

# The Light company

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May 31, 1985  
ST-HL-AE-1265  
File No.: G9.15

Mr. George W. Knighton, Chief  
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Division of Licensing  
U. S. Nuclear Regulatory Commission  
Washington, DC 20555

Dear Mr. Knighton:

South Texas Project  
Units 1 & 2  
Docket Nos. STN 50-498, STN 50-499  
Submittal of Additional Information

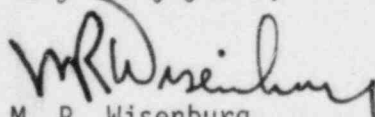
Reference: Letter NRC to HL&P; April 4, 1985; G.W. Knighton to  
J. H. Goldberg (ST-AE-HL-90578); Request for  
Additional Information.

Enclosed please find Houston Lighting and Power's (HL&P) responses to your recent Request for Additional Information (see reference). In the reference, the NRC forwarded PSB questions (430.106-136) and RSB questions (440.14-72). In Attachments 1 and 2 we have provided responses or anticipated response dates for all questions except 430.117, 430.120, 430.124, 430.126, 440.30, 440.38 and 440.39. Answers for these questions will be provided in future transmittals as they become available. For your information, marked-up FSAR sections are provided with the responses where appropriate.

Responses to the RSB questions (Attachment 2) were discussed at meetings between the NRC, HL&P, Bechtel and Westinghouse held May 7, 1985 in Bethesda and May 8-9, 1985 in Pittsburgh. Attachment 3 provides a list of the attendees for these meetings.

If you should have any questions, please contact Mr. M. E. Powell at (713) 993-1328.

Very truly yours,

  
M. R. Wisenburg  
Manager, Nuclear Licensing

JSP/as  
Attachments

W2/JSP/q

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Response to Request for  
Additional Information  
for the Power Systems Branch (PSB)

Questions 430.106 through 430.136

Question  
430.106  
(SRP 8.2)

Section 8.2.III.4 of the SRP requires determination that all component/equipment from and including the switchyard to the onsite Class 1E system are included in the quality assurance program. Confirm STP design for compliance.

Response: Q430.106

The switchyard and cable from the switchyard to the various transformers, e.g. main, standby and emergency, were installed, inspected and tested according to standard HL&P practices. The component/equipment from the aforementioned transformers to the onsite Class 1E system were installed, inspected, and tested according to STP QA requirements for non-class 1E components/equipment. Since the components/equipment discussed above are not safety related or "important to safety", the above complies with GDC 1. NUREG 0800, Section 8.2.III.4 was not applied for all of the offsite power system, but installed, inspected and tested in accordance with standard utility high quality.

Question  
430.107  
(SRP 8.1)

Table 8.1-2 of the FSAR includes BTP-ICSB-2 (PSB) which is superseded by IEEE 387 since 1981; and BTP ICSB-4 (PSB) which is included in Chapter 7 of the SRP, instead of Chapter 8. The table does not include IEEE Std 485 and the following branch technical positions of Chapter 8 of the SRP; thus, a positive statement as to compliance with the staff guidelines has not been provided in the FSAR. Provide a statement of compliance and justify noncompliance, if any. Also reference applicable section(s) of the FSAR where compliance to the following staff positions are discussed.

- (1) BTP PSB-1
- (2) BTP PSB-2
- (3) BTP ICSB-8 (PSB)
- (4) BTP ICSB-11 (PSB)
- (5) BTP ICSB-18 (PSB)

Response

Table 8.1-2 of the FSAR has been revised as follows:

Reference to BTP-ICSB-2 and BTP-ICSB-4 has been deleted. (BTP-ICSB-4 is included in Table 7.1-1 of the FSAR).

Reference to IEEE 387-1977 and IEEE 485-1978 has been added. Reference to IEEE-485-1978 has been added in Section 8.3.2.1.1.

In addition, both Table 8.1-2 and Table 7.1-1 have been revised to clarify the sections showing STP conformance with BTP ICSB-18.

STP conforms with BTP ICSB-18, as indicated in Section 6.3.1. Review of single failures and effects on plant safety has resulted in two applications where power lockout is used to design against a single failure. These applications are the accumulator discharge isolation valves and the safety injection hot leg recirculation isolation valves. These applications and the provisions made to meet the BTP are discussed in Sections 6.3.2.2, 6.3.5.5, 7.6.3 and 7.6.7. Figures 7.3-3 and 7.6-10 are also provided.

References to applicable sections of the FSAR are given on the second page of Table 8.1-2 for the following:

- (1) BTP PSB-1
- (2) BTP PSB-2
- (3) BTP ICSB-8 (PSB)
- (4) BTP ICSB-11 (PSB)
- (5) BTP ICSB-18 (PSB)

Positive statements as to compliance with BTP PSB-2 and BTP ICSB-8 are included in Sections 8.3.1.1.4.7 and 8.3.1.1.4 respectively.

Positive statements as to compliance with BTP PSB-1 and BTP ICSB-11 will be added in a future Amendment, in Sections 8.3.1.1.4.6 and 8.2.2.1 respectively.

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

Criteria	Title	Conformance Discussed In
BTP ICSB 13	Design Criteria for Auxiliary Feed-water Systems	See AFW System FMEA, Section 10.4.9., ESFAS design is given in Section 7.3.1.
BTP ICSB 14	Spurious Withdrawals of Single Control Rods in Pressurized Water Reactors	Conformance is demonstrated in Sections 7.7.2.2, 15.4.1, 15.4.2, and 15.4.3.
BTP ICSB 18	Application of the Single-Failure Criterion to Manually-Controlled, Electrically-Operated Valves	<sup>6.3.1, 6.3.2.2, 6.3.5.5,</sup> <del>Conformance is demonstrated in</del> Sections 7.6.3 and 7.6.7.6 See Figures 7.6-3, 7.6-10, and 8.3-13.
BTP ICSB 20	Design of Instrumentation and Controls Provided to Accomplish Changeover from Injection to Recirculation Mode	Conformance is demonstrated in Sections 6.3 and 7.6.4.
BTP ICSB 21	Guidance for Application of Regulatory Guide 1.47	7.5.4
BTP ICSB 22	Guidance for Application of Regulatory Guide 1.22	Conformance is demonstrated in Section 7.1.2.5.
BTP ICSB 24	Testing of Reactor Trip System and Engineered Safety Feature Actuation System Sensor Response Times	Conformance is demonstrated in Section 7.1.2.11.
BTP ICSB 25	Guidance for the Interpretation of GDC 37 for Testing the Operability of the Emergency Core Cooling System as a Whole	Conformance is demonstrated in Section 3.1
BTP ICSB 26	Requirements for Reactor Protection System Anticipatory Trips	Conformance is demonstrated in Section 7.2.1.
BTP RSB 5-2	Overpressurization Protection of Pressurized Water Reactors While Operating at Low Temperatures	7.6.6.3

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TABLE 8.1-2

LISTING OF APPLICABLE CRITERIA

Criteria	Title	Conformance Discussed In		
1. Regulatory Guides*				
2. Institute of Electrical and Electronics Engineers Standards Not Otherwise Incorporated by RG Reference:			36	
<del>IEEE Std. 338-1971</del>	<del>IEEE Standard Criteria for the Periodic Testing of Nuclear Power Generating Station Class 1E Power and Protection Systems</del>	<del>8.3.1.1.4.7</del>		
<del>IEEE Std. 387-1972</del>	<del>IEEE Standard Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Stations</del>	<del>8.3.1.1.4.2</del> <del>8.3.1.1.4.7</del>		2 Q40. 1
IEEE Std. 420-1973	IEEE Trial-Use Guide for Class 1E Control Switchboards for Nuclear Power Generating Stations	8.3.1.3	44	STP FSAR
IEEE Std. 485-1978	IEEE Recommended practice for sizing Large Lead Storage Batteries for Generating Stations and Substations	8.3.2.1.1		Q430.107
3. Branch Technical Positions				
<del>BTP ICSB 2 (PSB)</del>	<del>Diesel Generator Reliability Qualification Testing</del>	<del>8.3.1.1.4.2</del>		29 Q430. 04N
<del>BTP ICSB 4 (PSB)</del>	<del>Requirements on Motor-Operated Valves in the EGCS Accumulator Lines</del>	<del>6.3.2</del> <del>Table 6.3.1</del> <del>7.6.3</del>	36	
(IEEE 387-1977)				
*See Table 3.12-1 for revision and STP position on the following Regulatory Guide:				
1.6, 1.9, 1.22, 1.29, 1.30 (IEEE 336-1971), 1.32 (IEEE 308-1974), 1.40 (IEEE 334-1971), 1.41, 1.47 (IEEE 279-1971), 1.53 (IEEE 379-1972), 1.62 (IEEE 279-1971), 1.63 (IEEE 317-1976), 1.73 (IEEE 382-1972), 1.75 (IEEE 384-1974), 1.81, 1.89 (IEEE 323-1974), 1.93, 1.100 (IEEE 344-1975), 1.106, 1.108, 1.128 (IEEE 484-1975), 1.129 (IEEE 450-1975), and 1.131 (IEEE 383-1974)				
	1.118 (IEEE 338-1977)			Q430.108 Q430.107 Q430.108

TABLE 8.1-2 (Continued)

LISTING OF APPLICABLE CRITERIA

Criteria	Title	Conformance Discussed In
BTP ICSB 8 (PSB)	Use of Diesel Generator Sets for Peaking	8.3.1.1.4
BTP ICSB 11 (PSB)	Stability of Offsite Power Systems	8.2.2.1
BTP ICSB 18 (PSB)	Application of the Single Failure Criterion to Manually-Controlled Electrically Operated Valves	6.3.1, 6.3.2.2, 6.3.5.5, 7.6.3, 7.6.7. See figures 7.6-3 and 7.6-10
BTP ICSB 21	Guidance for Application of RG 1.47	7.1.2.6
BTP PSB-1	Adequacy of Station Electric Distribution System Voltages	8.3.1.1.4.6
BTP PSB-2	Criteria for Alarms and Indications Associated with Diesel Generator Unit Bypassed and Inoperable Status	8.3.1.1.4.7
4. General Design Criteria		
GDC 17	Electrical Power Systems	3.1.2.2.8.1 8.2.1.3 8.3.1.2.1 8.3.2.2.1
GDC 18	Inspection and Testing of Electric Power Systems	3.1.2.2.9.1 8.3.1.2 8.3.2.2.1
GDC 21	Protection System Reliability and Test Ability	3.1.2.2.12.1 8.3.1.2.1 8.3.2.2.1

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STP FSAR

6.3.5.5 Valve Position Indication. Valve positions are indicated on the main control board for all MOVs and air-operated valves (AOVs) by means of red (open) and green (closed) position indicating lights. These lights are located at the control switch for each valve. They are powered by valve control power and actuated by valve motor operator limit switches (for MOVs) or valve stem mounted limit switches (for AOVs).

Positions for these valves (all MOVs and AOVs) are also indicated (in the Bypass and Inoperable Status Indication System) by a "normal off" system. Should the valve not be in its proper position, thus disabling safeguards operations, a bright white light will be lit and will thus give a highly visible indication to the operator. This light is energized from a separate monitor light supply and actuated by a valve motor operator limit switch or, for AOVs, a stem mounted limit switch. An annunciator light and alarm are provided at the system level to further alert the operator should any valve in the ECCS be improperly aligned during operation.

Certain ECCS valves are provided with more extensive control features, as described in Sections 6.3.5.5.1 and 6.3.5.5.2.

\* 6.3.5.5.1 Accumulator Isolation Valve Position Indication and Power Lockout: These valves are required to remain in their aligned positions during certain phases of a LOCA or during plant shutdown, as described in Section 7.6.3. To ensure that no spurious movements of these valves can occur, the valves will be power locked-out from a control switch located at the main control panel or auxiliary shutdown panel. Indication is provided at the main control panel and auxiliary shutdown panel to monitor the position of the power lock-out breakers for these valves: red (power on) and green (power off).

(as required by BTP ICSB-18)

Redundant valve position indication is also provided at the main control panel and auxiliary shutdown panel to supplement the normal valve position indicators when the power lock-out is in operation. These redundant valve position indicating lights are powered independent of the valve operator control power, and are operated by valve stem-mounted limit switches to ensure complete independence from the normal valve position indication system.

An annunciator alarm point is activated by both a valve motor operator limit switch and by a valve position limit switch activated by stem travel whenever an accumulator valve is not fully open for any reason with the system at pressure (the pressure at which the safety injection block is unblocked is approximately 1900 psig). A separate annunciator point is used for each accumulator valve. This alarm is recycled at approximately one hour intervals to remind the operator of the improper valve lineup.

\* 6.3.5.5.2 Hot Leg Recirculation Isolation Valve Position Indication and Power Lockout: The hot leg recirculation isolation valves for each LHSI pump and each HHSI pump are required to remain in the closed position during the injection and recirculation phases of a LOCA, until operator action is taken to switch to hot leg recirculation in two of the safety injection trains. To ensure that no spurious movement of these valves can occur, the power for these valves is locked-out from a control switch located at the main control panel. Indication is provided at the main control panel to monitor the position of the power lock-out breakers for each valve: red (power on) and green (power off).

STP FSAR

<sup>BTP</sup>  
(as required by ICSB-18)

Redundant valve position indication is also provided<sup>^</sup> at the main control panel to supplement the normal valve position indicators when the power lock-out is in operation. These redundant valve position indicating lights are powered independent of the valve operator control power, and are operated by valve stem-mounted limit switches to ensure complete independence from the normal valve position indication system.

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## 8.2.2 Analysis

The stability of offsite power systems is in  
Compliance with BTP ICSB-11

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8.2.2.1 Steady State and Transient Stability Studies. Steady-state (load flow) and transient stability studies demonstrate that the loss of both units at the STP or the loss of one unit with the other unit on-line or off-line does not impair the ability of the system to supply power to the ESF Electrical System. These studies further demonstrate that the loss of any double-circuit 345 kV transmission line, ~~or~~ the loss of any two 345 kV transmission circuits or the loss of any single independent right-of-way does not endanger the supply of offsite power to the ESF Electrical System.

all circuits on

In addition, these studies demonstrate that the operation of the HVDC terminal does not have an adverse effect on the supply of offsite power to the ESF Electrical System.

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The transmission system associated with the STP is designed and constructed so that no loss of offsite power to the 345 kV switchyard is experienced with any occurrence of the following single events:

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- a. Loss of any two transmission circuits
- b. Loss of any one transmission circuit and any one generator
- c. Loss of any two generators
- d. A three-phase fault occurring on any transmission circuit which is cleared by either primary or backup relaying

Transient stability studies were run to demonstrate that the above events do not result in the nonavailability of offsite power. The transient stability studies included the modeling of variable flux linkages of the generator field and internal voltages represented on both the quadrature and direct axis. Where information was available, machines were modeled with full representation of excitation systems and voltage regulators as outlined in Institute of Electrical and Electronic Engineers publication "Computer Representation of Excitation Systems." Governor systems were represented in detail, including modeling of both reheat and non-reheat units. Governor systems of reheat units included modeling of the effects of the high-pressure section of the turbine and the combined effects of the intermediate and low-pressure sections of the turbine. The HVDC terminal control system was modeled in detail also.

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07N

Results of the transient stability studies, such as plots of frequency versus time and machine angle versus time, are given on Figures 8.2-10 through 8.2-12. Outages of critical generators and faulting of critical buses were selected as worst-case tests.

Load flow results in the form of load flow plots are given on Figures 8.2-6 through 8.2-9. These results demonstrate that sufficient offsite power is available at the STP switchyard when the postulated events given above are analyzed. The steady-state results further demonstrate that no inoperable voltage levels or overloaded transmission circuits which would hinder the availability of the offsite power supply would result for the conditions tested.

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- b. Reverse power flow
- c. Loss of field excitation
- d. Low lube oil pressure (engine and ~~turbo~~ turbocharger
- e. Excess vibration
- f. <sup>Turbocharger</sup> ~~Turbo~~ thrust bearing failure
- g. Engine overspeed trip
- h. High jacket water temperature
- i. High engine/generator bearing temperature
- j. ~~ESF bus differential~~
- k. Generator overcurrent
- l. Generator underfrequency

for the Diesel Generator and Generator Breaker  
 The above trips remain functional during periodic testing of the DGs. However, during emergency operation of the DGs all but the following protective trips are automatically bypassed:

36

- a. Generator differential
- b. Engine overspeed ~~trip~~

The bypassed protective functions are alarmed in the control room to alert the operator to take appropriate action.

3. ~~The undervoltage sensing scheme to be utilized in each of the three medium voltage safety-related trains includes four undervoltage relays. These four relays are connected in a two out of four logic are set to operate when the bus voltage is reduced to approximately 70-80 percent of rated switchgear voltage (i.e., 4160 volts). The four undervoltage relays produce output logic 0.4-1.5 second after their settings have been reached. Operation of two out of four undervoltage relays shall result in isolation of the safety-related buses from the offsite power system, tripping of all loads except those associated with the first load block, and starting and loading of the associated diesel generator. Since the minimum voltage which can result from starting the largest motor is greater than or equal to 80 percent of rated motor voltage (4000 volts) inadvertent operation of the undervoltage relays is precluded during all motor starting operations.~~

*Conc A* →  
 The second level of undervoltage protection is provided by undervoltage relays having time delay characteristics and set to alarm in the control room on a tolerable degraded bus condition; should a SI signal be present, Mode III is immediately entered. However upon further degradation of the ESF bus voltage or persistent degraded condition of a predetermined duration, the ESF bus is isolated from the offsite power

Insert A for page 8.3-12:

In addition the normal supply breaker overcurrent trip provides input to a lockout relay, which locks out the Diesel Generator Supply breaker from closing.

3. Each 4.16 KV ESF bus is provided with two levels of undervoltage detection as indicated in Figure 8.3-4, Sheet 5 of 5.

The adequacy of station electric distribution System voltages is in compliance with BTP PSB-1.

Q430.107

as shown in Figure 8.3-3. There are separate batteries provided with the plant computer, and other data acquisition systems. These batteries do not interface with the rest of the plant DC Power System.

8.3.2.1.1 Class 1E Battery Systems: The Class 1E 125 vdc Battery Systems of each unit consist of four independent, physically separated buses, each energized by two battery chargers and one battery. ~~The system voltage varies between 105-140 vdc depending on the operating mode of battery charging equipment and system loads.~~ The batteries are sized in accordance with IEEE 485-1978. Emergency power required for plant protection and control is supplied by the batteries without interruption when the power from ac sources is interrupted. Each battery system also supplies power to its associated inverter system, which converts the dc power to ac power at 118 vac, 60 Hz single phase for the vital instrumentation and protection system. The six vital ac buses supply power to instrumentation channels I, II, III, and IV. There are two vital ac buses for each of channels I and IV, and one vital ac bus for each of channels II and III.

The ampere-hour capacity of each battery is sufficient to provide, for a minimum of 2 hours, the power required by emergency dc controls and the vital ac instrumentation and protection system, ~~to shutdown the reactor and maintain it in a safe shutdown condition.~~ Only small dc loads and dc controls are supplied from the 125 vdc batteries.

The two battery chargers associated with each of the four 125 vdc buses are connected to separate ac buses of the same train to enhance the reliability of each dc bus. Only one charger each is required for channels II and III and both chargers for each of channels I and IV are required.

The four 125 vdc batteries are each located in separate rooms in a seismic Category I building which inhibits the propagation of fire and provides protection against missiles. Battery chargers and distribution panels associated with a given battery are located outside of the battery room. Each battery room is ventilated by the Heating, Ventilating, and Air Conditioning (HVAC) System (Section 9.4.1) through separate intake and exhaust ~~ducts~~ fans which are energized by the ESF buses from

The Class 1E DC Power Systems are designed to withstand the effects of tornadoes, fires, and the Safe Shutdown Earthquake (SSE) without loss of function. Flooding of the battery rooms is precluded by the elevation and location of the battery rooms in the Mechanical-Electrical Auxiliaries Building (MEAB).

The environmental and seismic qualification programs of the Class 1E battery system are discussed in Sections 3.10 and 3.11. The Class 1E Battery System are designed to comply with the requirements of NRC RGs 1.6 and 1.32.

Each DC System is provided with an annunciator window having inputs from each of the two chargers and the switchboard. The computer may be used to identify which of the three inputs is being alarmed.

Each battery charger is provided with the following alarm circuits which are connected in common to the control room annunciator/computer to indicate battery charger trouble:



Question  
430.108  
(SRP 8.1)

Staff's review of the FSAR is guided by the current revision of the applicable regulatory guides and the referenced standards. Tables 3.12-1 and 8.1-2 list old revisions of guides and standards for STP compliance. Clearly identify the differences between STP design and the requirements of the current revisions of the regulatory guides and the referenced standards listed below. Justify the differences.

<u>Guide (Standard)</u>	<u>Current Revision</u>	<u>Revision Listed in the Tables</u>
R.G. 1.9	Rev. 2 (12/79)	Rev. 0 (3/71)
R.G. 1.63	Rev. 2 (7/78)	Rev. 0 (10/73)
R.G. 1.75	Rev. 2 (9/78)	Rev. 1 (1/75)
IEEE Std 338	1975 (incorp. by R.G. 1.118)	1971
IEEE Std 387	1977 - (incorp. by R.G. 1.9)	1972

Response

Table 8.1-2 has been revised as shown:

R.G.	1.118	(IEEE 338-1977)
R.G.:	1.9	(IEEE 387-1977)

Table 3.12-1 has been revised as shown:

R.G. 1.9	Rev. 2 (12/79)	(FSAR Ref.)	8.3.1.1.4.7	(Status) C
R.G. 1.118	(FSAR Ref.)	8.3.1.1.4.7	(Rev. Status)	Rev. 2 (6/78)
(Status)	A			

The only substantive difference between Rev. 1 and Rev. 2 of R.G. 1.75 is the addition of the following paragraph in Rev. 2:

This guide addresses only some aspects of defense against the effects of fires. Additional criteria for protection against the effects of fires are provided in Regulatory Guide 1.120, "Fire Protection Guidelines for Nuclear Power Plants."

STP uses an alternate approach for R.G. 1.120 (fire protection); the criteria used is specified in BTP 9.5.1 Appendix A.

Compliance with R.G. 1.75 Rev. 2 is as stated in Section 8.3.1.4, with exceptions as stated in Sections 7.1.2.2.1 and 8.3.1.4.4.14 item Nos. 6 and 8.

The differences between STP design and the requirements of R.G.1.63 revision 2 with justification will be included in our response to question 430.21N.

Regarding R.G. 1.9, the diesel generator protective trips are tagged by the ERF computer with a time, but time resolution provided may not be sufficient to identify the first trip as depicted by Rev. 2 of R.G. 1.9.

TABLE 3.12-1 (CONT'D)  
REGULATORY GUIDE MATRIX

NO.	REGULATORY GUIDE TITLE	FSAR REFERENCE	REVISION STATUS	STATUS ON STP	
1.8	Personnel Selection and Training	13.1.3.1 Table 13.1-2 13.2.1 13.2.4	Rev 1-R (5/77)	A	38
1.9	Selection of Diesel Generator Set Capacity for Standby Power Supplies	8.3.1.2 8.3.1.2.3 8.3.1.1.4.2	Rev 2 (12/79) 8 (8/71)	1C (Exception is discussed in 8.3.1.2.3)	36 43 430.108
1.10	Mechanical (Cadmitec) Splices in Reinforcing Bars of Category I Concrete Structures	3.8.1.2.2 3.8.1.6.2.3 3.8.1.6.3 3.8.3.2.2 3.8.3.6.3 3.8.3.6.2.3 3.8.4.2.3	Rev 1 (1/73)	C (Exceptions are discussed in FSAR References)	45
1.11	Instrument Lines Penetrating Primary Reactor Containment	3.1.2.5.6.1 6.2.4.1 7.3.1.1.2 Table 7.1-1 Figure 7.1-1	Rev 0 (3/71)	A	32
1.12	Instrumentation for Earthquakes	3.7.4.1 Table 7.1-1	Rev 1 (4/74)	B, D	29Q 220. 17N Q220.
1.13	Spent Fuel Storage Facility Design Basis	3.1.2.6.3.1 3.8.4.2.3 9.1.1.3 9.1.2.3 9.1.4.3	Rev 1 (12/75) FC	A	
1.14	Reactor Coolant Pump Flywheel Integrity	5.4.1.5.2 5.4.1.5.3 5.4.1.5.4	Rev 1 (8/75) FC	C See Note 4	
1.15	Testing of Reinforcing Bars for Category I Concrete Structures	3.8.1.2.2 3.8.1.6.2.3 3.8.3.2.2 3.8.3.6.2.3 3.8.4.2.3	Rev 1 (12/72)	A	45
1.16	Reporting of Operating Information Appendix A Technical Specifications		Rev 4 (8/75)	B See Note 68	43
1.17	Protection of Nuclear Power Plants Against Industrial Sabotage		Rev 0 (6/73)	B	33

STP FSAR

(Above)  
 There are 24 electrical penetrations located above Elevation 68'-0" inside the Containment ~~and above~~ Elevation 60'-0" outside the Containment). These groups of electrical penetrations have been assigned to Train C, instrumentation channel IV, and ~~all~~ miscellaneous related ~~circuits of~~ the above. (For penetration locations and assignments refer to Table 8.3-12 and Figure 8.3-14.)

2  
Q40.4

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Design and qualification testing of electrical penetrations is in accordance with IEEE Standard 317-1976 and RG 1.63. Note, however, that electrical penetrations being purchased for the Containment personnel airlock are to be qualified to ~~RG 1.63 and~~ IEEE 317-1976, which is endorsed by RG 1.63, Rev. 2.

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Protection of the electrical penetrations is provided to preclude a single failure ~~from causing excessive currents in the penetration conductors~~ which would degrade the penetration seals.

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21N

Insert A

~~The Containment electrical penetration conductors for power circuits are one size larger than the external conductors outside Containment while they are equal to or less than the external conductors inside Containment.~~

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8.3.1.2 Analysis. The following summary describes how the AC Power Systems comply with the requirements of NRC General Design Criteria (GDC), NRC RGs, and IEEE Standards.

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8.3.1.2.1 Compliance with GDC 17, 18 and 21 and RG 1.93: Sections 8.3.1.1.2, and 8.3.1.1.4 describe the normal power distribution system of each unit, with provision for connection to the respective unit auxiliary transformer and the standby transformers, and the onsite standby sources of each unit. This arrangement affords sufficient flexibility and redundancy to ensure the availability of power to the ESF loads ~~after~~ the occurrence of a design basis event. Standby DGs reestablish power to the ESF buses within 10 seconds. The offsite power source ~~complies~~ with GDC 17 and RG 1.93.

43

Comply

In compliance with GDC 18 and 21, provisions are made to permit:

1. Periodic inspection and testing, during equipment shutdown, of wiring, insulation, connections, and relays to assess the integrity of the systems and the condition of components.
2. Periodic testing, during normal plant operation of the operability and functional performance of onsite power supplies, circuit breakers and associated control circuits, relays, and buses.
3. Testing, during plant shutdown, of the operability of the Class 1E system as a whole. Under conditions as close to design as practical, the full operation sequence that brings the system into operation, including operation of signals of the ESF actuation system and the transfer of power between the offsite and the onsite power system is tested.

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8.3.1.2.2 Compliance with RG 1.6: Section 8.3.1.1.4 describes the onsite standby power sources and explains the degree of separation and independence that exists between the three subsystems.

Insert A for page 8.3-20:

Power and control <sup>field</sup> cables to the electrical penetrations are capable of carrying the load current based on the penetration conductor ampacity as calculated for the electrical penetration protection.



The three-train arrangement of power sources and load groups is designed to meet the single-failure criterion.

8.3.1.2.3 Compliance With RG 1.9: Each standby DG is rated on the basis of the sum of the nameplate ratings of the ESF loads it energizes during an accident. During step loading of the standby DG, possible voltage dips and frequency deviations due to the application of large motor loads may occur. These deviations do not exceed 20 percent of the nominal voltage and 5 percent of the nominal frequency. Recovery from such variations is within the RG 1.9 position (i.e., voltage restored to within 10 percent of nominal and frequency within 2 percent of nominal in less than ~~20~~ percent of each load sequence time interval). *Amend 1* 36

8.3.1.2.4 Compliance With IEEE 279-1971 and RG 1.32: ~~All~~ Class 1E systems and equipment comply with the requirements of IEEE 279-1971 (as amended by RGs 1.47 and 1.62 and RG 1.32) by virtue of the separation, redundancy, and independence provided in the various systems and the location of equipment in Seismic Category I buildings and structures. Surveillance of Class 1E Systems will be described in the Technical Specifications. 36

8.3.1.2.5 Failure Mode Analysis: Application of the single-failure criterion to safety-related systems is used to analyze failures of components and causes and effects of failures in systems. Tabulations of failure modes and effects are shown in Tables 8.3-9 and 8.3-13. 4  
12

8.3.1.2.6 Effects of Hostile Environments on Electrical Equipment: ~~All~~ Class 1E electrical equipment is designed to withstand the effects of the environment existing at the equipment locations. All equipment located inside the Containment and required to operate during and after ~~an accident~~ is identified in Table 3.11-~~2.3~~ *a design basis event* 36

8.3.1.2.7 Compliance with RG 1.75: The design and layout of the electric system is in accordance with the intent of RG 1.75. As noted in Sections 8.3.1.3, and 8.3.1.4. For NSSS scope systems the position on RG 1.75 is described in Section 7.1.2.2.1. 36

8.3.1.2.8 Compliance with RG 1.53: The design of the safety-related electrical system is in accordance with the single failure criterion as discussed in RG 1.53.

8.3.1.2.9 Conformance With Appropriate Quality Assurance Standards: Conformance to RG 1.30 is as stated in Table ~~3.12~~ and Chapter 17. 36

8.3.1.2.10 Compliance With RG 1.108: Compliance with the intent of RG 1.108 ~~is~~ met with the following interpretations and exceptions: 45  
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14N

1. Starting air system: System boundary starts at <sup>five</sup> air receivers (isolation valve downstream of the air dryer). Air compressors and dryers are not included since the engine can be started ~~ten~~ times from air stored in 100 percent redundant (2 full capacity) receivers for each engine. 36
2. Fuel Oil System: Fuel oil system <sup>boundary</sup> starts from the diesel fuel oil tanks and this is not part of the diesel generator system for test purposes.

Insert 1 for page 8.3-21:

The diesel generator protective trips are tagged by the ERF computer with a time, but time resolution provided may not be sufficient to identify the first trip as depicted by Rev. 2 of RG 1.9.

Question  
430.109

Table 3.12.1 of the FSAR lists the following regulatory guides for its status on STP design with either partial exception or conforming to the intent of the guide. Clearly identify each exception and justify them against the applicable positions of each guide in reference. Also clearly explain the difference between "conform to guide" and "conform to intent of guide" as used in the reference table and identify the difference with justification.

Regulatory Guide 1.32 - with "partial exception"

Regulatory Guide 1.47 - with "conform to intent of guide"

Regulatory Guide 1.53 - with "conform to intent of guide"

Regulatory Guide 1.108 - with "partial exception" and a note that the guide is not applicable to STP design

Regulatory Guide 1.128 - with "conform to intent of guide"

Regulatory Guide 1.131 - with "partial exception"

Response

The "Status on STP" in Table 3.12-1 for R.G. 1.128 was revised to "A" (Conform to guide) in Amendment 45. For R.G.s 1.32 and 1.47 the status has been revised to "A".

STP conforms to R.G. 1.53 in all areas except in regard to the Westinghouse ESF Actuation System. The discussion showing conformance to the R.G. (for the Westinghouse system) is presented in Section 7.1.2.7. A note will be added to Table 3.12.-1 indicating this clarification.

STP complies with R.G. 1.108 with the interpretations and exceptions presented in Section 8.3.1.2.10. Please note that STP intends to follow the recommendations of Generic Letter 84-15 regarding the frequency of cold starts, thereby reducing premature diesel engine degradation.

Note 24 to Table 3.12-1 and Section 3.11.2.2 has been revised as follows:

"24. The only exception taken to RG 1.131 is explained in Section 3.11.2.2."

"Class 1E cables field splices, and terminations for use on the STP with the exception of single conductor high temperature silicon insulated cables meet the requirements of IEEE 383-1974 as modified by RG 1.131. Single conductor high temperature silicon insulated cables when used in a Class 1E circuit are installed in conduit only."

See also response to question 430.110.

