exchanger 1 Fails	1.79E-04
25	NDC0CSFBCF	Battery Charger CSF Fails	1.54E-04
Total			7.87E-02

Table 4

SSF RCMP Cutset Report, Run Failures Only

#	Inputs	Description	Event Prob
1	NACSFDGDGR	SSF Diesel Generator Fails To Run	1.70E-01
2	NSFCON1VCR	SSF Ventilation Chiller 1 Fails To Run	1.25E-03
3	NSFCON2VCR	SSF Ventilation Chiller 2 Fails To Run	1.25E-03
4	NSF3PU1DPR	Unit 3 SSF RCM Pump Fails To Run	5.71E-04
5	NACDJPUGPR	Diesel Service Water Pump Fails To Run	2.64E-04
6	NSFAHUFFNR	HVAC Air Handling Unit Fan Fails To Run	9.86E-05
7	NSFAHU0FLF	HVAC Air Handling Unit Filter Fails	4.58E-05
8	NHP3404RVT	Relief Valve 3HP-404 Transfers Open	3.53E-05
9	NACOTS4C4T	4160 V ac Switchgear OTS1 Breaker 4 Transfers Open (From Diesel)	2.52E-05

Table 4 (continued)

#	Inputs	Description	Event Prob
10	NSF3PU1PDF	RC Makeup Pump Pulsation Dampener Fails	1.13E-05
11	NSF3PU1ACF	SSF Suction Accumulator Fails	1.11E-05
Total			1.74E-01

Section 8 Comment on the probability of failing Emergency Feedwater:

Probability of loss of the Turbine Driven Emergency Feedwater Pump (TDEFWP) train and the ASW

The ASP analysis assumed that the TDEFWP could be started with high reliability, but then assumed that it would fail with a probability of 1.0 after one hour when it depletes the Upper Surge Tank (UST). This is not correct. Assuming typical UST levels, the TDEFWP can operate for 3 hours before completely depleting the UST. Additionally, credit should be given for operator action to replenish the UST from other plant systems, or for swapping to the hotwell. Both of these actions are covered in plant procedures and can be reliably accomplished even with a loss of 4160V power.

Probability of failing to establish the cross-tie

Previous validation data concludes that the unit can be cross-connected in approximately 17 minutes. The time includes five minutes to recognize the condition and dispatch an operator. Actual cross-connection of the unit requires 12 minutes. Operator's train on this task.

Comment On Sequence of Human Actions

The precursor analysis assumed that the Station ASW system could only be credited in conjunction with the TDEFWP. However, if the TDEFWP fails after an hour or more of operation, Emergency Feedwater (EFW) cross-tie, SSF ASW and Station ASW should be credited as additional success paths with at least 2 hours available for accomplishing these actions following the loss of the TDEFWP (Attachment 2 Case 3). This would also be appropriate for SSF ASW run failures.

Section 9 HPI Recovery Capability:

Sufficient time is available

Thermal-hydraulic Analysis Summary:

A thermal-hydraulic analysis was performed to evaluate the transient resulting from an HELB, which causes a failure of the 4kV switchgear. The specific scenario considered a loss of feedwater event, failure of primary system makeup, and includes leakage from RCP seals. Seal leak sizes of 60 and 182 gpm were considered based on Brookhaven National Laboratory (BNL) Technical Report, W6211-08/99, Guidance Document for Modeling Reactor Coolant Pump Seal Failures. The event is mitigated through initiation of EFW flow (TDEFWP), opening of the atmospheric dump valves, and the recovery of one HPI pump. This analysis is performed using the RELAP5/MOD2 computer program to determine the time available for the operators to initiate flow from one HPI pump.

