UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 6, 2000

Mr. William R. McCollum, Jr.
Vice President, Oconee Site
Duke Energy Corporation
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION, UNITS 1, 2 AND 3 RE: ISSUANCE OF AMENDMENTS (TAC NOS. MA4451, MA4452, AND MA4453)

Dear Mr. McCollum:

The Nuclear Regulatory Commission has issued the enclosed Amendment Nos. 314 , 314 , and 314 to Facility Operating Licenses DPR-38, DPR-47, and DPR-55, respectively, for the Oconee Nuclear Station, Units 1, 2, and 3. The amendments consist of changes to the Technical Specifications in response to your application dated December 16, 1998; supplemented January 25, August 5, and October 4, 1999; and March 29 and June 8, 2000.

The amendments revise the Technical Specifications associated with the High Pressure Injection (HPI) System. As pointed out in our safety evaluation, when a high pressure injection system component is inoperable, a prompt, adequate common cause failure evaluation is important and caution is necessary during pump work to ensure that the work does not adversely impact any other HPI pump.

A copy of the related Safety Evaluation is also enclosed. A Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice. We request that you inform the staff in writing upon implementation of the amendments.

Sincerely,

David E. LaBarge, Senior Project Manager, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-269, 50-270, and 50-287

Enclosures:
1. Amendment No. 314 to DPR-38
2. Amendment No. 314 to DPR-47
3. Amendment No. 314 to DPR-55
4. Safety Evaluation

cc w/encls: See next page

September 6, 2000

Mr. William R. McCollum, Jr.
Vice President, Oconee Site
Duke Energy Corporation
P. O. Box 1439
Seneca, SC 29679

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/RA/

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4. Safety Evaluation

cc w/encls: See next page

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NAME	DLaBarge:cn	CHawes	WBeckner	RWeisman	REmch
DATE	8/9/2000	8/24/2000	7/12/2000	Aug. /15/2000	9/6/2000

*See previous concurrence OFFICIAL RECORD COPY

* with comments, received SPSB agrees with revisions.

comments/revisions: agreement with SPSB.
DEL

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

DUKE ENERGY CORPORATION

DOCKET NO. 50-269

OCONEE NUCLEAR STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 314
License No. DPR-38

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Oconee Nuclear Station, Unit 1 (the facility) Facility Operating License No. DPR-38 filed by the Duke Energy Corporation (the licensee) dated December 16, 1998; supplemented January 25, August 5, and October 4, 1999; and March 29 and June 8, 2000, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 3.B of Facility Operating License No. DPR-38 is hereby amended to read as follows:

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 314 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 75 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Richard L. Emch, Jr.

Richard L. Emch, Jr., Chief, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification
Changes

Date of Issuance: September 6, 2000

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

DUKE ENERGY CORPORATION

DOCKET NO. 50-270

OCONEE NUCLEAR STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 314
License No. DPR-47

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Oconee Nuclear Station, Unit 2 (the facility) Facility Operating License No. DPR-47 filed by the Duke Energy Corporation (the licensee) dated December 16, 1998; supplemented January 25, August 5, and October 4, 1999; and March 29 and June 8, 2000, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 3.B of Facility Operating License No. DPR-47 is hereby amended to read as follows:

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 314 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 75 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Richard L. Emch, Jr.

Richard L. Emch, Jr., Chief, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification
Changes

Date of Issuance: September 6, 2000

DUKE ENERGY CORPORATION

DOCKET NO. 50-287

OCONEE NUCLEAR STATION, UNIT 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 314
License No. DPR-55

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Oconee Nuclear Station, Unit 3 (the facility) Facility Operating License No. DPR-55 filed by the Duke Energy Corporation (the licensee) dated December 16, 1998; supplemented January 25, August 5, and October 4, 1999; and March 29 and June 8, 2000, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 3.B of Facility Operating License No. DPR-55 is hereby amended to read as follows:

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 314 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 75 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Richard L. Emch, Jr.

Richard L. Emch, Jr., Chief, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification
Changes

Date of Issuance: September 6, 2000

ATTACHMENT TO LICENSE AMENDMENT NO. 314

FACILITY OPERATING LICENSE NO. DPR-38

DOCKET NO. 50-269

AND

TO LICENSE AMENDMENT NO. 314

FACILITY OPERATING LICENSE NO. DPR-47

DOCKET NO. 50-270

AND

TO LICENSE AMENDMENT NO. 314

FACILITY OPERATING LICENSE NO. DPR-55

DOCKET NO. 50-287

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert	Remove	Insert
TS LOEP1	TS LOEP1	BASES LOEP1	BASES LOEP1
TS LOEP5	TS LOEP5	BASES LOEP9	BASES LOEP9
3.5.2-1	3.5.2-1	BASES LEOP10	BASES LEOP10
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OCONEE NUCLEAR STATION
TECHNICAL SPECIFICATIONS
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1.4-4	300/300/300	12/16/98
2.0-1	313/313/313	6/21/00

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 High Pressure Injection (HPI)

LCO 3.5.2 The HPI System shall be OPERABLE with:

a. Two HPI trains OPERABLE;

b. An additional HPI pump OPERABLE;

c. Two LPI-HPI flow paths OPERABLE;

d. Two HPI discharge crossover valves OPERABLE;

e. HPI suction headers cross-connected; and

f. HPI discharge headers separated.

APPLICABILITY: MODES 1 and 2,
MODE 3 with Reactor Coolant System (RCS) temperature > 350°F.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One HPI pump inoperable. <u>OR</u> One or more HPI discharge crossover valve(s) inoperable.	A.1 Restore HPI pump to OPERABLE status. <u>AND</u> A.2 Restore HPI discharge crossover valve(s) to OPERABLE status.	72 hours 72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1	Reduce THERMAL POWER to $\leq$ 75% RTP.	12 hours
	AND		
	B.2	Verify by administrative means that the ADV flow path for each steam generator is OPERABLE.	12 hours
	AND		
	B.3	Restore HPI pump to OPERABLE status.	30 days from initial entry into Condition A
	AND		
	B.4	Restore HPI discharge crossover valve(s) to OPERABLE status.	30 days from initial entry into Condition A

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One HPI train inoperable.	C.1	---------NOTE--------- Only required when inoperable HPI train is incapable of automatic actuation and incapable of actuation through remote manual alignment. ---------------------- Reduce THERMAL POWER to $\leq$ 75% RTP.	3 hours
	<u>AND</u>		
	C.2	---------NOTE--------- Only required when THERMAL POWER $\leq$ 75% RTP. ---------------------- Verify by administrative means that the ADV flow path for each steam generator is OPERABLE.	3 hours
	<u>AND</u>		
	C.3	Restore HPI train to OPERABLE status.	72 hours
D. HPI suction headers not cross-connected.	D.1	Cross-connect HPI suction headers.	72 hours
E. HPI discharge headers cross-connected.	E.1	Hydraulically separate HPI discharge headers.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One LPI-HPI flow path inoperable.	F.1 Restore LPI-HPI flow path to OPERABLE status.	72 hours
G. Required Action and associated Completion Time of Condition B, C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Reduce RCS temperature to ≤ 350°F.	12 hours 60 hours
H. Two HPI trains inoperable. OR Two LPI-HPI flow paths inoperable.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify each HPI manual and non-automatic power operated valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.2.2	-------------------NOTE-------------------- Not applicable to operating HPI pump(s). --- Vent each HPI pump casing.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.3	Verify each HPI pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.4	Verify each HPI automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	18 months
SR 3.5.2.5	Verify each HPI pump starts automatically on an actual or simulated actuation signal.	18 months
SR 3.5.2.6	Verify, by visual inspection, each HPI train reactor building sump suction inlet is not restricted by debris and suction inlet trash racks and screens show no evidence of structural distress or abnormal corrosion.	18 months
SR 3.5.2.7	Cycle each HPI discharge crossover valve and LPI-HPI flow path discharge valve.	18 months

OCONEE NUCLEAR STATION
TECHNICAL SPECIFICATIONS - BASES
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LOEP15	BASES REVISION	01/31/00
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OCONEE NUCLEAR STATION
TECHNICAL SPECIFICATIONS - BASES
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B 3.4.12-9	307/307/307	10/01/99
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B 3.6.1-4	BASES REVISION	01/31/00
B 3.6.1-5	Delete	12/16/98
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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 High Pressure Injection (HPI)

BASES

BACKGROUND

The function of the ECCS is to provide core cooling to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA);

b. Rod ejection accident (REA);

c. Steam generator tube rupture (SGTR); and

d. Main steam line break (MSLB).

There are two phases of ECCS operation: injection and recirculation. In the injection phase, all injection is initially added to the Reactor Coolant System (RCS) via the cold legs or Core Flood Tank (CFT) lines to the reactor vessel. After the borated water storage tank (BWST) has been depleted, the recirculation phase is entered as the suction is transferred to the reactor building sump.

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

There are three ESPS actuated HPI pumps; the discharge flow paths for two of the pumps are normally aligned to automatically support HPI train "A" and the discharge flow path for the third pump is normally aligned to automatically support HPI train "B." The discharge flow paths can be manually aligned such that each of the HPI pumps can provide

(continued)

BASES

BACKGROUND (continued)

flow to either train. At least one pump is normally running to provide RCS makeup and seal injection to the reactor coolant pumps. Suction header cross-connect valves are normally open; cross-connecting the HPI suction headers during normal operation was approved by the NRC in Reference 6. The discharge crossover valves (HP-409 and HP-410) are normally closed; these valves can be used to bypass the normal discharge valves and assure the ability to feed either train's injection lines via HPI pump "B." For each discharge valve and discharge crossover valve, a safety grade flow indicator is provided to enable the operator to throttle flow during an accident to assure that runout limits are not exceeded.

A suction header supplies water from the BWST or the reactor building sump (via the LPI-HPI flow path) to the HPI pumps. HPI discharges into each of the four RCS cold legs between the reactor coolant pump and the reactor vessel. There is one flow limiting orifice in each of the four injection headers that connect to the RCS cold legs. If a pipe break were to occur in an HPI line between the last check valve and the RCS, the orifice in the broken line would limit the HPI flow lost through the break and maximize the flow supplied to the reactor vessel via the other line supplied by the HPI header.

The HPI pumps are capable of discharging to the RCS at an RCS pressure above the opening setpoint of the pressurizer safety valves. The HPI pumps cannot take suction directly from the sump. If the BWST is emptied and HPI is still needed, a cross-connect from the discharge side of the LPI pump to the suction of the HPI pumps would be opened. This is known as "piggy backing" HPI to LPI and enables continued HPI to the RCS.

The HPI System also functions to supply borated water to the reactor core following increased heat removal events, such as MSLBs.

The HPI and LPI (LCO 3.5.3, "Low Pressure Injection (LPI)") components, along with the passive CFTs and the BWST covered in LCO 3.5.1, "Core Flood Tanks (CFTs)," and LCO 3.5.4, "Borated Water Storage Tank (BWST)," provide the cooling water necessary to meet 10 CFR 50.46 (Ref. 1).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 1), will be met following a LOCA;

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The HPI System is credited in the small break LOCA analysis (Ref. 2). This analysis establishes the minimum required flow and discharge head requirements at the design point for the HPI pumps, as well as the minimum required response time for their actuation. The SGTR and MSLB analyses also credit the HPI pumps, but these events are bounded by the small break LOCA analyses with respect to the performance requirements for the HPI System. The HPI System is not credited for mitigation of a large break LOCA.

During a small break LOCA, the HPI System supplies makeup water to the reactor vessel via the RCS cold legs. The HPI System is actuated upon receipt of an ESPS signal. If offsite power is available, the safeguard loads start immediately. If offsite power is not available, the Engineered Safeguards (ES) buses are connected to the Keowee Hydro Units. The time delay associated with Keowee Hydro Unit startup, HPI valve opening, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

One HPI train provides sufficient flow to mitigate most small break LOCAs. However, for cold leg breaks located on the discharge of the reactor coolant pumps, some HPI injection will be lost out the break; for this case, two HPI trains are required. Thus, three HPI pumps must be OPERABLE to ensure adequate cooling in response to the design basis

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

RCP discharge small break LOCA. Additionally, in the event one HPI train fails to automatically actuate due to a single failure (e.g., failure of HPI pump "C" or HP-26), operator actions from the Control Room are required to cross-connect the HPI discharge headers within 10 minutes in order to provide HPI flow through a second HPI train (Ref. 6).

Hydraulic separation of the HPI discharge headers is required during normal operation to maintain defense-in-depth (i.e., independence of the HPI discharge headers). Additionally, hydraulic separation of the HPI discharge headers ensures that a complete loss of HPI would not occur in the event an accident were to occur with only two of the three HPI pumps OPERABLE coincident with the HPI discharge headers cross-connected. A single active failure of an HPI pump would leave only one HPI pump to mitigate the accident. The remaining HPI pump could experience runout conditions and could fail prior to operator action to throttle flow or start another pump.