TABLE 3.12-1 (CONT'D)  
REGULATORY GUIDE MATRIX

NO.	REGULATORY GUIDE TITLE	FSAR REFERENCE	REVISION STATUS	STATUS ON STP	
1.31	Control of Stainless Steel Welding	3.9.5.1 4.5.2.4 5.2.3.4.6 5.3.1.4 6.1.1 10.3.6.2	Rev 3 (4/78)	B	33
1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants	Table 7.1-1 Figure 7.1-1 7.1.2.1.3 7.6.1.2 7.6.2.2 8.2.1.3 8.3.1.2.4 8.3.2.1.1 8.3.2.1.4 8.3.2.2.3	Rev 2 (2/77)	A	38 (2430.109) 43 32 43 38
1.33	Quality Assurance Program Requirements (Operations)	13.5.1.1	Rev 2 (2/78)	A	43 11Q 21. 18
1.34	Control of Electroslag Weld Properties	4.5.2.4 5.2.3.3.2 5.2.3.4.6 5.3.1.4	Rev 0 (12/72)	A	32
1.35	In-Service Inspection of UngROUTED Tendons in Prestressed Concrete Containment Structures	3.8.1.7.3.1 3.8.1.7.3.1.1 3.8.1.2.2	Rev 2 (1/76)	A	45
1.36	Nonmetallic Thermal Insulation for Austenitic Stainless Steel	4.5.2.4 5.2.3.2.3 6.1.1.1 10.3.6.2	Rev 0 (2/73)	A	32
1.37	Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants	4.5.2.5 5.4.2.1.1 5.2.3.4 10.3.6.2	Rev 0 (3/73)	A See Note 60	33 3 43
1.38	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items of Water-Cooled Nuclear Power Plants	6.2.5.2.4	Rev 0 (3/73) Rev 2 (5/77)	A See Note 36 A	43
1.39	Housekeeping Requirements for Water-Cooled Nuclear Power Plants	9.5.1.A pg 14	Rev 0 (3/73) Rev 2 (9/77)	A A See Note 65	43

STP FSAR



TABLE 3.12-1 (CONT'D)  
REGULATORY GUIDE MATRIX

NO.	REGULATORY GUIDE TITLE	FSAR REFERENCE	REVISION STATUS	STATUS ON STP	
1.52	Design, Testing, and Maintenance Criteria for Atmospheric Cleanup System Air Filtration and Adsorption Units of Units of Light-Water-Cooled Nuclear Power Plants	3.11.1 6.4.2.2 6.4.5.2 6.5.1.1.1 6.5.1.1.2 6.5.1.2.1 6.5.1.2.2 Table 6.5-1 9.4.1.1 9.4.1.4 9.4.2.3 9.4.2.4 9.5.1.A pg 60 12.3.3 12.3.3.2	Rev 1 (7/76) FC	C See Note 49	33
1.53	Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems	7.1.2.7 7.2.1.1.3 <del>8.3.1.2</del> 8.3.1.2.8 8.3.2.2.7 Table 7.1-1 Figure 7.1-1 15.0.8	Rev 0 (6/73)	<sup>A</sup> See Note 2	32 33 43 p6
1.54	Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants	6.1.2.1	Rev 0 (6/73)	B	
1.55	Concrete Placement in Category I Structures	3.8.1.2.2 3.8.1.6.1.4 3.8.1.6.1.5 3.8.1.6.2.3 3.8.3.2.2 3.8.3.6.1.4 3.8.3.6.1.5 3.8.3.6.2.3 3.8.4.2.3	Rev 0 (6/73)	A	45
1.56	Maintenance of Water Purity in Boiling Water Reactors			NA See Note 1	
1.57	Design Limits and Loading Combinations for Hot Primary Reactor Containment System Components	3.8.2.3 3.8.2.5 3.8.1.2.2 3.8.3.2.2	Rev 0 (6/73)	A	

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STP FSAR

TABLE 3.12-1 (CONT'D)  
REGULATORY GUIDE MATRIX

NO.	REGULATORY GUIDE TITLE	FSAR REFERENCE	REVISION STATUS	STATUS ON STP
1.125	Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants		Rev 0 (3/77) FC	NA See Note 18
1.126	An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification		Rev 0 (3/77) FC	D See Note 25   23
1.127	Inspection of Water-Control Structures Associated with Nuclear Power Plants		Rev 0 (4/77) FC	A (Essential Cooling Pond only), See Note 22   22
1.128	Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants	8.3.2.2.5	Rev 0 (4/77) FC	A See Note 70   30, 14N
1.129	Maintenance, Testing, and Replacement of large lead Storage Batteries for Nuclear Power Plants	8.3.2.2.4 8.3.2.2.5	Rev 0 (4/77) FC	A See Note 26   36
1.130	Design Limits and Loading Combinations for Class 2 Plate-and-Shell-Type Component Supports		Rev 0 (7/77) FC	NA See Note 31
1.131	Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants	3.11.2.2 9.5.1.2.2	Rev 0 (8/77) FC	C See Note 3, Note 24   23
1.132	Site Investigations for Foundations of Nuclear Power Plants		Rev 0 (9/77) FC	NA See Note 2
1.133	Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors	4.4.6.4	Rev 1 (5/81)	A   360, 492, 02N
1.134	Medical Certification of Personnel Requiring Operating Licenses		Rev 0 (9/77) FC	B See Note 24   23
1.135	Normal Water Level and Discharge at Nuclear Power Plants		Rev 0 (9/77) FC	B See Note 3, Note 24
1.136	Material for Concrete Containments		Rev 0 (11/77) FC	NA See Note 2, Note 13   45
1.137	Fuel-Oil Systems for Standby Diesel Generators		Rev 0 (1/78) FC	NA See Note 2, Note 66   43
1.138	Laboratory Investigations of Soils for Engineering Analysis and Design of Nuclear Power Plants		Rev 0 (4/78)	NA See Note 2
1.139	Guidance for Residual Heat Removal		Rev 0 (5/78)	B See Note 43   23
1.140	Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Absorption Units of Light-Water-		Rev 0 (3/78)	See Note 61

STP FSAR

TABLE 3.12-1 (Cont'd.)  
REGULATORY GUIDE MATRIX  
NOTES

16. Guide is not applicable to STP in accordance with 10CFR50, Appendix I, Section II, Paragraph D.
17. STP fire protection utilizes criteria specified in BTP 9.5.1 Appendix A.
18. Guide is not applicable since such physical models have not been used for STP.
19. Deleted
20. The STP GWPS does not use gas decay tanks.
21. The STP power level is less than the maximum specified by the guide.
22. STP complies with the intent of the guide, but the guide is not applicable due to implementation date.
23. The STP FSAR is written and organized in compliance with the Standard Format and Content Guide.
24. *The only exception taken to RG 1.131 is explained in*  
~~The applicant intends to comply (as indicated), however, no FSAR discussion is provided.~~ Section 3.11.2.2.
25. Fuel for STP is being provided by Westinghouse. Westinghouse does not comply with Regulatory Guide 1.126; instead, an alternate approach is used as described in WCAP-8218-P-A.
26. The requirements of the guide will be met for Class 1E batteries. Generally, characteristics and specifications of the non-1E batteries are similar to those of the Class 1E Battery Systems, but it is not intended that they will necessarily meet Class 1E equipment requirements.
27. The STP control room layout has two panels and a separate area with controls located behind one of the panels. STP meets the intent of this guide by having sufficient operators on duty in the control room to assure visual contact with reactor controls and instrumentation during routine log rounds.
28. Regulatory Guide 1.105 is not discussed explicitly in the FSAR, however, instrument spans and setpoints are discussed in Sections 7.2.7.5 and in the Technical Specifications.
29. Electric power availability is discussed in the Technical Specifications although Regulatory Guide 1.93 is not explicitly discussed.
30. Compliance to Regulatory Guide 1.48 is explicitly discussed in Table 3.9-2.5.

TABLE 3.12-1 (Cont'd.)  
REGULATORY GUIDE MATRIX  
NOTES

- |     |   |                   |
|-----|---|-------------------|
| 31. | Regulatory Guide 1.130 is not applicable to STP due to both the implementation date and the fact that Class 1 Plate-and-Shell Type Components Supports are not used.  | 41                |
| 32. | The QA program for operations will conform to the requirements of Regulatory Guide 1.58, Revision 1 with the exception of regulatory position C.1. Personnel who (1) approve prerequisite and preoperational test procedures and test results and (2) direct or supervise the conduct of individual prerequisite and preoperational, tests will be qualified under the guidelines of ANSI N45.2.6-1978, rather than RG 1.8. | 43                |
| 33. | The subject RG endorses ACI-349 with exceptions as noted in the RG. Concrete structures (other than the RCB) on STP are designed in accordance with ACI-318. A discussion of the significant differences between the ACI-318 and ACI-349 Codes is provided in response to NRC Question 220.30N.   | 45                |
| 34. | This Regulatory Guide was withdrawn by the Commission on August 16, 1979 and replaced by NUREG-0554, "Single-Failure-Proof Cranes for Nuclear Power Plants." Withdrawal of this guide in no way alters any prior or existing licensing commitments based on its use.  | 23                |
| 35. | Qualification of cement and lime for soil-cement erosion protection and lime treatment of soil in safety-related applications at the UHS is verified by in-process testing performed under the Constructor's QA-Program, in lieu of a vendor furnished program.   |                   |
| 36. | Reference 6.2.5.2.4 specified Rev. 0 of RG 1.38 as it applies to the purchase of equipment during the construction phase; Rev. 2 of RG 1.38 applies to the operational phase.   | 43                |
| 37. | The STP Emergency Plan will follow the guidelines of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plan and Preparedness in Support of Nuclear Power Plants".   | 23                |
| 38. | The Operations QA Program for operations will conform to the requirements of Revision 3.  | 27C<br>26C<br>06N |
| 39. | The Operations QA Program for operations will conform to the requirements of Revision 1 of RG 1.39.   | 43                |
| 40. | STP will comply with <del>the intent of</del> RG 1.108 with the interpretations and exceptions presented in Section 8.3.1.2.10. <span style="margin-left: 20px;">Q430.109</span>  | 45C<br>43C<br>14N |
| 41. | HL&P does not plan to conduct in situ emergency sump recirculation testing (see Section 6.3.4.1 for details). The remainder of the preoperational testing program on the ECCS and its components will be conducted in accordance with Regulatory Guide 1.79.  | 29                |



TABLE 3.12-1 (Cont'd.)  
REGULATORY GUIDE MATRIX  
NOTES

- |     |   |                    |
|-----|---|--------------------|
| 70. | As stated in FSAR Section 8.3.2.2.5 the 1E DG system at STP is in compliance with RG 1.128.   | 45Q<br>43C.<br>14N |
| 71. | STP is not committed to RG 1.143. Most components of the radwaste system are housed within Category I Structures. Those components which are not housed within Category I Structures are either housed in or supplied on structures conforming to NRC BTP ETSB 11-1, Rev. 1, or their failure would not cause radiation release in excess of those considered in the accident analysis. See Section 11.2, 11.3, and 11.4. | 45                 |

*Note 2*

*STP conforms to RG 1.53 with clarifications as discussed in Section 7.1.2.7.*

430.  
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3.11.2.1 Equipment in the Applicant's Scope of Supply. Suppliers of safety-related equipment listed in Table 3.11-2 are required to qualify equipment in accordance with requirements listed in Tables 3.11-3 and 3.11-4.

The following information and requirements were specified in equipment purchase specifications.

1. Vendors have been required to submit a description of the method of qualification performed on each specified safety-related item located in the Containment and elsewhere to assure it will perform satisfactorily in the combined accident environment of temperature, pressure, humidity, chemical, and radiation doses.
2. Vendors have been required to provide evidence concerning the satisfactory behavior of proposed materials under the environmental conditions specified. Data on changes in material properties have been evaluated for adequacy.

Acceptable qualification programs, at the minimum, demonstrate the end-of-life qualification.

Qualification programs which do not demonstrate the qualification of equipment for its specified period of design life are identified with a supporting maintenance, replacement, and surveillance program. Acceptable qualification programs include prototype tests and/or analysis under conditions simulating the environmental conditions expected over the 40-year life plus the 30 days post-accident period for temperature and pressure and 180 days post-accident period for radiation in accordance with standards listed in Tables 3.11-3 and 3.11-4.

The conditions imposed for test and/or analysis include normal, abnormal, and DBA environmental conditions postulated to occur during the period of life for which the equipment is qualified.

Class 1E cables, field splices, and terminations for use on the STP meet the requirements of IEEE 383-1974 as modified by RG 1.131, ~~while operating in environments given in Table 3.11-1.~~ *with the exception of single conductor high temperature silicon insulated cables* Single conductor high temperature silicon insulated cables when used in a class 1E circuit are installed in conduit only.

### 3.11.3 Qualification Test Results

The results of qualification tests for the equipment in the applicant's scope of supply are provided in Table 3.11-5.

### 3.11.4 Loss of Ventilation

The majority of qualified equipment areas are served by safety class HVAC. These HVAC systems are designed to the single failure criteria and are supplied from the Onsite Standby Power System. Consequently, the normal environmental conditions which they provide will be maintained during all plant modes.

A small amount of qualified equipment is in areas served only by nonsafety HVAC. For these areas, the abnormal ranges of environmental conditions are based on the loss of HVAC.

3. Cooling Water System: The Essential Cooling Water (ECW) System cools the engine jacket water, lube oil, turbocharger discharge and intake air, and governor oil cooler. The ECW system is not part of the diesel generator unit.
4. Position on Paragraph C.2.e.7: Tests to verify correction will be conducted after the affected DG is declared "ready for service." The diesel and the associated systems may be operated as necessary to perform troubleshooting and verify correction of specific problems, prior to such declaration, without these operations counting as a test, for the purposes of complying with this Regulatory Guide.
5. Position on Paragraph C.2.a.(3): STP takes a partial exception to the periodic operational load testing of the standby diesel generators. STP will not perform the two hour run at the two hour rating during normal plant operation, as specified in position C.2.a.3 of this Guide. This test requirement is viewed as imposing unnecessary stresses on the machine since the maximum load required for the design basis accident loading sequence operation does not exceed the rating of the diesel generator. The type qualification test performed on an STP diesel generator proved that the STP diesel generator can operate for two hours at the two hour rating. The two hour test at the two hour rating will be performed under the preoperational program as described in Section 13.2.12.2.81. The results of this preoperational test will further demonstrate that the diesel generator and its subsystems will not exceed their respective design ratings under similar conditions. short time

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STP will run the diesel generator for 22 consecutive hours at the continuous rating of the diesel generator.

6. Position on Paragraph C.2.d: In addition to the above stated exceptions, the increased frequency of diesel testing in section C.2.d is excessive and may cause premature engine degradation. It is STP's intent to base the increase in testing frequency on the last 20 valid tests instead of the last 100 valid tests. This will reduce the RG 1.108 established reliability goal of .99 by four percentage points to .95, and will significantly reduce the rate of engine wear. The reliability goal of .95 is consistent with Generic Letter 84-15.

The criterion of first out alarm for diesel generator protection is not implemented as it does not reduce the damage to the diesel generator or the down time of the diesel generator.

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8.3.1.2.11 Compliance With RG 1.81: Safety-related electrical systems are not shared between Units 1 and 2. Therefore, the design is in compliance with RG 1.81.

8.3.1.2.12 Compliance With RG 1.106: Thermal overload units on safety-related motor operated valves are continuously bypassed under all conditions. Activation of these thermal overload units is alarmed in the control room. Since these overloads are not used for tripping, RG 1.106 is not applicable.

Question  
430.110  
(SRP 8.1)

Table 3.12-1 indicates the status of the following regulatory guides to be not applicable to STP design due to their implementation dates. Clearly identify where and how the STP design is not in accordance with the positions of these regulatory guides and justify the deviations.

Regulatory Guide 1.118, Rev. 1, dated 11/77  
Regulatory Guide 1.108, Rev. 1, dated 8/77  
Regulatory Guide 1.128, Rev. 0, dated 4/77  
Regulatory Guide 1.131, Rev. 0, dated 8/77

Response

Note 69 to Table 3.12-1 (as issued in Amendment 45) indicates STP conformance R.G. 1.118.

Note 40 to Table 3.12-1 (as issued in Amendment 45) explains, that STP will comply with R.G. 1.108 with the interpretations and exceptions presented in Section 8.3.1.2.10.

The "Status on STP" of R.G. 1.128 as shown in Table 3.12-1 was revised to "A" (conform to guide) in Amendment 45.

(See also revised response to Question 430.14N in Amendment 45.)

Note 24 to Table 3.12-1 and Section 3.11.2.2 have been revised as described in the response to Question 430.109, with regards to R.G. 1.131.



Question  
430.111  
(SRP 8.2)

Per section 8.1.4.1, two 4.16 kV ESF buses are supplied from the unit's standby transformer and the third 4.16 kV ESF bus is supplied from the unit auxiliary transformer during normal plant operation. For a reactor, turbine or generator trip, the generator circuit breaker automatically opens to maintain supply to the 4.16 kV ESF bus (the third bus) through the unit auxiliary transformer. In case the generator breaker fails to open thus tripping the switchyard breakers to isolate the unit, explain if the affected bus (third bus) will enter Mode II operation as stated in Section 8.3.1.1.4.4.2 while the other two 4.16 kV ESF buses operate with the offsite source from the standby transformer.

Response

In event of the unit generator switchyard 345KV circuit breakers opening while the unit is in operation, all power to the auxiliary distribution system connected to the unit auxiliary transformer will be lost. Undervoltage relays of the affected Class 1E 4.16 KV bus will sense the loss of voltage and initiate the ESF load sequencer to automatically implement a Mode II operation as described in Section 8.3.1.1.4.4.2.

Conformance with position 3 of PSB-1 will be provided in a future Amendment as stated in the response to question 430.20N.

Response cont'd

i) Mechanical operation test endurance is documented by Cogenel type test Report No. 1784A, dated May 1976 and Cogenel Endurance Test Report No. 314. The endurance test was performed 1/27/78 to 6/30/78.

Item 3. Offsite power is available independently of the generator breaker; manual realignment is required. (see response to Question 430,111).

Selectivity in tripping between the generator breaker and the two associate switchyard breakers is maintained in that a separate set of relays is used for each function. Only unit differentials and ground fault detection are common. The unit differential protection zone, includes the generator breaker and a short section of plant side isophase bus. Ground fault detection is provided by relaying on the generator neutral (trips generator breaker) and on the isophase bus section on the switchyard side of the generator breaker (trips switchyard). The ground fault detectors are coordinated so that the generator neutral detector operates first. The remaining relays used for switchyard relaying are directional and do not operate for a fault on the plant side of the generator breaker.

Item 4. This addresses load break switches and is not applicable to generator breakers.

Question  
430.112  
(SRP 8.2)

The use of a generator breaker to provide immediate access offsite power to a Class 1E bus requires the design to follow the guidelines provided in Appendix A to the SRP Section 8.2. STP design utilizes generator breaker to provide immediate access offsite power to one of the redundant Class 1E onsite distribution systems. Confirm that the STP design follows the guidelines for the performance and capability tests specified in section B of the reference SRP. Describe the test program with results which demonstrate the breaker's ability to perform its intended function during various modes of operation as specified in the SRP guidelines.

Response

In regard to specific guidelines of Appendix A to SRP, Section 8.2:

Item 1. The device is a circuit breaker capable of interrupting the maximum available fault current.

Item 2. STP has purchased Cogenel type PKG2C breakers. Unless noted otherwise test documents listed in a) through i) below have been performed on type PKG breakers with various voltage and current ratings.

a) Dielectric withstand strength is documented by Cogenel Type Test Report No. 1738A. The test documents comply with ANSI C37.09, but were completed prior to the issue of the 1979 version of the ANSI standard. The test report is dated 1/20/76.

b) Load current switching capability is documented by Cogenel Type Test Report No. 2090A.

c) Fault current interrupting capability is documented by Cogenel Report of Performance Test No. 291-81A.

d) The rate of rise of recovery voltage (RRRV) is specified by Cogenel to be greater than 6KV/microsecond. Justification that the system RRRV is less than circuit breaker RRRV will be provided.

e) Short term current carrying capability is documented by Cogenel Report of Performance Test No. 2283-74A. The test report is dated 4/29/74.

f) Momentary current carrying capability is documented by Cogenel Report of Performance Test No. 2945-78. The test report is dated 11/3/78.

g) The ability to interrupt magnetizing current of an unloaded station main and/or auxiliary transformer is documented by Cogenel Type Test Report No. 1720A. The test report is dated 11/24/75.

h) Thermal capability is documented by Cogenel Test Report No. HM51-02-806. The test was performed 3/15/78 to 3/17/78.

Question  
430.113  
(SRP 8.2)

Figure 8.2-3 indicates that the standby transformers No. 1 and No. 2 are supplied from the switchyard north and south buses respectively through disconnect switches which do not have fault interrupting capability. In order to isolate a fault in the standby transformers 1 or 2 or their associated cable, all the six breakers on the respective 345 KV switchyard bus will have to be automatically opened. Analyze this condition and certify that the relay coordination is so designed as not to cause, directly or indirectly, tripping of the other 345 kV bus breakers and the generator bay middle breakers which may cause loss of power to the other standby transformer and unit auxiliary transformer through the main transformer.

Response

The subject condition has been analyzed and it has been certified that the relay coordination will not trip, directly or indirectly, the south bus breakers for a fault on standby transformer #1 or other north bus faults. South bus protection is identical and likewise only the south bus breakers will trip. Generator bay middle breakers are not directly tripped for faults on the standby transformers or other bus faults, but upon failure of the generator bus breakers to properly clear the fault, the middle breaker will trip to isolate the fault. Even upon loss of the unit, however, the standby transformer is tied to the opposite bus and remains energized. By using primary and back-up systems on the bus differential control schemes, each with respective D.C. station battery power supplies and separately wired trip coils, a high level of reliability can be attained. Attached are relay wiring diagrams illustrating this point and various examples of potential faults with associated sequence of events summaries.



Question  
430.114  
(SRP 8.3.1)

IE information Notice 84-84 pointed out certain deficiencies in the connection and mounting of Ferro Resonant transformers used in Westinghouse inverters. STP design uses these inverters for vital ac instrument power. Identify corrective modification to eliminate these deficiencies.

Response

The above item has been reviewed by HL&P and the corrective action is addressed in "Final Report Concerning Vital 7.5kVA Invertor Ferro-Resonant Transformer" Letter to NRC (ST-HL-AE-1215, dated March 29, 1985). In summary the corrective action regarding the capacitor terminals will be to cutoff the fast-on terminals and solder the wire to the solder lug in accordance with W Technical Bulletin NSD-TB-84-08. The corrective action for the transformers is to test the transformers to verify that they are operating as expected, consistent with W Technical Bulletin NSD-TB-84-11.

Question

430.115

(SRP 8.3.1,  
8.3.2)

Provide additional information regarding the power sources supplied to the RHR isolation valves. The staff's position is that a single failure of a power supply should not prevent isolation of the RHR when RCS pressure exceeds the design pressure of the RHR system. Additionally, loss of a single power supply should not result in the inability to initiate at least one 100 percent RHR train.

Response

See Section 7.6.2. As indicated in that section, the two valves in each of the three RHR inlet lines are powered from different Class 1E power sources. The RCS pressure transmitters supplying pressure setpoint signals to the RHR inlet isolation valves provide signals to the valves of the associated power source. Isolation of each RHR line is ensured by the two valves in series, each receiving power and isolation signals from separate sources. Loss of a single power supply would result in the inoperability of one valve in each of two RHR trains, leaving one RHR train operable. As discussed in Sections 5.4.7.1 and 5.4.7.3, cooldown of the RCS using one RHR train is still accomplished in a reasonable time.

#### Question 040.5

Diesel generator alarms in the control room: A review of malfunction reports of diesel generators at operating nuclear plants has uncovered that in some cases the information available to the control room operator to indicate the operational status of the diesel generator may be imprecise and could lead to misinterpretation. This can be caused by the sharing of a single annunciator station to alarm conditions that render a diesel generator unable to respond to an automatic emergency start signal and to also alarm abnormal, but not disabling, conditions. Another cause can be the use of wording of an annunciator window that does not specifically say that a diesel generator is inoperable (i.e., unable at the time to respond to an automatic emergency start signal) when in fact it is inoperable for that purpose.

Provide the alarm and control circuitry logic for the diesel generators at your facility to determine how each condition that renders a diesel generator unable to respond to an automatic emergency start signal is alarmed in the control room. These conditions include not only the trips that lock out the diesel-generator start and require manual reset, but also control switch or mode switch positions that block automatic start, loss of control voltage, insufficient starting air pressure or battery voltage, etc. This review should consider all aspects of possible diesel generator operational condition for example text conditions and operation from local control stations. One area of particular concern is the unreset conditions following a manual stop at the location station which terminates a diesel generator test and prior to resetting the diesel generator controls for enabling subsequent automatic operation.

Provide the details of your evaluation, the results and conclusions, and a tabulation of the following information:

1. All conditions that render the diesel generator incapable of responding to an automatic emergency start signal for each operating mode as discussed above;
2. The wording on the annunciator window in the control room that is alarmed for each of the conditions identified in (1);
3. Any other alarm signals not included in (1) above that also cause the same annunciator to alarm;
4. Any condition that renders the diesel generator incapable of responding to an automatic emergency start signal which is not alarmed in the control room; and
5. Any proposed modifications resulting from this evaluation.

## Response

Figure 8.3-4 (sheet 1) shows the standby diesel generator (DG) logic, including alarm circuitry and local operation capability, and includes all operating modes for the standby DG. The ESF status monitoring system provides the operator with diesel generator bypass or inoperable status information in the control room. The ESF Status Monitoring System is described in Section 7.5.4. Other systems also provide status information to the operator, e.g. indicators, annunciators and computer alarms. However, the ESF Status Monitoring System is the specifically identified system for provision of bypass or inoperable status. This separation of functions eliminates one source of misinterpretation by the operators.

The specific information requested is provided as follows:

1. The following conditions render the diesel generator incapable of responding to an automatic emergency start signal for all operating modes:
  - a. Engine overspeed lockout not reset
  - b. Generator differential lockout not reset
  - c. Loss of control power
  - d. Mode selector switch not in "remote" position
  - e. Emergency stop push button not reset.
  - f. Loss of starting air pressure or starting system malfunction.
  - g. Start circuit inoperable.
2. Each of the conditions identified in (1) is alarmed through the ESF Status Monitoring System. The wording on the windows in the control room is:
  - a. OVER SP LCKOUT
  - b. GEN DIFF LCKOUT
  - c. LOSS DG CONT PWR
  - d. MODE SEL SW NOT RMT POS
  - e. EMERG STOP NOT RESET
  - f. LOSS STRT AIR
  - g. STRT CKT INOP



Response cont'd

3. No other signals cause the standby DG-related ESF Status Monitoring System windows to light.
4. No other standby DG conditions (anticipated more than once per year) could render the DG incapable of responding to an emergency start signal. Manual bypass or operable status indication may be initiated for conditions occurring infrequently (less than once per year). Electrical power distribution bypass or inoperable conditions, support systems (cooling water and HVAC) bypass or inoperable status conditions and ESF load sequencer bypass or inoperable conditions are alarmed using ESF Status Monitoring windows in the same group of windows. (As indicated in Section 7.5.4, lighting of a component-level bypass/inop window also results signal lighting of the system-level bypass/inop window.)
5. No modifications are required.

Question  
430.116  
SRP 8.3.1)

Section 6.4.2 of IEEE Standard 387-1977 requires, in part, that the load acceptance test consider the potential effects on load acceptance after prolonged no load or light load operation of the diesel generator. Provide the results of load acceptance tests or analysis that demonstrates the capability of the diesel generator to accept the design accident load sequence after prolonged no load operation. This capability should be demonstrated over the full range of ambient air temperatures that may exist at the diesel engine air intake. If this capability cannot be demonstrated for minimum ambient air temperature conditions, describe design provision that will assure an acceptable engine air intake temperature during no load operation.

Response

The diesel generator specification requires that the diesel generator be capable of running at no load for one hour without deterioration of the engine, generator or auxiliaries. In order to enhance the diesel generator availability, the manufacturer recommends that for each six hours of cumulative no load operation, the diesel generator should be run at least one hour at 50% or greater load. This is accomplished by manually synchronizing the diesel generator with the offsite power supply and loading to the desired point.

Station operating procedures will be provided to assure that after a six hour cumulative no load and/or light load (less than 50% rating) operation, a diesel generator will be operated at a minimum of 50% load for one hour per the manufacturer's recommendations.

Response to question 430.102 describes effect of ambient air temperature variations on the diesel generator's capability to carry full load.

Question  
430.118  
(SRP 8.3.1)

Provide the results of a reliability analysis for the solid state load sequencer that demonstrates that overall reliability or capability of the onsite power system to supply power to safety loads on demand has not been significantly reduced by the use of solid state load sequencers.

Response

The reliability analysis for the solid state ESF load sequencer is currently under review. It is anticipated that the approved analysis will be available by August 30, 1985.

Question  
430.119  
(SRP 8.3.2)

From the statement on battery capacity in section 8.3.2.1.2 of the FSAR it is implied that power will be available to dc system loads for at least two hours in the event of loss of all ac power. After two hours you have assumed that ac power is either restored or that the emergency generators are available to energize the battery chargers. Based on the staff's review of recent applications, this period for restoration of ac power appears to be too short. Provide the basis and operational experience data for the assumption that ac power can be restored within two hours.

Emergency procedures and training requirements for station blackout events are described in generic letter 81-04. Provide a statement of compliance with these generic requirements.

Response

It was not the intent in Section 8.3.2.1.1 to refer to a blackout. This Section has been revised to delete the word "all" to read: "The batteries are sized to carry their connected ESF loads for two hours without power flow from the chargers in the event of loss of ac power".

Plant specific procedure 1POP05-E0-EC00 - "Loss of All AC Power" was developed from the Westinghouse Owners Group (WOG) Emergency Response Guide line ECA - 0.0, "Loss of All AC Power". Reenergization of specific equipment, as required, is covered in other emergency operating procedures (1POP05 series). Operations training for all emergency procedures, including procedure 1POP05-E0-EC00, is scheduled for the first quarter of 1986. The South Texas Project is in compliance with Generic Letter 81-04.



Question  
430.121  
(SRP 8.3.1

The voltage levels at the safety-related loads should be optimized for the maximum and minimum load conditions that Appendix 8A) are expected throughout the anticipated range of voltage variations of the offsite power sources. Perform a voltage analysis and verification by actual measurement in accordance with the guidelines of positions 3 and 4 of branch technical position PSB-1 (NUREG-0800, Appendix 8A). Provide the voltage at the terminals of each Class 1E load as determined by analysis and by actual measurement for all modes of plant operation. Verify that all Class 1E loads will operate at or within design voltage limits under all condition of operation. Where terminal voltage determined by analysis is not adequate to meet the design voltage rating of the equipment, provide justification.

Response

As stated in the response to question 430.20N, the STP design will comply with the requirement for undervoltage protection for Class 1E buses (PSB-1). We are presently performing a voltage study including analysis of worst case conditions and conformance with PSB-1 position 3 will be provided in a future Amendment. Conformance to PSB-1 position 4 will be provided when station loading is equivalent to 30 percent.

Question  
430.122  
(SRP 8.3.1  
Appendix 8A)

Section 8.4.1.1.4.5 of the FSAR describes the surveillance instrumentation provided to monitor the status of the diesel generator. Expand the FSAR to describe how the STP design complies with the guidelines of branch technical position PSB-2 (NUREG-0800 Appendix 8A) and provide justification for any deviations.

Response

Section 8.3.1.1.4.5 will be revised to more clearly indicate what conditions are alarmed through the bypass/inoperative windows of the ESF Status Monitoring System. This monitoring system is described in Section 7.5.4.

As can be seen in these sections, STP complies with the guidelines of Branch Technical Position PSB-2.

The manual sequences for reconnecting other loads are shown in Table 8.3-3 and Figure 8.3-4.

Simulated testing of Mode III in Section 8.3.1.1.4.7(3).

8.3.1.1.4.5 Instrumentation and Control - Automatic and manual control of each of the standby DGs and the ESF equipment requiring automatic sequencing is provided. Controls for safety-related equipment are generally provided in the control room as well as at equipment locations. Redundant control circuitry and control power sources are compatible with their associated power circuits.

Instrumentation is provided to manually synchronize each standby DG with the ESF bus and to continuously monitor the status of the safety-related systems. Control power for the standby DG systems is obtained from the associated ESF 125 vdc systems. The status of each standby DG is indicated ~~and/or alarmed in~~ in the control room, including the following parameters; ~~and conditions:~~

1. Voltage, current, power, and frequency
2. Breaker position of each bus supply and feeder breaker
3. ~~Starting status and off-normal status~~

- 3 ~~4~~. Cooling water pressure and temperature, lube oil pressure and temperature, starting air pressure, fuel level, and engine rpm

add  
INSERT  
A →

AC control power for vital instrumentation and controls is supplied by six solid-state inverter/rectifier systems. The inverter/rectifiers are connected as shown on Figure 8.3-3. The inverter/rectifiers supplying power to instrumentation channels I and II are normally energized by 480 vac feeders from separate MCCs connected to different bus sections of the Train A, 480 vac switchgear. The inverters/rectifiers supplying power to channels III and IV are normally energized by 480 vac feeders from MCCs connected to the 480 vac switchgear in Trains B and C, respectively. Upon loss of power from the 480 vac feeds, the inverter/rectifiers are automatically powered from the Class 1E DC system. The output of the inverter/rectifier is 118 vac, single phase, 60 Hz. Vital AC power from the inverter/rectifier is distributed by the instrumentation power supply buses, which consist of Class 1E distribution panel boards. Manually operated, mechanically interlocked main circuit breakers in each distribution panel permit energization of the bus either by the corresponding inverter/rectifier or by an alternate 120 vac, single-phase, regulated, backup source, as shown on Figure 8.3-3.

8.3.1.1.4.6 Onsite Standby Power Supply System Protection - The onsite standby power system is provided with protective devices to:

Isolate faulted equipment and circuits from unfaulted equipment and circuits

Prevent damage to equipment

## INSERT 'A'

The bypass or inoperability status of each standby DG is automatically indicated in the control room through the ESF Status Monitoring System described in Section 7.5.4.

through this system

The conditions alarmed are the following:

1. DG not in remote mode
2. Loss of starting air/starting air system malfunction
3. Loss of control power
4. Start circuit inoperable
5. Emergency stop pushbutton not reset
6. Overspeed lockout not reset
7. Generator differential lockout not reset

Inoperability of the standby DGs may also be manually indicated through the Status Monitoring System. These conditions each have their own alarm windows.

These signals to the <sup>ESF</sup> Status Monitoring System, as well as other annunciator and computer alarms for various DG conditions, are shown on Figure 8.3-4 (Sheet 1).

The standby DG monitoring complies with the guidelines of Branch Technical Position PSB-2.

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122



1. Visual indication (though lampbox lights) that specific ESF equipment has been bypassed or deliberately rendered inoperable during normal plant operating modes.
2. Annunciation to alert the operator that an ESF system or any of its support systems has been bypassed or deliberately rendered inoperable during normal plant operating modes.

The bypass/inoperable status indication subsystem continuously monitors the status of field contacts and automatically indicates that a specific piece of ESF equipment has been bypassed or deliberately rendered inoperable. The following conditions (as applicable) are automatically detected for each monitored component of the ESF systems:

1. Loss of control power
2. Control handswitch in pull-to-lock position
3. Circuit breaker not in operating position
4. Control transferred from the control room to a remote panel
5. Component not in its proper aligned position

The bypass/inoperable status indication is accomplished by lighting up the component level window. This indication also provides individual system level annunciation to alert the control room operator that an ESF system has been bypassed or rendered inoperable.

In accordance with RG 1.47, bypass or inoperable status indication is provided automatically for conditions which meet all three of the following guidelines:

1. The bypass or inoperable condition affects a system that is designed to automatically perform a safety-related function.
2. The bypass is utilized by plant personnel or the inoperable condition can reasonably be expected to occur more frequently than once per year and,
3. The bypass or inoperable condition is expected to occur when the affected system is normally required to be operable.

Deliberate manual actions which render ESF actuated components and devices inoperable (once a year or more frequently) are automatically displayed on a component level. Active components not directly actuated by ESF signal but rendered inoperative once a year or more frequently such that it compromises the safety functions of the ESF system are also automatically displayed on a component level to the control room operator.