The scenario evaluated results in an immediate reactor trip and removes power to all of the Emergency Core Cooling System (ECCS) pumps. The RCPs are assumed to be tripped by the operators at 2 minutes in response to a loss of component cooling water to the RCPs. The RCS enters natural circulation and is cooled by the secondary inventory resident in the steam generators. The secondary code safety valves will cycle until the secondary inventory is depleted. The RCS rapidly pressurizes to the primary code safety valve lift setpoint which relieves steam until the pressurizer becomes water solid. The loss of power to the HPI pumps and component cooling also results in a loss of RCP seal and thermal barrier cooling. In this analysis it is conservatively assumed that a seal leak occurs at 10 minutes into the transient in all 4 RCPs. At 30 minutes into the event, operator action is taken to start the TDEFWP. At 45 minutes into the event, operator action is taken to open the atmospheric dump valves in response to a loss of primary system subcooling and a failure of primary system makeup

(HPI), as directed by the Emergency Operating Procedures (EOPs).

The results of the analysis demonstrated that with an assumed seal leak rate of 182 gpm per RCP, at least 2 hours is available for the operators to recover flow from 1 HPI pump. Flow from 1 HPI pump was demonstrated to be capable of recovering the core level and removing decay heat, and thus preventing significant core heatup. Seal leak rates smaller than 182 gpm will provide more time for HPI recovery.

Operator Response Comments:

There is a high level of confidence that actions to align an HPI pump would be directed within 20 minutes. Validation data indicates that the HPI alignment to the ASW switchgear would take less than 40 minutes. Thus, the total time to align HPI from the ASW switchgear can be reasonably estimated as one hour.

Section 10 Basis for HPI failure probability:

Comment on Credit for HPI Aligned to the ASW Switchgear

Credit should be given for the successful recovery of an HPI pump aligned to the ASW Switchgear. Even for the conservative case of a large seal LOCA on all four RCPs, Oconee specific RELAP5 analyses indicate at least 2 hours would be available for recovering an HPI pump (Attachment 2, Case 2). For smaller leakage rates and for run failures of the SSF, the time available would increase to provide even more time to take successful action. Personnel have demonstrated in actual exercises that this action can be accomplished in approximately one hour.

It should be noted that this credit would apply equally to the Units 2&3 Bingham Seals and to Unit 1 even before the Westinghouse Pump Seals were replaced with Bingham Seals. As indicated in BNL Technical Report, W6211-08/99, even for the Westinghouse unqualified seals, the probability of O-ring failure is 0.0 for the first two hours. Only after 3 hours would there be an increased chance of O-ring failure. Therefore, assuming adequate time available, that this is a relatively simple problem to diagnose but complex action to accomplish and assuming high stress, the probability for

Operators failing to establish HPI flow should be 0.03.

Comment on Table 1: Summary of Human Error Probabilities

The human error probabilities are too conservative and are not consistent with the analysis preformed for the Oconee PRA Study nor are they consistent with actual operator performance in testing and examinations. It appears that the choice of Performance Shaping Factors (PSF) for stress level and for complexity are overly conservative. The justification provided is that the short time available to accomplish an action is a reason to elevate the PSF for stress and complexity. However, this is not consistent with the methods referenced.

For example the choice of PSF for stress level of 5 for all diagnostic and manipulation errors would correlate to "extreme" stress. This would only be appropriate if as described in Reference 52, Revision of the 1994 ASP HRA Methodology (Draft), INEEL/EXT-99-00041, the action was associated with the "feeling of threat to one's physical well being or to one's self-esteem or professional status." The conditions present in the Control Room and in the SSF are no different than would occur during training. Therefore, a more appropriate PSF for stress level would be a factor of 2 as associated with "high" stress. This would be characterized as "multiple instruments and annunciators alarm, unexpectedly, at the same time; loud, continuous noise impacts ability to focus on the task." The use of the PSF of "extreme" stress is more appropriate for the actions associated with starting the TDEFWP or EFW cross-tie. Although the conditions have been evaluated for an HELB and found to be an acceptable environment for operators to accomplish these actions, there may be a concern about a "threat to physical well being" due to steam and humidity in the Turbine Building.