Hydraulic separation on the suction side of the HPI pumps could cause a loss of redundancy. With any one of the normally open suction header cross-connect valves closed, a failure of an automatic suction valve to open during an accident could cause two pumps to lose suction. Thus, the suction header cross-connect valves must remain open.

The safety analyses show that the HPI pump(s) will deliver sufficient water for a small break LOCA and provide sufficient boron to maintain the core subcritical.

The HPI System satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3).

LCO

In MODES 1 and 2, and MODE 3 with RCS temperature > 350°F, the HPI System is required to be OPERABLE with:

a. Two HPI trains OPERABLE;

b. An additional HPI pump OPERABLE;

c. Two LPI-HPI flow paths OPERABLE;

d. Two HPI discharge crossover valves OPERABLE;

(continued)

BASES

LCO (continued)

e. HPI suction headers cross-connected; and

f. HPI discharge headers separated.

The LCO establishes the minimum conditions required to ensure that the HPI System delivers sufficient water to mitigate a small break LOCA. Additionally, individual components within the HPI trains may be called upon to mitigate the consequences of other transients and accidents.

Each HPI train includes the piping, instruments, pump, valves, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST and injecting into the RCS cold legs upon an ESPS signal. For an HPI train to be OPERABLE, the associated HPI pump must be capable of taking suction from the BWST through the suction header valve associated with that train upon an ESPS signal. For example:

1) if HPI pump "B" is being credited as part of HPI train "A," then it must be capable of taking suction through HP-24 upon an ESPS signal; or

2) if HPI pump "B" is being credited as part of HPI train "B," then it must be capable of taking suction through HP-25 upon an ESPS signal.

The safety grade flow indicator associated with the normal discharge valve is required to be OPERABLE to support the associated HPI train's OPERABILITY.

To support HPI pump OPERABILITY, the piping, valves and controls which ensure the HPI pump can take suction from the BWST upon an ESPS signal are required to be OPERABLE.

To support HPI discharge crossover valve OPERABILITY, the safety grade flow indicator associated with the HPI discharge crossover valve is required to be OPERABLE.

Each LPI-HPI flow path includes the piping, instruments, valves and controls to ensure the capability to manually transfer suction to the reactor building sump (LPI-HPI flow path). The OPERABILITY requirements regarding the LPI System are addressed in LCO 3.5.3, "Low Pressure Injection (LPI)."

(continued)

BASES

LCO (continued)

During an event requiring HPI actuation, a flow path is provided to ensure an abundant supply of water from the BWST to the RCS via the HPI pumps and their respective discharge flow paths to each of the four cold leg injection nozzles and the reactor vessel. In the recirculation phase, this flow path is manually transferred to take its supply from the reactor building sump and to supply borated water to the RCS via the LPI-HPI flow path (piggy-back mode).

The OPERABILITY of the HPI System must be maintained to ensure that no single active failure can disable both HPI trains. Additionally, while the HPI System was not designed to cope with passive failures, the HPI trains must be maintained independent to the extent possible during normal operation. The NRC approved exception to this principle is cross-connecting the HPI suction headers during normal operation (Ref. 6).

APPLICABILITY

In MODES 1 and 2, and MODE 3 with RCS temperature > 350°F, the HPI System OPERABILITY requirements for the small break LOCA are based on analysis performed at 100% RTP. The HPI pump performance is based on the small break LOCA, which establishes the pump performance curve. Mode 2 and MODE 3 with RCS temperature > 350°F requirements are bounded by the MODE 1 analysis.

In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, the probability of an event requiring HPI actuation is significantly lessened. In this operating condition, the low probability of an event requiring HPI actuation and the LCO 3.5.3 requirements for the LPI System provide reasonable assurance that the safety injection function is preserved.

In MODES 5 and 6, unit conditions are such that the probability of an event requiring HPI injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation—High Water Level," and LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation—Low Water Level."

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With one HPI pump inoperable, or one or more HPI discharge crossover valve(s) (i.e., HP-409 and HP-410) inoperable, the HPI pump and discharge crossover valve(s) must be restored to OPERABLE status within 72 hours. The HPI System continues to be capable of mitigating an accident, barring a single failure. The 72 hour Completion Time is based on NRC recommendations (Ref. 4) that are based on a risk evaluation and is a reasonable time for many repairs.

In the event HPI pump "C" becomes inoperable, Condition C must be entered as well as Condition A. Until actions are taken to align an HPI pump to HPI train "B," HPI train "B" is inoperable due to the inability to automatically provide injection in response to an ESPS signal. Additionally, in order to utilize another HPI pump to supply HPI train "B," HP-116 must be opened. This action results in cross-connecting the HPI discharge headers; thus, Condition E must be entered. The HPI discharge headers cannot be separated in this situation, because it would require HPI pumps "A" and "B" to operate with flows less than the minimum requirements.

This Condition permits multiple components of the HPI System to be inoperable concurrently. When this occurs, other Conditions may also apply. For example, if HPI pump "C" and HP-409 are inoperable coincidentally, HPI train "B" is incapable of being automatically actuated or manually aligned from the Control Room. Thus, Required Action C.1 would apply.

B.1, B.2, B.3, and B.4

If the Required Action and associated Completion Time of Condition A is not met, THERMAL POWER of the unit must be reduced to ≤ 75% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reach the required unit condition from full power conditions in an orderly manner and without challenging unit systems. This time is less restrictive than the Completion Time for Required Action C.1, because the HPI System remains capable of performing its function, barring a single failure.

(continued)

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

Two HPI trains are required to mitigate specific small break LOCAs, if no credit for enhanced steam generator cooling is assumed in the accident analysis. However, if equipment not qualified as QA-1 (i.e., an atmospheric dump valve (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 reactor power is $\leq$ 75% RTP.

Required Actions B.2, B.3, and B.4 modify the HPI pump and discharge crossover valve OPERABILITY requirements to permit reduced requirements at power levels $\leq$ 75% RTP for an extended period of time. Required Action B.2 provides a compensatory measure to verify by administrative means that the ADV flow path for each steam generator is OPERABLE within 12 hours. This compensatory measure provides additional assurance regarding the ability of the plant to mitigate an accident. Compliance with this requirement can be established by ensuring that the ADV flow path for each steam generator is OPERABLE in accordance with LCO 3.7.4, "Atmospheric Dump Valve (ADV) Flow Paths."

Required Actions B.3 and B.4 require that the HPI pump and discharge crossover valve(s) be restored to OPERABLE status within 30 days from initial entry into Condition A. The 30-day time period limits the time that the plant can operate while relying on non QA-1 ADVs to provide enhanced steam generator cooling to mitigate small break LOCAs. The 30-day time period is acceptable, because:

1. Without crediting an ADV flow path, the HPI System remains capable of performing the safety function, barring a single failure;

2. If credit is taken for an ADV flow path for a steam generator, the safety analysis has demonstrated that only one HPI train is required to mitigate the consequences of a small break LOCA when THERMAL POWER is $\leq$ 75% RTP. Thus, for this case, the HPI System would be capable of performing its safety function even with an additional single failure;

(continued)

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

3. OPERABILITY of the ADV flow path for each steam generator is required to be confirmed by Required Action B.2 within 12 hours. Additional defense-in-depth is provided, because the ADV flow path for only one steam generator is required to mitigate the small break LOCA; and

4. A risk-informed assessment (Ref. 7) concluded that operating the plant in accordance with these Required Actions is acceptable.

C.1, C.2, and C.3

If the plant is operating with THERMAL POWER > 75% RTP, two HPI pumps capable of providing flow through two HPI trains are required. One HPI train is required to provide flow automatically upon receipt of an ESPS signal, while flow through the other HPI train must be capable of being established from the Control Room within 10 minutes. Thus, if the plant is operating at > 75% RTP, and one HPI train is inoperable and incapable of being automatically actuated or manually aligned from the Control Room to provide flow post-accident, the HPI System would be incapable of performing its safety function. For this Condition, Required Action C.1 requires the power to be reduced to ≤ 75% RTP within 3 hours. Required Action C.1 is modified by a Note which limits its applicability to the condition defined above. The 3 hour Completion Time is considered reasonable to reduce the unit from full power conditions to ≤ 75% RTP in an orderly manner and without challenging unit systems. The time frame is more restrictive than the Completion Time provided in Required Action B.1 for the same action, because the condition involves a loss of safety function.

If the plant is operating with THERMAL POWER > 75% RTP and the inoperable HPI train can be automatically actuated or manually aligned to provide flow post-accident, Required Action C.3 permits 72 hours to restore the HPI train to an OPERABLE status.

If enhanced steam generator cooling is not credited in the accident analysis, two HPI trains are required to mitigate specific small break LOCAs with THERMAL POWER ≤ 75% RTP. However, if equipment not qualified as QA-1 (i.e., an ADV

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

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. In order to permit an HPI train to be inoperable regardless of the reason when THERMAL POWER is ≤ 75% RTP, Required Action C.2 provides a compensatory measure to verify by administrative means that the ADV flow path for each steam generator is OPERABLE within 3 hours. This Required Action is modified by a Note which states that it is only required if THERMAL POWER is ≤ 75% RTP. This compensatory measure provides assurance regarding the ability of the plant to mitigate an accident while in the Condition and THERMAL POWER ≤ 75% RTP. Compliance with this requirement can be established by ensuring that the ADV flow path for each steam generator is OPERABLE in accordance with LCO 3.7.4, "Atmospheric Dump Valve (ADV) Flow Paths."

With one HPI train inoperable, the inoperable HPI train must be restored to OPERABLE status within 72 hours. This action is appropriate because:

1. With THERMAL POWER ≤ 75% RTP, the safety analysis demonstrates that only one HPI train is required to mitigate the consequences of a small break LOCA assuming credit is taken for the ADV flow path for one steam generator. The OPERABILITY of the ADV flow path for each steam generator is confirmed by Required Action C.2 within 3 hours. This provides additional defense-in-depth. Additionally, a risk-informed assessment (Ref. 7) concluded that operating the plant in accordance with this Required Action is acceptable.

2. With THERMAL POWER > 75% RTP, the remaining OPERABLE HPI train is capable of automatic actuation, and the inoperable train can be manually aligned by operator action to cross-connect the discharge headers of the HPI trains. This manual action was approved by the NRC in Reference 6.

(continued)

BASES

ACTIONS (continued)

D.1

With the HPI suction headers not cross-connected, the HPI suction headers must be cross-connected within 72 hours. The HPI System continues to be capable of mitigating an accident, barring a single failure. The 72 hour Completion Time is based on NRC recommendations (Ref. 4) that are based on a risk evaluation and is a reasonable time for many repairs.

An argument similar to that utilized for Required Actions B.2, B.3, and B.4 could have been made for operating the HPI System with the suction headers not cross-connected for an extended period of time. However, this action was not considered prudent, due to the potential of damaging two HPI pumps in the event HP-24 or HP-25 failed to open in response to an ESPS signal while the HPI suction headers were not cross-connected.

E.1

With the HPI discharge headers cross-connected, the independence of the HPI trains is not being maintained to the extent practical (i.e., defense-in-depth principle is not met). Thus, the HPI discharge headers must be hydraulically separated within 72 hours. This action limits the time period that the HPI discharge headers may be cross-connected. The 72-hour allowed outage time is acceptable, because cross-connecting the HPI discharge headers in conjunction with:

1. the rest of the HPI System being OPERABLE would not result in the inability of the HPI System to perform its safety function even assuming a single active failure; and

2. an HPI pump being inoperable would not result in the inability of the HPI System to perform its safety function, barring a single failure. However, in this condition, a single active failure of one of the two remaining OPERABLE HPI pumps could result in the remaining HPI pump failing due to runout.

(continued)

BASES

ACTIONS (continued)

F.1

With one LPI-HPI flow path inoperable, the inoperable LPI-HPI flow path must be restored to OPERABLE status within 72 hours. The HPI System continues to be capable of mitigating an accident, barring a single failure. The 72 hour Completion Time is justified because there is a limited range of break sizes, and therefore a lower probability for a small break LOCA which would require piggy back operation.

G.1 and G.2

If a Required Action and associated Completion Time of Condition B, C, D, E, or F are not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and the RCS temperature reduced to ≤ 350°F within 60 hours. The allowed 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.