Rendering a piece of ESF equipment inoperative through the use of features provided strictly for infrequent maintenance (less than once a year) is not automatically indicated. Such maintenance features may include manual valves provided for isolation of the equipment for repair and electrical cable connections, screw terminals or manual disconnects. The bypass/inoperable indication of these conditions is manually initiated on an ESF system level.

(within the  
ESF Status  
Monitoring  
System)

41

Question  
430.123  
(SRP 8.3.1)

Table 8.3-3 of the FSAR shows step 1 load to be 0 kW as this step only energizes the load center transformers. However, the total running load of step 2 as shown on page 8.3-43 is significantly less than the total step 2 loads shown on page 8.3-42. Explain the difference and confirm that the diesel generator is sized for the correct values of loads applied automatically in various loading steps and also all the manually applied loads to the diesel generator.

Response

There is no conflict in loading steps as delimited in note "e" of Table 8.3-3 as stated: "The HP valve shown represents a summation of all the MOVs connected to the diesel generator and this load is assumed to be intermittent. Therefore, it is not being added in the next step." The MOV loads on page 8.3-42 (step 2) are not included on page 8.3-43 (step 3), since the valves do not require continued power after their appropriate action is completed.

The diesel generator is sized for the correct values of loads which are applied automatically in various loading steps and also for all of the manually applied loads.

This fact is verified by a transient voltage response analysis of the diesel generator units (by Generator Manufacturer) to step loads indicated in Table 8.3-3.

Question  
430.125  
(SRP 8.3.1)

In section 8.3.1.4.4.8(2) of the FSAR the following is stated.

Where the safety related pipe failure requires protective action, Class 1E conduits and trays are not routed through the area except those which must terminate at devices or loads within the area.

Identify the FSAR section or provide a statement with design configuration which explains how the sections of these raceways, devices and loads are protected from the consequences of the pipe failure in the subject areas.

Response

Section 8.3.1.4.4.8 has been revised as follows:

Separation Criteria for Pipe Failure Hazard Areas - Separation of conduit and cable trays from pipe failure hazards in areas is accomplished by the use of barriers, restraints, separation distance or the appropriate combination thereof. Where it is not possible to prevent damage to a Class 1E raceway in the event of a pipe failure, an analysis is performed to assure that safe shutdown capability is maintained. The protective mechanisms provided for pipe failure are further discussed in Sections 3.6.1.3.2 and 3.6.2.4.

The following raceways are considered totally enclosed raceways:

Rigid steel conduit

Aluminum sheathed cable and copper sheathed cable

Enclosed metal wireways (gutters)

Flexible metal conduit (*seamless*)

Ventilated ~~and~~ steel cable trays with solid steel covers installed at top and bottom of tray

Solid bottom tray with solid steel covers

8.3.1.4.4.8 Separation Criteria for Pipe Failure Hazard Areas - Separation of conduit and cable trays from pipe failure hazard areas is accomplished ~~where possible~~ by the use of barriers, restraints, separation distance, or the appropriate combination thereof. ~~Where this separation is not practical, the routing of Class 1E conduit and trays in pipe failure hazard areas conforms to the following requirements unless it can be demonstrated that a pipe failure cannot prevent the Class 1E circuits from performing their protective function:~~

1. ~~Where the safety-related piping involved is not assignable to a single division, and the pipe failure requires no protective action, Class 1E conduit and trays routed through the area are limited to a single division.~~
2. ~~Where the safety-related pipe failure requires protective action, Class 1E conduit and trays are not routed through the area except those which must terminate at devices or loads within the area.~~
2. ~~Where the safety-related piping is assignable to a single division but the pipe failure does not require protective action, Class 1E conduit and trays routed through the area are limited to the same division as the piping.~~

8.3.1.4.4.9 Separation Criteria for Missile Hazard Areas - Separation of conduit and cable trays from missile hazard areas is accomplished where possible by the use of barriers, orientation, separation distance, or the appropriate combination thereof. Where this separation is not practical, the routing of Class 1E conduit and trays through the ~~same~~ area conforms to the following requirements:

1. Where the ~~safety-related~~ missile source involved is not assignable to a single division, and the failure causing the missile does not require protective action, Class 1E conduit and trays <sup>in all</sup> through the area are limited to a single division.
2. Where the failure of the ~~safety-related~~ missile source involved requires protective action, Class 1E conduit and trays are not routed through the area except for those which must terminate at devices or loads within the area.

36  
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Q40.4



Insert A for page 8.3-27:

where it is not possible to prevent damage to a class 1E raceway in the event of a pipe failure, an analysis is performed to assure that safe shutdown capability is maintained. The protective mechanisms provided for pipe failure are further discussed in Sections 3.6.1.3.2 and 3.6.2.4.

Q430.125

Question  
430.127  
(SRP 8.3.1)

In section 8.3.1.1.4.2.(5), it is stated that the diesel generator units are subjected to the qualification program outlined in HL&P letter dated September 29, 1976 which is in accordance with NRC Branch Technical Position BTP-ICSB-2. However, the subject BTP has been superseded by IEEE-387 since 1981. This IEEE standard is included in Table 8.1-2 of the FSAR as applicable criteria for the diesel generator units. Confirm that the qualification test program in STP design follows section 6.3 of IEEE-387. The FSAR section 8.3.1.1.4.2.5.2 indicates start and load acceptance test to follow BTP-ICSB-2 guidelines for loading values and not that of IEEE-387 section 6.3.2(2). Identify compliance or exemption to each subsection of section 6.3 of IEEE-387-1977 with justification.

Response

The last paragraph following section 8.3.1.1.4.2.(5) has been replaced with the following:

"The DG units are subjected to a qualification program in accordance with R.G.1.9 and IEEE 387-1977."

Question  
430.128  
(SRP 8.3.1)

ESF load sequencer drawing (5Z-10-9-Z-42117) indicates incoming breakers to 480 volt bus E1A1 and E1A2 are stripped in Mode II and also in Mode III for an emergency trip of the diesel generator and are resequenced for both modes. The logic does not show individual 480 volt and 120 volt loads stripped and sequenced. For this design, when the incoming breakers to 480 volt buses E1A1 and E1A2 close when sequenced, all their loads will be energized simultaneously. Confirm that this transient will not cause starting problems to Class 1E loads and all equipment will be energized without being overstressed. Substantiate your answer with the analysis results.

Response

The ESF Load Sequencer Actuations Train A Logic Diagram Fig. 8.3-4 sheet 2 (9-Z-42117) indicates that in the event that a LOOP condition is recognized, the 460V RHR pump, 460V RCFC Fans the 460V EAB HVAC supply air to 480V Pressurizer Heater Group, and 460V Essential Chiller are stripped from the Load Center Buses E1A1 and E1A2 and the Load Center 480V incoming breakers are opened. Upon closing of the Load Center incoming breakers in Load Sequence Step 2, approximately 920 Load KVA (3375 Starting KVA) is energized on the 480V and 120V distribution systems. The diesel generator transient voltage response analysis shows that the calculated 4.16 KV voltage dip is less than 11 percent for less than a third of a second at the generator terminals. It should be noted that if required, the generator voltage regulator can be set to provide a generator output voltage as high as 4160 V plus 10 percent. The results of the diesel generator transient voltage response analysis will be expanded to verify that voltages at the Class 1E loads are above the minimum voltage rating for satisfactory operation.

Question  
430.129  
(SRP 8.3.1)

STP drawing no. 5Z-10-9-Z-42117 indicates five seconds, four seconds and one second time delays in bus strip signal for various conditions. Explain the basic reason for each of these time delays. If the five seconds time delay for Mode III is interlocked as permissive with diesel generator breakers closure logic (reference drawing 5Z-10-9-Z-42121 and STP letter to NRC dated June 25, 1984), then explain why the load stripping is also delayed for five seconds. From the STP's referenced letter, we understood that the five second time delay in the diesel generator breaker closure was after the load stripping had taken place and was not to delay the load stripping also for five seconds.

#### Response

The load stripping is not delayed. Figure 8.3-4 sheet 2 (STP drawing 5Z-10-9-Z-42117) shows that the bus strip signals are pulse signals maintained for a duration of five seconds or one second (not delayed). The Mode II (or Mode III) signal is initially not present, satisfying only one-half of the 'AND' gate. When the Mode II (or Mode III) signal is generated the 'AND' gate is satisfied and the bus strip signal(s) generated. When the TDDO (time delay drop out) times out, the 'AND' gate is no longer satisfied, thus removing the bus strip signal and allowing reclosure of the indicated breakers. Thus the bus strip signals are pulsed, rather than delayed, for the times shown.

The bus strip signal pulse for five seconds (after a Mode III condition) ensures that the DG feeder breaker is not allowed to close (see Figure 8.3-4, sheet 3) until the closure springs for the first load breaker have recharged. The bus strip signal pulse for one second (after a Mode II condition) provides a positive strip signal to ensure that breakers are tripped before a closure signal is sent.

The second bus strip signal pulse for one second (after a coincident LOOP and DG emergency trip following closure of the DG breaker) provides a positive strip signal to ensure that breakers are tripped following a DG emergency trip after its breaker was closed following a LOOP. Follow-up after a DG emergency trip must be made by the operator; this strip signal ensures that loads have been stripped from the bus. The four second TDDO is provided to give positive input to the bus strip signal just described.

Section 8.3.1.1.4.4.3 has been revised to provide a description of the various entries to Mode III and the automatic features provided for each entry.



Question  
430.130  
(SRP 8.3.1)

Section 8.3.1.2.12 of the FSAR states that the thermal overload units on safety related MOV's are continuously bypassed under all conditions. This design meets the requirement of Regulatory Guide 1.106 position 1 except where it is not stated that these thermal overload units are temporarily placed in force when the valve motors are undergoing periodic or maintenance testing. Revise FSAR or provide justification. Also provide correction in this section of the FSAR and Table 3.12-1 where it states that Regulatory Guide 1.106 is not applicable to STP design since the overloads are not used for tripping.

Response

The STP design meets R.G. 1.106 with regard to safety related MOVs, that is to avoid unnecessary tripping of MOVs.

Thermal overload units for safety related MOVs on STP are not used to trip/stop the MOV, but their activation is alarmed in the control room. No overload protection is provided during normal or safety related operation of the MOVs as they are permanently bypassed. Regulatory Guide 1.106 does not address the circuit configuration as used on STP.

TABLE 3.12-1 (CONT'D)

## REGULATORY GUIDE MATRIX

NO.	REGULATORY GUIDE TITLE	PSAR REFERENCE	REVISION STATUS	STATUS ON STP	
1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident	Table 7.1-1 Figure 7.1-1 7.5 7.5.1 Table 7.5-1 App. 7A App. 7B	Rev 2 (8/77)	B See Note 3 and 64	40 43
1.98	Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Offgas System Failure in a Boiling Water Reactor			NA See Note 1	
1.99	Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials	5.3.2.1	Rev 1 (4/77)	D See Note 57	33
1.100	Seismic Qualification of Electric Equipment for Nuclear Power Plants	Table 7.1-1 Figure 7.1-1 3.10.1 3.10.2.2 3.10.2.2.1 3.10.2.2.2.2 3.10.4.1	Rev 1 (8/77)	B See Note 3	36 43
1.101	Emergency Planning for Nuclear Power Plants	9.5.1.A pg 18	Withdrawn	See Note 37	32
1.102	Flood Protection for Nuclear Power Plants	3.4 3.8.4.2.3	Rev 1 (9/76)	A	33
1.103	Post-Tensioned Prestressing Systems for Concrete Reactor Vessels and Containments	3.8.1.2.2 3.8.1.6.5.1	Rev 1 (10/76)	A	45
1.104	Overhead Crane Handling Systems for Nuclear Power Plants	9.1.4.3.1.6 Table 9.1-3	Rev 0 (2/76) PC	B See Note 34	23
1.105	Instrument Setpoints	Table 7.1-1 Figure 7.1-1	Rev 1 (11/76)	B See Note 3, Note 28	33
1.106	Thermal Overload Protection for Electric Motors on Motor-operated Valves	8.3.1.2.12 8.3.2.2.7	Rev 1 (3/77)	A <del>NA</del> See Note 14	38   2430.130
1.107	Qualifications for Cement Grouting for Prestressing Tendons in Containment Structures			NA See Note 11	23
1.108	Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Power Plants	8.3.1.1.4.7 8.3.1.2.10	Rev 1 (8-77)	C See Note 40	38
1.109	Calculations of Annual Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10CFR50, Appendix I	11.A.1 12.4.2	Rev 0 (3/76) PC Rev 1 (10/77)	A	32

STP PSAR

# STP FSAR

TABLE 3.12-1 (Cont'd.)  
REGULATORY GUIDE MATRIX  
NOTES

1. Guide is applicable only to BWRs.
2. Guide is not applicable to STP due to implementation date.
3. STP compliance status is indicated, but the guide is not applicable to STP due to implementation date.
4. Pre-spin inspections are considered to be adequate, and post-spin inspection is not performed. RG 1.14 definition of "Excessive Deformation" is not applicable to Westinghouse design. Specification of cross tolling-ratio is unnecessary. Vacuum melting and degassing process or the electro-slag process are not essential to meet balance of RG 1.14 requirements. 38
5. STP is in compliance with Rev 2 except for meteorological analysis which is in compliance with Rev 1.
6. The PSAR commitment to Rev 1 has been modified to a commitment to Rev 2 as noted in the August 25, 1977 letter to the NRC.
7. Deleted 36
8. Guide is not applicable since STP does not have a spray pond.
9. RG 1.80 has been withdrawn by the NRC. The regulatory position is now considered to be covered by RG 1.68.3, "Preoperational Testing of Instrument and Control Air Systems." The STP position on RG 1.68.3 will be provided consistent with final development of FSAR Section 14.2 scheduled for mid 1984. 33
10. Following plant retirement, STP will be decommissioned in accordance with applicable laws and regulations.
11. STP Containment does not use grouted tendons.
12. There is no chlorine storage onsite or in the vicinity of STP.
13. RG 1.136 was issued to incorporate the requirements of RGs 1.10, 1.15, 1.18, and 1.19. STP maintains its commitments to RGs 1.10, 1.15, 1.18, and 1.19 as delineated in Table 3.12-1 and the referenced FSAR Sections. Therefore a commitment to this guide is not necessary. 45
14. ~~RG 1.106 is not applicable for Class 1E motor operated valves, since thermal overloads are not used for trips at STP. Non 1E motor operated valves are treated on a case by case basis.~~  
for class 1E motors trip/stop  
alarmed only and are 430.  
130
15. STP does not use cement grouting.

3. Cooling Water System: The Essential Cooling Water (ECW) System cools the engine jacket water, lube oil, turbocharger discharge and intake air, and governor oil cooler. The ECW system is not part of the diesel generator unit.

4. Position on Paragraph C.2.e.7: Tests to verify correction will be conducted after the affected DG is declared "ready for service." The diesel and the associated systems may be operated as necessary to perform troubleshooting and verify correction of specific problems, prior to such declaration, without these operations counting as a test, for the purposes of complying with this Regulatory Guide.

5. Position on Paragraph C.2.a.(3): STP takes a partial exception to the periodic operational load testing of the standby diesel generators. STP will not perform the two hour run at the two hour rating during normal plant operation, as specified in position C.2.a.3 of this Guide. This test requirement is viewed as imposing unnecessary stresses on the machine since the maximum load required for the design basis accident loading sequence operation does not exceed the rating of the diesel generator. The type qualification test performed on an STP diesel generator proved that the STP diesel generator can operate for two hours at the two hour rating. The two hour test at the two hour rating will be performed under the preoperational program as described in Section 13.2.12.2.81. The results of this preoperational test will further demonstrate that the diesel generator and its subsystems will not exceed their respective design ratings under similar conditions.

STP will run the diesel generator for 22 consecutive hours at the continuous rating of the diesel generator.

6. Position on Paragraph C.2.d: In addition to the above stated exceptions, the increased frequency of diesel testing in section C.2.d is excessive and may cause premature engine degradation. It is STP's intent to base the increase in testing frequency on the last 20 valid tests instead of the last 100 valid tests. This will reduce the RG 1.108 established reliability goal of .99 by four percentage points to .95, and will significantly reduce the rate of engine wear. The reliability goal of .95 is consistent with Generic Letter 84-15.

The criterion of first out alarm for diesel generator protection is not implemented as it does not reduce the damage to the diesel generator or the down time of the diesel generator.

8.3.1.2.11 Compliance With RG 1.81: Safety-related electrical systems are not shared between Units 1 and 2. Therefore, the design is in compliance with RG 1.81.

8.3.1.2.12 Compliance With RG 1.106: Thermal overload units on safety-related motor operated valves are ~~continuously bypassed~~ under all conditions. Activation of these thermal overload units is alarmed in the control room. ~~Since these overloads are not used for tripping, RG 1.106, is not applicable.~~

↑ which

used to provide  
alarm only

↑ is not covered by



Question  
430.131  
(SRP 8.3.1)

FSAR section 8.3.2.1.3 includes various alarms, indications and meters for the status of various components in the 125 Vdc, Class 1E battery system. This section, however, does not include "Battery High Discharge Rate" alarm. In the absence of this alarm, the control room operator will only know of a discharging battery when he periodically checks the battery current indicator or when the battery has sufficiently been discharged to trip the undervoltage alarm. It is, therefore, a good engineering practice to provide a battery high discharge rate alarm and not take the risk of a partial discharge of the battery before the operator is alerted of this condition. We believe that STP design should include this alarm or justify its omission.

Response

Under normal operating conditions the battery is on float charge and the battery chargers supply all required power to the dc distribution switchboard. Any current flow from the battery to the dc distribution switchboard discharges the battery. This current flow is indicated on a meter in the control room. In addition it is alarmed in the control room at a preset level via the Emergency Response Facility Data Acquisition Display System (ERFDADS) computer. This alarm alerts the operator to the battery discharging condition.

Question  
430.132  
(SRP 8.3.1)

The TMI action plan requires the pressurizer level indication instruments to be powered from the vital instrument bus. STP response to NRC question 430.34N states "the pressurizer level indication instrumentation and their associated buses are Class 1E qualified and fed from Class 1E buses." Confirm that the supply source for these instruments are vital instrument buses that are fed from Class 1E inverters.

Response

The response to Q430.34N has been revised to refer to Appendix 7A for the STP positions on NUREG-0737, Items II.E.3.1 and II.G.1. The STP position on Item II.G.1, now presented in Appendix 7A, has been revised to clarify that the pressurizer level instruments power sources are the Class 1E vital instrument buses that are fed from Class 1E inverters.

Question 430.34N

Provide a detailed description, including drawing on how the requirements of NUREG-0737 (clarification of TMI Action Plan Requirements) section II.E.3.1 (Emergency Power Supply for Pressurizer Heaters) (enclosed) and II.G.1 (Emergency Power for Pressurizer Equipment) (enclosed) are met.

II.E.3.1 EMERGENCY POWER SUPPLY FOR PRESSURIZER HEATERSPosition

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

- (1) The pressurizer heater power supply design shall provide the capability to supply, from either the offsite power source or the emergency power source (when offsite power is not available), a predetermined number of pressurizer heaters and associated controls necessary to establish and maintain natural circulation at hot standby conditions. The required heaters and their controls shall be connected to the emergency buses in a manner that will provide redundant power supply capability.
- (2) Procedures and training shall be established to make the operator aware of when and how the required pressurizer heaters shall be connected to the emergency buses. If required, the procedures shall identify under what conditions selected emergency loads can be shed from the emergency power source to provide sufficient capacity for the connection of the pressurizer heaters.
- (3) The time required to accomplish the connection of the preselected pressurizer heater to the emergency buses shall be consistent with the timely initiation and maintenance of natural circulation conditions.
- (4) Pressurizer heater motive and control power interfaces with the emergency buses shall be accomplished through devices that have been qualified in accordance with safety-grade requirements.

Clarification

- (1) Redundant heater capacity must be provided, and each redundant heater or group of heaters should have access to only one Class 1E division power supply.
- (2) The number of heaters required to have access to each emergency power source is that number required to maintain natural circulation in the hot standby condition.
- (3) The power sources need not necessarily have the capacity to provide power to the heaters concurrently with the loads required for loss-of-coolant accident.

Question (Continued)

- (4) Any changeover of the heaters from normal offsite power to emergency onsite power is to be accomplished manually in the control room.
- (5) In establishing procedures to manually load the pressurizer heaters onto the emergency power sources, careful consideration must be given to:
  - (a) which (ESF) loads may be appropriately shed for a given situation;
  - (b) reset of the safety injection actuation signal to permit the operation of the heaters; and
  - (c) instrumentation and criteria for operator use to prevent overloading a diesel generator.
- (6) The class 1E interfaces for main power and control power are to be protected by safety-grade circuit breakers (see also Regulatory Guide 1.75).
- (7) Being non-Class 1E loads, the pressurizer heaters must be automatically shed from the emergency power sources upon the occurrence of a safety injection actuation signal (see item 5.b. above).

Documentation Required

The applicant shall provide sufficient documentation to support a reasonable assurance finding by the NRC that each of the subparts of the position stated above are met. The documentation should include as a minimum, supporting information including system design description, logic diagrams, electrical schematic, test procedures, and technical specifications.

Technical Specification Changes Required

Changes to technical specifications (if any) should be submitted as part of this response.

II.G.1 EMERGENCY POWER FOR PRESSURIZER EQUIPMENTPosition

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10 CFR Part 50 for the event of loss-of-offsite power, the following positions shall be implemented:

Power Supply for Pressurizer Relief and Block Valves and Pressurizer Level Indicators

- (1) Motive and control components of the power-operated relief valves (PORV) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.



Question (Continued)

- (2) Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.
- (3) Motive and control power connections to the emergency buses for the PORVs and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.
- (4) The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

Clarification

- (1) Although the primary concern resulting from lessons learned from the accident at TMI is that the PORV block valves must be closable, the design should retain, to the extent practical, the capability to also open these valves.
- (2) The motive and control power for the block-valve should be supplied from an emergency power bus different from the source supplying the PORV.
- (3) Any changeover of the PORV and block-valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room.
- (4) For those designs in which instrument air is needed for operation, the electrical power supply should be required to have the capability to be manually connected to the emergency power sources.

Documentation Required

The applicant shall provide sufficient documentation to support a reasonable assurance finding by the NRC that each of the positions stated above are met. The documentation should include, as a minimum, supporting information including system design description, logic diagrams, electrical schematics, test procedures, and technical specifications.

Technical Specification Changes Required

Changes to technical specifications (if any) should be submitted as part of this response.

*STP*  
The positions on NUREG-0737, Sections II.E.3.1 and II.G.1, are provided in Appendix 7A.

Response

The following are in response to the identically identified and numbered questions.

## II.E.3.1

Position

- (1) As stated in Section 8.3.1.1.4.1.1, two banks of pressurizer heaters are independently supplied from separate Class 1E systems, one from ESF Train A and one from ESF Train C. All loads connected to the Class 1E system have the capability of being supplied from the offsite power source and the (i.e., standby diesel generator (DG)) power source. The control circuits for these two heater banks are supplied from independent Class 1E DC systems. Only one set of heaters is required to maintain natural circulation at hot standby conditions.
- (2) As indicated in Table 8.3-3, these pressurizer heaters are capable of being manually loaded on the standby DG during LOOP. It is not necessary to shed load to connect these heaters to the standby DG. These heaters can be manually controlled from the Main Control Board or the Auxiliary Shutdown Panel. Procedures and training will include the operation of these heaters.
- (3) The pressurizer heaters can be manually energized within 55 seconds after LOOP if a safety injection (SI) signal is not present. (SI must be reset before the heaters can be energized.) This ensures the capability for maintenance of natural circulation. 36
- (4) The pressurizer heater power and control system power interfaces within the emergency buses are accomplished through isolation devices qualified as Class 1E.

Clarification

- (1) Each of the two pressurizer heater banks has access to only one Class 1E Train.
- (2) Either redundant bank of heaters will maintain natural circulation.
- (3) These heaters are not required during Loss-of-Coolant Accident (LOCA or Main Steam Line Break (MSLB) conditions. Under administrative control, each standby diesel generator (DG) has capacity to supply the necessary pressurizer heaters concurrently with LOOP loads.
- (4) These heaters are powered from ESF buses. Therefore, no manual change over from normal offsite to on-site power is required. The heaters are to be manually loaded on the Engineered Safety Feature (ESF) buses. The heaters are not automatically sequenced on and the SI signal must be reset before the heaters can be loaded on the ESF buses.
- (5) (a) Load shedding is not required. Each standby DG has the capacity to supply the necessary pressurizer heaters concurrently with LOOP loads (LOCA/MSLB loads not present).

Response (Continued)

- (b) Procedures will be established for resetting the SI signal. The SI signal must be reset to energize these heaters.
- (c) Not applicable, see Clarification (3) above.
- (6) The power and control circuits for these pressurizer heaters are from Class 1E load centers E1A and E1C (MCCs 1A5 and 1C5). Isolation devices are qualified as Class 1E devices.
- (7) As stated in Section 8.3.1.1.4.1.1 these heaters are disconnected in the presence of a SI signal.

Documentation Required

System descriptions, and testing are discussed in Section 8.3. The pressurizer heaters are shown on logic diagram 5R-14-9-Z-42151 and elementary diagrams.

Technical Specification Changes Required

The proposed STP Technical Specifications are scheduled to be submitted in 1985.

II.G.1

36

Position

- (1) The power-operated relief valves (PORVs) are solenoid operated valves and are Class 1E qualified. Power and control circuits are fed from Class 1E buses. Thus, these valves are capable of being supplied power from either the offsite power source or the emergency onsite power source.
- (2) The PORV block valves are motor operated valves and are Class 1E qualified. Power and control circuits are fed from Class 1E buses. Thus, these valves are capable of being supplied power from either the offsite power source or the emergency onsite power source.
- (3) See (1) and (2) above. Motive and control power is supplied to the PORVs and their associated block valves through Class 1E devices.
- (4) The pressurizer level indication instrumentation and their associated busses are Class 1E qualified and fed from Class 1E buses. They are capable of being supplied from either the offsite power source or the emergency onsite power source.

Clarification

- (1) The capability to open or close the PORV block valves is provided from the Main Control Board.

Response (Continued)

- (2) Two parallel sets of PORV and PORV block valves are provided with one set (PORV and block valve in series) assigned to Train A and the other set assigned to Train B. Requirements for redundant closure capability are satisfied by an active fail closed PORV (dc powered) and an active block valve (ac powered).
- (3) This does not apply to STP. The power and control circuits are fed from Class iE circuits.
- (4) These valves are not air operated.

36

Documentation Required

System descriptions and testing are discussed in Section 8.3

The pressurizer PORVs are shown on logic diagram 5R-14-9-Z-42160, elementary diagram 9-E-RC13-01, and FSAR Figure 5.1-3. The PORV block valves are shown on logic diagram 5R-14-9-Z-42160 and FSAR Figure 5.1-3.



## STP FSAR

Question 430.34N

Provide a detailed description, including drawing on how the requirements of NUREG-0737 (clarification of TMI Action Plan Requirements) section II.E.3.1 (Emergency Power Supply for Pressurizer Heaters) (enclosed) and II.G.1 (Emergency Power for Pressurizer Equipment) (enclosed) are met.

## II.E.3.1 EMERGENCY POWER SUPPLY FOR PRESSURIZER HEATERS

Position

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

- (1) The pressurizer heater power supply design shall provide the capability to supply, from either the offsite power source or the emergency power source (when offsite power is not available), a predetermined number of pressurizer heaters and associated controls necessary to establish and maintain natural circulation at hot standby conditions. The required heaters and their controls shall be connected to the emergency buses in a manner that will provide redundant power supply capability.
- (2) Procedures and training shall be established to make the operator aware of when and how the required pressurizer heaters shall be connected to the emergency buses. If required, the procedures shall identify under what conditions selected emergency loads can be shed from the emergency power source to provide sufficient capacity for the connection of the pressurizer heaters.
- (3) The time required to accomplish the connection of the preselected pressurizer heater to the emergency buses shall be consistent with the timely initiation and maintenance of natural circulation conditions.
- (4) Pressurizer heater motive and control power interfaces with the emergency buses shall be accomplished through devices that have been qualified in accordance with safety-grade requirements.

Clarification

- (1) Redundant heater capacity must be provided, and each redundant heater or group of heaters should have access to only one Class 1E division power supply.
- (2) The number of heaters required to have access to each emergency power source is that number required to maintain natural circulation in the hot standby condition.
- (3) The power sources need not necessarily have the capacity to provide power to the heaters concurrently with the loads required for loss-of-coolant accident.

Question (Continued)

- (4) Any changeover of the heaters from normal offsite power to emergency onsite power is to be accomplished manually in the control room.
- (5) In establishing procedures to manually load the pressurizer heaters onto the emergency power sources, careful consideration must be given to:
  - (a) which (ESF) loads may be appropriately shed for a given situation;
  - (b) reset of the safety injection actuation signal to permit the operation of the heaters; and
  - (c) instrumentation and criteria for operator use to prevent overloading a diesel generator.
- (6) The class 1E interfaces for main power and control power are to be protected by safety-grade circuit breakers (see also Regulatory Guide 1.75).
- (7) Being non-Class 1E loads, the pressurizer heaters must be automatically shed from the emergency power sources upon the occurrence of a safety injection actuation signal (see item 5.b. above).

Documentation Required

The applicant shall provide sufficient documentation to support a reasonable assurance finding by the NRC that each of the subparts of the position stated above are met. The documentation should include as a minimum, supporting information including system design description, logic diagrams, electrical schematic, test procedures, and technical specifications.

Technical Specification Changes Required

Changes to technical specifications (if any) should be submitted as part of this response.

II.G.1 EMERGENCY POWER FOR PRESSURIZER EQUIPMENTPosition

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10 CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

Power Supply for Pressurizer Relief and Block Valves and Pressurizer Level Indicators

- (1) Motive and control components of the power-operated relief valves (PORV) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

STP Response  
~~Response~~

The following are in response to the <sup>above positions and clarifications.</sup> ~~identically identified and numbered~~ questions.

II.E.3.1Position

- (1) As stated in Section 8.3.1.1.4.1.1, two banks of pressurizer heaters are independently supplied from separate Class 1E systems, one from ESF Train A and one from ESF Train C. All loads connected to the Class 1E system have the capability of being supplied from the offsite power source and the (i.e., standby diesel generator (DG)) power source. The control circuits for these two heater banks are supplied from independent Class 1E DC systems. Only one set of heaters is required to maintain natural circulation at hot standby conditions.

- emergency on-site*  
*required for this emergency condition* (2) As indicated in Table 8.3-3, these pressurizer heaters are capable of being manually loaded on the standby DG during LOOP. It is not necessary to shed load to connect these heaters to the standby DG. These heaters can be manually controlled from the Main Control Board or the Auxiliary Shutdown Panel. Procedures and training will include the operation of these heaters.

- (3) The pressurizer heaters can be manually energized within 55 seconds after LOOP if a safety injection (SI) signal is not present. (SI must be reset before the heaters can be energized.) This ensures the capability for maintenance of natural circulation.

- (4) The pressurizer heater power and control system power interfaces within the emergency buses are accomplished through isolation devices qualified as Class 1E.

Clarification

- (1) Each of the two pressurizer heater banks has access to only one Class 1E Train.
- (2) Either redundant bank of heaters will maintain natural circulation.
- (3) These heaters are not required during Loss-of-Coolant Accident (LOCA) or Main Steam Line Break (MSLB) conditions. Under administrative control, each standby diesel generator (DG) has capacity to supply the necessary pressurizer heaters concurrently with LOOP loads.
- (4) These heaters are powered from ESF buses. Therefore, no manual change-over from normal offsite to on-site power is required. The heaters are to be manually loaded on the Engineered Safety Feature (ESF) buses. The heaters are not automatically sequenced on and the SI signal must be reset before the heaters can be loaded on the ESF buses.
- (5) (a) Load shedding is not required. Each standby DG has the capacity to supply the necessary pressurizer heaters concurrently with LOOP loads (LOCA/MSLB loads not present).

Response (Continued)

- (b) Procedures will be established for resetting the SI signal. The SI signal must be reset to energize these heaters.
- (c) Not applicable, see Clarification (3) above.
- (6) The power and control circuits for these pressurizer heaters are from Class 1E load centers E1A and E1C (MCCs 1A5 and 1C5). Isolation devices are qualified as Class 1E devices.
- (7) As stated in Section 8.3.1.1.4.1.1 these heaters are disconnected in the presence of a SI signal.

Documentation Required

System descriptions <sup>is</sup> and testing are discussed in Section 8.3. The logic diagram for the pressurizer heaters ~~are shown on logic diagram 5R-14-9-Z-42151 and elementary diagrams. Figure 7.4-2.~~

Technical Specification Changes Required

The proposed STP Technical Specifications are scheduled to be submitted in mid 1985.

II.G.1Position

- (1) The power-operated relief valves (PORVs) are solenoid operated valves and are Class 1E qualified. Power and control circuits are fed from Class 1E buses. Thus, these valves are capable of being supplied power from either the offsite power source or the emergency onsite power source.
- (2) The PORV block valves are motor operated valves and are Class 1E qualified. Power and control circuits are fed from Class 1E buses. Thus, these valves are capable of being supplied power from either the offsite power source or the emergency onsite power source.
- (3) See (1) and (2) above. Motive and control power is supplied to the PORVs and their associated block valves through Class 1E devices.
- (4) The pressurizer level indication instrumentation and their associated busses are Class 1E qualified and <sup>replace by Insert 'A'</sup> ~~fed from Class 1E buses.~~ They are capable of being supplied from either the offsite power source or the emergency onsite power source.

Clarification

- (1) The capability to open or close the PORV block valves is provided from the Main Control Board.



Question (Continued)

- (4) Any changeover of the heaters from normal offsite power to emergency onsite power is to be accomplished manually in the control room.
- (5) In establishing procedures to manually load the pressurizer heaters onto the emergency power sources, careful consideration must be given to:
  - (a) which (ESF) loads may be appropriately shed for a given situation;
  - (b) reset of the safety injection actuation signal to permit the operation of the heaters; and
  - (c) instrumentation and criteria for operator use to prevent overloading a diesel generator.
- (6) The class 1E interfaces for main power and control power are to be protected by safety-grade circuit breakers (see also Regulatory Guide 1.75).
- (7) Being non-Class 1E loads, the pressurizer heaters must be automatically shed from the emergency power sources upon the occurrence of a safety injection actuation signal (see item 5.b. above).

Documentation Required

The applicant shall provide sufficient documentation to support a reasonable assurance finding by the NRC that each of the subparts of the position stated above are met. The documentation should include as a minimum, supporting information including system design description, logic diagrams, electrical schematic, test procedures, and technical specifications.

