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February 21, 2008

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION
DOCKET NOS. 50-445 AND 50-446
SUPPLEMENT TO LICENSE AMENDMENT REQUEST (LAR) 07-004
REVISION TO THE OPERATING LICENSE AND TECHNICAL SPECIFICATION 1.0, "USE AND APPLICATION" TO REVISE RATED THERMAL POWER FROM 3458 MWT TO 3612 MWT. (TAC NOS. MD6615 AND MD6616)

REFERENCE:
1. Letter logged TXX-07106 dated August 28, 2007 from Mike Blevins to the NRC submitting License Amendment Request (LAR) 07-004, proposing revisions to the Operating Licenses and to Technical Specifications 1.0, "USE AND APPLICATION" to revise rated thermal power from 3458 MWT to 3612 MWT

2. Letter logged TXX-08008 dated January 10, 2008 from Mike Blevins to the NRC submitting a supplement to License Amendment Request (LAR) 07-004

3. Letter logged TXX-08013 dated January 31, 2008 from Mike Blevins to the NRC submitting a supplement to License Amendment Request (LAR) 07-004

Dear Sir or Madam:

Per Reference 1, Luminant Generation Company LLC (Luminant Power) requested changes to the Comanche Peak Steam Electric Station, herein referred to as Comanche Peak Nuclear Power Plant (CPNPP), Units 1 and 2 Operating Licenses and to Technical Specification 1.0, "USE AND APPLICATION" to revise rated thermal power from 3458 MWT to 3612 MWT. Luminant Power supplemented that request by responding to NRC Requests for Additional Information (RAI) per References 2 and 3.

On February 11, 2008, the NRC provided Luminant Power with additional RAIs from the following branches regarding the proposed changes to rated thermal power.

Operator Licensing and Human Performance Branch
Mechanical and Civil Engineering Branch
Electrical Engineering Branch (follow-up questions)

The responses to these questions are provided in Attachment 1 to this letter. Attachment 2 provides additional information supporting Attachment 1. The responses to Mechanical and Civil Engineering Branch questions 12, 13, and 14 contain proprietary information and will be provided under separate cover letter.

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NRR

In accordance with 10CFR50.91(b), Luminant Power is providing the State of Texas with a copy of this proposed amendment supplement.

This communication contains the following new commitment which will be completed as noted.

Commitment #	Description	Due Date
3458447	A table of maximum stress values at the steam generator nozzles will be prepared for Units 1 and 2. In addition, a table of maximum stress values at a critical location closest to the containment penetration will be prepared for Units 1 and 2. These tables will be provided for your review by March 7, 2008.	March 7, 2008
3458484	A bounding temperature profile will be incorporated into design drawings and used as an input for EQ packages. The PAOT margin will be recalculated using this revised profile.	Prior to Unit 1, Cycle 13

The Commitment number is used by Luminant Power for the internal tracking of CPNPP commitments.

Should you have any questions, please contact Mr. J. D. Seawright at (254) 897-0140.

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

Executed on February 21, 2008.

Sincerely,

Luminant Generation Company LLC

Mike Blevins

By: Fred W. Madden

Fred W. Madden
Director, Oversight & Regulatory Affairs

Attachment - 1. Response to Requests for Additional Information
2. Additional information supporting Operator Licensing and Human Performance Branch Question 1

c - E. E. Collins, Region IV
B. K. Singal, NRR
Resident Inspectors, Comanche Peak

Ms. Alice Rogers
Environmental & Consumer Safety Section
Texas Department of State Health Services
1100 West 49th Street
Austin, Texas 78756-3189

RESFONSE TO REQUEST FOR ADDITIONAL INFORMATION

COMANCHE PEAK STRETCH POWER UPRATE

Operator Licensing and Human Performance Branch

NRC Question 1:

In Section 2.11.1.2 (page 2.11-2 of WCAP-16840-P, CPSES Units 1 and 2, Stretch Power Uprate Licensing Report (SPULR)), it is stated that the Emergency Operating Procedures (EOPs) "may" require changes to setpoints. Identify all changes to the EOPs and state whether any of the changes will affect the time required or the time available to perform EOP operator actions.

CPNPP Response:

Changes to the Emergency Response Guidelines (ERG) required as part of the Stretch Power Uprate (SPU) are provided in Attachment 2. For completeness, setpoints that were reviewed and not changed are also included. Since the changes are discreet (i.e., a small change in value due to revised PCWG parameters), there is no impact on the time required or the time available to perform EOP operator actions.

NRC Question 2:

Identify any operator manual acti~~ons credited in the Design-Basis~~ Accident analysis that are affected by the Stretch Power Uprate (SPU). Describe any changes to these actions or the associated controls, displays, or alarms. Specifically, address any changes to the time required or the time available for the actions.

CPNPP Response:

(a) Steam Generator Tube Rupture
The steam generator tube rupture analyses model operator actions to isolate the ruptured steam generator (including isolation of the failed-open ARV for the mass release case), cooldown the RCS using the intact SG ARVs, depressurize the RCS using the pressurizer PORVs, and terminate SI flow. The times credited are presented in Table 2.8.5.6.2-1 of WCAP-16840. The times for isolation of the ruptured SG (including isolation of the failed-open ARV for the mass release case), initiation of the RCS cooldown, and initiation of the RCS depressurization were not changed for the SPU program. The timing of the Safety Injection (SI) termination was changed for the uprate analysis. For the uprate analyses, the modeling was updated to model the termination of all SI injection flow to the RCS two minutes (previously 1 minute) after the end of depressurization . The break flow was then allowed to coast down to termination assuming no additional operator actions. This has been shown to be conservative compared to the pre-uprate modeling and supports the "Operator Action Time to Initiate Safety Injection Termination" entry in Table 2.8.5.6.2-1 of WCAP-16840-P.

(b) Inadvertent ECCS
The safety grade alarm (SI signal) is assumed to be initiated concurrent with the inadvertent SI signal. A simulator exercise was performed in accordance with CPNPP validation guidelines to assure that the assumed response times were reasonable. The simulator was set up to replicate many of the conservative assumptions of the FSAR Chapter 15 analyses, including the failure of automatic operation of the pressurizer PORVs, the Steam Dump System, and the automatic operation of the steam generator atmospheric relief valves (ARVs). Verifying the RCS average temperature is trending to 557°F and

taking manual control of the RCS average temperature occurred shortly after entry into the emergency procedures well within the assumed 7.5 minutes. Through the continuation of the simulator exercise, the crew was able to step through the procedures and secure ECCS well within the 13 minutes assumed in the analyses (close to 10 minutes). All communication protocols and management expectations for conduct of operations were met during the exercise.

NRC Question 3:

On page 2.11-5 of the SPULR, it is stated that "...hardware modifications may involve associated control system modifications..." Identify any control systems that will be modified and describe any resultant effects on plant operator actions, timing, or operator interfaces.

CPNPP Response:

Hardware modifications identified in Section 1.0 are required to support SPU. These modifications consist of:

Main Turbine - The Units 1 and 2 high pressure turbines will be replaced in order to pass the additional volumetric steam flow. Turbine digital controls and thyristor voltage regulator settings will be revised for uprate conditions. The replacement of the high pressure turbines affects turbine impulse pressure and subsequently calculated T_{ref} and associated control system.

Condensate and Feedwater - Higher condensate pump flow rate and additional head loss in the condensate and feedwater piping will result in lower suction pressure at the MFP. To preserve operating margin to alarms and automatic actions on low MFP suction pressure, the setpoints and instrumentation associated with MFP net positive suction head (NPSH) protection, condensate polisher bypass, and feedwater heater bypass will be changed.

Extraction Steam and Heater Drains - There will be slight increases in the temperatures, pressures, and flows in the extraction steam piping and in the various heater drains. Modifications to increase the capacity of the heater drain pumps will be installed to satisfy uprate heater drain flow requirements.

Main Generator - The main generator electrical output will increase by approximately 49 MWe (Unit 1) and 37 MWe (Unit 2). Each main generator will be re-rated from 1,350 to 1,410 MVA with an allowable power factor of 0.9.

The hydrogen coolers and exciter coolers will be replaced to provide additional cooling capacity during the summer months.

Iso-Phase Bus Ducts/Main Transformers - To transfer the power from the main generator to the grid the design capacity of the iso-phase bus duct system will be increased. The bus duct cooling fan/coil capacity will be increased to provide additional cooling.

The main transformers are currently operating under administrative voltage limits. The main transformers have been evaluated and found acceptable at SPU conditions with the current administrative limits. The main transformers are scheduled to be replaced due to their age and to enhance their MVAR support capability. Unit 2 transformers are scheduled to be replaced in 2009 and Unit 1 in 2010, after one cycle of SPU operation.

The modifications identified above will not impact control systems which affect plant operator actions, timing, or operator interfaces. Modifications associated with the installation of new hydrogen coolers, which will have the same type of local controls, will not change the plant operator actions in response to any detected system trouble or failure. Additionally, the change in the setpoints associated with MFP net positive suction head (NPSH) protection, condensate polisher bypass, and feedwater heater bypass will not affect the existing control system and will not affect the plant operator actions, timing, or operator interfaces in response to a loss of suction transient.

NRC Question 4:

On page 2.11-5 of the SPULR, it is stated that no changes to the Safety Parameter Display System (SPDS) are anticipated. Determine whether changes to the SPDS will be made and, if so, describe them and their effect on operators' ability to monitor critical safety functions.

CPNPP Response:

The function of the Safety Parameter Display System (SPDS) is to aid control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by the operator to avoid a degraded core. The SPDS display variables available to the operator via the plant computer system are as follows:

Power Range Power
Intermediate Range Power
Intermediate Range Start-up Rate
Source Range High Voltage
Source Range Start-up Rate
Neutron Flux Wide Range
Neutron Flux Source Range
Core Exit Temperature
RCS Margin to Saturation
RCP Breaker Status
RVLIS Indication - Bottom Level
Steam Generator Levels
Steam Generator Pressures
Auxiliary Feedwater Flows
RCS Cold Leg Temperature
RCS Hot Leg Temperature
RCS Pressurizer Pressure
RCS Pressure
Containment Pressure
Containment Water Level
Containment Radiation
Pressurizer Level
Reactor Vessel Level

Critical safety function status trees reflecting the above identified parameters have been considered during the design process for the SPU. The Power Uprate will not impact the displays, calculations, or functional requirements of the SPDS. However, it is contemplated that several warning limits on SPU affected parameters of the SPDS will require modification similar to control board banding modifications once design has been finalized. These changes will not impact operator cognizance or the operator's ability to monitor safety functions.

NRC Question 5:

Describe any controls, displays, or alarms that will be upgraded from analog to digital instruments as a result of the SPU. Describe how upgraded instruments will be tested for usability to confirm that operators can use the digital instruments reliably.

CPNPP Response:

There are no controls, displays, or alarms being upgraded from analog to digital instrumentation as a result of the SPU.

MECHANNICAL AND CIVIL ENGINEERING BRANCH

NRC Question 1:

Section 2.2.1.1 of the SPULR states that that as discussed in Final Safety Analysis Report (FSAR) Sections 3.6B.2.1.1 and 3.6B.2.1.2, the current licensing basis of CPSES, Units 1 and 2, utilizes the NUREG-16061 Volume 3, leak-before-break (LBB) methodology and excludes the dynamic effects of postulated pipe ruptures in the primary coolant loop piping and 10-inch and larger reactor coolant loop (RCL) branch lines from the design basis.

a) **Identify branch line breaks that are used for the reactor coolant system Loss-of-coolant accident analysis for CPSES, Units 1 and 2 at the SPU conditions.**

b) **Confirm that the pressurizer spray line, the safety-injection line, the main steam (MS), feewdwater (FW), and auxiliary FW line breaks are considered in the analyses for the SPU conditions. If not, provide technical justification for not including these pipe breaks.**

c) **Provide justification that the basis for using LBB methodology is still valid under the proposed SPU conditions.**

CPNPP Response 1 (a) and 1(b):

For a loss of coolant accident on the primary side of the Nuclear Steam Supply System, a hydraulic analysis and a structural analysis were explicitly done for two breaks, the break of the 6 inch safety injection line to the hot leg and the break of the 4 inch spray line from the cold leg. In addition to the break of the spray line, to account for the breaks of 3 inch auxiliary lines on the cold leg, structural analysis is done in which the internal hydraulic forces for the break of the spray line are applied to the model along with the thrust force emanating from the break of the 3 inch auxiliary line on the cold leg. Also, to account for the breaks of auxiliary lines on the crossover leg, structural analysis is done in which the thrust force emanating from the break on the crossover leg is applied to the model, and the results from this structural analysis are then combined with the results of the structural analysis for the breaks on the cold leg.

For a pipe break accident on the secondary side, a break of the main steam line, a break of the main feed water line, and a break of the auxiliary feed water line are considered.

CPNPP Response 1 (c):

The justification for using LBB methodology under the proposed SPU conditions is included in SPULR section 2.1.6.

NRC Question 2:

The postulated pipe break acceptance criteria are described in FSAR Section 3.6B. The pipe rupture protection criteria conforms to the guidelines of Branch Technical Position MEB 3-1. Section 2.2.1.2.2 of the SPULR states that "Affected piping systems were evaluated to address revised SPU operating conditions". Section 2.2.1.2.2 also states that "[t]he evaluations performed for these piping systems did not result in any new or revised pipe break locations. The evaluations performed for these systems, with the exception of the main feedwater system, did not identify any significant increases in operating conditions that would impact existing design basis pipe break, jet impingement, and pipe-whip analyses. The feedwater system will experience an increase in operating pressure due to SPU. Any resulting modifications to existing pipe whip restraints and/or pipe supports will be provided, if required, to accommodate the higher pipe break loadings."

a) **Provide a summary description of the evaluations, explaining how the evaluations were performed. Include assumptions and load combinations along with summaries of results that show that you meet the FSAR pipe break acceptance criteria when SPU conditions are included.**

b) **Provide a description of any new pipe whip restraints, pipe supports or modifications to existing installations that are required due to higher SPU conditions and discuss the projected schedule of work completion.**

CPNPP Response 2 (a):

Pipe break evaluations were performed in accordance with existing licensing and design basis requirements for Comanche Peak. These requirements are contained in Comanche Peak FSAR Section 3.6B, Comanche Peak Design Basis Documents (DBDs). These documents commit to meeting the criteria as provided 10CFR50 Appendix A Criteria 1 and 4, and Appendix B, NUREG-0800 Section 3.6.1 and 3.6.2 and BTPs APCSB 3-1 and MEB 3-1 in accordance with RG 1.64 and ANSI N45.2 and ANSI/ANS-58.2.

For jet impingement and pipe whip analyses, bounding parameters had been utilized to establish the current design basis and therefore SPU conditions did not impact the design basis. For break postulation in piping in containment penetration areas that must meet the requirements of BTP MEB 3-1:B.1.b for break exclusion, the current (pre-SPU) design basis did not utilize parameters that envelope new SPU conditions for the feedwater piping system. Therefore, revised pipe break postulation evaluations were performed to demonstrate that no new feedwater breaks needed to be considered for SPU conditions. Evaluation methodology and load combinations were consistent with the references identified above except that SPU conditions were used as input. Consistent with the requirements contained in the references identified above, stress limits for Total Additive Stress (with an allowable limit of 0.8 (1.2 Sh + SA) and stress limits for the Break Exclusion Zone (with an allowable limit of 1.8 Sh for a postulated pipe break outside the Zone) were used.

The feedwater piping analyses described above are in process and will demonstrate that the resulting actual stress levels for total additive and break exclusion are less than the allowable total additive stress limit of 32,400 psi, and the allowable stress within the break exclusion zone (due to a break outside this zone) of 27,000 psi.

CPNPP Response 2 (b):

With regard to pipe break loadings, there are no new or modified pipe whip restraints and no new or modified pipe supports required due to higher SPU conditions in the feedwater system.

NRC Question 3:

Identify the code of record utilized in qualifying Nuclear Steam Supply System (NSSS) and Balance of Plant (BOP) piping and pipe supports for SPU conditions. If different from the plant Code of Record, provide justification.

CPNPP Response:

The codes of record utilized in qualifying the Nuclear Steam Supply System and Balance of Plant (BOP) piping and supports for the Stretch Power Uprate conditions are the same as the plant codes of record.

- For Reactor Coolant Loop (RCL) piping, the code of record is the ASME Code, 1977 Edition and Addenda up to and including the Summer 1979 Addenda.

- For RCL supports, the code of record is the ASME Code, 1974 Edition and Addenda up to and including the Summer 1974 Addenda.

For BOP piping and supports, the codes of record are as follows.

a. For ASME Code Class 2 and 3 piping, the code of record is the ASME III Code, 1974 Edition up to and including the Summer 1974 Addenda.

b. For ASME Code Class 2 and 3 supports, the code of record is the AMSE III Code, 1974 Edition up to and including the Winter 1974 Addenda.

For non-ASME piping and supports, the code of record is the ANSI 31.1 Code, 1973 Edition up to and including the Winter 1974 Addenda.

NRC Question 4:

Tables 1.1-1 and 1.1-2 of the SPULR provide SPU NSSS performance capability working group (PCWG) parameters. Included are pressures and temperatures for reactor coolant and steam generator (SG).

a) Provide PCWG parameters for licensed power.
b) Show licensed and SPU FW flow.
c) Provide maximum operating and design pressures and temperatures for RCL, MS and FW piping for licensed and SPU power.

CPNPP Response 4 (a)

The current licensed power conditions are shown in the below table, for comparison to the uprate conditions. Unit 1 and Unit 2 values are provided for comparison.

