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A Duke Energy Company

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March 29, 2000

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

SUBJECT: Duke Energy Corporation
Docket No(s). 50-269, -270, -287
Oconee Nuclear Station Units 1, 2, and 3
Supplement to December 16, 1998, LAR
Regarding the HPI System, Removal of the proposed ADV Technical Specification 3.7.4 due to approval of Amendment 309,309,309 dated 1/18/00, and revision of commitment related to implementation of the Configuration Risk Management Program
Technical Specification Change # 98-13

On December 16, 1998, Duke submitted a proposed license amendment for Facility Operating License Nos. DPR-38, DPR-47, and DPR-55 for Oconee Nuclear Station Units 1, 2, and 3, respectively. The license amendment request (LAR) corrects previously identified deficiencies in the Technical Specifications related to the High Pressure Injection (HPI) system.

In January 1999, a verbal request was made to include additional justification for the No Significant Hazards Consideration. This was provided in a submittal dated January 25, 1999.

In May and June 1999, the NRC Staff and Duke had several discussions (telephone calls and an onsite visit by one NRR reviewer) regarding the LAR submitted on December 16, 1998. During these discussions, the NRC Staff requested the submittal of additional information regarding the

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aforementioned LAR. This was provided in a submittal dated August 5, 1999.

In the August 5, 1999 submittal, Duke committed to issue a Selected Licensee Commitment to describe the Configuration Risk Management Program (CRMP). The NRC has amended its regulations to require that licensees assess the effect of equipment maintenance on the plant's capability to perform safety functions before beginning maintenance activities on structures, systems and components within the scope of the maintenance rule. When implementation of the rule ((a)(4) of 10CFR50.65) is approved, the NRC will support licensee requests to remove CRMP from plant TS. The implementation process for 10CFR50.65, paragraph (a)(4) is scheduled to be approved in May, 2000 via the issuance of the revised Regulatory Guide. Therefore, Duke requests to modify its commitment to implement the CRMP by using paragraph (a)(4) of 10CFR50.65. Duke will implement 10CFR50.65 paragraph (a)(4) by September 1, 2000, as required for this TS.

Additional Information was also provided related to Atmospheric Dump Valve Simulator Validation in a letter dated October 20, 1999.

In November and December 1999, the NRC Staff and Duke had several conference calls regarding the LAR and its subsequent packages. In a request for additional information (RAI) dated February 2, 2000, the NRC staff requested that Duke document responses to the issues discussed in the conference calls.

The submittal contains the following attachments:

Attachment 1 provides the response to the RAI dated February 2, 2000.

Attachment 2 provides revised pages of the previous submittals dated December 16, 1998 and August 5, 1999. The revisions are necessary to delete the proposed Atmospheric Dump Valves (ADVs) TS 3.7.4 from the submittals. The TS for ADVs was approved by the NRC in amendment 309, 309, 309 dated January 18, 2000.

This supplement contains the following commitments:

1) Prior to or during the implementation phase of this LAR, all operating crews will be exercised on feeding Emergency Feedwater to raise Steam Generator levels to the Loss of Sub-cooling Margin Setpoint to ensure that time critical operator actions can be consistently met.

2) Prior to or during the implementation phase of this LAR, all operating crews will be exercised on opening ADVs to ensure that time critical operator actions can be consistently met.

3) The Turbine Bypass System will be added to ORAM-SENTINEL.

4) As part of implementation, pass/fail criteria for licensed operator exams that involve the tasks of opening the ADVs will be modified to include performance of the task within the required time frame.

5) The Minimum Staffing SLC will be revised to reflect the requirement of an additional 3 operators upon entry in condition B using the 10CFR50.59 process.

6) Duke modifies its previous commitment in the submittal dated August 5, 1999 to implement the CRMP by using (a)(4) of 10CFR50.65. Implementation as required per this TS will occur no later than September 1, 2000.

Pursuant to 10 CFR 50.91, a copy of this supplement to the December 16, 1998, LAR is being sent to the State of South Carolina.

Inquiries on this matter should be directed to R. V. Gambrell at (864) 885-3364.

Very truly yours,

W. R. McCollum, Jr., Site Vice President
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Attachments

xc w/attachments:

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AFFIDAVIT

W. R. McCollum, Jr., being duly sworn, states that he is Site Vice President of Duke Energy Corporation; that he is authorized on the part of said corporation to sign and file with the Nuclear Regulatory Commission this revision to the Oconee Nuclear Station License Nos. DPR-38, DPR-47, and DPR-55; and that all statements and matters set forth therein are true and correct to the best of his knowledge.

W. R. McCollum, Jr., Site Vice President

Subscribed and sworn to me: MARCH 29, 2000
Date

Notary Public: Robert C. Dougla

My Commission Expires: AUGUST 13, 2009
Date

SEAL

ATTACHMENT 1

REQUEST FOR ADDITIONAL INFORMATION

HIGH PRESSURE INJECTION (HPI) SYSTEM

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3

Request For Additional Information
High Pressure Injection (HPI) System
Oconee Nuclear Station, Units 1, 2, and 3

1. The revision to the Small Break Loss of Coolant Accident (SBLOCA) analyses has been proposed to credit three operator actions in the SBLOCA mitigation strategy. These actions are: (1) in the event one HPI train fails to automatically actuate, cross-connecting the HPI discharge headers within 10 minutes in order to provide HPI flow through a second HPI train; (2) feeding the steam generators (SGs) to the loss of sub-cooled margin setpoint with emergency feedwater; and (3) depressurizing and steaming the SGs using the atmospheric dump valves (ADVs). Operator action to cross-connect the HPI discharge headers was previously reviewed and approved by the staff in a Safety Evaluation dated December 13, 1978. The submittal indicates that the revised SBLOCA analysis does not revise in any way this operator action.

   Operator action is required to initiate Emergency Feedwater (EFW) flow and raise SG levels to the loss of subcooling margin setpoint if either Low Pressure Injection header flow indicates less than 1000 gallons per minute (gpm) flow. The "Full Power, Two HPI Pump Analyses" assume operator actions to begin to manually increase SG levels to the loss of subcooling margin setpoint will occur within 20 minutes of reactor trip for one SG and within 30 minutes for the second SG. The "Reduced Power, One HPI Pump Analyses" take credit for operator action to provide EFW flow to one SG within 20 minutes and to provide cooldown of one SG within 25 minutes. The submittal indicates that direction to initiate EFW flows to raise SG levels to the loss of subcooling margin setpoint is provided in the Emergency Operating Procedures (EOPs), and subcooling margin and low pressure injection (LPI) header flows can be monitored from the front control board using QA-1 instruments. Success is verified by monitoring increasing SG levels using Extended Startup Range Level Instrumentation.

   Information Needed:

   The submittal indicates that operator action to perform this function has been validated through simulator exercise. The submittal does not provide any details concerning the validation process. Please provide sufficient details concerning the simulator exercises to substantiate that the validation process provides reasonable assurance that the operator actions can be performed within the allowed times in a reliable manner (e.g., how many crews were tested, the test conditions and assumptions, the range of completion times observed, and the acceptance criteria that was used). NRC Information Notice 97-78: "Crediting of Operator Actions In Place of Automatic Actions and Modifications of Operator Actions, Including Response Times" contains a listing of the items that the NRC typically reviews.

Response to Information needed:

Validation is the process of exercising procedures to ensure that they are usable, that the language and level of information is appropriate for the people for whom they are intended, and that the procedures will function as intended.

Validation may be performed by one or any combination of the following methods:

- Table-Top Validation - Method of validation whereby personnel explain and/or discuss procedure steps in response to a scenario or as part of an actual industry operating experience review. Table-top method may be used where access to plant equipment is not practical.

- Walk-Through Validation - Method of validation whereby personnel conduct a step-by-step enactment of their actions without carrying out the actual control functions. This includes equipment access and equipment staging when required.

- Simulator Validation - Method of validation whereby control room personnel perform actual control functions in the simulator Control Room during a scenario for an observer/reviewer. Simulator validation uses a simulator to create dynamic simulation of control room systems to provide a realistic reproduction of control room responses and actions.

Simulator Validation provides a safe environment in which to test the procedure.

Procedure validations are initially performed as part of the procedure change process to ensure operators and support staff can manage emergency conditions through the use of EOPs, APs, and Support Procedures. Continuing procedure validations can also be performed during training and scheduled drills.