As another example, all manipulation errors were assigned a PSF of 5 for complexity of task. According to Reference 52, Revision of the 1994 ASP HRA Methodology (Draft), INEEL/EXT-99-00041, this would correspond to "Highly Complex" actions. "Highly Complex" actions are characterized as "Very difficult to perform. Much ambiguity in what needs to be diagnosed or executed. Many variables involved, with concurrent diagnoses or actions." The actions modeled such as starting the

TDEFWP, EFW cross-tie and activating the SSF do not fit this description. Instead, a more consistent PSF for the complexity of these actions would be "Normal." Defined as: "Not difficult. Little ambiguity. Single or few variables involved." The only actions that might be considered "Highly Complex" would be those associated with establishing the station ASW and establishing HPI from the ASW switchgear.

ATTACHMENT 2

THERMAL HYDRAULIC ANALYSIS

Attachment 2
Oconee Nuclear Station RELAP5/MOD2 HELB Analyses

1.0 OBJECTIVE

The objective of this analysis is to evaluate the transient resulting from a High Energy Line Break (HELB) which causes a failure of the 4kV switchgear. The specific scenario considered includes a Reactor Coolant Pump (RCP) Seal Loss Of Coolant Accident (LOCA) and is mitigated through the use of the Turbine-Driven Emergency Feedwater (TDEFW) pump, the Atmospheric Dump Valves (ADVs), and the recovery of one High Pressure Injection (HPI) pump. This analysis is performed using RELAP5/MOD2 to determine the time available for the operators to initiate flow from one HPI pump.

2.0 METHODOLOGY

The HELB event is analyzed using a version of the RELAP5/MOD2-B&W computer program. This version of RELAP5/MOD2-B&W has been approved by the NRC for use by Duke Power Company in SBLOCA (and LBLOCA) mass and energy release analyses (DPC-NE-3003-PA, Reference 1)

3.0 DESCRIPTION OF ANALYSIS

The scenario evaluated assumes that an HELB (feedline break) causes a failure of the 4kV switchgear. This immediately trips the reactor and removes power to all of the Emergency Core Cooling System (ECCS) pumps. The RCPs are assumed to be tripped by the operators at 2 minutes in response to a loss of component cooling water to the RCPs. The Reactor Coolant System (RCS) enters natural circulation and is cooled by the secondary inventory resident in the Once Through Steam Generators (OTSGs). The secondary code safety valves will cycle until the secondary inventory is depleted. The RCS rapidly pressurizes to the primary code safety valve lift setpoint which relieves steam until the pressurizer becomes water solid. The loss of power to the HPI pumps and component cooling also results in a loss of RCP seal and thermal barrier cooling. In this analysis it is conservatively assumed that a seal leak occurs at 10 minutes into the transient for all 4 RCPs. At 30 minutes into the event, operator action is taken to start the TDEFW pump. At 45 minutes into the event, operator action is taken to open the atmospheric dump valves in response to a loss of primary system subcooling and a failure of primary system makeup (HPI), as directed by the Emergency Operating Procedures (EOPs).

4.0 ASSUMPTIONS

1. Seal LOCA occurs at 10 minutes.
2. Operator action is taken at 30 minutes to start the TDEFW pump to both OTSGs.
3. Operator action is taken at 45 minutes to open the atmospheric dump valves on both steam lines.
4. The analysis conservatively assumes Primary-to-secondary heat transfer is lost after the Core Flood Tanks (CFTs) empty and the nitrogen cover gas has the potential to enter the RCS.

5.0 RESULTS

The results of the four cases analyzed are summarized below.

Note: Case 3 is a separate evaluation to study the impact of a delayed Emergency Feedwater (EFW) failure. Case 3 assessed the condition of no seal LOCA with TDEFW available from 15 minutes to 1 hour. Case 4 considered a stuck open Pressurizer Safety Valve (PSV) instead of a seal LOCA. The safety valve was assumed to stick open at 20 minutes into the event. The recovery actions and response times for this sequence are the same as for the seal LOCA cases.