CPNPP Response 4 (b)

The current licensed power feedwater flow is provided in Tables 2.5.5.4-1 (Unit 1) and 2.5.5.4-2 (Unit 2). These tables show the following:

Unit	Current FW Flow	Uprate FW Flow
1	15,508,480 lbm/hr	16,322,730 lbm/hr
2	15,479,410 lbm/hr	16,229,900 lbm/hr

CPNPP Response 4 (c)

The operating pressures and temperatures of the RCL piping are provided in the attached table. The operating pressures and temperatures of the MSS and FW systems for licensed and SPU power levels are provided in Tables 2.5.5.4-1 and 2.5.5.4-2.

The design pressure and temperature of the RCL piping are 2485 psig and 680°F.

The design pressure and temperature of the MSS piping are:

- Piping from the Steam Generators to the Main Steam Isolation Valve is class 1303-2. The pipe class has a design pressure of 1200 psig and a design Temperature of 650°F.

- Piping downstream of the Main Steam Isolation Valve is class 1302G. The pipe class has a design pressure of 1200 psig and a design Temperature of 650°F.

The design pressures and temperatures of the FW piping are:

- Piping from the SGFP to the SG Building is class 2002G. The pipe class has a design pressure of 2045 psig and a design Temperature of 650°F.

- Piping from the SG Building to the moment restraint is class 2002-5. The pipe class has a design pressure of 2045 psig and a design Temperature of 650°F.

- Piping from the moment restraint to 1 ft. downstream of the FW Isolation Valve is class 2003-2. The pipe class has a design pressure of 2045 psig and a design Temperature of 650°F.

Piping from 1 ft. downstream of the FW Isolation Valve to the Steam Generators is class 1303-2. The pipe class has a design pressure of 1200 psig and a design Temperature of 650°F.

NSSS PCWG Parameters for CPNPP Unit 1 SPU Program – Comparison with Current Licensed Power Parameters

Thermal Design Parameters	Current Licensed Power	**Uprate Program**			
		Case 1	**Case 2**	**Case 3**	**Case 4**
NSSS Power, MWt	3,475	3,628	3,628	3,628	3,628
Reactor Power, MWt	3,458	3,612	3,612	3,612	3,612
Thermal Design Flow, loop gpm	U1: 95,700 gpm/loop U2: 97,700 gpm/loop	95,700	95,700	95,700	95,700
Reactor Coolant Pressure, psia	2,250	2,250	2,250	2,250	2,250
Reactor Coolant Temperature, °F					
Core Outlet	608.4 – 622.5	609.8	609.8	623.8	623.8
Vessel Outlet	605.0 – 619.2	606.2	606.2	620.4	620.4
Core Average	577.4 – 592.6	577.6	577.6	592.8	592.8
Vessel Average	574.2 – 589.2	574.2	574.2	589.2	589.2
Vessel/Core Inlet	543.5 – 559.2	542.2	542.2	558.0	558.0
Steam Generator Outlet	543.1 – 558.9	541.9	541.9	557.6	557.6
Steam Generator					
Steam Outlet Temperature, °F	529.0 – 547.1	528.9	526.9	545.1(2)	543.1
Steam Outlet Pressure, psia	877 – 1021	877	862	1,005(2)	988
Steam Outlet Flow, 106 lb/hr total	15.36 – 15.46	14.89/16.17	14.88/16.16	14.97/16.26(2)	14.96/16.25
Feed Temperature, °F	444.6	390.0/450.3	390.0/450.3	390.0/450.3	390.0/450.3
Steam Outlet Moisture, % max.	0.10	0.10	0.10	0.10	0.10
SG Tube Plugging Level, %	0-10	0	10	0	10
Zero-Load Temperature, °F	557	557	557	557	557

NSSS PCWG Parameters for CPNPP Unit 2 SPU Program - Comparison with Current Licensed Power Parameters

Thermal Design Parameters	Current Licensed Power	**Uprate Program**			
		Case 1	**Case 2**	**Case 3**	**Case 4**
NSSS Power, MWt	3,475	3,628	3,628	3,628	3,628
Reactor Power, MWt	3,458	3,612	3,612	3,612	3,612
Thermal Design Flow, loop gpm	97,700	95,700	95,700	95,700	95,700
Reactor Coolant Pressure, psia	2,250	2,250	2,250	2,250	2,250
Reactor Coolant Temperature, °F					
Core Outlet	618.5 - 625.0	609.8	609.8	623.8	623.8
Vessel Outlet	616.1 - 621.9	606.2	606.2	620.4	620.4
Core Average	588.9 - 592.7	577.6	577.6	592.8	592.8
Vessel Average	585.7 - 592.7	574.2	574.2	589.2	589.2
Vessel/Core Inlet	556.1 - 562.7	542.2	542.2	558.0	558.0
Steam Generator Outlet	555.8 - 563.2	541.9	541.9	557.6	557.6
Steam Generator					
Steam Outlet Temperature, °F	537.3 - 547.2	522.6	518.7	539.7	535.9
Steam Outlet Pressure, psia	941 - 1000	831	804	961	930
Steam Outlet Flow, 106 lb/hr total	15.43- 15.49	14.90/16.17	14.89/16.15	14.99/16.26	14.97/16.24
Feed Temperature, °F	444.6	390.0/450.3	390.0/450.3	390.0/450.3	390.0/450.3
Steam Outlet Moisture, % max.	0.25	0.25	0.25	0.25	0.25
SG Tube Plugging Level, %	0-5	0	10	0	10
Zero-Load Temperature, °F	557	557	557	557	557

NRC Question 5:

Section 2.2.2.1.2.2 of the SPULR refers to Table 2.2.2-1 for RCL pipe stresses. Table 2.2.2-1 is not included in the application.

a) **Confirm that the tables which contain the RCL pipe stresses are Table 2.2.2.1-1 for Unit 1 and Table 2.2.2.1-2 for Unit 2.**

b) **Confirm that the values in these tables are for SPU conditions and provide corresponding values at current conditions.**

c) **Provide stresses, cumulative usage factors (CUFs) and allowable values for loop drains and fills.**

d) **For CUF values that exceed 0.1, verify that these location are postulated pipe breaks.**

CPNPP Response 5 (a), (b), and (c)

The tables which contain the reactor coolant loop piping stresses for the Stretch Power Uprate conditions are table 2.2.2.1-1 for Unit 1 and table 2.2.2.1-2 for Unit 2. The corresponding values for the current conditions have been added to the above two tables, which are attached for your information.

Because the breaks of the 10 inch and larger auxiliary lines have been eliminated with the application of leak before break technology and because the breaks of the other auxiliary lines have been considered as noted in the response to 1a and 1b, the stresses and cumulative usage factors at the branch connections are not provided in this response.

CPNPP Response 5 (d)

The cumulative usage factors calculated for the in-line piping components and the branch connections on the reactor coolant loops exceed 0.1. Because of the application of leak before break technology to the in-line piping and the 10 inch and larger auxiliary lines, breaks are not postulated along the in-line piping and at the 10 inch and larger branch connections. Breaks are explicitly postulated, however, at the branch connections to the 2 inch through 6 inch auxiliary lines. In addition, the analysis explicitly done for breaks at the branch connections to the 2 inch through 6 inch auxiliary lines is considered to envelop the effects of breaks at the smaller branch connections such as the branch connections for the 3/4 inch sample lines and flow taps, the thermowell bosses, and the plugged RTD branch connections. Therefore, it is concluded that breaks were considered when required at all points for which the cumulative usage factors exceed 0.1.

Stress Analysis Summary for Current Conditions for Unit 1

	Hot Leg		Crossover Leg		Cold Leg	
Evaluation	**Maximum**	**Allowable**	**Maximum**	**Allowable**	**Maximum**	**Allowable**
Eq. 9 design stress (ksi) (DW, P) Level A	14.67	28.35	17.57	28.35	17.54	28.35
Eq. 9 design stress (ksi) (DW, P, OBE) Level B	25.40	28.35	24.40	28.35	22.2	28.35
Eq. 9 faulted stress (ksi) (DW, P, SSE, Break Jet) Level D	53.50	56.70	30.70	56.7	26.1	56.7
Eq. 12 stress (ksi)	31.33	56.70	6.51	56.70	20.17	56.70
Eq. 13 stress (ksi)	56.80	57.46*	55.60	56.70	57.10	57.46*
Fatigue usage factor	0.85	1.0	0.12	1.0	0.22	1.0

Notes:

Because breaks of the 10 inch and larger auxiliary lines have been eliminated with the application of leak before break technology, the stresses and cumulative usage factors at the branch connections are not provided in this table.

Allowable stress based on material type SA-351-CF8A at 650°F unless otherwise noted (*).

(*) Allowable stress based on material type SA 351-CF8A at 618°F per paragraphs NB-3653 and NB-3222 of the Code.

Stress Analysis Summary for Current Conditions for Unit 2

	Hot Leg		Crossover Leg		Cold Leg	
Evaluation	**Maximum**	**Allowable**	**Maximum**	**Allowable**	**Maximum**	**Allowable**
Eq. 9 design stress (ksi) (DW, P) Level A	14.84	28.35	15.53	28.35	15.55	28.35
Eq. 9 design stress (ksi) (DW, P, OBE) Level B	20.70	28.35	22.68	28.35	22.31	28.35
Eq. 9 faulted stress (ksi) (DW, P, SSE, Break Jet) Level D	26.35	56.70	29.72	56.70	28.59	56.70
Eq. 12 stress (ksi)	31.33	56.70	6.51	56.70	20.17	56.70
Eq. 13 stress (ksi)	57.45	57.46*	55.60	56.70	57.10	57.46*
Fatigue usage factor	0.85	1.0	0.12	1.0	0.22	1.0

Notes:

Because breaks of the 10 inch and larger auxiliary lines have been eliminated with the application of leak before break technology, the stresses and cumulative usage factors at the branch connections are not provided in this table.

Allowable stress based on material type SA-351-CF8A at 650°F unless otherwise noted (*).

(*) Allowable stress based on material type SA 351-CF8A at 618°F per paragraphs NB-3653 and NB-3222 of the Code.

NRC Question 6:

Section 2.2.2.2.2.2 of the SPULR states that "[t]he two piping systems of most concern with respect to flow rate increases are the main steam and feedwater systems." Section 2.2.2.2.2.3 states that "[a]dditionally, the implementation of the SPU will result in higher flow rates for several piping systems. Piping systems experiencing these higher flow rates will be reviewed for potential vibration issues."

a) **Identify all piping systems that would experience higher flow rates due to the SPU implementation.**

b) **Provide a clear description of the planned activities to address flow-induced vibration (FIV) on susceptible systems.**

c) **Describe the methodology and provide the acceptance criteria for the evaluation of FIV for these piping systems.**

d) **Provide evaluation summaries which show that the acceptance criteria have been met for SPU conditions.**

e) **Describe the vibration monitoring program at the startup for the SPU implementation, its basis and acceptance criteria. Confirm whether it is in accordance with the American Society of Mechanical Engineer's (ASME) Code for Operation and Maintenance of Nuclear Power Plants, Part 3.**

CPNPP Response 6 (a):

The implementation of SPU will result in higher flow rates for Balance of Plant (BOP) piping systems within the main power cycle. These piping systems include main steam, feedwater, condensate, extraction steam and heater drains.

CPNPP Response 6 (b):

CPNPP has developed a comprehensive plan to address flow induced vibration in piping affected by power uprate. The plan began with the development of a program to address scope, method, evaluation and acceptance criteria. The scope includes all piping with increased flow rates resulting from power uprate. The method is based on performing a series of walkdowns spanning from the current plant condition to the completion of power ascension testing following the implementation of power uprate. The acceptance criteria for all piping evaluations will be in accordance with ASME OM Part 3.

CPNPP Response 6 (c):

The methodology is based on performing a series of walkdowns spanning from the current plant condition to the completion of power ascension testing following the implementation of power uprate. Acceptance criteria for all piping evaluations will be in accordance with ASME OM Part 3.

CPNPP Response 6 (d):

Based on clarification of Question 6 (d) with the NRC and as noted above, CPNPP has developed a plan to address flow induced vibration in piping affected by power uprate. The method is based on performing a series of walkdowns spanning from the current plant condition to the completion of power ascension testing following the implementation of power uprate. The evaluation summaries to be prepared in support of these walkdown activities will demonstrate that the acceptance criteria contained in ASME OM Part 3 will be satisfied.

CPNPP Response 6 (e):

Piping systems that will experience increased flow rates due to SPU will be inspected using visual methods during SPU implementation. Initially, simple tools and methods as described in ASME OM Part 3 will be used. If warranted, instrumented data acquisition will be employed for further evaluation in accordance with ASME OM Part 3 as also committed in the piping vibration plan for the CPNPP SPU.

NRC Question 7:

Section 2.2.2.2.2.2 of the SPULR indicates the following:

The BOP piping and support systems listed in Section 2.2.2.2.2.1 have been evaluated relative to the impact of SPU. Thermal, pressure and flow change factors equal to the ratio of SPU to actual analyzed value were determined. "For change factors greater than 1.00, an additional evaluation was performed to address the specific increase in temperature, pressure and/or flow rate in order to determine piping and support system acceptability.

a) **List all systems (inside and outside containment) with "change factors" greater than 1.00.**

b) **For systems with "change factors" greater than 1.00, provide the method of your evaluation. Provide a quantitative summary of the maximum stresses and fatigue usage factors (if applicable) for original and SPU conditions with a comparison to code of record allowable stresses. Include only maximum stresses and data at critical locations (i.e. nozzles, penetrations, etc). List all pipe system modifications (for pipe supports see (d) below) required due to SPU and schedule of completion. For affected nozzles and containment penetrations, provide a summary of loads compared to specific allowable values for the nozzles and penetrations.**

c) **For systems with a thermal change factor greater than 1.00, provide a description of preoperational measures taken to ensure that thermal expansion will not impose an unanalyzed condition that could potentially overstress piping and supports. In addition, confirm that a program will be in place for monitoring thermal expansion at the startup of the SPU.**

d) **For systems in (b), state the method used for evaluating pipe supports when considering SPU conditions and confirm that the supports on affected piping systems have been evaluated and shown to remain structurally adequate to perform their intended design function. Provide description of all pipe support modifications needed to meet design basis at SPU conditions. In addition, list the type, size, loading (current and SPU), and location of supports that need to be modified and added due to SPU conditions.**

e) **Discuss schedule for completion of all piping and pipe support modifications and additions.**

CPNPP Response 7 (a):

Portions of the feedwater, condensate, feedwater heater drains, extraction steam and auxiliary feedwater piping systems contained change factors greater than 1.00.

CPNPP Response 7 (b):

For piping systems containing change factors greater than 1.00, these piping systems were evaluated using simplified hand calculation methods (manually increasing existing stresses and loads) or by performing more detailed computer analyses, in order to reconcile the specific change factor increases. For example, if a piping temperature increased from 150°F to 160°F due to SPU, the resulting thermal change factor would be equal to 1.13 based on the ratio of (160-70)/(150-70). The existing thermal expansion stress levels and support loads based on 150°F would be increased by 13 percent to determine the corresponding values at 160°F. The revised thermal expansion stress levels would then be demonstrated to be less than the applicable allowable stress limit for this loading condition. The revised thermal expansion pipe support loads would be combined with other concurrent loadings to determine a revised pipe support design load. This revised design load would then be demonstrated to be acceptable for the applicable pipe support components. In cases where simplified hand calculation methods were not utilized, more detailed pipe stress and/or pipe support computer analyses were used to demonstrate component acceptability. Also, a 7 percent damping value was used in determining fluid transient loads for non safety-related supports located in the turbine building. This is consistent with the damping values for typical dynamic events as provided in RG 1.61.

A summary of the maximum stress levels for current and SPU conditions including a comparison to code of record allowable stress levels are provided in Table 2.2.2.2-1 (for Unit 1) and Table 2.2.2.2-2 (for Unit 2). For each piping system listed in these tables, the stresses reported are at the most critical location of the piping system, corresponding to the piping location containing the highest stress interaction ratio (i.e., stress interaction ratio is defined as the ratio of SPU stress divided by the allowable stress). These critical stress locations may be at equipment nozzles, containment penetrations, or any in line piping component (e.g., valve, elbow, reducer, etc.) within the analytical boundaries of the piping stress model.

There were no piping modifications (i.e., physical piping re-routes) required due to SPU. With respect to pipe support modifications, specific details are provided in response to item D below.

A discussion/summary of SPU loads and/or stresses and related allowable values for nozzles and penetrations that were most affected by SPU are as follows.

Feedwater Pumps
Revised nozzle loads for SPU conditions were generated and are currently being evaluated by the pump vendor in order to document acceptability. Based on the results of the vendor evaluations, any required modification will be installed prior to the implementation of the SPU.

Steam Generators
The maximum stress values at the steam generator nozzles were determined by analyses and found to be acceptable compared to the allowable limits. An SPU "change factor" (+14% for upset conditions and +0% for faulted conditions for Unit 1, and +5% for upset conditions and +2.2% for faulted conditions for Unit 2) was determined for each unit and was applied to the stress intensity ratios corresponding to the nozzle locations and the resulting values were found to also be acceptable compared to the allowable limits. A table of these values will be prepared for Units 1 and 2 and provided for your review by March 7, 2008.

Containment Penetrations
Maximum stress values in all piping were analyzed for post-SPU conditions and determined to be within allowable limits, moreover, no maximum stress point was found to coincide with a containment penetration point. In the unlikely event of a pipe break at a containment penetration point, the containment structure is designed to absorb the energy of a pipe break through plastic deformation.

The containment wall is reinforced with rebar surrounding each penetration. Minor increases in the fluid energy such as those due to SPU have been analyzed and do not compromise the containment structure if a pipe break were to occur at a penetration point. A table of these values at a critical location closest to the containment penetration will be prepared for Units 1 and 2 and provided for your review by March 7, 2008.