The procedure writer identifies the methods of validation. Methods of validation are based on the procedure characteristics necessary to ensure the intent of the new or revised procedure is met and is based on nature of changes to the procedure. More than one validation method may be appropriate. The following table is used as a guide to select the validation method:

	VALIDATION METHODS		
CHARACTERISTIC TO BE VALIDATED	Simulator	Walk-Through	Table-Top
Procedure information for management of the emergency condition is sufficient & consistent with training	X	X	X
Procedure information is easily comprehensible	X	X	X
Compatible with control room hardware	X	X	
Compatible with remotely located hardware & response	X	X	
Compatible with shift manning levels & policies	X	X	
Compatible with plant response	X		
Accessibility		X	

Simulator validations are only applicable to Unit 1 procedures. An evaluation may be performed for Unit 2 and 3 procedures to see if the validation of Unit 1 procedures on the simulator can be applied to these procedures.

Validation is not required for simple editorial changes that do not alter the intent, scope or technical accuracy of the procedure.

For the EOP, only the steps in the associated procedure must be validated. The following is required for EOP validation:

- Determination of step timing
- Description of the scenario including the expected paths to be utilized
- List of any procedures referenced/branched to by the scenario
- Determination of support staff involvement

If a simulator validation is being performed, then time is scheduled on the simulator and the scenario is reviewed to ensure that it falls within the simulator's tested scope of simulation. An observer(s) is designated to monitor and note the procedure validation process as the procedure is used. Observers are required to have an experience level and/or training background to support their assigned function in the assessment. Control Room Simulator validations require a minimum of one individual with a Senior Reactor Operator (SRO) license to act as the procedure director and two individuals with a Reactor Operator (RO) or SRO license to fill the role of Control Room Operators.

The observer is responsible for the following:

- Familiarity with the procedure
- Familiarity with other related or referenced procedures
- Familiarity with reference drawings
- Familiarity with the operation of systems and equipment
- Familiarity with the environment in which the procedure will be performed
- Reviewing related design bases and Improved Technical Specifications.

During a simulator validation, the observer ensures the following tasks are completed:

- Procedures are available
- Provides a brief on purpose and technique of assessment

- Provides a brief of rules to be followed during simulator validation
- Tracks timing of step performance
- Maintains data
- Identifies discrepancies
- Records comments noted during the validation

After the procedure is validated, the observer ensures the following tasks are accomplished:

- Procedures that were referenced or branched to during the scenario are documented
- A debrief to identify any problems not apparent during the validation for each procedure involved in the validation
- Documents discrepancies
- Records crew names for the assessment

The observer forwards this information back to the procedure writer who then resolves any problems found and documents the resolution. The procedure writer is responsible for reviewing the step timing to ensure that "Time Critical Actions" are acceptable.

Simulator Validation

Six crews were tested on raising Steam Generator (SG) levels to the loss of subcooling margin (LOSCM) setpoint. Two individuals participated as members on two crews. This was acceptable because there was a six week time lapse between the first and second simulator validation for each.

A project to perform simulator validations of a significant number of the potential paths through the Emergency Operating Procedure (EOP) is currently in progress at Oconee. The action to begin to manually increase SG levels to the LOSCM setpoint was included as part of the Small Break Loss Of Coolant Accident (SBLOCA) scenarios. The simulator was left running continuously throughout the scenarios to simulate real accident conditions. At the time this data was gathered, crews used for validating this action were also being used to validate other scenarios such as SG Tube Ruptures, Large Break Loss Of Coolant Accidents (LBLOCA) and Steam Line Breaks, etc. Thus, the crews had no previous knowledge of which scenarios they were to be tested on. The crews were also unaware of the time criticality associated with the task.

The following information is a description of each scenario. It includes test conditions, assumptions and completion times observed. The acceptance criterion for raising SG levels to the LOSCM setpoint is 20 minutes.

EFW Scenario #1

A SBLOCA occurs from 75% power. The "1A" High Pressure Injection (HPI) pump is out of service for repairs at the beginning of the scenario. The "1C" HPI pump fails to start and run at the time of the event. In addition, Turbine Bypass Valves (TBVs) fail closed requiring that the Atmospheric Dump Valves (ADVs) be used. Since there is only flow in the "1A" HPI header (1HP-409 is not used to cross connect with only one HPI pump), a rapid cooldown will be performed.

There were four objectives for this scenario. They are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs and Emergency Feedwater (EFW).

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25 minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that the EOP adequately addresses the new philosophy of not cross connecting HPI headers if only one HPI pump is available.

4. This scenario tests that EFW flow to at least one Steam Generator (SG) is established within 20 minutes of the reactor trip.

Many accident mitigation functions were being performed as the crews performed the EOP. Feeding of EFW to raise SG levels to the LOSCM setpoint was commenced in 10 minutes, 44 seconds.

EFW Scenario #2

A SBLOCA occurs with no failures. When subcooled margin reaches 0°F, the evaluator tells the team not to secure RCPs within the "two" minute criteria time to force the team into performing a "rapid" cooldown in Section CP-602.

The objective for this scenario is to follow the path of the EOP for a SBLOCA with RCPs not secured within the "two" minute time criteria to force the team into performing a "rapid" cooldown in Section CP-602.

Many accident mitigation functions were being performed as the crews performed the AP and EOP. Feeding of EFW to raise SG levels to the LOSCM was commenced at 13 minutes, 36 seconds.

EFW Scenario #3 and #6

This scenario was run once each on two separate crews. At the beginning of the scenario, the reactor is ≈ 75% power with "1B" HPI pump out of service for repairs. A SBLOCA occurs which results in either a manual reactor trip based on excessive makeup flow or an automatic reactor trip. Concurrent with the reactor trip, the TBVs fail closed and a switchgear lockout occurs. Since only one HPI pump is operating, 1HP-409 is not used to cross connect HPI headers. With HPI flow available in only the "A" header, a rapid cooldown of the RCS will be performed.

The objectives for this scenario are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs and EFW.

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25 minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that EFW flow to at least one SG is established within 20 minutes of the reactor trip.

Many accident mitigation functions were being performed as the crews performed the EOP. Feeding of EFW to raise SG levels to the LOSCM was commenced at 17 minutes, 53 seconds by one crew and at 12 minutes, 8 seconds for the second crew.

EFW Scenario #4 & #5

This scenario was also run once each on two separate crews. At the beginning of the scenario, the reactor is ≈ 75% power with "1B" HPI pump out of service for repairs. A SBLOCA occurs which results in either a manual reactor trip based on excessive makeup flow or an automatic reactor trip. Concurrent with the reactor trip, the TBVs fail closed and a switchgear lockout occurs. Since only one HPI pump is operating, HPI cross-over valves are not used to cross connect HPI headers. With HPI flow available in only the "B" header, a rapid cooldown of the RCS will be performed.

The objectives for this scenario are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs and EFW.

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25 minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that EFW flow to at least one SG is established within 20 minutes of the reactor trip.

Many accident mitigation functions were being performed as the crews performed the EOP. Feeding of EFW to raise the SG levels to the LOSCM setpoint was commenced at 14 minutes, 13 seconds by one crew and 11 minutes, 31 seconds for the second crew.

The requirements for the critical task of beginning to raise SG levels to the LOSCM is dependent on the initial conditions and operable equipment for the scenario. For the case that started from full power with two HPI pumps available, operator actions to begin increasing SG levels to the LOSCM setpoint must occur within 20 minutes of reactor trip for one SG and within 30 minutes for the second SG. For the scenario from reduced power with one HPI pump available, operator action to provide EFW flow to one SG within 20 minutes is required. In the validation scenarios run, EFW flow was initiated to both SGs at approximately the same time so for cases where feed to both SGs is needed, the 30 minute requirement was satisfied.

The completion times from the scenarios run above ranged from 17 minutes 53 seconds to 10 minutes 44 seconds. This is within the acceptance criteria of 20 minutes.

Since the crews were being tested on a variety of scenarios and had no previous knowledge of the scenarios to be run, reasonable assurance is given that operator actions can be reliably performed within the 20 minute completion time associated with this task.

The EOP verification and validation process ensures that future revisions to the EOP will not invalidate these results.

Either, prior to or during the implementation phase of this LAR, all operating crews will be exercised on this scenario to ensure that time critical actions can be consistently met.