Case 1 - 60 gpm/pump RCP seal leak

The predominant parameters of interest are RCS pressure, core exit fluid temperature, OTSG pressure, and the reactor vessel level. These parameters are discussed below.

The RCS pressure increases to the safety valve setpoint and cycles on the safety valve until operator action is taken to open the ADVs. Pressure decreases below the CFT pressure fairly rapidly, and continues to decrease until the CFTs empty at roughly 1 hour. In the analysis the CFT nitrogen is prevented from entering the RCS (a limitation of the RELAP5 analysis method). To account for the potential degradation in the primary-to-secondary heat transfer caused by the nitrogen, primary-to-secondary heat transfer is essentially terminated following CFT emptying. This is accomplished by reducing the OTSG tube surface area to 1% of its initial value and bottling up the OTSGs (stopping the EFW flow and closing the ADVs). The RCS repressurizes up to the safety valve setpoint at about 3 hours. The safety valves cycle beyond this point and control the RCS pressure. This case is terminated at the onset of core uncovery. Initiation of HPI flow at this time will recover RCS inventory and provide adequate core cooling. (see Case 2).

The core exit fluid temperatures are the next parameters of interest. The core exit fluid conditions are subcooled for the initial 28 minutes. Following this point in time, the core exit conditions are saturated. The core exit temperature decreases following the opening of the ADVs. Once the CFTs empty and the primary-to-secondary heat transfer is blocked, the core exit temperatures increase since the RCP seal leak is not large enough to remove the decay heat.

OTSG pressure increases to the lowest safety valve setpoint and remains there until operator action is taken to open the ADVs. Pressure drops until the CFTs empty and the OTSG is bottled up (EFW flow terminated and the ADVs are closed).

The last parameter of interest is the collapsed liquid level above the core. About 30 minutes into the event, voiding in the reactor vessel first occurs. The collapsed liquid level flattens out about 50 inches above the core, which roughly corresponds to the elevation of the primary coolant loops. At slightly before 1 hour the impact of the CFT injection is seen which increases the collapsed level and prolongs the time to core uncovery. At roughly 3.5 hours into the event the collapsed liquid level drops below the top of the active fuel, and the calculation is terminated.

Case 2 - 182 gpm/pump RCP seal leak

The predominant parameters of interest are RCS pressure, core exit fluid temperature, reactor vessel level, steam generator pressure, reactor vessel level, and total seal leakage flow versus HPI flow. These parameters are discussed below.

The RCS pressure increases to the safety valve setpoint and cycles on the safety valve until operator action is taken to open the ADVs. Pressure decreases below the CFT pressure fairly rapidly, and continues to decrease until the CFTs empty at roughly 1 hour. In the analysis the CFT nitrogen is prevented from entering the RCS (a limitation of the RELAP5 analysis method). To account for the potential degradation in the primary-to-secondary heat transfer caused by the nitrogen, primary-to-secondary heat transfer is essentially terminated following CFT emptying. This is accomplished by reducing the SG tube area to 1% of its initial value and bottling up the OTSG (stopping the EFW flow and closing the ADVs). Following the loss of primary-to secondary heat transfer, the RCS repressurizes up to about 1900 psig at about 2.5 hours. At this time, operator action to recover flow from 1 HPI pump is assumed and the pressure initially decreases as the HPI flow condenses steam in the primary system. RCS pressure beyond this point in time is the result of the energy balance between HPI flow/seal leakage and decay heat.

The core exit fluid temperatures are the next parameters of interests. The core exit fluid conditions are subcooled for the initial 28 minutes. Following this point in time, the core exit conditions are saturated. The core exit temperature decreases following the opening of the ADVs. Once the CFTs empty and the primary-to-secondary heat transfer is blocked, the core exit temperature increases since the decay heat can not be removed by the RCP seal LOCA. Once the operator starts the HPI pump, the core exit temperature stabilizes and the cooler HPI water absorbs some of the core decay heat.