CPNPP Response 7 (c):

During the planned baseline walkdowns to be performed for piping vibration, piping systems subjected to a temperature increase associated with SPU will be inspected to identify any locations where there is a potential for unacceptable thermal expansion interaction. The increases in thermal expansion displacements associated with SPU are less than 1/16 inch, and therefore these increased displacements should not be a significant concern. However, during startup of the SPU, piping systems subjected to a temperature increase will be observed to identify any unanticipated unacceptable conditions.

CPNPP Response 7 (d):

For pipe supports on systems containing change factors greater than 1.00, these pipe supports were evaluated either using simplified hand calculation methods (manually increasing existing loads) or by performing more detailed computer analyses, in order to reconcile the specific support load increases. For example, if a piping temperature increased from 150°F to 160°F due to SPU, the resulting thermal change factor would be equal to 1.13 based on the ratio of (160-70)/(150-70). The existing thermal expansion support loads based on 150°F would be increased by 13 percent to determine the corresponding values at 160°F. These revised thermal expansion pipe support loads would then be combined with other concurrent loadings, to determine a revised pipe support design load for SPU. Applicable pipe supports would then be evaluated using these revised design loads in order to demonstrate that stresses and loads for affected pipe support components remain within acceptable design basis limits. In cases where simplified hand calculation methods were not utilized, more detailed pipe support computer analyses were used to demonstrate pipe support component acceptability. Also, for evaluation of non-safety related supports in the Turbine Building, the component stresses for these supports under fluid transient loading conditions were compared to the equivalent of Level "C" allowable stress limits.

Based on the ongoing evaluations, a total of nine pipe support modifications (all related to the feedwater system) will be required due to SPU conditions. The location of two support modifications is in the Safeguards Building and the remaining seven pipe support modifications are located in the Turbine Building. The support modifications are minor in nature and involve the installation of one new pipe support (on a 3/4 inch drain line) and additional items such as increasing existing weld sizes, adding gussets, and where required reinforcing existing support frame members. The following table provides specific information related to these nine modifications.

Location	Support Mark Number	Support Attribute of Concern
U1 Turbine Bldg	FW-1-001-002-T34R	Tube Steel Members (REINFORCE MEMBERS), Welds (ADD WELD)
U1 Turbine Bldg	FW-1-001-006-T44R	Weld (ADD WELD), Tube steel member connections (ADD WELD OR REINFORCE MEMBERS)
U1 Turbine Bldg	FW-1-001-007-T44R	Welds (ADD WELD), Tube steel member connections (ADD WELD OR REINFORCE MEMBERS)
U1 Turbine Bldg	FW-1-002-002-T34R	Anchor bolts (ADD BRACE OR INCREASE BOLT SIZE OR ADD BOLTS)
U1 Turbine Bldg	FW-1-004-006-T34R	Weld (ADD WELD)
U1 Turbine Bldg	FW-1-009-008-T34R	Struts (REPLACE STRUTS), Members (REINFORCE MEMBERS), Welds (ADD WELD)
U1 Turbine Bldg	FW-1-011-011-T44R	Struts (REPLACE STRUTS), Members (REINFORCE MEMBERS), Welds (ADD WELD), Tube steel member connection (ADD WELD OR REINFORCE MEMBER)
U1 Safeguards	FW-1-105-015-S62R	Baseplate (ADD GUSSET)
U1 Safeguards	New Support	Add New Tieback Support

CPNPP Response 7 (e):

The schedule to complete the installation of all required piping and pipe support modifications to support SPU is that all physical work will be completed during the outage prior to the restart of the plant which implements the SPU.

NRC Question 8:

Section 2.2.2.2.2.2 of the SPULR states that "an evaluation of the feedwater system was required to address the flow rate increase resulting from the SPU and its impact on fluid transient loads (that is, water hammer loads) resulting from feedwater isolation valve closure/check valve slam/feedwater pump trip events."

a) Provide a discussion of the results and whether the FW piping and supports are capable of withstanding water hammer loads resulting from the higher SPU flow rates without any modifications. If modifications are required, provide a detailed description of such modifications and projected completion schedule.

b) Confirm whether stress summaries of Tables 2.2.2.2-1 and 2.2.2.2-2 include stresses due to fluid transient loads associated with the SPU. If not, provide a stress summary of the FW system

piping evaluation that contains stresses due to SPU higher fluid transient loads. In addition, for FW nozzles and containment penetrations provide a summary of loads compared to specific allowable values for the nozzles and penetrations.

CPNPP Response 8 (a):

Based on the ongoing evaluations, the feedwater piping system will require nine pipe support modifications to withstand water hammer loads resulting from SPU conditions. The location of two support modifications is in the Safeguards Building and the remaining seven support modifications are located in the Turbine Building. Refer to the table provided in the response to NRC Question 7 (Item D) for specific information related to these nine support modifications. The schedule to complete these support modifications is that all physical work will be completed during the outage prior to the restart of the plant which implements the SPU.

CPNPP Response 8 (b):

The stress summaries for applicable feedwater piping contained in Tables 2.2.2.2-1 and 2.2.2.2-2 include stresses due to fluid transient loads associated with SPU. A summary of FW nozzle and containment penetration loads are as follows:

<u>Feedwater Pumps</u>
Revised nozzle loads for SPU conditions were generated and are currently being evaluated by the pump vendor in order to document acceptability.

<u>Steam Generators</u>
The maximum stress values at the steam generator nozzles were determined by analyses and found to be acceptable compared to the allowable limits. An SPU "change factor" (+14% for upset conditions and +0% for faulted conditions for Unit 1, and +5% for upset conditions and +2.2% for faulted conditions for Unit 2) was determined for each unit and was applied to the stress intensity ratios corresponding to the nozzle locations and the resulting values were found to also be acceptable compared to the allowable limits. A table of these values will be prepared for Units 1 and 2 and provided for your review by March 7, 2008.

<u>Containment Penetrations</u>
Maximum stress values in all piping were analyzed for post-SPU conditions and determined to be within allowable limits, moreover, no maximum stress point was found to coincide with a containment penetration point. In the unlikely event of a pipe break at a containment penetration point, the containment structure is designed to absorb the energy of a pipe break through plastic deformation. The containment wall is reinforced with rebar surrounding each penetration. Minor increases in the fluid energy such as those due to SPU have been analyzed and do not compromise the containment structure if a pipe break were to occur at a penetration point. A table of these values at a critical location closest to the containment penetration will be prepared for Units 1 and 2 and provided for your review by March 7, 2008.

NRC Question 9:

Section 2.2.2.2.2.3 of the SPULR states that "[f]or piping systems that will experience plant modifications (see LR Section 1.0) to address SPU conditions, the piping and support evaluations will be performed as part of the overall design change package associated with the specific plant modification." Note that SPULR Section 1.0 does not specifically list any piping or pipe support modifications but simply refers to Section 2.2.2.2 for pipe support modifications. The next paragraph in Section 2.2.2.2.2.3 states that "[t]he piping and support evaluations performed

concluded that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions, with pipe support modifications if required in order to accommodate the revised support loads due to the SPU." These statements are confusing. Since the evaluations for piping and pipe supports have been completed and it has been determined, as implied above, that all piping systems remain acceptable and will continue to satisfy design-basis requirements, it should be known whether plant modifications are required to satisfy design-basis requirements. Provide a list of all piping systems that will experience plant modifications and clearly describe any plant modification to piping and/or pipe supports. Also, provide the schedule of modification completion.

CPNPP Response 9:

All piping and support systems will meet applicable design basis limits when considering SPU conditions, although the ongoing evaluations have resulted in nine pipe support modifications being required for the feedwater piping system. Refer to the table provided in the response to RAI Number 7 (Item D) for specific information related to these nine support modifications. The schedule to complete these support modifications is that all physical work will be completed during the outage prior to the restart of the plant which implements the SPU.

NRC Question 10:

Section 2.2.2.2.2.3 of the SPULR states that "Piping systems not specifically listed in Tables 2.2.2.2-1 and 2.2.2.2-2 did not require detailed evaluation to reconcile SPU conditions or involve piping and support systems that will experience plant modifications." This statement is not clear as it implies that piping systems not specifically listed in Tables 2.2.2.2-1 and 2.2.2.2-2 involve piping and support systems that will experience plant modifications.

a) **Clarify whether or not these tables contain piping systems that require modifications. If not, provide a similar summary for all piping systems that will experience plant modifications.**

b) **Identify all piping systems that require modifications. Provide descriptions of the modifications and projected completion schedule.**

CPNPP Response 10 (a):

The subject statement should have read "Piping systems not specifically listed in Tables 2.2.2.2-1 and 2.2.2.2-2 did not require detailed evaluation to reconcile SPU conditions". Tables 2.2.2.2-1 and 2.2.2.2-2 include systems (i.e., feedwater) that require plant modifications.

CPNPP Response 10 (b):

The feedwater piping system is the only system that will require pipe support modifications due to SPU. The ongoing evaluations of the feedwater system have resulted in nine pipe support modifications being required due to SPU conditions. Refer to the table provided in the response to RAI Number 7 (Item D) for specific information related to these nine support modifications. The schedule to complete these support modifications is that all physical work will be completed during the outage prior to the restart of the plant which implements the SPU.

NRC Question 11:

Tables 2.2.2.2-1 and Tables 2.2.2.2-2 of the SPULR show calculated and allowable stress values and refer to equations 9, 13 and 14.

a) **Confirm whether the referred "Equation 9", "Equation 13", and "Equation 14" correspond to stresses due to ASME Boiler and Pressure Vessel Code (ASME Code), Section III, Subsection NC specified "Occasional Loadings", "Thermal Expansion", and "Sustained loads" plus "Thermal Expansion" respectively.**

b) **Provide the basis for the allowable stress values of 48,000 psi and 24,000 psi and explain quantitatively how they were derived. These allowable values are shown in the 2nd and 4th rows respectively of Table 2.2.2.2-1.**

c) **The allowable value of 22,500 psi is shown on Table 2.2.2.2-2 for the Extraction Steam to Heaters 3A and 3B. Verify whether this allowable value is correct for the indicated loading condition.**

CPNPP Response 11 (a):

The loading conditions identified as "Equation 9", "Equation 13", and "Equation 14" correspond to stresses due to ASME Code Subsection NC/ND ("Equation 9" for safety related piping) and ANSI B31.1 ("Equation 13", and "Equation 14" for non safety-related piping) specified "Occasional Loadings", "Thermal Expansion", and "Sustained loads" plus "Thermal Expansion" respectively.

CPNPP Response 11(b):

The allowable stress values of 48,000 psi and 24,000 psi were derived by applying the factors 2.4 and 1.2, respectively, to the 20,000 psi hot stress allowable value characteristic of SA-508 Grade 2 Class 1 material (formerly SA-508 Class2 in accordance with ASME code 1974 edition). The SG feedwater elbow nozzles at Unit 1 are made of SA-508 Grade 2 Class 1 material and Unit 2 are SA-420 Grade WPL6.

CPNPP Response 11(c):

The allowable stress value of 22,500 psi is correct. However, the corresponding Equation 14 loading condition shown should actually be Equation 13.

NRC Question 12:

The SPULR notes that various ASME Class 1 components have failed to meet the primary plus secondary stress intensity requirement of 3Sm (ASME Section III, Paragraph NB-3222.2) but have been found acceptable as they have met alternate subparagraphs of ASME Code, Section III, Subsection NB.

a) **For these components discuss the basis that allows usage of each of the alternate subparagraphs quoted in the SPULR.**

b) **Provide summaries of the evaluations which show that the special rules and requirements for exceeding 3Sm as provided by the alternate subparagraphs have been met.**

c) **Show values in tables where reference to notes is made without the provision of values. Include Tables 2.2.2.5-10 and 2.2.2.5-11.**

d) **For Tables containing structural integrity values only at SPU conditions, include similar values at current licensing conditions.**

CPNPP Response:

The Response to NRC Question 12 contains information proprietary to Westinghouse and will be submitted under separate cover letter.

NRC Question 13:

For RPV internals, the FIV analyses results are shown in Tables 2.2.3-4 and 2.2.3-5 of the SPULR. Table 2.2.3-6 shows a summary of component stresses and fatigue usage factors.

a) **Verify whether the reported values in Tables 2.2.3-4, 2.2.3-5 and 2.2.3-6 are for both CPSES units and confirm that the reported values are for SPU conditions. Also, provide corresponding values at current conditions.**

b) **Table 2.2.3-5 provides a material endurance limit for the guide tubes of 101.5 x10^{-6} in/in strain. This material endurance limit appears to be very low. Provide the material for the guide tubes and the source that shows this material endurance limit or the source that is used to derive it.**

CPNPP Response:

The Response to NRC Question 13 contains information proprietary to Westinghouse and will be submitted under separate cover letter.

NRC Question 14:

Tables 2.2.2.5-5, 2.2.2.5-6 and 2.2.2.5-7 of the SPULR contain summaries of the FIV analyses results for the CPSES, Unit 1 SG tubes.

a) **Provide similar summaries for CPSES, Unit 2.**

b) **Include FIV analyses summaries for the steam dryer, dryer supports and flow-reflector with respect to the fluid-elastic instability, acoustic loads and vortex shedding due to the SPU higher steam flow for both CPSES units. If FIV analysis for the dryer, supports and flow reflector has not been performed or FIV is not thought to be a concern for these components, provide an acceptable justification.**

CPNPP Response:

The Response to NRC Question 14 contains information proprietary to Westinghouse and will be submitted under separate cover letter.

NRC Question 15:

Tables 2.2.2.5-10 and 2.2.2.5-11 of the SPULR contain CPSES, Unit 2 stress and fatigue evaluation summaries for the SG primary and secondary components respectively. Provide similar summaries for CPSES, Unit 1. If there are no changes from the original analyses, provide summaries from the original analyses along with an explanation why the stresses and fatigue usage factors increased for the CPSES, Unit 2 SG primary and secondary components, but remained the same for CPSES, Unit 1. Include stress and fatigue evaluation summaries for the FW ring for both CPSES units.

CPNPP Response 15:

When the Comanche Peak Unit 1 replacement steam generators (RSGs) were designed, an extended operating range was incorporated into the design analysis. Upon reviewing the actual design parameters for the uprate it was determined that the differences between the design and the proposed uprate were insignificant and would not change the design analysis. Therefore, for Unit 1 there is only one value to report for each stress category as the design analysis already considered the effect of the uprate.

Similar summaries for Unit 1 are provided in the response to question 12c & d above, (Tables 1a and 1b).

The Unit 2 Model D-5 steam generators are of a preheater design with the feedwater nozzle above the first tube support plate and injecting water through a series of baffles. Therefore, for this design there is no feedring. Feedwater nozzle stress data is provided as part of Table 2.2.2.5-11 in WCAP-16840-P.

Unit 1 FW ring summary is provide in Table 1b presented in response to Question 12c & d above.

NRC Question 16:

Discuss in detail the method for avoiding adverse flow effects during power ascension and after achieving SPU conditions. Include systems to be monitored, data to be collected and methods of data collection. Specify hold points and duration, inspections, plant walkdowns, vibration data locations, and planned data evaluation.

CPNPP Response 16:

The CPNPP Power Ascension and Testing Plan (Test Plan) is described in Section 2.12 of the Licensing Report. This testing plan will demonstrate that changes made to CPNPP as a result of the SPU have been properly designed and implemented to preclude adverse flow effects during and following power ascension and that CPNPP can be safely operated at the SPU power level of 3612 MWt.

The SPU Test Plan has been detailed in the SPU "Piping Vibration Monitoring Program Reports" prepared for Unit 1 & Unit 2 and in accordance with the Plant established procedure for "Piping and Pipe Support Evaluation for Thermal Expansion Testing and Piping Vibration Monitoring". The intent of these procedures is to utilize plant and industry operating experience to identify locations and systems susceptible to vibration fatigue for further review and evaluation consistent with industry Standard and Guides of the ASME OM-S/G-2003 Part 3 "Vibration Testing of Piping Systems". Testing will be performed at pre-designated plant hold points during power ascension to ensure that system modes of operation where adverse vibratory stresses could occur are addressed or captured as reasonably possible. The purpose is to ensure that steady state flow induced piping vibrations following SPU implementation are not detrimental to the plant, piping, pipe supports or connected equipment or if found corrective action will be implemented to restore vibration levels to acceptable conditions.

There are no CPNPP primary side mass or volumetric flow rate changes. Flow induced vibration at SPU conditions was evaluated for the reactor vessel internals and steam generator tubes. The proposed SPU does not adversely impact the reactor vessel internals structural integrity. Operation at the higher power level will not result in rapid rates of steam generator tube wear or high levels of tube vibration to the general tube population. Therefore, vibration issues on the plant primary side are not expected.

NRC Question 17:

Discuss the procedure that will be utilized for preparation and response to the potential occurrence of loose parts as a result of the SPU. The evaluations should also include calculations, when applicable, of the fluid-elastic stability ratio, and stresses due to turbulent and vortex shedding.

CPNPP Response 17:

Engineering evaluations have determined that loose parts are not expected to be generated as a result of the SPU in either CPNPP Unit 1 or Unit 2. The potential effects of the fluid flow mechanisms on various steam generator internal components have been determined to be acceptable and not significantly different from non-SPU conditions. However, Luminant recognizes that some types of loose parts may result in degradation of SG components and will continue to take preventative actions designed to detect loose parts, inspect for loose parts and when found, take necessary actions to evaluate these parts for the potential for SG degradation and/or remove loose parts from the system. Detection of loose parts during operation is performed using the Metal Impact Monitoring System (MIMS) that is installed at various locations in the NSSS system, including the steam generator. The MIMS system is designed to detect both primary and secondary side loose parts. In addition, Luminant will continue to perform foreign object search and retrievals (FOSAR) during regularly scheduled maintenance periods. Lastly, regularly scheduled eddy current inspections of the steam generator tubes will continue. Eddy current inspections provide additional data that can be used to detect the presence of loose parts, and also any tube wear that could potentially occur inside the steam generators.