H.1

If two HPI trains are inoperable or two LPI-HPI flow paths are inoperable, the HPI System is incapable of performing its safety function and in a condition not explicitly addressed in the Actions for ITS 3.5.2. Thus, immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verifying the correct alignment for manual and non-automatic power operated valves in the HPI flow paths provides assurance that the proper flow paths will exist for HPI operation. This SR does apply to the HPI suction header cross-connect valves, the HPI discharge cross-connect valves, the HPI discharge crossover valves, and the LPI-HPI flow path discharge valves (LP-15 and LP-16). This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. Similarly, this SR does not apply to automatic valves since automatic valves actuate to their required

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

position upon an accident signal. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.2

With the exception of the HPI pump operating to provide normal makeup, the other two HPI pumps are normally in a standby, non-operating mode. As such, the emergency injection flow path piping has the potential to develop voids and pockets of entrained gases. Venting the HPI pump casings periodically reduces the potential that such voids and pockets of entrained gases can adversely affect operation of the HPI System. This will also reduce the potential for water hammer, pump cavitation, and pumping of noncondensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an ESPS signal. This Surveillance is modified by a Note that indicates it is not applicable to operating HPI pump(s) providing normal makeup. The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the HPI piping and the existence of procedural controls governing system operation.

SR 3.5.2.3

Periodic surveillance testing of HPI pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the ASME Code (Ref. 5). SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code.

SR 3.5.2.4 and SR 3.5.2.5

These SRs demonstrate that each automatic HPI valve actuates to the required position on an actual or simulated ESPS signal and that each HPI pump starts on receipt of an actual or simulated ESPS signal. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The test will be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.4 and SR 3.5.2.5 (continued)

considered satisfactory if control board indication verifies that all components have responded to the ESPS actuation signal properly (all appropriate ESPS actuated pump breakers have opened or closed and all ESPS actuated valves have completed their travel). The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the ESPS testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.6

Periodic inspections of the reactor building sump suction inlet (for LPI-HPI flow path) ensure that it is unrestricted and stays in proper operating condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage, on the need to preserve access to the location, and on the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency has been found to be sufficient to detect abnormal degradation and has been confirmed by operating experience.

SR 3.5.2.7

Periodic stroke testing of the HPI discharge crossover valves (HP-409 and HP-410) and LPI-HPI flow path discharge valves (LP-15 and LP-16) is required to ensure that the valves can be manually cycled. The HPI discharge crossover valves must be capable of being stroked from the Control Room. The LPI-HPI flow path discharge valves must be capable of being stroked locally. This test is performed on an 18-month Frequency. Operating experience has shown that these components usually pass the surveillance when performed at this Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.46.
2. UFSAR, Section 15.14.3.3.6.
3. 10 CFR 50.36.
4. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
5. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400.
6. Letter from R. W. Reid (NRC) to W. O. Parker, Jr. (Duke) transmitting Safety Evaluation for Oconee Nuclear Station, Units Nos. 1, 2, and 3, Modifications to the High Pressure Injection System, dated December 13, 1978.
7. Letter from W. R. McCollum (Duke) to the U. S. NRC, "Proposed Amendment to the Facility Operating License Regarding the High Pressure Injection System Requirements," dated December 16, 1998.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 314 TO FACILITY OPERATING LICENSE DPR-38

AMENDMENT NO. 314 TO FACILITY OPERATING LICENSE DPR-47

AND AMENDMENT NO. 314 TO FACILITY OPERATING LICENSE DPR-55

DUKE ENERGY CORPORATION

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3

DOCKET NOS. 50-269, 50-270, AND 50-287

1.0 INTRODUCTION

By letter dated December 16, 1998; as supplemented January 25, August 5, and October 4, 1999; and March 29 and June 8, 2000, Duke Energy Corporation (the licensee) submitted a request for changes to the Oconee Nuclear Station, Units 1, 2, and 3, Technical Specifications (TS). The requested changes would revise the TS for the High Pressure Injection (HPI) system. The no significant hazards consideration evaluation contained in the December 16, 1998, submittal was revised by the letter dated January 25, 1999, and the Nuclear Regulatory Commission (NRC) published a proposed no significant hazards consideration determination on February 24, 1999. The supplements dated August 5 and October 4, 1999; and March 29 and June 8, 2000, provided clarifying information that did not change the scope of the December 16, 1998, or the January 25, 1998, submittals or the proposed no significant hazards consideration determination.

2.0 BACKGROUND

The Oconee HPI system was originally designed with an installed spare pump and the TS required only two HPI pumps be operable so that one pump could be out of service for maintenance. In the late 1970's, a problem was discovered in the emergency core cooling system (ECCS) analyses with the result that all three pumps were needed to be operable. At that time, the TS were modified to require that all three pumps be operable. However, this did not provide the flexibility of removing one pump from service for maintenance. As a result, the TS were modified such that one HPI pump could be removed indefinitely if the reactor coolant system temperature was above 350°F and reactor power was below 60 percent rated thermal power (RTP). These requirements were based on the analysis of a small break loss of coolant accident (SBLOCA), which assumed a break on the discharge side of the reactor coolant pumps (RCPs). The analysis concluded that one HPI train had sufficient capacity to mitigate SBLOCAs when reactor power was below 60 percent RTP.

However, as reported in Licensee Event Report (LER) 269/90-15, the licensee has discovered that this analysis is nonconservative since it assumed:

a. An even flow split between the injection line connected to the broken cold leg and the injection line connected to the intact cold leg. The even flow split resulted from the assumption that the back pressure on each line was equal to reactor coolant system (RCS) pressure; and

b. HPI flow from the injection line connected to the broken leg is injected into the RCP discharge volume. A computer model then determined how much of the injection flow is lost out the break.

In the LER, the licensee reported that one HPI train was inadequate to mitigate a break of an HPI injection line when reactor power was < 60 percent RTP. In this case, the appropriate back pressure assumption would be containment pressure for the broken injection line and RCS pressure for the intact injection lines. Additionally, none of the HPI flow through the broken injection line would reach the RCS. The resulting flow split from this asymmetric pressure boundary condition would cause less injection flow to reach the reactor.

The reason for the requested changes is to correct this non-conservative finding that one HPI train is inadequate to mitigate a break of an HPI injection line when reactor power is < 60 percent RTP. This would be accomplished by providing a technical evaluation for revising the licensing basis and additional restrictions for operation following loss of an HPI component. As an interim measure, the licensee has imposed additional restrictions on operation with reactor power < 60 percent full power. These restrictions are equivalent to the requirements for operations with reactor power > 60 percent full power. That is, a third HPI pump and HPI discharge crossover valves must be operable, and the HPI suction headers must be cross-connected. If these conditions cannot be established within the allowed outage time, TS 3.0.3 would be entered, which would require that the reactor be shut down.

The purpose of the proposed TS changes is to resolve the issue identified in LER 269/90-15 and other deficiencies with the HPI TS.

3.0 <u>PROPOSED CHANGES</u>

3.1 Description of Limiting Condition for Operation (LCO) 3.5.2 Changes

The present LCO 3.5.2 requires two HPI trains and two Low Pressure Injection (LPI)-HPI flow paths to be operable when in Mode 1, Mode 2, and Mode 3 with RCS temperature > 350°F. It also requires that when reactor power is > 60 percent RTP, three HPI pumps and the HPI discharge crossover valves be operable and the suction header cross-connected. The licensee has proposed to revise LCO 3.5.2 by:

a. Expanding its applicability by requiring the third HPI pump and the HPI discharge crossover valves to be operable and the suction header to be cross-connected whenever LCO 3.5.2 is applicable; and

b. Specifically requiring that the HPI discharge headers be separated whenever LCO 3.5.2 is applicable.

3.1.1 Discussion of LCO 3.5.2 Changes

One HPI train provides sufficient flow to mitigate most SBLOCAs. However, for cold leg breaks located on the discharge of the RCPs, some HPI injection will be lost out the break. For this case, two HPI trains are required. Thus, three HPI pumps must be operable to ensure adequate cooling in response to the design basis RCP discharge SBLOCA. Additionally, in the event one HPI train fails to automatically actuate due to a single failure (i.e., failure of HPI Pump C or HP-26), operator actions are required to cross-connect the HPI discharge header valves HP-409 and HP-410 within ten minutes from the Control Room in order to provide HPI flow through a second HPI train. These operator actions were previously reviewed and approved in a safety evaluation dated December 13, 1978.

The proposed changes to LCO 3.5.2 establish the minimum conditions required to ensure that the HPI system can deliver sufficient water to mitigate a SBLOCA. The safety analysis requires that, at a minimum, one HPI train must be capable of automatically responding to an accident and the other HPI train must be capable of being manually aligned from the Control Room within 10 minutes in the event of a SBLOCA.

Hydraulic separation of the HPI discharge headers is required during normal operation to maintain defense-in-depth (i.e., independence of the HPI discharge headers). Additionally, hydraulic separation of the HPI discharge headers ensures that a complete loss of HPI would not occur in the event of an accident with only two of the three HPI pumps operable. In this case, a single active failure of an HPI pump would leave only one HPI pump available to mitigate the accident. If the HPI discharge headers were cross-connected under such circumstances, the remaining HPI pump could experience runout conditions and fail prior to operator action to throttle flow or start another pump.

The proposed change to specifically address cross-connecting the HPI discharge headers clarifies the requirement to maintain the HPI discharge headers hydraulically separated to the extent possible.

3.1.2 Description of LCO 3.5.2 Condition A Changes

Condition A of LCO 3.5.2 addresses the condition when one HPI pump is inoperable, one or more HPI discharge crossover valves are inoperable, or the HPI suction header is not cross-connected with reactor power > 60 percent RTP. The licensee has proposed to:

a. Expand the applicability of this Condition by deleting the phrase "with THERMAL POWER > 60 percent RTP" and

b. Address a failure to cross-connect the HPI suction headers as an independent condition. This condition is designated Condition D.

3.1.3 Discussion of LCO 3.5.2 Condition A Changes

The proposed change to apply Condition A regardless of reactor power level supports a proposed change to LCO 3.5.2. The proposed revised LCO would require the third HPI pump to be operable, the discharge crossover valves to be operable, and the HPI suction headers to

be cross-connected whenever the LCO is applicable. The SBLOCA analysis requires two HPI trains to mitigate the accident (one operating automatically, and the other manually aligned from the Control Room within ten minutes). The proposed requirements are more restrictive than the present TS.

The proposed change to address cross-connecting the HPI suction headers as an independent condition does not result in any technical changes to the requirements regarding the HPI suction headers. The Required Action continues to limit the period of time that the HPI suction headers can be hydraulically separated to 72 hours. This proposed change is an administrative change.

3.1.4 Description of LCO 3.5.2 Condition B Changes

In the event a Required Action or Completion Time of Condition A of LCO 3.5.2 is not met, Condition B of LCO 3.5.2 would apply. Required Action B.1 of LCO 3.5.2 requires reactor power to be reduced to < 60 percent RTP. The licensee has proposed to revise this condition by:

a. Revising Required Action B.1 to require reactor power to be reduced to only < 75 percent RTP; and

b. Adding Required Actions B.2, B.3, and B.4. These required actions limit the amount of time that a plant may be operated with reactor power < 75 percent RTP in the event an HPI pump is inoperable, or one or more HPI discharge crossover valves are inoperable. Required Action B.2 would require verification by administrative means that the atmospheric dump valve (ADV) flow path for each steam generator (SG) is operable within 12 hours. Required Action B.3 would require restoration of the HPI pump to an operable status within 30 days. Required Action B.4 would require restoration of the HPI discharge crossover valve(s) to an operable status within 30 days.

3.1.5 Discussion of LCO 3.5.2 Condition B Changes

If enhanced SG cooling is not credited in the SBLOCA analysis, two HPI trains are required to mitigate specific SBLOCAs. However, if equipment not qualified as Quality Assurance(QA)-1 (i.e., an ADV flow path for a SG) is credited for enhanced SG cooling, the licensee, based on its safety analyses, has determined that the capacity of one HPI train is sufficient to mitigate a SBLOCA on the discharge of the RCPs, if reactor power is < 75 percent RTP.

Required Action B.1 would require reactor power to be reduced to < 75 percent RTP. At this power level, the licensee, based on its SBLOCA analysis, has determined that only one HPI train is required to mitigate SBLOCAs, if credit is taken for an ADV flow path for one SG. Since the ADV flow paths are not fully qualified as QA-1, Required Actions B.2, B.3, and B.4 would limit the period of time that the licensee would rely upon the ADV flow path for one SG for accident mitigation in order to operate the plant.

Proposed Required Action B.2 would provide a compensatory measure to verify by administrative means that the ADV flow path for each SG is operable within 12 hours. This compensatory measure provides additional assurance regarding the ability of the plant to mitigate an accident.