2. As stated in the Attachment 4, Enclosure 3 of the December 16, 1998, submittal:

   The reduced power SBLOCA analyses credit operator action to depressurize the SGs by the ADV opening flow paths. These analyses assume operator action within 25 minutes of reactor trip. The following factors have been provided in the evaluation of the acceptability of crediting operator action:

   a. Step 4.1 of CP-602 "SG Cooldown with Saturated RCS" directs the operators to maintain SG pressure less than RCS pressure. If SG pressure does not decrease as Turbine Bypass Valve (TBV) demand is increased, the EOP directs use of the ADVs.

b. The valves that must be operated to open flow paths for the ADVs are outside the control room but readily accessible (i.e., the valves are on the fifth floor of the turbine building, the same level as the control room). The valves are not expected to be in a harsh or inhospitable environment during a SBLOCA.

c. Two non-licensed operators (NLOs) are initially required to open the ADV flow path, but only one operator is required to throttle flow. One operator will be dedicated to throttling flow after initial opening of the valve. No additional support personnel or equipment are required.

d. Operators will communicate with the control room via hand held radio.

e. An EOP upgrade will require operators to check TBV operability as part of the second step of the Subsequent Actions sections of the EOP. If the TBVs are inoperable the NLOs will be dispatched immediately to prepare for steaming the generators with the ADVs.

f. An expert panel of representatives from Operations, Operator Training, Engineering, and Licensing reviewed the EOP and operator action and concluded that past Job Performance Measures (JPMs) and simulator cases for the relevant SBLOCAs support the adequacy of the assumed 25 minutes.

Information needed:

a. The submittal does not address whether the panel's assessment assumed minimum staffing and the impact of any other tasks the assigned personnel may be required to perform for mitigating this event. The submittal should address these issues.

Response to Information needed:

The conclusions that the expert panel reached related to the adequacy of the assumed 25 minutes based on Job Performance Measures (JPMs) and simulator cases can now be supported with data gathered by the EOP project. The EOP project has been reviewing EOPs, EOP programs and processes, the EOP technical basis, the ability to implement the EOP in the field and perform any necessary corrective actions. These tasks have been accomplished through programmatic reviews, field walkdowns, field timing studies, simulator validations and calculation review and creation.

One of the items addressed by the EOP project was minimum staffing. The EOP project conducted an extensive, integrated evaluation of the staffing needs for mitigating events. The evaluation encompassed a wide range of accident scenarios coupled with additional external events, such as tornadoes. An evaluation was done against time critical operator actions to ensure that minimum staffing is onsite at all times.

The results of the EOP project review produced Minimum Staffing requirements. Minimum Staffing requirements are recorded in and controlled by a Selected Licensee Commitment (SLC). SLCs are previous technical specification requirements that no longer meet the technical specification criteria. SLCs also contain additional NRC commitments as deemed appropriate by Duke management. Changes to SLCs may be made pursuant to 10CFR50.59.

Each shift is staffed such that when any unit is in Modes 1-4, a minimum of 8 non-licensed operators (NLOs) are required. There are typically 13 NLOs assigned to each shift. During an innage, 2 NLOs are allowed to be off at the same time. The least number of NLOs for any given shift during an innage is typically 11.

The NLOs divide their responsibilities between two roles. Unit NLOs monitor the operating equipment on their assigned watchstation and a Work Control Center (WCC) NLO performs work activities such as tagging, valve checklists, and assists Operations Test Group in surveillance testing.

NLOs are required to carry radios when they are performing tasks outside the control room. This allows them to stay in constant communication with the Control Room and the WCC.

During an emergency or transient, all NLOs are required to report to the affected Control Room for specific directions. If an NLO is performing a task that involves a System, Structure or Component (SSC) important to safety, the SSC will be placed in a safe state prior to the NLO reporting to the control room.

Each Unit has one NLO assigned to complete critical AP and EOP actions. This function is assigned to the NLO at the beginning of each shift. The NLO will stay inside the protected area at all times during the shift.

Transit times for an NLO coming from a remote part of the plant reporting to the control room are typically 5 minutes. Five minutes does not include having to place an SSC into a safe state prior to leaving the area. Typical staffing numbers would allow for at least 2 NLOs to be in the affected unit's control room within 5 minutes of a reactor trip.

For the SBLOCA scenario, two NLOs are dispatched from the control room typically within 5 minutes of the initiating event. NLOs will not be given other tasks to perform until they have completed opening the ADVs. Once the NLOs are dispatched to the valves, which are located outside the control room, they open the block valves and then report status to the Control Room. After reporting status, they await further instruction from the control room. Control Room Operators are performing EOP activities. The NLOs open the ADVs at the Control Room Operators instruction. Once the ADVs are open, one NLO is required to stay at the ADVs for throttling purposes. The other NLO can be released and utilized for other tasks.

Simulator validations indicate that it is necessary to increase minimum staffing upon entry into condition B of the TS. Minimum staffing levels will be increased by 3 Operator's during the AOT of the condition entry. Since condition A would be entered prior to entry into condition B, Operations will have 72 hours to designate the additional staff. Minimum Staffing requirements are controlled by a SLC. The Minimum Staffing SLC will be revised to reflect the requirement of an additional 3 operators upon entry in condition B using the 10CFR50.59 process. This will be done as an implementation item and pends approval of this TS. This change to minimum staffing will be temporary as plant enhancements are continually being made to eliminate manual actions. Each plant enhancement will evaluate and change minimum staffing as appropriate.

b. The submittal should address how much margin is available between the observed times in JPMs and simulator scenarios and the assumed 25 minutes available for this action. Some of this information was addressed in the October 4, 1999, submittal that described a validation effort involving simulator exercises. However, the submittal did not provide sufficient detail concerning the simulator exercises. Sufficient detail is needed for the staff to make a determination that the validity of the evaluation to determine the operators' ability to reliably perform the actions within the time available. As described in the information needs described above, these details might include how many crews were tested, the test conditions and assumptions (e.g., minimum staffing, delays in personnel availability), the range of completion times observed, and the acceptance criteria that was used.

Response to Information Needed:

Six crews were tested on opening the Atmospheric Dump Valves (ADVs) within 25 minutes. As described above for initiating EFW flow to the SGs, this action was also included in part of the Small Break Loss Of Coolant Accident (SBLOCA) validation scenarios performed as part of the EOP project. The simulator was left running continuously throughout the scenarios to simulate real accident conditions. Due to the variety of scenarios run, the crews had no previous knowledge of which scenarios they were to validate. The crews were also unaware of the time criticality associated with the task.

The stroke times used for the valves were obtained during a Unit 2 outage. Four data sets were recorded for each steam line so there are a total of eight data sets. Worst case total stroke time for opening the 3 valves on a SG is 5 minutes.

The time required to operate the ADV blocks was obtained by combining the stroke time data with the total time to complete communications and travel to each component comprising the task. Four separate walkdowns were conducted to obtain these times. Initial communication, travel time to and between valves, and communication after opening the block valves ranged from 2 minutes, 25 seconds to 5 minutes, 25 seconds. The table below illustrates how this data was derived:

	Worst Case Observed	Time Used for Validation
Time to receive direction and arrive at 1st valve	02:46	03:00
Time to open the ADV block bypass valve and ADV block valve on both SGs	08:21	09:00
Time to fully open 1 ADV	01:39	02:00
Total	12:46	14:00

The SBLOCA scenario was run seven times to test the Operator's ability to open the ADVs within 25 minutes. One crew was tested twice. The following is a description of the scenarios used. It includes test conditions, assumptions and completion times observed. The acceptance criterion for opening the ADVs is 25 minutes.

ADV Scenario #1:

A SBLOCA occurs from 75% power. The "1B" High Pressure Injection (HPI) pump is out of service for repairs at the beginning of the scenario. The "1C" HPI pump fails to start and run at the time of the event. In addition, TBVs fail closed requiring that the ADVs be used. Since there is only flow in the "1A" HPI header (1HP-409 is not used to cross connect with only one HPI pump), a rapid cooldown will be performed.

There were three objectives for this scenario. They are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs;

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25

minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that EFW flow to at least one SG is established within 20 minutes of the reactor trip.

The Control Room Operator (CRO) dispatched the NLO in 3 minutes, 54 seconds. This time includes pulling the EOP and providing repeat backs. The NLO is at the valves within 6 minutes, 54 seconds. The ADV on one SG was fully open at 21 minutes, 19 seconds.