NRC Question 18:

Provide a summary of the evaluation of thermowells and sample probes in the Main Steam, FW and Condensate piping systems for increased vibrations due to the increased SPU flow rate.

CPNPP Response 18:

The thermowells installed in the condensate, feedwater and main steam systems are designed for the maximum velocities listed below:

Water systems	220 ft/sec.
Steam systems	285 ft/sec.

As part of the SPU evaluations, the velocities in each system were calculated. The maximum velocity in the main steam piping was calculated to be 212 feet per second, which is below the 285 feet per second maximum design velocity for thermowells in steam systems. The maximum velocity in a line which contains a thermowell in the condensate and feedwater systems is 22.6 feet per second in the feedwater pump discharge piping, which is below the 220 feet per second design velocity for water systems. The SPU velocities are lower than the design velocities for thermowells and therefore they are acceptable for the increased flow and potential increased vibration.

The Condensate System does not contain any sample probes extending into the flow stream. The Feedwater System contains one sample probe that extends into the flow stream ½ inch. There are no sample probes in the class 2 piping in the Main Steam System. There is a probe located downstream of the MS isolation valves. This sampling probe is made from a forging of A105 with a 3/8" bore in a 2 ½" diameter pipe welded into the MS piping. The increase in velocity from 90 fps to 96 fps in this section of piping is considered minimal compared to the robustness inherent in the sample probe.

NRC Question 19:

Section 2.2.2.4 of the SPULR, CRDM, states that "[a] summary of the stress results of the evaluations performed for the SPU is presented in Tables 2.2.2.4-1 and 2.2.2.4-4 through 2.2.2.4-6", and "[t]he cumulative usage factors that were calculated are given in Tables 2.2.2.4-2 and 2.2.2.4-3."

a) **In Table 2.2.2.4-1 through 2.2.2.4-6, provide corresponding values for the current licensed power and material designations.**

b) **For CPSES, Unit 1, provide stress and CUF values at same locations for the upper middle and lower joints as shown for CPSES, Unit 2 in Tables 2.2.2.4-3 through 2.2.2.4-6.**

c) **In Tables 2.2.2.4-4 the yield stress for the upset condition is shown to be higher than the yield stress of the normal condition. Explain why the temperature in the upset condition would be lower than the temperature in the normal condition.**

CPNPP Response 19 (a):

Tables 2.2.2.4-1 through 2.2.2.4-6 have been revised (attached) to include corresponding values for the current licensed power and material designations. Since most of the values listed in Tables 2.2.2.4-1 through 2.2.2.4-6 are unchanged from the current licensed power, only the changed values will be noted and accompanied by the current value.

CPNPP Response 19 (b):

The model CRDM for Unit 1 and 2 are different and the Analysis of Records (AORs) of each unit do not contain the same locations for stress and CUF values. The uprate evaluation updates the information provided in the respective AORs, therefore it is not possible to provide that information.

CPNPP Response 19(c):

The values in Table 2.2.2.4-4 are correct and the upset condition is based on a lower temperature than the normal condition. In order to eliminate conservatism in an area of low margin, the local temperatures at points of maximum stress were considered to provide a more accurate and higher allowable stress. The maximum stress for the upset condition occurred during the rod drop transient and the temperature of the node that experienced the max stress was 349°F, which corresponds to the allowable yield stress of 21,611 psi. Similarly for the normal condition, heat-up, the local temperature was 416°F, corresponding to the allowable yield stress of 20,487 psi. The local temperatures were determined from the AOR.

Table 2.2.2.4-1: Unit 1 Stress Summary

		Design Condition		Normal/Upset Condition		Testing Condition		Special Condition	
Component	**Param. Per ASME Code III**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**
Top Cap (SA-336 F304LN)	P_m	4,000	16,200			6,000	27,000		
	P_m+P_b	5,900	24,300			8,880	40,500		
	P_m+P_b+Q			31,270	48,600				
				64390(1)	48,600				
	Thermal Stress Ratchet			25,410	97,810				
	$\sigma_1+\sigma_2+\sigma_3$							19,240	80,000
Lower Section (SA-336 F304LN and SA-182 F304)	P_m	13,970	16,200			20,960	27,000		
	P_m+P_b	16,160	24,300			24,230	39,350		
	P_m+P_b+Q			48,780	51,810				
				81050(1)	51,810				
	Thermal Stress Ratchet			35,590	42,300				
	Bearing							3,433	17,900
	$\sigma_1+\sigma_2+\sigma_3$							38,180	80,000

(1) Includes design condition seismic load factors. Acceptable per NB-3228.5.

Table 2.2.2.4-2: Unit 1 Cumulative Fatigue Usage Factors

Component		Total Usage Factor	Allowable Usage Factor
Top Cap (SA-336 F304LN)	**w/o seismic**	0.0431	1.0
	w/seismic	0.2838	1.0
Lower Section (SA-336 F304LN and SA-182 F304)	**w/o seismic**	0.4938	1.0
	w/seismic	0.9719	1.0

Table 2.2.2.4-3: Unit 2 Cumulative Fatigue Usage Factors

Joint	Component	Material	Total Usage Factor		Allowable Usage Factor
			Current Analysis	SPU Analysis	
UPPER	Cap	SA479 304	**0.0**	0.0	1.0
	Rod Travel Housing	SA336 F8	**0.0**	0.0	1.0
	Canopy	SA336 F8 and SA479 304	**0.858**	0.491	1.0
	Weld Canopy		0.505	**0.549**	1.0
	Threaded Area	SA336 F8 and SA479 304	**0.360**	0.252	1.0
MIDDLE	Rod Travel Housing	SA336 F8	**0.0**	0.0	1.0
	Latch Housing	SA351 CF8	**0.0**	0.0	1.0
	Canopy	SA336 F8 and SA351 CF8	**0.0**	0.0	1.0
	Weld Canopy		**0.524**	0.014	1.0
	Threaded Area	SA336 F8 and SA351 CF8	0.000	**0.034**	1.0
LOWER	Latch Housing	SA351 CF8	**0.0**	0.0	1.0
	Head Adaptor	SA182 304	**0.0**	0.0	1.0
	Canopy	SA182 304 and SA351 CF8	0.000	**0.010**	1.0
	Weld Canopy		**0.0242**	0.016	1.0
	Threaded Area	SA182 304 and SA351 CF8	0.000	**0.028**	1.0

Note: Values in bold represent the bounding usage factors. All bounding values are less than the allowable usage factor of 1.0; therefore they are acceptable.

Table 2.2.2.4-4: Unit 2 Upper Joint Stress Summary[4]

Upper Joint		Design Condition		Normal Condition		Upset Condition		Testing Condition		Special Condition		Faulted Condition	
Component	**Param. Per ASME Code III**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**
Cap (SA479 304)	P_m	5,954 Note 3	16,100 Note 3					7,400 Note 2 (5,994)	16,110 Note 3			7,216 Note 2 (5,994)	38,640 Note 3
	P_m+P_b	20,757 Note 3	24,150 Note 3					22,203 Note 2 (20,757)	24,165 Note 3			22,019 Note 2 (20,757)	57,960 Note 3
	P_m+P_b+Q			19,107 Note 3	48,300 Note 3	19,113 Note 3	48,300 Note 3						
	$\sigma_1+\sigma_2+\sigma_3$									-16,522 Note 3	64,400 Note 3		
Rod Travel Housing (SA336 F8)	P_m	14,172 Note 3	16,100 Note 3					17,613 Note 2 (14,172)	21,420 Note 2 (16,110)			17,176 Note 2 (14,172)	38,640 Note 3
	P_m+P_b	19,419 Note 3	24,150 Note 3					20,826 Note 2 (17,385)	32,130 Note 2 (24,165)			20,389 Note 2 (17,385)	57,960 Note 3
	P_m+P_b+Q			23,574 Note 3	48,300 Note 3	21,106 Note 3	48,300 Note 3						
	$\sigma_1+\sigma_2+\sigma_3$									13,922 Note 3	64,400 Note 3		
Canopy (SA336 F8 and SA479 304)	P_m	4,606 Note 3	16,100 Note 3					5,724 Note 2 (4,606)	16,110 Note 3			5,582 Note 2 (4,606)	38,640 Note 3
	P_m+P_b	8,254 Note 3	24,150 Note 3					9,372 Note 2 (8,254)	24,165 Note 3			9,230 Note 2 (8,254)	57,960 Note 3
	P_m+P_b+Q			27,594 Note 3	48,300 Note 3	40,057 Note 3	48,300 Note 3						
	$\sigma_1+\sigma_2+\sigma_3$									9,667 Note 3	64,400 Note 3		
Threaded Area (SA336 F8 and SA479 304)	Pm (Shear)									5,370 Note 3	9,660 Note 3		
	2x Shear									38,020 Note 3	48,300 Note 3		
	P_m+P_b+Q									47,500 Note 3	48,300 Note 3		
	Bell Mouthing Stress Intensity			19695 Note 1, 2 (21,022)	20487 Note 1, 2 (19,720)	20874 Note 2 (21,106)	21611 Note 2 (21,907)						

Note 1 : This stress exceeds the allowable by 160 psi. This is considered acceptable due to the conservatism that the maximum design temperature of 650°F was used, as opposed to the hot leg temperature of 622.6°F, for the hot boundary of the steady state transient. The ASME Code allowable yield strength, S_y, is 19,479 psi at the nodal temperature of 494°F. Reducing the nodal temperature by the ratio (622.6/650) to 473°F yields an allowable Sy of 19,749 psi.

Note 2: New stress per uprate analysis. Stress corresponding to current licensing power is listed in parentheses ().

Note 3: Stress is not impacted by uprate.

Note 4: Shaded sections indicate inapplicability.

Table 2.2.2.4-5: Unit 2 Middle Joint Stress Summary[3]

Middle Joint		**Design Condition**		**Normal Condition**		**Upset Condition**		**Testing Condition**		**Special Condition**		**Faulted Condition**	
Component	**Param. Per ASME Code III**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**
Rod Travel Housing (SA336 F8)	P_m	6,288 Note 2	16,100 Note 2					7,815 Note 1 (6,288)	16,110 Note 2			7,621 Note 1 (6,288)	38,640 Note 2
	P_m+P_b	8,172 Note 2	24,150 Note 2					9,669 Note 1 (8,172)	24,165 Note 2			9,505 Note 1 (8,172)	57,960 Note 2
	P_m+P_b+Q			16,669 Note 2	48,300 Note 2	14,388 Note 2	48,300 Note 2						
	$\sigma_1+\sigma_2+\sigma_3$									-14,654 Note 2	64,400 Note 2		
Latch Housing (SA351 CF8)	P_m	11,930 Note 2	15,300 Note 2					14,827 Note 1 (11,930)	15,300 Note 2			14,459 Note 1 (11,930)	36,720 Note 2
	P_m+P_b	15,659 Note 2	22,950 Note 2					18556 Note 1 (15,659)	22,950 Note 2			18,188 Note 1 (15,659)	55,080 Note 2
	P_m+P_b+Q			17,431	45,900	16,395	45,900						
	$\sigma_1+\sigma_2+\sigma_3$									15,056 Note 2	61,200 Note 2		
Canopy (SA336 F8 and SA351 CF8)	P_m	4,460 Note 2	15,300 Note 2					5,543 Note 1 (4,460)	15,300 Note 2			5,406 Note 1 (4,460)	36,720 Note 2
	P_m+P_b	6,844 Note 2	22,950 Note 2					7,927 Note 1 (6,844)	22,950 Note 2			7,790 Note 1 (6,844)	55,080 Note 2
	P_m+P_b+Q			45,504 Note 2	45,900 Note 2	38,164 Note 2	45,900 Note 2						
	$\sigma_1+\sigma_2+\sigma_3$									5,439 Note 2	61,200 Note 2		
Threaded Area (SA336 F8 and SA351 CF8)	Pm (Shear)									3,314 Note 2	9,180 Note 2		
	2x Shear									11,272 Note 2	45,900 Note 2		
	P_m+P_b+Q									31,100 Note 2	45,900 Note 2		
	Bell Mouthing Stress Intensity			14,136 Note 2	17,000 Note 2	11,069 Note 2	17,000 Note 2						

Note 1: New stress per uprate analysis. Stress corresponding to current licensing power is listed in parentheses ().

Note 2: Stress is not impacted by uprate.

Note 3: Shaded sections indicate inapplicability.

Table 2.2.2.4-6: Unit 2 Lower Joint Stress Summary[4]

Lower Joint		**Design Condition**		**Normal Condition**		**Upset Condition**		**Testing Condition**		**Special Condition**		**Faulted Condition**	
Component	**Param. Per ASME Code III**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**	**Calc (psi)**	**Allow (psi)**
Latch Housing (SA351 CF8)	P_m	12,380 Note 3	15,300 Note 3					15,386 Note 2 (12,380)	21,375 Note 2 (15,300)			15,005 Note 2 (12,380)	36,720 Note 3
	P_m+P_b	16,650 Note 3	22,950 Note 3					19,656 Note 2 (16,650)	32,062 Note 2 (22,950)			19,275 Note 2 (16,650)	55,080 Note 3
	P_m+P_b+Q			16,921 Note 3	45,900 Note 3	15,228 Note 3	45,900 Note 3						
	$\sigma_1+\sigma_2+\sigma_3$									15,560 Note 3	61,200 Note 3		
Head Adaptor (SA182 304)	P_m	7,343 Note 3	16,100 Note 3					9,126 Note 2 (7,343)	16,100 Note 3			8,900 Note 2 (7,343)	38,640 Note 3
	P_m+P_b	10,070 Note 3	24,150 Note 3					11,853 Note 2 (10,070)	24,165 Note 3			11,627 Note 2 (10,070)	57,960 Note 3
	P_m+P_b+Q			15,165 Note 3	48,300 Note 3	13,467 Note 3	48,300 Note 3						
	$\sigma_1+\sigma_2+\sigma_3$									15,824 Note 3	64,400 Note 3		
Canopy (SA182 304 and SA351 CF8)	P_m	9,345 Note 3	15,300 Note 3					11,614 Note 2 (9,345)	15,300 Note 3			11,326 Note 2 (9,345)	36,720 Note 3
	P_m+P_b	19,011 Note 3	22,950 Note 3					21,280 Note 2 (19,011)	22,950 Note 3			20,992 Note 2 (19,011)	55,080 Note 3
	P_m+P_b+Q			45,985 Note 1, 3	45,900 Note 3	37,560 Note 3	45,900 Note 3						
	$\sigma_1+\sigma_2+\sigma_3$									28,702 Note 3	61,200 Note 3		
Threaded Area (SA182 304 and SA351 CF8)	Pm (Shear)									4,103 Note 3	9,180 Note 3		
	2x Shear									12,852 Note 3	45,900 Note 3		
	P_m+P_b+Q									33,200 Note 3	45,900 Note 3		
	Bell Mouthing Stress Intensity			13,733 Note 3	17,000 Note 3	9,720 Note 3	17,000 Note 3						

Note 1: This stress exceeds the allowable by 0.2%. This is considered insignificant due to the conservatism that the allowable is based on the design temperature of 650°F as opposed to the actual nodal temperature of 78°F. The ASME Code allowable stress intensity $3S_m$ is 60 ksi at 78°F and 45.9 ksi at 650°F.

Note 2: New stress per uprate analysis. Stress corresponding to current licensing power is listed in parentheses ().

Note 3: Stress is not impacted by uprate.

Note 4: Shaded sections indicate inapplicability.

ELECTRICAL ENGINEERING BRANCH

NRC Question 1:

In response to Question 1[December 11, 2007, page 5], the licensee stated that the Post Accident Operability Time (PAOT) impact is minor, since there is only 7 Degree Fahrenheit (°F) difference between the SPU Loss-of-coolant-accident (LOCA) curve (170°F) and the intersection point of the Equipment Qualification (EQ) profile (163°F) at the 24 hour mark.

Provide justification why the small temperature difference between SPU LOCA curve and the intersection point of the EQ profile at the 24 hour mark and later is considered acceptable.

CPNPP Response:

In our previous response reference was made to a new EQ profile which was shown in figure E 1-1. Figure E 1-1 reflected changes made as a result of the Unit 1 Steam Generator Replacement Project. The curve enveloped the peak plateau of the Stretch Power Uprate (SPU) loss of coolant-accident (LOCA) curve. This LOCA curve has been incorporated into a site design drawing and was an input for profile changes made within EQ packages for the Steam Generator Replacement Project.

The additional information provided within our response indicated that the impact on PAOT, as a result of SPU, was minor. The discussion of the minor impact was an attempt to state that the required profile changes will not significantly affect current PAOT margins. This was based on the similarity of the two curves.

It is, and was our intent, to modify the temperature profiles utilized by the equipment qualification program to bound or reflect any changes that are the result of the SPU LOCA curve. A bounding temperature profile will be incorporated into design drawings and used as an input for EQ packages. The PAOT margin will be recalculated using this revised profile.