OTSG pressure increases to the lowest safety valve setpoint and remains there until operator action is taken to open the ADVs. Pressure drops until the CFTs empty and the steam generator is bottled up (EFW flow terminated and the ADVs are closed).

The core water inventory is evaluated by examining the calculated collapsed liquid level above the core. About 30 minutes into the event, voiding in the reactor vessel first occurs. The collapsed liquid level flattens out about 50 inches above the core, which roughly corresponds to the elevation of the primary coolant loops. At slightly before 1 hour the impact of the CFT injection is seen which increases the collapsed level and prolongs the time to core uncovery. At roughly 2.5 hours into the event the collapsed level drops to near the top of the active fuel, at which time the A loop HPI pump is started, increasing the level. The collapsed level plateaus at an elevation of the RCP seal at roughly 3.5 hours. At this time, water is relieved out of the A loop pump seals while mostly steam is discharged out of the B loop pump seals.

Recovery of the RCS inventory occurs when the HPI flow equals or exceeds the RCP seal leak flow. When the HPI flow starts at 2.5 hours, the flow rate exceeds the leak flow since most of the leak flow is steam. At about 3.5 hours, the vessel water level reaches the elevation of the pump seals and liquid is discharged from the A loop pump seals while mostly steam is relieved out of the B loop pump seals. At this time the HPI flow is comparable to the leak flow and thus, the core level stabilizes. Beyond 3.5 hours the HPI flow exceeds the leak flow, increasing the RCS water inventory.

Case 3 - No pump RCP seal leak

The predominant parameters of interest are RCS pressure, core exit fluid temperature, reactor vessel level, OTSG pressure, and the reactor vessel level. These parameters are discussed below.

This case is somewhat different than Cases 1 & 2 presented above in that there is no RCP seal leak, and TDEFW is recovered at 15 minutes and lost at 1 hour. Since there is no RCS system leakage and core exit subcooling is recovered soon after TDEFW flow is established, the operators are assumed not to open the ADVs and as such the CFTs do not inject. The purpose of this case is to examine how long core uncovery is delayed with EFW flow provided during the early stages of the event.

The RCS pressure increases to the safety valve setpoint and cycles on the safety valve until TDEFW flow is recovered. Pressure decreases to about 1500 psig when EFW flow is recovered. The lower RCS pressure is a result of the RCS shrinkage coupled with the RCS inventory lost through the safety valves. Once the TDEFW pump fails, the RCS heats up and the RCS increases to the safety valve setpoint. Cycling of the safety valves control the RCS pressure for the remainder of the event.

The core exit fluid conditions for this case remain subcooled for roughly 2.5 hours. Following this point in time, the core exit conditions are saturated.

OTSG pressure increases to the lowest safety valve setpoint and remains there for most of the event. Between 4 and 4.5 hours the OTSG pressure decreases slightly as decay heat is removed by primary system feed and bleed cooling.

The last parameter of interest is the collapsed liquid level above the core. About 20 minutes into the event the voiding in the reactor vessel first occurs caused by the RCS inventory depletion and the shrinkage of the RCS water following initiation of TDEFW flow. The level stabilizes at about 200 inches above the core up until the time EFW flow is lost and RCS heat up begins. The RCS heat up causes an increase in the reactor vessel level. At slightly after 2.5 hours into the event, voiding in the reactor vessel resumes and the collapsed level starts to drop. At about 3 hours into the event the collapsed water level drops down to reach the loop elevation. At this time, recovery of HPI is assumed and the vessel level is maintained at this elevation. An energy and mass balance is achieved between HPI flow, safety valve relief flow and the decay heat. Recovery of HPI at 3 hours is capable of removing the decay heat and keeping the core covered.