Proposed Required Actions B.3 and B.4 would require that the HPI pump and discharge crossover valves be restored to operable status within 30 days from initial entry into Condition A. The 30-day time period limits the time that the licensee can operate the plant while relying on the non QA-1 ADVs to provide enhanced SG cooling to mitigate SBLOCAs. According to the licensee, the 30-day time period was chosen because:

a. Without crediting an ADV flow path, the HPI system remains capable of performing the safety function, barring a single failure.

b. If credit is taken for an ADV flow path for a SG, the safety analysis has demonstrated that only one HPI train is required to mitigate the consequences of a SBLOCA when reactor power < 75 percent RTP. Thus, for this case, the HPI system would be capable of performing its safety function even with an additional single failure.

c. Operability of the ADV flow path for each SG is required to be confirmed by Required Action B.2 within 12 hours. Additional defense-in-depth is provided because only the ADV flow path for one SG is required to mitigate the SBLOCA.

d. A risk-informed assessment concluded that operating the plant in accordance with these Required Actions is reasonable.

3.1.6 Additional Consideration Regarding RCP Seal Injection

Proposed Conditions B and C of LCO 3.5.2 were not developed to ensure that the HPI system remained capable of supplying RCP seal injection assuming an additional single failure while operating in the condition. The licensee's rationale for this decision is:

a. Typically, an additional single failure is not addressed while a plant is operating in a Condition permitted by the TS.

b. A risk-informed analysis performed by the licensee determined that the impact of proposed Conditions B and C of LCO 3.5.2 on the core damage frequency associated with an RCP seal LOCA was low.

c. While the component cooling system would be isolated following an Engineered Safeguards Protective System (ESPS) signal, the current Emergency Operating Procedure (EOP) requires the component cooling system to be unisolated.

d. The licensee has committed to control maintenance of the component cooling system while the HPI system is degraded in accordance with the Maintenance Rule configuration management program.

e. Procedural guidance is in place to establish Standby Shutdown Facility reactor coolant makeup flow to the RCP seals in the event the component cooling system and HPI system are lost.

3.1.6 Discussion of LCO 3.5.2 Condition C Changes

Condition C of LCO 3.5.2 has been renamed Condition F. This is an administrative change that does not affect the technical content or requirements in the condition.

3.1.7 Description of LCO 3.5.2 Condition D Changes

Condition D of LCO 3.5.2 addresses the condition of one HPI train being incapable of automatic actuation but capable of being manually actuated with reactor power > 60 percent RTP or one HPI train being inoperable with reactor power < 60 percent RTP. If either of these conditions exist, Required Action D.1 requires the ability to automatically actuate the HPI train be restored within 24 hours, and Required Action D.2 requires the HPI train to be restored to an operable status within 24 hours. The licensee has proposed the following changes to this condition:

a. Relabeling the condition as Condition C;

b. Simplifying the condition to address the condition of one HPI train being inoperable regardless of the power level that the plant is being operated or the reason for the inoperability;

c. Deleting the explicit requirement to restore the capability to automatically actuate the train within 24 hours;

d. Adding a Required Action to reduce reactor power to < 75 percent RTP within three hours in the event an HPI train cannot be actuated using automatic or manual means;

e. Adding a Required Action to verify by administrative means that the ADV flow path for each SG is operable within three hours; and

f. Extending the Completion Time for restoring an inoperable HPI train to 72 hours.

3.1.9 Discussion of LCO 3.5.2 Condition D Changes

Renaming Condition D to Condition C is an administrative change that does not affect the technical content or requirements in the condition.

The remaining proposed changes reflect the licensee's new SBLOCA analysis. If enhanced SG cooling is not credited in the SBLOCA analysis, two HPI trains are required to mitigate specific SBLOCAs. One HPI train is required to provide flow automatically upon receipt of an ESPS signal, while flow through the other HPI train must be capable of being established from the Control Room within ten minutes. However, if equipment not qualified as QA-1 (i.e., an ADV flow path for a SG) is credited for enhanced SG cooling, the licensee, based on its safety analyses, has determined that the capacity of one HPI train is sufficient to mitigate SBLOCAs if reactor power is < 75 percent RTP.

If the plant is operating at > 75 percent RTP, and one HPI train is inoperable and incapable of being automatically actuated or manually aligned from the Control Room to provide post-accident flow, the HPI system would be incapable of performing its safety function. To address this situation, the licensee has proposed to add Required Action C.l, which requires the power

to be reduced to < 75 percent RTP within three hours in the event an HPI train is incapable of being automatically actuated and incapable of being manually aligned. The licensee considers the three-hour Completion Time to be reasonable to reduce the unit from full power conditions to < 75 percent RTP in an orderly manner and without challenging unit systems. The time frame is more restrictive than the Completion Time provided in Required Action B.l for the same action, because the condition involves a loss of the safety function.

In order to permit an HPI train to be inoperable regardless of the reason when reactor power is < 75 percent RTP, Required Action C.2 provides a compensatory measure to verify by administrative means that the ADV flow path for each SG is operable within three hours. This Required Action is modified by a Note that states this action is only required if reactor power is < 75 percent RTP. This compensatory measure provides assurance regarding the ability of the plant to mitigate an accident while in the Condition with reactor power < 75 percent RTP.

With one HPI train inoperable, the inoperable HPI train must be restored to operable status within 72 hours. This action has been proposed because:

a. With reactor power < 75 percent RTP, the licensee's safety analysis has demonstrated that only one HPI train is required to mitigate the consequences of a SBLOCA assuming credit is taken for an ADV flow path for one SG. The operability of the ADV flow path for each SG is confirmed by Required Action C.2 within three hours. This provides additional defense-in-depth.

b. With reactor power > 75 percent RTP, the remaining operable HPI train is capable of automatic actuation, and the inoperable train can be manually aligned by operator action to cross-connect the discharge headers of the HPI trains. This manual action was approved by the staff in a Safety Evaluation dated December 13, 1978.

3.1.10 Description of LCO 3.5.2 Condition E Changes

Condition E of LCO 3.5.2 addresses the condition of failing to meet a Required Action and associated Completion Time of Condition C or D. The licensee has proposed the following changes to this condition:

a. Renaming the condition as Condition G; and

b. Expanding the applicability of this condition to address failure to meet a Required Action and associated Completion Time of Condition B, C, D, E, or F.

3.1.11 Discussion of LCO 3.5.2 Condition E Changes

Reordering the condition does not affect the technical content or requirements in the condition. This is an administrative change.

In the event a Required Action or associated Completion Time for Condition B, C, D, E, or F of LCO 3.5.2 is not met, action should be required to place the unit in a mode or condition in which the LCO does not apply. The proposed Condition G achieves this by requiring the plant to be brought to Mode 3 within 12 hours and the RCS temperature to be reduced to < 350°F within

60 hours. These requirements are consistent with other existing shutdown requirements contained in the Oconee TS.

3.2 New Conditions

3.2.1 Description of New Conditions

a. The current TS require entry into Condition C of TS 3.5.2 when the HPI discharge headers are cross-connected and require the inoperable HPI train to be restored within 24 hours. Proposed Condition E would specifically address cross-connecting the HPI discharge headers by requiring the HPI discharge headers to be hydraulically separated within 72 hours of cross-connecting them.

b. Condition H would be added to direct entry into LCO 3.0.3 immediately in the event two HPI trains or two LPI-HPI flow paths are inoperable.

3.2.2 Discussion of New Conditions

a. Adding a condition to specifically address cross-connecting the HPI discharge headers provides clarity, and ensures that the appropriate action is taken with respect to the condition. With the HPI discharge headers cross-connected, the independence of the HPI trains is not being maintained (i.e., defense-in-depth principle is not met). This action assures that cross-connecting the discharge headers of the HPI system is limited to 72 hours. The licensee has proposed the 72-hour allowed outage time because cross-connecting the HPI discharge headers in conjunction with:

   (1) the rest of the HPI system being operable would not result in the inability of the HPI system to perform its safety function even assuming a single active failure; and

   (2) an HPI pump being inoperable would not result in the inability of the HPI system to perform its safety function, barring a single failure.

b. Adding a condition that directs entry into LCO 3.0.3 in the event two HPI trains or two LPI-HPI flow paths are inoperable clarifies the TS requirements and is consistent with other requirements of the TS.

3.3 Changes to Surveillance Requirements

3.3.1 Description of Proposed Change to Surveillance Requirement (SR) 3.5.2.7

SR 3.5.2.7 currently requires each discharge valve to the LPI-HPI flow path to be manually cycled open every 18 months. The proposed change would revise this SR to require that the HPI discharge crossover valves also be cycled every 18 months. This proposed change is more restrictive.

3.3.2 Discussion of Proposed Change to SR 3.5.2.7

Currently, the TS do not contain a SR that demonstrates operability of the HPI discharge crossover valves. These valves are required to be manually aligned from the Control Room under certain conditions following an accident to provide coolant flow from the second HPI train within ten 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, which is consistent with tests of similar components.

3.4 Atmospheric Dump Valves, LCO 3.7.4

In the December 16, 1998, and the August 5, 1999, submittals, the licensee proposed to add LCO 3.7.4 regarding operability requirements for the ADVs. However, the same requirements were subsequently added by Amendments 309, 309, and 309 to the Oconee Units 1, 2, and 3 (respectively) TS on January 18, 2000. As a result, the proposed change was no longer needed and was, therefore, deleted from the proposed HPI changes by letter dated March 29, 2000.

3.5 Bases Changes

By letter dated December 16, 1998, the licensee proposed changes to the HPI Bases to reflect the proposed LCO changes, and set forth additional information regarding the licensing basis, conditions, and requirements. Additional information was included on such topics as eliminating HPI system single failure vulnerability, passive failure considerations, elimination of LPI operability requirements from the HPI TS, HPI and crossover valve operability determinations, HPI TS considerations, and surveillance requirements.

Proposed changes to Bases Index Page iii to correct editorial errors and incorporate other changes to the HPI Bases were included in the submittal dated August 5, 1999.

4.0 EVALUATION

4.1 LOCA Analysis

The licensee performed two separate sets of analyses to justify the proposed TS change. The first was performed at full power with the minimum complement of ECCS equipment available, considering the single failure criterion. The second was performed at 75 percent rated thermal power with one HPI train, considers the single failure criterion, and includes enhanced SG cooling heat removal to ensure that the same performance requirements are satisfied. The purpose of the analysis was to show that the requirements of 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-water Nuclear Power Reactors" and 10 CFR Part 50, Appendix K are met for each. Both sets of analyses were performed using the methodology in the NRC-approved Topical Report BAW-10192P-A, which will be reflected in the UFSAR.

The licensee was able to show that, for the proposed TS changes, all of the LOCA acceptance criteria of 10 CFR 50.46 and 10 CFR Part 50, Appendix K will continue to be met. The limiting peak central fuel temperature was well within the 2200°F limit and the SBLOCA local cladding oxidation was confirmed to be less than the 17 percent limit. The calculated SBLOCA hot

channel oxidation is less than one percent, which ensures that the whole core oxidation is less than one percent. Thermal and mechanical deformations of the fuel assemblies have been shown by the licensee to maintain coolable core configurations. The long-term cooling of the core is ensured by maintaining ECCS flow in excess of the decay heat load and by preventing boric acid precipitation by establishing a long-term boron concentration control process. The ECCS design and EOPs accomplish the long-term cooling function and meet these acceptance criteria.

The licensee has addressed all the applicable computer code limitations and restrictions in the implementation of the model. In addition, the licensee used conservatism in the evaluation model and to establish initial and boundary conditions in the model that has been reviewed and approved by the NRC.

4.1.1 Mode 4 Operation

In the submittal, the licensee addressed the absence of a requirement for an HPI pump in Mode 4, Hot Shutdown. The licensee stated that an HPI pump in Mode 4 is not necessary because, should a SBLOCA occur, the reactor would eventually depressurize and the coolant would become saturated. Before the coolant would become completely saturated, the loss of reactor coolant inventory and depressurization would allow the LPI system to provide make-up and cooling.

The staff does not agree that this is an appropriate strategy for mitigating a SBLOCA. Allowing the coolant in a Babcock and Wilcox pressurized water reactor to become saturated in Mode 4 introduces additional complications, and the staff believes that it is more prudent to maintain an HPI pump available for injection. However, the HPI requirements related to this proposed amendment are not meant to address or affect operation in Mode 4. As a result, the staff has determined that this evaluation is not relevant to the amendment requested and will not be considered at this time.

4.1.2 Hot Leg Void Formation

Some loss-of-coolant accidents can lead to void formation in the hot leg that interrupts subcooled natural circulation (NC). In the larger cold-leg break LOCAs, the reactor coolant system continues to depressurize, the core flood tanks (CFTs) transfer their inventory into the RCS, and depressurization continues as the LPI systems start providing water to the RCS. In this situation, RCS heat is removed by water and steam flowing out the break and SG cooling is not needed. Therefore, void formation in the upper elevations of the hot legs and loss of NC with the accompanying loss of heat transfer to the SGs is of no concern.