<u>ADV Scenario #2</u>

A SBLOCA occurs from 75% power. The "1B" High Pressure Injection (HPI) pump is out of service for repairs at the beginning of the scenario. A Loss of Offsite Power occurs at the time of the event. The "1C" HPI pump also fails to start and run. In addition, TBVs fail closed requiring that the ADVs be used. Since there is only flow in the "1A" HPI header (1HP-409 is not used to cross connect with only one HPI pump), a rapid cooldown will be performed.

There were three objectives for this scenario. They are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs;

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25 minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that EFW flow to at least one SG is established within 20 minutes of the reactor trip.

The CRO dispatched the NLO in 3 minutes, 26 seconds. This time includes pulling the EOP and providing repeat backs. The NLO is at the valves within 6 minutes, 26 seconds. The ADV on one SG was fully opened at 17 minutes, 26 seconds.

<u>ADV Scenario #3:</u>

A SBLOCA occurs from 75% power. The "1A" High Pressure Injection (HPI) pump is out of service for repairs at the beginning of the scenario. The "1C" HPI pump fails to start and run at the time of the event. In addition, TBVs fail closed requiring that the ADVs be used. Since there is only flow in the "1A" HPI header (1HP-409 is not used to cross connect with only one HPI pump), a rapid cooldown will be performed.

There were four objectives for this scenario. They are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs and EFW;

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25 minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that the EOP adequately addresses the new philosophy of not cross connecting HPI headers if only one HPI pump is available.

4. This scenario tests that EFW flow to at least one SG is established within 20 minutes of the reactor trip.

The Control Room Operator (CRO) dispatched the NLO in 1 minute, 42 seconds. This time includes pulling the EOP and providing repeat backs. The NLO is at the valves within 4 minutes, 42 seconds. The ADV on one SG was fully opened at 18 minutes, 55 seconds.

ADV Scenarios #4 & #7:

This scenario was run once each on two separate crews. At the beginning of the scenario, the reactor is ≈ 75% power with "1B" HPI pump out of service for repairs. A SBLOCA occurs which results in either a manual reactor trip based on excessive makeup flow or an automatic reactor trip. Concurrent with the reactor trip, the TBVs fail closed and a switchgear lockout occurs. Since only one HPI pump is operating, 1HP-409 is not used to cross connect HPI headers. With HPI flow available in only the "A" header, a rapid cooldown of the RCS will be performed.

The objectives for this scenario are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs and EFW.

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25 minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that EFW flow to at least one SG is established within 20 minutes of the reactor trip.

The CRO dispatched the NLOs in 4 minutes, 8 seconds on the first crew and in 2 minutes, 57 seconds on the second crew. This time includes pulling the EOP and providing repeat backs. The NLOs are at the valves within 7 minutes, 8 seconds and 5 minutes, 57 seconds for the first and second crews, respectively. The ADV on one SG was fully opened at 19 minutes, 4 seconds by the first crew and in 18 minutes, 33 seconds by the second.

ADV Scenarios #5 & #6:

This scenario was also run once each on two separate crews. At the beginning of the scenario, the reactor is ≈ 75% power with "1B" HPI pump out of service for repairs. A SBLOCA occurs which results in either a manual reactor trip based on excessive makeup flow or an automatic reactor trip. Concurrent with the reactor trip, the TBVs fail closed and a switchgear lockout occurs. Since only one HPI pump is operating HPI cross-over valves are not used to cross connect HPI headers. With HPI flow available in only the "B" header, a rapid cooldown of the RCS will be performed.

The objectives for this scenario are as follows:

1. Follow the path of the EOP for a SBLOCA with multiple failures that require a rapid cooldown be performed using ADVs and EFW.

2. This scenario tests that operators are sent out early enough in the EOP to use ADVs within 25 minutes of Engineered Safeguards actuation. TBVs are failed closed when the SBLOCA occurs. Two NLOs are sent to align ADVs if TBVs are not controlling as expected post trip.

3. This scenario tests that EFW flow to at least one Steam Generator (SG) is established within 20 minutes of the reactor trip.

The CRO dispatched the NLO in 3 minutes, 49 seconds on the first crew and in 3 minutes, 23 seconds on the second crew. This time includes pulling the EOP and providing repeat backs. The NLO is at the valves within 6 minutes, 49 seconds and 6 minutes, 23 seconds for the first and second crews, respectively. The ADV on one SG was full open at 19 minutes, 32 seconds by the first crew and in 19 minutes, 11 seconds by the second.

Again, valves are outside the control room in an area that will not be affected by a SBLOCA. The approved written procedure for opening the valves is prestaged at the valves. NLOs will use the approved written procedure to open the valves.

The completion times for the testing ranged from 17 minutes, 26 seconds to 21 minutes, 19 seconds. Worst case margin was over 3 minutes.

Since the crews being tested had no previous knowledge of the scenarios to be run, reasonable assurance is given that operator actions can be reliably performed within the 25 minute completion time associated with this task.

Following a reactor trip, one operator begins checking for symptoms while the other is performing immediate manual actions. For the SBLOCA scenarios, the symptom of a LOSCM appears within typically 1 minute of the initiating event. Upon recognition of the symptom, an operator commit to memory item requires immediate implementation of EOP specific rule #2. The fifth step of this rule is where it is determined that ADVs are required and NLOs are dispatched. In the scenarios run, this time ranged from 3 to 4 minutes. Opening ADVs are one of the first two critical tasks performed in the SBLOCA scenarios. This order assures that NLOs are available to respond when necessary. The margins stated for these scenarios are not expected to vary significantly due to minimal interaction between operators, memory requirement for implementing the rule, the availability of the rule on the control board apron and the few steps required to reach the point in the rule before dispatching NLOs.

Usage of this TS for either, an inoperable HPI pump or inoperable discharge crossover valve(s) will have Operations designating the additional staff required for accident mitigation within 72 hours of entry into condition A. Therefore, if it is necessary to enter condition B, staffing will be in place. Entry into condition B necessitates that Operations will reduce power and check ADV operability within 12 hours of entering the action statement. These actions provide a heightened awareness to the potential need for the time critical task of opening the ADVs.

Either, prior to or during the implementation phase of this LAR, all operating crews will be exercised on this scenario to ensure that time critical actions can be consistently met.

As previously stated in Attachment 4, Enclosure 3 of the submittal dated December 16, 1998, the NLOs task of opening the ADVs will be evaluated at least bi-annually using JPMs. As part of implementation, pass/fail criteria for licensed operator exams that involve the tasks of opening the ADVs will be modified to include performance of the task within the required time frame. These training activites ensure the NLOs and licensed operator's ability to open the ADVs within the specified time frame.

c. Regarding the October 4, 1999, submittal, it was not clear how many simulator runs were completed as part of the validation effort and how 2 crews were run on multiple scenarios. However, the crews were described as having no prior knowledge of the scenarios.

Response to Information Needed:

The scenarios run to obtain this data were performed as part of the EOP project, which included a variety of scenarios such as SGTR, LBLOCA and Steam Line Breaks. Two of these scenarios required opening the ADVs. As such, the operating crew had no prior knowledge of what would be required of them. The crew that was used twice ran ADV scenarios #1 and #2 as described above for question b. One of the scenarios was run with power available, while the other was run with a Loss of Offsite Power (LOOP). Since the October 4, 1999 submittal, more scenarios have been run and the results of those scenarios are included in question b.

d. The October 4, 1999, submittal described transit times for the NLOs, but did not provide sufficient detail to determine if the transit times addressed the potential for the operators to be responding from remote areas of the plant. In addition, the submittal did not address whether the calculations of time for the NLOs to respond considered the possibility that those operators may be engaged in an activity that would require time for them to place a system or equipment in a safe state before they could respond to the event.

Response to Information Needed:

For these scenarios, two NLOs are assumed dispatched from the control room or work control center typically within 5 minutes of the initiating event. NLOs will not be given other tasks to perform until they have completed opening the ADVs. Once the NLOs are dispatched to the valves, which are located outside the control room, they open the block valves and then report status to the Control Room. After reporting status, they await further instruction from the control room. Control Room Operators are performing EOP activities. The NLOs open the ADVs at the Control Room Operators instruction. Once the ADVs are open, one NLO is required to stay at the ADVs for throttling purposes. The other NLO can be released and utilized for other tasks.

The EOP project validated time critical operator actions. Through this effort, improvements have been made in the area of resources and response. Minimum staffing was put in place through a 10CFR50.59 controlled SLC, NLOs report to the control room upon unit trip, three NLOs are designated to perform AP/EOP activities and do not leave the protected area during shift, and NLOs are in constant contact with the Control Room via radios.