A variation of Case 3 was also analyzed where EFW flow was recovered at 3.3 hours instead of flow from the HPI pump. This case also demonstrated a successful system recovery (preventing core uncovery and providing decay heat removal) but at a reduced RCS pressure (roughly 1100 psig).

Case 4 - No pump RCP seal leak, PSV stuck open

The predominant parameters of interest are RCS pressure, core exit fluid temperature, OTSG pressure, and reactor vessel level. These parameters are discussed below.

This case is similar to Cases 1 & 2 presented above except in place of a seal LOCA at 10 minutes, a PSV is assumed to stick at the full open position at 20 minutes. The main difference is the leak area and its elevation.

The RCS pressure increases to the safety valve setpoint and cycles on the safety valve until one of the PSVs sticks open and the TDEFW flow is recovered. Pressure decreases to about 1200 psig at 45 minutes at which time the ADVs are opened. The RCS pressure continues to decrease until the CFTs discharge and empty. At this time the CFT nitrogen is expected to enter the primary system. Similar to Cases 1 & 2, it is assumed that the nitrogen (if modeled in RELAP5) could interrupt primary-to-secondary heat transfer. Therefore, in the analysis, heat transfer from the primary to the secondary is inhibited. This results in the repressurization of the primary system up to about 850 psig. Later in the event, the primary pressure starts to decrease roughly at the time where core uncovery starts and the rate of steam production (void formation) in the core decreases.

The core exit fluid temperatures are the next parameters of interests. The core exit fluid conditions are subcooled for the initial 20 minutes. Following this point in time, the core exit conditions are saturated until core uncovery occurs. The core exit temperature decreases following the start of TDEFW flow and the opening of the ADVs. Once the CFTs empty and the primary-to-secondary heat transfer is blocked, the core exit temperature increases since the decay heat can not be removed by the flow rate out of the stuck open PSV at the reduced RCS pressure. The core exit liquid temperature levels off as the RCS pressure plateaus. The core exit vapor temperature follows the liquid temperature until core uncovery occurs at 1.9 hours.

OTSG pressure increases to the lowest safety valve setpoint and remains there until operator action is taken to open the ADVs.

Pressure drops until the CFTs empty and the OTSG is bottled up (EFW flow terminated and the ADVs are closed).

The final parameter of interest is the collapsed liquid level above the core. About 20 minutes into the event, voiding in the reactor vessel first occurs caused by the RCS inventory depletion from cycling of the PSV. The stuck open safety valve at 20 minutes leads to continued void formation in the reactor vessel. At 30 minutes, shrinkage of the RCS water follows the initiation of TDEFW flow. This adds to the rate of level decrease in the reactor vessel. The opening of the ADVs at 45 minutes leads to a rapid decrease in the collapsed vessel level to below the top of the core. No core heat up occurs since the actual or two-phase mixture level remains above the core. At 48 minutes, the CFTs inject resulting in an increase in the reactor vessel level. After the CFTs empty, the reactor vessel continues to drop as flow persists out of the stuck open safety valve. At about 1.9 hours into the event, the reactor vessel mixture level drops below the top of the core and core heat up begins.

6.0 CONCLUSIONS

For the cases with assumed seal leak rates of up to 182 gpm per reactor coolant pump, at least 2 hours is available for the operators to recover flow from 1 HPI pump. It was also shown for the larger seal leak case that the flow capacity of 1 HPI pump is capable of recovering the core level and removing decay heat. Seal leaks smaller than 182 gpm provide more time for HPI recovery. For the case with no RCP seal leak (and a delayed loss of EFW flow), at least 3 hours are available for the operators to recover an HPI pump or an EFW pump. For the case of a stuck open PSV without a RCP seal leak, at least 1 ¾ hours are available for the operators to recover flow from 1 HPI pump.

7.0 REFERENCES

1. DPC-NE-3003-PA, Mass and Energy Release and Containment Response Methodology, Oconee Nuclear Station, November 1997, Duke Power Company.