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A Duke Energy Company

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September 25, 2003

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
Emergency Plan Implementing Procedures Manual
Volume C Revision 2003-09

Please find attached for your use and review copies of the revision to the Oconee Nuclear Station Emergency Plan: Volume C Revision 2003-09, September 2003.

This revision is being submitted in accordance with 10 CFR 50-54(q) and does not decrease the effectiveness of the Emergency Plan or the Emergency Plan Implementing Procedures.

Any questions or concerns pertaining to this revision please call Rodney Brown, Emergency Planning Manager at 864-885-3301.

By copy of this letter, two copies of this revision are being provided to the NRC, Region II, Atlanta, Georgia.

Very truly yours,

R. A. Jones.
VP, Oconee Nuclear Site

xc: (w/2 copies of attachments)
Mr. Luis Reyes,
Regional Administrator, Region II
U. S. Nuclear Regulatory Commission
61 Forsyth St., SW, Suite 24T23
Atlanta, GA 30303

w/copy of attachments
Mr. James R. Hall
Rockville, Maryland

(w/o Attachments, Oconee Nuclear Station)
NRC Resident Inspector
J. R. Brown, Manager, Emergency Planning

A045

September 25, 2003

OCONEE NUCLEAR SITE
INTRASITE LETTER

SUBJECT: Emergency Plan Implementing Procedures
Volume C, Revision 2003-09

Please make the following changes to the Emergency Plan Implementing Procedures Volume C by following the below instructions.

REMOVE	**INSERT**
Cover Sheet 2003-08	Cover Sheet 2003-09
Table of Contents page 1 & 2	Table of Contents page 1 & 2
EM 5.1,-Rev. 11 - Engineering Emergency Response Plan - 08/19/03	EM 5.1,-Rev. 12 - Engineering Emergency Response Plan - 09/17/03

DUKE POWER

EMERGENCY PLAN
IMPLEMENTING PROCEDURES
VOLUME C

APPROVED:

W. W. Foster, Manager
Safety Assurance

09/29/03

Date Approved

09/29/03

Effective Date

VOLUME C
REVISION 2003-09
SEPTEMBER 2003

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INFORMATION
ONLY

Duke Power
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Oconee Nuclear Site
Engineering Manual

Section Title: EM-5.1 - Engineering Emergency Response Plan
Revision No.: 12

Reference:			
Approved By:	Paul Neef	Approved Date:	9-17-03
Revised By:	Mary Jo Clarkson	Revised Date:	9-17-03
Reviewed By:	[illegible]	Original Date:	5-27-92
		Effective Date:	9-17-03

DOCUMENT REVISION DESCRIPTION

REVISION NO.	PAGES or SECTIONS REVISED AND DESCRIPTION
1	3.1, 3.2, 4.1, 4.3, 4.4, 4.5, 5.1.3, 5.2.2, 5.2.4, 5.2.5, 5.2.6, 6.3, 6.7 7.3.1, 8.3 - General update – Added EOF facility into several steps, clarified Evacuation Coordinator duties, added TSC/OSC Liaison duties, revised site assembly reporting locations, changed "Security Shift Lieutenant" to "Security Shift Supervisor", clarified duties of TSC Offsite Dose Liaison.
2	5.1.2,5.1.3 - Inserted instructions for swiping badge when assembly inside Protected Area is required.
	5.1.3 – 5.1.8 - Renumbered because 5.1.2 was inserted.
3	1.0 - Changed 3 working days to 7 working days
	2.0 - Added NSD 117 as a reference
	4 - Deleted 4.3 Engineering Section Manager
	4.5 - Changed "impassable" to "damaged: use caution"
	Added requirement to stay within response time.
	5.2.2 - Changed title to TSC Eng. Mgr. from MSE Mgr.
	6.2 - Changed MSE to MCE
	6.5.1,6.5.2 - Changed Nuclear Eng to Reactor Systems Eng
	6.6.1,6.6.2, and 6.6.3 - Changed title to TSC Engineering Manager and MSE To MCE
	6.6.2 - Added electrical to the support required
	6.8 - Added section Primary and BOP Systems Eng duties.
	7.3.1, 7.3.2 - Changed CEN to RES
	General - Changed MG to ED in 3 locations
4	Add Enclosure 9.1 for TSC Guidance Document
5	Minor editorial changes, added Section M and revised 6.8 to only require one engineer.
6	Minor editorial changes, added Section N.
7	Add Section O to TSC Guidance Document
8	Editorial changes to Section O
9	Enclosure 9.1 Section F – Added background information and instructions concerning recovery from a boiling spent fuel pool
10	Revise Section O to incorporate PIP 00-2707 CA# 7
11	Editoral Changes Only
12	Added Section P for guidance on depressurizing the reactor building after a loss of DHR event during MODES 5 and 6.

Table of Contents

1.0 Purpose

The purpose of this directive is to identify The Engineering Division responsibilities during an emergency at Oconee Nuclear Station. This directive is an implementation directive to the site emergency plan. Upon revision, a copy of this directive must be forwarded to Emergency Planning within seven (7) working days of its approval.

2.0 References

1. Oconee Nuclear Site Emergency Response Plan
2. NSD 117 Emergency Response Organization, Training, and Responsibilities

3.0 Definitions

3.1 Essential Personnel

Personnel needed to mitigate the emergency as determined by the EOF, TSC, or OSC.

3.2 Engineering Emergency Response Person

Engineering personnel assigned to those positions in the EOF, TSC, or OSC listed in Sections 6.0 and 7.0 of this directive.

4.0 Responsibilities

4.1 Engineering Division Manager

The Engineering Division Manager shall be responsible for the implementation of this directive. During a site assembly he/she shall be responsible to account for all engineering personnel to the Security Shift Supervisor or designee.

4.2 Engineering Group Manager

During a site assembly each Engineering Group Manager shall be responsible to account for each person in his/her Group to the Engineering Division Manager or designee.

4.3 Engineering Supervisor

During a site assembly each Engineering Supervisor shall be responsible to account for each person on his/her team to his/her Engineering Group Manager or designee.

4.4 Engineering Emergency Response Person

When notified of EOF/TSC/OSC activation, the engineering emergency response persons will report to their assigned position in the EOF, TSC, or OSC. Notification during normally scheduled work hours will be by an announcement on the station PA system. Notification during unscheduled work hours will be by pager or Community Alert Network using the following:

PAGER CODES:

- Blue Delta – EOF/TSC/OSC activated for a drill.
- Blue Echo – EOF/TSC/OSC activated for an emergency.

Note: During flooding/dam failure/earthquake conditions assume bridges may be damaged; use caution.

Blue Delta Bridges – Pager message used when bridges may be damaged and EOF/TSC/OSC activation is needed. Use caution.

Blue Echo Bridges – Pager message used when EOF/TSC/OSC activated for an emergency and the bridges may be damaged; use caution.

Each engineering emergency response person will carry a pager which will be turned on when leaving the station and left on at all times. He/she will remain fit for duty at all times while serving duty as an engineering emergency response person, and will stay within required response times for his/her facility. For specifics, see NSD 117.

4.5 Employee

During a site assembly each employee will proceed to his/her site assembly location (generally the person's work area) and report to his/her supervisor within the specified time.

5.0 SITE ASSEMBLY AND EVACUATION

5.1 Site Assembly

5.1.1

When a site assembly is commenced, a warbling tone will be broadcast over the Station PA system and the outdoor Site Assembly Horn will sound. All Engineering personnel shall immediately proceed to their site assembly location and report to his/her supervisor. Any person who cannot report to his/her designated area within eight (8) minutes of the commencement of the site assembly shall contact his/her supervisor by telephone for assembling instructions.

5.1.2

Personnel inside the Protected Area (PA) who must assemble at a location inside the PA or who cannot make it to their assembly point outside the PA shall card in at the nearest card reader, notify their supervisor of their location, and wait for further instructions.

5.1.3

Personnel working in an RCZ in protective clothing should leave the work area and go to the appropriate Change Room. Once in the Change Room area, they should card in (swipe their security badge) and contact their supervisor for accountability. Personnel should then follow the instructions of the RP personnel in the Change Room or RCZ.

5.1.4

Each Engineering Section Manager/Supervisor shall account for all personnel in his/her Section/Team and report the result to his/her Engineering Group Manager or designee. Unaccounted for personnel shall be reported by name. This report should be made within 10 minutes of the commencement of the site assembly. Do NOT leave phone mail messages when reporting.

5.1.5

Each Engineering Group Manager shall account for all personnel in his/her Group and report the result to the Engineering Division Manager or designee. Unaccounted for personnel shall report by name. This report should be made within 15 minutes of the commencement of the site assembly. Do NOT leave phone mail messages when reporting.

5.1.6

The Engineering Division Manager or designee shall account for all Engineering personnel and report the result to the Security Shift Supervisor or designee. Do not report unaccounted for personnel by name at this time. This report shall be made within 20 minutes of the commencement of the site assembly.

5.1.7

During unscheduled work hours, each employee on site shall report to his/her assigned assembly area. If a Supervisor is present, the supervisor will call directly to the Security Shift Supervisor and report accountability within 15 minutes. If no Supervisor is present, the senior employee (or lone employee) will call the Security Shift Supervisor directly and report accountability. If working in an RCZ in protective clothing, proceed to the appropriate Change Room. Report to the individual in charge of the change room. If no one is in charge of the change room, call the Security Shift Supervisor directly and report accountability.

5.2 Site Evacuation Instructions

Initial Notification:

5.2.1

Site evacuation will be activated only after a site assembly. When it has been deemed necessary to evacuate the site, an announcement will be made on the PA system and a Lotus Note sent to group evacuation coordinators giving instructions for an evacuation.

5.2.2

The Engineering Evacuation Coordinator monitors LOTUS Notes during an emergency, passes evacuation information on to Engineering group administrative assistants, and gets acknowledgement back that the information has been received.

The Evacuation Coordinator also lets Engineering Managers know that they need to provide 24 hour coverage for their areas during the emergency, gets that information from the managers, and relays it to the TSC Engineering manager in the TSC.

5.2.3

The Engineering Section Manager/Supervisors will determine which, if any, essential personnel should not evacuate. This will be based on the needs communicated from the TSC or OSC.

5.2.4

The Engineering Section Managers/Supervisors, based on needs communicated from the TSC or OSC, will establish shift lead persons and a continuous 24 hour staffing schedule, and communicate this schedule to all personnel in their section/team.

5.2.5

The Engineering Section Managers/Supervisors will give evacuation instructions to all personnel in their sections/teams and implement the evacuation plan.

Accountability Notification:

5.2.6

The Engineering Section Managers/Supervisors will report to their respective Engineering Group Manager or designee if transportation assistance is needed. They will report which personnel, if any, have been deemed essential and their location along with their shift lead persons and continuous 24 hour staffing schedule to the Engineering Evacuation Coordinator and their respective Group Manager.

5.2.7

The Engineering Sections Managers/Supervisors or designee will report the status of their sections/teams to the Group Evacuation Coordinator.

NOTE: Subsequent Evacuations will be coordinated from the designated relocation area(s) per NSD 114.

6.0 Technical Support Center

6.1

The Technical Support Center (TSC) is located on the Unit 2 side of the Units 1&2 control room. When reporting to the TSC, pick up ED and TLD, go to the Unit 1 or 2 Control Room Lobby, and frisk for possible contamination before entering the Control Room.

EMERGENCY RESPONSE SRWP NUMBER: 33 (For drills and emergency response)

If evacuation from the TSC becomes necessary, report to the alternate TSC on the third floor, room 316, of the Oconee Office Building. Assume the same duties as in the Primary TSC.

6.2 Technical Assistant to Emergency Coordinator

6.2.1

The Technical Assistant to Emergency Coordinator will report to the Emergency Coordinator. This position is staffed by the Mechanical and Civil Engineering Section (MCE). This position should be staffed within 75 minutes of the emergency declaration.

6.2.2

The Technical Assistant to Emergency Coordinator's main duty will be to maintain a log of activities in the TSC. This log will include systems and components status, decisions, and announcements made in the TSC. The Technical Assistant to Emergency Coordinator will also perform any other duties assigned by the Emergency Coordinator.

6.3 TSC/OSC Liaison

6.3.1

The TSC/OSC Liaison will report to the Emergency Coordinator. This position is staffed by Engineering within 75 minutes.

6.3.2

The TSC/OSC Liaison is responsible for communicating task priority and status information between the TSC and OSC.

6.4 Technical Assistant to TSC/OSC Liaison:

6.4.1

The Technical Assistant to TSC/OSC Liaison will report to the TSC/OSC Liaison. This position is staffed by Modification Engineering. Individuals staffing this position will be contacted by the Community Alert Network (CAN) system.

6.4.2

The Technical Assistant to TSC/OSC Liaison will maintain the Plant status board in the TSC. The Technical Assistant to TSC/OSC Liaison will perform any other duties as assigned by the TSC/OSC Liaison.

6.5 Nuclear Engineer

6.5.1

Reactor Systems Engineering will provide personnel for this position. This position is required by regulation with the person being available in the TSC within 75 minutes of the emergency declaration. This person is required to be in place prior to Control Room turnover to the TSC. The Nuclear Engineer will report to the TSC Engineering Manager in the TSC.

6.5.2

A second person from Reactor Systems Engineering will be called by the Community Alert Network System.

6.5.3

The Nuclear Engineer(s) will provide engineering support and recommendations in the following areas:

1. Reactor core physics
2. Shutdown margin calculations
3. Transient assessment functions via the transient monitors
4. Safety review function
5. Core damage assessment.

6.6 TSC Engineering Manager:

6.6.1

The TSC Engineering Manager should report to the TSC within 75 Minutes of emergency declaration and report to the Emergency Coordinator. The MCE Section is responsible for assuring this position is filled.