In some of the smaller size LOCAs, the break flow may be insufficient to remove RCS heat and the RCS may not depressurize sufficiently for the CFTs to inject water. In such a case, SG cooling may be necessary to accomplish RCS depressurization to enhance high pressure injection HPI flow rate or to depressurize the RCS to the pressure where CFTs and LPI would become effective. In such cases, voiding of the upper elevations of the hot legs and the resultant loss of SG cooling are not of concern because the RCS design (piping is attached to the reactor vessel above the core) ensures that the SG tubes will be exposed to RCS steam

(making SG cooling available) before the RCS water level decreases below the top of the core.[1] This prevents core damage.

A 0.024 square-foot break of an HPI pipe is the most challenging condition at Oconee because of the HPI system alignment. Under some equipment failure conditions, it may be necessary to enhance HPI flow into the RCS by separating the HPI trains so that flow from one train is not lost directly through the break. This can be accomplished from the control room using existing procedures, and ten minutes are available to accomplish this separation. Using the SGs to depressurize the RCS below the SG safety valve setpoint usually will require using turbine bypass or atmospheric dump valves (ADVs) to decrease the SG secondary side pressure and temperature, which may lead to void formation in the top of the RCS hot legs. Although the turbine bypass valves are actuated from the control room, they will not be available if, for example, condenser vacuum cannot be maintained. In this event, an ADV flow path, which requires local operation, will be opened within 25 minutes and provides adequate core cooling. Further, the pressurizer power operated relief valves (PORVs) may be used to depressurize the RCS directly, although there may be some single failures that disable both the PORVs and other equipment that would be needed for LOCA mitigation. All of the identified activities are addressed in emergency operating procedures and any one method will provide adequate core protection. Therefore, based on this analysis, the staff has determined void formation in the hot legs, should it occur during a LOCA, will not result in core damage and is acceptable.

4.1.3 Conclusion

The general philosophy used for the LCO and the allowed outage time (AOT) are: (1) for the loss of single failure protection, the 72 hour AOT applies, and (2) for a loss of safety function, TS 3.0.3 applies. This is consistent with the philosophy developed in the standard TS, and in view of the staff's analysis in Section 4.3 of this safety evaluation, the staff finds the approach and the proposed TS change acceptable.

The staff finds that the LOCA analysis that was performed to support the amendment provisions meets the acceptance criteria in 10 CFR 50.46 and was performed using an NRC-approved evaluation model. Therefore, for the LOCA analysis considerations, the proposed TS change is acceptable.

4.2 Operator Actions

4.2.1 Evaluation Basis

The licensee revised its SBLOCA analyses to credit three operator actions in the SBLOCA mitigation strategy. These actions are: (1) in the event one HPI train fails to automatically actuate, to cross-connect the HPI discharge headers within ten minutes in order to provide HPI flow through a second HPI train, (2) to feed the SGs with water to maintain SG level at the loss of sub-cooled margin setpoint with the emergency feedwater (EFW) system, and (3) to depressurize and release steam from the SGs using the ADVs.

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[1]RCS conditions, injection water flow rates, and time available to respond to the LOCA may be affected by the short-term loss of SG cooling, conditions that are considered in response planning.

The staff used guidance concerning the allowance of credit for manual operator actions that is provided in Generic Letter (GL) 91-18, Section 6.7, "Use of Manual Action in Place of Automatic Action," and ANSI-58.8, "Time Response Design Criteria for Safety Related Operator Actions," 1984, to evaluate the licensee's submittals relative to crediting of operator actions. GL 91-18 states: "The consideration of manual action in ... areas must also include the ability and timing in getting to the work area, training of personnel to accomplish the task, and occupational hazards to be incurred such as radiation, temperature, chemical, sound, or visibility hazards." ANSI-58.8 supplies estimates of reasonable response times for operator actions, but allows use of time intervals derived from independent sources, provided they are based on task analyses with consideration given to human performance.

4.2.2 Operator Actions Evaluation

4.2.2.1 Cross-Connecting HPI Discharge Headers

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 licensee's submittal indicates that the revised SBLOCA analysis does not revise in any way this operator action. Consequently the staff did not re-evaluate the acceptability of crediting this operator action for the revised SBLOCA analysis.

4.2.2.2 Feeding the SGs to the Loss of Subcooled Margin Setpoint

Operator action is required to initiate EFW flow and raise SG levels to the loss of subcooling margin setpoint if either LPI header flow indicates less than 1000 gpm flow. The license's "Full Power, Two HPI Pump Analyses" procedure assumes that manual operator actions to begin to increase SG levels to the loss of subcooling margin setpoint will occur within 20 minutes after a reactor trip for one SG and within 30 minutes for the second SG. The "Reduced Power, One HPI Pump Analyses" procedure takes credit for operator action to provide EFW flow to one SG within 20 minutes and cooldown of one SG within 25 minutes. The licensee's December 16, 1998, submittal indicates that direction to initiate EFW flows to raise SG levels to the loss of subcooling margin setpoint is provided in the EOPs, and that subcooling margin and LPI header flows can be monitored from the control room using QA-1 instruments. Success is verified by monitoring increasing SG levels using Extended Startup Range Level Instrumentation. The licensee has indicated that the ability of the operators to perform this function has been verified though simulator exercises.

By letter dated February 2, 2000, the staff requested additional information concerning the licensees's validation of operator action times using simulator exercises. The licensee provided the following additional information in a supplemental submittal dated March 29, 2000. Six crews were tested in simulator exercises on raising SG levels to the loss of subcooling margin setpoint. Four different scenarios were used for these tests. The time to complete this activity in the six simulator exercises ranged from 10 minutes 44 seconds to 17 minutes 53 seconds. These times are within the acceptance criteria of 20 minutes to begin increasing level in the first SG using EFW flow. EFW flow was initiated to both SGs at approximately the same time so that the 30 minute requirement for initiating EFW flow to the second SG was met.

The licensee noted that the EOP verification and validation process ensures that future revisions of the EOP will not invalidate the results of the validation tests. In addition, the

licensee stated that prior to or during the implementation phase of this license amendment, all operating crews will be exercised on using Emergency Feedwater to raise SG levels to the loss of sub-cooling margin setpoint to ensure that the time requirements for important operator actions can be consistently met.

The staff finds that, based on the above, the licensee has provided reasonable assurance that operator actions to initiate EFW flow to increase SG levels to the loss of subcooling margin setpoint can be performed reliably within the times assumed in the licensee's revised SBLOCA analyses.

4.2.2.3 Depressurizing and Steaming the SGs using Atmospheric Dump Valves

The licensee's reduced power SBLOCA analyses credit operator action to depressurize the SGs by opening flow paths for the ADVs. These analyses assume operator action to initiate depressurization of at least one SG within 25 minutes after the reactor trip. The staff considered the following factors stated in the licensee's December 16, 1998, submittal in its evaluation of the acceptability of crediting operator action:

As stated in Attachment 4, Enclosure 3 of the licensee's December 16, 1998, submittal:

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 operators 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, two non-licensed operators (NLOs) will be dispatched immediately to prepare for steaming the generators with the ADVs.

f. An expert panel of representatives from Operations, Operations Training, Engineering, and Licensing reviewed the EOP and operator action and concluded that past job performance measures (JPMs) and simulator exercises for the relevant SBLOCAs support the adequacy of the assumed 25 minutes.

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

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

b. 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.

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

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

The licensee provided additional information concerning its validation efforts in a letter dated October 4, 1999.

By letter dated February 2, 2000, the staff requested additional information concerning: (a) the bases for the expert panel's determination of the adequacy of the assumed 25 minutes for operator action to initiate depressurization of the SGs using the ADVs, including the panel's assumptions pertaining to staffing levels and transit times; (b) the validation of operator action times through simulator exercises; and (c) the ability of operators to recover from credible errors or complications in the opening of the ADV flow path. The licensee provided the additional information in a supplemental submittal dated March 29, 2000.

4.2.2.3.1 Bases for the Licensee's Expert Panel's Conclusions

The supplemental submittal stated that the expert panel's conclusions concerning the adequacy of the assumed 25 minutes are supported by data gathered from the licensee's EOP upgrade project. The submittal indicated that the EOP upgrade project produced minimum staffing requirements that are controlled by a selected licensee commitment (SLC), which is part of Oconee's Updated Safety Analysis Report. Changes to the SLC may, therefore, be made pursuant to 10 CFR 50.59. Each shift is staffed such that when any unit is in Modes 1 through 4, a minimum of 8 non-licensed operators are required. The licensee stated that NLOs are required to carry radios when they are outside the control room, thereby allowing them to stay in constant communication with the control room and the Work Control Center. During an emergency or transient, all NLOs are required to report to the affected control room. Each unit has one NLO assigned to complete certain abnormal procedures and EOP actions (AP/EOP NLO). This function is assigned to the AP/EOP NLO at the beginning of the shift and the NLO will stay inside the protected area at all times during the shift. Transit time for an NLO reporting to the control room from a remote part of the plant is typically 5 minutes. Five minutes does not include having to place a system, structure, or component (SSC) important to safety in a safe state prior to leaving the area.

For a SBLOCA, two NLOs would typically be dispatched from the control room within 5 minutes of the initiating event. NLOs will not be given other tasks to perform until they have completed opening the ADVs. Simulator validations indicated that it is necessary to increase minimum

staffing by three operators upon entry into Condition B of the technical specification (TS).[2] The licensee stated in the supplemental submittal that the minimum staffing SLC will be revised to reflect the requirement for an additional three operators using the 10 CFR 50.59 process and that this will be done as an implementation item following receipt of the amendment.

The staff noted that the expectation to dispatch NLOs to the ADVs within 5 minutes of event initiation does not allow for 5-minute transit times from remote areas of the plant, particularly if an SSC must be placed in a safe state. In a conference call on May 16, 2000, the staff requested additional information related to the ability of NLOs to report to the control room within 5 minutes of event initiation. By letter dated June 8, 2000, the licensee provided the following information:

a. Two of the three NLOs that will augment plant staff during Condition B of the technical specification will be designated to perform the activities associated with opening of the ADVs.

b. The NLOs with responsibility for opening the ADVs will be designated to respond to the control room within 5 minutes and will not be given duties that will prevent this from happening.

c. The AP/EOP NLO (one for each unit) does not enter containment or make trips to the switchyard; nor is the NLO given tasks that prevent responding to the control room within 5 minutes of an emergency situation.

Based on this information, the staff's judgement is that operators will be available to open the ADVs within the time limit required in the event such operation is necessary in accordance with this proposed change to the TS.

4.2.2.3.2 Licensee's Validation of Operator Action Times Using Simulator Exercises

Six crews were tested on opening an ADV within 25 minutes. The tests were completed using seven simulator scenarios. Completion times were calculated from reactor trip to the opening of one ADV. The required time for the manual actions performed outside the control room (i.e., manual alignment of an ADV flow path) was calculated by combining valve stroke time data obtained during a Unit 2 outage with times recorded for four separate walkdowns that included travel time between the components and communication with the control room. The worst case observed time for receiving direction and opening one ADV was 12 minutes 46 seconds. The licensee used 14 minutes for purposes of integrating the manual actions with the simulator validation. The licensee's submittal indicated that the time to open an ADV, as determined through the simulator validations, ranged from 17 minutes 26 seconds to 21 minutes 19 seconds. The staff noted that in each simulator exercise the NLOs were dispatched in less than the 5 minutes that is assumed for an NLO to report from a remote area of the plant. The staff calculated that completion times, assuming NLOs are not available for 5 minutes following a reactor trip, would range from 18 minutes 33 seconds to 22 minutes 25 seconds. These

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[2] Condition B of proposed technical specification 3.5.2, HPI, is entered when the Required Action and Completion Time of Condition A is not met. Condition A is entered when one HPI pump is inoperable or one or more HPI discharge crossover valve(s) is inoperable.

times are all within the 25 minutes credited in the SBLOCA analyses and provided margins to the required completion time ranging from 6 minutes 27 seconds to 2 minutes 35 seconds.

The licensee addressed the adequacy of the margin between the observed completion times in the simulator exercises and the 25-minute completion time credited in the SBLOCA analysis. In its supplemental submittal, the licensee stated that the 3 to 4 minute time interval between the reactor trip and dispatching NLOs to the ADVs is not expected to vary substantially because (a) there is minimal interaction required between operators during the initial phase of response to this event, (b) an operator "commit-to-memory" item is EOP specific rule #2 (step 5 of this rule is where it is determined that ADVs are required and NLOs are dispatched), and (c) the rule is available on the control board apron. The licensee's supplemental submittal also states that if it is necessary to enter the TS action statement for either an inoperable HPI pump or one or more inoperable discharge crossover valves, Operations will have designated the additional staff required for accident mitigation within 72 hours of entry into Condition A, and entry into Condition B will necessitate that Operations reduce power and check ADV operability within 12 hours of entering the action statement. The licensee believes these actions will heighten awareness for the potential need to implement the time-critical task of opening the ADVs.