Technical Specification Changes Required

Changes to technical specifications (if any) should be submitted as part of this response.

## II.G.1 EMERGENCY POWER FOR PRESSURIZER EQUIPMENT

Position

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10 CFR Part 50 for the event of loss-of-offsite power, the following positions shall be implemented:

## Power Supply for Pressurizer Relief and Block Valves and Pressurizer Level Indicators

- (1) Motive and control components of the power-operated relief valves (PORV) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

Question (Continued)

- (2) Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.
- (3) Motive and control power connections to the emergency buses for the PORVs and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.
- (4) The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

Clarification

- (1) Although the primary concern resulting from lessons learned from the accident at TMI is that the PORV block valves must be closable, the design should retain, to the extent practical, the capability to also open these valves.
- (2) The motive and control power for the block-valve should be supplied from an emergency power bus different from the source supplying the PORV.
- (3) Any changeover of the PORV and block-valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room.
- (4) For those designs in which instrument air is needed for operation, the electrical power supply should be required to have the capability to be manually connected to the emergency power sources.

Documentation Required

The applicant shall provide sufficient documentation to support a reasonable assurance finding by the NRC that each of the positions stated above are met. The documentation should include, as a minimum, supporting information including system design description, logic diagrams, electrical schematics, test procedures, and technical specifications.

Technical Specification Changes Required

Changes to technical specifications (if any) should be submitted as part of this response.

STP Response

The following are in response to the above positions and clarifications.

7.A.II.G.1-2

~~Vol. 2 Q&R 8.3-31N~~

~~Amendment 29~~

Response (Continued)

- (b) Procedures will be established for resetting the SI signal. The SI signal must be reset to energize these heaters.
- (c) Not applicable, see Clarification (3) above.
- (6) The power and control circuits for these pressurizer heaters are from Class 1E load centers E1A and E1C (MCCs 1A5 and 1C5). Isolation devices are qualified as Class 1E devices.
- (7) As stated in Section 8.3.1.1.4.1.1 these heaters are disconnected in the presence of a SI signal.

Documentation Required

System descriptions, and testing are discussed in Section 8.3. The pressurizer heaters are shown on logic diagram 5R-14-9-Z-42151 and elementary diagrams.

Technical Specification Changes Required

The proposed STP Technical Specifications are scheduled to be submitted in 1985.

## II.G.1

Position

- (1) The power-operated relief valves (PORVs) are solenoid operated valves and are Class 1E qualified. Power and control circuits are fed from Class 1E buses. Thus, these valves are capable of being supplied power from either the offsite power source or the emergency onsite power source.
- (2) The PORV block valves are motor operated valves and are Class 1E qualified. Power and control circuits are fed from Class 1E buses. Thus, these valves are capable of being supplied power from either the offsite power source or the emergency onsite power source.
- (3) See (1) and (2) above. Motive and control power is supplied to the PORVs and their associated block valves through Class 1E devices.
- (4) The pressurizer level indication instrumentation and their associated busses are Class 1E qualified and fed from Class 1E buses. They are capable of being supplied from either the offsite power source or the emergency onsite power source.

replace with INSERT A

Clarification

- (1) The capability to open or close the PORV block valves is provided from the Main Control Board.

INSERT 'A'

powered from the Class 1E vital instrument buses. As indicated in Section 8.3.1.1.4.5, these vital instrument buses are fed from Class 1E inverters. Thus, they

Q432

132



Response (Continued)

- (2) Two parallel sets of PORV and PORV block valves are provided with one set (PORV and block valve in series) assigned to Train A and the other set assigned to Train B. Requirements for redundant closure capability are satisfied by an active fail closed PORV (dc powered) and an active block valve (ac powered).
- (3) This does not apply to STP. The power and control circuits are fed from Class 1E circuits.
- (4) These valves are not air operated.

36

Documentation Required

System descriptions and testing are discussed in Section 8.3.

The pressurizer PORVs are shown on logic diagram ~~SR-14-9-Z-42160~~, elementary diagram ~~9-E-RG13-01~~, and FSAR Figure 5.1-3. The PORV block valves are shown on logic diagram ~~SR-14-9-Z-42160~~ and FSAR Figure 5.1-3.

*Figure II.G.1-2*

Technical Specification Changes Required

The proposed STP Technical Specifications are scheduled to be submitted in mid 1985.

FIGURE II. G.1-1

Dwg 9Z42160      Pressurizer PORV  
Logic Diagram

FIGURE II. G.1-2

Dwg 9Z42155      Pressurizer PORV Block  
Valve Logic Diagram

Question  
430.133  
(SRP 8.3.1)

Response to NRC question 430.30N refers to section 8.3.1.1.4.1.1 and Table 8.3-3 of the FSAR. However, these two references include only the ac non-Class 1E loads being supplied from Class 1E buses. The question also requested similar information for dc non-Class 1E loads being supplied from Class 1E buses and should be tripped on receipt of an accident signal. The ac loads included in Table 8.3-3 do not include 120 V ac vital instrument bus loads and any non-Class 1E loads fed from the 120 V ac vital instrument buses that are being shed by an accident signal. Explicitly list all such ac and dc loads.

Response

Table 8.3-3 is being revised and will be submitted in a future amendment. The following non-Class 1E loads are tripped in the event of an SI signal.

480V	LC EIA Press HTR Group A	431KW
480V	LC EIC Press HTR Group B	431KW
480V	MCC 1A5* (as listed)	156KW
	DGB OILTK RM EXH FAN	1HP
	REACTOR CAVITY VENT FAN 11B	40HP
	REACTOR SUPPORT EXH FAN	20HP
	CRDM VENT FAN	40HP
	RHRPIA MINIFLOW MOV	1.9HP
	STBY DG11 AIRCOMPR 12	15HP
	STBY DG11 AIRCOMPR 11	15HP
	N1E 125V dc BAT CHRG#2	75 KVA
480V	MCC 1B5* (as listed)	80KW
	RHRP 1B MINIFLOW MOV	1.9HP
	CRDM VENT FAN	40 HP
	REACTOR SUPPORT EXH FAN	20 HP
	DGB OILTK RM EXH FAN	1 HP
	STBY DG #12 AIR COMPR 14	15 HP
	STBY DG #12 AIR COMPR 13	15 HP
480V	MCC 1C5* (as listed)	110KW
	RHRP 1C MINIFLOW MOV	1.9HP
	REACTOR CAVITY VENT FAN 11A	40HP
	CRDM VENT FAN	40 HP
	STBY DG 13 AIR COMPR 16	15 HP
	STBY DG 13 AIR COMPR 15	15 HP
	DGB OILTK RM EXH FAN	1 HP

\* MCC SUPPLY BREAKER TRIPPED

Response cont'd

Distribution Panels (DP)

208/120V	DP A435	9.518KW
	Circuits for DG, motors and switchgear (Train A) space heaters	
208/120V	DP B435	9.858KW
	Circuits for DG, motors and switchgear (Train B) space heaters	
208/120V	DP C435	9.858KW
	Circuits for DG, Motors and switchgear (Train C) space heaters	
120V	DP A335    Branch CKT 1	0.15 KW
	For ECWIS Equipment space heaters (Train A)	
120V	DP B335    Branch CKT 1	0.15 KW
	For ECWIS Equipment space heaters (Train B)	
120V	DP C335    Branch CKT 1	0.15 KW
	For ECWIS Equipment space heaters (Train C)	

Note: The EAB & control room essential lighting (non Class 1E) loads are connected to MCC E1A2 and MCC E1C2, through 30 KVA isolation/distribution transformers which are not stripped from the buses in the vent of an SI signal.

Also, electrical heat tracing (non-Class 1E) will be supplied from Class 1E buses through redundant Class 1E thermal magnetic trip devices in series which are not tripped in the event of an SI signal.

There are no non-class 1E 125V DC, nor non-Class 1E 120V vital ac loads connected to the Class 1E channel buses.



Question

430.134

(SRP 8.3.1,  
8.3.2)

STP response to NRC question 040.4 refers section 8.3.1.4.2 to answer part 6 and 7 of the question. This section does not include the necessary answer. Provide answer with correct references.

Response

As stated in the FSAR (page Q&R 8.3-3, Amendment 36) the response to part 6 of NRC question 040.4 is included in Section 8.3.1.4.4.11 and the response to part 7 is included in Section 8.3.1.1.5.

That portion of Section 8.3.1.1.5 responding to part 7 of NRC question 040.4 will be revised in a future Amendment to read:

"Power and control field cables to the electric penetrations are capable of carrying the load current based on the penetration conductor ampacity as calculated for the electric penetration protection."

Question

430.135  
(SRP 8.3.1,  
8.3.2)

In response to question 040.2, it is indicated that power lockout of ECCS valves was discussed in STP's response to NRC's question 032.32. However, response to our question 032.32 which deals with the operating, maintenance and testing procedure used by STP, is scheduled to be provided by mid 1985. Clarify the discrepancy and provide the requested response. The response should also include compliance to BTP-18 regarding technical specification listings and position indication of these valves satisfying the single failure criterion.

Response

The response to Q032.32 identifies the FSAR sections which discuss the accumulator discharge isolation valves and the Safety Injection System hot leg isolation valves, the two applications on STP using power lock-out to meet the single failure criterion. The design complies with Branch Technical Position ICSB-18, as indicated in the response to Q032.32 and in the referenced sections.

The proposed draft STP Technical Specifications are scheduled to be submitted in mid-1985.

Question 040.2

Provide a listing of all motor operated valves within your scope of design that require power lockout in order to meet the single failure criterion and provide the details of your design that accomplish this requirement.

Response

There are a total of four manually controlled motor-operated valves which require power lockout in order to meet the single failure criterion during certain phases of a postulated loss-of-coolant accident (LOCA). The valves involved are Component Cooling Water System valves CC0139, CC0142, CC0143, and CC-0146. These four valves are associated with Loop "B" RCECs and may be submerged for a period of time during post-LOCA conditions. These valves are normally open and could be manually controlled from the control room. By administrative control, the power to these valves is electrically removed from the main control board during normal plant operations should the plant personnel decide to close any valve, e.g. for maintenance purposes, the operator must first provide power to the breaker, then close the valve (see Figure 8.3-13).

Power lockout of Emergency Core Cooling System (ECCS) valves (Safety Injection System Accumulator Discharge Isolation Valves and Hot Leg Isolation Valves) is discussed in the response to question 032.32. *These are the only motor operated valves that require power lockout in order to meet the single failure criterion.*

Question 032.32

Identify all remotely controlled valves in the Engineered Safety Features Systems which require power lockout during a certain mode of operation of the system to satisfy single failure criterion. It is the staff's position that your design should also satisfy the Branch Technical positions EICB-4 and EICSB-18. Provide detailed descriptions, with schematic diagrams for the circuitry associated with these valves, illustrating how the above stated staff positions are satisfied in the design.

Response

Remotely controlled valves in the Engineered Safety Features (ESF) Systems which require power lockout during certain modes of operation are as follows:

1. Reactor Containment fan cooler (RCFC) cooling water valves CC0139, CC0142, CC0143, and CC0146. As indicated in the response to Questions 032.35 and 040.2, the power to these valves is electrically removed from the main control board. This power removal is also shown on Figure 8.3-13.

17. Accumulator discharge isolation valves XSI0039A, XSI0039B, and XSI0039C. As discussed in Sections 6.3.2.2, and 6.3.5.5.1, the power to these valves is electrically removed from the main control board. This power removal is also shown on Figure 7.6-3.

27. Hot leg recirculation isolation valves XSI0008A, XSI0008B, XSI0008C, XRH0019A, XRH0019B, and XRH0019C. As discussed in Sections 6.3.2.2, and 6.3.5.5.2, the power to these valves is electrically removed from the main control board. This power removal is also shown on Figure 7.6-10.

Based upon the plant design as discussed in the referenced sections, STP complies with Branch Technical Positions ICSB-4 and ICSB-18.

ICSB-18



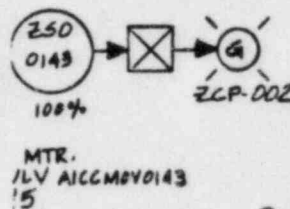
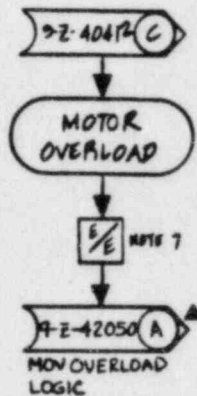
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*DELETE THIS FIGURE  
AND REPLACE WITH A SHEET  
SAYING "FIGURE 8.3-12 HAS  
BEEN DELETED"*

**SOUTH TEXAS PROJECT  
UNITS 1 & 2**

HIGH AND LOW HEAD SAFETY  
INJECTION HOT LEG  
ISOLATION VALVES LOGIC  
DIAGRAM

FIGURE 8.3-12



DELETE THIS  
FIGURE AND  
REPLACE WITH A  
SHEET SAYING  
"FIGURE 8.3-13 HAS  
BEEN DELETED"



MICRO SWITCH TYPE P.T.S.  
FIGURE 1

REFERENCE DWGS:

P&ID: 9-F-05017, 9-F-05018,  
9-F-05019

LOGIC SYMBOLS: 9-Z-40412 AND  
9-Z-40421

GENERAL NOTE:

THIS DWG REPRESENTS FUNCTIONAL  
REQUIREMENTS ONLY

**SOUTH TEXAS PROJECT  
UNITS 1 & 2**

**CCW RCFC INLET & OUTLET MOTOR  
OPERATED VALVES  
LOGIC DIAGRAM  
SYSTEM CC**

Dwg. No. 5R-20-9-Z-42043 Rev. 2

Question  
430.136  
(SRP 8.3.2)

1E Information Notices 83-11 and 84-83 addressed to holders of operating license (OL) and construction permit (CP) reported failure and/or degradation of batteries at various power plants. This has been attributed to swollen positive plates and/or cracked cases of the battery cells. A seismic event might accelerate the degradation of the battery and could cause a common mode failure of the plant dc systems. Conform that the 1E notices and the concerns therein were evaluated for their impact on the STP design of Class 1E batteries and the seismic capability of its racks.

Response

IN 83-11 expresses a concern that old lead-acid storage batteries may fail during a seismic event and cause a common mode failure of plant dc systems.

The STP specification for Class 1E lead storage batteries requires the batteries to be qualified in accordance with IEEE 535-1979. This document requires that the increased seismic vulnerability of old batteries be reflected in a battery's qualified life.

Therefore, this concern has been evaluated and should have no impact on the South Texas Project.

IN 84-83 expresses concerns of overloading dc buses and solvent included battery case cracking. STP is continuing the review of the loading to ensure that adequate capacity is maintained.

All STP batteries are sized and designed to carry all loads connected to the associated action including 20 percent spare capacity for future loads, for a period of two hours. The Class 1E battery manufacturer's (GNB) instruction manual includes a "CAUTION" against the use of solvent as a cleaning agent for plastic battery cells, jars and battery covers. This manual also includes instructions for cleaning the battery posts.

The concerns contained in IN 83-11 and 84-83 were evaluated and are not applicable to STP.

Response to Request for  
Additional Information  
for the Reactor Systems Branch (RSB)

Questions 440.14 through 440.72



QUESTION 440.14  
(Section 5.2)

FSAR Section 5.2.2 states that the transient for which the overpressure protection requirements are determined is a complete loss of steam flow to the turbine, no reactor trip, with credit taken for the steam generator safety valves and maintaining main feedwater (MFW) flow. However, WCAP-7769, Rev. 1, which is referenced in the FSAR, also states that for plants having turbine driven MFW pumps another analysis is required, i.e., a simultaneous loss of load and MFW, with credit taken for Doppler feedback and reactor trip (other than reactor trip on turbine trip) and no credit taken for PORV, ADV and steam dump operation, reactor and pressurizer controls and spray. Discuss whether this analysis was performed for STP, and what the results were.

RESPONSE:

WCAP-7769 discusses the generic methodology for sizing safety valves. It is intended to relate this methodology to a typical plant. The results presented in the WCAP are not intended to demonstrate that the South Texas plant complies with ASME Code requirements. Such compliance is demonstrated in an overpressure protection report specifically for the South Texas plant which is prepared in accordance with Article NB-7300 of Section III of the ASME Code. FSAR Section 5.2.2 will be modified to clarify this item.

The following additional information may provide more insight into the process employed to verify that adequate RCS overpressure protection is provided:

Verification of adequate overpressure protection for the RCS is accomplished in several stages.

Initially, all transients that may cause overpressurization of the RCS are identified. That transient which is anticipated to result in the maximum system pressure and maximum safety valve capacity is then chosen as the design transient for determining the actual safety valve capacity to be provided. This design transient is then analyzed, utilizing input parameters that are conservatively chosen to result in a higher RCS pressure and safety valve capacity requirement. Following selection of the valve capacity, the overpressure transients previously identified are analyzed to verify that the chosen capacity results in peak RCS pressures within that identified in Article NB-7000 of Section III of the ASME Code.

QUESTION 440.14 (Continued)

For South Texas, the protection is afforded for the following events which envelop those credible events which could lead to overpressure of the RCS if adequate overpressure protection were not provided:

1. Loss of Electrical Load and/or Turbine Trip (FSAR Sections 15.2.2 and 15.2.3)
2. Uncontrolled Rod Withdrawal at Power (FSAR Section 15.4.2)
3. Loss of Reactor Coolant Flow (FSAR Section 15.3)
4. Loss of Normal Feedwater (FSAR Section 15.2.7)
5. Loss of Offsite Power to the Station Auxiliaries (FSAR Section 15.2.6)

Review of these transients shows that the turbine trip transient results in the maximum system pressure and the maximum safety valve relief requirements. Therefore, to determine the required safety valve capacity, the turbine trip transient was analyzed, with additional conservatisms included over those considered for FSAR Chapter 15 analyses. The sizing of the pressurizer safety valves was based on analysis of a complete loss of steam flow to the turbine with the reactor operating at 102 percent of the engineered safeguards design power. In this analysis, feedwater flow was assumed to be lost; (This is more conservative than maintaining feedwater flow in that it reduces heat transfer capability thereby increasing primary system pressure). No credit was taken for operation of pressurizer power operated relief valves, pressurizer level control system, pressurizer spray system, rod control system, steam dump system, or steam line power-operated relief valves. The reactor was maintained at full power (no credit for reactor trip), and steam relief through the steam generator safety valves was considered.

The maximum surge rate into the pressurizer during this transient was identified and a total safety valve capacity in excess of this value was chosen. As no reactor trip was assumed, the safety valves by themselves provide adequate capacity to turn around the overpressure transient.

Following selection of the safety valve size and quantity the overpressure transients listed above were analyzed. These analyses confirmed that the overpressure protection afforded the RCS is in accordance with ASME Code requirements. Discussion of those transients and their results is provided in FSAR Chapter 15.

OVERPRESSURE PROTECTION REPORT

FOR

SOUTH TEXAS NUCLEAR POWER PLANT  
UNITS 1 & 2

AS REQUIRED BY

ASME BOILER AND PRESSURE VESSEL CODE  
SECTION III, ARTICLE NB-7300

APRIL 1982

Prepared by: K. A. Forcht

Approved:

G. E. Lang  
G. E. Lang  
Transient Analysis

Certified:

Robert A. Wieseemann  
Robert A. Wieseemann  
Professional Engineer-0087772  
Commonwealth of Pennsylvania



## 1.0 Purpose of Report

This report documents the overpressure protection provided for the Reactor Coolant System (RCS) in accordance with the ASME Boiler and Pressure Vessel Code, Section III, NB-7300.

## 2.0 Description of Overpressure Protection

2.1 Overpressure protection is provided for the RCS and its components to prevent a rise in pressure of more than 10% above the system design pressure of 2485 psig, in accordance with NB-7400. This protection is afforded for the following events which envelope those credible events which could lead to overpressure of the RCS if adequate over pressure protection were not provided.

1. Loss of Electrical Load and/or Turbine Trip
2. Uncontrolled Rod Withdrawal at Power
3. Loss of Reactor Coolant Flow
4. Loss of Normal Feedwater
5. Loss of Offsite Power to the Station Auxiliaries

2.2 The extent of the RCS is as defined in 10CFR50 and includes:

1. The reactor vessel including control rod drive mechanism housings.
2. The reactor coolant side of the steam generators.
3. Reactor coolant pumps.
4. A pressurizer attached to one of the reactor coolant loops.
5. Safety and relief valves.
6. The interconnecting piping, valves and fittings between the principal components listed above.
7. The piping, fittings and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high pressure side) on each line.

2.3 The pressurizer provides volume surge capacity and is designed to mitigate pressure increases (as well as decreases) caused by load transients. A pressurizer spray system condenses steam at a rate sufficient to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves during a step reduction in power level equivalent to ten percent of full rated load.



The spray nozzle is located in the top head of the pressurizer. Spray is initiated when the pressure controlled spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing compensated error signal until it reaches a maximum value. The compensated error signal is the output of a proportional plus integral controller, the input to which is an error signal based on the difference between actual pressure and a reference pressure.

The pressurizer is equipped with 2 power-operated relief valves which limit system pressure for a large power mismatch to avoid actuation of the fixed high pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the frequency of opening of the spring-loaded safety valves. Remotely operated stop valves are provided to isolate the power-operated relief valves if excessive leakage occurs. The relief valves are designed to limit the pressurizer pressure to a value below the high pressure trip setpoint for all design transients up to and including the design percentage step load decrease with steam dump but without reactor trip.

Isolated output signals from the pressurizer pressure protection channels are used for pressure control. These are used to control pressurizer spray and power-operated relief valves in the event of increase in RCS pressure.

In the event of unavailability of the pressurizer spray or power operated relief valves, and a complete loss of steam flow to the turbine, protection of the RCS against overpressure is afforded by the pressurizer safety valves in conjunction with the steam generator safety valves and a reactor trip initiated by the Reactor Protection System.

There are 3 safety valves with a minimum required capacity of 501,700 lb/hour for each valve at system design pressure plus 3% allowance for accumulation. The pressurizer safety valves are totally enclosed pop-type, spring loaded, self-activated valves with back pressure compensation. The set pressure of the safety valves will be no greater than system design pressure of 2485 psig in accordance with section NB7511. The pressurizer safety valves and power operated relief valves discharge to the pressurizer relief tank (PRT). Rupture disks are installed on the pressurizer relief tank to prevent PRT overpressurization.

Figure 1 shows a schematic arrangement of the pressure relieving devices.

### 3.0 Sizing of Pressurizer Safety Valves

- 3.1 The sizing of the pressurizer safety valves is based on analysis of a complete loss of steam flow to the turbine with the reactor operating at 102% of Engineered Safeguards Design Power. In this analysis, feedwater flow is also assumed to be

lost, and no credit is taken for operation of pressurizer power operated relief valves, pressurizer level control system, pressurizer spray system, rod control system, steamdump system or steam line power operated relief valves. The reactor is maintained at full power (no credit for reactor trip), and steam relief through the steam generator safety valves is considered. The total pressurizer safety valve capacity is required to be at least as large as the maximum surge rate into the pressurizer during this transient.

This sizing procedure results in a safety valve capacity well in excess of the capacity required to prevent exceeding 110% of system design pressure for the events listed in Section 2.1. The conservative nature of this sizing procedure is demonstrated in the following section.

- 3.2 Each of the overpressure transients listed in Section 2.1 has been analyzed and reported in the Final Safety Analysis Report. The analysis methods, computer codes, plant initial conditions and relevant assumptions are discussed in the FSAR for each transient.

Review of these transients shows that the Turbine Trip results in the maximum system pressure and the maximum safety valve relief requirements. This transient is presented in detail below.

For a turbine trip event, the reactor would be tripped directly (unless below approximately 10 percent power) from a signal derived from the turbine stop emergency trip fluid pressure and turbine stop valves. The turbine stop valves close rapidly (typically 0.1 seconds) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. This will cause a sudden reduction in steam flow, resulting in an increase in pressure and temperature in the steam generator shell. As a result, heat transfer rate in the steam generator is reduced, causing the reactor coolant temperature to rise, which in turn causes coolant expansion, pressurizer insurge, and RCS pressure rise.

The automatic steam dump system would normally accommodate the excess steam generation. Reactor coolant temperature and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere and main feedwater flow would be lost. For this situation feedwater flow would be maintained by the Auxiliary Feedwater System to ensure adequate residual and decay heat removal capability. Should the steam dump system fail to operate, the steam generator safety valves may lift to provide pressure control.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 102 percent of full power without direct reactor trip; that is, the turbine is assumed to trip without actuating all the sensors for reactor trip on the turbine stop valves. The assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst transient. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for auxiliary feedwater to mitigate the consequences of the transient.

The turbine trip transients are analyzed by employing the detailed digital computer program LOFTRAN. The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

Major assumptions are summarized below:

a. Initial operating conditions

The initial reactor power and RCS temperatures are assumed at their maximum values consistent with the steady state full power operation including allowances for calibration and instrument errors. The initial RCS pressure is assumed at a minimum value consistent with the steady state full power operation including allowances for calibration and instrument errors. This results in the maximum power difference for the load loss, and the minimum margin to core protection limits at the initiation of the accident.

b. Moderator and Doppler coefficients of reactivity

The analysis assumes both a least negative moderator coefficient and a least negative Doppler power coefficient, as this results in maximum pressure relieving requirements.

c. Reactor control

From the standpoint of the maximum pressures attained it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.



d. Steam release

No credit is taken for the operation of the steam dump system or steam generator power operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

e. Pressurizer spray and power operated relief valves

No credit is taken for the effect of pressurizer spray and power operated relief valves in reducing or limiting the coolant pressure. Safety valves are operable.

f. Feedwater flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur; however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

g. Reactor trip

Reactor trip is actuated by the first Reactor Protection System trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip. Trip signals are expected due to high pressurizer pressure, Overtemperature  $\Delta T$ , high pressurizer water level, and low-low steam generator water level.

The results of the Turbine Trip transient are shown in Figures 2 and 3. Figure 2 shows the pressurizer pressure, the reactor coolant pump discharge pressure, which is the point of highest pressure in the RCS, and the pressurizer safety valve relief rate. Figure 3 shows steam generator shell side pressure, reactor coolant loop hot leg and cold leg temperature, and nuclear power. The reactor is tripped on a high pressurizer pressure signal for this transient.

The results of this analysis show that the overpressure protection provided is sufficient to maintain peak RCS pressure below the code limit of 110% of system design pressure. The plot of pressurizer safety valve relief rate also shows that adequate overpressure protection for this limiting event could be provided by two of the three installed safety valves.



#### 4.0 References

1. ASME Boiler and Pressure Vessel Code, Section III, Article NB 7000, 1971 Edition Winter 1972 Addenda.
2. Topical Report - Overpressure Protection for Westinghouse Pressurizer Water Reactors, WCAP 7769, Rev. 1, June 1972.
3. Certified Safety Valve Capacity, Calculation No. CPA-73-39; FA-793, July 23, 1980.
4. TGX Loss of Load Analysis, Calculation No. CN-RPA-77-211, November, 1977.
5. TGX Rod Withdrawal at Power Analysis, Calculation No. CN-RPA-77-180, November, 1977.
6. TGX Loss of Flow/Locked Rotor Analysis, Calculation No. CN-RPA-77-216, November, 1977.
7. TGX Loss of Normal Feedwater/Station Blackout, Calculation No. CN-RPA-77-209, November, 1977.
8. TGX Loss of Load Analysis with Reduced Flow, Calculation No. CN-RPA-79-122, August, 1979.
9. TGX Rod Withdrawal at Power Analysis with Reduced Flow, Calculation No. CN-RPA-79-118, September, 1979.
10. TGX Loss of Flow/Locked Rotor Analysis with Reduced Flow, Calculation No. CN-RPA-79-109, July, 1979.
11. TGX Loss of Normal Feedwater/Station Blackout Analysis with Reduced Flow, Calculation No. CN-RPA-79-117, August, 1979.

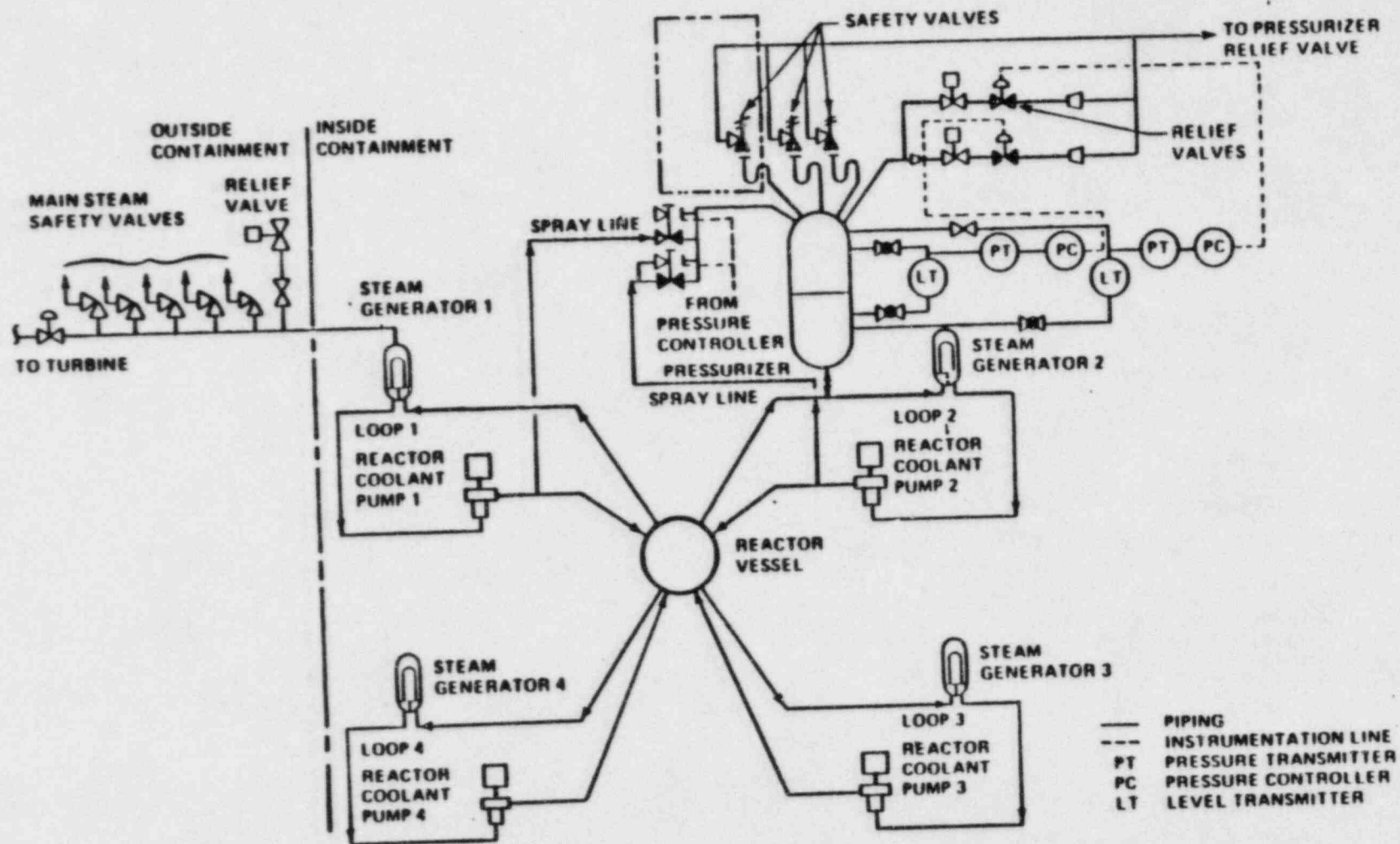


Figure 1 Schematic Arrangement of Pressure Relieving Devices

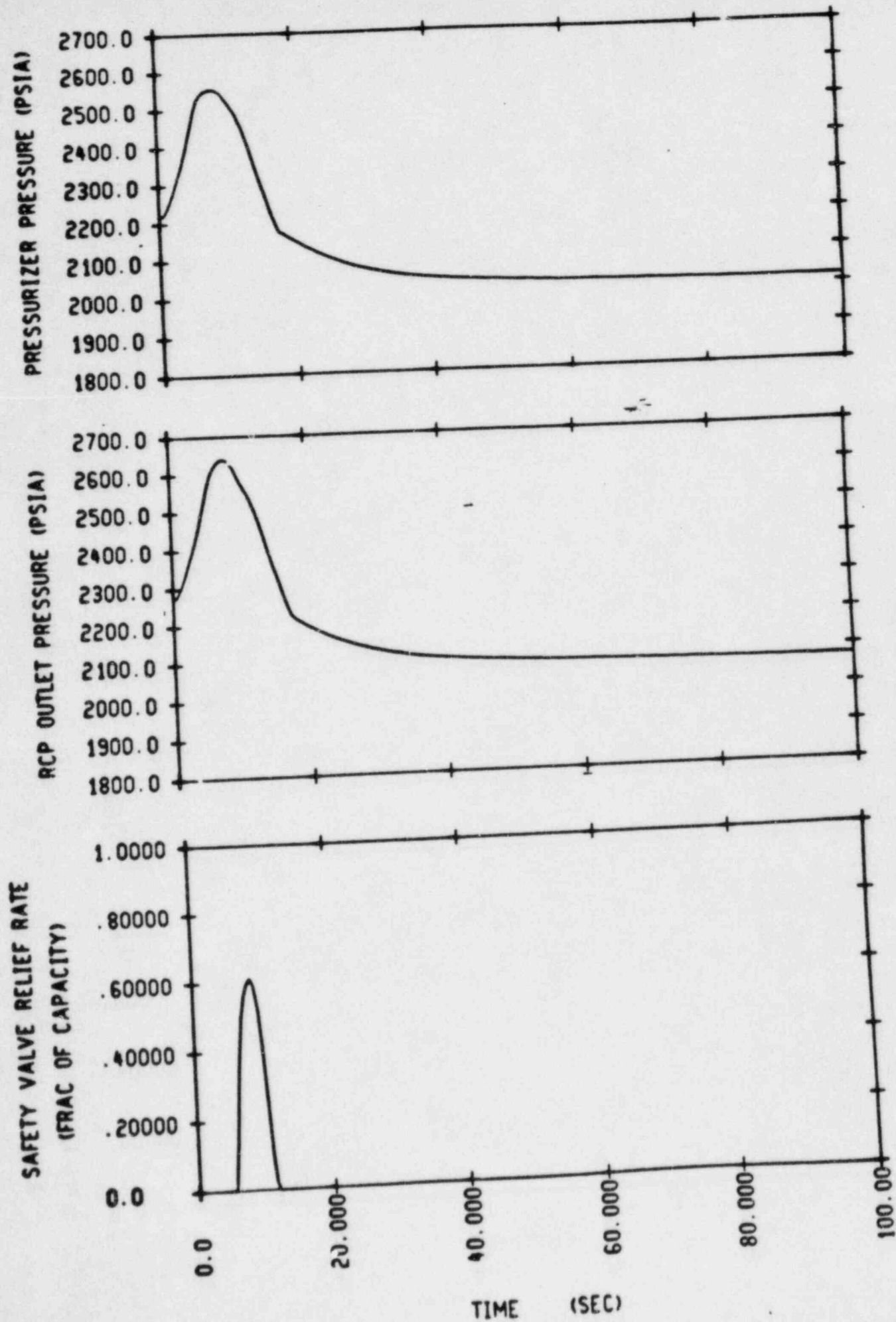


Figure 2

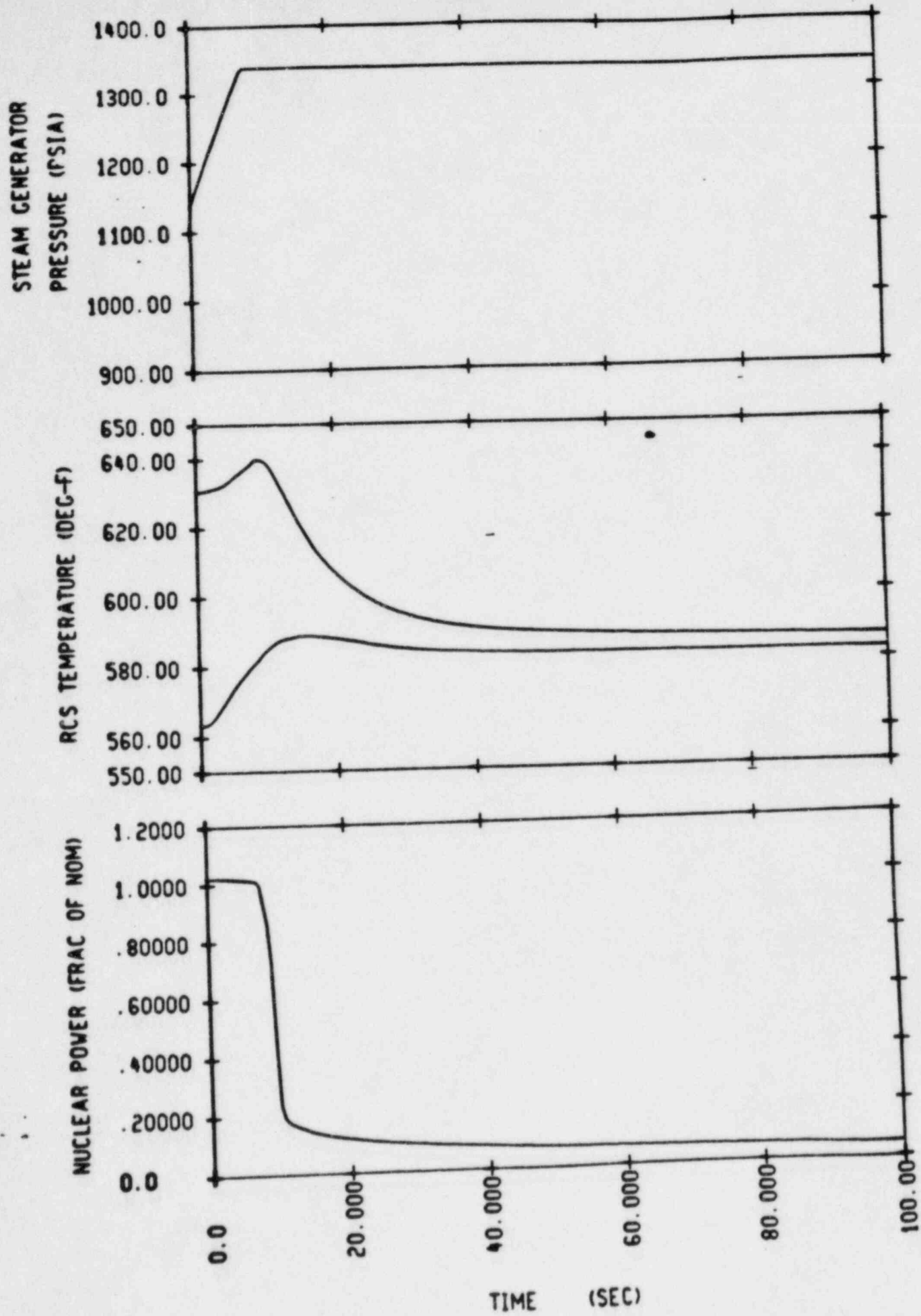


Figure 3



5.2.2.1 Design Bases. Overpressure protection is provided for the RCS by the pressurizer safety valves, which discharge to the pressurizer relief tank (PRT) by a common header. The transient on which the design requirements are set for the primary system overpressure protection is a complete loss of steam flow to the turbine with credit taken for steam generator (SG) safety valve operation and main feedwater (FW) flow maintained. However, for the sizing of the pressurizer safety valves, no credit is taken for reactor trip or for operation of the following:

1. Pressurizer power-operated relief valves
2. Steam line relief valve
3. Steam Dump System
4. Reactor Control System
5. Pressurizer Level Control System
6. Pressurizer spray valve

For this transient, the peak RCS and peak Steam System pressures must be limited to 110 percent of their respective design values.

Assumptions for the overpressure analysis include: (1) the plant is operating at the power level corresponding to the engineered safeguards design rating; and (2) the RCS average temperature and pressure are at their maximum values. These are the most limiting assumptions with respect to system overpressure.

Overpressure protection for the Steam System is provided by SG safety valves. The Steam System safety valve capacity is based on providing enough relief to remove 105 percent of the engineered safeguards design steam flow. This must be done by limiting the maximum Steam System pressure to less than 110 percent of the SG shell side design pressure.

Blowdown and heat dissipation systems of the Nuclear Steam Supply System (NSSS) connected to the discharge of these pressure relieving devices are discussed in Section 5.4.11.

SG blowdown systems for the balance of plant are discussed in Chapter 10.

~~Postulated events and transients on which the design requirements of the Overpressure Protection System are based are discussed in Reference 5.2-1.~~

5.2.2.2 Design Evaluation. The relief capacities of the pressurizer and SG safety valves are determined from the postulated overpressure transient conditions in conjunction with the action of the Reactor Protection System.

INSERT  
1. → An evaluation of the functional design of the system and an analysis of the capability of the system to perform its function is presented in Reference 5.2-1. The report describes in detail the types and number of pressure relief devices employed and gives relief device description, locations in

STP FSAR

An Overpressure Protection Report (Reference 5.2-8), specifically for South Texas Units 1 and 2 was prepared in accordance with article 7300 Section III of the ASME Code. This report addresses the following events which envelope credible events which could lead to overpressurization of the RCS if adequate overpressure protection were not provided:

1. Loss of Electrical Load and/or Turbine Trip
2. Uncontrolled Rod Withdrawal at Power
3. Loss of Reactor Coolant Flow
4. Loss of Normal Feedwater
5. Loss of Offsite Power to the Station Auxiliaries

Description of these transients, assumptions made, methods of analysis and conclusions are presented in Chapter 15.

Reference 5.2-1 discusses the generic methodology for sizing the pressurizer safety valves.

*delete*

~~the systems, reliability history, and the details of the methods used for relief device sizing based on typical worst-case transient conditions and analysis data for each transient condition. The description of the analytical model used in the analysis of the Overpressure Protection System and the basis for its validity is discussed in Reference 5.2-2.~~

A description of the pressurizer safety valves' performance characteristics, along with the design description of the incidents, assumptions made, method of analysis, and conclusions, is given in Chapter 15.

5.2.2.3 Piping and Instrumentation Diagrams. Overpressure protection for the RCS is provided by pressurizer safety valves, shown on Figure 5.1-2. These discharge to the PRT by a common header.

The Steam System safety valves are discussed in Chapter 10 and are shown on Figure 10.3-1.

5.2.2.4 Equipment and Component Description. The operation, significant design parameters, number and types of operating cycles, and environmental qualification of the pressurizer safety valves are discussed in Section 5.4.13.

A discussion of the equipment and components of the Steam System Overpressure System is in Chapter 10.

5.2.2.5 Mounting of Pressure Relief Devices. Westinghouse provides mounting brackets on the pressurizer which can be used to support the pressurizer safety valves. Bechtel Energy Corporation (BEC) is responsible for the design and mounting of the supports for these valves, and for determining reactions on the pressurizer mounting brackets. Mounting of pressure relief devices is discussed in Subsection 3.9.3.3.

5.2.2.6 Applicable Codes and Classifications. The requirements of ASME Code, Section III, NB-7300 ("Overpressure Protection Report") and NC-7300 ("Overpressure Protection Analysis"), are followed and complied with for PWR systems.

Piping, valves, and associated equipment used for overpressure protection are classified in accordance with ANSI-N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants." These safety class designations are delineated in Section 3.2 and shown on Figures 5.1-1 through 5.1-4.

For further information, refer to Section 3.9, "Mechanical Systems and Components."

5.2.2.7 Material Specifications. Refer to Section 5.2.3, "Reactor Coolant Pressure Boundary Material."

5.2.2.8 Process Instrumentation. Each pressurizer safety valve discharge line incorporates a control board temperature indicator and alarm to notify the operator of steam discharge due to either leakage or actual valve operation. For a further discussion of process instrumentation associated with the system, refer to Subsection 7.2.2.3.3.

REFERENCESSection 5.2:

- 5.2-1 WCAP-7769, Revision 1 (Topical Report - "Overpressure Protection for Westinghouse Pressurized Water Reactors"); approved by R. Salvatori, dated June 1972. Also, letter NS-CE-622, dated April 16, 1975: C. Eicheldinger to D. B. Vassallo; additional information on WCAP-7769, Revision 1.
- 5.2-2 WCAP-7907 (Loftran Code Description); approved by J. O. Cermak, dated October 1972.
- 5.2-3 Golik, M. A., "Sensitized Stainless Steel in Westinghouse PWR Nuclear Steam Supply Systems," WCAP-7735 (August 1971).
- 5.2-4 Enrietto, J. F., "Control of Delta Ferrite in Austenitic Stainless Steel Weldments," WCAP-8324-A (June 1974).
- 5.2-5 Enrietto, J. F., "Delta Ferrite in Production Austenitic Stainless Steel Weldments," WCAP-8693 (January 1976).
- 5.2-6 Cuplan, J., "The Application of Pre-Heat Temperatures after Welding Pressure Vessel Steel," WCAP-8577 (September 1975).
- 5.2-7 "Dynamic Fracture Toughness of ASME SA-508 Class 2a and ASME SA-533 Grade A Class 2 Base and Heat Affected Zone Material and Applicable Weld Metals," WCAP-9292, March 1978. Q005.1  
6
- 5.2-8 "Overpressure Protection Report on South Texas Nuclear Power Plant Units 1 & 2," Certified: E. A. Wusemisa, April 1982.



QUESTION 440.15

Figure 5.1.3 is incomplete, e.g., the pressurizer heater controls are not shown, nor are the level transmitter condensate pots, PORV and block valve controls. Also in accordance with Amendment 37 the PORVs are solenoid operated. This is not indicated in the figure. Therefore, please make all necessary changes to show the complete pressurizer and PORV controls and any other missing information.

RESPONSE:

Figures 5.1-1 through 5.1-4 have been updated. The pressurizer heater controls, pressurizer PORV controls, PORV block valve controls and solenoid-operated PORV's are shown on Figure 5.1-3. The pressurizer level transmitter condensate pots are not shown on this P&ID figure, since they are shown on the installation details for the pressurizer level transmitters.

More detail regarding pressurizer heater controls, PORV operation and control, and PORV block valve control may be found in Chapter 5, Chapter 7 and Appendix 7A.

QUESTION 440.16

Describe the position indications provided for the pressurizer safety and relief valves. Demonstrate compliance with the position indication requirements of NUREG-0737 Item II.D.3.

RESPONSE:

Compliance with the requirements of NUREG-0737 is presented in Appendix 7A. As shown in Appendix 7A, Section II.D.3 and the sections referenced therein, STP complies with the position indication requirements of NUREG-0737, Item II.D.3.

QUESTION 440.17  
(Section 5.2. & 5.4)

Has the delay due to the time it takes to discharge the water from the pressurizer safety valve loop seals been accounted for in the limiting pressure transient? If it has not been accounted for, how would this delay affect the results?

RESPONSE:

The delay due to the time it takes to discharge the water from the pressurizer safety valve loop seals has been accounted for in the limiting pressure transient.

QUESTION 440.18  
(Section 5.2)

WCAP-7769, Section 3.4 assumes failure of one steam generator safety relief valve per loop. Provide assurance that your remaining safety valves can provide the required minimum capacity.

RESPONSE:

As stated in the WCAP the maximum steam generator safety valve required capacity is 78% of the provided capacity for the limiting case which is the loss of electrical load transient. Twenty safety valves are provided. If 78% of the valves open, 78% of the total provided relieving capacity is available. Sixteen valves would provide 80% of the total relieving capacity.



QUESTION 440.19  
(Section 5.2)

- a. Demonstrate compliance with the performance testing requirements of NUREG-0737 Item II.D.1 for the PORVs, block valves and safety valves.
- b. Provide assurance that the dynamic loading of the PORVs and safety valves due to water relief during transients and accidents has been considered in the piping and support analysis including the passage of a water slug and effects of water hammer. What liquid water relief rates were assumed in the loading analysis? Are these values consistent with experimental results? Are the PORVs, block valves and safety valves predicted or expected to relieve liquid for any transient or accident analyzed in Chapter 15, or for events postulated for overpressure protection evaluation? If so, confirm that they are designed for liquid relief.
- c. Have the pressurizer PORVs been qualified for the dynamic loads that could be sustained for the maximum liquid flow rate or maximum acceleration of liquid that would occur during a low temperature overpressurization?

RESPONSE:

- a) A response to NUREG-0737 Item II.D.1 is being prepared to address this question and will be available in the third quarter of 1985.
- b) Same as response A.
- c) Same as response A.

QUESTION 440.20  
(Section 5.2.7.5.4)

Section 5.4.13 cites a backpressure compensation feature on the pressurizer safety valves. Provide a discussion of this feature which explains how this function is performed.

RESPONSE:

Backpressure compensation for the pressurizer safety valves is provided by a balancing bellows and balancing piston. These features are incorporated in Crosby style HB safety valves and were tested as part of the recently completed EPRI safety valve test program (NUREG-0737, Item II.D.1). The results from these tests demonstrated that backpressure has little if any effect on valve performance.

QUESTION 440.21  
(Section 5.2)

For RCS pressure control during low temperature operation, discuss whether the analyses performed to determine the maximum pressure for the postulated worst case mass and heat input events assumed relief by the pressurizer PORVs only or whether credit is also taken for the RHR relief valves. If credit is taken for the RHR relief valves, then demonstrate that the overpressure protection functions would not be defeated by interlocks which would isolate the RHR system, or by common mode failures (e.g., failure of a d.c. bus). See also Question 440.28.

RESPONSE:

No credit is taken for the RHR relief valves in the Cold Overpressure Mitigation System (COMS) analysis. In the COMS analysis it is assumed only one PORV is available for RCS pressure mitigation.

QUESTION 440.22  
(Section 5.2)

In accordance with Section 5.2.2.11.2 the bounding mass input analysis for RCS pressure control during low temperature operation was performed assuming letdown isolation with 2 charging pumps operating. There has been an operating plant incident involving inadvertent SI pump actuation during low temperature conditions. Our position is that the low temperature overpressure protection system (LTOPS) be designed to handle actuation of one high head safety injection (HHSI) pump. Therefore discuss whether the STP LTOPS has sufficient capacity for this type of transient.

RESPONSE:

In accordance with WCAP-10529, "Cold Overpressure Mitigation System", we assume in the COMS analysis that a charging/letdown flow mismatch results from the isolation of letdown in coincidence with the inadvertent start of a charging pump, delivering full flow. Consistent with standard Technical Specification 3.5.3 during low temperature operation the HHSI pumps will be locked out of service.



QUESTION 440.23  
(Section 5.2)

Your response to Questions 211.2 and 211.12 regarding compliance of the STP design with Branch Technical Position (BTP) RSB 5-2 "Overpressurization Protection of PWRs While Operating at Low Temperatures" is incomplete. The following information is required.

- a. Provide preliminary applicable tech specs and Appendix G limits or provide a target date for this submittal. If the PORV setpoints are not provided, discuss the methods to be used in determining these values.
- b. Provide a failure mode and effects analysis to demonstrate that a single mechanical or electrical failure will not disable both PORV trains. In addition, confirm that your technical specifications, when written, will preclude taking PORV/block valves out of service such that the single failure criteria cannot be met.
- c. If credit is taken for prevention of any potential overpressurization events by protection interlocks or locking out power, these events should be identified. Technical Specifications should require the valve, pump, or circuit breaker operations that prevent the overpressurization event.
- d. State whether tests will be performed to assure the operability of the system (exclusive of relief valves) prior to each shutdown.
- e. State how the system meets the quality group requirements of Regulatory Guide 1.26.
- f. State what power source are available to operate the LTOPS in the event of loss of offsite power and how the system meets the criteria of RSB 5-2, Item B.7.

RESPONSE:

- a) Upon completion of the COMS analysis Technical Specifications input will be provided.  
  
The details of PORV setpoint determination are contained in WCAP-10529, "Cold Overpressure Mitigation System".
- b) Each PORV is part of a separate electrical train. The isolation of each train precludes the possibility of any single failure disabling both PORVs. (See Table 5.4.A-2)
- c) In the COMS analysis it assumed only one charging pump is operable below the arming temperature of COMS (typically 350°F). The Technical Specifications are written such that all other charging/SI pumps are "locked out".

QUESTION 440.23 (Continued)

- d) Tests will be performed in accordance with Technical Specifications 4.4.9.3.1 and 4.4.9.3.2 to assure the operability of the Low Temperature Overpressure Protection System (exclusive of relief valves) prior to each shutdown.
- e) Westinghouse adheres to the classification system, developed by the American Nuclear Society in the standard Nuclear Safety Criteria for Design of Stationary Pressurized Water Reactor Plant," ANSI N18.2-1973 in lieu of Regulatory Guide 1.26. (See Section 3.2)

For the referenced system the PORVs and block valves are both Safety Class 1.

- f) As indicated in Section 7.6.6.3, the interlocks for RCS pressure control during low temperature operation are provided with redundant Class 1E power. The interlock system for PORV PCV-655A is powered from Train A; the interlock system for PORV PCV-656A is powered from Train B. Power for the protection sets of the Process Control System and for the Solid State Protection System is provided from the Class 1E vital instrument bases, which are fed from Class 1E inverters.

The overpressure protection system is fully qualified; it meets Class 1E environmental and seismic qualification requirements. As indicated in Section 3.10N, the system components are classified as Seismic Category I components. Thus the criteria of Branch Technical Position RSB 5-2, Item B.7 are met.

Question 211.2

A new Branch Technical Position (BTP RSB 5-2) related to overpressurization protection of PWR's while operating at low temperatures has been recently approved by the Regulatory Requirements Review Committee. The technical requirements of this position to which the South Texas Project must comply prior to initial startup are described below.

1. A system should be designed and installed which will prevent exceeding the applicable Technical Specifications and Appendix G limits for the Reactor Coolant System while operating at low temperatures. The system should be capable of relieving pressure during all anticipated overpressurization events at a rate sufficient to satisfy the Technical Specification limits, particularly while the Reactor Coolant System is in a water-solid condition.
2. The system must be able to perform its function assuming any single active component failure. Analyses using appropriate calculational techniques must be provided which demonstrate that the system will provide the required pressure relief capacity assuming the most limiting single active failure. The cause for initiation of the event (e.g., operator error, component malfunction) will not be considered as the single active failure. The analysis should assume the most limiting allowable operating conditions and systems configuration at the time of the postulated cause of the overpressure event. All potential overpressurization events must be considered when establishing the worst case event. Potential events may not be eliminated from consideration in overpressure protection system design analyses merely by the imposition of technical specifications or other administrative controls (e.g., prohibitions on safety injection pump operation).
3. The system must meet the design requirements of IEEE std. 279-1971. The system may be manually enabled; however, the electrical instrumentation and control system must provide alarms to alert the operator to:
  - a. Properly enable the system at the correct plant condition during cooldown.
  - b. Indicate if a pressure transient is occurring.
4. To assure operational readiness, the overpressure protection system must be tested in the following manner:
  - a. A test must be performed to assure operability of the system electronics prior to each shutdown.
  - b. A test for valve operability must, as a minimum, be conducted as specified in the ASME Code Section XI.

- c. Subsequent to system, valve, or electronics maintenance, a test on that portion(s) of the system must be performed prior to declaring the system operational.
5. The system must meet the requirements of Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants" and Section III of the ASME Code.
6. The overpressure protection system must be designed to function during an Operating Basis Earthquake. It must not compromise the design criteria of any other safety-grade system with which it would interface, such that the requirements of Regulatory Guide 1.29, "Seismic Design Classification" are met.
7. The overpressure protection system must not depend on the availability of offsite power to perform its function.
8. Overpressure protection systems which take credit for an active component(s) to mitigate the consequences of an overpressurization event must include additional analyses considering inadvertent system initiation/actuation or provide justification to show that existing analyses bound such an event.

Address detailed compliance of South Texas to each of the above criteria.

#### Response

1. An evaluation of the applicable Technical Specifications and Appendix G limits will be provided in a future amendment.
2. Refer to new Section 5.2.2.11.2.
3. Refer to new Sections 5.2.2.11 and 7.6.6.
4. Responses to parts a, b, and c follow:
  - a) Refer to new Section 7.6.6.
  - b) A valve operability test in accordance with ASME Code Section XI will be provided.
5. Refer to Section 3.12 for a discussion of Regulatory Guide 1.26. *This system meets the requirements of RG 1.26.*
6. *Low temperature operation exists as a small period of time during plant operation. A coincident earthquake during that time is a low probability event and consequently is not a credible design basis. An evaluation will be done to determine the potential for an occurrence*

*The cold overpressure mitigation system meets the requirements of Regulatory Guide 1.29.*



of an overpressure situation as a consequence of an OBE. The results of the evaluation will determine if either the plant design will be modified such as to preclude the event or the overpressure relief system will be qualified to function following an OBE. In either case the relief system will not compromise the design criteria of any other safety grade system.

9

7. Refer to item 3 of Section 7.6.6.3.1.
8. The analysis presented in Section 15.6.1 (Inadvertent Opening of a Pressurizer Safety or Relief Valve) provides justification that the event is bounded by existing analyses.



Question 211.12

Your response to Question 211.2 is not acceptable. Per the requirements of BTP RSB 5-2 the low temperature overpressure protection system must be designed to meet the requirements of IEEE 279 and must be designed to function during an operating basis earthquake.

Provisions to allow testing prior to shutdown must be provided to assure operability of the system.

Provide a discussion of a direct current bus failure which would cause isolation of letdown flow (fail closed valves) and initiate an overpressure transient. On some recently reviewed plants, this failure would simultaneously disable a PORV. If the dc bus failure was assumed to be the initiating event, the overpressure protection system would not meet the single failure criteria.

Response

In accordance with the guidelines of BTP RSB 5-2, the cold overpressure protection system is designed to the guidance of IEEE 279 and is designed to function during an operating basis earthquake.

Provisions to allow testing of this cold overpressure protection system will be provided.

The South Texas Project design is not subject to the postulated failure of a PORV and simultaneous isolation of letdown by the failure of a DC bus. Valves in the letdown line inside the Containment are motor-operated and fail as-is. There are no fail-closed valves in the letdown line inside Containment. The failure of a DC vital bus may result in the loss of one PORV but will not cause any valve in the letdown line to change positions. If the letdown line has been in service when the DC bus failure occurs, the valves in the letdown line between the RCS and the letdown relief valve will remain open. Thus, in addition to the unaffected PORV, the letdown relief valve (with a set pressure of 600 psig) is available to provide RCS overpressure protection with one or more charging pumps in operation. In addition, the redundant PORV is on a different DC bus and will be operable at this time.

36

QUESTION 440.24  
(Section 5.2)

In Section 5.2.2.11.1 of the FSAR, you indicate that an auctioneered system temperature is continuously converted to an allowable pressure and then compared to the actual RCS pressure. "This comparison will provide an actuation signal to the PORVs when required, to prevent pressure-temperature conditions from exceeding the allowable limits." Our review of the low temperature overpressure protection design for certain other Westinghouse plants indicates that a failure in the temperature auctioneer for one PORV (signalling it to remain closed) could also fail the other PORV closed (by denying its permissive to open). Address this concern about a potential common mode failure in the low temperature overpressure protection system for STP.

RESPONSE:

Past COMS logic called for the output of the temperature auctioneer of either train to serve as a permissive for the other train's PORV. This is not the case for STP. Failure of the temperature auctioneer will only disable the PORV in one train.

QUESTION 440.25  
(Section 5.2)

Provide your limiting Appendix G curve for the first eighteen full power months of operation. Discuss the operational procedures which will minimize the likelihood of an overpressure event.

RESPONSE:

See response to MEB Question 251.14 figures 1 through 4.

QUESTION 440.26  
(Section 5.2)

The staff is concerned that your proposed LTOP system does not adequately protect the reactor vessel during transient events where the vessel wall temperature lags behind the temperature used in the variable setpoint calculator. For example, starting a RCP in a loop with a hot steam generator when the RCS is water solid causes the RCS pressure and temperature to rise. Your LTOP system would automatically raise the PORV setpoint as a function of auctioneered cold or hot leg temperature, but the vessel wall will not be heated in this transient at the same rate. Thus, due to the LTOP system auctioneering scheme, the part of the RCS most vulnerable to brittle fracture may not be adequately protected because the relief valves would open at a higher pressure than what the true vessel wall temperature would allow.

If, during a cooldown, a mass input event occurred, your proposed LTOP system may not protect the coldest location in the vessel since the setpoint would not be based on the coldest fluid temperature.

Address the above concerns by discussing the following:

- a. Discuss the events you considered when establishing the worst case scenario for LTOPs evaluation, show how the event selected is worst case regarding vessel temperature, and show how your LTOP system protects the vessel at its coldest location.
- b. Include in your analyses the most limiting single active failure, and justify the choice.
- c. Include in your analyses the effects of system and component response times, including:
  1. temperature detectors
  2. pressure detectors
  3. logic circuitry

Show the response times that were assumed and the extent of conservatism in the assumed values.

RESPONSE:

- a) The events considered when establishing the worst case scenario for COMS evaluation are documented in WCAP-10529, "Cold Overpressure Mitigation System". The worst case event from the standpoint of vessel temperature is the heat input transient. In the heat input transient we assume a RCP is started when the steam generator is 50°F hotter than the RCS.

QUESTION 440.26 (Continued)

The conservatism built in to our setpoint determination algorithm ensures the coldest location in the vessel is protected. For any given RCS temperature, setpoints are selected such that the Appendix G pressure limit is satisfied for the RCS temperature 50°F less than the temperature used in the analysis. For example, if selecting setpoints for a RCS temperature of 200°F, we select setpoints that satisfy the Appendix G pressure constraints at 150°F.

- b) In the COMS analysis it is assumed one PORV is inoperative. This results in the availability of only one PORV for RCS pressure mitigation.
- c) 1. The response time of the temperature detectors are not considered in COMS analysis for the following reasons:
  - o In the case of the mass input transient we have isothermal conditions in the RCS, therefore the response time of the temperature detectors is not a factor.
  - o In the case of the heat input transient the temperature of the RCS is increasing. Delay in temperature detector response will result in a measured temperature that is less than the actual RCS temperature, which is conservative.
- 2,3 We assume there is a 0.6 second delay before the PORV starts to stroke. The breakdown is as follows:
  - o 0.4 sec pressure transmitter delay
  - o 0.1 sec solenoid actuation delay
  - o 0.1 sec logic circuitry delay



QUESTION 440.27

Explain the differences between the RHR cooldown rates listed in the text and those shown in Figures 5.4-8 and 5.4-9 (Amendment 38). As example, the time for 3 train cooldown from 350°F to 150°F is given as 8 hours in the text and shown as 12 hours in Figure 5.4-8. The time for 2 train cooldown from 350°F to 200°F is given as 5 hours in the text and shown as 8.5 hours in Figure 5.4-9.

RESPONSE:

The times required to cooldown the Reactor Coolant System using various configurations of the Residual Heat Removal System which are provided by Figures 5.4-8 and 5.4-9 of the South Texas Project FSAR are consistent with the calculated performance capabilities of the system. The FSAR text will be revised to be consistent with the figures.

**5.4.4.2 Design Description.** The flow restrictor consists of seven Inconel venturi inserts which are inserted into the holes in an integral steam outlet low alloy steel forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle and the other six equally spaced around it. After insertion into the low alloy steel forging holes, the Inconel venturi nozzles are welded to the Inconel cladding on the inner surface of the forging. See Figure 5.4-5.

**5.4.4.3 Design Evaluation.** The flow restrictor design has been sufficiently analyzed to assure its structural adequacy. The equivalent throat diameter of the steam generator outlet is 16 in, and the resultant pressure drop through the restrictor at 100 percent steam flow is approximately 3.4 psig. This is based on a design flow rate of  $3.79 \times 10^6$  lb/hr. Materials of construction and manufacturing of the flow restrictor are in accordance with Section III of the ASME Code.

**5.4.4.4 Tests and Inspections.** Since the restrictor is not a part of the steam system boundary, no tests and inspection beyond those during fabrication are anticipated.

#### 5.4.5 Main Steam Line Isolation System

Refer to Section 10.3.2.

#### 5.4.6 N/A

#### 5.4.7 Residual Heat Removal System

The Residual Heat Removal System (RHRS) transfers heat from the RCS to the Component Cooling Water System (CCWS) to reduce the temperature of the reactor coolant to the cold shutdown temperature at a controlled rate during the second part of normal plant cooldown and maintains its temperature until the plant is started up again.

Parts of the RHRS also serve as parts of the Safety Injection System (SIS) during the injection and recirculation phases of a loss of coolant accident (see Section 6.3).

The RHRS also is used to transfer refueling water from the refueling cavity to the refueling water storage tank after the refueling operations are completed.

##### 5.4.7.1 Design Bases. RHRS design parameters are listed in Table 5.4-7.

The RHRS is placed in operation approximately four hours after reactor shutdown when the temperature and pressure of the RCS are approximately 350°F and 400 psig, respectively. Assuming that three heat exchangers and three pumps are in service and that each heat exchanger is supplied with CCW at design flow and temperature, the RHRS is designed to reduce the temperature of the reactor coolant from 350°F to 150°F within 7 hours. The time required under these conditions to reduce reactor coolant temperature from 350°F to 212°F is 7 hours. The heat load handled by the RHRS during the cooldown transient includes residual and decay heat from the core and heat from a single operating reactor coolant pump. The design heat load is based on the decay heat fraction that exists at 12 hours following reactor shutdown from an extended run at full power.

Assuming that two heat exchangers and pumps are in service and that the heat exchangers are supplied with CCW at design flow and temperature, the RHRS is capable of reducing the temperature of the reactor coolant from 350°F to 200°F within 9 hours. The time required under these conditions to reduce reactor coolant temperature from 350°F to 212°F is approximately 3.5 hours. 8

Assuming that only one heat exchanger and pump are in service and that the heat exchanger is supplied with CCW at design flow and temperature, the RHRS is capable of reducing the temperature of the reactor coolant from 350°F to 200°F within 22 hours. The time required under these conditions to reduce reactor coolant temperature from 350°F to 212°F is approximately 12 hours. 16

The RHRS is designed to be isolated from the RCS whenever the RCS pressure exceeds the RHRS design pressure. The RHRS is isolated from the RCS on the suction side by two motor operated valves in series on each suction line. Each motor operated valve is interlocked to prevent its opening if RCS pressure is greater than 425 psig during plant cooldown and to automatically close if RCS pressure exceeds 750 psig. The RHRS is isolated from the RCS on the discharge side by two check valves in each return line. Also provided on the discharge side is a normally open motor operated valve downstream of each RHRS heat exchanger. 38

Each RHR subsystem is equipped with a pressure relief valve designed to relieve the combined flow of all the charging pumps at the relief valve set pressure of 600 psig. These relief valves also protect the system from inadvertent overpressurization during plant cooldown or startup.

Each South Texas Project nuclear unit has a RHRS and there is no sharing of the RHRS between the two units.

The RHRS is designed to be fully operable from the control room for normal operation. Manual operations required of the operator are: opening the suction isolation and miniflow recirculation valves, positioning the flow control valves downstream of the RHRS heat exchangers, and starting the RHR pumps. By nature of its redundant three train design, the RHRS is designed to accept single failures, including the low probability electrical failure of the suction isolation valve interlock circuitry, with the only effect being an extension in the required cooldown time. The arrangement of interlock logic and power train alignment ensure that at least one RHR train can be placed into service assuming the most limiting conditions (i.e., the low probability electrical single failure of one emergency diesel generator in conjunction with LOOP). A detailed description of this arrangement is given in Section 5.4.7.2.6. The only motor operated valves in the RHRS which are subject to flooding (suction isolation valves) are valves not required to function after a LOCA. Although Westinghouse considers it to be of low probability, spurious operation of a single motor operated valve can be accepted without loss of function as a result of the redundant three train design. 38

Missile protection, protection against dynamic effects associated with the postulated rupture of piping, and seismic design are discussed in Sections 3.5, 3.6, and 3.7 respectively.

RHR and CCW systems are calculated and used as input to the next interval's heat balance calculation.

Assumptions utilized in the series of heat balance calculations describing normal plant shutdown are as follows:

38

- ✓ 1. RHR operation is initiated four (4) hours after reactor shutdown.
- ✓ 2. RHR operation begins at a reactor coolant temperature of 350°F.
- ✓ 3. Thermal equilibrium is maintained throughout the RCS during the cooldown.
- ✓ 4. CCW temperature during cooldown is limited to a maximum of 120°F.

OK Cooldown curves calculated using this method are provided for the cases of three RHR trains operable (Figure 5.4.-8) and two RHR trains operable and one RHR train operable (Figure 5.4-9).

5.4.7.4 Preoperational Testing. Preoperational testing of the RHRS is addressed in Chapter 14.

#### 5.4.8 Reactor Water Cleanup System

This does not apply to STP.