6.6.2

The TSC Engineering Manager will be responsible for providing engineering support required by the TSC. He/she will be responsible for resolving engineering problems. Also he/she will assure that any needed mechanical or electrical systems engineering personnel are contacted and given instruction on the necessary actions to be taken.

6.6.3

The TSC Engineering Manager will be responsible for making contact with the Accident Assessment Team in the Corporate Office to provide additional assessment expertise to the Technical Support Center.

6.7 Offsite Dose Assessment

6.7.1

The TSC Dose Assessment Liaison will report to the Emergency Coordinator in the TSC. He/she will be responsible for providing offsite Dose Assessment as needed and is to **report within 45 minutes of the emergency classification.**

6.7.2

The Offsite Dose Assessors report to the TSC Dose Assessment Liaison within 75 minutes of the emergency classification and provide dose assessment as needed.

6.8 Engineering Manager Assistant

6.8.1

This individual should report to the TSC within 75 minutes of emergency declaration and report to the TSC Engineering Manager.

6.8.2

The Engineering Manager Assistant will be responsible for providing Primary and BOP systems support required by the TSC and will report to the TSC Engineering Manager.

7.0 Operational Support Center

7.1

The Operational Support Center (OSC) is located at the back of the Unit 3 Control Room. When reporting to the OSC, carry ED and TLD, go to the Unit 3 Control Room Elevator Lobby, and frisk for possible contamination before entering the Control Room.

EMERGENCY RESPONSE SRWP NUMBER: 33 (For drills and emergencies)

7.2

If evacuation from the OSC becomes necessary, report to the alternate OSC located on the third floor, room 316A, of the Oconee Office Building. Assume the same duties as in the Primary OSC.

7.3 Equipment Engineering Support for OSC

7.3.1

The RES Engineering Support duty person is required to report to the OSC within 75 minutes of emergency declaration. This position will report to the OSC Manager.

7.3.2

RES Engineering Support will be responsible for providing Electrical Engineering support for any work performed by the OSC. Should any Mechanical/Civil Engineering needs arise from the OSC, this person will inform the appropriate party.

8.0 Emergency Operations Facility:

8.1

The Emergency Operations Facility (EOF) is located in Clemson on Isaqueena Trail next to Duke's Southern Operation Center. TLDs and EDs are not required for this facility.

8.2 Offsite Dose Assessment

8.2.1

The Offsite Dose Assessment persons will report to the Radiological Assessment Manager in the EOF. They will be responsible for providing Offsite Dose Assessment as needed.

8.3 Technical Briefers:

8.3.1

The Technical Briefers will be notified as needed by the Joint Information Center (located at the EOF). They will report to the Technical Briefers Section Head in the Joint Information Center.

8.3.2

The Technical Briefers will be responsible for reading news releases or predeveloped messages for technical accuracy and responding to calls by following the rumor control procedure.

8.3.3

The Technical Briefers will keep the Technical Briefer Section Head informed of calls being received and assist in coordinating activities as needed.

8.3.4

The Technical Briefer position is filled by persons from across the organization who possess the skills needed.

9.0 Enclosures

9.1 Oconee Technical Support Center Guideline

Enclosure 9.1 - Oconee Technical Support Center Guideline

Rev. 7

Gregg Swindlehurst	8/6/01
TSCG Section A	Date
Stephen Parrish	8/6/01
TSCG Section B	Date
Ron Harris	8/9/01
TSCG Section C	Date
Stephen Parrish	8/6/01
TSCG Section D	Date
Gregg Swindlehurst	8/6/01
TSCG Section E	Date
Ken Grayson	8/8/01
TSCG Section F	Date
Ron Harris	8/9/01
TSCG Section G	Date
Stephen Parrish	8/6/01
TSCG Section H	Date
Stephen Parrish	8/6/01
TSCG Section I	Date
Camilo Abellana	8/9/01
TSCG Section J	Date
Jeff Rowell	8/9/01
TSCG Section K	Date
Ed Burchfield	8/9/01
TSCG Section L	Date
Vance Bowman	3/1/02
TSCG Section M	Date

Ron Harris	5/21/02
TSCG Section N	Date
Gregg Swindlehurst	7/12/02
TSCG Section O	Date

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1.0 INTRODUCTION

The purpose of the Technical Support Center Guideline (TSCG) is to present accident mitigation guidance and facilitate ad hoc accident evaluation and decision making. The guidance contained herein provides the TSC with pertinent background information and candidate actions. Alternate methods not discussed herein may be used at the discretion of the TSC.

2.0 DIAGNOSIS AND MITIGATION

The TSCG consists of individual sections linked to specific TSC requested actions. Each requested action is linked to specific EOPs and/or AOPs. The sections are:

A. Starting or bumping a RCP following loss of SCM

B. Steaming a steam generator with water in the steam line

C. Refill the EWST

D. Evaluate outside air booster fan operation

E. Natural circulation cooldown considerations

F. Makeup and monitoring of the SFP

G. Makeup and monitoring of CCW intake pipe inventory

H. Conserve BWST inventory

I. CFT core cooling following loss of decay heat removal

J. Mitigate LPI pump interaction and LPI pump restart

K. Energize the ASW switchgear from an operating Oconee unit

L. Limitations on aligning HPI suction from the SFP

M. Ensure total LPSW recirculation flow is ≤9000 GPM during CCW dam failure

N. Manage Keowee Lake Level During a LOOP

Each section contains the following subsections:

1.0 SAFETY CONCERN

A brief statement highlighting the requested action or safety issue requiring TSC consideration.

2.0 PROCEDURE ENTRY CONDITIONS

This section lists the plant conditions, consistent with the procedure entry conditions, that are considered in development of the guidance. These bulleted items highlight these applicable plant conditions and/or initiating events.

3.0 REQUESTED ACTION

3.1 Requested Action Summary

This section summarizes the requested actions and their purpose.

3.2 Background

This section provides technical background and information pertaining to plant conditions and the requested actions. Information considered common knowledge is typically not included, unless necessary to characterize or support potential actions.

3.3 Implementation

This section details the requested actions. It contains information such as applicable procedures, system and component details and requirements, observations and system expert opinion.

3.4 Expected Plant Response

This section summarizes plant response to implementation of the requested action.

A. STARTING OR BUMPING A RCP FOLLOWING LOSS OF SCM

1.0 SAFETY CONCERN

Bumping or restarting a RCP may result in transferring unborated or underborated primary coolant to the core that may result in a critical condition.

2.0 PROCEDURE ENTRY CONDITIONS

EOP guidance exists to bump/restart a RCP given the following plant conditions:

- Evidence of a loss of coolant and/or SG tube leak.
- Loss of heat transfer.
- Loss of or degraded natural circulation cooling.
- HPI cooling.
- Following recovery of subcooled margin (SCM)
- Evidence of hot leg voiding
- Evidence of boiler-condenser mode (BCM) cooling
- No RCPs on or large void in loop opposite with one RCP on

The above conditions were considered in preparation of the following guidance.

3.0 Requested Action

3.1 Requested Action Summary

Bump or restart a RCP in an idle loop.

The purpose of restarting or bumping a RCP in an idle loop is to promote primary-to-secondary heat transfer by either establishing forced circulation cooling or assisting natural circulation cooling.

3.2 Background

Restarting or bumping a RCP following loss of SCM risks introducing excessive positive reactivity by pumping unborated or underborated coolant to the core. An RCP bump consists of a pump restart of sufficient duration to allow pump motor amps to stabilize (approximately 10 seconds) followed by an immediate trip of the pump.

For a range of SBLOCA break sizes that exceed the capacity of the HPI system, yet require steam generator heat transfer to cooldown and depressurize, the RCS may experience BCM cooling. With the RCS in a saturated condition, core decay heat causes boiling to occur and steam to be transferred to the hot legs. BCM mode develops when the steam void that initially forms in the top of the hot leg expands down into the steam generator tubes where it is condensed. The primary coolant is condensed by EFW or MFW delivered through the auxiliary header when the steam void expands below the elevation of the auxiliary header nozzles. This is referred to as EFW-BCM. When the steam void expands below the secondary pool level in the steam generator, primary coolant will condense due to pool-BCM. Both EFW-BCM and pool-BCM are effective forms of heat transfer, and are either cyclic or stable in nature.

However, both forms of BCM can cause underborated water to accumulate in the steam generator tubes, lower steam generator head and cold leg up to the RCP spill-over. This occurs because only a small percentage of the boron is transported with the steam that is condensed during BCM cooling. The volume of this underborated RCS condensate would be swept into the core upon bumping a RCP. The consequences of a RCP restart could introduce greater than $5 of reactivity and be as severe as a rapid power excursion with the potential for significant fuel damage and RCS pressure boundary damage.

The most likely indication of boron maldistribution is inconsistent boron sample results. However, the capability to quantify the size of a region of unborated or underborated water is limited. If BCM has occurred the volume of condensed RCS coolant consisting of unborated or underborated water should be assumed large.

The potential for a rapid boron dilution event decreases as the RCS boron concentration decreases with cycle burnup. Towards the end-of-cycle when the boron concentration is lower, RCS conditions exist which permit safely bumping or restarting a RCP in a formerly idle loop assumed to have undergone some boiler condenser heat transfer.

If hot leg level remains above the elevation of the auxiliary header, it can be concluded BCM cooling has not occurred. In other words, primary coolant level greater than the auxiliary header elevation precludes significant accumulation of unborated or underborated primary coolant. Likewise, if no feedwater has been supplied to a steam generator it can be concluded that BCM has not occurred.

Insufficient boron mixing in the RCS can also exist for the following conditions. With a single RCP in operation and a large void indicated in the opposite loop, no mixing in the idle loop should be assumed. The void may prevent reverse flow, and an underborated region may therefore exist in the idle loop. An RCP bump or restart must not be attempted in this plant configuration without careful consideration of the potential for a reactivity insertion event.

3.3 Implementation

Three sets of guidance are provided. The first considers a loss of SCM and a void in the hot leg, but is subject to one of the following conditions: 1) the void is not large enough to result in unborated/underborated primary condensate or 2) the void extends into the tube region, but the SG has not been fed. The second set of guidance considers adequate mixing of the primary coolant during natural circulation to allow for a pump bump or restart. Lastly, guidance is provided for time in core life where boron concentration is less due to burnup. For certain conditions RCP restart can be performed since a significant boron dilution event cannot occur. A combination of RCP cold leg temperature or SG pressure, pre-accident boron concentration, and elapsed time are used to determine when bumping or restarting a RCP is recommended.

<u>No Boiler Condenser Mode Confirmed</u>

- A RCP may be bumped or restarted if one of the following is true:
  a. Hot leg level remained > 389 inches (value includes allowances for instrument uncertainty)

     The primary coolant level has remained at an elevation greater than the EFW upper header. This value reflects an elevation at the secondary face of the upper tube sheet.

     It can be concluded that a significant volume of unborated/underborated condensate has not accumulated in the tubes if the hot leg void has not penetrated the SG tube region.

  b. If during HPI forced cooling neither SG has been fed while the RCPs were off and adequate core exit subcooling has been restored, a RCP may be restarted. Without feedwater being delivered BCM cannot occur and there is no concern.

<u>Adequate Natural Circulation Mixing Confirmed</u>

- A RCP may be restarted if all of the following conditions are satisfied:

1. Subcooled natural circulation has existed in both loops for > 2 hours, and,
2. There is no indication of increasing reactivity during natural circulation on available nuclear instrumentation.

If the above conditions are satisfied adequate boron mixing in each loop exists and a region of unborated or underborated primary coolant does not exist.

Criteria for RCP Bump/Restart Due to Low Initial Boron Concentration

One of two figures may be used to determine if bumping or restarting a RCP is advisable following BCM cooling. The first figure is a function of RCS cold leg temperature and elapsed time. The second figure is a function of SG pressure and elapsed time since reactor trip. If cold leg temperature indication is available in the loop with a pump to be bumped/restarted Figure 1 should be used. If cold leg temperature indication is unavailable, but SG pressure indication is available then Figure 2 should be used. The following criteria must be satisfied prior to using either Figure.

- Verify all control rods are fully inserted
- Verify reactor power was ≥ 70% prior to reactor trip
- Verify time since reactor trip is within analyzed limits (< 48 h)

Figure 1 uses RCS cold leg temperature as a function of elapsed time since reactor trip for various RCS boron concentration pre-conditions. Figure 2 uses SG pressure as a function of elapsed time since reactor trip for various RCS boron concentration pre-conditions. The figures are generated assuming the following:

- All control rods are fully inserted
- Assumes 70% full power equilibrium xenon.
- Includes 50 ppmB concentration measurement uncertainty in initial RCS concentration (prior to accident)
- In Figure 1, a 9 °F uncertainty allowance for RCS temperature indication. In Figure 2, a 110 psi uncertainty allowance for SG pressure indication.

To use either Figure 1 or Figure 2, determine:

1. For Figure 1 determine the lowest indicated cold leg temperature.

   For Figure 2, determine the lowest indicated SG pressure during the accident.
2. The pre-accident RCS boron concentration, and
3. the elapsed time since reactor trip.
4. Given the above considerations, if the lowest indicated RCS cold leg temperature or SG pressure is greater than the line corresponding to the pre-accident RCS boron concentration, a RCP may be bumped or restarted per the EOP.

If any of the above conditions are not met, evaluation by site and G.O. nuclear engineering can be requested.

3.4 Expected Plant Response

Plant response to bumping or restarting a RCP will depend upon the plant conditions prior to a bump/restart. When a RCP is bumped or restarted with a hot leg void, expect the void to collapse as it is quenched in the SG. If the RCP is bumped, RCS pressure will decrease rapidly as a result. One RCP at a time should be bumped for a period of time sufficient to allow the pump motor amps to stabilize (approximately 10 seconds). If plant conditions do not indicate the presence of natural circulation cooling following the pump bump, the other RCPs may each be bumped one time. If bumping the RCPs does not start natural circulation cooling, then refer to: E. Natural Circulation Cooldown Considerations.