NRC Question 2:

In response to NRC staff Question 4 [December 11, 2007, page 5], the licensee stated that Electric Reliability Council of Texas (ERCOT) was requested to perform the necessary studies to accept the uprated plant power output level changes of about 49 MW for CPSES, Unit 1 and 37 MW for CPSES, Unit 2. However, in a meeting held between ERCOT and TXU Electric Delivery (TXUED) on December 14, 2006, ERCOT stated that an additional steady state study and a stability study would not be required for this small addition of 86 MWs to the ERCOT grid. Further, a TXUED letter dated April 24, 2007 states that based on a recent review of the ERCOT Steady State Working Group (SSWG) base cases, transmission circuit line capacities were sufficient to handle the proposed increase in generation capability.

The NRC staff's review focuses on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in the loss of offsite power to the plant following implementation of the proposed SPU. It is not clear from TXUED letter dated April 24, 2007 whether all aspects of the impact on the grid due to implementation of the proposed SPU have been evaluated. Also, in response to NRC staff Question 5, the expected increase in power level change for CPSES, Unit 1 is calculated as 56.76 MW, and for CPSES, Unit 2 as 44 MW, a total of 100.76 MW (compared to 86 MW stated in response to the staff Question 4). Provide an evaluation which confirms that all the aspects of the impact due to maximum increase in power level of 100.76 MW has been studied.

CPNPP Response:

CPNPP requires that Oncor Electric Delivery perform an annual review of the contingencies for voltage conditions that are stated in the CPNPP Design Basis Document and our agreements with Oncor Electric Delivery for availability of voltage at CPNPP switchyards. Oncor Electric Delivery then submits a report to CPNPP on the voltage conditions. The annual reports conclude that under the defined contingencies, CPNPP switchyard voltage requirements are met.

According to ERCOT/ Oncor Electric Delivery, there will be an insignificant change in the grid model as a result of CPNPP SPU. Please note that CPNPP has modified its response to Question 5. The corrected MW addition for Unit 1 is 50.6 MW and for Unit 2 is 38.6 MW. These values are almost the same as the original submittal and are considered an insignificant change. There will be no impact on the availability or reliability of the offsite power to CPNPP as a result of this change.

As a result of CPNPP SPU, the grid will remain stable and Loss of Offsite Power to CPNPP will not occur for the following conditions:

1. Loss of one or both CPNPP units and the transfer of plant auxiliaries to the standby source,

2. Simultaneous loss of either CPNPP unit and the most critical generator to CPNPP.

3. Simultaneous loss of either CPNPP unit and the most critical transmission line to CPNPP.

The SPU data is incorporated into the ERCOT/ Oncor Electric Delivery model at the time the SPU occurs (fall 2008 for Unit 1 and fall 2009 for Unit 2). CPNPP has requested that ERCOT/ Oncor Electric Delivery include the SPU conditions in the August 2008 review report.

This response has been reviewed and concurred with Oncor Electric Delivery.

NRC Question 3:

In response to NRC staff Question 6 [December 11, 2007, page 6], the licensee stated that it has been decided to replace the main transformers at CPSES, Units 1 and 2 to remove the voltage restriction and add additional margin. The new main transformers for CPSES, Unit 2 will be installed in the fall of 2009, in the spring of 2010 for CPSES, Unit 1.

Confirm whether studies have been completed to determine any adverse impact of the proposed main transformer data on the various grid related studies.

CPNPP Response:

As described in response to request 2 above, the CPNPP SPU changes are considered insignificant. These changes have no adverse impact on the various grid related studies. The change in transformer size will provide additional margin and flexibility to CPNPP for meeting ERCOT/ Oncor Electric Delivery needs.

The changes that will be introduced by the replacement of the main transformers are small from the grid perspective. ERCOT and Oncor Electric Delivery believe that no adverse impacts will occur due to the small change. CPNPP is required by ERCOT to provide the exact transformer impedances and other details to ERCOT prior to returning to power after the replacement of the transformers. The transformers for Unit 2 are scheduled for shipment in July 2009 and will be replaced during the fall 2009 refueling outage. The transformers for Unit 1 are scheduled for shipment in January 2010 and will be replaced during the spring 2010 refueling outage. CPNPP has already provided transformer specification data to ERCOT/Oncor Electric Delivery and will provide per ERCOT requirements, on delivery of the transformers, the tested values for the transformers for inclusion in ERCOT/Oncor Electric Delivery models.

This response has been reviewed and concurred with Oncor Electric Delivery.

Attachment 2 to TXX-08031

ATTACHMENT 5
PAGE 1 OF 1

MINIMUM REQUIRED ECCS FLOW

TIME AFTER REACTOR TRIP (MINUTES)	MINIMUM REQUIRED ECCS FLOW (GPM)
10	585 620
20	495 525
30	445 470
60	365 380
90	320 340
120 (2 HOURS)	295 315
240 (4 HOURS)	240 255
360 (6 HOURS)	215 230
480 (8 HOURS)	200 210
720 (12 HOURS)	180 190
1440 (1 DAY)	150 155
2160 (1 DAY 12 HOURS)	135 140
2880 (2 DAYS)	125 130
4320 (3 DAYS)	110 115
10080 (7 DAYS)	85 90

ATTACHMENT 5
PAGE 1 OF 1

MINIMUM REQUIRED ECCS FLOW

TIME AFTER REACTOR TRIP (MINUTES)	MINIMUM REQUIRED ECCS FLOW (GPM)
10	585 620
20	495 525
30	445 470
60	365 380
90	320 340
120 (2 HOURS)	295 315
240 (4 HOURS)	240 255
360 (6 HOURS)	215 230
480 (8 HOURS)	200 210
720 (12 HOURS)	180 190
1440 (1 DAY)	150 155
2160 (1 DAY 12 HOURS)	135 140
2880 (2 DAYS)	125 130
4320 (3 DAYS)	110 115
10080 (7 DAYS)	85 90

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
* 3	Check Bleed And Feed - REQUIRED:	
	a. Check the following: • Actual wide range level (per Attachment 2) in at least 3 SGs - LESS THAN 27% NO CHANGE (NO CHANGE 50% FOR ADVERSE CONTAINMENT) -OR- • PRZR pressure - GREATER THAN OR EQUAL TO 2335 PSIG DUE TO LOSS OF SECONDARY HEAT SINK	a. Go to Step 4.
	b. Trip all RCPs.	
	c. Go to Step 12 AND perform Steps 12 through 21 without delay.	
* 4	Check CST Level - GREATER THAN 10%	Perform ABN-305, AUXILIARY FEEDWATER SYSTEM MALFUNCTION while continuing with this procedure.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
10	Check SG Levels:	
	a. Narrow range level in at least one SG - GREATER THAN 10% (26% FOR ADVERSE CONTAINMENT)	a. IF feed flow to at least one SG verified, THEN maintain flow to restore narrow range level to greater than 10% (26% FOR ADVERSE CONTAINMENT). IF NOT verified, THEN go to Step 11.
	b. Return to procedure and step in effect.	
11	Check Bleed And Feed - REQUIRED	
	a. Check the following: • Actual wide range level (per Attachment 2) in at least 3 SGs - LESS THAN 27% (50% FOR ADVERSE CONTAINMENT) -OR- • PRZR pressure - GREATER THAN OR EQUAL TO 2335 PSIG DUE TO LOSS OF SECONDARY HEAT SINK	a. Return to Step 1.

NO CHANGE NO CHANGE

CAUTION: Steps 12 through 21 must be performed quickly in order to establish RCS heat removal by RCS bleed and feed.

12	Actuate SI.	

ATTACHMENT 1.B
PAGE 1 OF 1

FRH-0.1A CONTINUOUS ACTION STEPS

Step No.	Major Step Description	Condition to Monitor
2	Check CCP Status - BOTH AVAILABLE	Perform Step 2 RNO if BOTH CCPs are NOT available.
3	Check Feed and Bleed - REQUIRED	• Actual wide range level (per Attachment 2) in at least 3 SGs - LESS THAN 27% NO CHANGE (NO CHANGE 50% FOR ADVERSE CONTAINMENT), or • PRZR pressure - GREATER THAN OR EQUAL TO 2335 PSIG DUE TO LOSS OF SECONDARY HEAT SINK.
4	Check CST Level - GREATER THAN 10%	CST Level - GREATER THAN 10%.
23	Maintain RCS Heat Removal	• Maintain ECCS flow • Maintain PRZR PORVs - BOTH OPEN
24	Check RWST Level - GREATER THAN LO-LO LEVEL	RWST Level - GREATER THAN LO-LO LEVEL
25	Check Containment Spray Status	Containment Pressure - HAS REMAINED LESS THAN 18.0 PSIG. • 1-ALB-2B window 1.8, CS ACT NOT ILLUMINATED • 1-ALB-2B window 4.11, CNTMT ISOL PHASE B ACT - NOT ILLUMINATED • Containment Pressure - LESS THAN 18.0 PSIG
26	Continue Attempts To Establish Secondary Heat Sink In At Least One SG.	Continue attempts to establish SG feed flow capability.
36	Check RCS Hot Leg Temperatures - STABLE OR DECREASING	Control feed flow and steam dump as necessary to establish stable RCS hot leg temperatures.
38	Control Charging Flow To Maintain PRZR Level On Scale	Control charging flow to maintain PRZR level.

ATTACHMENT 4
PAGE 8 OF 25

BASES

STEP 10: Following actions to establish condensate flow to the SGs, the operator checks the SG narrow range levels to determine if adequate flow has been established to maintain secondary heat sink. If narrow range level has been restored to at least one SG, an adequate secondary heat sink exists and the operator is transferred to the procedure in effect. If this level does not exist, but feed flow is verified to at least one SG (e.g., by core exit thermocouple indications decreasing or SG wide range level increasing), then subsequent steps to check secondary heat sink effectiveness are not required and the operator transfers to the procedure in effect.

It should be noted that accurate condensate flow indication may not be available at low flow rates and SG wide range level indication may not be accurate under adverse containment conditions.

NO CHANGE

STEP 11: The operator should continue attempts to establish flow to the steam generators until WR SG level is less than 27% in any three steam generators (50% for adverse containment) or pressurizer pressure is greater than or equal to 2335 psig due to loss of secondary heat sink, which indicates the need for initiation of bleed and feed. If the operator gets to Step 11, initial attempts to establish AFW flow, main feedwater flow or condensate flow have been unsuccessful. This step checks the required indications to determine if the secondary heat sink is still effective. If it is not effective, the operator continues to Step 12 to establish RCS bleed and feed heat removal. If the secondary heat removal is still effective, the operator returns to Step 1 to continue attempts to restore feed flow to the SGs. If at any time the SG level and PRZR pressure limits are exceeded bleed and feed should be immediately initiated.

NO CHANGE

Initiation of bleed and feed as directed by these setpoints is based on sufficient SG liquid mass being available to ensure some energy removal capability exists from the secondary heat sink in addition to the PRZR PORVs to help minimize RCS pressurization.

The operator must be aware that in addition to parameter identified in this step, increasing RCS temperature and pressure are an indication of secondary heat sink degradation. The parameters selected for initiation of Bleed and Feed are selected on the basis that they will be exceeded at the same time or before RCS temperature and pressure start increasing. Therefore, if RCS temperature and pressure start increasing without exceeding the specified parameters, RCS bleed and feed heat removal should be initiated.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
4	Establish Stable RCS Conditions:	
	a. PRZR level - GREATER THAN 90% (98% FOR ADVERSE CONTAINMENT)	a. Control charging and letdown as necessary.
	b. RCS pressure - STABLE	b. Cycle PRZR heaters and use normal PRZR spray as necessary. <u>IF</u> normal spray <u>NOT</u> available and letdown in service, <u>THEN</u> use auxiliary spray.
	c. RCS hot leg temperatures - STABLE	c. Dump steam as necessary.
5	Check RCPs - ALL STOPPED	Go to Step 12.
6	Check If RCS Pressure Should Be Increased:	
	a. Pressure - AT LEAST 100 PSIG LESS THAN LIMIT OF PTLR FIGURE 2-2 (ATTACHMENT 2)	a. Go to Step 9. OBSERVE CAUTION <u>AND</u> NOTE PRIOR TO STEP 9.
	b. Pressure - LESS THAN 1900 1875 PSIG (2000 1975 PSIG FOR ADVERSE CONTAINMENT)	b. Go to Step 9. OBSERVE CAUTION <u>AND</u> NOTE PRIOR TO STEP 9.
	c. Cycle PRZR heaters to increase RCS pressure by 50 psi.	
* 7	Control Charging And Letdown As Necessary To Maintain PRZR Level Greater Than 30% (50% FOR ADVERSE CONTAINMENT).	

ECA-0.0A **LOSS OF ALL AC POWER**
REV. 8

MAJOR ACTION CATEGORIES

A. CHECK PLANT CONDITIONS
B. RESTORE AC POWER
C. MAINTAIN PLANT CONDITIONS FOR OPTMAL RECOVERY
D. EVALUATE ENERGIZED AC EMERGENCY BUS
E. SELECT RECOVERY PROCEDURE AFTER AC RESTORED

A.	1. VERIFY REACTOR TRIP
	2. VERIFY TURBINE TRIP
	3. CHECK IF RCS IS ISOLATED
	4. VERIFY AFW FLOW > 460 GPM
B.	5. RESTORE POWER TO ANY AC SAFEGUARDS BUS
	*6. WHEN POWER IS RESTORED TO ANY AC SAFEGUARDS BUS, RECOVERY ACTION SHOULD CONTINUE STARTING WITH STEP 26
	*7. CHECK SI SIGNAL STATUS
	8. PLACE FOLLOWING EQUIPMENT SWITCHES IN PULL-OUT POSITION
	*9. DISPATCH PERSONNEL TO LOCALLY RESTORE AC POWER USING ABN-601 RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION OR ABN-602, RESPONSE TO A 6900/480 VOLT SYSTEM MALFUNCTION WHILE CONTINUING WITH THIS PROCEDURE
C.	10. DISPATCH PERSONNEL TO LOCALLY CLOSE VALVES TO ISOLATE RCP SEALS
	11. CHECK IF CST IS ISOLATED FROM HOTWELL
	12. CHECK SG STATUS
	13. CHECK IF ANY SG IS FAULTED
	*14. CHECK IF SG TUBES ARE RUPTURED
	*15. CHECK INTACT SG LEVELS
	16. CHECK DC BUS LOADS
	*17. CHECK CST LEVEL > 10%
	*18. DEPRESSURIZE INTACT SGs TO 250 PSIG 270
	*19. CHECK REACTOR SUBCRITICAL
	*20. CHECK SI SIGNAL STATUS
	21. VERIFY CONTAINMENT ISOLATION PHASE A
	22. VERIFY CONTAINMENT VENTILATION ISOLATION
	23. CHECK CONTAINMENT PRESSURE - HAS REMAINED < 18 PSIG
	24. CHECK CORE EXIT TCs < 1200° F
D.	25. CHECK IF AC SAFEGUARDS POWER IS RESTORED
	*26. STABILIZE SG PRESSURES
	27. VERIFY SSW SYSTEM OPERATION
	28. ENSURE FOLLOWING EQUIPMENT LOADED ON AC SAFEGUARDS AND DC BUS
E.	29. SELECT RECOVERY PROCEDURE

Step 5 →
- ABN-601, RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION OR ABN-602, RESPONSE TO 6900/480 VOLT SYSTEM MALFUNCTION
- RETURN TO PROCEDURE AND STEP IN EFFECT

Step 9 → ABN-601, RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION OR ABN-602, RESPONSE TO 6900/480 VOLT SYSTEM MALFUNCTION

Step 17 → ABN-305, AUXILIARY FEEDWATER SYSTEM MALFUNCTION

Step 24 → SACRG-1, SEVERE ACCIDENT CONTROL ROOM GUIDELINE INITIAL RESPONSE

Step 28 →
- ECA-0.1A, LOSS OF ALL AC POWER RECOVERY WITHOUT SI REQUIRED
- ECA-0.2A, LOSS OF ALL AC POWER RECOVERY WITH SI REQUIRED

CONTINUOUS ACTION STEP

STEP — ACTION/EXPECTED RESPONSE — RESPONSE NOT OBTAINED

170

CAUTION: SG pressures should not be decreased to less than 150 psig to prevent injection of accumulator nitrogen into the RCS.

CAUTION: SG narrow range level should be maintained greater than 10% (26% FOR ADVERSE CONTAINMENT) in at least one intact SG. If level cannot be maintained, SG depressurization should be stopped until level is restored in at least one SG.

NOTE: Depressurization of SGs will result in SI actuation. SI should be reset to permit manual loading of equipment on AC safeguards bus.

NOTE: PRZR level may be lost and reactor vessel upper head voiding may occur due to depressurization of SGs. Depressurization should not be stopped to prevent these occurrences.

*18 Depressurize Intact SGs To 250 PSIG:

270

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
a. Check SG narrow range levels - GREATER THAN 10% (26% FOR ADVERSE CONTAINMENT) in at least one SG	a. Perform the following: 1) Maintain maximum AFW flow until narrow range level greater than 10% (26% FOR ADVERSE CONTAINMENT) in at least one intact SG.