3. As stated in Attachment 4, Enclosure 2 of the December 16, 1998 submittal:

- The ADV flow path consists of the atmospheric dump block valve bypass (a 1" bypass), the atmospheric vent valve (a 12" block valve), the atmospheric dump control valve (a throttle valve), and the atmospheric vent block valve (an isolation). The throttle valve and isolation valve are in parallel and are located downstream of the atmospheric vent valve.

- The valves are not necessarily the same type from unit to unit or SG to SG on a given unit. The valves are clearly visible with labels identifying the valves in a manner consistent with the valve designations referenced in the EOP.

- Each of the valves is chain operated and none are reverse acting. The valves do not possess position indicators.

- The ADV should be opened prior to opening the throttle valve or isolation valve but there is no consequence of opening the valves out of sequence.

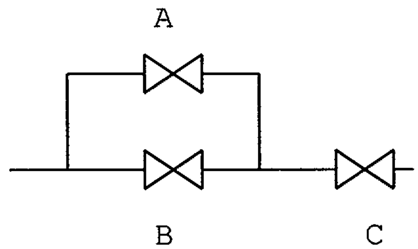
Information needed:

The submittal should address the ability to recover from credible errors or complications in performance of the task. For example, it would appear that the error of opening the throttle valve or the isolation valve before opening the block valve would delay/prevent pressure equalization across the block valve and could delay depressurizing the SGs. A potential complication would be operator difficulty in obtaining sufficient break-away force to unseat one of the chain operated valves.

Response to Information needed:

This activity is controlled by an approved written procedure that is pre-staged at the ADVs. The procedure provides a simple, straight-forward sequence for opening the ADVs. The procedure was validated and verified by the EOP project. Procedure enhancements have been made as a part of the EOP effort to ensure optimum performance. The EOP project also improved component labeling, so the ADVs are labeled and easily identified. Mechanical tools are provided to assist the NLOs in opening the valves, if necessary. All three valves are located together outside the Unit control rooms. Two NLOs are dispatched to the ADVs. Two NLOs will provide an independent means of ensuring that the correct valves are opened in the correct sequence. The task of opening ADVs is required to be walked through every two years using a JPM. Credible operator error is lessened by the usage of two NLOs, component identification upgrades, component location, training, and the procedure sequence.

ATMOSPHERIC DUMP VALVE OPERATION



Procedure Sequence

- Open Valve "A"
- Open Valve "B"
- When Directed, Open Valve "C"

4. Risk Analysis information needed:

   a. Risk insights indicate that, during the proposed Limiting Conditions for Operation (LCOs), the risk associated with common cause failure(s) of the HPI system pumps and valves is an important consideration. If common cause failure(s) of HPI pump(s) and valves(s) exist during the proposed LCOs, the risk would be substantial. Discuss measures taken to decrease the risk due to potential common cause failure(s) if the proposed LCOs are entered for corrective maintenance reasons.

Response to a.

In a conference call on 10/28/99, this issue was discussed in relationship to entering condition B of the proposed technical specification. Condition A allows 72 hours to restore an inoperable HPI pump and/or discharge crossover valve to an operable status. If the Allowed Outage Time (AOT) cannot be met, then Condition B of the proposed TS can be entered. Condition B requires reducing thermal power to ≤ 75% Rated Thermal Power, verification that the ADV flow path for each steam generator is operable, and returning the inoperable HPI pump and/or discharge crossover valve to an operable status within 30 days.

The process of ensuring operability is continuous and consists of the verification of operability by surveillances and operability evaluations when required. Verification of operability is supplemented by continuous and ongoing processes such as: daily plant operation, plant walkdowns, control room observations, etc. Operation's uses training, TS, observations, etc. to routinely question and determine operability.

Necessary entry into Condition B is indicative of a failure that is difficult to determine. Entry into Condition B would not be done routinely. Duke uses the corrective action program to reduce the risk of common cause failures. The Corrective Action Program is controlled by Nuclear System Directive (NSD) 210. The primary program used at Duke to identify, track, trend and resolve problems is the Problem Investigation Process (PIP). The PIP process establishes the threshold for entry into the program, screening criteria for determining the significance of the problem and establishes requirements for assessing the cause, development of corrective actions, and determination of generic applicability within the site boundary. The significance screening determines the degree of cause analysis needed and establishes the time limit for completion of corrective actions. PIP is not designed to identify and resolve failures of equipment due to normal expected wear and operation and should only be used for equipment failures when the equipment does not perform as expected or when a failure trend exists. PIP would then be initiated to document a detailed root cause analysis as to the cause of failures and establish corrective actions to prevent recurrence. Nuclear System Directive (NSD) 208 controls the PIP process.

The Root Cause Analysis Program exists for the purpose of determining why significant events occur and what actions are necessary to prevent recurrence. The Failure Investigation Process (FIP) is a tool that provides a systematic method for performing equipment root cause analysis. When the FIP is invoked, a FIP team is assigned to investigate. A FIP team has a management sponsor and a team leader. Other team members are assigned depending on the type of event and expertise needed. A root cause expert is included on the team to ensure the root cause process is methodically followed. The FIP process provides a timely, methodical and systematic way of collecting data to determine the root cause. This process ensures that operability and generic applicability/transportability are addressed. Timeliness is commensurate with safety significance. This process is controlled by NSD 212, Cause Analysis.

The processes described above are inclusive of the corrective action program. They all serve as tools to reduce the risk of common cause failures.

If a failure of an HPI pump or HPI discharge crossover valve occurs, the component is declared inoperable and condition A of the proposed TS is entered. A root cause investigation begins on the affected HPI component. The FIP process is invoked and the problem is documented in PIP. A timely, methodical and systematic data collection begins to determine root cause. Once the root cause for the affected component is determined, the FIP process ensures that the operability and generic applicability/transportability is addressed. Corrective actions will be initiated to address, correct and prevent recurrence of the failure. Timeliness of this process is commensurate with safety significance.

THE NRC AEOD/INEEL Common Cause Database contains 105 events that had common cause implications for HPI systems. Duke reviewed these events and concluded the following:

- 20% involved degradation but no failures
- 20% involved causes that had obvious implications for other trains
- 50% involved causes that would be easily detected through an operability evaluation
- 10% had causes that were difficult to determine

Verifying that the remaining equipment is not subject to failure due to common cause effects is a primary focus following failure of a component in the HPI system. In nearly all cases, the potential for common cause effects would be eliminated during the period allowed by the current completion time. If we assume that the reviews are effective, then the reliability of the remaining equipment can be assumed to take on the random failure probabilities following completion of the evaluation. If 3 days is assumed as the time required to complete a thorough common cause evaluation, then the Incremental Conditional Core Damage Probability (ICCDP) for condition B could be estimated as 1.3E-8/day * 27 days + 7.8E-8/day * 3 days = 5.9E-7. The daily probabilities have been estimated from the information previously submitted in August, 1999. Duke believes this represents a more realistic assessment of the Core Damage Probability (CDP) for the condition than does assuming a common cause failure probability on the remaining components for the duration of the AOT. The ICCDP of Condition C is less affected by this consideration due to the short duration of the AOT.

b. Would the Turbine Bypass System (TBS) function be protected during the proposed LCOs? Would a check on the TBS operability be made if the proposed LCOs were to be entered? Please discuss.

Response to b.

Currently, monitoring the reliability and availability of the TBS is similar to other important balance of plant systems. It is not considered to be a risk significant system. Duke considers the TBS to be available at all times. As stated in a previous response for this submittal dated August 5, 1999, the TBS is the preferred heat sink. As discussed in that response, ten years of historical data was reviewed to make a determination of the TBS availability. It was determined that the TBS would be available to mitigate an event.

As previously discussed in Attachment 7 of the submittal dated December 16, 1998, ORAM-SENTINEL is the software tool used to help facilitate risk informed decision making associated with work at Oconee. This process is independent of the requirements of TS and SLC and is based on traditional deterministic approaches and PRA studies. WPM 608, Outage Risk Assessment Utilizing ORAM-SENTINEL and WPM 609, Innage Risk Assessment Utilizing ORAM-SENTINEL provide control for the process.