If the RCP is restarted, RCS pressure will decrease. A loss of SCM may occur with the initial decrease in system pressure and require the RCP to be tripped shortly after it is restarted. If adequate SCM remains, plant response should then be consistent with forced circulation cooling. However, if a large void exists in the loop opposite the operating RCP, forced circulation cooling may be prevented.

Figure 1: RCP Bump/Restart Criteria

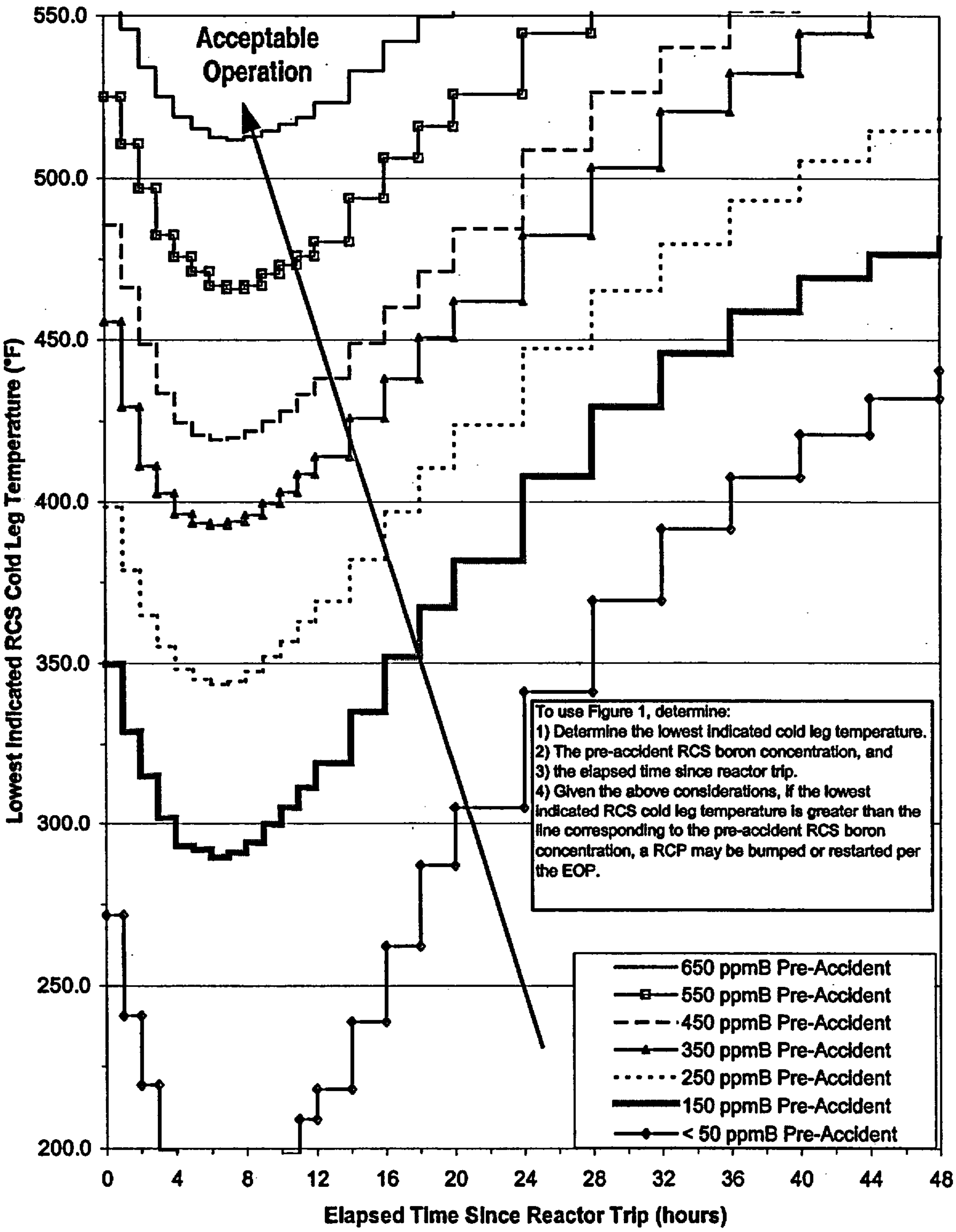
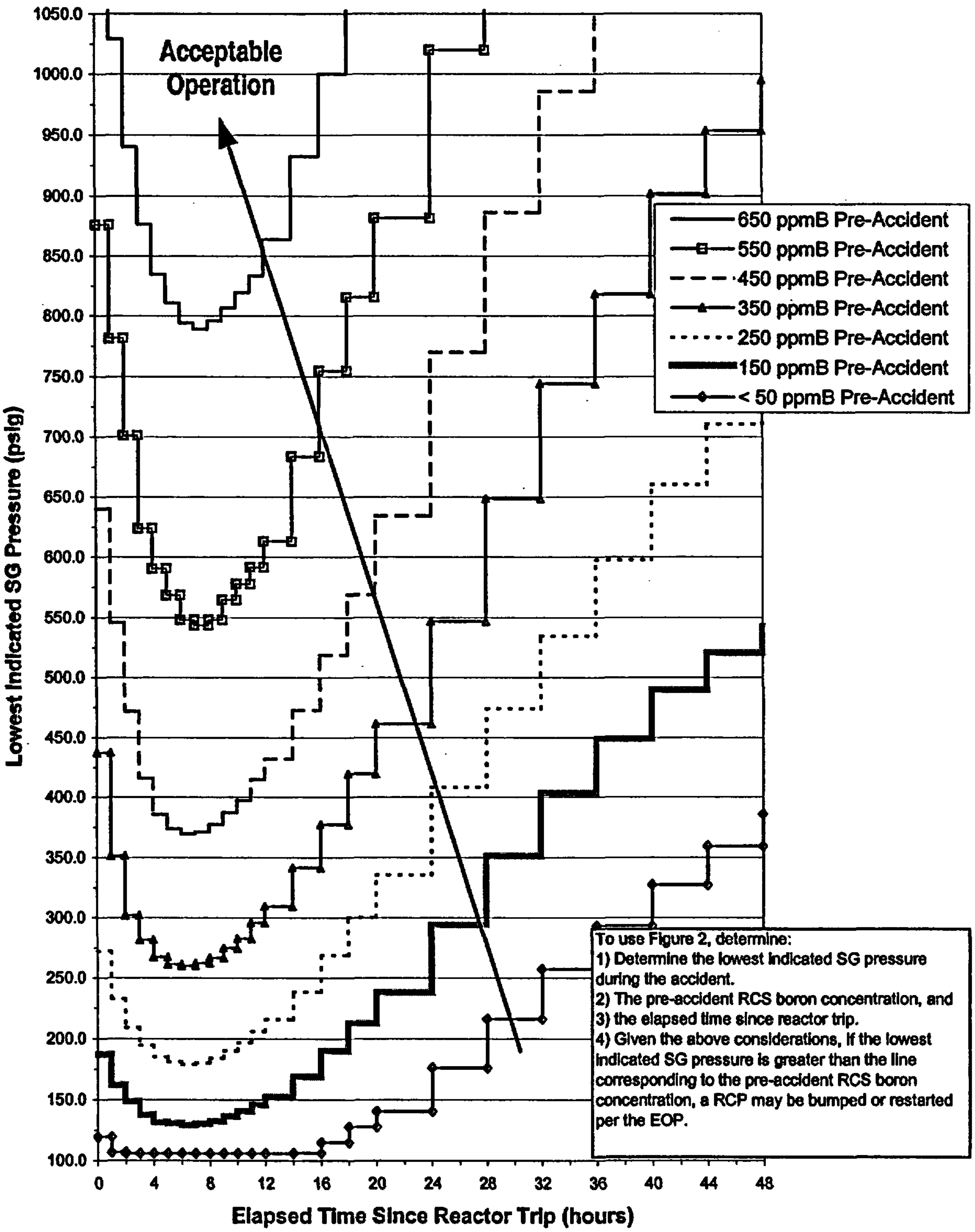


Figure 2: RCP Bump/Restart Criteria



B. STEAMING A STEAM GENERATOR WITH WATER IN THE STEAM LINE

1.0 SAFETY CONCERN

Potential loss of secondary pressure control due to waterhammer causing steam line rupture and/or loss of turbine-driven pump steam supply.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Evidence of a SG tube leak.
- SG level of 96 %OR or greater.
- Inadequate core cooling.
- HPI cooling cooldown.

3.0 REQUESTED ACTION

3.1 Requested action Summary

- Steam a SG with indication of water in the steam line.

3.2 Background

Opening a valve to reduce secondary pressure and cooldown the primary system with water in the steam line risks: 1) waterhammer, 2) losing steam supply to pump turbines, and/or 3) transferring water to pump turbines. A waterhammer event could ultimately result in loss of secondary pressure control due to pipe break or failure of a valve to reseat.

At SG levels of 96 %OR and greater it is possible that water has leaked-by the outlet annulus via a SG level instrument tap near the top of the baffle. The water will pool in the outlet annulus until it spills into the steam line. The steam line exits the steam generator horizontally for ~10 feet before turning and increasing in elevation 10 feet or greater. The water level in this section of the pipe will be approximately the same as in the steam generator. When steam generator level drops below the upper tap location, water will begin to drain back into the steam generator. Consideration should be given to some water remaining in the steam line immediately exiting the SG despite a reduction in SG level.

Expect condensation to occur over the length of the steam lines under low flow or stagnant conditions. The steam lines are horizontal or downward sloping the entire length of the run to the turbine after the initial rise in elevation at the steam generator exit. Therefore, the condensate will not accumulate in a "water catch" piping arrangement other than at the SG exit.

With water leaking by the instrument tap, the water will pool in the length of pipe exiting the SG. The level in this pipe will be approximately the same as the level indicated in the SG. With a level established in the pipe, high steam velocity is then necessary to form a plug of water. High steam velocity is also required to entrain liquid in a partially liquid filled pipe. A controlled cooldown using the ADVs or the Turbine Bypass System does not typically generate steam velocities large enough to entrain liquid or form a plug in a steam line with a residual level of water (in cases where indicated SG level has decreased below 96 %OR). The velocity necessary to do so depends upon the liquid level in the steam line as well, but once the line has been drained steaming the SG is allowable as very high steam velocities are required with lower levels.

If there is indication of SG levels approaching 120 inches above the instrument tap elevation, then water has spilled into the steam line above the exit. Full range indication is uncompensated and unreliable in this condition of operation. However when full range SG level indicates an increasing trend in SG level, well above the instrument tap elevation (500 inches or greater), it can be assumed water has spilled into the length of pipe rising above the exit (approximately 10 feet). The SG should not be steamed at all in this instance, even if the OR level decreases below 96 %OR.

If neither steam line is available, HPI cooling should be used to cool down the unit.

3.3 Implementation

If SG level is greater than 96% OR (or equivalent temperature compensated XSUR level) do not steam the SG.

If full range indication does not indicate SG levels continued to increase above the instrument tap level to a level greater than 450 inches (69 %FR), and SG level has reduced to a level less than 96 %OR, the SG may then be steamed.

Otherwise, HPI cooling should be used to cooldown the unit if water is suspected in both steam lines.

3.4 Expected Plant Response

Secondary pressure control should not be lost if the guidance is followed during RCS cooldown. Controlling to the prescribed cooldown rate precludes liquid entrainment and/or plug formation in the steam line piping exiting the SG.

C. REFILL THE EWST

1.0 SAFETY CONCERN

Loss of HPSW resulting in loss of backup cooling water to HPI pump motor coolers, cooling water to the TDEFW pump, and/or loss of fire suppression capability.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Loss of offsite power.
- Station blackout.
- Turbine Building flooding.
- Loss of LPSW
- EWST level low.

3.0 REQUESTED ACTION

3.1 Requested Action Summary

- Provide power to a HPSW pump.
- Refill EWST using offsite fire department engine.
- Use Keowee Hydro Station portable backup jockey pump on the discharge structure.

3.2 Background:

The EWST provides the following functions:

- The EWST is capable of delivering the demands of each fire suppression system individually. This constitutes a significant demand on the EWST, which cannot be sustained for very long.
- During loss of all AC power (station blackout), HPSW could provide cooling water to the turbine driven EFW pump.
- During loss of normal LPSW supply due to a Turbine Building flood: HPSW provide cooling water to the HPI pump motor coolers.
- Upon CCW pump restart after loss of LPSW, HPSW is needed to supply water via SSW piping to the CCW pumps for bearing lubrication and motor cooling.

Replenishing the EWST is a risk-significant operation. Failure to replenish the EWST increases the core damage frequency by a factor of three. Approximately 9% of the total core damage frequency involve failure of this action.

3.3 Implementation

Refill the EWST through a method delineated in:

AP/1/A/1700/010, Enclosure 6.1

Two methods are presented in the Enclosure. Options 1 and 2 will deliver a maximum flow of 1500 gpm. Consider the following when choosing a method:

<u>Option 1: Use offsite fire department engine on the intake structure.</u>

- Location on the intake near 2C CCW pump available for fire department engine.
- Fire department has length of hard pipe suction hose to reach 4 to 6 feet below water surface.
- Fire hydrant HY-26 available. (OFD-124C-1.4)

Option 2: Use offsite fire department engine on the discharge structure.