The licensee also stated in its supplemental submittal that prior to or during the implementation phase of the license amendment request, all operating crews will be exercised on this scenario to ensure that time-critical actions can be consistently met. The NLO task of opening the ADVs will be evaluated at least biennially using JPMs. As part of implementation, the pass/fail criteria will be modified for licensed operator exams that involve the opening of the ADVs to include performance of the task within the required time frame. The licensee believes that these training activities will ensure the NLOs and licensed operators retain the ability to open the ADVs within the specified time frame.

Based on the licensee's analysis as described above, the staff finds that the training program and staffing level for the operating crews that has been implemented will ensure timely manual operation of the ADVs when required.

4.2.2.3.3 Ability to Recover from Credible Errors or Complications in Opening the ADVs

In its supplemental submittal, the licensee stated its belief that credible operator error is lessened by pre-staging at the ADVs an approved written procedure that prescribes a simple straight-forward sequence of steps for opening the ADVs. The procedure has been validated through the EOP upgrade project. The EOP project improved component labeling so the valves are labeled and easily identified.

During an emergency when operation of the ADVs is needed, two NLOs are dispatched to the ADVs to provide an independent means of ensuring that the correct valves are opened in the proper sequence. The task of opening ADVs is required to be walked through every two years using a JPM. The licensee addressed potential complications in opening the valves by noting in its supplemental submittal that mechanical tools are provided to assist the NLOs in opening the valves, if necessary.

For the reasons described above, the staff finds that the operator actions to depressurize the SGs using the ADVs can be performed reliably within the time assumed in the licensee's revised SBLOCA analyses.

4.2.2.4 Summary of Operator Actions Conclusions

The staff has reviewed the licensee's submittals dated December 16, 1998, and supplemental submittals dated October 4, 1999, and March 29, 2000. The staff evaluated the acceptability of crediting operator action in the licensee's SBLOCA analyses as described in Attachment 4, Enclosure 3 of the licensee's December 16, 1998, submittal. The staff concludes that the licensee has provided reasonable assurance that operators can reliably perform the manual actions credited in the SBLOCA analysis within the required completion times. This conclusion is based upon the considerations described above, including the following one-time enhancements to the training program, as described in the licensee's March 29 and June 8, 2000, supplements to the December 16, 1998, submittal:

a. Prior to or during the implementation phase of this license amendment request, all operating crews will have been exercised on using EFW to raise SG levels to the loss of sub-cooling margin setpoint to ensure that time-critical operator actions can be met.

b. Prior to or during the implementation phase of this amendment request, all operating crews will have been exercised on opening ADVs to ensure that time-critical operator actions can be consistently met.

c. As part of implementation, the pass/fail criteria for licensed operator examinations that involve the tasks of opening the ADVs will have been modified to include performance of the task within the required time frame.

In addition, in the March 29, 2000, letter, the licensee committed to use the 10 CFR 50.59 process prior to implementation of this amendment request to revise the SLC that establishes the minimum staffing levels to reflect the requirement to add three operators upon entry into Condition B. Two of these operators will be designated to perform activities related to the ADVs. Since the SLC is part of the FSAR and changes to it are controlled pursuant to 10 CFR 50.59, the staff finds this process satisfactory.

4.3 Probabilistic Risk Assessment (PRA) Evaluation

4.3.1 Background

Since the proposed changes rely on an SBLOCA analysis that credits enhanced SG cooling using an ADV flow path, it needed to be supported by a risk-informed evaluation conducted in accordance with Regulatory Guides (RGs) 1.174 and 1.177. The changes would permit operation to continue with reactor power $\leq$ 75 percent RTP: 1) in proposed Condition B for 30 days with an HPI pump and/or one or more HPI discharge crossover valves inoperable; and 2) in proposed Condition C for 72 hours with an HPI train inoperable. Proposed Condition B represents an increase in outage time from the licensee's self-imposed administrative limit of 3 days. Proposed Condition C represents an increase in outage time from the current TS 3.5.2 Condition D Completion Time of 24 hours. As described in its August 5, 1999, submittal, the licensee assumed an expected frequency of entry into Conditions B or C of once per year in its analysis, but believes that a more realistic frequency is once every 9 years.

The risk informed portion of the submittal is as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER to ≤ 75 percent RTP. AND B.2 Verify by administrative means that the ADV flow path for each steam generator is OPERABLE. AND B.3 Restore HPI pump to OPERABLE status. AND B.4 Restore HPI discharge crossover valve(s) to OPERABLE status.	 12 hours 12 hours 30 days from initial entry into Condition A 30 days from initial entry into Condition A.

C. One HPI train inoperable.	C.1 ------------NOTE------------------ Only required when inoperable HPI train is incapable of automatic actuation and incapable of actuation through remote manual alignment. ------------------------------------ Reduce THERMAL POWER to $\leq$ 75 percent RTP. <u>AND</u> C.2 ------------NOTE------------------ Only required when THERMAL POWER $\leq$ 75 percent RTP. ------------------------------------ Verify by administrative means that the ADV flow path for each steam generator is OPERABLE. <u>AND</u> C.3 Restore HPI train to OPERABLE status.	3 hours 3 hours 72 hours

4.3.2 Success Criteria

The HPI system at Oconee provides a number of functions. During normal operation at power, it is used for charging flow and provides RCP seal injection. In the event of a small or medium break LOCA or SG tube rupture, the system provides high pressure coolant makeup. It also is used for feed and bleed cooling following a loss of feedwater to the SGs. In addition, it provides emergency boration for mitigation of anticipated transient without scram (ATWS) scenarios. The HPI system success criteria depends on the event, and are indicated by the licensee as follows.

A SBLOCA is defined in Oconee's Individual Plant Examination (IPE)[3] as loss of primary coolant at a rate greater than normal makeup capacity but less than the equivalent of a 1.5-inch diameter hole. A break on the HPI injection line or the RCP discharge line, referred to as a "limiting" break location, would cause some HPI flow into the header to be lost out the break. A "random" SBLOCA location is defined to be a location other than a limiting break location. A stuck open pressurizer power operated relief valve (PORV) and block valve, for example, could be a random small break in the primary boundary integrity.

Success criteria for a small break at "limiting" locations is dependent on a number of factors. The break is assumed to occur on one of two HPI train headers. (The term HPI train refers to one HPI pump injecting into a header that feeds two reactor coolant system cold legs.) When thermal power is ≤ 75 percent RTP, one HPI train injecting into the intact header is considered success. If the train injecting into an intact header fails, one HPI train injecting into the broken header provides sufficient flow if secondary side steam is dumped to either the condenser (through the turbine bypass system (TBS)) or to the atmosphere (through the ADV system) within a certain time period following the break. The licensee's analysis showed that this time period is 25 minutes in the most restrictive case. Releasing steam from the SGs (steaming) within 25 minutes, either to the condenser or through the ADVs, helps the primary side to depressurize enough to allow sufficient HPI flow to cool the core. If a secondary side steam path is not established with one HPI train injecting into a broken header within 25 minutes, then core damage is predicted to result.[4] If steaming fails, it is not likely that depressurizing to use LPI can be credited to avoid core damage. However, depressurization to LPI pressure is assumed to be credible for all other small break cases without the dependence on establishing a secondary side steam path in 25 minutes.

This requested TS amendment credits the Atmospheric Dump System (ADS) steaming to the atmosphere if the TBS steaming to the condenser is unavailable. However, the TBS is the preferred and usual means of cooldown.

The TBS, by itself, can provide the necessary assistance for HPI success with one train as long as thermal power is ≤ 75 percent RTP. There are four TBVs, and only one valve is needed to open. Also, the condenser must be available.

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[3] The Oconee update IPE (Reference 10) study tasks included the traditional PRA tasks of initiating event analysis, systems analysis, data analysis, human reliability analysis, accident sequence qualification, in-plant consequence analysis, and ex-plant consequence analysis to revise earlier IPE submittals.

[4] The licensee indicated that 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 exceeding the acceptance criteria. With more realistic assumptions on decay heat and core power distribution, more time would be available and the extent of core uncovery and fuel assembly damage will be less. Analyses to further quantify the extent of core damage have not been performed as part of the scope of design basis LOCA analysis and are not available.

Either SG can be used for successful steaming to the atmosphere with the ADS, which has dependence on the ADVs and the EFW system. The ADVs are a set of manually operated valves on the main steam lines. Before any steam is released, a block valve and a vent valve need to be opened before opening the atmospheric dump control valve (or the atmospheric vent block valve) and throttling steam flow. These actions must be accomplished within 25 minutes after the occurrence of the limiting SBLOCA if the TBS is unavailable in order for one HPI train to provide sufficient flow (with reactor power $\leq$ 75 percent RTP). Further, the EFW system must fill the SGs to the subcooled margin level by 20 minutes for successful steaming with the ADVs.

Success criteria for a random SBLOCA is one HPI train (without requiring steaming in 25 minutes) or EFW cooling to the SGs and operator depressurization of the primary side to LPI system injection pressure.

A medium break LOCA size in the IPE is considered to range from 1.5 to 4 inches in diameter. One HPI train is needed for mitigation. The licensee's analysis does not credit depressurizing to LPI pressure if the HPI system fails following a medium break LOCA.

One HPI pump provides sufficient RCP seal injection.

The licensee's risk analysis assumes for SGTR that one HPI train is needed for success, and that depressurization to LPI conditions can be achieved with no credit for ADV steaming in 25 minutes for the requested TS changes.

Feed and bleed cooling requires two HPI pumps during the injection phase with flow into an intact header. Only one pump is needed in the recirculation phase.

For an ATWS scenario, the HPI system may be needed for emergency boration. With secondary side heat removal available, successful injection from one HPI pump can bring the reactor to a safe condition.

4.3.3 Evaluation

The licensee provided a risk-informed technical specification change request using the guidance in RG 1.177, "AN APPROACH FOR PLANT-SPECIFIC, RISK-INFORMED DECISIONMAKING: TECHNICAL SPECIFICATIONS" and RG 1.174, "AN APPROACH FOR USING PROBABILISTIC RISK ASSESSMENT IN RISK-INFORMED DECISIONS ON PLANT-SPECIFIC CHANGES TO THE LICENSING BASIS." Risk-informed TS amendments follow a three-tiered process as discussed in RG 1.177. Tier 1 involves using PRA techniques to gain risk insights. This step includes estimating the annual average change in core damage frequency (ΔCDF) and the incremental conditional core damage probability (ICCDP) for the subject equipment out of service. The second tier addresses the avoidance of risk-significant configurations. For this tier, the licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out of service consistent with the proposed TS change. Finally, for Tier 3, the licensee should have a risk-informed configuration management program. The need for this third tier stems from the difficulty of identifying all possible risk-significant configurations under Tier 2 that will ever be encountered over extended periods of plant operation.

4.3.3.1 Tier 1: PRA Capability and Insights

The licensee periodically evaluates changes to the plant with respect to the assumptions and modeling in the Oconee IPE. In 1995, the licensee initiated an update (Reference 10) of the 1990 Individual Plant Examination, and provided the results to the staff in 1997. The total CDF resulting from both “internal” and “external” accident initiating events was reported to be 8.9E-5/yr.

Further updates to the Oconee IPE model have been made since 1997. In 1998, a detailed and comprehensive reliability study of the HPI system (Reference 7) was completed. This study was performed at the request of the staff to identify HPI system reliability improvements following two events (Reference 11) that significantly challenged the reliability of the HPI system. The licensee indicated in the study that the Oconee IPE model was modified to create a more complete reliability model of the HPI system and its interfaces. The Oconee IPE model has also been modified to include the limiting location SBLOCA initiator in response to a staff question (Reference 6) during the review of this proposed TS amendment. The licensee indicated that these changes do not significantly impact the total CDF (References 6, 8).

The risk measures discussed in the regulatory guidance for risk-informed TS are:

i. the increase in annual average ΔCDF,

j. the ICCDP,

k. the increase in annual average large early release frequency (ΔLERF), and

l. the incremental large early release probability (ICLERP).

The ΔCDF and ΔLERF are measures of the annual average risk increase associated with the TS LCO. The ICCDP is a measure of the increase in the probability of core damage, conditional on the subject equipment being unavailable during the LCO. The ICLERP is a measure of the increase in the probability of a large, early release of radionuclides, conditional on the subject equipment being unavailable during the LCO. The acceptance guidelines for the ΔCDF over the baseline CDF and the ΔLERF over the baseline LERF are provided in RG 1.174. The acceptance guidelines for the ICCDP and the ICLERP are provided in RG 1.177.