#### 5.4.9 Main Steam and Feedwater Piping

Refer to Chapter 10.

#### 5.4.10 Pressurizer

5.4.10.1 Design Bases. The general configuration of the pressurizer is shown on Figure 5.4-10. The design data of the pressurizer are given in Table 5.4-9. Codes and material requirements are provided in Section 5.2.

The pressurizer provides a point in the RCS where liquid and vapor can be maintained in equilibrium under saturated conditions for pressure control purposes.

5.4.10.1.1 Pressurizer Surge Line: The surge line is sized to limit the pressure drop between the RCS and the safety valves with maximum allowable discharge flow from the safety valves. Overpressure of the RCS does not exceed 110 percent of the design pressure.

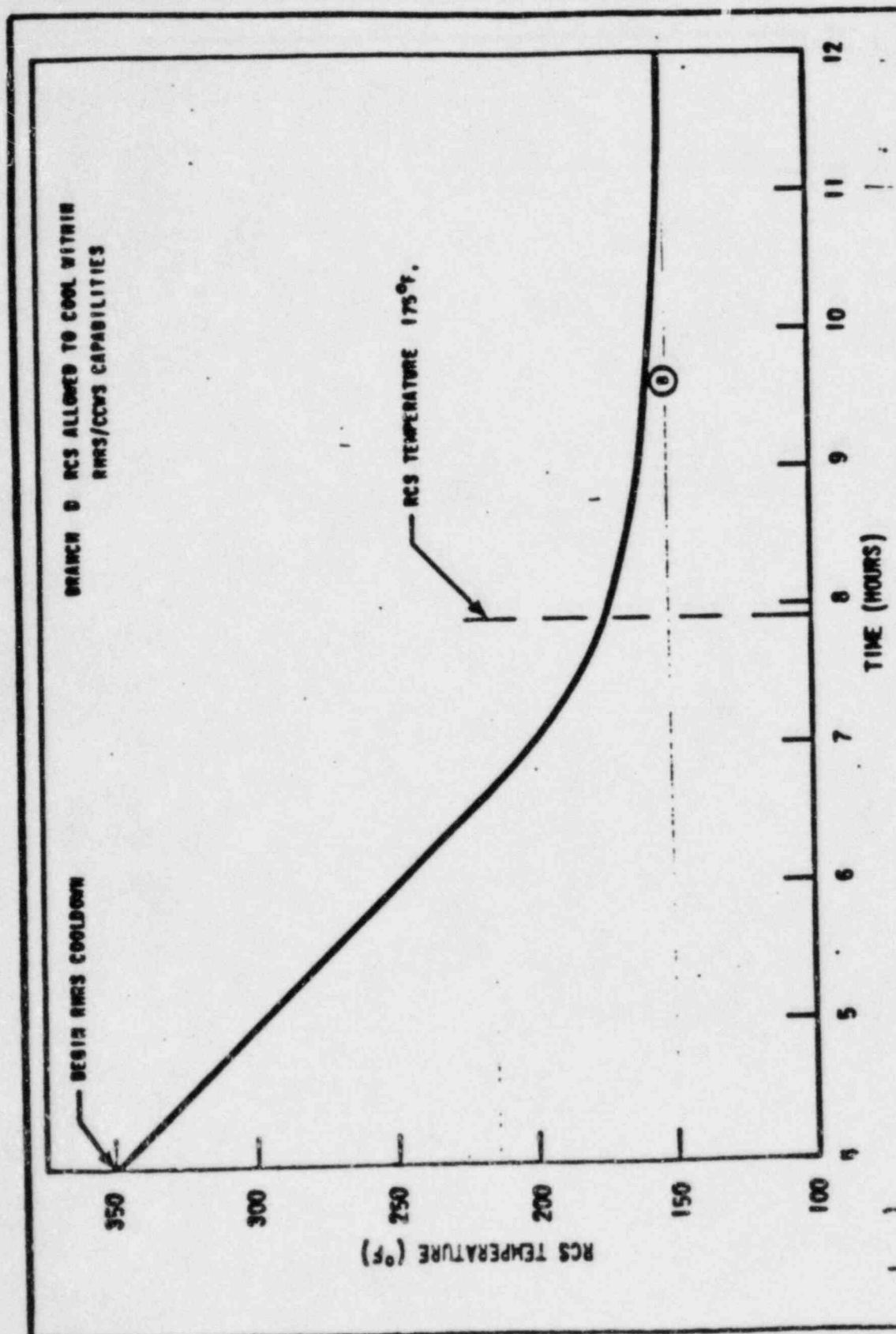
The surge line and the thermal sleeve in the pressurizer surge nozzle are designed to withstand the thermal stresses resulting from volume surges of relatively hotter or colder water which may occur during operation.

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The 16 in. pressurizer surge line is shown on Figure 5.1-3.

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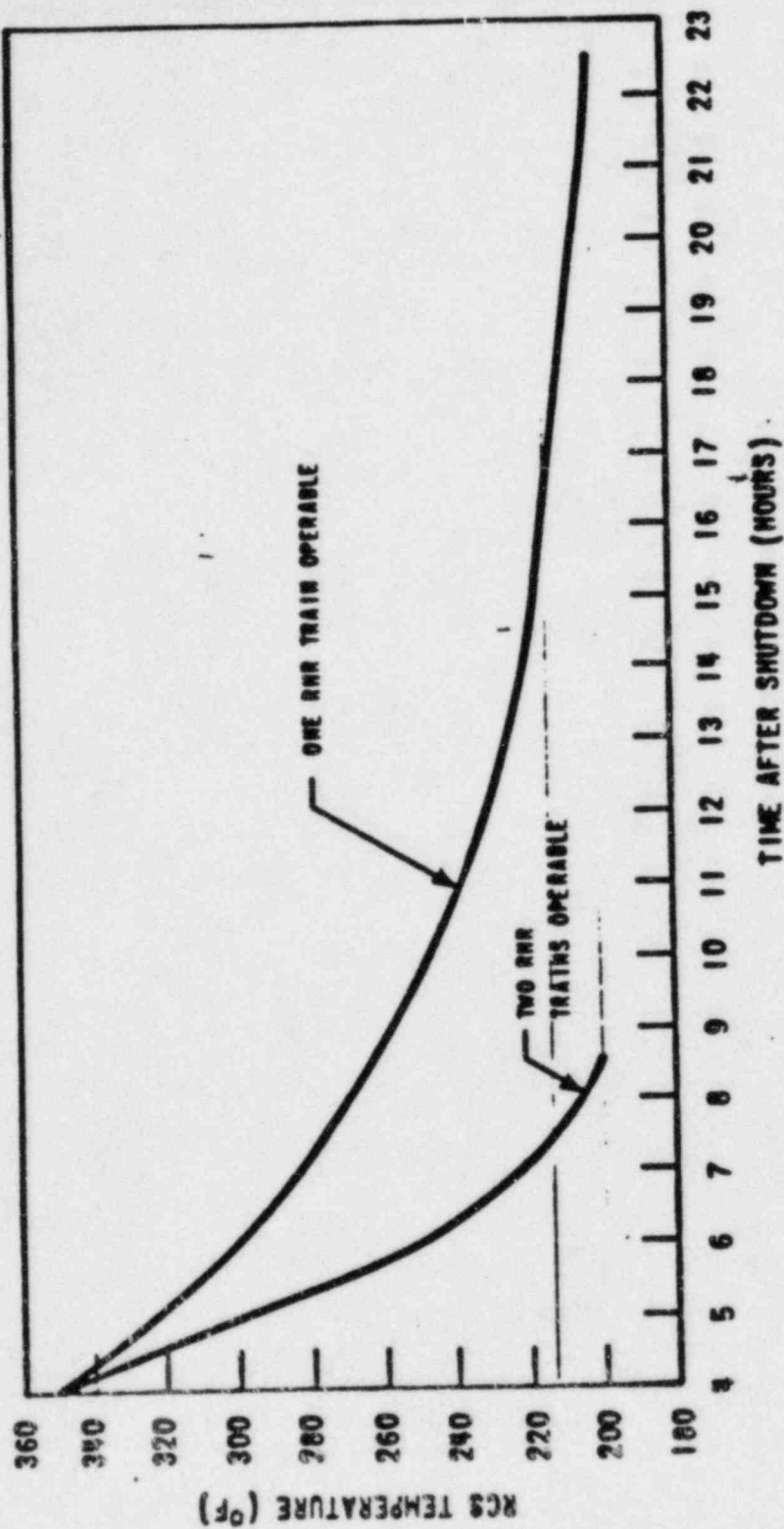




**SOUTH TEXAS PROJECT  
UNITS 1 & 2**

RHR Cooldown, 3 Trains Operable





## SOUTH TEXAS PROJECT UNITS 1 & 2

RHR COOLDOWN, 2 TRAINS OPERABLE  
AND ONE TRAIN OPERABLE  
FIGURE 5.4-9

QUESTION 440.28  
(Section 5.4.7)

Provide the basis for sizing the RHR relief valves. Also justify using 600 psig as the valve set pressure, in view of the fact that the RHR system design pressure is also 600 psig. Other recent Westinghouse plants, which also have RHR systems designed to 600 psig, utilize 450 psig as the valve setpoint. If the RHR relief valve is utilized for LTOPS purpose, discuss the suitability of the valve capacity and setpoint for this purpose.

RESPONSE:

As reported in Section 5.4.7.1, each RHR sub-system is equipped with a pressure relief valve designed to relieve the combined flow of all the charging pumps at the relief valve set pressure of 600 psig. The potential and capacity for charging pumps to overpressurize the residual heat removal system, therefore, represent the sizing basis for the valves.

The reason for the variation in relief valve set pressures between the South Texas Project and other Westinghouse designs is that the South Texas relief valve is in the RHR pump discharge rather than the suction line. In effect, to protect against system overpressurization via a pump suction side relief valve, the developed head of the subject pump must be considered in the establishment of the relief valve set pressure. Consequently, the set pressure variance to effect the same system protection is appropriate.

The South Texas cold overpressure mitigation system does not take credit for the availability or relief capacity of the RHR relief valves.

QUESTION 440.29

Figure 5.4.6 "RHRS Piping Diagram" indicates ESF signals to the RHR inlet valves and does not show the open permissive and auto closure interlocks. Are these interlocks combined with the ESF controls? If so, can the RHR inlet valves be inadvertently opened when the RCS is at high pressure or closed when the plant is on RHR cooldown in the event of an ESF actuation? Figure 5.4.6 should show the interlocks and power diversity as described in the text.

RESPONSE:

For consistency in representation of signals to equipment, the ESF symbol has been used to represent protection-grade (Class 1E) signals to equipment. On Figure 5.4-6, the ESF symbol for the RHR inlet isolation valves represents the open permissive and auto closure interlock signals to the valves from the Solid State Protection System, which are Class 1E signals. These signals are discussed in Sections 5.4.7 and 7.6.2; the logic diagram for these valves is shown in Figure 7.6-2. As shown on this figure, no other signals are sent to these valves.

The power diversity for these valves is discussed in the above referenced sections, and is also shown on Figures 7.6-2 and 5.4-6.

QUESTION 440.30

With regard to the information in Appendix 5.4A "Cold Shutdown Capability" identify the most limiting single failure with regard to cooldown capability and verify that the statement of Table 5.4A-1 that the auxiliary feedwater storage tank (AFST) "capacity of 500,000 gallons is adequate to support 4 hours at hot standby conditions followed by 10 hours cooldown to RHR cut in condition with a margin for contingencies" considers this failure.

RESPONSE:

The response to this question will be provided later.

QUESTION 440.31  
(Section 5.4.7)

Provide RHR pump performance curves.

RESPONSE:

A performance curve for the South Texas Project Residual Heat Removal Pump will be provided as FSAR Figure 5.4-20.



cooling train and is aligned as part of the cold leg safety injection path. The use of this portion of the RHRS as part of the SIS is more completely described in Section 6.3. |38

The RHR suction isolation valves in each inlet line from the RCS are separately interlocked to prevent their being opened when RCS pressure is greater than 425 psig and to automatically close if RCS pressure exceeds 750 psig. These interlocks are described in more detail in Sections 5.4.7.2.4 and Section 7.6.2.

5.4.7.2.2 Equipment and Component Descriptions: The materials used to fabricate RHRS components are in accordance with the applicable Code requirements. All parts of components in contact with borated water are fabricated of, or clad with, austenitic stainless steel or equivalent corrosion resistant material. Component parameters are given in Table 5.4-8.

#### Residual Heat Removal Pumps

Three pumps are installed in the RHRS. The pumps are sized to deliver reactor coolant flow through the RHR heat exchangers to meet the plant cooldown requirements. The use of three separate residual heat removal trains assures that cooling capacity is only partially lost should one pump become inoperative. A Pump performance curve is provided in Figure 5.4-XX. |38

The RHR pumps are protected from overheating and loss of suction flow by miniflow bypass lines that assure flow to the pump suction. A valve located in each miniflow line is under remote manual control by the operator, prior to starting the RHR pump, the miniflow valve is opened and pump minimum flow rate is established through an orifice which is in each bypass line. Flow instrumentation is provided in the discharge line of each pump to indicate pump flow (see Section 5.4.7.2.4).

A pressure sensor in each pump discharge header provides a signal for an indicator in the control room. A high pressure alarm is also actuated by the pressure sensor. A local pressure gauge in each pump suction line is used for start-up and testing purposes.

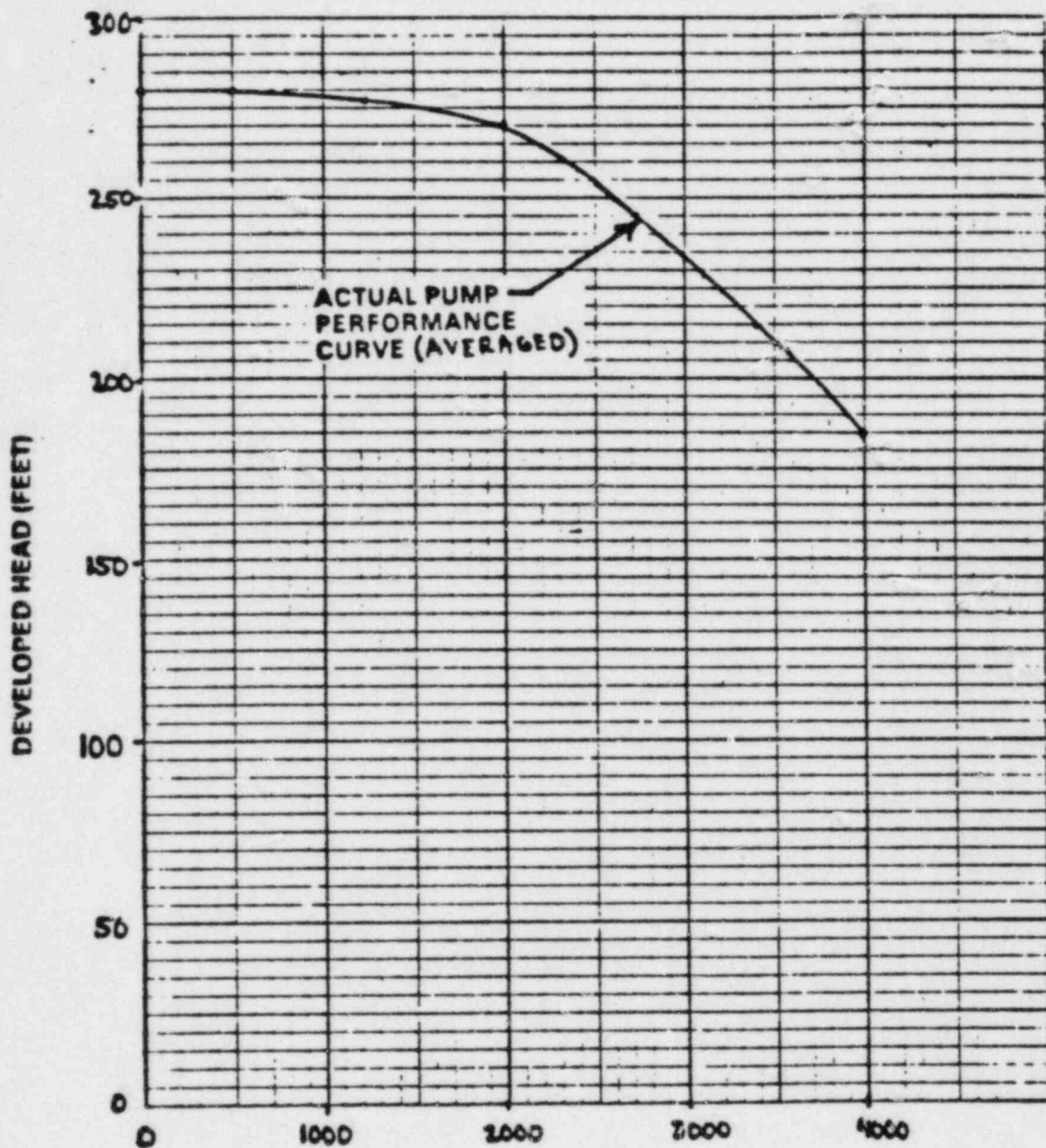
The three pumps are vertical centrifugal units with mechanical seals on the shafts. All pump surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

#### RHR Heat Exchangers

Three RHR heat exchangers are installed in the system. The heat exchanger design is based on heat load and temperature differences between reactor coolant and CCW existing twelve hours after reactor shutdown when the temperature difference between the two systems is small. |38

The installation of three heat exchangers in separate and independent residual heat removal trains assures that the heat removal capacity of the system is only partially lost if one train becomes inoperative.

The RHR heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while CCW circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant. |38



Points for Curve Preparation

0, 280  
 500, 280  
 1250, 277  
 2000, 270  
 2750, 245  
 3400, 215  
 4000, 185

## SOUTH TEXAS PROJECT UNITS 1 & 2

Residual Heat Removal  
 LOW HEAD PUMP  
 PERFORMANCE CURVES

Figure 5.4-20 Amendment

QUESTION 440.32

For each mode of operation, state whether the RHR inlet valve motor power supply breakers are locked open. If the breakers are locked open during modes 1, 2 and 3, state how the plant is brought to cold shutdown from the control room.

RESPONSE:

The RHR inlet isolation valve motor power supply breakers are not locked open during any mode of operation.

QUESTION 440.33  
(Section 5.4.7)

- a. Table 5.4 A-1 "Compliance Comparison with BTP RSB 5-1" states that during cold shutdown boron sampling is not required. Will boronometers be used for boron concentration measurements, and if so, are they safety grade? We consider periodic boron concentration measurements necessary, particularly if the plant is in natural circulation.
- b. Table 5.4 A-1, Item V, indicates that "test data and analysis for a plant similar in design to STP will verify adequate mixing and cooldown under natural circulation conditions." State which plant test would be utilized, and justify why the plant is similar to the STP design, considering possible differences in core and RCS design,  $T_{ave}$ , upper head volume and temperature, and other pertinent parameters.

RESPONSE:

SOUTH TEXAS COMPARISON OF TO DIABLO CANYON

- a) The response will be provided in September 1985.
- b) South Texas and Diablo Canyon Unit 1 have been compared in detail to ascertain any differences between the two plants that could potentially affect natural circulation flow and attendant boron mixing. Because of the similarity between the plants, it was concluded that the natural circulation capabilities would be similar. Therefore, the results of prototypical natural circulation cooldown tests conducted at Diablo Canyon will be representative of the capability at South Texas.

The general configuration of the piping and components in each reactor coolant loop is the same in both South Texas and Diablo Canyon. The elevation head represented by these components and the system piping is similar in both plants.



QUESTION 440.33 (Continued)

To compare the natural circulation capabilities of South Texas and Diablo Canyon, the hydraulic resistance coefficients were compared. The coefficients were generated on a per loop basis. The hydraulic resistance coefficients applicable to normal flow conditions are as follows:

	DIABLO CANYON <u>UNIT 1</u>	<u>South Texas</u>
Reactor Core & Internals	$128.4 \times 10^{-10}$	$149.7 \times 10^{-10} \text{ Ft}/(\text{Loop gpm})^2$
Reactor Nozzles	$36.7 \times 10^{-10}$	$27.3 \times 10^{-10} \text{ Ft}/(\text{Loop gpm})^2$
RCS Piping		
R.V.Outlet to S.G. Inlet		$4.0 \times 10^{-10} \text{ Ft}/(\text{Loop gpm})^2$
S.G. Outlet to R.C. Pump Inlet		$10.0 \times 10^{-10} \text{ Ft}/(\text{Loop gpm})^2$
R.C. Pump Discharge to R.V. Inlet		$\underline{4.0 \times 10^{-10}} \text{ Ft}/(\text{Loop gpm})^2$
Total R.C. Loop	$24.0 \times 10^{-10}$	$18.0 \times 10^{-10} \text{ Ft}/(\text{Loop gpm})^2$
Steam Generator	$\underline{114.5 \times 10^{-10}}$	$\underline{132.1 \times 10^{-10}} \text{ Ft}/(\text{Loop gpm})^2$
Total	$303.6 \times 10^{-10}$	$327.1 \times 10^{-10} \text{ Ft}/(\text{Loop gpm})^2$
Flow Ratio Per Loop	$\frac{\text{South Texas}}{\text{DIABLO CANYON}} = \sim \left( \frac{303.6}{327.1} \right)^{-1/2} = \underline{0.963}$	

The general arrangement of the reactor core and internals is the same in Diablo Canyon and South Texas. The coefficients indicated represent the resistance seen by the flow in one loop.



QUESTION 440.33 (Continued)

The reactor vessel outlet nozzles configuration for both plants is the same. The radius of curvature between the vessel inlet nozzle and downcomer section of the vessel on the two plants is different. Based on 1/7 scale model testing performed by Westinghouse and other literature, the radius on the vessel nozzle/vessel downcomer juncture influences the hydraulic resistance of the flow turning from the nozzle to the downcomer. The Diablo Canyon vessel inlet nozzle radius is significantly smaller than that of South Texas, as reflected by the higher coefficient for Diablo Canyon.

Steam generator units were also compared to ascertain any variation that could affect natural circulation capability by changing the effective elevation of the heat sink or the hydraulic resistance seen by the primary coolant. It was concluded that there are no differences in the design of the steam generators in the two plants that would adversely affect the natural circulation characteristics.

It is expected that the relative effect of the coefficients would be the same under natural circulation conditions such that the natural circulation loop flowrate for South Texas would be within five percent of that for Diablo Canyon.

For typical 4-loop plants there are two potential flow paths by which flow crosses the upper head region boundary in a reactor. These paths are the flow nozzles into the upper head and the guide tubes. The flow nozzles provide a flow path between the downcomer region and the upper head region. The temperature of the flow which enters the head via this path corresponds to the cold leg value (i.e.  $T_{cold}$ ). Fluid may also be exchanged between the upper plenum region (i.e., the portion of the reactor between the upper core plate and the upper support plate) and the upper head region via the guide tubes. Guide tubes are dispersed in the upper plenum region from the center to the periphery. Because of the non-uniform pressure distribution at the upper core plate elevation and the flow distribution in the upper plenum region, the pressure in the guide tube varies from location to location. These guide tube pressure variations create the potential for flow to either enter or exit the upper head region via the guide tubes.

QUESTION 440.33 (Continued)

To ascertain any difference between the upper head cooling capabilities between Diablo Canyon and South Texas, a comparison of the hydraulic resistance of the upper head regions was made. These flow paths were considered in parallel to obtain the following results.

	<u>DIABLO CANYON UNIT 1</u>	<u>SOUTH TEXAS</u>
Flow area (ft <sup>2</sup> )	0.77	.788
Loss coefficient	1.51	1.50
Overall hydraulic resistance (ft <sup>-4</sup> )	2.57	2.413
Relative head region flowrate (Based on hydraulic resistance)	1.00	1.03

As indicated above, the effective hydraulic resistance to flow in South Texas is slightly less than Diablo Canyon. Assuming that the same pressure differential existed in both plants the South Texas head flow rate would be 103 percent of the Diablo Canyon flow.

It can, therefore, be concluded that the results of the natural circulation cooldown tests performed at Diablo Canyon will be representative of the natural circulation and boron mixing capability of South Texas. The results of these tests will be reviewed for applicability.

QUESTION 440.34

Describe the preoperational test program for the RHR system.

RESPONSE:

The preoperational test for the RHR system is described in Item 78 of Section 14.2.12.2.

QUESTION 440.35  
(Section 5.4.7)

Recent plant experience has identified a potential problem regarding the loss of shutdown cooling during certain reactor coolant system maintenance operations. On a number of occasions when the reactor coolant system has been partially drained, improper RCS level control, a partial loss of reactor coolant inventory, or operating the RHR system at an inadequate NPSH has resulted in air binding of the RHR pumps with a subsequent loss of shutdown cooling. Regarding this potential problem, provide the following additional information.

- a. Discuss the design or procedural provisions incorporated to maintain adequate reactor coolant system inventory, level control, and NPSH during all operations in which RHR cooling is required.
- b. Discuss the provisions incorporated to ensure the rapid detection of air binding of the RHR pumps so that they are not damaged. What provisions are there to vent or otherwise remove the trapped air in the pumps and rapidly put the RHR system back into service prior to excessive core heatup?
- c. Discuss the provisions incorporated to provide alternate methods of shutdown cooling in the event of loss of RHR cooling during shutdown maintenance. These provisions should consider maintenance periods during which more than one cooling system may be unavailable, such as loss of steam generators when the reactor coolant system has been partially drained for steam generator inspection or maintenance.

RESPONSE:

- a. Both system design features and operational procedures are provided to ensure that Residual Heat Removal System (RHRS) suction flow is maintained during shutdowns when the Reactor Coolant System (RCS) has been partially drained for maintenance. Note that the water level in the RCS is manually controlled at this time.

Westinghouse operating instruction M-1, "Draining the Reactor Coolant System," Rev. 0, March, 1980 recommends that a tygon hose be connected to the drain line of reactor coolant loop #1 and extended at least two feet above the top of the pressurizer, where it is vented to the containment atmosphere. This connection is shown in location C-1 of the South Texas Project RCS Flow Diagram Figure 5-1.1, sheet 1 of 4. The water level in the RCS loops can be closely monitored by means of this tygon tube. This operating instruction will be used as a guideline in the development of a STP procedure.



QUESTION 440.35 (Continued)

If maintenance operations require that the water level be lowered to the point where gas could enter the RCS piping through the pressurizer surge line, the nitrogen supply line to the pressurizer relief tank will be isolated. Also, if it is necessary to drain the steam generator tubes for maintenance, the RHR flow rate will be reduced to approximately 1500 gpm per train to preclude vortex formation at the RHR hot leg connection. Core outlet temperatures must be closely monitored under reduced RHR flow conditions. Because water drains from the steam generator tubes in a slugging fashion, RCS water level indication may be erratic. For this reason, the draining operation should be stopped periodically to allow the water level in the system to stabilize.

An additional check on the RCS water level can be obtained by observing the increase in the level in the Recycle Holdup Tank (RHT), to which the drainage from the RCS is transferred.

The net positive suction head (NPSH) which is available to the South Texas Project RHR pumps has been calculated based on a conservative set of conditions. These conditions include the water level in the RCS at the midplane of the reactor vessel nozzles and the fluid in the RCS at saturated conditions at 150°F, due to the effect of vacuum degassing on the RCS. Under these conditions, more than adequate NPSH is available at the centerline of the RHR pump impeller.

- b. The South Texas Project Residual Heat Removal System (RHRS) consists of three parallel and identical trains, each consisting of an RHR pump, an RHR heat exchanger and the associated piping, valves and instrumentation required for operational control. The system is sized to permit RCS cooldown from 350°F to 175°F in 8 hours with all three RHR trains in operation. However, after cooldown is complete, a single RHR train provides adequate residual heat removal capability and the remaining two RHR trains may be shut down. Thus, following RCS draindown, if the RCS water level should fluctuate or be inadvertently reduced to the point at which air is drawn into the suction of the operating RHR pump, resulting in air binding, one of the two unimpaired RHR pumps may be started after the RCS water level is restored. Consequently, only a minimal interruption in RCS cooling will be experienced due to air binding of any one RHR pump.

There are a number of indications provided in the RHRS design which would provide rapid detection of air binding of the RHR pumps. A low flow condition as measured at the discharge of the RHR pump is alarmed in the Main Control Room at a flowrate of 525 gpm. The RHR pump is also tripped at this low flow rate (as discussed in Section 7.6). Indication of pump discharge flow rate is also provided on the Main Control Board.

Other indications of abnormal RHR pump operation are provided by readout of the pump discharge pressure on the Main Control Board and local readout of the pump suction pressure.



QUESTION 440.35 (Continued)

Should an RHR pump become air bound, the RCS water level should be restored and an unimpaired pump should be started, as described previously, to resume the cooling of the reactor. The gas bound pump may be restored to operational status by reflooding the pump suction piping and by opening the manual vent valves on the pump suction and discharge piping to vent the air from the pump casing and connecting piping. The pump may then be re-started as required.

- c. Under shutdown conditions, any of the three South Texas Project Residual Heat Removal System trains are adequate to remove the low level of decay heat which would be generated at the time the RCS is drained for maintenance. There is, therefore, redundancy in the RHR cooling capacity at this time.

Accepting, for the sake of discussion, however, the possibility of the total loss of RHR cooling during shutdown, the following options would be available to restore cooling of the reactor.

1. Use the charging system to refill the RCS and establish a natural circulation cooling path, removing decay heat via the steam generators and the auxiliary feedwater system.
2. Use the charging system to refill the RCS and establish circulation by starting one or more reactor coolant pumps; as in option 1, decay heat removal would be provided by the secondary system.
3. The cavity could be flooded via the LHSI pumps using water from the RWST, thereby assuring that the core is covered.

QUESTION 440.36  
(Section 5.4.15)

- a. Describe the compliance of the reactor vessel head vent system (RVHVS) with NUREG-0737 Item II.B.1 "RCS Vents". Provide an item by item comparison of the NUREG -0737 requirements with the STP RVHVS design.
- b. The FSAR indicates that the RVHVS is also used for primary coolant letdown. State during what operational modes the RVHVS would be used for letdown, whether it would be used together with or as an alternate to CVCS letdown, and whether there could be interference between the letdown function and the system's primary function of head venting.
- c. Revise Figure 5.1-1 to depict the RVHVS as described in the Amendment 38 submittal, including the existence of redundant remote operated isolation and throttling valves. Also clarify whether the system discharges to the PRT, as stated in Section 5.4.15, or to the reactor coolant drain tank, as shown in figure 5.1-1.

RESPONSE:

A.

1. A description of the design, location, size and power supply for the head vent system is provided in Section 5.4.15 of the STP FSAR. As indicated in Section 5.4.15.3 of the STP FSAR a break in a vent pipe would be similar to the hot leg break case in WCAP-9600 and the results presented therein are applicable.
2. Westinghouse Emergency Response Guideline FRI-3, "Response to voids in the Reactor Vessel" provides guidance on the operation of the head vent system. STP plant specific procedures relating to the operation of the head vent system will be developed by Houston Lighting and Power.

Also see Appendix 7A, item II.B.1 for further information.

- B. As described in Section 5.4.A.1 the safe shutdown design basis for the STP is hot standby. The cold shutdown capability of the plant has however been evaluated. In this scenario the head vent line may be used as a letdown path should the primary (CVCS) letdown path be unavailable.
- C. The head vent system discharges to the pressurizer relief tank. Figure 5.1-1 will be corrected.

QUESTION 440.37  
(Section 5.4.15)

State what provisions have been made for pressurizer and RCS loop venting.

RESPONSE:

Noncondensable gases would be expected to collect in the reactor vessel head or the pressurizer. The reactor vessel may be vented via the reactor vessel head vent system while the pressurizer may be vented via the safety related PORVs.

QUESTION 440.38  
(Section 6.3. & 15.6.5)

- a. Demonstrate that the STP ECCS meets 10 CFR Part 50.46 criteria for long term decay heat removal in the event of a small break LOCA of a size such that recirculation would be required but the RCS pressure either remains above the low head safety injection (LHSI) pump shutoff head or recovers after loss of the secondary heat sink. An examination of Figures 6.3-1 through 6.3-5 does not indicate that the STP ECCS is designed for high head recirculation combined with decay heat removal by the RHR heat exchangers, i.e., there are no apparent provisions for routing recirculation flow from the RHR heat exchangers to the HHSI pumps. Also, as described in Appendix 5.4A "Cold Shutdown Capability," the steam generators have a limited supply of safety grade secondary water supply, since there is not a safety grade backup to the auxiliary feedwater storage tank (AFST). Therefore, provide long term analyses for a spectrum of small break LOCAs that demonstrate that decay heat can be adequately removed and the RCS depressurized using only safety grade equipment and water sources, assuming loss of offsite power and the most severe single failure. If credit is taken for operator actions, the STP emergency response guideline (ERG) sequence of operator actions should be followed. Justify the timing of operator actions if they are less conservative than those recommended in ANSI N-660 for a condition IV event.
- b. In a conference call held on March 8, 1985, the applicant indicated to NRC that for small break LOCAs the combined heat sink capacity of the RWST and the steam generators would provide core cooling for approximately 18 hours, after which the reactor containment fan coolers (RCFCs) would provide an adequate heat sink for decay heat removal. No credit is taken for heat removal by the RHR heat exchangers. Provide a detailed explanation of the mechanism of energy removal from the RCS after loss of the secondary heat sink and supporting analyses that demonstrate that energy can be adequately removed to meet the acceptance criteria of 10 CFR Part 50.46. We are concerned that for very small break LOCAs (e.g., 1 inch) energy would not be adequately removed from the RCS for a considerable period of time after the accident. Thus, WCAP-9600, "Report on Small Break Accidents for Westinghouse NSSS System" June 1979, indicates that for 1 inch breaks the break can remove all the decay heat only after about 24 hours, and that prior to that time, auxiliary feedwater is required to maintain the heat sink.

RESPONSE:

This response will be provided later.

QUESTION 440.39  
(Section 6.3)

- a. It is stated in 10 CFR Part 50.46(b)(5) that, for long term cooling, "the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-term radioactivity remaining in the core." In order to assure this, heat removal for this extended period must utilize equipment that is fully qualified for the environmental conditions that prevail during the accident. Please demonstrate that decay heat can be removed from the STP core with qualified equipment only, following all sizes of LOCAs, including all LOCAs which could be subsequently isolated by the operator. Include consideration of the post-LOCA cooldown period in your response, and the fact that for isolated LOCAs, the sump would not be available for long term cooling.
- b. Discuss whether the RHR pumps are qualified for the environmental effects of the large and small break LOCAs and steam line breaks. If the RHR pumps are not qualified discuss how long term mitigation of these accidents would be accomplished.