- Location on the CCW discharge available for fire department engine.
- Fire department has length of hard pipe suction hose to reach 4 to 6 feet below water surface.
- Fire hydrant HY-7 available. (OFD-124C-1.5)

3.4 Expected Plant Response

Employing a method detailed in procedure AP/1/A/1700/010 should result in maintaining or increasing EWST level.

D. EVALUATE OUTSIDE AIR BOOSTER FAN OPERATION

1.0 SAFETY CONCERN

Control Room habitability.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- 1/2/3RIA-39 CNTRL RM Gas Alarm actuated
- Outside air booster fans are operating

3.0 REQUESTED ACTION

3.1 Requested Action Summary

- Terminate outside air booster fan operation
- Continue outside air booster fan operation

3.2 Background:

The outside air booster fans are operated when a control room air handling unit return air radiation monitor (1/3RIA-39 (CNTL RM Gas)) alarms. The outside air booster fans provide filtered air to positively pressurize the control room.

The outside air booster fans should not be disabled prior to terminating the radiation release. The in-line filters should remain operable for greater than 20 days. Therefore if radiation protection or available radiation monitoring indicates the event has not been terminated it is prudent to maintain the outside air booster fans operable.

The location of the source term is important to the decision. If release is a result of component or penetration failure in the Auxiliary Building, continued operation of the outside are booster fans is prudent. Bypassing the Auxiliary Building via the emergency or equipment hatches could result in a release effecting the booster fan suction source. If RIA-39 counts do not stabilize or reduce with booster fan operation, consideration should be given to isolating the outside air booster fans.

In addition, chlorine release or smoke near the fan suction could prompt isolating the fans depending on the magnitude of the source term.

3.3 Implementation

Determine location of source. If source is such that operation of the outside air booster fans result in continued and increasing 1/2/3RIA-39 CNTRL RM gas alarm counts, it may be prudent to terminate operation of the fans.

Consider extenuating circumstances which may effect Control Room habitability, such as fire or noxious gas, to evaluate continued operation of the outside air booster fans.

3.4 Expected Plant Response

Operation of the control room air booster fans should result in reducing counts on or stopping the 1/2/3RIA-30 CNTRL RM gas alarm.

E. NATURAL CIRCULATION COOLDOWN CONSIDERATIONS

1.0 SAFETY CONCERN

Loss of or degraded natural circulation.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Loss of CCW intake canal.
- Fire.
- Loss of any fire zone due to (10 CFR 50 Appendix R) fire.
- Station blackout.
- Loss of all equipment (except cabling) in non-vital areas due to sabotage.
- Loss of equipment in the Turbine and Auxiliary Buildings due to a flood resulting from CCW System ruptures.
- Loss of equipment in the Turbine and Auxiliary Buildings due to a tornado missile event.
- Indication of loose parts alarms or sustained large magnitude noise in the RCS.
- Loss of subcooling margin.

3.0 REQUESTED ACTION

3.1 Requested Action Summary

- Evaluate natural circulation cooldown conditions.

3.2 Background:

The following summarizes various natural circulation cooldown scenarios and provides plant conditions and expected response to operator intervention. The guidance considers thermally coupled primary and secondary systems as a function of RCS SCM, loop asymmetry during natural circulation, phenomena which will interrupt natural circulation, and what is necessary to enhance or restart natural circulation.

<u>Primary/Secondary Coupled – RCS is Subcooled</u>

Subcooled natural circulation is indicated by:

1. T_{cold} coupled to the saturation temperature at the SG pressure,
2. Incore T/C temperature indication should track T_{hot} within approximately 10 °F, and
3. T_{hot} and T_{cold} temperature difference should be between 30 to 50 °F.
4. SG level at 50 %OR, 240 in XSUR.

The ΔT between T_{hot} and T_{cold} is expected to be 50 °F or less. The magnitude of the flow rate will decrease as the ΔT decreases and as core decay heat decreases.

<u>Primary/Secondary Coupled – RCS is Saturated</u>

Saturated natural circulation is indicated by:

1. T_{cold} coupled to the saturation temperature at the SG pressure.
2. Loss of SCM SG level

With the RCS saturated, incore T/C temperature will track T_{hot} whether natural circulation flow exists or not. The ΔT between T_{hot} and T_{cold} will vary between 50 °F and 0 °F, depending upon how much of the core heat is transferred to the primary coolant as latent heat of vaporization. The magnitude of the flow rate will decrease as the ΔT decreases as core decay heat decreases.

Primary/Secondary Coupled – One SG Operable, Subcooled or Saturated

If only one SG is operating during natural circulation only T_{hot} in the operating loop will indicate core outlet temperature. T_{cold} on the operating SG will be approximately equal to T_{sat} in the operating SG. T_{cold} in the isolated SG may not be equal to T_{sat} in the isolated SG. It will probably be colder due to ambient losses and due to cooler injection water (seal injection, MU, HPI). ΔT on the operating SG may be 10 °F higher than the 50 °F expected with two operating SGs. The loop with the idle SG may prevent primary depressurization.

Interruption of Natural Circulation

Natural circulation can be challenged and lost by three causes. Inadequate steam generator level and/or loss of steam generator steaming capability (including overfilling the SG) will result in degraded or loss of natural circulation. Hot leg voids collecting in the top of the hot leg will degrade or stop natural circulation. Generally, the benefits of maintaining or restoring primary-to-secondary heat transfer warrants operator action to do so.

Two sets of symptoms indicate whether natural circulation will be interrupted due to hot leg void formation. The first set are identified by a diagnosis of plant conditions that could result in void formation:

- Loss of RCS inventory
- Loss of subcooled margin that might result in water flashing to steam
- Contraction of the RCS inventory due to an overcooling event
- Cooldown and depressurization with an idle loop
- An outsurge of hot water from the pressurizer
- Accumulation of noncondensible gases following ICC or from any other source

The second set of symptoms include indications that heat transfer has been interrupted:

- Hot leg level < 537 inches (void large enough to interrupt natural circulation)
- RCS temperatures increasing, with CETC temperature diverging from hot leg RTDs
- Pressurizer level increasing due to void growth or thermal expansion (primarily if subcooled)
- Steam generator pressure decreasing due to injection of feedwater
- RCS temperature and pressure increasing along the saturation curve (if subcooling lost)

The first set of symptoms will likely lead to the second, with natural circulation being lost due to a hot leg void forming. As the void in the hot leg continues to expand into the steam generator tube region, boiler-condenser mode heat transfer will occur. Natural circulation can be regained after it has been lost, and the cooldown could be expected to occur in a cyclic manner.

Enhancing/Stimulating Natural Circulation

- Increase ΔT between primary and secondary
- Open hot leg high point vents if a void is indicated

- Bump or restart a RCP

Increasing the temperature difference between the primary and secondary increases the density differences between the hot legs and the SGs. This is accomplished by raising SG levels and/or steaming the SGs.

The optimum cooldown method includes balanced steaming of both steam generators in order to maintain a symmetric coolant temperature distribution.

Natural circulation will become intermittent and then will be lost as a hot leg void increases. The void can be vented to mitigate the cause and duration of the loss of natural circulation. This is effective in scenarios where a primary system break cannot provide sufficient cooling. The operator is instructed to open a high point vent if subcooled margin is lost and RCS pressure is increasing due to RCS heatup. If RCS pressurization persists, the pressurizer PORV is also opened to assist in removing decay energy and increasing HPI flow by decreasing RCS pressure.

If a hot leg void exists and SCM has not been lost, then once-through cooling is adequately removing decay heat and the primary may be thermally decoupled from the secondary. In this case, venting a hot leg void is not necessary. However, the void may be vented to restore natural circulation.

Bumping or restarting a RCP may also be utilized to mitigate voiding in the RCS. A RCP bump consists of a pump restart of sufficient duration to allow pump motor amps to stabilize (approximately 10 seconds) followed by an immediate trip of the pump. Bumping or restarting a RCP sweeps the void into the steam generator tubes where it condenses. RCS pressure decreases as the void is condensed and more of the RCS is exposed to the steam generator. Refer to TSCG Section A.

3.3 Implementation

Enhancing Natural Circulation

Evaluate the following actions that enhance natural circulation.

- SG levels may be raised up to 96 %OR.
- Steam SGs to increase ΔT between the primary and secondary.
- Maintain makeup to the RCS for losses and shrink (preserve loop thermal communication).

Restarting Natural Circulation

Evaluate the following actions, which may aid in restarting natural circulation:

- Maintain makeup to the RCS for losses and shrink (preserve loop thermal communication by minimizing hot leg void growth). This is necessary to restart natural circulation if the plant is in intermittent natural circulation or BCM cooling.
- Open hot leg high point vents to aid thermal connection between the hot legs and the steam generators if a hot leg void indicated.
- Bump or restart a RCP (refer to TSCG Section A).

3.4 Expected Plant Response

The plant will generally respond in a sluggish manner to operator intervention when in natural circulation cooling. However, if the plant is in BCM cooling, the plant can respond quickly to operator intervention.

When natural circulation exists, it can be enhanced by increasing the thermal center (raising SG level) or increasing ΔT between the primary and secondary (steaming the SG). Consideration should be given to raising SG levels above target setpoints but less than 96 %OR.

When natural circulation is degraded or intermittent, verify SG level and ensure steaming capacity is available. Makeup should be increased to enhance thermal coupling between the primary and the secondary. Intermittent natural circulation may exist initially or may follow natural circulation. It precedes BCM cooling if makeup is insufficient to match system losses and shrink.

If natural circulation has ceased, verify adequate RCS makeup and try to vent the RCS hot leg void. The plant may be in BCM cooling if the SGs remain operable and the primary and secondary systems are coupled. BCM cooling is an excellent mode of heat transfer, however a large region of underborated/unborated primary fluid may accumulate. As makeup matches break flow and system shrink (or the hot leg void is vented) the system will transition back to natural circulation though intermittent natural circulation.

F. MAKEUP AND MONITORING OF THE SFP AND RECOVERY FROM A BOILING CONDITION

1.0 SAFETY CONCERN

Maintain and/or recover SFP inventory, boron concentration, and normal mode of cooling.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Loss of spent fuel pool cooling.
- Torriado accident.
- SSF RC makeup required.
- Boiling SFP

3.0 REQUESTED ACTION

3.1 Requested Action Summary

Makeup and/or monitoring the spent fuel pools

3.2 Background:

Maintaining SFP level is important for radiological, fuel integrity, reactivity management, and accident mitigation reasons. The SFP is designed for boiling heat transfer, however makeup for boil-off needs to be assured for radiological and fuel integrity concerns. In addition, makeup to the SFP may be required to make up for SSF demands. Makeup may be from a borated or unborated/underborated source. This will affect reactivity management and accident mitigation when the SFP is used as a source for SSF demands.

Monitors 1RIA-6 (Spent Fuel Pool) and 1RIA-41 (Spent Fuel Pool Bldg Gas Mon) should be monitored for an increase in radiation level inside the Units 1 and 2 SFP area. Monitor 3RIA-6 (Spent Fuel Pool) and 3RIA-41 (Spent Fuel Bldg Gas Mon) for an increase in radiation level inside the Unit 3 SFP area.

SFP heat load and SSF demands determine the urgency of monitoring and necessity for makeup. For example, following an outage, and at an initial 150 °F, the spent fuel pool time to boil is approximately 20 hours after loss of SFP cooling. If the SFP is verified intact (e.g. following a tornado or seismic event) sufficient time exists to provide makeup to the spent fuel pool.

If for some reason normal SFP cooling is lost and cannot be established within the time to boil, special actions must be taken to recover the normal cooling mode. As the spent fuel pool temperature rises it will approach the saturation temperature. At or near saturation temperature, normal cooling can no longer be used due to the lack of NPSH. As the pumps try to draw the boiling water up, out of the pool, the decrease in pressure inside the pipe will cause the water to flash to steam and the SFP water cannot be made to flow to the SF coolers. The bulk temperature of the SFP must be lowered to at least 180 °F before normal cooling can be reestablished. This can be accomplished by allowing the pool to first boil down and then adding cooling water to it at a sufficiently high rate to cool the pool down before it over fills. This rate is dependent on the heat load in the pool.

Normal makeup is available from the BHUT, CBAST, BAMT and DW. Emergency makeup is available using offsite fire department equipment. Makeup to recover from a boiling condition is available from the BWST.

3.3 Implementation

Monitor SFP Level Locally

Monitor Hourly if:

- Level indication is not available, and no demand on SFP inventory (SSF RC makeup or HPI suction) in the first 15 hours following loss of SFP cooling.
- Level indication is available, and SFP inventory is a suction source for SSF or HPI with borated makeup established.

Monitor Continuously if (or as allowed considering radiological and environmental conditions):

- Level indication not available, and no demand on SFP inventory (not a SSF or HPI suction source), and greater than 15 hours (or within 4 hours of SFP calculated time-to-boil and no makeup source aligned) following loss of SFP cooling.
- Level indication is not available and SFP inventory is a suction source for HPI or the SSF with borated makeup established.
- Changing the makeup or SFP cooling alignments.

<u>Normal Makeup Sources:</u>

Procedures OP/1&2/A/1104/006/C and OP/3/A/1104/006/E are used when making up to the SFP from:

- RC BHUT 1,2,3A/B
- CBAST (Units 1,2,3)
- BAMT (Units1&2,3)
- DW

<u>Emergency Plan for Refilling Spent Fuel:</u>

Procedure MP/0/A/3009/012A details makeup to the spent fuel pool using the offsite fire department.