The proposed LCOs for Conditions B and C may be entered for either planned or unplanned maintenance. The reason for entering the LCO is an important consideration in evaluating the risk measures. If HPI component(s) have failed due to random causes, similar HPI component(s) are subject to a substantially increased failure probability due to potential common cause failure (CCF) mechanisms. An evaluation of the failure mechanism and corrective maintenance (CM) would be needed in such a situation. Entering an LCO due to unplanned or random HPI component failure(s) that requires CM is more challenging to HPI system reliability than for planned preventive maintenance (PM). The method for calculating CCF probabilities for both planned unavailability (i.e., PM CCF modeling) and unplanned unavailability (i.e., CM CCF modeling) is discussed in RG 1.177.

The risk associated with random failures depends on when the CCF evaluation is started and finished, as well as its adequacy. During the evaluation time period, the method for modeling

CCF given a random failure is appropriate and not necessarily conservative. The longer this time period, the greater the risk due to internally or externally initiated events. After the licensee has determined that similar HPI component(s) are not inoperable due to potential CCF, the likelihood of CCF of those components is reduced.

In the event of a component failure, the licensee would use its Problem Investigation Process (PIP), a formal systematic procedure, to determine if a CCF exists. For equipment failures, one of the criteria for initiating an immediate investigation is whether the failure may result in single failure vulnerabilities of components. The PIP is invoked for a number of events or conditions, and documented as the problem investigation progresses. An integral part of the process is root cause determination, the effect of the failure on operability, and the vulnerability of other equipment or components to similar failures (i.e., review of an HPI train or pump inoperability for generic applicability). Corrective actions are identified and initiated to address, correct, and prevent recurrence of the failure. Whenever the licensee's evaluation determines that a common cause condition affects both HPI trains or two or more HPI pumps, then proposed Condition H of TS 3.5.2 would be entered, which requires the plant to enter TS 3.0.3. TS 3.0.3 provides actions that would lead to the plant being placed in a condition outside the applicability of TS 3.5.2; i.e., the reactor would be shut down.

By letter dated August 5, 1999, the licensee explained the PIP process and their configuration risk management program. This program provides a proceduralized risk-informed assessment and manages the risk associated with equipment inoperability. It applies to structures, systems, or components for which a risk-informed allowed outage time has been granted in the TS. A commitment to add this program to the Selected Licensee Commitments Manual (which is part of the UFSAR and, therefore, subject to the 10 CFR 50.59 rules for changes) was included in the August 5, 1999, letter. Moreover, a CCF evaluation is part of any equipment operability determination that is made when an HPI pump or valve becomes inoperable. The NRC staff finds that reasonable controls for implementation, component evaluation, and subsequent evaluation of proposed changes is best provided by the licensee's administrative processes. Therefore, this regulatory commitment does not warrant the creation of a separate regulatory requirement.

4.3.3.1.1 Condition B

CCF considerations are directly related to the unreliability of the HPI system. The approach taken in the submittal estimated the unreliability of a two train and a three train HPI system. The difference between these estimates was assumed to represent the increase in HPI system unreliability associated with one HPI pump out of service and the cross-over discharge header unavailable. (This cross-over discharge header contains the HP-409 and HP-410 valves.) The staff's review noted that the increase in HPI system unreliability derived from this approach most closely reflected an HPI pump out of service for planned PM and the cross-over discharge valve(s) not out of service due to random failures. If one HPI pump or HP-409/HP-410 failed randomly, the potential HPI system unreliability is increased beyond that estimated in the submittal, resulting in a larger predicted risk. The risk associated with the HPI system unreliability is discussed below for: 1) the reported estimates in the submittal, and 2) CM CCF modeling for the full duration of the LCO.

The licensee reported for Condition B a ΔCDF of 2.8E-7/yr and an ICCDP of 3.9E-7, given one HPI pump out of service and the cross-over discharge header unavailable. When CM CCF

modeling was applied to the remaining HPI pumps over the 30-day LCO, the ΔCDF increased to approximately 1.4E-6/yr and the ICCDP increased to approximately 2E-6. CM CCF modeling had not been taken into account for the cross-over discharge header valve(s) in these estimates. The staff notes that these estimates of average annual CDF increase are even lower if the LCO is entered only for CM on an HPI pump once every several years (as stated previously, the licensee assumed a frequency of once per year in its analysis, but believes a more realistic frequency is once per 9 years). Therefore, when one HPI pump is out of service for CM and the cross-over discharge valve(s) are inoperable for reasons other than random failures, the staff believes that the annual average risk increase is low. It is noted that the ICCDP is not necessarily small if the CCF evaluation of the remaining HPI pumps takes too long. When CCF is considered, the ICCDP is believed to be generally close to the RG 1.177 acceptance criteria of 5E-7, provided that an adequate CCF evaluation is completed promptly. There are other uncertainties besides CCF in the ICCDP, however, that tend to increase this risk measure and are discussed below.

The licensee indicated that LERF considerations were negligible with an HPI pump out of service. The staff noted that initiating events identified in the release categories of the IPE study are not expected to result in significant LERF increases for this proposed LCO. The limiting SBLOCA, which may result in early fuel damage, is not expected to be a LERF contributor since the reactor building cooling units are able to control containment pressure to prevent a large early release. However, the staff identified the SGTR event as a potential contributor to LERF. For maintenance on an HPI pump, the SGTR risk was reported in the licensee's submittal as 1.2E-7/yr for the ΔCDF and 1.7E-7 for the ICCDP. Applying CM CCF modeling for the full duration of the LCO, the increase in SGTR CDF becomes 7.4E-7/yr and its ICCDP becomes 8.3E-7 (based on the HPI system failure probability discussed in Reference 4).

The licensee informed the staff that SGTR events were not expected to result in significant early health effects based on the Oconee IPE study Level 3 results. However, the staff believes that it is appropriate to consider SGTR as a LERF contributor. The licensee did not provide a baseline LERF since they believe the LERF increase associated with the proposed TS is negligible. The staff notes, though, that the baseline LERF appears to be in the E-7 range from the sum of the early containment failure frequency and the SGTR CDF in the updated IPE study. Equating SGTR to a LERF event indicates that, for this proposed TS amendment, the ΔLERF is small with respect to the RG 1.174 acceptance guidelines when an HPI pump is unavailable for CM. It is noted that the ICLERP is not necessarily small if the CCF evaluation of the remaining HPI pumps takes too long. When CCF is considered, the ICLERP due to SGTR is best characterized as generally close to the RG 1.177 guideline of 5E-8, provided that an adequate CCF evaluation is completed promptly.

The licensee's risk assessment provided in the submittal did not consider CM CCF modeling of HPI MOVs, given that one or both cross-over discharge headers fail to open. If the proposed Condition B were to be entered due to HP-409 or HP-410 failing to open, the staff believes that the associated risk is comparable or smaller than that associated with entering proposed Condition B due solely to an inoperable HPI pump. If one of these valves and one HPI pump were inoperable due to random causes, the predicted decrease in HPI system reliability (using the CM CCF method) can result in increasing risk measures above guidance if a CCF evaluation is not aggressively applied.

The risk associated with both cross-over discharge valves being inoperable can be more significant. Until the licensee's CCF evaluation can determine the operability of other closed HPI system MOVs, one HPI train or the system itself can have a very high probability of failure depending on the nature of the valve failures and the applicability of the valve failure to other closed HPI MOVs. The staff applied the CM CCF modeling method for the 30-day LCO to HP-24, HP-25, and HP-26 using HPI system MOV data from the NRC CCF database (Reference 12). Assuming that the CCF probabilities in this database apply to these valves, an ICCDP in the low E-5 range results from the sum of SGTR and medium break LOCA events. Both cross-over discharge valves failing simultaneously is expected to be a rare event. The implications to the HPI system reliability, should this event happen, further indicates the need for an aggressive CCF evaluation program.

The staff notes that the licensee has reviewed a number of potential CCF mechanisms in the Oconee HPI system reliability study. This study considered well known mechanisms such as gas expansion in the pumps' common suction header, as well as a subtle mechanism involving the potential for flow diversion into the letdown storage tank (LDST) in the recirculation mode. Also, following the event on May 3, 1997, in which two HPI pumps experienced damage due to inadequate net positive suction head, corrective actions were taken to prevent re-occurrence of this event. Therefore, the licensee is aware of a number of potential CCF mechanisms through the reliability study and operational experience.

The licensee indicated that the need for the 30-day LCO is to allow sufficient time for one HPI pump to be removed, repaired, and replaced while the plant is at power. For such work, the staff notes that, due to the spatial layout of the HPI pumps, it is very important that caution is used not to adversely impact the other pumps. Damage to the running pump may cause a plant transient with loss of feed and bleed capability, if needed.

The staff also reviewed the risk associated with the limiting location SBLOCA since the licensee submitted the proposed TS amendment to address this scenario. As previously noted, a limiting SBLOCA is predicted to result in core damage if only one HPI pump is injecting into the broken header and a secondary side steaming path is not established in 25 minutes.

The risk associated with this scenario is decreased by the ability of the HPI system to withstand a single failure (e.g., pump or discharge valve) and still mitigate the LOCA event by establishing a secondary steam path in the required time. Successful steaming requires successful operation of the TBS or the ADV system. In addition, the EFW system is required to raise the SG water level to the subcooled margin level in 20 minutes on one SG.

Using the TBS is the preferred means for steaming. However, failure of certain support systems could cause the TBS to be unavailable, while the ADVs would remain available since they are manually operated. The updated Oconee IPE study indicates there were zero occurrences of a loss of condenser vacuum in 34 reactor-years. In response to a staff question, the licensee also reviewed the TBV operational data from January 1, 1988, through June 1999. The data showed that the TBVs operated as expected after a total of 51 reactor trips, with two problems that did not prevent the TBS from being used to dump steam to the condenser. Operational experience also indicates that the TBS may be available following a loss of offsite power (LOOP) event, as was the plant response to a Unit 2 LOOP event in October of 1992. However, loss of support systems to the TBVs or the condenser following a LOOP can result in the need to establish an alternative steam path to the atmosphere through

the ADVs. Thus, operational data indicates that the TBS will most likely be available after a limiting location SBLOCA. However, there is uncertainty about its availability if a LOOP occurs after the reactor trips.

The ADVs are on the turbine deck, immediately outside the control room, and easily accessible. There is one set of valves for each steam line and, hence, each SG. Long chains are attached to each of the ADVs for manual operation. Operation of each set involves opening two valves before the control valve can be opened to complete the steam path to atmosphere. The Oconee Emergency Operations Procedure requires that the operators open the ADVs on both SGs when their operation is required. Both the accessibility of the ADVs and the practice of simultaneously taking ADV action on both SGs increase the chances of successful steaming. However, licensee exercises indicated that the time to take the necessary actions were in the range of 17 to 22 minutes (Reference 5). Due to the short time margin to complete the ADV steam path before predicted core damage in 25 minutes, the staff believes that steaming to the atmosphere is acceptable from a human factors standpoint (see Section 4.2.2.3.2 of this safety evaluation).

The staff notes that there are a number of operational challenges after a limiting location SBLOCA. The challenges are increased if a delayed LOOP occurs following the LOCA. In this case, the TBS may not be available. Since the staff believes that using the ADVs for steaming is not very reliable, there is a significantly increased likelihood that the secondary side steam path cannot be established in the required time. The frequency of a SBLOCA resulting in a delayed LOOP following a reactor trip is believed to be low (Reference 13). However, for Condition Statements with long Completion Times, it is possible that conditions arise that result in a LOOP if there is a reactor trip (e.g., switchyard problems or grid conditions). Thus, while in the Condition Statement corresponding to the LCO, the licensee should be aware of conditions (such as LOOP after a reactor trip) that can impact the availability of the TBS after a limiting location SBLOCA. The licensee addressed TBS operability in Tier 2 and Tier 3.

If either or both of the crossover discharge header valves (HP-409/HP-410) are inoperable, the normal discharge cross connect path would not be available. Therefore, it would be necessary to open the manual valve, HP-116, to cross connect the discharge headers. Under this condition, the pumps injecting into the broken header are capable of providing the required core cooling in the event that HPI flow into the intact header fails. The licensee's submittal indicates that HPI injection into the broken header provides the required core cooling if a secondary side steam path is established within 25 minutes. For this reason, the proposed TS required actions for inoperable crossover valve(s) is the same as that for the loss of an HPI pump. In the event that both an HPI pump and crossover valve(s) are inoperable, the proposed change to the Bases explains that the manual valve would be opened to cross-connect the discharge headers. TS Condition E would allow the headers to be cross connected for 72 hours.

On April 21, 1997, Oconee Unit 2 experienced a 12 gal/min leak developed in the reactor coolant system, HPI nozzle safe end-to-piping weld downstream of RCP 2A1, which was categorized as an unisolable leak at a limiting location. The piping failures were caused by high-cycle thermal fatigue that resulted from the mixing of makeup, warming, and reactor coolant system flows. The licensee undertook and performed corrective actions to prevent re-occurrence of this event.