Duke will add the TBS to ORAM-SENTINEL. When HPI train/corrective maintenance is required, ORAM-SENTINEL will assess the risk of the work based on the availability of the TBS. The ORAM-SENTINEL color scheme will flag the work evolution as red if the TBS is unavailable. The color red indicates that a key safety function is immediately and directly threatened. Operation in a valid red configuration is not normally allowed and will not be intentionally scheduled. The normal options for resolving a red configuration are to coordinate the work to eliminate schedule conflicts (i.e. wait for conflicting equipment to be returned to service prior to allowing work to begin on the component in question) or have the work rescheduled to eliminate the conflict. If it is desired to perform work which produces a valid RED condition indicated by ORAM-SENTINEL, then a Plant Operational Review Committee (PORC) meeting must be convened. The PORC may consider and/or request that special PRA analysis be performed and compensatory measures be taken, etc. to aid in the decision making process. Any PORC decisions made concerning an ORAM-SENTINEL high RISK scenario will be documented in the PORC meeting minutes and communicated to Work Control and referenced in the proposed and/or committed schedule.

The above actions will ensure that TBS operability and functionality are protected during HPI condition entries or that contingencies are provided via PORC review.

The process described is controlled by WPM 609, Innage Risk Assessment Utilizing ORAM-SENTINEL. The colors produced by ORAM-SENTINEL and their set points and definitions are provided as follows:

Color	Set Points	Definition
Green	Base - < 2 X Base CDF	The **KEY SAFETY FUNCTION** is at minimum **RISK**. The plant is fully capable of performing the associated safety function. GREEN is the baseline for the **SAFETY FUNCTION ASSESSMENT** Trees and **PLANT TRANSIENT ASSESSMENT** Trees.
Yellow	$\geq$ 2 X Base - < 2.5E-4	The **KEY SAFETY FUNCTION** is in a reduced condition. The plant's ability to perform the associated safety function is reduced but still acceptable.
Orange	$\geq$ 2.5E-4 - < 1E-3	The **KEY SAFETY FUNCTION** is in a degraded condition, and steps should be taken to minimize the amount of time in this condition. When entering a <u>planned</u> activity which ORAM-SENTINEL has assessed as an ORANGE condition, there should be in place a written contingency plan developed by the Work

		Control organization. The Work Control organization will ensure that this written contingency plan is developed. When entering an orange condition from emergent work , the Shift Work Manager will ensure development of a work plan to restore the system, structure, or component (SSC). This may require involvement from Maintenance Tech Support and/or Engineering. The Operations Shift Manager will evaluate the restoration plan and have final authority whether the plan is implemented. Additionally, at their discretion, the OSM's may require development of a written contingency plan for actions to be taken in the event of further degradations. The plan will be developed in parallel with equipment restoration efforts. This plan may resemble the current Defense-In-Depth Sheet philosophy and reference an Abnormal or Emergency Procedure for the loss of that associated function.
Red	$\geq$ 1E-3	The **KEY SAFETY FUNCTION** is immediately and directly threatened. Operation in a valid red configuration is not normally allowed and will not be intentionally scheduled. If the plant is unexpectedly placed into a RED configuration, IMMEDIATE remedial action is required. RED is the highest **RISK** level for the **SAFETY FUNCTION ASSESSMENT** Trees and **PLANT TRANSIENT ASSESSMENT** Trees.
White		The data represents a situation that exceeds the capabilities of the O-S software (i.e. - missing data, not a logical configuration or N/A to operating mode). This condition requires review by the Site O-S Expert.

It will not be necessary to track the availability of the TBS when the HPI LCO's are met. The TBS is a highly reliable, non-risk significant system.

Adding the TBS to ORAM-SENTINEL pends approval of this LAR.

c. Provide assurance that there is procedural guidance for using Probabilistic Risk Assessment (PRA) techniques, as appropriate, to assess combinations of multiple equipment out of service simultaneously, and not only for pairs of systems/components as done in the Risk Assessment Matrix. Discuss the current practice of assessing combinations of multiple equipment out of service simultaneously using PRA techniques as appropriate.

Response to c.

Work Process Manual sections WPM-607, Maintenance Rule Assessment of Equipment Removed From Service, WPM-608, Innage Risk Assessment Utilizing ORAM-SENTINEL and WPM-609, Outage Risk Assessment Utilizing ORAM-SENTINEL provide the framework for implementation of the configuration risk management program. These procedures require analyses be performed during scheduling and execution of maintenance that takes equipment out of service. The computer program ORAM-SENTINEL is applied in conjunction with the WPM-607 matrix to assess the risk implications of equipment out of service. Multiple component unavailabilities are assessed by ORAM-SENTINEL. Component unavailability combinations are pre-solved by the PRA group using the complete Oconee PRA model and stored in the ORAM-SENTINEL database. The results are then retrieved when the combinations are input into the software. Unrecognized combinations are flagged and the PRA group is contacted for input into the risk assessment for the combination of interest.

d. Indicate how each of the Configuration Risk Management Program (CRMP) provisions (a) through (e) in RG 1.177 are met (e.g., applicable procedural guidance for each provision).

Response to d.

WPM-607, WPM-608, and WPM-609 provide the framework for implementation of the configuration risk management program. For innage related maintenance activities, WPM-609 identifies the responsible individuals for providing risk assessments for both scheduled and emerging activities. These work process manuals establish the processes that satisfy provisions (b) through (d) of the regulatory guide.

WPM 607 is used in parallel with WPM 609 to assess the risk associated with work activities during innage conditions. Quantitative assessment of many possible combinations have been developed as part of the ORAM-SENTINEL implementation. Should the combination not exist in the ORAM-SENTINEL database, the PRA group can be contacted to provide an assessment of the significance. The assessments performed with ORAM-SENTINEL consider both internal and external initiating events. These events are included in the Oconee PRA on which the ORAM-SENTINEL model is based. ORAM-SENTINEL also includes a qualitative assessment in addition to the quantitative provided from the PRA results. The guidance in the qualitative assessment module of ORAM-SENTINEL was developed similarly to the PRA Matrix in that the PRA insights were used to develop the end state colors for each safety function/event.

Level 2 concerns are address by both the ORAM-SENTINEL model and the PRA Matrix. The Matrix contains systems that are important to level 1 and level 2. In identifying the important combinations, both level 1 and level 2 concerns were considered. The qualitative assessment of ORAM-SENTINEL as well as the PRA Matrix considers those systems important to containment pressure control and containment isolation.

These capabilities satisfy provisions (a) and (e).

e. Although the limiting location SBLOCA initiator is not modeled in the Oconee PRA, this initiating event needs to be considered in CRMP assessments. Provide assurance that this initiator will be included in CRMP assessments as appropriate.

Response to e.

The risk significance of the limiting small break LOCA has been estimated to not be very different from the non-specific small LOCA explicitly modeled in the Oconee PRA. Those systems important for mitigating a small LOCA (HPI, LPI, LPSW) are no different for the two situations. WPM-607, WPM-608, and WPM-609 provide the framework for implementation of the CRMP. The assessments provided by the current CRMP are judged to provide an appropriate level of assessment for the special case.

f. Discuss your assessment of the Incremental Large Early Release Probability for the SG tube rupture and the limiting location SBLOCA sequences if the proposed LCOs are entered for corrective maintenance reasons.

Response to f.

The SGTR and small LOCA initiators are not expected to contribute to an increase in large early release frequency (LERF) as a result of entry into the proposed LCO. These initiators do not contribute to LERF, as described in the following.

In the context of the discussions of RG 1.174 (see footnote 5 of the RG), LERF is being used as a surrogate for the early fatality QHO. It is defined as the frequency of those accidents leading to significant unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects. The Oconee PRA includes an offsite consequence evaluation, Level 3 of the PRA, and the following insights have been drawn from the analysis performed for revision 2 of the Oconee PRA.

The SGTR accident is a containment bypass sequence. The SGTR CDF for Oconee is dominated by tube rupture sequences with secondary side heat removal available and the release occurring through cycling of the steam line relief valves. The time period between the expected declaration of a general emergency (evacuation begins) and the occurrence of a significant release is long enough, greater than 5 hours, that the evacuation is expected to be complete. In addition, the release fractions of Cesium and Iodine are relatively low, approximately 1% of the core inventory. Early health effects are not expected to be significant for these release fractions. As a result, the occurrence of early health effects is quite low. This can be seen in the Oconee PRA report in Table 6.3-1. The CDF associated with SGTR sequences is 4.1E-07/year. This resulted in frequencies of 0 fatalities per year (conditional probability of an early fatality for an SGTR is near 0) and 2.6E-09 early injuries per year (conditional probability of 6.3E-03). These consequences are judged not to be consistent with the concept of a large early release.