<u>Emergency Plan for Recovering from a Boiling SFP:</u>

In order to recover from a boiling SFP, water must be drawn from the BWST. T.S. 3.5.4 SR 3.5.4.2 states that the BWST must have more than 350,000 gallons available with a 1 hour required action time. Recovery could potentially use up to 2/3 of the BWST inventory. If BWST inventory can't be made up within the required action time, the unit will have to be shut down. Additionally, the SSF RCMU Pump is inoperable when the SFP temperature reaches 141 °F per OSS-0254.00-00-1004, Design Basis Specification for the SSF RC Makeup System. T.S. 3.10.1 states that the RCMU system must be operable with a 7 day required action time. If SFP temperature can't be reduced to less than 141 °F within 7 days the unit(s) will have to be shut down. During recovery of the SFP, provisions should be made to reserve enough water in the BWST to shut down the unit(s). Recovery of the SFP may require as much as 220,000 gallons of water.

Makeup to the SFP to recover from a boiling condition will require the use of the A and B SF cooling pumps. These pumps can achieve a combined flow rate of about 1600 gpm. This is adequate flow to lower the spent fuel pool bulk temperature to 180 °F even at the abnormal maximum heat load. (See Calculation OSC-8079 – Recovery of SFP from a Boiling Condition) To lower the temperature of the pool sufficiently, large quantities of cool water must be added at a high flow rate. In order to align the Unit 1&2 SFP to the BWST through the SFP Cooler Pumps, SF-53 and either SF-55 (for Unit 1 BWST) or SF-56 (for Unit 2 BWST) should be opened and SF-5 should be closed. For Unit 3 SFP, 3SF-53 and 3SF-55 should be opened and 3SF-5 should be closed. In order to have room to add this make-up water, make-up for the boil off must be stopped and the pool must be allowed to boil down to no less than 9 ft over the fuel racks. 9 ft over the fuel racks is considered the minimum allowable level due to ALARA. A note about boron concentration; Boiling off a large amount of water will have a concentrating effect on the boron in the pool as a large volume of water is removed while most of the boron remains. Worst case boron concentration after boil off and make up from the BWST is about 1300 ppmB above the procedural limit set for the SFP. Once normal cooling has been reestablished the SFP boron concentration should then be placed back within procedural limits.

Boil off times depend on the heat load in the pool and range from ~35.5 days at minimum heat load to ~50 hours at maximum heat load for the Unit 1&2 SFP and ~25 days at minimum heat load to ~38.5 hours at maximum heat load for the Unit 3 SFP. Once the required minimum pool level has been reached, make-up water, from the BWST through the SF cooling pumps, can then be added. The required flow rates for this make-up water (assuming pool is boiled down to 9 ft above the SF racks), based on heat load, can be determined with the following formulas:

Unit 1&2

To fill the pool to normal level
$$\dot{V} = 53.4 \times \dot{Q}_L - 5.73$$

To fill the pool to maximum level
$$\dot{V} = 42.7 \times \dot{Q}_L - 5.14$$

Unit 3

To fill the pool to normal level
$$\dot{V} = 53.7 \times \dot{Q}_L - 6.45$$

To fill the pool to maximum level
$$\dot{V} = 43.1 \times \dot{Q}_L - 3.23$$

Note: Heat load values, $\dot{Q}_L$, are in millions of Btu/hr and flow rate, $\dot{V}$, is in gpm

If heat loads in the SFP are less than the abnormal maximum, Calculation OSC-8079 includes an Excel Spreadsheet that will determine the minimum required boil down level given the actual pool heat load and actual BWST temperature.

3.4 Expected Plant Response

SFP level increases or is maintained. Radiation levels in the SFP area are constant or decreasing. Verify boron concentration in the SFP continues to satisfy shutdown margin.

For SFP boiling, SFP temperature decreases. SFP level is kept below maximum elevation of 844'. Radiation levels in the SFP are constant or decreasing. Verify boron concentration in the SFP continues to satisfy shutdown margin. Normal SF cooling is reestablished.

G. MAKEUP AND MONITORING OF CCW INLET PIPE INVENTORY

1.0 SAFETY CONCERN

Preservation of SSF ASW pump and/or ASW pump suction supply.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Tornado or loss of Lake Keowee event (SSF ASW, ASW).
- Fire, flood, or sabotage event (SSF ASW, ASW (potentially w/flood)).
- Station blackout. (SSF ASW)

3.0 REQUESTED ACTION

3.1 Requested Action Summary

1. Monitor Unit 2 CCW piping inventory, using SSF ASW/ASW pump suction pressure gauges.
2. If the Unit 2 CCW piping is intact, then makeup should be supplied by one or a combination of the following:

- Running a Unit 2 CCW pump
- Gravity flow from CCW discharge
- Dedicated portable submersible pump
- Cross connect the Unit 1 and Unit 3 CCW intake/discharge piping and Unit 2 CCW discharge piping to the Unit 2 inlet piping.

If the Unit CCW pipe integrity is questionable, then the method of making up will need to fit the system conditions.

3.2 Background:

The Unit 2 CCW inlet is the assured source of water satisfying the unit ultimate heat sink requirements. This mission is accomplished by serving as a source of supply water for SSF ASW demands. Worst case required ASW inventory to remove core decay is approximately 37 days if Units 1, 2, and 3 intake and discharge piping volumes are available (inventory available below 791 feet). Action may be required in as little as 6 hours.

With Unit 2 and either Unit 1 or 3 intake and discharge piping, core decay heat can be removed from 2 Units for 37 days. Action may be required in as little as 4 hours.

3.3 Implementation

- Monitor Unit 2 CCW intake pipe inventory

For loss of lake, loss of intake canal, tornado or other events requiring SSF ASW operation, evaluating CCW intake pipe inventory requires removing high point manways and using direct observation of level following loss of siphon. Prior to losing the siphon, use the SSF ASW pump suction gauge. The structural integrity of the pipe should be considered when obtaining the level observation/measurement.

- Makeup to Unit 2 CCW intake pipe inventory

The methods to provide makeup to the Unit 2 CCW intake are:

1. Running a Unit 2 CCW pump

-FOREBAY ELEV is above 67 feet

-SSW (HPSW) supply to CCW pump

-Power to CCW pump discharge valve

-CCW cross-over aligned to other units (as necessary)

2. Gravity flow from CCW discharge
3. Dedicated portable submersible pump
   MP/0/A/1300/059
4. Cross connected with another unit and available water supply

<u>3 Units intake and discharge pipes available:</u>

Where the SSF ASW pump is in service and the station ASW pump is off, action must be taken within 24 hours of reactor trip to cross-connect the Unit's CCW intake and discharge unwatering pipes. This will assure 37 days of inventory where the SSF ASW pump is initially providing core decay heat removal.

Where the station ASW pump is in service with the SSF ASW pump off, action must be taken in 6 hours of reactor trip to cross-connect the Unit's CCW intake and discharge unwatering pipes. This will assure 37 days of inventory where the station ASW pump is initially providing core decay heat and the SSF diesel engine service water is routed to the yard drain.

<u>Unit 2 and either Unit 1 or 3 CCW intake and discharge pipes available:</u>

Where the SSF ASW pump is in service and the station ASW pump is off, action must be taken in 16 hours of reactor trip to cross-connect the available (not unwatered) Units' CCW intake and discharge unwatering pipes and to open or verify open 2CCW-75, 2CCW-78, 2CCW-79, 2CCW-86 and 2CCW-87 (if Unit 1 CCW intake pipe is unwatered). This will assure 37 days of inventory where the SSW ASW pump is initially providing core decay heat removal.

Where the station ASW pump is in service with the SSF ASW pump off, action must be taken within 4 hours of reactor trip to cross-connect the available (not unwatered) Units' CCW intake and discharge unwatering pipes and open or verify open 2CCW-75, 2CCW-78, 2CCW-79, 2CCW-86 and 2CCW-87 (if Unit 1 CCW intake pipe is unwatered). This will assure 37 days of inventory where the station ASW pump is initially providing core decay heat and the SSF diesel engine service water is routed to the yard drain.

5. Supply CCW intake from CCW discharge

3.4 Expected Plant Response

Unit 2 CCW intake pipe inventory is maintained to accommodate demands due to SSF operation and/or possible losses due to leakage from the system.

H. CONSERVE BWST INVENTORY

1.0 SAFETY CONCERN

- Loss of LPSW and BWST inventory depletion.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Uncontrollable flooding of the Turbine Building.
- Loss of primary to secondary heat transfer control from Unit Control Rooms and aux shutdown panels.
- SSF ASW system and station ASW System unavailable.
- Using forced HPI cooling.

3.0 REQUESTED ACTIONS

3.1 Requested Action Summary

- Provide guidance to conserve BWST inventory to extend HPI cooling, considering the following potential actions:

  - Throttle HPI flow to balance decay heat.

  - Secure RBS system.

  - Vent the RB.

3.2 Background

BWST inventory constitutes the ultimate heat sink when primary-to-secondary heat transfer is lost and LPSW is unavailable. Forced HPI cooling is used to remove core decay heat when primary-to-secondary heat transfer is lost. Therefore, conserving BWST inventory by limiting what systems place demands on it extends the time available for forced HPI cooling. Aligning makeup to and replenishing the BWST inventory should be pursued while attempting to conserve the inventory.

HPI forced cooling is initiated by manually establishing HPI flow in the injection mode and latching open the PORV to create a relief flowpath. With subcooling margin all but one RCP is tripped to minimize the heat load on the system and maintain good circulation and mixing of injection flow.

HPI forced cooling results in energy relief to the RB. Without LPSW the RB structure and internal structures are the only heat sinks available to remove the energy from core decay heat, RCS metal, and secondary metal released by venting the RCS via the PORV. The controlled release of primary fluid to the building via the pressurizer PORV, safety valves or the hot leg high point vents via quench tank relief will result in increasing containment temperature and pressure. If there is no evidence of a high energy line break, and LPSW is unavailable, operation of the RBS system will only be marginally effective in removing energy from the atmosphere to containment structures. The RBS system should be isolated to minimize BWST drawdown rate.

Venting the RB removes energy primarily from the RB atmosphere. The RB purge system is not designed to operate under the differential pressure expected during HPI forced cooling. Venting would endanger the in-line filter package given environmental conditions present in the RB during HPI forced cooling. Likewise, venting RB may challenge the isolation valves ability to reseat. Lastly, removing air from the RB without replenishing it may complicate restarting RBS if required. If the air is removed and the atmosphere is predominantly saturated steam, spraying down containment could result in a differential pressure greater than design. Given these concerns it is not recommended the RB be vented prior to establishing LPSW flow. If venting containment, purged air should be replenished with fresh air.

3.3 Implementation

Minimize BWST Drawdown

RBS should be isolated if there is no evidence of a HELB. Indication of a HELB would include: rapidly changing RB pressure and temperature, rapidly increasing RB sump level, and possibly increasing radiation levels in the building. If RB pressure remains less than 40 psig, RBS should remain isolated. HPI cooling, without a large HELB, will only produce a gradual worsening of Reactor Building conditions.

Depending on the predicted time to recover LPSW or acquire a makeup source for the BWST, consideration should be given to minimizing HPI flow. This can be done by matching HPI forced cooling flow with the core decay heat demand. This will result in losing SCM, but would further extend the BWST inventory. Refer to EP/1,2,3/A/1800/001 Section 502.

Venting the Reactor Building

Venting the RB risks subsequent loss of the ability to isolate, filter, and monitor any radiological release. As Reactor Building ultimate design pressure is near 144 psig, venting the Reactor Building should not be considered unless failure is deemed imminent.

3.4 Expected Plant Response

The energy storage and conduction capacity of the RB during HPI cooling is sufficient to preserve Reactor Building integrity. As such, neither RBS or venting the Reactor Building should be necessary. Therefore, BWST inventory can be conserved by minimizing demand, or isolating RBS.

I. CFT CORE COOLING FOLLOWING LOSS OF DECAY HEAT REMOVAL

1.0 SAFETY CONCERN

Use of CFTs to remove decay heat.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Loss of decay heat removal.
- BWST inventory approaching depletion.
- BWST aligned for gravity flow to RCS.

3.0 REQUESTED ACTIONS:

3.1 Requested action Summary

- Drain CFTs to RCS to remove decay heat/makeup for boil off (when the BWST is unavailable).

3.2 Background

A CFT contains 1040 +/- 30 cu-ft of borated water. In a shutdown condition one or more CFTs may not be available. CFTs may be at Reactor Building atmospheric conditions or have a nitrogen overpressure of 50 psi or greater (OP/1(2,3)/A/1104/001, Core Flooding System).

The location of the RCS vent, the presence of steam generator nozzle dams, and RCS level should be considered when pressurizing and discharging the CFTs in a shutdown condition. If the RCS vent is in the upper SG, completely discharging a CFT with a pressurizer level of 360 inches could result in inventory loss out the vent. If SG nozzle dams are installed the CFTs must not be discharged.

The CFTs can be pressurized as necessary to discharge liquid volume for makeup. Each CFT should be discharged separately to maximize the liquid available to remove decay heat.

3.3 Implementation

<u>CFT Discharge for Decay Heat Removal:</u>

Refer to OP/1(2,3)/A/1104/001, Enclosure 4.14, for details regarding discharging the CFTs to the RCS.

Equipment required/considerations:

Inventory in the CFT.

Nitrogen high pressure header available.

Power supply to valves, 1/2/3CF-1 and/or 1/2/3CF-2.

The valves CF-1 and CF-2 can be operated locally. However, Reactor Building radiological and environmental conditions may preclude local operation.

The flow rate necessary to remove decay heat 1 day after shutdown from full power operation is 108 gpm and at 5 days the required flow rate is 62 gpm. Controlling CFT discharge to match decay heat will be difficult. CFT inventory should be discharged to preserve RCS level, but flow rates much greater than required to remove decay heat and maintain RCS level is likely. With the RV head removed, the difference in head generated by the initial CFT and RCS levels will produce CFT flows of several thousand GPM even if the CFT were vented to RB atmosphere.