-CONT 18-

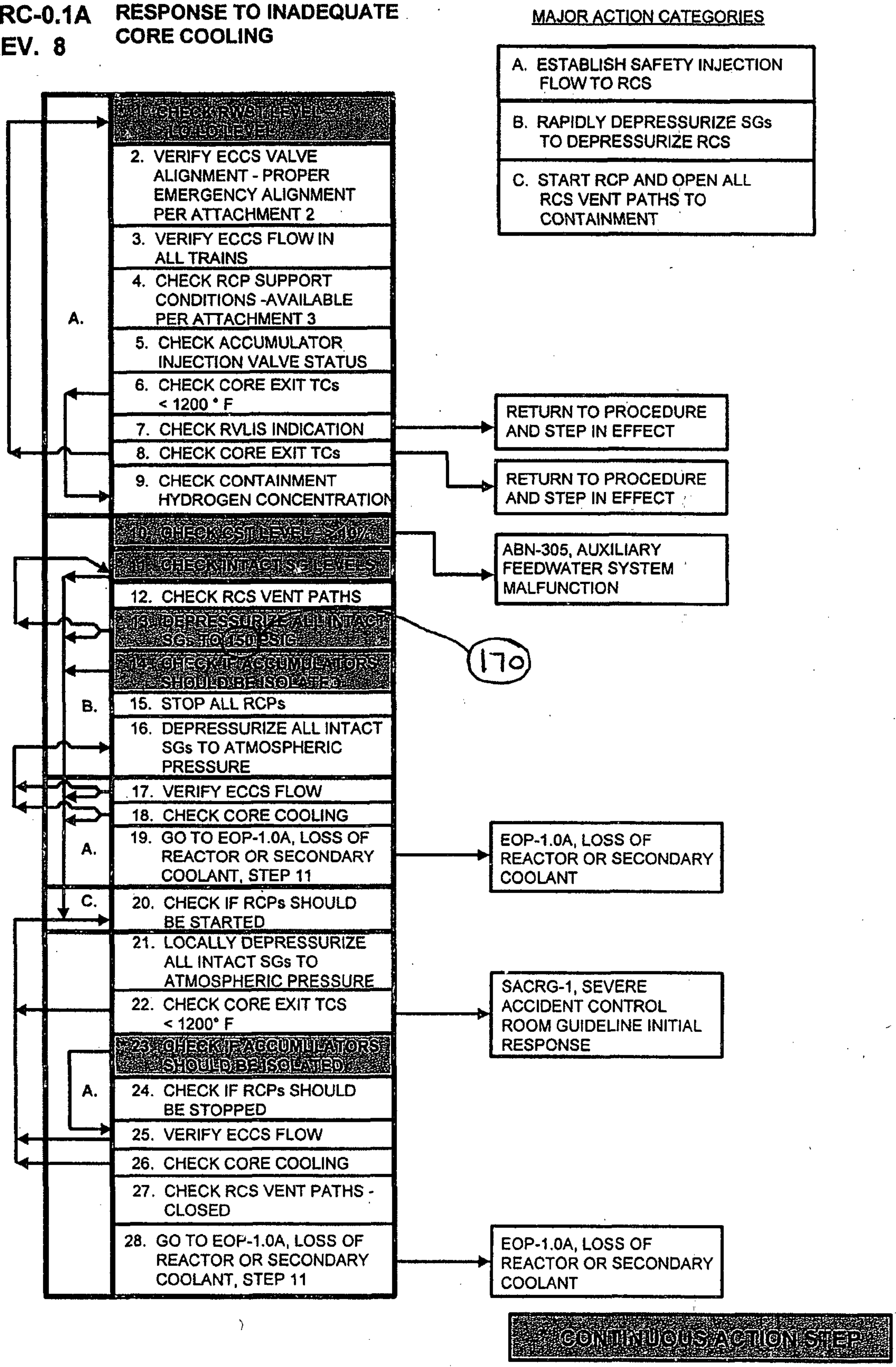
STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
		2) Continue with Step 19. <u>WHEN</u> narrow range level greater than 10% (26% FOR ADVERSE CONTAINMENT) in at least one intact SG, <u>THEN</u> do Steps 18b, 18c, 18d and 18e.
	b. Maintain cooldown rate in RCS cold legs - LESS THAN 100°F/HR	
	c. Manually dump steam using SG atmospheric(s).	c. Locally dump steam using SG atmospheric(s).
	d. Check SG pressures - LESS THAN 250 PSIG 270	d. Continue with Step 19. <u>WHEN</u> SG pressures decreased to less than 250 psig, <u>THEN</u> do Step 18e. 270
	e. Manually control SG atmospheric(s) to maintain SG pressures at 250 psig. 270	e. Locally control SG atmospheric(s) to maintain SG pressure at 250 psig. 270
*19	Check Reactor Subcritical: • Intermediate range channels - ZERO OR NEGATIVE STARTUP RATE • Source range channels - ZERO OR NEGATIVE STARTUP RATE	Control SG atmospheric(s) to stop SG depressurization and allow RCS to heat up sufficiently to restore and maintain core shutdown conditions.
*20	Check SI Signal Status:	
	a. SI - HAS BEEN ACTUATED	a. Go to Step 24. <u>WHEN</u> SI actuated, <u>THEN</u> do Steps 20b, 21, 22 and 23.
	b. Verify Steps 7b and 7c complete.	

ATTACHMENT 1.B
PAGE 2 OF 2

ECA-0.0A CONTINUOUS ACTION STEPS

Step No.	Major Step Description	Condition to Monitor
18	Depressurize Intact SGs To 250 psig. 270	• Maintain maximum AFW flow until narrow range level greater than 10%(26% FOR ADVERSE CONTAINMENT) in at least one intact SG. • WHEN narrow range level greater than 10%(26% FOR ADVERSE CONTAINMENT) in at least one intact SG, THEN do Steps 18b, 18c, 18d and 18e. • Maintain cooldown rate in RCS cold legs - LESS THAN 100°F/hr • WHEN SG pressures decreased to less than 250 psig, 270 THEN do Step 18e. • Manually/Locally control SG atmospheric(s) to maintain SG pressures at 250 psig. 270
19	Check Reactor Subcritical	• Intermediate range channels - ZERO OR NEGATIVE STARTUP RATE • Source range channels - ZERO OR NEGATIVE STARTUP RATE • Control SG atmospheric(s) to stop SG depressurization and allow RCS to heat up sufficiently to restore and maintain core shutdown conditions.
20	Check SI Signal Status	WHEN SI actuated, THEN do Steps 20b, 21, 22, and 23.
26	Stabilize SG Pressures	Manually/Locally control SG atmospheric(s).

FRC-0.1A **RESPONSE TO INADEQUATE CORE COOLING**
REV. 8



STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: Partial uncovering of SG tubes is acceptable in the following steps.

NOTE: After the low steamline pressure SI signal is blocked, main steamline isolation will occur if the high steam pressure rate setpoint is exceeded.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
*13	Depressurize All Intact SGs To 150 PSIG: 170	
	a. Dump steam to condenser at maximum rate and avoid main steam isolation.	a. Manually or locally dump steam at maximum rate from intact SG(s) atmospheric.
	b. WHEN PRZR pressure is less than 1960 psig, THEN block low steamline pressure SI signal.	
	c. Check SG pressures - LESS THAN 150 PSIG 170	c. IF SG pressure decreasing, THEN return to Step 11. OBSERVE CAUTION PRIOR TO STEP 11. IF NOT, THEN go to Step 20. OBSERVE NOTE PRIOR TO STEP 20.
	d. Check RCS hot leg temperatures - AT LEAST TWO LESS THAN 380°F	d. IF RCS hot leg temperatures decreasing, THEN return to Step 11. OBSERVE CAUTION PRIOR TO STEP 11. IF NOT, THEN go to Step 20. OBSERVE NOTE PRIOR TO STEP 20.
	e. Stop SG depressurization.	

ATTACHMENT 1.B
PAGE 1 OF 1

FRC-0.1A CONTINUOUS ACTION STEPS

NOTE: A Continuous Action Step is applicable from the point at which it is first encountered.

Step No.	Major Step Description	Condition to Monitor
1	Check RWST Level -GREATER THAN LO-LO LEVEL	RWST Level - GREATER THAN LO-LO LEVEL.
10	Check CST Level - GREATER THAN 10%	CST Level - GREATER THAN 10%.
11	Check Intact SG Levels	• Maintain AFW flow greater than 460 gpm until narrow range level greater than 10% (26% FOR ADVERSE CONTAINMENT) in at least one intact SG. • Control AFW flow to maintain narrow range level between 10%(26% FOR ADVERSE CONTAINMENT) and 50%.
13	Depressurize All Intact SGs To 150 psig 170	WHEN PRZR pressure decreases to less than 1960 psig, THEN block the low steamline pressure SI signal.
14	Check If Accumulators Should Be Isolated	WHEN the accumulator is depressurized, THEN continue step (14.f.5 RNO).
23	Check If Accumulators Should Be Isolated	WHEN the accumulator is depressurized, THEN continue step (23.f.5 RNO).

BASES

The main steamline isolation signal from low steamline pressure is rate sensitive and also after the low steamline pressure SI is blocked, main steamline isolation will occur if the high steam pressure rate setpoint is exceeded. Instruction is provided to avoid isolating the main steam lines. This serves as reminder to the operator to carefully increase the steaming rate to maximum in order to maintain the ability to dump steam to the main condenser.

The SI actuation signal on low steamline pressure can be blocked during cooldown once the PRZR pressure decreases to the P-11 setpoint. This prevents MSIV closure, thus allowing cooldown by (the preferred method of) steam dump to condenser. 170

To prevent accumulator nitrogen injection, the operator should stop the secondary depressurization when the SG pressure reaches 150 psig and when at least two RCS hot leg temperatures fall below 380°F. A steam generator pressure limit is set to preclude significant nitrogen introduction into the RCS following accumulator injection.

STEP 14: SI accumulators are isolated to prevent nitrogen injection into the RCS when the RCS hot leg temperature criterion is satisfied (two RTDs are used to ensure that one RTD is not giving an erroneous reading). Nitrogen could collect in the high places and produce either a "hard" PRZR bubble or cause gas binding and reduced heat transfer in the SG U-tubes. Venting the nitrogen gas also prevents injection. If it is necessary to vent the nitrogen, the operator should open the vent lines and then continue with this procedure.

If it is determined that any SI accumulator cannot be isolated or vented, the Plant Staff should be consulted to evaluate the effect of nitrogen in the RCS on plant recovery actions. Nitrogen in the RCS may interfere with core cooling by natural circulation, if required, following a small-break LOCA. The Plant Staff should evaluate whether actions should be taken to prevent or minimize nitrogen injection, or vent the nitrogen from the RCS following injection.

STEP 15: In preparation for the subsequent depressurization of the SGs to atmospheric pressure, the RCPs are stopped due to the anticipated loss of Number 1 seal requirements. Continued operation may result in damage to the RCPs.

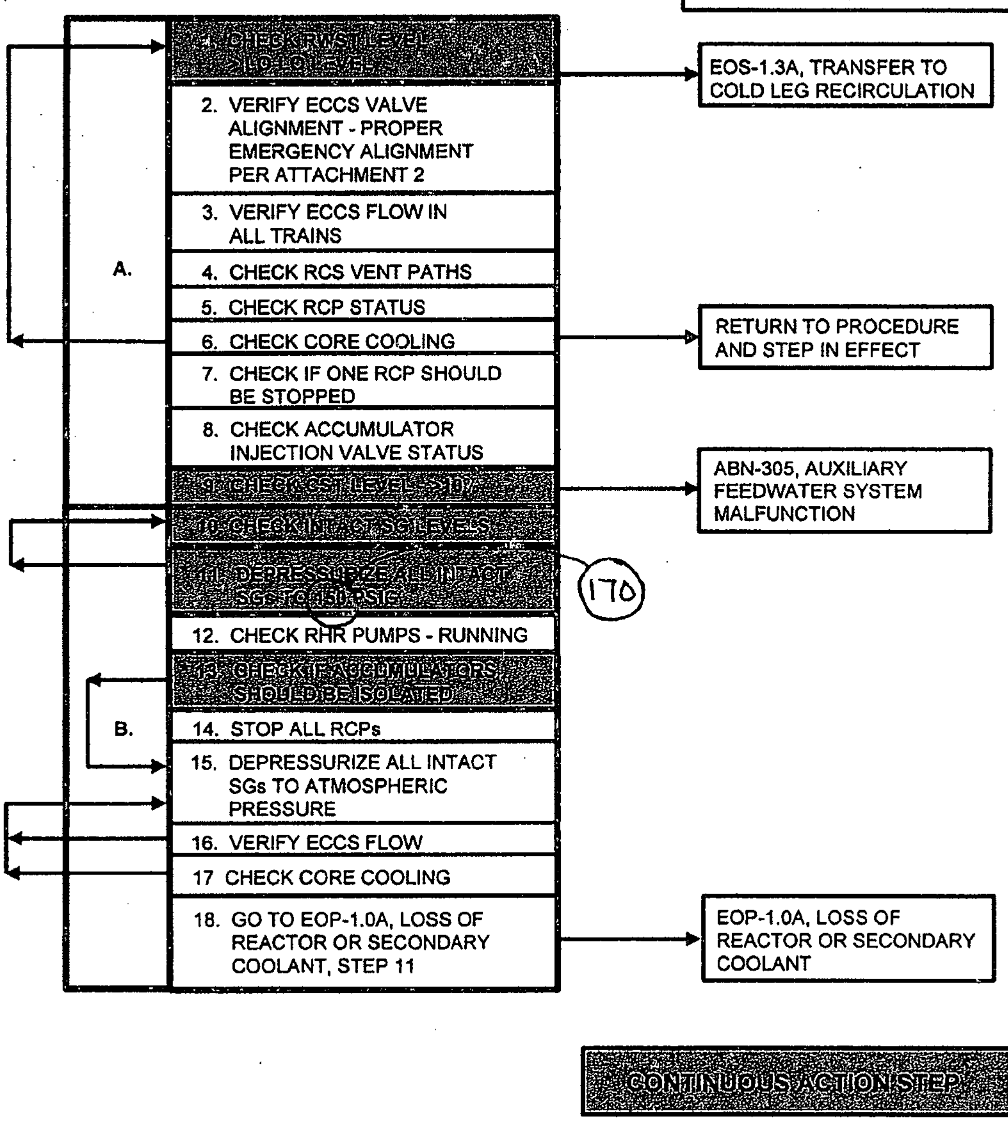
STEP 16: With continued SG depressurization, RCS pressure should follow secondary pressure until the shutoff head of the RHR pumps is reached. Then, RHR should begin to refill the RCS.

FRC-0.2A
REV. 8

RESPONSE TO DEGRADED CORE COOLING

<u>MAJOR ACTION CATEGORIES</u>

A. ESTABLISH SAFETY INJECTION FLOW TO THE RCS
B. INITIATE A CONTROLLED SG DEPRESSURIZATION TO COOLDOWN AND DEPRESSURIZE THE RCS



STEP — ACTION/EXPECTED RESPONSE — RESPONSE NOT OBTAINED

CAUTION: The following step will cause accumulator injection which may cause a red path condition in the Integrity Status Tree. This procedure shall be completed before transition to FRP-0.1A, RESPONSE TO IMMINENT PRESSURIZED THERMAL SHOCK CONDITION.

NOTE: After low steamline pressure SI signal is blocked, main steamline isolation will occur if the high steam pressure rate setpoint is exceeded.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
*11	Depressurize All Intact SGs To 150 PSIG:	
170	a. Maintain cooldown rate in RCS cold legs - LESS THAN 100°F/HR	
	b. WHEN PRZR pressure decreases to less than 1960 psig, THEN block the low steamline pressure SI signal.	
	c. Dump steam to condenser.	c. Manually or locally dump steam from intact SG(s) using SG atmospheric(s).
170	d. Check SG pressures - LESS THAN 150 PSIG	d. Return to Step 10. OBSERVE CAUTION PRIOR TO STEP 10.
	e. Check RCS hot leg temperatures - AT LEAST TWO LESS THAN 380°F	e. Return to Step 10. OBSERVE CAUTION PRIOR TO STEP 10
	f. Stop SG depressurization.	

ATTACHMENT 1.B
PAGE 1 OF 1

FRC-0.2A CONTINUOUS ACTION STEPS

NOTE: A Continuous Action Step is applicable from the point at which it is first encountered.

Step No.	Major Step Description	Condition to Monitor
1	Check RWST Level -GREATER THAN LO-LO LEVEL	RWST Level - GREATER THAN LO-LO LEVEL.
9	Check CST Level - GREATER THAN 10%	CST Level - GREATER THAN 10%.
10	Check Intact SG Levels	Control AFW flow to maintain narrow range level between 10% (26% FOR ADVERSE CONTAINMENT) and 50%
11	Depressurize All Intact SGs To 150 psig 170	WHEN PRZR pressure decreases to less than 1960 psig, THEN block the low steamline pressure SI signal.
13	Check If Accumulators Should Be Isolated	• WHEN at least two RCS hot leg temperatures are less than 380°F, THEN do Steps 13b and 13c. • WHEN the accumulator is depressurized, THEN continue step (13.f.5 RNO).

ATTACHMENT 4
PAGE 4 OF 10

BASES

NOTE: Following low steamline pressure SI signal block, the high steam pressure rate main steamline isolation signal will be enabled. This note warns the operator of this condition to prevent a main steamline isolation which might result if the cooldown is initiated too rapidly. Note that the rate of SG depressurization will be affected by AFW flow, SG levels, and whether the RCS is in natural circulation. If MSIV closure occurs, the rapid cooldown should be continued using the SG atmospherics.

STEP 11: The controlled secondary depressurization, similar to the one in EOS-1.2A, POST LOCA COOLDOWN AND DEPRESSURIZATION, has been shown to be an effective way to reduce RCS pressure. RCS pressure must be reduced in order for the accumulator and RHR pumps to inject.

The hot leg temperature value is selected to ensure the RCS saturation pressure exceeds the accumulator pressure after the accumulator has been discharged. This precludes nitrogen injection into the RCS.

Main steamline pressure SI is blocked to maintain MSIVs open to utilize steam dump valves for cooldown.

170

To prevent accumulator nitrogen injection, the operator should stop the secondary depressurization when the SG pressure reaches 150 psig. A steam generator pressure limit is set to preclude significant nitrogen introduction into the RCS following accumulator injection.