Small LOCA initiated accidents do not contribute to the LERF in any meaningful way. Oconee has a large dry containment, which is robust relative to the containment challenges. With the Reactor Building Cooling Units (RBCUs) in service the containment pressure is low and containment challenges such as hydrogen combustion and high pressure melt ejection are very unlikely to result in containment failure.

When the RBCUs are not in service, the containment pressure increases but the conditional probability of containment failure remains low. For these reasons, the conditional probability of early containment failure is small. This is evident from the low frequency (< 0.4% of CDF) of early containment failures as reported in Table 6.2-1 of the PRA revision 2 summary report. The performance of the RBCUs is independent of the small LOCA initiator; the probability of containment failure for small LOCAs is less than the overall average reported in Table 6.2-1.

g. The HPI system is ranked for the Maintenance Rule Program as "high safety significance" and "low risk" because the Oconee PRA indicated a Risk Achievement Worth (RAW) of less than two. Discuss why the HPI system RAW is less than two. How does consideration of the limiting location SBLOCA initiator affect the HPI system RAW, and thus its Maintenance Rule Program relative risk ranking?

Response to g.

As a point of clarification, the Oconee Maintenance Rule Program uses train level RAW to determine risk categories for availability and reliability performance criteria. It is the HPI train RAW which is less than two, not the HPI system level RAW. Therefore, this response will explain why the train level RAW is not affected as a result of including the limiting location SBLOCA.

The HPI system performs two primary functions with regard to core damage prevention. First, the system provides a means to maintain RCS inventory for a broad range of accidents. Second, the system provides reactor coolant pump seal injection as one of the means to maintain RCS integrity following some transient initiating events. The overall importance of a train of the HPI system is low because the design includes three pumps and the capability to bypass failures of HP-26 and HP-27 by using valves HP-409 and HP-410. The importance of an HPI train is further reduced by the fact that HPI is not the sole means to perform these functions for most accidents.

The injection function of HPI can often be accomplished alternatively by a depressurization of the RCS using secondary side heat removal so that LPI can be used to accomplish the RCS inventory control function.

The SSF provides an alternative to the seal injection function of HPI.

Finally, the CDF for Oconee contains a significant contribution from external events, in particular the tornado initiator. The core damage sequences associated with most of the external initiators are characterized by the failure of significant support systems, usually AC power. With AC power not available, the HPI system becomes irrelevant. The significance of these external event initiators tends to reduce the overall importance of independent failure of HPI.

Including the HPI line (or RCP discharge) break as a unique initiator in the Oconee PRA would not be expected to result in a significant change in the RAW. Multiple pump failures are still required in order to fail the system function. This is because as long as at least two pumps are operating, injection can be established into both headers using valves HP-409 and HP-410. Any increase in CDF that may result by including the special case should be small and little impact on the RAW calculation would be expected. This has been confirmed, approximately, by modifying the existing Oconee PRA model to include another LOCA initiator that fails one of the injection headers. The increase in CDF obtained when HPI train B is made unavailable (Pump C through HP-27) is approximately 10%, a RAW of 1.1.

The conservative treatment of this condition (e.g., condition C) in the HPI submittal ignored the availability of the third HPI pump and the HP-409 and HP-410 flow paths thus overestimating the increase in CDF associated with this condition. The submittal analysis can also be used to estimate the increase in CDF for the condition of a train out of service. The following is extracted from the submittal:

For the limiting break location, core damage occurs if the break occurs on the header of the available pump *and the operators fail to depressurize to increase flow, or if the available HPI train fails and the operators fail to depressurize to LPI entry conditions. The resulting change in CDF is estimated by the following formula.*

δCDF = (Limiting small LOCA IE frequency) x [(probability that failed HPI train is on the intact header) x (failure to depressurize) + (HPI failure probability) x (failure to depressurize to LPI)] x (fractional increase in AOT)

δCDF = 5E-4 x [(0.5 x 1E-1) + (3.0E-2 x 0.1)] x 5.5E-3 = 1.5E-07

The annual change in CDF is estimated as
δCDF = 5E-4 x [(0.5 x 1E-1) + (3.0E-2 x 0.1)] = 2.7E-05

This is 55% of the base non-seismic CDF which is used in the maintenance rule evaluation. A RAW of 1.55 would be estimated for a train of HPI from the conservative evaluation included in the HPI submittal.

In the base case PRA model, placing a train of HPI in maintenance results in a trivial increase, less than 1%, in the CDF. For the case of the limiting small break, the approximate treatment added to the Oconee PRA model is expected to represent a somewhat conservative treatment for this case. However, even with this conservative treatment, HPI would still be considered a "high safety significance" and "low risk" because the train level RAW would be less than two.

ATTACHMENT 2
Revisions due to removal of ADV spec 3.7.4

Submittal dated December 16, 1998

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Attachment 1

Instructions for Updating the Technical Specifications

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3.7 PLANT SYSTEMS

3.7.4 Atmospheric Dump Valve (ADV) Flow Paths

LCO 3.7.4 The ADV flow path for each steam generator shall be OPERABLE.

APPLICABILITY: When required by Required Actions B.2 and C.2 of LCO 3.5.2, "High Pressure Injection (HPI)"

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both required ADV flow path(s) inoperable.	A.1 Be in MODE 3. AND A.2 Reduce RCS temperature to $\leq 350°F$.	12 hours 60 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.7.4.1 Cycle the valves which comprise the ADV flow paths.	18 months

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B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Dump Valve (ADV) Flow Paths

BASES

BACKGROUND

The ADV flow path for each steam generator is credited as a compensatory measure in Actions B and C of LCO 3.5.2, "High Pressure Injection (HPI)," to permit operation to continue with THERMAL POWER ≤ 75% RTP: a) for 30 days with an HPI pump or HPI discharge crossover valve(s) inoperable; and b) for 72 hours with an HPI train inoperable.

During these periods of time, the ADV flow path for one steam generator is credited to depressurize the steam generator and enhance primary-to-secondary heat transfer during certain small break loss of coolant accidents (LOCAs). This is done in conjunction with the secondary cooling water from the Emergency Feedwater (EFW) System. The preferred heat sink via the Turbine Bypass System to the condenser may not be available following a small break LOCA.

For each steam generator, the ADV flow path is comprised of the atmospheric dump block valve bypass (1" bypass), the atmospheric vent valve (a 12" block valve), the atmospheric dump control valve (i.e., throttle valve), and the atmospheric vent block valve (i.e., isolation valve). The throttle valve and the isolation valve are in parallel and are located downstream of the atmospheric vent valve.

The atmospheric vent valve should be opened prior to opening the throttle valve or isolation valve. This is accomplished by first opening the atmospheric dump block valve bypass. This equalizes the differential pressure across the atmospheric vent valve. Once the atmospheric vent valve is opened, the cool down rate is controlled using the throttle valve. If additional relief capacity is needed, the isolation valve can be opened. The capacity of the throttle or isolation valve exceeds decay heat loads and is sufficient to cool down the plant.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

If enhanced steam generator cooling is not credited in the small break LOCA analysis, two HPI trains are required to mitigate specific small break LOCAs. However, if equipment not qualified as QA-1 (i.e., an ADV flow path for a steam generator) is credited for enhanced steam generator cooling, the safety analyses have determined that the capacity of one HPI train is sufficient to mitigate a small break LOCA on the discharge of the reactor coolant pumps if THERMAL POWER is ≤ 75% RTP.

The analysis for Action C of LCO 3.5.2, "High Pressure Injection (HPI)," credits an ADV flow path for one steam generator as a compensatory measure in the event an HPI train is inoperable and THERMAL POWER is ≤ 75% RTP. During this situation, the ADV flow path for one steam generator is credited during certain small break LOCAs to depressurize the steam generator and enhance primary-to-secondary heat transfer. This is done in conjunction with the EFW System providing cooling water to the steam generator. The ADV flow path is comprised of manual valves. Operator action is credited within 25 minutes of an Engineered Safeguards Protective System (ESPS) signal to open them.