CFT nitrogen pressure should be reduced to minimize rate of discharge prior to opening the discharge valves. Consideration of the RCS vent location will affect how the CFTs are discharged as well. If the RV head is removed, inventory will spill from the RV given coarse flow control from the CFT. However, if the RCS vent is in the pressurizer or the upper SG head, CFT discharge should be controlled to a level several hundred inches below the vent location. The flow rate from a single CFT is sufficient to match decay heat at 1 day of shutdown, therefore the CFTs should be discharged one at a time.

A CFT must not be discharged if SG nozzle dams are installed.

3.4 Expected Plant Response

CFT inventory can be used to makeup for boil-off following loss of DHR. Control of the injection rate will not be precise and a flow rate of less than 100 gpm is only required to makeup for decay heat. The CFTs should be discharged by pressurizing with nitrogen and pushing water through the injection lines as needed to maintain RCS level. The amount of fluid discharged will depend upon the location of the RCS vent. Do not attempt to discharge the CFTs if the nozzle dams are installed.

J. MITIGATE LPI PUMP INTERACTION AND LPI PUMP RESTART

1.0 SAFETY CONCERN

Protect LPI pumps during low flow operation.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Two LPI pumps in operation and BWST inventory decreasing, requiring LPI/HPI "piggyback" operation to provide HPI suction from the RBES and restart of an LPI pump following deadhead operation
- SBLOCA
- HPI forced cooling
- SGTR

3.0 REQUESTED ACTION

3.1 Requested Action Summary

Evaluate restarting an LPI pump following a low flow condition or continued operation of LPI pumps at low flow conditions.

EOP cautions the operator and informs station management if LPI pumps are operated below minimum flow values:

- Any LPI pump operated at <100 gpm.
- Two LPI pumps operating in piggyback with NO LPI header flow and total indicated HPI flow <500 gpm.

Turn off an LPI pump.

3.2 Background:

The manufacturer's recommended minimum flows: (recommended for accident condition only to minimize undue stresses)

- LPI flow > 100 gpm (5 continuous days)
- LPI flow > 200 gpm (one year continuous)

For some SBLOCAs, HPI cooling, or SGTR events, an interaction between the LPI pumps can occur during LPI/HPI-piggyback operation. In particular, under low flow conditions a weak-pump strong-pump interaction is established. The acceptability of the LPI/HPI piggyback alignment with two trains of LPI supplying suction to two HPI pumps through both LP-15 and LP-16 is a function of total HPI injection flow assuming no LPI flow injecting into the RCS. Analysis has been performed modeling the weak pump/strong pump interaction with both trains at a combined flowrate of 500 gpm. The analysis shows if pumps differ by as much as 7% in developed head that flow from the weaker pump will be limited. Periodic testing verifies that the "A" & "B" LPI pumps are within this 7% assumption. If two LPI pumps are operating in piggyback with no LPI header flow and total indicated HPI flow ≤ 500 gpm, it is recommended that one LPI pump be secured. A single LPI pump can provide sufficient flow for 2 HPI pumps.

Operating the LPI pumps below minimum flow will cause hydraulic instabilities. Operating the LPI pump for an extended period (@ <100 gpm) can lead to fluid flashing in the casing that can lead to cavitation and seal failure. This can be catastrophic.

Vendor recommendation is based on a similar pump that was operated at approximately 100 gpm for one month. This test showed no degradation in pump performance or component damage. To minimize undue pump stress, this manufacturer's recommendation must be adhered to.

3.3 Implementation

Re-energizing an LPI pump after it has been secured because it was deadheaded or if two LPI pumps operating in piggyback with no LPI header flow and total indicated HPI flow <500 gpm requires an evaluation.

- Depending on RCS conditions, specifically RCS pressure and the rate it is decreasing, it may be advisable to secure an LPI pump in support of piggyback. A single LPI pump can provide sufficient flow for 2 HPI pumps. If acceptable increase total indicated HPI flow to >500 gpm to maintain two LPI pumps in operation.
- The temperature of the fluid in the LPI pump is a function of the length of time the LPI pump has been operating at deadhead condition. It is advisable to restart the LPI pump when it can be assured that RCS pressure has decreased that will allow LPI injection. An LPI pump can develop approximately 180 psi of developed head.
- When restarting an LPI pump for piggyback operation after it has been secured due to deadhead operation, consideration must be given to the fact that the LPI pump may only have minimum recirc flow until LP-15 & 16 are opened. Minimize the time between pump restart and opening LP-15 or LP-16.

<u>Approximate LPI Flow Rate Calculation</u>

- The indicated LPI flow is inaccurate at low flowrates. For example the indicated flow can vary between 0.0 gpm to 1200 gpm if actual flow is <750 gpm. Based on LPI performance, it is expected that LPI flow should rapidly increase to >1000 gpm as RCS pressure decreases below shut off head (approximately 180 psig). LPI flow can be estimated based on the BWST draindown rate as follows (assuming a relatively constant rate of BWST level decrease):

  - The volume of the BWST is ≈ 7613 gals/ft.

  - LPI flow = {(initial level – current level)/time} (7613) = sum of HPI and RBS flow

  - The instrument uncertainty analysis (worst case) are:

  If RBS is operating, the flowrate should be throttled to ≤ 1500 gpm (when taking suction from BWST). The flow rate uncertainty is approximately 143 gpm.

  HPI flow uncertainty is approximately 25 gpm if flow >500 gpm. For indicated HPI flow below 125 gpm, actual flow can be 0.0 gpm or > 189 gpm

  - Comparison of header flows allows one to diagnose the validity of the indicated flow.

  - Analysis shows that two HPI pumps can deliver approximately 550 gpm & 650 gpm @ RCS pressures of 1500 psig and 1200 psig respectively. This is assuming the HPI pumps developed head have degraded 10%.

  - RB pressure can influence LPI total developed head when aligned to the BWST.

  - RCS pressure must be considered in the evaluation.

3.4 Expected Plant Response

The guidance assures the minimum required flow for LPI pump during long term cooling. In addition, the guidance assures successful operation following restart of a pump after deadhead operation.

K. ENERGIZE THE ASW SWITCHGEAR FROM AN OPERATING OCONEE UNIT

1.0 SAFETY CONCERN

Restore power supply to the HPI and ASW pumps from Oconee unit not experiencing SBO.

2.0 PROCEDURE ENTRY CONDITIONS

Evaluate continued operation of LPI pumps at low flow conditions.

- An Oconee unit has tripped and is experiencing a station blackout (SBO)
- The main feeder bus cannot be energized through the startup transformer and the standby bus cannot be energized from either Keowee or CT-5
- Another Oconee Unit is generating and is energizing both its MFBs.

3.0 REQUESTED ACTION

3.1 Requested action Summary:

- Close the operating Oconee unit's standby breaker 1 (S1) to energize standby bus 1 (SB1) and power the auxiliary service water switchgear (ASWS) from the operating Oconee generator.
- Connect a HPI pump (HPIP), from the Oconee unit experiencing the SBO, to the ASWS.
- This would allow HPI forced cooling of the core, while power is being restored. Also the auxiliary service water pump (ASWP) would be available to provide inventory to the steam generators if needed for cooling.

3.2 Background:

During a loss of switchgear event, the underground emergency power path or a Lee combustion turbine can supply one HPIP and the ASWP through SB1 and the ASWS. The HPIP can maintain water on the core and the ASWP can supply water to the steam generators providing a heat sink for the reactor coolant system. If the underground emergency power path or a Lee combustion turbine can not energize the standby bus, the HPIP and the ASWP would not be available. If another Oconee unit were generating, that unit could energize SB1 by closing its S1 breaker. The S1 breaker close logic will allow the breaker to close as long as the standby bus is not energized. The ASWS could then be energized to provide power to a HPIP and the ASWP.

The typical load for a running Oconee Unit is 12–15MW. The auxiliary and startup transformers are rated at 33.6MVA. The addition load of one HPIP and an ASWP is < 1MVA or 137 amps. With both main feeder buses in service, the load on main feeder bus 1 would be within its limits. UFSAR 8.2.1 3 states that each unit's auxiliary startup transformer is sized to carry full load auxiliaries for one nuclear generating unit plus the engineered safeguards equipment of another unit. The operating load of a HPIP and an ASWP is considerably less than a unit's engineered safeguards load, thus there would be sufficient power available should the operating unit trip.

3.3 Implementation

1. Verify SB1 is not energized.
2. Ensure all breakers for SB1 are open.
3. Place CT4 BUS 1 "AUTO/MAN" transfer switch in "MANUAL".
4. Place Standby Bus 1 "AUTO/MANUAL" transfer switches in "MANUAL".

5. Close Breaker S1.
6. Have I&E perform procedure IP/0/A/0050/001, Procedure To Provide Emergency Power To An HPI Pump Motor From The ASW Switchgear.

3.4 Expected Plant Response

ASW Switchgear will be energized from an operating Oconee Unit. One HPI pump and the ASW pump can be operated as desired.

L. LIMITATIONS ON ALIGNING HPI SUCTION FROM THE SFP

1.0 SAFETY CONCERN

Loss of suction source to the HPI pumps when aligned to the SFP.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- An Oconee unit has tripped and is experiencing a station blackout (SBO)
- SSF RC makeup pump is not available
- An HPI pump can be powered from the ASW switchgear
- The BWST and LDST are not available as suction sources to the HPI pumps
- The SFP can be aligned as a suction source for the HPI pumps

3.0 REQUESTED ACTION

3.1 Requested action Summary:

- Provide guidance to monitor the SFP and ensure suction remains available to the HPI pumps based on limitations on the following parameters:
- SFP level
- HPI flow rate
- SFP temperature

3.2 Background:

If the BWST and LDST are not available as a suction source for the HPI pumps, it is possible to align the suction of an HPI pump to the SFP. Conditions in the SFP need to be monitored to ensure suction to the HPI pumps is not interrupted. Design calculations demonstrate that an HPI pump will have adequate NPSH when aligned to the SFP. However, suction could be interrupted based on the following two concerns:

- Siphon break at elevation 822 feet in the SFP:

The suction line as a siphon break at 822 feet. This consists of two 1/2 inch holes. If the SFP level decreases to 822 feet, suction to the HPI pumps will be interrupted. Thus, this is one limit that the TSC must consider.

- Flashing in the high point of the SFP suction line:

HPI flow can be interrupted if the pressure in the high point of the suction line from the SFP equals the vapor pressure based on SFP temperature. This is the primary concern when aligning HPI to the SFP. The factors that influence flashing are:

SFP temperature - If SFP cooling is lost, SFP temperature will increase. The higher the temperature, the less margin to flashing in the high point. The factor that influences SFP temperature is the decay heat load in the SFP.

SFP level - SFP level impacts flashing in that a lower SFP level results in lower elevation head and a lower pressure in the high point of the suction line. SFP level will decrease based on the HPI flow rate.

HPI flow rate - HPI flow rate impacts margin to flashing by its effect on the pressure in the high point of the SFP suction line. As HPI flow rate increases, the frictional losses in the suction pipe increase. Increased frictional losses decrease the pressure in the high point of the line, thus reducing the margin to the vapor pressure. The frictional losses due to the flow rate are a second order effect when compared to SFP level and temperature. Thus, the primary issue with SFP flow rate is its impact on SFP level.

3.3 Implementation

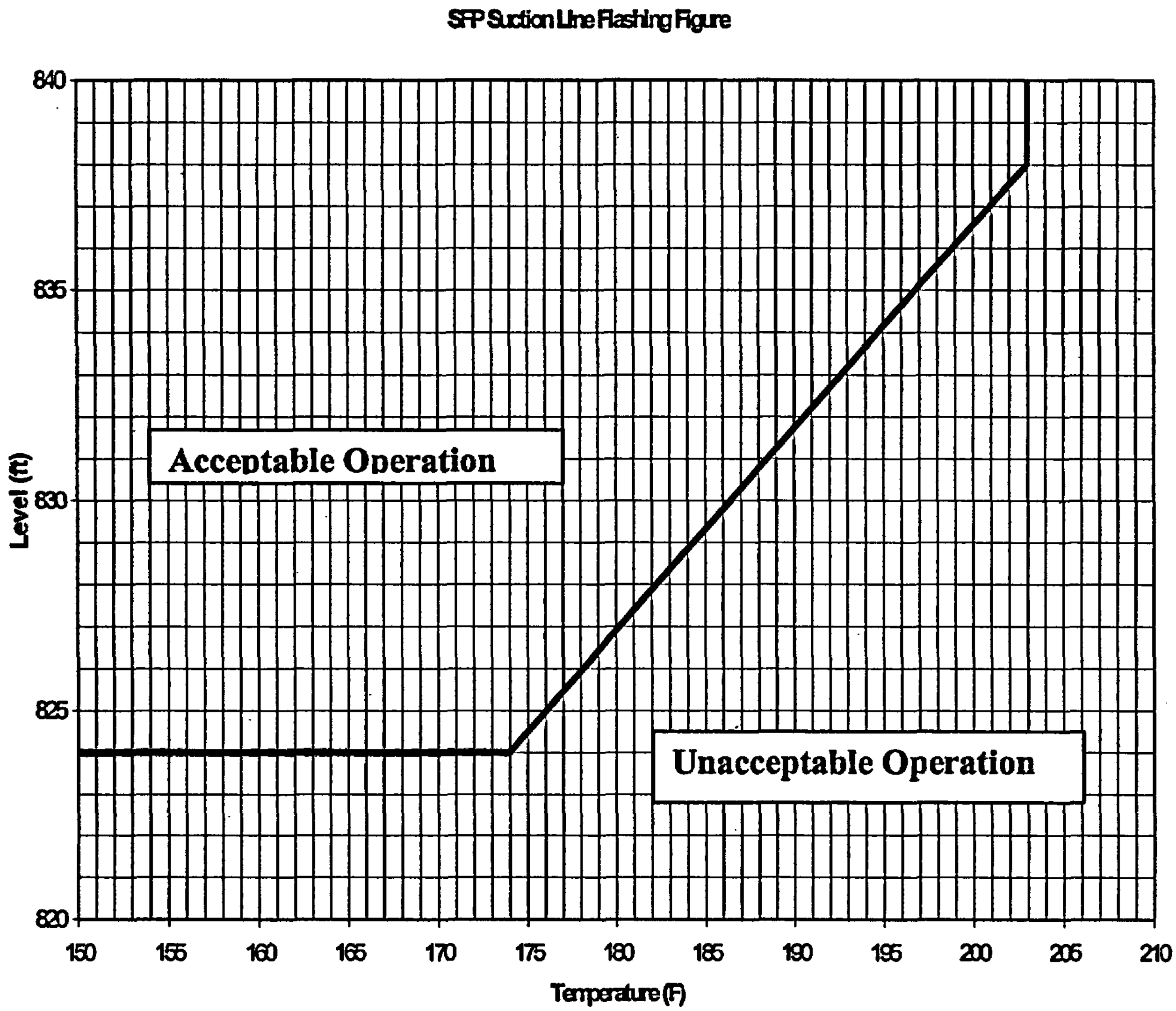
Siphon Break

If an HPI pump is aligned to the SFP, the pump should be secured prior to SFP level decreasing below 824 feet. The 824 feet criterion is selected to provide margin to the elevation of the siphon break (siphon break is at a SFP level of 822 feet).