This is a Continuous Action Step.

CAUTION: RHR pumps utilize seal coolers and the RHR heat exchangers to remove pump heat. The seal coolers and RHR heat exchangers are cooled by CCW. If the RCS pressure is above the shutoff head of the RHR pumps and these pumps are run in the injection mode for an extended period of time without CCW to the seal coolers and the RHR heat exchangers, they may be damaged due to excessive heatup. There are two basic failure mechanisms for the RHR pumps when CCW to the RHR heat exchangers is lost. The failure mechanisms depend on the pump's mechanical components and the NPSH requirements of the pump. With no cooling provided to the RHR heat exchangers, the temperature of the pumped fluid will gradually increase. As a result, the NPSH requirements may not be satisfied and cavitation of the pumps may occur, causing excessive vibration, possible pump seizure, bearing damage, gasket and seal leakage, and motor failure. In addition, lack of cooling flow will increase the temperature of the mechanical seal unit resulting in deterioration and increased seal leakage or failure.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
34	Check If All Intact SGs Should Be Depressurized To 700 PSIG:	
	a. Check SG Pressures - GREATER THAN 700 PSIG	a. Go to Step 35.
	b. Dump steam to condenser at maximum rate and avoid main steam isolation.	b. Manually or locally dump steam at maximum rate from intact SG(s) atmospheric.
	c. Check SG pressure - LESS THAN 700 PSIG	c. Return to Step 34b.
	d. Stop SG depressurization.	
35	Depressurize All Intact SGs To Inject Accumulators As Necessary:	
	a. Dump steam to condenser as necessary to maintain RVLIS indications - GREATER THAN <u>OR</u> EQUAL TO 11 IN ABOVE CORE PLATE LIGHT LIT	a. Manually or locally dump steam from intact SG(s) atmospheric as necessary to maintain RVLIS indication.
	b. Check SG pressures - LESS THAN 150 PSIG	b. Return to Step 35a.
170	c. Stop SG depressurization.	

BASES

STEP 34: Since the RCS will be saturated at this time, RCS pressure is approximately the same as SG pressure. In this step SG pressures (and thus RCS pressure) are decreased at the maximum rate to 25 psig above the accumulator high pressure alarm setpoint. SG pressure is used due to its accuracy; i.e., the RCS pressure instrument may have high inaccuracies since it is located inside containment. The value of 25 psig is arbitrarily selected as a pressure which is slightly above the accumulator high pressure alarm setpoint.

If the condenser and ARVs are not available, the operator should evaluate using any means of removing water or steam from the SGs. This could include opening the blowdown lines or operating the TDAFW pump.

If the SG pressure are less than 700 psig, the operator is instructed to proceed to Step 35 to inject the accumulators as necessary.

STEP 35: As mentioned in the previous step the RCS will be saturated at this time and therefore, RCS pressure is approximately equal to SG pressure. In this step the intact SGs are depressurized (and thus the RCS) to inject the accumulators. SG depressurization is used here due to its accuracy; i.e., the RCS pressure instrument may have high inaccuracies since it is located inside containment.

Steam is dumped as necessary to maintain RVLIS indication at the top of the core from the accumulator water injection. In other words, the SGs are depressurized relatively slowly such that the accumulator water injection is minimized, extending the time to depletion of the accumulators. When SG pressures of less than 150 psig are reached, the accumulator contents will have been injected into the RCS and the SG depressurization is stopped. 170

A steam generator pressure limit is set to preclude significant nitrogen injection into the RCS.

If the condenser and ARVs are not available, the operator should evaluate using any plant specific means of removing water or steam from the SGs. This could include opening the blowdown lines and operating the TDAFW pump.

STEP 36: Accumulators are isolated or vented after their liquid contents are discharged into the RCS. Isolating or venting accumulators prevents nitrogen injection into the RCS. Nitrogen could collect in high places and render PRZR pressure control ineffective or cause gas binding in the SG U-tubes. Venting nitrogen gas also prevents nitrogen injection.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
* 3	Check Bleed And Feed - REQUIRED:	
	a. Check the following: • Actual wide range level (per Attachment 2) in at least 3 SGs - LESS THAN 27% (30% FOR ADVERSE CONTAINMENT) -OR- • PRZR pressure - GREATER THAN OR EQUAL TO 2335 PSIG DUE TO LOSS OF SECONDARY HEAT SINK	a. Go to Step 4.
	b. Trip all RCPs.	
	c. Go to Step 12 AND perform steps 12 through 21 without delay.	
* 4	Check CST Level - GREATER THAN 10%	Perform ABN-305, AUXILIARY FEEDWATER SYSTEM MALFUNCTION while continuing with this procedure.

NO CHANGE

NO CHANGE

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
10	Check SG Levels:	
	a. Narrow range level in at least one SG - GREATER THAN 10% (18% FOR ADVERSE CONTAINMENT)	a. IF feed flow to at least one SG verified, THEN maintain flow to restore narrow range level to greater than 10% (18% FOR ADVERSE CONTAINMENT). IF NOT verified, THEN go to Step 11.
	b. Return to procedure and step in effect.	
11	Check Bleed And Feed - REQUIRED	
	a. Check the following:	a. Return to Step 1.
	• Actual wide range level (per Attachment 2) in at least 3 SGs - LESS THAN 27% NO CHANGE (NO CHANGE 30% FOR ADVERSE CONTAINMENT) -OR- • PRZR pressure - GREATER THAN OR EQUAL TO 2335 PSIG DUE TO LOSS OF SECONDARY HEAT SINK	

CAUTION: Steps 12 through 21 must be performed quickly in order to establish RCS heat removal by RCS bleed and feed.

12	Actuate SI.	

ATTACHMENT 1.B
PAGE 1 OF 1

FRH-0.1B CONTINUOUS ACTION STEPS

Step No.	Major Step Description	Condition to Monitor
2	Check CCP Status - BOTH AVAILABLE	Perform Step 2 RNO if BOTH CCPs are NOT available.
3	Check Feed and Bleed - REQUIRED	• Actual wide range level (per Attachment 2) in at least 3 SGs - LESS THAN 27% NO CHANGE (NO CHANGE 30% FOR ADVERSE CONTAINMENT), or • PRZR pressure - GREATER THAN OR EQUAL TO 2335 PSIG DUE TO LOSS OF SECONDARY HEAT SINK.
4	Check CST Level - GREATER THAN 10%	CST Level - GREATER THAN 10%.
23	Maintain RCS Heat Removal	• Maintain ECCS flow • Maintain PRZR PORVs - BOTH OPEN
24	Check RWST Level - GREATER THAN LO-LO LEVEL	RWST Level - GREATER THAN LO-LO LEVEL
25	Check Containment Spray Status	Containment Pressure - HAS REMAINED LESS THAN 18.0 PSIG. • 2-ALB-2B window 1.8, CS ACT NOT ILLUMINATED • 2-ALB-2B window 4.11, CNTMT ISOL PHASE B ACT - NOT ILLUMINATED • Containment Pressure - LESS THAN 18.0 PSIG
26	Continue Attempts To Establish Secondary Heat Sink In At Least One SG.	Continue attempts to establish SG feed flow capability.
36	Check RCS Hot Leg Temperatures - STABLE OR DECREASING	Control feed flow and steam dump as necessary to establish stable RCS hot leg temperatures.
38	Control Charging Flow To Maintain PRZR Level On Scale	Control charging flow to maintain PRZR level.

ATTACHMENT 4
PAGE 8 OF 25

BASES

STEP 10: Following actions to establish condensate flow to the SGs, the operator checks the SG narrow range levels to determine if adequate flow has been established to maintain secondary heat sink. If narrow range level has been restored to at least one SG, an adequate secondary heat sink exists and the operator is transferred to the procedure in effect. If this level does not exist, but feed flow is verified to at least one SG (e.g., by core exit thermocouple indications decreasing or SG wide range level increasing), then subsequent steps to check secondary heat sink effectiveness are not required and the operator transfers to the procedure in effect.

It should be noted that accurate condensate flow indication may not be available at low flow rates and SG wide range level indication may not be accurate under adverse containment conditions.

NO CHANGE

STEP 11: The operator should continue attempts to establish flow to the steam generators until WR SG level is less than 27% in any three steam generators (30% for adverse containment) or pressurizer pressure is greater than or equal to 2335 psig due to loss of secondary heat sink, which indicates the need for initiation of bleed and feed. If the operator gets to Step 11, initial attempts to establish AFW flow, main feedwater flow or condensate flow have been unsuccessful. This step checks the required indications to determine if the secondary heat sink is still effective. If it is not effective, the operator continues to Step 12 to establish RCS bleed and feed heat removal. If the secondary heat removal is still effective, the operator returns to Step 1 to continue attempts to restore feed flow to the SGs. If at any time the SG level and PRZR pressure limits are exceeded bleed and feed should be immediately initiated.

NO CHANGE

Initiation of bleed and feed as directed by these setpoints is based on sufficient SG liquid mass being available to ensure some energy removal capability exists from the secondary heat sink in addition to the PRZR PORVs to help minimize RCS pressurization.

The operator must be aware that in addition to parameter identified in this step, increasing RCS temperature and pressure are an indication of secondary heat sink degradation. The parameters selected for initiation of Bleed and Feed are selected on the basis that they will be exceeded at the same time or before RCS temperature and pressure start increasing. Therefore, if RCS temperature and pressure start increasing without exceeding the specified parameters, RCS bleed and feed heat removal should be initiated.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
4	Establish Stable RCS Conditions:	
	a. PRZR level - GREATER THAN 90% (98% FOR ADVERSE CONTAINMENT)	a. Control charging and letdown as necessary.
	b. RCS pressure - STABLE	b. Cycle PRZR heaters and use normal PRZR spray as necessary. IF normal spray NOT available and letdown in service, THEN use auxiliary spray.
	c. RCS hot leg temperatures - STABLE	c. Dump steam as necessary.
5	Check RCPs - ALL STOPPED	Go to Step 12.
6	Check If RCS Pressure Should Be Increased:	
	a. Pressure - AT LEAST 100 PSIG LESS THAN LIMIT OF PTLR FIGURE 2-2 (ATTACHMENT 2)	a. Go to Step 9. OBSERVE CAUTION AND NOTE PRIOR TO STEP 9.
	b. Pressure - LESS THAN 2000 1900 1875 PSIG (1975 PSIG FOR ADVERSE CONTAINMENT)	b. Go to Step 9. OBSERVE CAUTION AND NOTE PRIOR TO STEP 9.
	c. Cycle PRZR heaters to increase RCS pressure by 50 psi.	
* 7	Control Charging And Letdown As Necessary To Maintain PRZR Level Greater Than 30% (32% FOR ADVERSE CONTAINMENT).	

ECA-0.0B **LOSS OF ALL AC POWER**
REV. 8

MAJOR ACTION CATEGORIES

A. CHECK PLANT CONDITIONS
B. RESTORE AC POWER
C. MAINTAIN PLANT CONDITIONS FOR OPTMAL RECOVERY
D. EVALUATE ENERGIZED AC EMERGENCY BUS
E. SELECT RECOVERY PROCEDURE AFTER AC RESTORED

A.	1. VERIFY REACTOR TRIP	
	2. VERIFY TURBINE TRIP	
	3. CHECK IF RCS IS ISOLATED	
	4. VERIFY AFW FLOW > 460 GPM	
B.	5. RESTORE POWER TO ANY AC SAFEGUARDS BUS	ABN-601, RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION OR ABN-602, RESPONSE TO 6900/480 VOLT SYSTEM MALFUNCTION; RETURN TO PROCEDURE AND STEP IN EFFECT
	6. WHEN POWER IS RESTORED TO ANY AC SAFEGUARDS BUS, RECOVERY ACTION SHOULD CONTINUE STARTING WITH STEP 26	
	7. CHECK SI SIGNAL STATUS	
	8. PLACE FOLLOWING EQUIPMENT SWITCHES IN PULL-OUT POSITION	
	9. DISPATCH PERSONNEL TO LOCALLY RESTORE AC POWER USING ABN-601 RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION OR ABN-602 RESPONSE TO A 6900/480 VOLT SYSTEM MALFUNCTION WHILE CONTINUING WITH THIS PROCEDURE	ABN-601, RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION OR ABN-602, RESPONSE TO 6900/480 VOLT SYSTEM MALFUNCTION
C.	10. DISPATCH PERSONNEL TO LOCALLY CLOSE VALVES TO ISOLATE RCP SEALS	
	11. CHECK IF CST IS ISOLATED FROM HOTWELL	
	12. CHECK SG STATUS	
	13. CHECK IF ANY SG IS FAULTED	
	14. CHECK IF SG TUBES ARE RUPTURED	
	15. CHECK INTACT SG LEVELS	
	16. CHECK DC BUS LOADS	
	17. CHECK CST LEVEL > 10%	ABN-305, AUXILIARY FEEDWATER SYSTEM MALFUNCTION
	18. DEPRESSURIZE INTACT SGs TO 250 PSIG (270)	
	19. CHECK REACTOR SUBCRITICAL	
	20. CHECK SI SIGNAL STATUS	
	21. VERIFY CONTAINMENT ISOLATION PHASE A	
	22. VERIFY CONTAINMENT VENTILATION ISOLATION	
	23. CHECK CONTAINMENT PRESSURE - HAS REMAINED < 18 PSIG	
	24. CHECK CORE EXIT TCs < 1200° F	SACRG-1, SEVERE ACCIDENT CONTROL ROOM GUIDELINE INITIAL RESPONSE
	25. CHECK IF AC SAFEGUARDS POWER IS RESTORED	
	26. STABILIZE SG PRESSURES	
D.	27. VERIFY SSW SYSTEM OPERATION	
	28. ENSURE FOLLOWING EQUIPMENT LOADED ON AC SAFEGUARDS AND DC BUS	ECA-0.1B, LOSS OF ALL AC POWER RECOVERY WITHOUT SI REQUIRED; ECA-0.2B, LOSS OF ALL AC POWER RECOVERY WITH SI REQUIRED
E.	29. SELECT RECOVERY PROCEDURE	

CONTINUOUS ACTION STEP

STEP — ACTION/EXPECTED RESPONSE — RESPONSE NOT OBTAINED

170

CAUTION: SG pressures should not be decreased to less than 150 psig to prevent injection of accumulator nitrogen into the RCS.

CAUTION: SG narrow range level should be maintained greater than 10% (18% FOR ADVERSE CONTAINMENT) in at least one intact SG. If level cannot be maintained, SG depressurization should be stopped until level is restored in at least one SG.

NOTE: Depressurization of SGs will result in SI actuation. SI should be reset to permit manual loading of equipment on AC safeguards bus.

NOTE: PRZR level may be lost and reactor vessel upper head voiding may occur due to depressurization of SGs. Depressurization should not be stopped to prevent these occurrences.

*18 Depressurize Intact SGs To
270 250 PSIG:

a. Check SG narrow range levels - GREATER THAN 10% (18% FOR ADVERSE CONTAINMENT) in at least one SG

a. Perform the following:

1) Maintain maximum AFW flow until narrow range level greater than 10% (18% FOR ADVERSE CONTAINMENT) in at least one intact SG.