RESPONSE:

This response will be provided later.



QUESTION 440.40

Your list of actions initiated by the SI signal (Section 6.3.2.1) does not include diesel-generator start nor closure of the SI jockey pump inlet isolation valves. These actions should be included.

RESPONSE:

Section 6.3.2.1 will be revised to clarify that the standby diesel generators, ESF load sequencers and other equipment needed to support the ECCS is also actuated by the SI signal.

The SI jockey pump system has been deleted (Section 6.3 will be revised).

are powered from separate buses which are energized from offsite power supplies.

In addition, the standby diesel generators (DGs) assure adequate redundant sources of auxiliary onsite power are available to meet all ECCS power requirements. Each diesel is capable of driving all pumps, valves and necessary instruments associated with one train of the ECCS.

In response to NRC Branch Technical Position EICSB-18, protection against spurious movement by power lockout has been included in the design of certain MOVs as described in Section 6.3.2.2 and 6.3.5.5.

The elevated temperature of the sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long term recirculation operations.

Environmental qualification of ECCS equipment which is required to operate following a LOCA is discussed in Section 3.11.

### 6.3.2 System Design

The ECCS components are designed such that a minimum of two accumulators delivering to two unaffected loops, and one high head and one low head safety injection pump delivering to an unaffected loop will assure adequate core cooling in the event of a design basis LOCA. The redundant onsite standby diesels assure adequate emergency power to all electrically operated components in the event that a loss of offsite power occurs simultaneously with a LOCA, even assuming a single failure in the emergency power system such as the failure of one diesel to start.

6.3.2.1 Schematic Piping and Instrumentation Diagrams. Flow diagrams of the ECCS are shown on Figures 6.3-1 thru 6.3-5. Pertinent design and operating parameters for the components of the ECCS are given in Table 6.3-1. The codes and standards to which the individual components of the ECCS are designed are listed in Section 3.2.

The component interlocks used in different modes of <sup>ECCS</sup> system operation are listed below.

1. The safety injection (SI) signal is interlocked with the following components and ~~in conjunction with the load sequencer~~ initiates the indicated action:
  - a. HHSI pumps start: *(through the ESF load sequencer signal)*
  - b. LHSI pumps start:
  - c. Any closed accumulator isolation valves open.
  - d. RWST discharge isolation valves to Spent Fuel Pool Cooling and Cleanup System (SFPCS) close.

(jockey pump system deletion)

e. The normally closed LHSI and HHSI pump miniflow isolation valves open.

e. The component cooling water system (CCWS) valves for the RHR HX open.

2. Switchover of one train from injection mode to recirculation mode involves an interlock where the suction valves from the sump open and the HHSI and LHSI pump mini-flow valves close when the level transmitter indicates a low-low level in the RWST, coincident with an SI signal.

3. Additionally, the system includes an interlock which prevents the RWST isolation valves from being opened unless the corresponding recirculation sump valves are closed.

6.3.2.2 Equipment and Component Descriptions. The component design and operating conditions are specified as the most severe conditions to which each respective component is exposed during either normal plant operation, or during operation of the ECCS. For each component, these conditions are considered in relation to the code to which it is designed. By designing the components in accordance with applicable codes, and with due consideration for the design and operating conditions, the fundamental assurance of structural integrity of the ECCS components is maintained. Components of the ECCS are designed to withstand the appropriate seismic loadings in accordance with their safety class as given in Section 3.2. Active, powered components required for ECCS operation are listed in Table 6.3-12.

The major mechanical components of the ECCS follow. ECCS component parameters are provided in Table 6.3-1.

#### Accumulators

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the RCS by two check valves in series. Should the RCS pressure fall below the accumulator pressure, the check valves open and borated water is forced into the RCS. One accumulator is attached to each of the cold legs of loops 1, 2 and 3 of the RCS. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

Connections are provided for remotely adjusting the level and boron concentration of the borated water in each accumulator during normal plant operation as required. Accumulator water level may be adjusted by pumping borated water from the RWST to the accumulator. Samples of the solution in the accumulators are taken periodically for checks of boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas, and can be adjusted as required during normal plant operation; however, the accumulators are normally isolated from this nitrogen supply. Gas relief valves on the accumulators provide protection from pressures in excess of design pressure.

The accumulators are located within the Containment but outside of the secondary shield wall thus providing missile protection.

Insert "A"

As indicated in Section 7.3.1, the standby diesel generators, ESF load sequencers, HVAC equipment, cooling water systems and other components required to support the ECCS equipment are also actuated by the SI signal.

TABLE 7.3-2A

FUNCTIONS/SYSTEMS ACTUATED BY WESTINGHOUSE ESFAS SIGNALS

SAFETY INJECTION SIGNAL

Reactor Trip System

Turbine Trip

Feedwater Isolation

Auxiliary Feedwater System

Main Steam Line Isolation

\* Standby Diesel Generators

\* Component Cooling Water System

Safety Injection System

\* Essential Cooling Water System

Reactor Containment Fan Coolers

Containment Isolation Phase A

Containment Ventilation Isolation

Control Room Envelope HVAC System

EAB Main Area HVAC System

FHB HVAC Exhaust Subsystem

\* ESF Load Sequences

CONTAINMENT SPRAY SIGNAL

Containment Spray System

Containment Isolation Phase  
B (no actuated equipment)

AUXILIARY FEEDWATER INITIATION SIGNAL

Auxiliary Feedwater System

Steam Generator Blowdown Isolation

Steam Generator Sample Isolation

43

43

Q32.16

43



17. Electrical Penetration Space HVAC System, to provide cooling for essential equipment located in that area.

Supporting HVAC equipment is also actuated as required, to cool the above equipment. For example, cubicle coolers are required to operate in the rooms containing the safety injection and containment spray pumps, and are therefore actuated.

7.3.1.1.2 Analog Circuitry: The process analog sensors and racks for the ESFAS are discussed in Reference 7.3-1. Discussed in this report are the parameters to be measured, including pressures, flows, tank and vessel water levels, and temperatures, as well as the measurement and signal transmission considerations. These latter considerations include the transmitters, orifices, flow elements, and resistance temperature detectors as well as automatic calculations, signal conditioning, and location and mounting of the devices.

The sensors monitoring the primary system are shown on process and instrument diagrams presented in Chapter 5. The secondary system sensors are shown on process and instrument diagrams presented in Chapter 10.

Containment pressure is sensed by four physically separated seismically supported differential pressure transmitters outside of the Containment. (They are connected to the Containment atmosphere by a filled and sealed hydraulic transmission system.) The distance from penetration to transmitter is kept to a minimum, and separation is maintained. This arrangement, together with the pressure sensors external to the Containment, forms a double barrier and conforms to GDC 56 and Regulatory Guide (RG) 1.11.

For the Containment ventilation isolation function, input is provided to the Westinghouse ESFAS from radiation detection equipment on the Normal Containment Purge System exhaust line. During a plant shutdown for refueling, the Normal Containment Purge System is in operation, as discussed in Section 9.4.5. Redundant Class 1E radiation monitors, i.e., the RCB Purge Isolation monitors, monitor the radiation in these purge lines, as discussed in Section 11.5. Upon either monitor sensing radiation above a preset limit, a signal is sent to the logic trains of the Westinghouse ESFAS, and the Containment ventilation signal is actuated. Additionally, as a diverse measurement, the Containment atmosphere radiation monitor, also discussed in Section 11.5, is used to monitor Containment atmosphere radiation levels and provide signals to both logic trains.

The logic for the radiation monitoring inputs to the Westinghouse ESFAS is shown in Figure 7.3-2A. Separation criteria, as required by RG 1.75 and IEEE 384-1974, are followed.

7.3.1.1.3 Digital Circuitry: The ESF logic racks are discussed in detail in Reference 7.3-2. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference 7.3-2 also covers certain aspects of on-line test provisions, provisions for test points, considerations for the instrument power source, and considerations for accomplishing physical separation. The outputs from the analog channels are combined into actuation logic as shown on Figures 7.2-6 (pressurizer pressure), 7.2-7 (steam generator water level and

QUESTION 440.41

Provide and justify the allowable temperature range for the RWST. Discuss what provisions are made to maintain the RWST temperature within this range.

RESPONSE:

The RWST is located inside the Mechanical Electric Auxiliary Building. During normal operation, the RWST room temperature is maintained between 50°F and 104°F by the MAB HVAC system.

QUESTION 440.42  
(Section 6.3)

State how unacceptable HHSI and LHSI pump runout conditions are prevented during ECCS operation at low RCS pressure.

RESPONSE:

Two orifices are provided on the discharge of each HHSI pump and one orifice is provided on the discharge of each LHSI pump.

QUESTION 440.43

Figure 9.3.4-3 indicates that normally closed valves MOV-0113B and -0112C, which can route RWST water to the charging pumps, are respectively actuated by ESF-B and ESF-C. Clarify whether this is a signal to open or close the valves. If these valves are actuated open on an SI signal, explain whether the charging pumps are utilized for safety injection.

RESPONSE:

As shown in Table 7.3-5, the SI signals close the Volume Control Tank outlet isolation valves (XCV0112B and XCV0113A) and open the RWST to charging pump valves (XCV0112C and XCV0113B). The logic diagrams for these valves are shown on Figures 7.6-12 and 7.6-13.

The purpose of these actuations following an SI signal is to align an assured source of water to the centrifugal charging pumps and allow seal injection for the reactor coolant pumps.

If a loss of offsite power occurs concurrent with the SI signal, this actuation has aligned the charging pumps to the RWST. After the sequenced loading of the standby DGs, the operator may manually load the charging pumps and reinitiate seal injection.

Should a loss of offsite power not occur concurrent with the SI signal, the charging pump(s) which were operating are not tripped and continue to operate, providing seal injection using RWST water.

The centrifugal charging pumps are not utilized for safety injection, and are not actuated by the safety injection signal.

TABLE 7.3-5

SAFETY INJECTION ACTUATED EQUIPMENT LIST

Equipment Identification	Description	ESF Train	Function	Figure Number	P&ID Number
1A	High-head safety injection pump	A	Start*	6.3-1	9F05013
1B	High-head safety injection pump	B	Start*	6.3-2	9F05014
1C	High-head safety injection pump	C	Start*	6.3-3	9F05015
1A	Low-head safety injection pump	A	Start*	6.3-1	9F05013
1B	Low-head safety injection pump	B	Start*	6.3-2	9F05014
1C	Low-head safety injection pump	C	Start*	6.3-3	9F05015
XS10039A	Accumulator 1A discharge isolation valve	A	Open	6.3-4	9F05016
XS10039B	Accumulator 1B discharge isolation valve	B	Open	6.3-4	9F05016
XS10039C	Accumulator 1C discharge isolation valve	C	Open	6.3-4	9F05016
XCV0113B	RWST to charging pump valve	B	Open	9.3.4-3	9F05007
XCV0112C	RWST to charging pump valve	C	Open	9.3.4-3	9F05007
XCV0113A	VCT outlet isolation valve	B	Close	9.3.4-3	9F05007
XCV0112B	VCT outlet isolation valve	C	Close	9.3.4-3	9F05007
FV-3936	RWST to SFPCCS valve	A	Close	6.3-1	9F05013
FV-3937	RWST to SFPCCS valve	B	Close	6.3-1	9F05013
1A	CCW Pump	A	Start*	9.2.2-1	9F05017
1B	CCW Pump	B	Start*	9.2.2-2	9F05018
1C	CCW Pump	C	Start*	9.2.2-3	9F05019
CC0297	CCW to RCDT HX and excess letdown HX isolation valve	A	Close	9.2.2-5	9F05021

\* Through ESF load sequencers

STP FSAR

7.3-37

Amendment 43



#### QUESTION 440.44

Figure 6.3-1 through 6.3-4 indicate a number of low pressure non-safety grade lines that are separated from the ECCS safety grade lines by only one valve, e.g., the SI jockey pump return line is separated from the LHSI pump discharge line by one safety grade check valve, the test lines are separated from the SI pump discharge lines by only one fail closed air operated valve, and the drain lines are only separated from the safety grade ECCS piping by single manual valves, most but not all of which are locked closed. We are concerned that valve failure or erroneous operator action could cause ECCS flow to be diverted to these lines. Provide a list of all non-safety grade lines that are connected to the ECCS, including the portions of the RHRs that are utilized for ECCS purposes, and describe the adequacy of their design regarding separation. In particular, SRP Section 6.3 states that long term decay heat removal should be provided assuming a single passive failure. Show that a failure of the single check valve off of the SI jockey pump discharge line or active failures of other valves will not result in a violation of the long term cooling requirement.

#### RESPONSE:

The requested list of all non-safety grade lines connected to the ECCS is provided herein under Tables Q440.44-1 and Q440.44-2.

The SI jockey pumps have been deleted from the design. Section 6.3.2.2, Figures 6.3-1 through 6.3-4 and Figure 5.4-6 will be revised to reflect this change.

Table Q440.44-1 lists the non-safety grade lines inside the containment connected to the ECCS. SIS test lines and accumulator nitrogen supply lines are the only two lines where single valves are provided with operators. The SIS test lines are designed for full RCS pressure up to and including the containment isolation valves. Leakage through one of the valves in the test line or nitrogen supply line would be very small and would be stopped by the containment isolation valves if the non-safety grade portion of the line remained intact, or would leak into the containment if the non-safety grade pipe had failed. Neither case would affect the long term cooling capability of the system or water inventory. The vent and drain valves are manual, normally closed valves which would not be opened in a post LOCA environment.

➤ A passive failure in any of the connections listed under Table Q440.44-1 would cause a very small leakage directly into the containment and would not affect the water inventory or long term cooling capability of the system.

The non-safety lines outside the containment, connected to the ECCS, are listed in Table Q440.44-2. As listed in the table, the vents, drain, and test connections are provided with manual, normally closed valves plus a threaded pipe cap. The vent and drain lines which may contain recirculation fluid will be provided with a locked closed valve. If a passive failure is assumed in one of the connections listed in Table Q440.44-2 it would cause a small amount of leakage into the SI pump cubicle sumps. The safety related instrumentation provided in the FHB SI pump cubicle sump will alarm and

QUESTION 440.44 (Continued)

appropriate operator action can be taken to isolate any leakage. Failure of locked closed manual valves is not postulated, thus the quantity of ECCS fluid lost outside the containment will not be substantial enough to affect the ECCS performance.

It should be noted that the SI system is provided with three independent trains. The three trains consist of an accumulator and HHSI, LHSI, and a containment spray pump. Any two trains provide adequate capacity and will be available in the case of a single failure in the third train.

TABLE Q440.44-1

Non-Safety Grade Lines Connected  
to the ECCS Inside Containment

<u>Number Per Train</u>	<u>Service Description</u>	<u>Size</u>	<u>Isolation Provided</u>
7	SIS Test Lines	3/4"	Air operated valve, fail close
1	Accumulator PSV	1"	Code safety valve
1	SI header PSV	3/4"	Code safety valve
1	Standpipe connection	3/4"	Two check valves
1	Accumulator drain	2"	Closed manual valve plus blind flange
1	Accumulator N <sub>2</sub> Supply	1"	Solenoid valve, fail close
1	RHR heat exchanger channel drain	1"	Closed manual valve
Various	Local vents, drains and test connections	1"	Closed manual valve plus threaded pipe cap

TABLE Q440.44-2

Non-Safety Grade Lines Connected  
to the ECCS Outside Containment

<u>Number Per Train</u>	<u>Service Description</u>	<u>Size</u>	<u>Isolation Provided</u>
2	SI pumps miniflow	2"	Two MOV's
1	CSS test line	6"	Locked closed manual valve
4	Containment penetration test connections	1"	Locked closed manual valve plus threaded pipe cap
Various	Local vents, drains, and test connections	1-3/4"	Closed manual valve plus threaded* pipe cap
1 (Total)	RWST drain	2"	Locked closed manual valve
1 (Total)	RWST local sample	3/4"	Closed manual valve plus threaded pipe cap
1	SIS pump suction header PSV	3/4"	Code safety
4	Lines piped to CS and SIS pump sump	2"	Locked closed manual valve
1	SI sample	3/4"	Locked closed manual valve

\*These will be changed to locked closed.

QUESTION 440.45

Clarify the source of seal cooling for the HHSI and LHSI pumps. Figure 6.3-5 "ECCS Process Flow Diagram" indicates that component cooling water is used for pump seal cooling but this function is not identified in Section 9.2.2, and the FSAR does not appear to have any other information on this. Identify any other system(s) utilized for seal cooling and other SI pump auxiliary functions, and describe the consequences of loss of these systems.

RESPONSE:

No pump seal cooling or other SI pump auxiliary functions are required for the HHSI or LHSI pumps on this project. Figures 6.3-5 and 5.4-7 will be revised to so indicate. Section 6.3 will be revised later to provide further information on the pump design.



QUESTION 440.46

Your response to question 440.13N regarding adequacy of HHSI and LHSI pump NPSH during recirculation indicates that the minimum flood level assumed in the RCB is -7.6 ft., and this elevation was used in your calculations. However, an examination of Figure 1.2-18 shows a sump screen top elevation of -7.4 ft and a bottom elevation of -11.25 ft. Use of a minimum submergence within 2 inches of the screen top elevation appears nonconservative. Please explain the adequacy of this design regarding NPSH requirements. Alternately, please provide a conservative minimum submergence height and recalculate SI pump NPSH, utilizing conservative values for suction line pressure drop, and making due allowance for vortexing. Include these calculations in your submittal.

RESPONSE:

This response revises the response to Question 440.13 to incorporate the following changes:

1. New minimum flood level is changed from -7.6 ft. to -8.1 ft.
2. NPSH is recalculated considering the new water level and the pressure drop across the screen.

The emergency sump is provided with a vortex suppression device. This device consists of standard 1-1/2" grating. The grating forms two sides and top of a cube with the remainder of the cube being bounded by the sump floors and walls. The pressure drop across the vortex breaker has been calculated and found to be negligible (less than 0.1 ft.).

Table A-2 of the proposed Revision 1 to Regulatory Guide 1.82 specifies that the minimum water level should be sufficient to cover 1.5 ft. of open screen. STP design provides 3.15 ft. of water above the bottom of the screen.

As shown in the response to Question 440.13, the pumps are provided with adequate NPSH.

QUESTION 440.13N

Demonstrate that the required NPSH is available for the HHSI and LHSI pumps by providing pertinent data and drawings, including the pressure drop due to pump suction piping system losses and the elevational difference between the emergency sump bottom and pump impeller.

RESPONSE:

The high-head safety injection (HHSI) and low-head safety injection (LHSI) pumps are similar to the containment spray pumps in that they are deepwell pumps requiring only a positive head of water at the pump suction nozzle. The net positive suction head (NPSH) calculations for the safety injection pumps use similar assumptions as discussed in Section 6.2.2.3.5 for the containment spray pumps.

Elevations used in the analyses are:

RWST (centerline of outlet nozzle)	13.0 ft
Emergency sumps (containment floor)	(-) 11.25 ft
LHSI pump suction nozzle (centerline)	(-) 22.1 ft
HHSI pump suction nozzle (centerline)	(-) 21.9 ft
Minimum flood level in the RCB	(-) 8.1 ft

The pressure drop due to pump suction piping system losses was determined by calculating the piping, elbows, tees, valves, and entrance and exit losses for each pump suction line. Fluid velocities, hence piping system losses, were maximized by assuming that all pumps are operating at their maximum (runout) flow rate. The piping system losses (in feet) for the most conservative piping routing are:

	<u>RWST</u>	<u>Emergency Sump</u>
HHSI Pump A	28.4	9.8
LHSI Pump A	29.0	8.9

The available NPSH for the limiting pump drawing from the refueling water storage tank (RWST) is given by:

$$\begin{aligned}
 NPSH_A &= (\text{Overpressure} - \text{vapor pressure}) + (\text{elevational head differences}) - (\text{piping system losses}) \\
 &= (14.7 - 1.1) \left( \frac{144}{61.7} \right) + (13.0 - (-22.1)) - 29.0 \text{ ft} \\
 &= 37.8 \text{ ft (at pump suction nozzle)}
 \end{aligned}$$

QUESTION 440.13N (Continued)

The available NPSH for the limiting pump (HHSI) drawing from the emergency sump is given by:

$$\begin{aligned} \text{NPSH}_A &= (\text{zero}) + (-8.1 - (-21.9)) - (9.8) \text{ ft} - 1.1 \text{ (head loss} \\ &\hspace{15em} \text{through the} \\ &\hspace{15em} \text{screen and} \\ &\hspace{15em} \text{insulation} \\ &\hspace{15em} \text{debris)} \\ &= 2.9 \text{ ft (at pump suction nozzle)} \end{aligned}$$

The first stage impeller is located 15 ft below the suction nozzle; therefore, the available NPSH is 17.9 feet when stated in terms of the pump impeller.

NPSH required for the LHSI and HHSI pumps is 15 feet referenced to the first stage impeller.

$\text{NPSH}_A$  is greater than NPSH required using a conservative calculation so the design is adequate.

## STP FSAR

TABLE 6.3-1

EMERGENCY CORE COOLING SYSTEM  
COMPONENT PARAMETERS

Accumulators

Number	3	
Design Pressure, psig	700	
Design Temperature, °F	300	
Operating Temperature, °F	100-150	
Normal Operating Pressure, psig	630	36
Minimum Operating Pressure, psig	600	
Total Volume, ft <sup>3</sup>	2500 each	
Normal Water Volume, ft <sup>3</sup>	1200	
N <sub>2</sub> Gas Volume, ft <sup>3</sup>	1300	7
Boron Concentration (as Boric Acid), ppm	2400-2600	
Relief Valve Setpoint, psig	700	36

High Head Safety Injection Pumps

Number	3	
Design Pressure, psig	1750	
Design Temperature, °F	300	
*Design Flowrate, gal/min	800	
Design Head, ft	2850	
Max. Flowrate gal/min	1600	
Head at Max. Flowrate, ft.	1600	36
Differential Head at Shutoff, ft. (Max)	3900	
+Motor Rating, bhp	975	
Required NPSH at Max. Flowrate, ft. (Max)	15	
Available NPSH, ft.	17.9	36

\* Includes miniflow

+ 1.15 service factor not included

TABLE 6.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM  
COMPONENT PARAMETERS

Low Head Safety Injection Pumps

Number	3
Design Pressure, psig	495
Design Temperature, °F	300
Design Flowrate, gal/min	1900
Design Head, ft.	560
Max. Flowrate, gal/min	2900
Head at Max. Flowrate, ft.	400
Differential Head at Shutoff, ft.	700
+Motor Rating, bhp	400
Required NPSH, ft. (Max)	15
Available NPSH, ft.	19.0 → 19.5

Safety Injection System Jockey Pumps

Number	2
Design Pressure, psig	700
Design Temperature, °F	300
Design Flowrate, gal/min	later
Design Head, ft.	later
Maximum Flowrate, gal/min	later
Head at Maximum Flowrate, ft.	later
Discharge Head at Shutoff, ft.	later
Motor Rating, bhp	later
Required NPSH, ft. (Max.)	later
Available NPSH, ft.	later

*Deleted in previous SARCR*

36

Residual Heat Exchangers

(See Section 5.4.7 for design parameters)

Refueling Water Storage Tank

Number	1
Total Volume, gal	531,609*
Minimum Volume, gal	443,893
Normal Pressure, psig	Atmospheric
Operating Temperature, °F	Above freezing (37°F min)
Design Pressure, psig	Atmospheric
Design Temperature, °F	120
Boron Concentration (as boric acid), ppm	2500-2700

36

3

+1.15 service Factor not included

\*During normal power operation - includes 17,132 gal. of unusable volume



QUESTION 440.47  
(Section 15.0)

General Design Criterion 17 states "...The safety function for each (onsite or offsite electric power) system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits (SAFDLs) and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences (AOOs) and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents (PAs)."

Please demonstrate that for all AOOs and PAs analyzed in Chapter 15 these limits are still met assuming loss of offsite power (LOOP). For those AOO and PA analyses which do not assume LOOP, demonstrate the conservatism of this assumption. Justify any delay time assumed between turbine trip and LOOP occurrence. Consider the effect of the assumed delay time on the conservatism of the Chapter 15 AOO and PA analyses, particularly for the "complete loss of RCS flow" and "locked rotor" analyses (See also Question 440.65).

RESPONSE:

Upon loss of offsite power, the following pumps lose power: the reactor coolant pumps, circulating water pump and the condensate pumps. As a result of losing power to the RCPs, the reactor would trip on the RCP undervoltage signal and follow the transient scenario described in Section 15.3.2, Complete Loss of Forced Reactor Coolant Flow. Even though this event is a Condition III event, it is analyzed to show that the minimum DNBR is greater than the limiting value. The results reported in the FSAR show that this is indeed the case.

All of the Condition II events are analyzed assuming offsite power is available with the exception of the Loss of Nonemergency AC Power to the Station Auxiliaries. This event is the Loss of Normal Feedwater transient without offsite power.

For the purposes of the analyses, the staff has previously stated it is acceptable to assume that loss of offsite power results from turbine trip, and that any delay that is expected to occur between turbine trip, and loss of offsite power due to frequency decay time can be assumed. Grid stability analyses have shown that the grid will remain stable and that offsite power will not be lost because of a unit trip from 100% power. A 2 second delay for loss of offsite power is a conservative assumption based on grid stability analyses.

QUESTION 440.47 (Continued)

As shown in Table Q440.47-1, the minimum DNBR and rod motion for most of the Condition II events occur in less than 2 seconds after reactor trip. Should a loss of offsite power occur 2 seconds after reactor trip, the reactor coolant pumps would coast down at the same rate as the complete loss of flow analysis (Section 15.3.2). Since the coastdown is occurring after the time of minimum DNBR and the reactor power is decreasing rapidly due to rod motion, the minimum DNBR is not adversely affected. For the cases where the minimum DNBR occurs after the conservatively assumed 2 second delay, it is easy to show that should a loss of offsite power occur 2 seconds after reactor trip, the results would be bounded by the Complete Loss of Flow. For example, in case b) of the Uncontrolled RCCA Withdrawal at Power analysis, the minimum DNBR occurs 2.5 seconds after reactor trip and rod motion 2 seconds after reactor trip. Should a loss of offsite power occur at the time of rod motion the nuclear power would decrease rapidly due to the rod motion, while the flow would be approximately 98% of thermal design flow. These core conditions are less severe than those of the complete loss of flow at the time of minimum DNBR. Thus, the Uncontrolled RCCA Withdrawal at Power event with loss of offsite power is bounded by the complete loss of flow event. A similar argument can be made for the Inadvertent Opening of a Pressurizer Safety or Relief Valve event.

All of the design basis events are analyzed with and without offsite power available.

TABLE Q440.47-1

F SAR Section	Accident	Time of Reactor Trip	Time of Rod Motion	Time of minimum DNBR	Comments
15.1.1	Feedwater Malfunctions that results in a Decrease in Feedwater Temperature				Bounded by results of Sec. 15.1.3
15.1.2	Feedwater Malfunctions 137 that result in an Increase in Feedwater Flow			27	
15.1.3	Excessive Increase in Secondary Steam Flow				No reactor trip
15.1.4	Inadvertant Opening of a Steam Generator Relief or Safety Valve				Bounded by results of Sec. 15.1.5
15.1.5	Steam System Piping Failure				Analysis done with and without offsite power available
15.2.1	Steam Pressure Regulator Malfunction or Failure that results in Decreasing Steam Flow				Not applicable to South Texas
15.2.2	Loss of Electrical Load				Bounded by results of Sec. 15.2.3
15.2.3	Turbine Trip				
	1)	5.9	7.9	(a)	
	2)	5.8	7.8	(a)	
	3)	4.4	6.4	(a)	
	4)	4.4	6.4	(a)	
15.2.4	Inadvertent Closure of Main Steam Isolation Valves				Bounded by results of Sec. 15.2.3
15.2.5	Loss of Condenser Trip Vacuum and Other Events resulting in a Turbine Trip				Bounded by results of Sec. 15.2.3

TABLE Q440.47-1 (continued)

15.2.6	Loss of Nonemergency ac Power to the Plant Auxiliaries				This is a LOOP
15.2.7	Loss of Normal Feedwater Flow				Sec. 15.2.6 is case with LOOP
15.2.8	Feedwater System Pipe Break				Done with and wihout LOOP
15.3	Decrease in Reactor Coolant System Flowrate				Bounded by Complete Loss of Flow
15.4.1	Uncontrolled RCCS Withdrawal from a Subcritical or Low Power Startup Condition	10.2	10.7	12.0	
15.4.2	Uncontrolled RCCA Withdrawal at Power				
	a)	1.2	1.7	2.6	
	b)	10.2	12.2	12.7	
15.4.3	RCCA Misalignment				DNB design basis will be met. FSAR being updated to incorporate negative flux rate trip methodology per CAP-10297-P-A.
15.4.4	Startup of an Inactive Reactor Coolant Loop at an Incorrect Temperature	10.2	11.2	12.0	
15.4.5	Failure of a BWR Flow controller				Not applicable to South Texas
15.4.6	CVCS Malfunctions that results in a decrease in the Boron Concentration in the Reactor Coolant				At-power case bounded by Sec. 15.4.2
15.4.7	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position				Static analysis

TABLE Q440.47-1 (continued)

15.4.8	Spectrum of RCCA Ejection Accidents			
	1) BOL HFP	0.05	0.55	NA
	2) EOL HZP	0.14	0.64	NA
15.5.1	Inadvertent Operation of the ECCS During Power Operation			Not applicable to South Texas due to low ECCS shutoff head of 1600 psia
15.5.2	CVCS Malfunctions that Increase Reactor Coolant Inventory			
	1)	349	351	NA
	2)	278	280	NA
	3)	462	464	NA
	4)	363	365	NA
15.6.1	Inadvertent Opening of a Pressurizer Safety or Relief Valve	18.8	20.8	21.0

(a) The minimum DNBR increases throughout the transient.  
NA - Not Applicable.



QUESTION 440.48  
(Section 15.0)

Provide as part of a table; or where appropriate, the initial pressurizer water volume assumed in all Chapter 15 transients and accidents analyses. Include a discussion to indicate the degree of conservatism assumed. Discuss whether those values are compatible with the planned STP technical specification limits.

RESPONSE:

The accident analyses assume event initiation from nominal conditions with allowances for uncertainties such as measurement error and rod controller dead band. These nominal conditions are maintained by automatic control systems such that deviation from the nominal operating points are limited to within the allowance bands. It is not necessary to add to the Technical Specifications restrictions on the pressurizer water level used in the Safety Analysis. Where the Technical Specifications do contain restrictions on process variables the specified limiting values are typically actual values, that is either design values or those used in the analysis without additional allowances for measurement uncertainty.

All values in the Technical Specifications other than those whose uncertainties are specifically specified as analytical, design, etc. may be treated as indicated values without regard for instrument uncertainties. This is acceptable because of the relatively small magnitude of typical measurement uncertainties (one to two percent of calibrated span) when compared to the conservatisms included in the plant design and safety analysis. Small deviations in plant parameters resulting from measurement uncertainty are negligible considering the conservatisms upon which the "limiting" values are based.

QUESTION 440.49  
(Section 15.0)

Your response to our Question 211.7 regarding provision of a summary table of transient and accident analysis results for DNBR, a peak RCS pressure, and fraction of failed fuel refers to a "Section 15.0.11". We do not have this FSAR section. Therefore, please provide the requested information.

RESPONSE:

This has been provided in FSAR Section 15.0.11 which is included in Amendment 43 of the FSAR.

QUESTION 440.50  
(Section 15.0)

Your response to Questions 211.43 and 211.45 indicate that the pressurizer safety and relief valves have adequate capacity for liquid relief in the event of a feedwater line break or inadvertent continued charging pump operation. However, because of previous incidents with these type of valves, there is a concern whether the valves would reseal properly after prolonged relieving of liquid or 2 phase flow. State whether these valves are designed specifically for this service. If they are not designed for liquid or two phase relief, please justify why this is acceptable and conforms with the ASME code. Confirm that all Chapter 15 events which either predict or expect a two-phase or liquid relief from the safety or relief valves assumed the valves to fail open in the analysis.

RESPONSE:

Only two events predict the pressurizer to fill during or as a result of the transient. In Section 15.5.2, "Chemical and Volume Control Systems Malfunction that Increases Reactor Coolant Inventory," it is specifically stated that to prevent filling the pressurizer with water, the operator must terminate charging and the sequence of events presented in Table 15.5-1 shows that the operator has sufficient time to take corrective action.

Section 15.2.8 discusses the Main Feedline Rupture with offsite power available. An analysis is currently being performed to remove unnecessary conservatism and to provide results showing that the pressurizer will not fill as a result of this event. Upon completion of this analysis, revised FSAR documentation and figures will be provided during third quarter of 1985.

QUESTION 440.51

Your response to Question 211.52 is incomplete. The following requested information is missing and should be provided:

- a. No information is given for anticipated operational occurrences (A00s). Pages "Q&R15.0-18 a-d" are missing.
- b. For accidents, the requested delay time for operator action is not given. Provide this information and justify the acceptability of the assumed delay times if they are less than those recommended in draft ANSI N-660.

RESPONSE:

- a. The A00's are described on pages "Q&R 15.0-18 a-d".
- b. Table 211.52-1 will be revised to include operator delay times.

QUESTION 440.52

Clarify whether the STP A00 and PA analyses were performed assuming the maximum steam generator tube leakage allowed by the technical specifications. If this was not the case, justify the conservatism of your analyses.

RESPONSE:

The accident dose analyses presented in Chapter 15 have assumed the Standard Technical Specification steam generator tube leakage (1 gpm) value when determining the activity in the secondary water.



QUESTION 440.53  
(Section 15.0)

- a. State how the STP AOO analyses meet the requirements of GDC-26 regarding the capability of the control rod system to reliably control reactivity changes to assure that, for any AOO, the specified acceptable fuel design limits are not exceeded with appropriate margin for malfunctions such as stuck rods.
- b. State how the STP PA analyses meet the requirements of GDC-27 regarding the capability of the reactivity control systems, in conjunction with boron addition by the ECCS, of reliably controlling reactivity changes to assure that, under PA conditions and with appropriate margin for stuck rods, the capability to cool the core is maintained.