In summary, the ΔCDF and ΔLERF are believed to be small with respect to guidance due to the rare expected use of the proposed LCO. In addition, as explained above, the staff has determined that the ICCDP and the ICLERP are acceptable in view of the following: (a) the licensee has made a commitment to perform a prompt and adequate CCF evaluation, (b) the systems needed for secondary side steaming can reasonably be expected to be operable and, (c) void formation in the hot legs, if it occurs after a limiting-location SBLOCA, does not result in loss of SGs for primary system depressurization.

4.3.3.1.2 Condition C

The licensee reported for Condition C a ΔCDF of 3.3E-7/yr and an ICCDP of 4.9E-7, given one train available. Application of a generic train CCF probability for the duration of the LCO, given one train unavailable, resulted in increasing these estimates by approximately a factor of 3. The staff believes the licensee's estimated annual average CDF increase is small in the context of RG 1.174 guidance. Also, the ICCDP is generally close to the RG 1.177 guidance, provided an adequate CCF evaluation is completed promptly.

The licensee indicated that LERF considerations were negligible with one HPI train inoperable. Following a similar line of reasoning as explained for Condition B, the staff believes that the principal potential contributor to LERF is from SGTR events. The SGTR ΔCDF in the submittal was reported to be 8.7E-8/yr, and the SGTR ICCDP to be 1.3E-7. Application of a generic train CCF probability for the duration of the LCO, given one train unavailable, resulted in increasing these estimates by approximately a factor of 3. For the proposed Condition C, the ΔLERF is small with respect to the RG 1.174 guidance. Also, the ICLERP is best characterized as generally close to the RG 1.177 guidance, provided an adequate CCF evaluation is completed promptly.

For the limiting SBLOCA location, there is increased emphasis on the ability to successfully cool the core with HPI injection into the broken header while in proposed Condition C. This is because the reliability of the HPI system in this case is dependent on the primary coolant pressure, which in turn is dependent on steaming with one of two non-safety related systems (i.e., the TBS or the ADVs) according to the licensee's submittal. It is also noted that instead of injecting into the broken header with only one HPI pump, a second pump may be available to increase the flow into the vessel.

The sources of uncertainties in the risk measures discussed above for proposed Condition B are also applicable for proposed Condition C. In addition, as explained above, the staff has determined that the ICCDP and the ICLERP are acceptable in view of the following: (a) the licensee has made a commitment to perform a prompt and adequate CCF evaluation, (b) the systems needed for secondary side steaming can reasonably be expected to be operable and, (c) void formation in the hot legs, if it occurs after a limiting-location SBLOCA, does not result in loss of SGs for primary system depressurization.

4.3.3.1.3 Maintenance Rule Control

The licensee's Maintenance Rule program considers unavailability and reliability of systems. For this program, unavailability and reliability goals have been established for the HPI system. The HPI trains have an unavailability performance criterion of less then 6 percent unavailability and a system reliability performance criterion of less than three maintenance preventable

functional failures (MPFFs) per fuel cycle. The performance criteria for the ADV functional test run only at an 18 month frequency is zero MPFFs.

The licensee indicated that, to assure the safety of the plant is maintained, the IPE model is periodically updated using actual plant experience. Additionally, as part of the Maintenance Rule Periodic Assessment, the risk impact of the actual unavailability and functional failures over the period are evaluated using the plant IPE model and statistical analysis methods. If the overall plant risk is significantly affected by the actual performance, the performance criteria will be adjusted, or the equipment will fall under the Maintenance Rule provisions in 10 CFR 50.65(a)(1), have goals established, and performance monitored to those goals.

The licensee considered the impact of the limiting location SBLOCA on CDF to determine if it resulted in any Maintenance Rule performance criterion changes for the HPI trains. The licensee determined that it did not result in any changes.

4.3.3.1.4 Conclusions

For the reasons discussed above, the staff believes that the RG 1.174 and RG 1.177 guidance are met for the proposed Conditions B and C. Furthermore, the risk from a small break in a cold leg is low since the HPI train injecting into the broken header is believed to be successful (given successful secondary side steaming at the required time) in the event of hot leg voiding. The staff also believes that it is important that caution is used to not adversely impact the other HPI pump(s) during pump work.

Control of system configurations that could increase risk during the LCOs (such as systems needed for secondary side steaming) is captured by the Tier 2 and Tier 3 considerations, and is discussed below.

4.3.3.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

The second tier provides reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out of service consistent with the proposed TS change. Based on the Tier 1 analysis and the PRA matrix of procedure Work Process Manual (WPM) 607, "Maintenance Rule Assessment Of Equipment Removed From Service," the licensee derived conclusions for the avoidance of risk-significant plant configurations during the proposed LCOs. WPM 607 is used at Oconee to prevent high risk combinations of equipment from being out of service at the same time. WPM 607 contains a Risk Assessment Matrix (i.e., PRA matrix) that uses risk insights from the 1996 Oconee IPE model. Currently, an update to this model is being developed.

In addition, WPM 608, "Outage Risk Management Utilizing ORAM-Sentinel" and WPM 609, "Innage Risk Management Utilizing ORAM-Sentinel" are used to address the Maintenance Rule requirement and the On-Line Maintenance Policy requirement to control the safety impact of combinations of equipment removed from service.

4.3.3.2.1 Component Cooling (CC) Water System

The CC system along with the HPI system is designed to maintain proper RCP seal cooling. The proposed TS would permit operating conditions during which the ability of the HPI system

to maintain seal injection is degraded. The relative importance of the CC system function increases when an HPI pump is out of service. An increase in CC system failure probability, as might be associated with having a CC pump out of service, would have a significant impact on the frequency of transients initiated by an HPI loss of seal injection. The licensee has committed to include control of the CC system maintenance in its Maintenance Rule configuration program.

4.3.3.2.2 Safe Shutdown Facility (SSF) - Reactor Coolant Makeup (RCM)

The SSF provides an alternate means of seal injection. The connection between the HPI seal injection function and the SSF is recognized and controlled in the Maintenance Rule configuration program.

4.3.3.2.3 EFW System

The importance of EFW increases when HPI components are out of service. Main feedwater, EFW from another unit, and the SSF-auxiliary service water (ASW) system are other sources of feedwater to the SGs. The availability of these other feedwater sources, in addition to the EFW system, decreases the likelihood of loss of all feedwater and subsequent need to use the HPI system for feed and bleed cooling. Controls on concurrent unavailability of the HPI and EFW systems have been implemented through the Maintenance Rule configuration management program. The SSF-ASW is also considered in this program.

4.3.3.2.4 SG Depressurization

The ADV flow path for each SG in the proposed TS change is to be verified operable by administrative means. The ADVs are in the licensee's Maintenance Rule program.

The licensee will add the TBS to ORAM-Sentinel. This will ensure that the TBS operability and functionality are protected during HPI condition entries or that contingencies are provided via Plant Operational Review Committee (PORC) review. When HPI 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 red configurations are to coordinate the work to eliminate schedule conflicts. If it is desired to perform work that produces a valid red condition indicated by ORAM-Sentinel, a PORC meeting must be convened. The PORC may consider special PRA analysis or request that such analysis be performed and compensatory measures be taken to aid in the decision making process. Per licensee procedures, any PORC decisions made concerning an ORAM-Sentinel high risk scenario must be documented in the PORC meeting minutes, communicated to the Work Control Center, and referenced in the proposed or committed schedule.

The staff finds Tier 2 to be acceptable for these proposed TS changes.

4.3.3.3 Tier 3: Risk-Informed Configuration Management

Tier 3 describes the Configuration Risk Management Program (CRMP), which includes provisions for assessing scheduled and unscheduled plant configurations. Guidance for the requirements of a CRMP are provided in RG 1.177. RG 1.177 indicates that a licensee's CRMP for risk-informed TS should be described in the TS Administrative Controls section. In lieu of placing the CRMP in the TS Administrative Controls section, the licensee is placing it in its SLC document. Since it is part of the FSAR, changes to the SLC are subject to the requirements of 10 CFR 50.59. The staff finds that placing the CRMP in the SLC provides adequate assurance that future changes will receive an appropriate level of management and, if necessary, NRC staff review.

The CRMP provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to structures or components for which a risk-informed allowed outage time has been granted in the TS. The program includes the following:

a. Provisions for the control and implementation of a Level 1 at-power internal events PRA-informed methodology. The assessment provides for evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the plant configuration described by the LCO Action Statement for preplanned activities.

c. Provisions for performing an assessment after entering the plant configurations described by the LCO Action Statement for unplanned entry into the LCO Action Statement.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the plant configuration described by the LCO Action Statement.

e. Provisions for considering other applicable risk-significant contributors such as Level 2 issues and external events, qualitatively or quantitatively.

Procedures WPM 607, WPM 608, and WPM 609 provide the framework for implementation of the CRMP. For maintenance activities during innages (time between refueling outages), 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 RG.

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 of equipment out of service 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 IPE, which is the basis for the ORAM-Sentinel model. ORAM-Sentinel also includes a qualitative assessment in addition to the quantitative provided from the IPE results. The guidance in the qualitative assessment module of ORAM-Sentinel was developed similarly to the IPE Matrix in that the IPE insights were used to develop the end state colors for each safety function/event.

to the IPE Matrix in that the IPE insights were used to develop the end state colors for each safety function/event.

Level 2 concerns are addressed by both the ORAM-Sentinel and the IPE 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 IPE Matrix considers those systems important to containment pressure control and isolation.

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

Based on the above, the staff finds that the Tier 3 requirements are met for these proposed TS changes.

4.3.4 Conclusion

For the reasons discussed above, the staff finds that the RG 1.174 and RG 1.177 Tier 1 guidance are met for the proposed Conditions B and C. Furthermore, the risk from a small break in a cold leg is low in the event of hot leg voiding. Also, the staff finds that it is important that caution is used to not adversely impact the other HPI pump(s) during pump work. Finally, the staff finds that Tier 2 and Tier 3 have been adequately addressed by the licensee for these proposed TS changes. Therefore, the proposed changes are acceptable.

4.3.5 References

1. NRC, RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," July 1998.

2. NRC, RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," August 1998.

3. "Oconee Nuclear Station Units 1, 2, and 3 Proposed Amendment to the Facility Operating License Regarding the High Pressure Injection System Requirements Technical Specification Change No. 98-13," Duke Energy Corporation letter to NRC, December 16, 1998.

4. "Oconee Nuclear Station Units 1, 2, and 3 Supplement to December 16, 1998, LAR Regarding the HPI System Technical Specification Change No. 98-13-01," Duke Energy Corporation letter to NRC, August 5, 1999.

5. "Oconee Nuclear Station Units 1, 2, and 3 Supplement to December 16, 1998, LAR Regarding the HPI System Technical Specification Change No. 98-13-01," Duke Energy Corporation letter to NRC, October 4, 1999.

6. "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 No. 98-13," Duke Energy Corporation letter to NRC, March 29, 2000.

7. "High Pressure Injection (HPI) Reliability Study," Oconee Nuclear Station letter to NRC, December 18, 1997.

8. Oconee Nuclear Station High Pressure Injection (HPI) Reliability Study meeting slides, Duke-NRC meeting, April 1, 1998. (See Meeting Summary dated April 7, 1998).

9. "Oconee Nuclear Station Unit 3 Probabilistic Risk Assessment," Volumes 1-3, Duke Power Company, November 30, 1990.

10. "Probabilistic Risk Assessment Individual Plant Examination," Oconee Nuclear Site letter to NRC, February 13, 1997.

11. NUREG/CR-4674, Vol. 26, "Precursors to Potential Severe Core Damage Accidents: 1997", LER 287/97-003 and LER 270/97-001, Oak Ridge National Laboratory, November 1998.

12. NUREG/CR-5497, "Common-Cause Failure Parameter Estimations," Idaho National Engineering and Environmental Laboratory, October 1998.

13. NUREG/CR-6538, "Evaluation of LOCA With Delayed LOOP and LOOP With Delayed LOCA Accident Scenarios," Brookhaven National Laboratory, July 1997.

14. "Oconee Nuclear Station Docket Nos. 5–269, 270, 287 High Pressure Injection System Requirements Response to Request for Additional Information Technical Specification Change No. 96-10," Duke Power Company letter to NRC, June 17, 1998.

5.0 SUMMARY

Based on the staff's review of the information submitted by the licensee, as described above, the staff finds the proposed changes acceptable. In addition, the staff has determined that the proposed Bases changes and editorial changes are consistent with the TS changes, supply supporting information, and are acceptable.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the South Carolina State official was notified of the proposed issuance of the amendments. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued proposed findings that

the amendments involve no significant hazards consideration, and there has been no public comment on such finding (64 FR 9187). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

8.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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