-CONT 18-

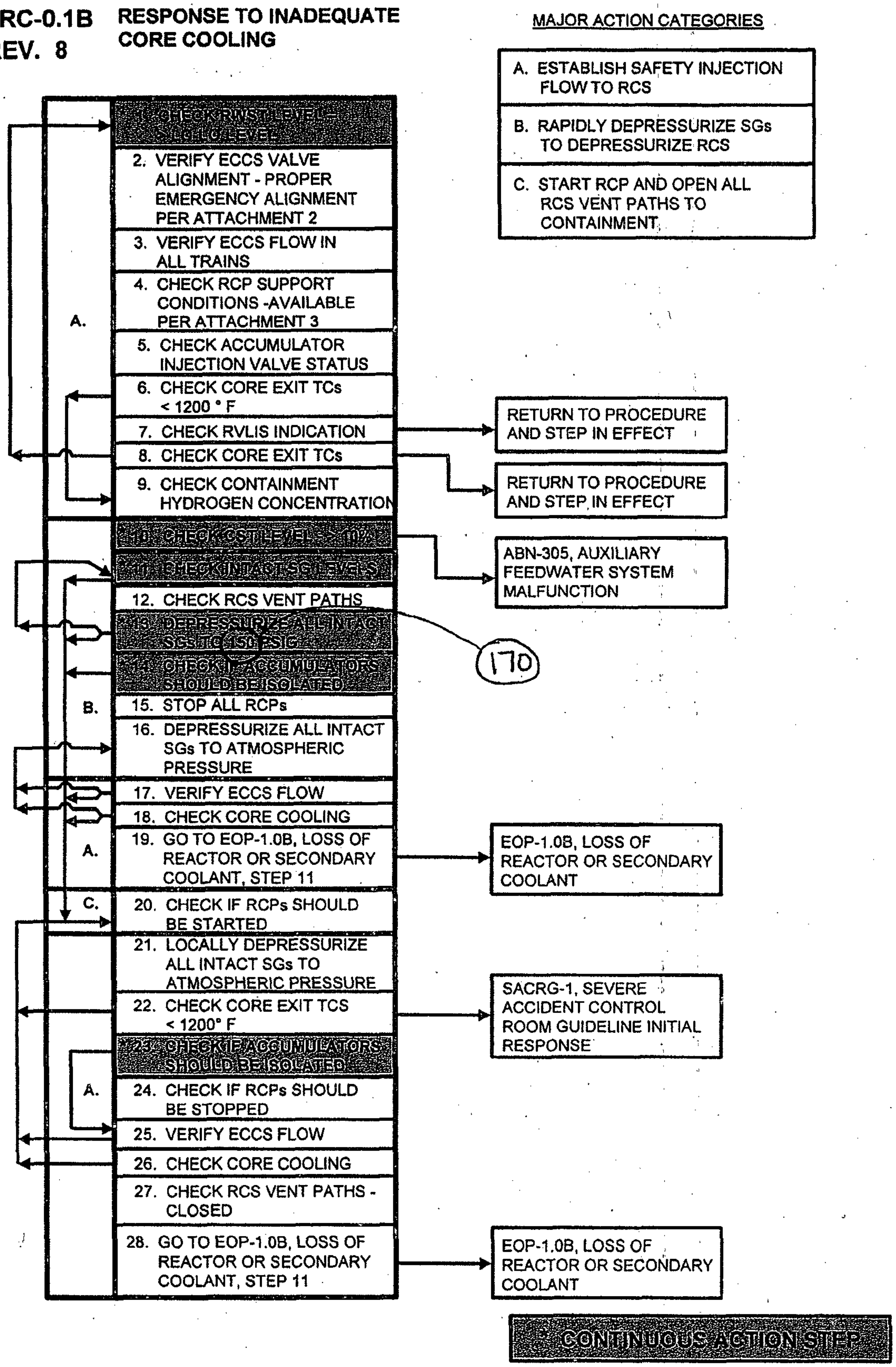
STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
		2) Continue with Step 19. <u>WHEN</u> narrow range level greater than 10% (18% FOR ADVERSE CONTAINMENT) in at least one intact SG, <u>THEN</u> do Steps 18b, 18c, 18d and 18e.
	b. Maintain cooldown rate in RCS cold legs - LESS THAN 100°F/HR	
	c. Manually dump steam using SG atmospheric(s).	c. Locally dump steam using SG atmospheric(s).
	d. Check SG pressures - LESS THAN 250 PSIG 270	d. Continue with Step 19. <u>WHEN</u> SG pressures decreased to less than 250 psig, <u>THEN</u> do Step 18e. 270
	e. Manually control SG atmospheric(s) to maintain SG pressures at 250 psig. 270	e. Locally control SG atmospheric(s) to maintain SG pressure at 250 psig. 270
*19	Check Reactor Subcritical: • Intermediate range channels - ZERO OR NEGATIVE STARTUP RATE • Source range channels - ZERO OR NEGATIVE STARTUP RATE	Control SG atmospheric(s) to stop SG depressurization and allow RCS to heat up sufficiently to restore and maintain core shutdown conditions.
*20	Check SI Signal Status:	
	a. SI - HAS BEEN ACTUATED	a. Go to Step 24. <u>WHEN</u> SI actuated, <u>THEN</u> do Steps 20b, 21, 22 and 23.
	b. Verify Steps 7b and 7c complete.	

ATTACHMENT 1.B
PAGE 2 OF 2

ECA-0.0B CONTINUOUS ACTION STEPS

Step No.	Major Step Description	Condition to Monitor
18	Depressurize Intact SGs To 250 psig. 270	• Maintain maximum AFW flow until narrow range level greater than 10%(18% FOR ADVERSE CONTAINMENT) in at least one intact SG. • WHEN narrow range level greater than 10%(18% FOR ADVERSE CONTAINMENT) in at least one intact SG, THEN do Steps 18b, 18c, 18d and 18e. • Maintain cooldown rate in RCS cold legs - LESS THAN 100°F/hr • WHEN SG pressures decreased to less than 250 psig, THEN do Step 18e. 270 • Manually/Locally control SG atmospheric(s) to maintain SG pressures at 250 psig. 270
19	Check Reactor Subcritical	• Intermediate range channels - ZERO OR NEGATIVE STARTUP RATE • Source range channels - ZERO OR NEGATIVE STARTUP RATE • Control SG atmospheric(s) to stop SG depressurization and allow RCS to heat up sufficiently to restore and maintain core shutdown conditions.
20	Check SI Signal Status	WHEN SI actuated, THEN do Steps 20b, 21, 22, and 23.
26	Stabilize SG Pressures	Manually/Locally control SG atmospheric(s).

FRC-0.1B **RESPONSE TO INADEQUATE CORE COOLING**
REV. 8



STEP — ACTION/EXPECTED RESPONSE — RESPONSE NOT OBTAINED

NOTE: Partial uncovering of SG tubes is acceptable in the following steps.

NOTE: After the low steamline pressure SI signal is blocked, main steamline isolation will occur if the high steam pressure rate setpoint is exceeded.

*13 Depressurize All Intact SGs To 150 PSIG: 170

a. Dump steam to condenser at maximum rate and avoid main steam isolation.

  - RNO: a. Manually or locally dump steam at maximum rate from intact SG(s) atmospheric.

b. WHEN PRZR pressure is less than 1960 psig, THEN block low steamline pressure SI signal.

c. Check SG pressures - LESS THAN 150 PSIG 170

  - RNO: c. IF SG pressure decreasing, THEN return to Step 11. OBSERVE CAUTION PRIOR TO STEP 11. IF NOT, THEN go to Step 20. OBSERVE NOTE PRIOR TO STEP 20.

d. Check RCS hot leg temperatures - AT LEAST TWO LESS THAN 380°F

  - RNO: d. IF RCS hot leg temperatures decreasing, THEN return to Step 11. OBSERVE CAUTION PRIOR TO STEP 11. IF NOT, THEN go to Step 20. OBSERVE NOTE PRIOR TO STEP 20.

e. Stop SG depressurization.

ATTACHMENT 1.B
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FRC-0.1B CONTINUOUS ACTION STEPS

NOTE: A Continuous Action Step is applicable from the point at which it is first encountered.

Step No.	Major Step Description	Condition to Monitor
1	Check RWST Level -GREATER THAN LO-LO LEVEL	RWST Level - GREATER THAN LO-LO LEVEL.
10	Check CST Level - GREATER THAN 10%	CST Level - GREATER THAN 10%.
11	Check Intact SG Levels	• Maintain AFW flow greater than 460 gpm until narrow range level greater than 10% (18% FOR ADVERSE CONTAINMENT) in at least one intact SG. • Control AFW flow to maintain narrow range level between 10%(18% FOR ADVERSE CONTAINMENT) and 50%.
13	Depressurize All Intact SGs To 150 psig 170	WHEN PRZR pressure decreases to less than 1960 psig, THEN block the low steamline pressure SI signal.
14	Check If Accumulators Should Be Isolated	WHEN the accumulator is depressurized, THEN continue step (14.f.5 RNO).
23	Check If Accumulators Should Be Isolated	WHEN the accumulator is depressurized, THEN continue step (23.f.5 RNO).

BASES

The main steamline isolation signal from low steamline pressure is rate sensitive and also after the low steamline pressure SI is blocked, main steamline isolation will occur if the high steam pressure rate setpoint is exceeded. Instruction is provided to avoid isolating the main steam lines. This serves as reminder to the operator to carefully increase the steaming rate to maximum in order to maintain the ability to dump steam to the main condenser.

The SI actuation signal on low steamline pressure can be blocked during cooldown once the PRZR pressure decreases to the P-11 setpoint. This prevents MSIV closure, thus allowing cooldown by (the preferred method of) steam dump to condenser.

170

To prevent accumulator nitrogen injection, the operator should stop the secondary depressurization when the SG pressure reaches ~~150~~ psig and when at least two RCS hot leg temperatures fall below 380°F. A steam generator pressure limit is set to preclude significant nitrogen introduction into the RCS following accumulator injection.

STEP 14: SI accumulators are isolated to prevent nitrogen injection into the RCS when the RCS hot leg temperature criterion is satisfied (two RTDs are used to ensure that one RTD is not giving an erroneous reading). Nitrogen could collect in the high places and produce either a "hard" PRZR bubble or cause gas binding and reduced heat transfer in the SG U-tubes. Venting the nitrogen gas also prevents injection. If it is necessary to vent the nitrogen, the operator should open the vent lines and then continue with this procedure.

If it is determined that any SI accumulator cannot be isolated or vented, the Plant Staff should be consulted to evaluate the effect of nitrogen in the RCS on plant recovery actions. Nitrogen in the RCS may interfere with core cooling by natural circulation, if required, following a small-break LOCA. The Plant Staff should evaluate whether actions should be taken to prevent or minimize nitrogen injection, or vent the nitrogen from the RCS following injection.

STEP 15: In preparation for the subsequent depressurization of the SGs to atmospheric pressure, the RCPs are stopped due to the anticipated loss of Number 1 seal requirements. Continued operation may result in damage to the RCPs.

STEP 16: With continued SG depressurization, RCS pressure should follow secondary pressure until the shutoff head of the RHR pumps is reached. Then, RHR should begin to refill the RCS.

FRC-0.2B
REV. 8

RESPONSE TO DEGRADED CORE COOLING

MAJOR ACTION CATEGORIES

A. ESTABLISH SAFETY INJECTION FLOW TO THE RCS
B. INITIATE A CONTROLLED SG DEPRESSURIZATION TO COOLDOWN AND DEPRESSURIZE THE RCS

A.

1. CHECK RWST LEVEL - > LO-LO LEVEL → EOS-1.3B, TRANSFER TO COLD LEG RECIRCULATION
2. VERIFY ECCS VALVE ALIGNMENT - PROPER EMERGENCY ALIGNMENT PER ATTACHMENT 2
3. VERIFY ECCS FLOW IN ALL TRAINS
4. CHECK RCS VENT PATHS
5. CHECK RCP STATUS
6. CHECK CORE COOLING → RETURN TO PROCEDURE AND STEP IN EFFECT
7. CHECK IF ONE RCP SHOULD BE STOPPED
8. CHECK ACCUMULATOR INJECTION VALVE STATUS
9. CHECK CST LEVEL - > 10% → ABN-305, AUXILIARY FEEDWATER SYSTEM MALFUNCTION

B.

10. CHECK INTACT SG LEVELS
11. DEPRESSURIZE ALL INTACT SGs TO 150 PSIG — 170
12. CHECK RHR PUMPS - RUNNING
13. CHECK IF ACCUMULATORS SHOULD BE ISOLATED
14. STOP ALL RCPs
15. DEPRESSURIZE ALL INTACT SGs TO ATMOSPHERIC PRESSURE
16. VERIFY ECCS FLOW
17. CHECK CORE COOLING
18. GO TO EOP-1.0B, LOSS OF REACTOR OR SECONDARY COOLANT, STEP 11 → EOP-1.0B, LOSS OF REACTOR OR SECONDARY COOLANT

CONTINUOUS ACTION STEP

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION: The following step will cause accumulator injection which may cause a red path condition in the Integrity Status Tree. This procedure shall be completed before transition to FRP-0.1B, RESPONSE TO IMMINENT PRESSURIZED THERMAL SHOCK CONDITION.

NOTE: After low steamline pressure SI signal is blocked, main steamline isolation will occur if the high steam pressure rate setpoint is exceeded.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
*11	Depressurize All Intact SGs To 150 PSIG:	
170	a. Maintain cooldown rate in RCS cold legs - LESS THAN 100°F/HR	
	b. WHEN PRZR pressure decreases to less than 1960 psig, THEN block the low steamline pressure SI signal.	
	c. Dump steam to condenser.	c. Manually or locally dump steam from intact SG(s) using SG atmospheric(s).
170	d. Check SG pressures - LESS THAN 150 PSIG	d. Return to Step 10. OBSERVE CAUTION PRIOR TO STEP 10.
	e. Check RCS hot leg temperatures - AT LEAST TWO LESS THAN 380°F	e. Return to Step 10. OBSERVE CAUTION PRIOR TO STEP 10
	f. Stop SG depressurization.	

ATTACHMENT 1.B
PAGE 1 OF 1

FRC-0.2B CONTINUOUS ACTION STEPS

NOTE: A Continuous Action Step is applicable from the point at which it is first encountered.

Step No.	Major Step Description	Condition to Monitor
1	Check RWST Level -GREATER THAN LO-LO LEVEL	RWST Level - GREATER THAN LO-LO LEVEL.
9	Check CST Level - GREATER THAN 10%	CST Level - GREATER THAN 10%.
10	Check Intact SG Levels	Control AFW flow to maintain narrow range level between 10% (18% FOR ADVERSE CONTAINMENT) and 50%
11	Depressurize All Intact SGs To 150 psig 170	WHEN PRZR pressure decreases to less than 1960 psig, THEN block the low steamline pressure SI signal.
13	Check If Accumulators Should Be Isolated	• WHEN at least two RCS hot leg temperatures are less than 380°F, THEN do Steps 13b and 13c. • WHEN the accumulator is depressurized, THEN continue step (13.f.5 RNO).

BASES

NOTE: Following low steamline pressure SI signal block, the high steam pressure rate main steamline isolation signal will be enabled. This note warns the operator of this condition to prevent a main steamline isolation which might result if the cooldown is initiated too rapidly. Note that the rate of SG depressurization will be affected by AFW flow, SG levels, and whether the RCS is in natural circulation. If MSIV closure occurs, the rapid cooldown should be continued using the SG atmospherics.

STEP 11: The controlled secondary depressurization, similar to the one in EOS-1.2B, POST LOCA COOLDOWN AND DEPRESSURIZATION, has been shown to be an effective way to reduce RCS pressure. RCS pressure must be reduced in order for the accumulator and RHR pumps to inject.

The hot leg temperature value is selected to ensure the RCS saturation pressure exceeds the accumulator pressure after the accumulator has been discharged. This precludes nitrogen injection into the RCS.

Main steamline pressure SI is blocked to maintain MSIVs open to utilize steam dump valves for cooldown.

170

To prevent accumulator nitrogen injection, the operator should stop the secondary depressurization when the SG pressure reaches 150 psig. A steam generator pressure limit is set to preclude significant nitrogen introduction into the RCS following accumulator injection.

This is a Continuous Action Step.

CAUTION: RHR pumps utilize seal coolers and the RHR heat exchangers to remove pump heat. The seal coolers and RHR heat exchangers are cooled by CCW. If the RCS pressure is above the shutoff head of the RHR pumps and these pumps are run in the injection mode for an extended period of time without CCW to the seal coolers and the RHR heat exchangers, they may be damaged due to excessive heatup. There are two basic failure mechanisms for the RHR pumps when CCW to the RHR heat exchangers is lost. The failure mechanisms depend on the pump's mechanical components and the NPSH requirements of the pump. With no cooling provided to the RHR heat exchangers, the temperature of the pumped fluid will gradually increase. As a result, the NPSH requirements may not be satisfied and cavitation of the pumps may occur, causing excessive vibration, possible pump seizure, bearing damage, gasket and seal leakage, and motor failure. In addition, lack of cooling flow will increase the temperature of the mechanical seal unit resulting in deterioration and increased seal leakage or failure.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
34	Check If All Intact SGs Should Be Depressurized To 700 PSIG:	
	a. Check SG Pressures - GREATER THAN 700 PSIG	a. Go to Step 35.
	b. Dump steam to condenser at maximum rate and avoid main steam isolation.	b. Manually or locally dump steam at maximum rate from intact SG(s) atmospheric.
	c. Check SG pressure - LESS THAN 700 PSIG	c. Return to Step 34b.
	d. Stop SG depressurization.	
35	Depressurize All Intact SGs To Inject Accumulators As Necessary:	
	a. Dump steam to condenser as necessary to maintain RVLIS indications - GREATER THAN <u>OR</u> EQUAL TO 11 IN ABOVE CORE PLATE LIGHT LIT	a. Manually or locally dump steam from intact SG(s) atmospheric as necessary to maintain RVLIS indication.
170	b. Check SG pressures - LESS THAN 150 PSIG	b. Return to Step 35a.
	c. Stop SG depressurization.	

ATTACHMENT 7
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BASES

STEP 34: Since the RCS will be saturated at this time, RCS pressure is approximately the same as SG pressure. In this step SG pressures (and thus RCS pressure) are decreased at the maximum rate to 25 psig above the accumulator high pressure alarm setpoint. SG pressure is used due to its accuracy; i.e., the RCS pressure instrument may have high inaccuracies since it is located inside containment. The value of 25 psig is arbitrarily selected as a pressure which is slightly above the accumulator high pressure alarm setpoint.

If the condenser and ARVs are not available, the operator should evaluate using any means of removing water or steam from the SGs. This could include opening the blowdown lines or operating the TDAFW pump.

If the SG pressure are less than 700 psig, the operator is instructed to proceed to Step 35 to inject the accumulators as necessary.

STEP 35: As mentioned in the previous step the RCS will be saturated at this time and therefore, RCS pressure is approximately equal to SG pressure. In this step the intact SGs are depressurized (and thus the RCS) to inject the accumulators. SG depressurization is used here due to its accuracy; i.e., the RCS pressure instrument may have high inaccuracies since it is located inside containment.

Steam is dumped as necessary to maintain RVLIS indication at the top of the core from the accumulator water injection. In other words, the SGs are depressurized relatively slowly such that the accumulator water injection is minimized, extending the time to depletion of the accumulators. When SG pressures of less than 150 psig are reached, the accumulator contents will have been injected into the RCS and the SG depressurization is stopped.

170

A steam generator pressure limit is set to preclude significant nitrogen injection into the RCS.

If the condenser and ARVs are not available, the operator should evaluate using any plant specific means of removing water or steam from the SGs. This could include opening the blowdown lines and operating the TDAFW pump.

STEP 36: Accumulators are isolated or vented after their liquid contents are discharged into the RCS. Isolating or venting accumulators prevents nitrogen injection into the RCS. Nitrogen could collect in high places and render PRZR pressure control ineffective or cause gas binding in the SG U-tubes. Venting nitrogen gas also prevents nitrogen injection.