Additionally, the ADV flow path for each steam generator is credited as a compensatory measure in the analysis for Action B of LCO 3.5.2, "High Pressure Injection (HPI)," to permit an HPI pump or HPI discharge crossover valve(s) to be inoperable for 30 days with the THERMAL POWER ≤ 75% RTP. Typically, single failures are not considered once the plant has entered a condition defined in the Technical Specifications. However, the Completion Time permitted by Required Actions B.3 and B.4 of LCO 3.5.2, "High Pressure Injection (HPI)," is an extended period of time (i.e., 30 days). In the event an accident occurred during this 30-day Completion Time and a single failure were to occur in the degraded HPI System, the ability of a plant to mitigate the consequences of specific small break LOCAs continues to be assured by the ADV flow path for one steam generator.

The ADV flow path satisfies Criterion 3 of 10 CFR 50.36 (Ref.1).

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BASES (continued)

LCO

The ADV flow path for each steam generator is required to be OPERABLE. Failure to meet the LCO can result in the inability to depressurize a steam generator following a small break LOCA. This function is required to support operation with a degraded HPI System when THERMAL POWER is ≤ 75% RTP.

An ADV flow path is considered OPERABLE when it is capable of providing a controlled relief of the main steam flow, and each valve which comprises the ADV flow path is capable of opening and closing.

APPLICABILITY

When required by Required Actions B.2 and C.2 of LCO 3.5.2, "High Pressure Injection (HPI)," the ADV flow path for each steam generator is required to be OPERABLE.

For all other conditions, an ADV flow path is not credited for mitigating a small break LOCA to satisfy the conditions of 10 CFR 50.46.

ACTIONS

A.1 and A.2

With one or both of the required ADV flow path(s) inoperable, the unit must be placed in a condition in which the LCO does not apply. The ADV flow path for each steam generator is required to support operation with a degraded HPI System. Thus, the unit must be placed in a condition outside the Applicability of LCO 3.5.2, "High Pressure Injection (HPI)." To achieve this status, the unit must be placed in at least MODE 3 within 12 hours, and RCS temperature reduced to ≤ 350°F within 60 hours. The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. They are consistent with the Completion Times provided in Required Actions G.1 and G.2 of LCO 3.5.2, "High Pressure Injection (HPI)."

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cool down of the RCS, the valves which comprise the ADV flow path for each steam generator must be able to perform the following functions:

a) the atmospheric dump block valve bypass and the atmospheric vent valve must be capable of being opened and closed; and

b) the atmospheric dump control valve and atmospheric vent block valve must be capable of being opened and throttled through their full range.

This SR ensures that the valves which comprise the ADV flow path for each steam generator are tested through a full control cycle at least once per 18 months. Performance of inservice testing or use of an ADV flow path during a unit cool down may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50.36.

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3.7 PLANT SYSTEMS

3.7.4 ~~Not used~~

INSERT ITS 3.7.4, "Atmospheric Dump Valve (ADV) Flow PATHS"

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B 3.7 PLANT SYSTEMS

B 3.7.4 Not used

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ITS 3.7.4, "Atmospheric Dump Valve (ADV) Flow Paths"

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ITS SR 3.5.2.7

Description of Proposed Changes

ITS Surveillance Requirement (SR) 3.5.2.7 requires each discharge valve to the LPI-HPI flow path to be manually cycled open every 18 months. Duke proposes to revise this SR to require the HPI discharge crossover valves to be cycled every 18 months. This proposed change is more restrictive.

Justification for Proposed Changes

Currently, the ITS does not contain an SR which demonstrates operability of the HPI discharge crossover valves. These valves are required to be manually aligned from the Control Room post-accident to provide coolant flow from the second HPI train within 10 minutes. Periodic stroke testing of the HPI discharge crossover valves (HP-409 and HP-410) ensures that the valves can be manually cycled from the Control Room. This test is performed on an 18-month Frequency. Operating experience has shown that this type of component usually pass the surveillance when performed at this Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

Discussion of Proposed Changes to the ITS Bases

The majority of the changes to the Bases were made to reflect the proposed changes to the Technical Specifications. These changes are not described in detail, because the justifications are identical to those provided for the proposed changes to the Technical Specifications. Proposed changes to the Bases that are not related to the proposed changes to the Technical Specifications are addressed individually. Additionally, no specific justification is provided for obvious minor editorial corrections.

Background Section of Bases for ITS 3.5.2

Description of Proposed Changes

a) Currently, the Bases state: "The two HPI trains are designed and aligned such that they are not both susceptible to any single active failure including the failure on any power operating component to operator or any single failure of electrical equipment."

Duke proposes to add a statement to clarify that the HPI System is not required to withstand passive failures.

b) Currently, the Bases state: "There are three ESPS actuated HPI pumps, each of which can provide flow to either train. At least one pump is normally running providing RCS makeup and seal injection to the reactor coolant pumps. Suction header cross-connect valves are normally open, and discharge header cross-connect valves are normally closed. Additional discharge valves (HPI discharge crossover valves) can be used to bypass the normal discharge valves and assure the ability to feed either trains' injection lines from the pump(s) on the other train. A safety grade flow indicator is provided for the flow path associated with

HPI train is aligned via manual operator actions from the Control Room within 10 minutes) and it provides the basis for operation with the HPI suction headers cross-connected.

The reference to this submittal is appropriate, because it provides part of the basis for operation of the unit for a limited period of time with Thermal Power ≤ 75% RTP and an HPI pump, HPI discharge crossover valve(s), or HPI train inoperable.

3) The resultant proposed changes to the ITS Bases.

Reason for Requested Change

Duke is submitting this LAR to resolve deficiencies associated with Current Technical Specification (CTS) 3.3.1. CTS 3.3.1 provides requirements regarding the HPI System. These requirements were converted into the Improved Technical Specifications (ITS) as ITS 3.5.2.

The principal deficiency being resolved was reported in Licensee Event Report (LER) 269/90-15. In the LER, Duke reported that the SBLOCA analysis was non-conservative in that one HPI train was inadequate to mitigate a break of an HPI injection line when reactor power was < 60% full power. As a result, Duke imposed additional requirements upon the operation of Oconee Nuclear Station Units 1, 2, and 3 with reactor power < 60% full power. These additional requirements were equivalent to the requirements for operation with reactor power > 60% full power (i.e., a third HPI pump and HPI discharge crossover valves were required to be operable, and the HPI suction headers were required to be cross-connected).

The proposed changes will reduce unnecessary burdens associated with the additional self-imposed administrative requirements. They permit operation to continue with Thermal Power ≤ 75% RTP: a) for 30 days with an HPI pump or one or more HPI discharge crossover valve(s) inoperable; and b) for 72 hours with an HPI train inoperable. This additional time could prevent an unnecessary plant transient (i.e., an unplanned shutdown) and its associated challenges. The 30-day Completion Time for Required Actions B.3 and B.4 of ITS 3.5.2 provides time for rebuilding a spare pump or obtaining a replacement part (e.g., a replacement motor) from an outside source.

The data collected would suggest a random failure probability for the TBVs that is < 1E-02 per demand per valve. Thus, there is a high probability that TBVs would be available for controlling steam pressure following a reactor trip. This should be especially true for LOCAs, where a coincident independent failure of the ICS or other TBV support systems is unlikely.

The TBV System may be available following a LOOP event. The Condenser Circulating Water (CCW) Systems at Oconee are operated with the supply headers cross-connected. In the event of a LOOP on a unit, the CCW pumps of the other units will continue to supply forced flow through the condenser of the affected unit. This was the plant response to the Unit 2 LOOP event in October of 1992, when the TBVs remained available and were used to control steam generator pressure. Should CCW flow from the other units not be available (e.g., units shutdown), the siphon flow through the condenser is expected to maintain condenser vacuum. As long as the condenser vacuum is maintained and instrument air is available, the TBVs will be used for control of the main steam pressure.

Based on the above, the probability is high that the TBVs would be available to mitigate an event.

2. Can the Turbine Bypass Valves provide the required cooling?

Yes, the TBVs can provide the required cooling. The TBVs are the preferred heat sink. The design flow rate of each TBV is 704,000 pounds per hour (pph), while the design flow rate for each ADV is 225,000 pph.

3. If ADV steaming is not accomplished within the assumed 25 minutes, would core damage occur?

With an ADV flow path steaming at 25 minutes, the 10 CFR 50.46 acceptance criteria are met, but the peak cladding temperatures are high enough that the fuel assemblies will be damaged given the conservative analysis assumptions required by Appendix K. With these Appendix K assumptions, very little time beyond 25 minutes is available without

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