RESPONSE:

- a) For each of the Non-LOCA AOOs in the STP FSAR, the requirement of GDC-26 is satisfied in that the analyses assume that the most reactive RCCA is stuck in its fully withdrawn position and that the plant is in manual rod control except where automatic control worsens the vent. Plant characteristics related to the initial reactivity conditions are discussed in Section 15.0.3. The results summary in Section 15.0.11 (see Q440.49) indicates that the acceptance criteria for each event are met with these assumptions implemented in the analyses.
- b) For each of the non-LOCA PAs in the STP FSAR, the requirement of GDC-27 is satisfied in that the analyses assume that the most reactive RCCA is stuck in its fully withdrawn position and that plant characteristics related to reactivity conditions are combined for conservative feedback response. The results summary in Section 15.0.11 (see Q440.49) indicates that the design basis conditions for each event are met with these assumptions implemented in the analyses.

#### 15.0.4 Reactivity Coefficients Assumed in the Accident Analyses

The transient response of the reactor system is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients and their values are discussed in detail in Chapter 4.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values whereas in the analysis of other events, conservatism requires the use of small reactivity coefficient values. Some analyses such as loss of reactor coolant from cracks or ruptures in the RCS do not depend on reactivity feedback effects. The values used are given in Table 15.0-2. Reference is made in that table to Figure 15.0-2 which shows the upper and lower bound Doppler power coefficients as a function of power, used in the transient analysis. The justification for use of conservatively large versus small reactivity coefficient values are treated on an event-by-event basis. In some cases conservative combinations of parameters are used to bound the effects of core life. For example, in a load increase transient it is conservative to use a small Doppler defect and a small moderator coefficient.

#### 15.0.5 Rod Cluster Control Assembly Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCAs and the variation in rod worth as a function of rod position. With respect to accident analyses, the critical parameter is the time of insertion up to the dashpot entry or approximately 85 percent of the rod cluster travel. The RCCA position versus time assumed in accident analyses is shown on Figure 15.0-3. Both the rod position and the rod insertion time are normalized to the dashpot. The RCCA insertion time to dashpot entry is taken as 2.8 seconds unless otherwise noted in the discussion.

Figure 15.0-4 shows the fraction of total negative reactivity insertion versus rod position for a core where the axial distribution is skewed to the lower region of the core. An axial distribution which is skewed to the lower region of the core can arise from an unbalanced xenon distribution. This curve is used to compute the negative reactivity insertion versus time following a reactor trip which is input to all point kinetics core models used in transient analyses. The bottom skewed power distribution itself is not an input into the point kinetics core model.

There is inherent conservatism in the use of Figure 15.0-4 in that it is based on a skewed flux distribution which would exist relatively infrequently. For cases other than those associated with unbalanced xenon distributions, significant negative reactivity would have been inserted due to the more favorable axial distribution existing prior to trip.

The normalized RCCA negative reactivity insertion versus time is shown on Figure 15.0-5. The curve shown in this figure was obtained from Figures 15.0-3 and 15.0-4. ~~A total negative reactivity insertion following a trip of four percent  $\Delta K$  is assumed in the transient analyses except where specifically noted otherwise.~~ This assumption is conservative with respect to the calculated trip reactivity worth available as shown in Table 4.3-3. For Figures 15.0-3 and 15.0-5, the RCCA drop time is normalized to 2.8 seconds, unless otherwise noted for a particular event.

440.53

A total negative reactivity insertion of four percent  $\Delta K$  following a trip, equivalent to that of the most reactive rod in the <sup>Amendment 43</sup> with drawn stuck position, is assumed in the transient analyses except where specifically noted.

QUESTION 440.54  
(Section 15.0)

State whether the STP AOO and PA analyses were performed for all operational modes. If not, or the assumption is made that Mode 1 bounds all the others, please review each AOO and PA to provide assurance that all equipment and systems relied upon for AOO or PA mitigation whose availability and operability is assured by the STP Technical Specifications in Modes 1 and 2 can also be relied on to provide mitigation in other modes. If this assurance can not be provided, then provide a detailed accounting of what systems, equipment, and protective functions were assumed for these modes, a justification of why the Modes 1 and 2 analyses are bounding, and a confirmation from the applicant that the technical specifications applicable in Modes 3, 4 and 5 will be consistent with and provide the same level of intended protection as the technical specifications in Modes 1 and 2. If differences exist between the Modes 1 and 2 analyses and those for other modes, these should be discussed in detail.

RESPONSE:

A review of all STP AOO and PA analyses for all modes and a discussion of the bounding analysis will be completed. A detailed confirmation that the Technical Specifications applicable in Modes 3, 4 & 5 are consistent with modes 1 & 2 analyses will be done. The results will be available in the third quarter of 1985.

QUESTION 440.55  
(Section 15.0)

Table 7.2-1 indicates that the low flow reactor trip is "blocked below P-7". Define the P-7 power level. Provide analyses for this power level which demonstrate that adequate core cooling will be maintained with natural circulation flow. Demonstrate that the core fission power is controllable and stable under natural circulation. State whether you intend to perform a natural circulation test at this power level at STP. If not, explain why not and whether this is due to any safety concerns, and demonstrate that blocking the reactor trip below P-7 for forced circulation flow will not degrade plant safety.

RESPONSE:

The P-7 power level blocks reactor trip from a 2/4 power range neutron flux below the setpoint value for the following trip signals:

- a) low reactor coolant flow in more than one loop,
- b) undervoltage,
- c) underfrequency,
- d) pressurizer low pressure,
- e) pressurizer high level.

For STP, this setpoint is 10 percent of rated Thermal Power. It should be noted that this power level is not intended to be a normal mode of operation but has been put into the design to aid in the plant startup.

At 10 percent power, there is flow resulting from the natural circulation head in the RCS. This flow is approximately proportional to the cube root of the power. At 10 percent power, this flow is typically 6.5 percent of nominal, therefore, power increases above 10 percent would result in only small flow increments. It is known that for a constant DNB ratio, the power-to-flow ratio increases as the power and flow are decreased.

Provisions have been made as indicated in Section 14.2.12.3 for a natural circulation test during plant startup at a power level less than that defined by the P-7 interlock setpoint.



QUESTION 440.56  
(Section 15.0)

The staff cannot fully complete its evaluation of the Chapter 15 AOO and PA analyses until the technical specification safety limits and limiting conditions for operation (LCOs) are compared with the parameters utilized in the AOO and PA analyses to assure their conservatism. Therefore, unless the STP technical specifications become available to the staff within a time frame sufficient to allow a full evaluation prior to final SER issuance, the staff will not be able to conclude in the SER that the Chapter 15 analyses are fully acceptable, unless the applicant commits at this time to make the technical specification safety limits and LCOs fully compatible and consistent with the Chapter 15 analysis parameters.

RESPONSE:

The Technical Specifications will be made consistent with the Chapter 15 analyses.



QUESTION 440.57  
(Section 15.0, 15.1.4  
and 15.1.5)

In Amendment 43, Figure 15.0-9 and the information in Sections 15.1.4 and 15.1.5, and the revised response to Question 440.01 (Amendment 44) all indicate that the MSIVs are closed on any SI signal. Amendment 44 indicates that this includes SI actuation on low RCS pressure. The previous FSAR version indicated that the MSIV would close on high containment pressure or evidence of steam line break, which is typical of most Westinghouse plants. Closure of the intact steam generator MSIVs on any SI signal would prevent utilization of condenser steam dump in the event of steam generator tube rupture (SGTR) or a small break LOCA when offsite power is available. This would probably result in slower mitigation of the accident and increase the offsite dose. The Westinghouse Emergency Response Guidelines (ERGs) which have been approved by NRC take credit for condenser steam dump when it is available. Therefore please justify this design change on the basis of increased safety.

RESPONSE:

The automatic closure of the MSIVs on an SI signal is not expected to have any adverse impact on the mitigation or recovery from an SGTR or small break LOCA. The ERG for SGTR recovery requires that the operator isolate the ruptured steam generator from the intact steam generators prior to the initial cooldown of the reactor coolant system (RCS). This isolation step is accomplished by either closing the MSIV for the ruptured steam generator or the MSIVs for the intact steam generators. If the MSIVs are automatically closed on an SI signal, the operator will not have to perform this step. If the condenser is not available, as assumed in the design basis analysis, the RCS cooldown can be accomplished by using the PORVs on the intact steam generators, and the MSIVs would not have to be opened. If the condenser is available, the MSIVs or bypass valves for the intact steam generators would have to be opened to permit steam dump to the condenser. However, the time required for opening the MSIVs would be offset by the time saved by not having to perform the isolation step initially. Thus, it is concluded that the automatic closure of the MSIVs on an SI signal would not adversely affect the SGTR recovery actions.

For a small break LOCA, steam dump is utilized for the RCS cooldown in the post-LOCA cooldown ERG. If the condenser is available, the MSIVs can be opened to permit steam dump to the condenser for the RCS cooldown, or alternatively, the cooldown can be performed using the steam generator PORVs. Since the time required to perform the post-LOCA cooldown is not critical to the recovery operation, the time required to open the MSIVs would not adversely affect the recovery.

Since the ERGs were developed for a reference plant which does not have automatic closure of the MSIVs on an SI signal, the changes required to accommodate this design feature will be incorporated in the conversion of the ERGs to plant specific Emergency Operating Procedures for STP.

QUESTION 440.58

Figures 15.0-9 thru 15.0-25 appear inconsistent with regard to main feedwater isolation on ESFAS actuation. Please clarify under what circumstances the main feedwater isolation valves are closed on ESFAS actuation.

RESPONSE:

The ESFAS signal to the main feedwater isolation valves is the feedwater isolation signal; this signal closes the valves. The derivation of the feedwater isolation signal is shown in Table 7.3-3.

The figures in Section 15.0 provide an indication of the features required to mitigate the consequences of the particular accident scenario. Section 7.3 provides tables to show what equipment is actuated by each ESFAS signal.

QUESTION 440.59  
(Section 15.1.5)

Provide the assumptions used regarding AFW availability for the "Spectrum of Steam Piping Failures Inside and Outside Containment" analysis. In particular, discuss whether AFW flow to the faulted SG is assumed.

RESPONSE:

The "Spectrum of Steam Piping Failure Inside and Outside Containment" is one of five postulated events that results in an increase in heat removal from the RCS. Event simulation is done using assumptions which maximize the cooldown of the primary system. Such assumptions include conservatively high AFW flow, minimum delay for AFW pump start, and minimum purge volume of the AFW lines.

For the Spectrum of Steam Piping Failures Inside and Outside Containment, auxiliary feedwater was assumed to be available and operable following the steamline rupture. In the analysis presented in Section 15.1.5, auxiliary feedwater is started on a low steamline pressure SI signal about 1 second after the start of the transient. No delay for starting the auxiliary feedwater pumps was assumed. The auxiliary feedwater piping volume which must be purged before the cold auxiliary feedwater flow can be injected was conservatively assumed to be 0.0 ft<sup>3</sup>. The auxiliary feedwater was assumed to be at a conservatively low temperature of 38°F.

The auxiliary feedwater flow assumed to be delivered to the faulted steam generator was 1110 gpm. This flow was assumed constant throughout the entire transient and corresponds to the expected flow rate with the faulted steam generator depressurized to atmospheric pressure.

QUESTION 440.60  
(Section 15.1.5)

Provide plots of DNBR versus time for the 1.4 ft<sup>2</sup> steam line break analysis, for both "offsite power available" and "offsite power not available" cases.

RESPONSE:

Transient plots of the 1.4 ft<sup>2</sup> steamline break analysis are illustrated in Figures 15.1-15 through 15.1-20 of the STP FSAR. Historically, DNBR versus time plots have never been presented in Chapter 15 of the FSAR. The main steamline break is a Condition IV event and, consequentially, must meet the radiological dose release requirements of 10CFR100. Limited fuel damage is permitted as long as the above criteria are met.

Based on previous steamline break results, the minimum DNBR has always been found to occur at the time of maximum return to power. Therefore, only a few statepoints in the range of peak core heat flux are evaluated.

In evaluating the minimum DNBR for the steamline break transient, a detailed statepoint evaluation method is employed. First, the core heat flux transient is generated by the LOFTRAN code. Several statepoints are taken around the time of maximum return to power. Then peaking factor and axial power shapes are calculated using more detailed nuclear computer codes. The LOFTRAN statepoints, peaking factors and axial power shapes are used in the DNBR calculation by the THINC computer code. Using the statepoint method only, the minimum DNBR was calculated. The minimum DNBR for South Texas was above the design basis limit and no fuel was calculated to fail.

QUESTION 440.61  
(Section 15.1.5)

State what assurance is provided that the MSIVs will close under the dynamic blowdown loads of a steam line break.

RESPONSE:

Assurance is provided that the MSIVs of STP will close under the dynamic blowdown loads of a steamline break by virtue of the following:

1. Those Atwood and Morrill valves are tested in accordance with the Westinghouse Valve Operability Program discussed in the FSAR.
2. Atwood and Morrill has conducted both static and operational tests to qualify its designs and to ensure that the valves met current specifications. A test of considerable significance in this ongoing program was a Sonic Flow Test designed to comply with one of the preferred methods of testing described in USNRC Regulatory Guide 1.48, i.e., full scale prototype testing. This test was the first ever performed on a valve as large as a 26 inch valve.

The purpose of the Sonic Flow Test was to show that the Atwood and Morrill Main Steam Isolation Valve would close within specified time limits against high reverse flow rates and pressure differentials such as would occur after a steam line break in a nuclear power station.

The valve selected for the flow test was a 26-inch production valve modified to represent an even larger 32-inch valve. Both valves are designed to close and shut-off flow in either direction. Basic construction of the test valve was carbon steel with stainless steel and hard-faced trim. The operator was an air-and-spring system of the "fail closed" design. The bi-directional valve design is presently being furnished for active service in PWR plants, and conforms to ASME Class 2 requirements.



QUESTION 440.62  
(Section 15.2.7)

Provide the values of the moderator and Doppler coefficients of reactivity used in the loss of normal feedwater/loss of offsite power analysis and verify their conservatism.

RESPONSE:

The acceptance criteria used for these transients are a) the pressurizer was not permitted to become water solid and b) the minimum DNBR must be greater than 1.30. Thus, the moderator and Doppler coefficients of reactivity were selected to yield conservative results. This was done by selecting the moderator and Doppler coefficients of reactivity to maximize core power which in turn maximizes the volume expansion. The pertinent coefficients are listed in Table 15.0-2.

QUESTION 440.63  
(Section 15.27)

Figure 15.2-10 "S.G. Water Volume Transient for Loss of Normal Feedwater" shows the secondary volume curve as peaking at 6000 ft<sup>3</sup>. Can this result in liquid flooding the steam lines, dryers or separators? Can steam line flooding result from other analyzed AOO's, e.g., turbine trip without pressurizer spray, no PORV actuation, and no turbine bypass? Discuss the consequences of steam line flooding (See Question 440.70b.).

RESPONSE:

A steam generator water volume of 6000 ft<sup>3</sup> will result in liquid flooding of the separators but will not fill the SG such that the steam lines are flooded. A volume of 8000 ft<sup>3</sup> will fill the SGs. The Loss of Normal Feedwater analysis presented in Section 15.2.7 assumes that the operator terminated AFW flow at 3350 seconds to prevent flooding of the separators. Operator action at 3100 seconds or sooner (minimum of 30 minutes) is needed to prevent flooding. For the other AOO mentioned, e.g., turbine trip, no credit is taken for AFW flow and feedwater isolation will be achieved once the SG hi-hi level is reached. Thus, there is no chance of flooding the steam lines as a result of any other AOO.

QUESTION 440.64  
(Section 15.2.8)

For the main feedwater system pipe break accident analysis, provide the following information:

- a. Justify the conservatism of your assumption that the initial steam generator level is at the nominal value +5 percent in the faulted steam generator and at the nominal value -5 percent in the intact steam generators. Compare this assumption with that of other Westinghouse plant analyses.
- b. Clarify whether the analysis takes credit for PORV actuation, as stated on page 15.2-17, or for safety valve actuation only, as indicated in Figure 15.0-13. If credit is taken for PORV actuation, verify that the PORVs, including ancillary systems such as controls, power and/or air supplies are safety grade, redundant, designed to IEEE-279, where applicable, and seismically and environmentally qualified. Also states whether credit is taken for PORV actuation in other Chapter 15 transient and accident analyses.
- c. Your response to Question 211.73 states that the feedwater system pipe break analysis does not assume that the operator isolates the break. The analysis described in Section 15.2.8.2 does assume break isolation by the operator. Please clarify this discrepancy, and explain whether this refers to isolation of auxiliary feedwater, main feedwater or both (See also Question 440.58 regarding automatic feedwater isolation). If credit is taken for operator action, please justify why it can be taken.

RESPONSE:

- A. The analyses assumptions regarding the initial steam generator level are consistent with those specified in WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture", dated January 1978. The results of a sensitivity study to initial steam generator level in both the faulted and intact steam generators on the peak reactor coolant system temperatures are provided in Table 5.1-1. As demonstrated, the peak reactor coolant system temperature reaches the highest value when the initial steam generator level in the faulted loop is +5 percent of nominal level and the initial steam generator levels in the intact loops are -5 percent of nominal level. These assumptions are utilized on all recent main feedwater system pipe breaks analyzed by Westinghouse.

QUESTION 440.64 (Continued)

- B. Sensitivity studies within Westinghouse have demonstrated that plants without centrifugal charging pumps which serve a safety injection function, the normal operation (i.e., expected operating characteristics) of pressurizer PORV's results in a lower margin to reactor coolant system hot leg saturation. If the PORV's were not assumed to operate normally (PORV's in manual mode or assumed to fail closed) in the STP main feedline rupture analyses, the margin to reactor coolant system hot leg saturation would have been considerably higher. Hence, an assumption of normal operation of the pressurizer PORV's is made even through the PORV control system is control grade hardware.

This criterion is consistent with the assumptions made in all other STP Chapter 15 accident analyses. The normal operation of the pressurizer PORV's, because of the control grade actuation circuitry, is assumed in the accident analyses only if the normal operation results in a more severe reactor coolant system transient, e.g., higher peak reactor coolant system temperature for the main feedline rupture.

- C. The STP auxiliary feedwater system is designed such that the operator is not required to take manual action to ensure the minimum required auxiliary feedwater flow is injected into the intact steam generators even assuming the worst single active failure is one auxiliary feedwater pump. However, the transient analyses provided in Section 15.2.8.2 of the STP FSAR assume the operator takes action following the feedline rupture to isolate the auxiliary feedwater flow spilling out the ruptured feedwater line. This operator action is not required to mitigate the consequences of a main feedline rupture. However, the operator action to isolate the auxiliary feedwater flow spilling out the rupture is assumed in order to conserve the plant condensate quality water supply to the auxiliary feedwater pumps. Should this action not be taken by the operator, the first required action by the operator would be to terminate the safety injection flow within a minimum of 30 minutes in the accident analysis following the initiation of the rupture.

All main feedwater flow to the steam generators is isolated on receipt of a safety injection signal on 2/3 low steamline pressure in the faulted steam generator. Auxiliary feedwater flow is automatically initiated on a safety injection signal or on low-low steam generator level in any steam generator.

QUESTION 440.65  
(Section 15.3.3)

The STP locked rotor analysis for four operating loops assumes that at 10 seconds after the event, the core flow is 75% of nominal flow (Figure 15.3-17), while for three loop operation the core flow at 10 seconds is 65% of nominal flow (Figure 15.3-21). These numbers indicate that either loss of offsite power (LOOP) was not assumed, or a very long delay time between turbine trip and LOOP occurrence was assumed. In order to fully meet GDC-17, please analyze this event assuming LOOP, and determine the resulting peak pressure, peak clad temperature, percent of failed fuel and resulting offsite dose, to determine if the acceptance criteria of SRP Section 15.3.3 - 15.3.4 are met. (See also Question 440.47)

RESPONSE:

The South Texas Project (STP) locked rotor event has not been analyzed with loss of offsite power. However, the STP locked rotor event without offsite power (4-loop operation) will be analyzed and subsequent revisions made to the STP FSAR. The STP results are expected to be similar to those obtained by other 4 loop plants which show acceptable results. These results are expected to indicate that the present FSAR locked rotor analysis (with offsite power) will bound the locked rotor event with LOOP.

Such an analysis will not be performed for N-1 (3) loop operation, though, since Houston Lighting and Power is not pursuing a license for this mode of operation.



QUESTION 440.66  
(Section 15.4.4)

With regard to your "Startup of an Inactive Reactor Coolant Loop at an Incorrect Temperature" analysis, provide the following information:

- a. Figure 15.4-16 shows an initial power level of about 72%. Discuss how this compares to Tech Spec values for the initial power level with 3 loop operation. Also discuss what the time limit for this type of operation is.
- b. Provide the Tech Spec value for the maximum allowable cold leg temperature difference between the idle loop and the highest cold leg temperature of the operating loops for idle RCP start and compare this limit with the assumptions in your analysis.

RESPONSE:

Houston Lighting and Power is not pursuing a license for N-1 (3) loop operation thus no Technical Specification values for the initial power level with 3 loop operation are required. In addition, there is no Tech Spec value for the maximum allowable cold leg temperature difference.

QUESTION 440.67  
(Section 15.4.6)

Provide the following information with regard to the "CVCS Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant" analysis:

- a. For each operational mode, list the alarms and indications that would alert the operators to the occurrence of a BDE, and verify their redundancy. Also describe any automatic mitigation systems. Confirm that your technical specification will require two alarms to be operable during all shutdown and refueling modes.
- b. The FSAR states that the maximum dilution flow during startup and hot standby is 382 gpm based on operation of two reactor makeup water (RMW) pumps while the RCS is at 2250 psi. For this dilution flow rate, the minimum time for loss of shutdown margin is 19.6 minutes.
  1. Please confirm that you will impose technical specification limits to ensure that RCS pressure, when accounting for instrument error, will not be dropped below 2250 psi in either of these two modes.
  2. Please provide analyses of boron dilution events in modes 4, 5 and 6. How do you intent to ensure RCS pressure never drops below the pressure corresponding to the maximum dilution flow assumed in your analysis? Our concern is that the SRP Section 15.4.6 criterion of 15 minutes (30 minutes for Mode 6) for minimum time availability before shutdown margin is lost will be met with maximum dilution flows assuming operation of two charging pumps and two RMW pumps at minimum RCS pressure for the particular mode analyzed.
- c. The FSAR states that valve CV0298 in the CVCS will be locked closed during refueling. Discuss whether additional valves should also be locked closed for redundancy.

Demonstrate that all possible dilution flow paths have locked closed valves, and confirm that the tech specs will contain this information.

RESPONSE:

The response to this question will be provided in September 1985.

QUESTION 440.68  
(Section 18.4.6)

Describe or reference the analytical model used in the BDE calculations. Discuss the degree of conservatism of this model, including that of scram times, moderator and Doppler coefficients, and mixing of coolant.

RESPONSE:

The response to this question will be provided in September 1985.

QUESTION 440.69  
(Section 15.6.1)

- a. The information provided in the "Inadvertent Opening of a Pressurizer Safety or Relief Valve" is incomplete. Since this event is equivalent to a small break LOCA, extend your calculational results shown in the submitted tables and figures to the time utilized in LOCA analyses. (See also Question 440.39). Include plots of core mixture height, clad temperature, and hot spot fluid temperature versus time. Discuss how long-term decay heat removal will be accomplished using equipment qualified for the LOCA environment if the stuck open valve subsequently reseats or is isolated with a block valve.
- b. Figure 15.6-4 for the above analysis indicates that no SI train failure is assumed. We require that the stuck safety valve analysis assume the most severe single active failure. Either describe the single failure assumed and explain why it is the most severe, or provide an analysis with the most severe single failure. Also provide times for SI actuation and RCP trip, mode of primary loop heat removal (e.g., by single or two phase natural circulation, refluxing, etc.) and operator actions required.

RESPONSE:

- A. The acceptance criteria for this event as described in SRP are different from that of the small break LOCA event. For this reason, only the plots of nuclear power, pressurizer pressure, core average temperature, and DNBR are provided in the FSAR, and only out as far as required such that it is evident that the transient has reversed. With respect to long-term decay heat removal, the case of inadvertent opening of a pressurizer safety or relief valve was analyzed generically in WCAP-9600 "Report on Small Break Accidents in W N S S S," Section 3.0. Two cases of break size were analyzed representing one small PORV and three large PORV's opening, and then sticking in the full open position. This break size range covers a safety valve opening as well. The characteristics of both cases were similar as shown in WCAP-9600. In both cases pressurizer water level rises, Reactor Coolant System (RCS) depressurization occurs resulting in automatic actuation of reactor trip and safety injection (SI) based on low pressurizer pressure signals. The RCS depressurizes to the point where leak flow equals the SI flow. If only minimum safeguards safety injection is available, there is voiding in the core and hot legs, but no core uncover. The clad temperature remains below steady state operating temperatures, and decay heat is removed via natural circulation. If maximum safeguards safety injection is available, depending on the leak size the RCS may repressurize and return to subcooled conditions. The scenario of a stuck open pressurizer PORV or safety valve does not represent the limiting small break scenario. The small cold leg breaks analyzed in the FSAR are the worst small breaks.

QUESTION 440.69 (Continued)

- B. Figure 15.6-4 was deleted in Amendment 45 of the STP FSAR. However, the Inadvertent Opening of a Pressurizer Safety or Relief Valve event assumes the opening of a pressurizer PORV or safety valve which initiates the transient. Although ESF components might be actuated, they are not required to mitigate the consequences of the event from the standpoint of the core response, since the DNBR rises after reactor trip. Thus, ESF failures are not limiting and the worst single failure is loss of one protection train.

Because the minimum DNBR occurs within the first 30 seconds of the transient, the criteria delineated in the SRP are satisfied during this period. No Safety Injection actuation or RCP trip is assumed within this short transient. Likewise, the loop heat removal and operator action are beyond the scope of this event and must be determined via the small break LOCA analysis.



QUESTION 440.70  
(Section 15.6.3)

Steam generator tube rupture (SGTR events at R. E. Ginna and other PWRs indicate the need for a more detailed review of the analysis for this accident. Our review of the STP FSAR Section 15.6.3 in view of this plant experience has resulted in a need for the following additional information and clarification:

- a. FSAR Section 15.6.3 indicates equalization of primary and secondary pressure 30 minutes after the SGTR event, with consequent termination of steam generator tube leakage. We consider this time period unrealistic based on previous SGTR incidents. Assuming loss of offsite power, provide the sequence of events which includes the automatic initiations and actuations as well as identification of operator action in chronological order. Justify the timing of operator actions if they are less conservative than those recommended in draft ANSI N660 for a condition IV event. Include the most limiting single active failure in your analysis.
- b. Discuss whether as a result of possible modifications to your analysis including consideration of longer leak times, liquid can enter the main steam lines. If so, discuss the effects on the integrity of the steam piping and supports.

Consider both the liquid dead weight and the possibility of water hammer. Also discuss whether the steam generator safety and relief valves would function properly if their actuation pressures are reached with the main steam lines filled with liquid and whether they would reseal at the proper pressure.

- c. Provide the following parameters as a function of time, until releases from the ruptured steam generator are terminated:
  1. the primary system pressure;
  2. the secondary system pressure in each steam generator;
  3. the secondary liquid water mass and level in each steam generator
  4. the charging and safety injection flow rate
  5. the intact and ruptured loop  $T_H$  and  $T_{ave}$
  6. the integrated mass released out of the atmospheric relief valves or safety valves for the intact steam generators and for the ruptured steam generator;
  7. pressurizer level;
  8. the tube rupture flow rate and integrated tube rupture flow;

QUESTION 440.70 (Continued)

9. the extent of upper head voiding if predicted;
10. the steam and feedwater flow rates for the ruptured and intact steam generators;
11. the primary system liquid mass;
12. the reactor vessel and steam generator temperatures;
13. the intact and ruptured loop mass flow rate.

These analyses should be based on loss of offsite power, the most severe single active failure, and the most reactive control rod stuck in the fully withdrawn position.

- d. Describe, or reference the computer codes utilized to calculate the primary and secondary system response. Justify that the code is appropriate for the STP SGTR analysis.
- e. Identify all equipment which is relied upon to mitigate a design basis SGTR event. Justify that this equipment meets NRC requirements for safety related equipment. If reliance on the primary PORVs and/or steam generator ADVs is essential for the SGTR mitigation, the applicant should either: (1) develop appropriate Technical Specification limits to ensure the continued operability of this equipment or (2) explain why, in the absence of any technical specification requirements, credit should be given for operability of these valves. Describe what controls will be put in place to prevent operators taking valves out of service such that safety analysis assumptions are violated.
- f. The analysis should assume that the accident begins with the primary cooling iodine concentrations at the Technical Specification limit. Both pre-existing and concurrent iodine spikes should be assumed for calculating offsite consequences.

RESPONSE:

A subgroup of the Westinghouse Owners Group has been formed to generically address several of the SGTR issues which have been raised for NTOL plants, and Houston Lighting and Power is a member of this subgroup. The initial results of the generic program are presented in WCAP-10698, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill", December 1984. A supplement to WCAP-10698 titled "Evaluation of Offsite Radiation Doses for a Steam Generator Tube Rupture Accident" is scheduled to be issued in May 1985. An additional supplement on the evaluation of the potential consequences of steam generator overfill resulting from an SGTR is also scheduled for submittal later this year.

The resolution of this question will be addressed as part of the subgroup program and will be provided after completion of the generic program.

QUESTION 440.71  
(Section 15.6.5)

Table 15.6-7 states that the large break LOCA analysis was performed assuming that "3 SI pumps" were operating. Clarify whether this means that all 3 SI pump trains were operating. How does this compare with your response to Question 440.08N which indicates that failure of one diesel generator train was assumed? We require assumption of loss of offsite power and the most severe single active failure for the LOCA injection phase analysis.

RESPONSE:

Chapter 15.6.5 is currently being revised to incorporate both minimum and maximum safety injection. This will be provided in the next FSAR amendment of Section 15.6.5. Also attached as Table 15.6-5 from the LOCA reanalysis which shows input parameters used in the ECCS analysis. The calculations resulted in a peak clad temperature of 1981°F for a C<sub>D</sub>=0.6 break with an assumption of maximum of safety injection flowrates.

Per the large break LOCA analysis, the nominal accumulator water volume will be revised to a value of 1580 ft<sup>3</sup>. This value is the water volume specified in the original plant design, but which had been revised to 1200ft<sup>3</sup> as a result of an interim LOCA analysis.

STP FSAR

TABLE ~~15.6-5~~ Q440.71-1

INPUT PARAMETERS USED IN THE ECCS ANALYSES

Core Power <sup>(1)</sup> (MWt)	3800
Peak Linear Power (Includes 102% factor) (kW/ft)	13.257
Total Peaking Factor	2.5
Axial Peaking Factor	1.645
Power Shape	Large Break - Chopped Cosine Small Break - See Figure 15.6-52
Fuel Assembly Array	17X17
Accumulator Water Volume (nominal) (Ft <sup>3</sup> /accumulator)	1580
Accumulator Tank Volume (nominal) (Ft <sup>3</sup> /accumulator)	2500
Accumulator Gas Pressure (minimum) (psia)	600
Safety Injection Pumped Flow	See Note 2
Containment Parameters	See Section 6.2.1
Initial Loop Flow (lb/sec)	9707
Vessel Inlet Temperature (°F)	559
Vessel Outlet Temperature (°F)	626.4
Reactor Coolant Pressure (psia)	2280
Steam Pressure (psia)	1081.8
Steam Generator Tube Plugging Level (%)	5
Fuel Parameters	Cycle 1, Region 1

NOTES:

- (1) Two percent is added to this power to account for calorimetric error.
- (2) Minimum safety injection capacity calculations were based upon one HHSI/LHSI train injecting and one spilling to containment. Maximum safety injection capacity calculations were based upon two HHSI/LHSI trains injecting and one spilling to containment.

QUESTION 440.72  
(Section 15.6.5)

The FSAR does not provide analytical results for the large break LOCA recirculation phase. State whether the heat removal capacity of one RHR heat exchanger is sufficient for decay heat removal during recirculation phase initiation, or whether 2 RHR heat exchangers are required. For the most limiting combination of break location and single active or passive failure, provide core and downcomer water level and peak clad temperature for the early part of the recirculation phase.

RESPONSE:

Based upon the calculated containment pressures, sump temperatures, SI flows and RHR heat exchanger performance curves, one RHR heat exchanger can adequately provide core cooling for the entire recirculation phase. The fluid exiting the break under this condition would be a low quality mixture with the injection rate from one train much in excess of steady state core boiloff. The loss of one LHSI/RHR heat removal path would have some impact on containment conditions and sump temperatures but calculations show that the effect on the SI conditions would be small and would not effect core coolability.

Also, since the injected SI water still has some subcooling, there will be no significant change in fluid density. Therefore, there is no apparent mechanism whereby the core mixture level could decrease to the point that another core temperature excursion would occur. Conditions for core cooling would continually improve with the decreasing core decay heat generation rate. Clad temperatures would remain near fluid saturation.

The current ECCS model used in large break LOCA calculations assumed that only one LHSI/HHSI train injects into the RCB. One train is assumed to be unavailable and one spills to the containment through the broken loop. Water is supplied from the RWST for the entire 300s duration of the calculation at assumed conditions of 90°F and 1 atm. At the end of the calculation the downcomer is liquid full and the core is covered and well cooled.



NRC/HL&P/Bechtel/Westinghouse Meeting

Meeting Date: May 7, 1985  
Meeting Location: bethesday (NRC)  
Attendees:

<u>NRC</u>	<u>HL&amp;P</u>	<u>Bechtel</u>	<u>Westinghouse</u>
B. Sheron	M. Wisenburg	W. Watson	W. Spezialetti
P. Kadambi	J. Bailey		G. Harkness
B. Mann	J. Phelps		F. Twogood
	S. Head		J. Reck
			A. DiCesaro

Meeting Date: May 8 & 9, 1985  
Meeting Location: Pittsburgh (Westinghouse)  
Attendees:

<u>NRC</u>	<u>HL&amp;P</u>	<u>Bechtel</u>	<u>Westinghouse</u>	
P. Kadambi	J. Bailey	W. Watson	W. Johnson	K. Slaby
B. Mann	J. Phelps	J. Atwell	A. Paterson	B. Montey
	L. Schlazer	Y. Williams	W. Spezialetti	D. Shimeck
	M. Powell		G. Harkness	M. Adler
			F. Twogood	B. Grayson
			J. Reck	D. Kitch
			A. DiCesaro	G. Lang
			N. Lewis	