Flashing at SFP Suction High Point

Flashing in the high point of the SFP suction line depends on SFP temperature, SFP level, and the HPI flow rate. Calculation OSC-3873, Rev. 4, provides data on the SFP as a suction source for the HPI pumps. The analyses in this calculation demonstrate that the frictional losses associated with the HPI flow rate are small. Thus, the conditions at which flashing occurs can be directly determined based on only SFP level and temperature. Also, for a given SFP level and temperature, the differences between the Units 1 and 2 SFP and the Unit 3 SFP are negligible. Thus, the same data to determine the flashing point can be used for both SFPs.

The following figure provides the flashing curve as a function of SFP temperature and SFP level. For a given SFP temperature, the level must be maintained greater than the level in the following curve.



- Monitor SFP level and temperature initially on a one half hour frequency and project changes in temperature and level to ensure continued suction remains to the HPI pumps. Adjust monitoring frequency based on projections of SFP temperature and level.
- HPI flow rate should be adjusted based on RCS requirements taking into consideration the impact of changing flow rates on SFP level.

3.4 Expected Plant Response

HPI flow is successfully established from the SFP. Monitoring is in place to determine when HPI flow from the SFP should be terminated.

M. ENSURE TOTAL LPSW RECIRCULATION FLOW IS ≤9000 GPM DURING CCW DAM FAILURE

1.0 SAFETY CONCERN

Total LPSW flow is maintained ≤9000 gpm during a CCW Dam failure scenario. Flow to various LPSW loads may require throttling to achieve desired flow rate.

2.0 PROCEDURE ENTRY CONDITIONS

This guidance is used during Case B of AP/1/A/1700/013 (Dam Failure Without Loss of CCW Intake Canal). The Symptoms for entering AP/1/A/1700/013 are:

- Visual observation of decreasing lake level or dam failure
- Telephone communication of a Keowee or Little River dam failure
- "CCW LAKE LEVEL LOW" statalarm (1SA-09/B-10)
- "FOREBAY ELEV" decreasing toward 70 feet

3.0 REQUESTED ACTION

Determine which LPSW loads should be throttled to ensure total LPSW recirculation flow is ≤9000 gpm.

3.1 Background:

In the event of a Loss of Lake Keowee, the preferred method of decay heat removal is via the CCW System recirculation mode. In this alignment, the Unit 1&2 and Unit 3 LPSW systems are cross-connected and one LPSW pump operated to supply the required loads for all three units. The LPSW System is aligned so that the normal discharge paths are isolated such that flow is forced in the reverse direction through the Unit 1 RCW coolers and back to the CCW crossover.

Per OSC-5739, total LPSW flow is limited to 9000 gpm to ensure excessive velocities are not generated in the tubes of the RCW Coolers and to reduce the likelihood of undesirable internal LPSW recirculation in certain system configurations.

3.2 Implementation:

Since total LPSW flow is limited to 9000 gpm and only one LPSW pump is operating, each unit is allowed 3000 gpm of LPSW flow. The only available LPSW loads on each unit are listed below as well as the LPSW throttle valve associated with each load.

- "B" RBCU and RBACs - 1/2/3LPSW-21
- "A" LPI Cooler - 1/2/3LPSW-4 or 1/2/3LPSW-251
- "B" LPI Cooler - 1/2/3LPSW-5 or 1/2/3LPSW-252

The above loads must be throttled as required on each unit to maintain total LPSW pump flow ≤9000 gpm.

3.3 Expected Plant Response

Total LPSW flow as indicated on the operating LPSW Pump's discharge flow gauge should indicate ≤9000 gpm.

N. N. MANAGE KEOWEE LAKE LEVEL DURING A LOOP

1.0 SAFETY CONCERN

During any event involving a loss of off-site power (LOOP) and operation of Keowee Hydro Station, the lake level will decrease significantly. Decreasing lake level can adversely affect the operability of several plant systems and equipment.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of the following guidance.

- Loss of off-site power.
- Keowee Hydro Station in operation.

3.0 REQUESTED ACTION

3.1 Requested Action Summary

- Minimize usage of Lake Keowee inventory.
- Supplement Lake Keowee inventory from Lake Jocassee.
- Take actions to mitigate effects of decreasing lake level on Oconee systems/equipment as follows:
  1. Minimize LPSW System demand to reduce NPSH required.
  2. Align LPSW supply to Chiller Condenser Service Water Pump suction to increase NPSH available.
  3. Place HPSW pumps in OFF position to increase NPSH available for LPSW pumps.
  4. Isolate RWF Equipment Cooling supply and return lines from ECCW siphon headers to maintain operability of ECCW first siphon.
  5. Restart two CCW pumps (one each on two separate Oconee units) to eliminate reliance on ECCW first siphon.

3.2 Background:

SLC 16.9.7 provides operability requirements for Oconee systems and equipment based on Keowee lake level. As an event progresses and lake level decreases, various actions are necessary to ensure systems and equipment remain capable of performing their functions.

The Oconee licensing basis does not provide a duration for a LOOP, but a reasonable duration for Keowee operation is 7 days (ref. PIP O-02-136). Assuming an event begins with the lake level at 791 feet and both Keowee units are operating, the lake level would be 783.6 feet after 7 days (ref. OSC-3528). This assumes no water transferred to Lake Keowee from Lake Jocassee.

Section 3.3 contains several estimates of the time available based on an initial lake level of 791 feet. If an event begins at some lake level above 791 feet, add about 1 day for each foot above 791 feet. For example, if an event begins at 794 feet, add three days.

3.3 Implementation

3.3.1 Minimize usage of Lake Keowee inventory

If all plant loads are being supplied by one unit at Keowee Hydro and the other Keowee unit is running at speed no-load, consider stopping the unloaded unit to conserve inventory. Operation of a Keowee unit with no load uses almost as much water as operation fully loaded to the maximum emergency loads. Therefore, stopping one Keowee unit would reduce water usage by more than 40% (ref. OSC-3528).

If both Keowee units are carrying some load, procedures do not exist to manually transfer plant loads from one Keowee unit to another in order to stop one Keowee unit. However, this action should be considered by the TSC if the event is expected to last significantly beyond 7 days. Differences in reliability and the potential for inducing an undesirable transient (i.e., loss of all AC power) should be considered before taking this action.

Operation and loading of combustion turbines at Lee Steam Station may allow stopping both Keowee units, thus conserving water in Lake Keowee. However, differences in reliability and the potential for inducing an undesirable transient (i.e., loss of all AC power) should be considered before taking this action.

If Jocassee Hydro is capable of starting and generating to the grid, evaluate the possibility of energizing the Oconee switchyard from Jocassee and providing power to the LOOP units from the switchyard. This would allow both Keowee units to be shutdown for some period of time to conserve water. However, differences in reliability and the potential for inducing an undesirable transient (i.e., loss of all AC power) should be considered before taking this action.

The ECCW second siphon discharge at CCW-8 transfers a small amount of flow (~30,000 gpm) from Lake Keowee to Lake Hartwell. If the second siphon is not needed, this discharge can be eliminated by closing CCW-8 per OP/1,2,3/A/1104/012 (CCW System).

3.3.2 Transfer water from Lake Jocassee to Lake Keowee

The System Operating Center (SOC) should be contacted to request transfer of water from Lake Jocassee to Lake Keowee. In order to transfer water from Lake Jocassee at the same rate that two Keowee units would use, at least one unit at Jocassee Hydro Station would have to be generating to the grid. However, water can be transferred at a slower rate by operating Jocassee units at speed no-load or by opening the spillway gates. This would at least reduce the rate of decrease of the Keowee lake level. Depending upon the Jocassee lake level, operation at speed no-load plus opening the spillway gates may supply adequate flow rate to match two units at Keowee Hydro.

3.3.3 Minimize LPSW System Demand

If a loss of Instrument Air (IA) has occurred, maximum LPSW flow will be supplied to each LPI cooler. LPSW flow to LPI coolers must be throttled on any non-ES unit to <6000 gpm (total flow for both coolers). There would be >9 hours before LPSW flow to LPI coolers must be throttled to maintain adequate NPSH for LPSW pumps (based on 790.6 feet actual limit per calculation). Operations estimated that this action would be completed within 4 hours using existing procedures. After throttling, the LPSW NPSH limit would become 781.6 feet (ref. OSC-2280).

The LPSW pump NPSH limits discussed above assume administrative controls are in place to ensure the A HPSW pump is not operating. This means that the A HPSW pump should be in "standby" with the B HPSW pump in "base" (i.e., the normal alignment) or place the A HPSW pump in "off" to prevent it from operating.

3.3.4 Align LPSW Supply to Chiller Condenser Service Water Pump Suction

There would be >23 hours before we would reach the 790 ft. limit for the Chiller Condenser Service Water Pump. A procedure exists to vent air from the Chiller Condenser Service Water Pump suction piping. This procedure temporarily aligns the LPSW supply, but the procedure restores the CCW supply after venting. As lake level decreases, this would lead to further air binding problems. Procedure changes are pending (ref. PIP O-02-136) that would allow the LPSW supply to remain aligned to the Chiller

Condenser Service Water Pump during the remainder of the event. Until those procedures are revised, the TSC should consider aligning the LPSW supply and leaving it aligned to prevent the need for repetitive venting.

3.3.5 Place HPSW Pumps in OFF Position

The A HPSW pump may have inadequate NPSH below 791 feet. The B HPSW pump may have inadequate NPSH below 789 feet. To ensure protection of the pumps, consider placing the pumps in the OFF position to prevent automatic start. If available, use the Jockey pump to maintain EWST level instead of the A or B HPSW pumps. Also, consider temporary charging of the HPSW system using the off-site fire department per the emergency operating procedure. If short-term operation of the A or B HPSW pump is required to maintain EWST level, this should be performed manually and the duration should be minimized to avoid pump damage due to inadequate NPSH.

3.3.6 Isolate RWF Equipment Cooling Supply and Return Lines from ECCW Siphon Headers

Lake level must be above 787 feet to prevent a postulated pipe break at normally open seismic boundary valves 1,2,3CCW-319 and 1,2,3CCW-320 from potentially affecting the ECCW first siphon via air in-leakage. If lake level approaches 787 feet, these valves should be closed. There would be >3.9 days before the lake level would reach 787 feet.

If enough ECCW siphon headers are operable, it may be desirable to leave the valves open on one Oconee unit to continue supplying the RWF. However, this would make the ECCW siphon headers inoperable on that unit.

As an alternative, restart of CCW pumps may be performed as discussed below instead of closing the valves.

3.3.7 Restart Two CCW Pumps

Lake level must be above 786 feet to meet operability requirements for the ECCW first siphon, since the ECCW test acceptance criteria assumes a minimum lake level of 786 feet. There would be >4.8 days before the lake level would decrease to 786 feet. This is enough time for operators to restart two CCW pumps, one each on two separate Oconee units, using existing procedures (AP/1,2,3/A/1700/011). The CCW pumps would be able to supply suction to LPSW pumps without relying on the first siphon.

If necessary, the ECCW first siphon would continue to supply adequate suction to LPSW pumps down to 782 feet or lower. The 786 feet requirement is conservatively based on maintaining the ECCW header full. Engineering calculations have determined that adequate flow can be supplied to LPSW pumps with the water level inside the pipe about 4 feet (or less) below the top of the pipe, depending upon the number of open CCW pump discharge valves (ref. OSC-5349). Also, the actual ECCW test results may be better than the minimum acceptable results, thus providing additional margin.

If lake level is less than 786 feet and CCW pumps are not running, periodically monitor the following pumps that take suction from the CCW crossover for evidence of inadequate suction (i.e., amps fluctuating, cavitation noise at pumps):

- LPSW pumps
- Chiller Condenser Service Water pumps for A, B, C, and D chillers
- HPSW Jockey pump
- CCW Booster pump

3.4 Expected Plant Response

By taking actions as recommended above, the important plant systems and equipment needed for accident mitigation will remain capable of performing their functions for >7 days during a LOOP.

O. OPENING THE ALTERNATE POST-LOCA BORON DILUTION FLOWPATH

1.0 Safety Concern

Opening the alternate post-LOCA boron dilution flowpath at elevated RCS pressure may damage the RB sump screen or supply two-phase water to the suction of the LPI pumps.

2.0 Procedure Entry Conditions.

EOP Section LOCA Cooldown/HPI Cooldown, Response Not Obtained

- An Oconee unit is experiencing a LOCA.
- The primary boron dilution flowpath cannot be opened.
- The alternate post-LOCA boron dilution flowpath is to be opened.

3.0 Requested Action

3.1 Requested Action Summary:

Open the alternate post-LOCA boron dilution flowpath.

3.2 Background:

An LPI boron dilution flowpath is opened to prevent excessive boron concentrations in the reactor vessel due to extended operation in the "boiling pot mode" following LOCAs. In the boiling pot mode the reactor vessel functions as an evaporator and concentrates the boric acid. The guidance is in EOP LOCA and HPI Cooldown Sections. Excessive boron concentrations can result in precipitation of boric acid crystals that can lead to obstructing long-term cooling of the core. Calculations have shown that opening an LPI boron dilution flowpath is required no earlier than 9 hours following a large cold leg break LOCA, which is the limiting break size and location for this issue. The EOP does not include the 9 hour requirement, with the expectation that this action will occur prior to 9 hours. The EOP does not require this action unless the core exit thermocouple temperatures are less than 400°F, and the subcooled margin does not exist. Also, RCS pressure must be less than 320 psig, to support operation of valves LP-103 and LP-104. These criteria are based on the higher solubility of the boric acid at temperatures of 400°F and higher, and that the boiling pot mode does not exist if the core exit thermocouple temperatures indicate subcooled conditions.

There is a good likelihood that gaps in the reactor vessel internals where the hot legs nozzles match up with the upper internals will provide a leakage path that will serve to prevent the concentration of boric acid in the core region. The B&WOG has analyzed these gaps and have concluded that they will function to prevent excessive boric acid concentration buildup. One drawback to crediting these gaps exists, and that is the possibility that the gaps will be plugged by debris circulated by the LPI System while drawing water from the RB sump. This possibility has been recognized by the industry and by the NRC, and so reliance on the gaps, while likely, should not be the sole method of preventing post-LOCA boric acid precipitation.

Opening the primary boron dilution flowpath through LP-103 and LP-104 does not involve any additional considerations, and is not the subject of this TSC Guideline.

Opening the alternate post-LOCA boron dilution flowpath through LP-1, LP-2, and LP-105 (Unit 1), and through LP-1, LP-2, and LP-3 (Units 2 and 3), does involve additional considerations, and that is the subject of this TSC Guideline.

The first consideration is that opening the alternate post-LOCA boron dilution flowpath can result in a high velocity discharge that can impinge on the emergency sump screen. This high velocity can result from the RCS being at a higher pressure than the emergency sump, and opening the alternate flowpath will then accelerate water through the pipe and towards the sump and sump screen. The second consideration is that opening the alternate post-LOCA boron dilution flowpath can result in two-phase conditions at the suction of the A LPI pump. This is possible due to the depressurization of the RCS (if the RCS pressure is higher than the RB pressure) and the possibility that water flowing through the LPI piping will flash. This situation must not be allowed since continued stable operation of the LPI pumps must be maintained.

For large break LOCAs the RCS and the RB will have equalized in pressure, and there is no adverse consequence of opening the alternate post-LOCA boron dilution flowpath. The objectives of this TSC guidance is therefore to ensure 1) that opening the alternate post-LOCA boron dilution flowpath is necessary, 2) that for SBLOCAs that the RCS and RB pressures have equalized prior to opening the alternate post-LOCA boron dilution flowpath, and 3) if pressure equalization cannot be confirmed, then the alternate post-LOCA boron dilution flowpath must not be opened.

3.3 Implementation

<u>Step 1: Determine if the boiling pot mode exists</u>: If the core exit thermocouple temperature indicates that the water exiting the core is subcooled, then the boiling pot mode cannot exist, and there is no requirement for opening the alternate post-LOCA boron dilution flowpath. The actual core exit thermocouple temperatures should be considered in this determination, rather than relying on the ICCM subcooled margin, since the worst-case instrument uncertainty is included in the ICCM software. Similarly, the available RCS and RB pressure instrumentation should be used rather than just relying on the ICCM subcooled margin. LPI System flow can also be used to confirm the RCS pressure. Trends of these temperature and pressure indications should be considered since for all LOCAs the pressures and temperatures will steadily decrease in the long-term as decay heat decreases.

<u>Step 2: Determine if the RCS level is high enough to spill borated water out the break</u>: The reactor vessel and hot leg level indications can be used to determine if the water level is high enough in the reactor vessel to provide flow from the core outlet, through the reactor vessel internal vent valves, into the vessel upper downcomer, and then towards the cold leg break location. If this flowpath exists, then the core boron concentration cannot increase to an unacceptable value. A vessel level of 120 inches, and a hot leg level of 120 inches is sufficient for confirming that this flowpath exists, and that the alternate post-LOCA boron dilution line does not need to be opened.

<u>Step 3: Determine if the RCS boron concentration is increasing by sampling the RB sump boron concentration</u>: Concentration of boric acid in the reactor vessel can be evaluated by periodic sampling of the boron concentration in the RB sump. If the RB sump boron concentration is not decreasing, then the reactor vessel boron concentration cannot be increasing. An absence of a decreasing trend in the RB boron sump concentration precludes the need to open the boron dilution flowpath.

<u>Step 4: Determine how much time is available to make this decision</u>: A conservative earliest time requirement for opening a boron dilution flowpath is 9 hours. This value is the result of a conservative calculation and includes many worst-case assumptions, including a large cold leg break LOCA. For SBLOCAs a significantly longer period of time is available, since the boiling pot mode starts later, there may be a period of natural circulation, etc. For SBLOCA, boron precipitation is a concern when the RCS is saturated with CETC temperature less than 305°F (saturated pressure of 72 psia). If the core is above 72 psia no boron precipitation can occur (reference FTI Doc. 51-1266113-00 Post LOCA Boron Concentration Management). If additional determination is required, the G. O. Safety Analysis Section

will be available to support Oconee Engineering and Operations following any station event, this determination will be their responsibility. The associated calculations can be performed in a short period of time and within the time available. The purpose of extending the time for making the decision to open the alternate post-LOCA boron dilution flowpath is to allow the RCS and RB pressures more time to equalize, or to allow the boiling pot mode to cease. Both of these situations are more likely as decay heat diminishes over time.

Step 5: Continue efforts to recover the primary boron dilution flowpath: Since there are no adverse consequences associated with the primary boron dilution flowpath, it is the preferred mitigation method. Recovery of the use of the primary boron dilution flowpath should be a priority.

Step 6: Confirm equalization of RCS and RB pressures: During the time period available (9 hours plus the additional hours resulting from the Step 4 analysis), evaluate the available data to determine if RCS and RB pressures have equalized. Engineering should be consulted to obtain information on the uncertainty in the process data, so that the possible adverse effect of instrument uncertainty is considered. Since some uncertainty in the process data will exist, confirming that RCS and RB pressure have equalized will involve some degree of judgment. Management concurrence with a decision to open the alternate post-LOCA boron dilution flowpath is required.

Step 7: Open the alternate post-LOCA boron dilution flowpath and monitor the LPI pumps: If Steps 1-6 have been performed and opening the alternate post-LOCA boron dilution flowpath is still necessary, and the allowable time determined in Step 4 has expired, and management concurs, then the alternate post-LOCA boron dilution flowpath is opened. Note that opening the alternate path is not recommended unless RCS is saturated with CETC temperature less than 305°F (saturated pressure of 72 psia). Align alternate boron dilution flow path as follows:

Note: The minimum system design (pressure & temp. rating) for both LPI & RBS in all units is 200 psig /300F.

1. Ensure LP-6, LP-9, LP-21 are closed
2. Ensure B or C LPI pump providing HPI piggy back through LP-16
3. Secure A BS pump and close BS-1
4. Secure A LPI pump
5. Close LP-19
6. Open LP-3, LP-2, LP-1
7. Throttle open BS-1 to obtain flow indication (nominally 100 gpm). Note this action could potentially wind mill the RBS pump
8. When RCS pressure decays flow and thru BS-1 will diminish, close BS-1.
9. Align A LPI in DHR alignment.

Step 8: Report to management on the plant response to opening the alternate post-LOCA boron dilution flowpath.

3.4 Expected Plant Response

No observable change in RCS conditions is expected.

P. DEPRESSURIZING THE REACTOR BUILDING AFTER A LOSS OF DHR EVENT DURING MODES 5 AND 6

1.0 SAFETY CONCERN

Depressurize the reactor building when building pressure reaches 1 psig to maintain containment closure during MODES 5 and 6. This guidance is mainly applicable to the steam generator replacement outage when building tendons will be detensioned and concrete will be removed beginning in MODE 5, but could be applied generically.

2.0 PROCEDURE ENTRY CONDITIONS

The following conditions are considered in preparation of this guidance.

- Loss of offsite power during MODES 5 and 6
- Loss of DHR during MODES 5 and 6

3.0 REQUESTED ACTION

3.1 Requested Action Summary

Depressurize the reactor building when pressure reaches 1 psig and maintain pressure below 8 psig via the reactor building purge pathway during MODES 5 and 6.

3.2 Background:

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, a release of fission product radioactivity within containment is restricted from escaping to the environment. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in ITS LCO 3.6.1, "Containment." In MODES 5 and 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. In order to make this distinction, the penetration requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that specified escape paths are closed or capable of being closed. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the specified escaped paths that are controlled by LCO 3.9.3 are the equipment hatch, the air locks, and the penetrations which provide direct access from the containment atmosphere to the outside atmosphere. Since there is no significant potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The requirements on containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling. However, to ensure containment closure is maintained during a loss of DHR event that causes building pressure to escalate, additional guidance will be presented in this section to depressurize the reactor building through the purge release pathway via opening valves PR-1, -2, -3 and starting the purge fan. This pathway will filter the building air using the purge exhaust filter, monitor the air using the Unit Vent Radiation Monitor (1,2,3 RIA-45), and exhaust the air to the vent stack. There will be guidance provide for 1) a loss of DHR event caused from the loss of power and 2) a loss of DHR event NOT caused from a loss of power. It should be noted that this guidance is specific to the steam generator replacement outage when building tendons will be detensioned and concrete will be removed beginning in MODE 5, but could be applied generically.

The Reactor Building Purge System includes a supply penetration and exhaust penetration. During MODES 1, 2, 3, and 4, two valves in each of the supply and exhaust penetrations are secured in the closed position. The system is not subject to a Specification in MODE 5. In MODE 6, large air exchanges are necessary to support refueling operations. The purge system is used for this purpose, and two valves in each penetration flow path may be closed on a unit vent high radiation signal. The Unit Vent Radiation Monitor (1,2,3 RIA-45) closes the four outboard isolation valves (1,2,3 PR-2, -3, -4, -5) associated with R.B. Purge Penetrations (19 and 20). The capability of RIA-45 to close the valves is verified immediately prior to refueling operations. If a loss of DHR event occurs, AP/1,2,3/A/1700/026 secures RB purge and closes 1,2,3 PR-1, -2, -3, -4, -5, and -6. However, if during this event the building begins to pressurize and jeopardize containment closure during MODES 5 or 6, purge will be restarted per this guidance document.

It should again be noted that this guidance is specific to the steam generator replacement outage when building tendons will be detensioned and concrete will be removed beginning in MODE 5, but could be applied generically. In addition, with respect to accident analyses, there is no credit taken for any containment boundary in limiting releases during MODES 5 or 6. However, as a defensive measure, containment closure is maintained per Technical Specifications.

3.3 Implementation

3.3.1 Loss of DHR Event Caused from a Loss of Power Event

Monitor Reactor Building Pressure

During the steam generator replacement outages, if a loss of DHR event occurs, reactor building pressure should be continuously monitored and should not exceed 8 psig, as this is the limiting pressure the liner plate can withstand without buckling or rupturing. Action will be taken to depressurize the building when pressure reaches 1 psig.

Depressurize Reactor Building

Upon a loss of DHR event that causes reactor building pressure to escalate, the following steps should be taken when building pressure reaches 1 psig:

1. Upon loss of power, wait until power is restored (estimated at approximately 23 seconds).
2. Restore reactor building purge via OP/1,2,3/A/1102/014 Enclosure "RB Purge Release." Ensure purge flow rate does not exceed 50,000 cfm.
3. If the purge filter high dP alarm is received, slow the release by throttling PR-3 until alarm is silenced.
4. If core damage is indicated, terminate the purge by closing PR-1, -2, and -3. Indication can include, but is not limited to, reactor engineering recommendation, RP offsite sampling, or RIA response.

3.3.2 Loss of DHR Event NOT Caused from a Loss of Power Event

Monitor Reactor Building Pressure

During the steam generator replacement outages, if a loss of DHR event occurs, reactor building pressure should be continuously monitored and should not exceed 8 psig, as this is the limiting pressure the liner plate can withstand without buckling or rupturing. Action will be taken to depressurize the building when pressure reaches 1 psig.

Depressurize Reactor Building

Upon a loss of DHR event that causes reactor building pressure to escalate, the following steps should be taken when building pressure reaches 1 psig:

1. Restore reactor building purge via OP/1,2,3/A/1102/014 Enclosure "RB Purge Release." Ensure purge flow rate does not exceed 50,000 cfm.
2. If the purge filter high dP alarm is received, slow the release by throttling PR-3 until alarm is silenced.
3. If core damage is indicated, terminate the purge by closing PR-1, -2, and -3. Indication can include, but is not limited to, reactor engineering recommendation, RP offsite sampling, or RIA response.

3.4 Expected Plant Response

It is expected that the reactor building pressure will decrease and the air being released via the purge pathway will be filtered adequately.