APR 4 1985

Docket Nos.: 50-498
and 50-499

Mr. J. H. Goldberg
Group Vice President, Nuclear
Houston Lighting and Power Company
Post Office Box 1700
Houston, Texas 77001

Dear Mr. Goldberg:

Subject: South Texas Project, Units 1 and 2 - Request for Additional Information

The NRC staff has determined that additional information is required for the safety review of the South Texas Project operating license application. Enclosed are the following Requests for Additional Information (RAI's):

Power Systems Branch (PSB, Electrical) (430.106 - 136)
Reactor Systems Branch (RSB) (440.14 - 72)

The staff is available to discuss the above RAI's as may be required to provide any necessary clarification. Please inform us as to your schedule for responding to the RAI's. Please contact the Project Manager if you have any questions.

Sincerely,

V. Nerses for

George W. Knighton, Chief, Chief
Licensing Branch No. 3
Division of Licensing

Enclosure:
As stated

cc: See next page

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SUPPLEMENTAL REQUEST FOR ADDITIONAL INFORMATION
SOUTH TEXAS PROJECT, UNITS 1 & 2
POWER SYSTEMS BRANCH

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.

430.107 (SRP 8.1) Table 8.1-2 of the FSAR includes BTP-ICSB-2 (PSB) which is superseded by IEEE 387 since 1981; and BTP ICSB-4 (PSB) which is included in Chapter 7 of the SRP, instead of Chapter 8.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)

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.

Guide (Standard)	Current Revision	Revision Listed in the Tables
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

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 hat 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"

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

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.

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.

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 cables, 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.

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.

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.

430.116 (SRP 8.3.1) Section 6.4.2 of IEEE Standard 384-1977 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.

430.117 (SRP 8.3.2) Loads connected to the dc bus may be subject to voltage variations from 105 to 140 volts due to battery discharge and equalizing charge as stated in section 8.3.2.1 of the FSAR. It is the staff position that dc loads be designed and qualified to operate when subject to these voltage variations. Describe compliance of STP design to this position for both minimum and maximum voltages.

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.

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.

430.120 (SRP 8.3.1)

Recent experience with nuclear power plant Class 1E motor-operated valve motors has shown that in some instances the motor winding on the valve operator could fail when the valve is subjected to frequent cycling. This is primarily due to the limited duty cycle of the motor. Provide the required duty cycle of the following valves as it relates to system mode of operation in various events:

1. Steam supply valve to AFW pump turbine (if they are MOVS)
2. Auxiliary feedwater flow control valves
3. RHR heat exchanger valves
4. SI injection valves
5. SI discharge valves
6. Atmospheric dump valves (if they are MOVS)

Demonstrate that the availability of the safety systems in the South Texas design will not be compromised due to the limited duty cycle of the valve operator motors.

430.121 (SRP 8.3.1 Appendix 8A)

The voltage levels at the safety-related loads should be optimized for the maximum and minimum load conditions that 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.

430.122 (SRP 8.3.1 Appendix 8A)

Section 8.3.1.1.4.5 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.

430.123 (SRP 8.3.1)

Table 8.3-3 of the FSAR shows step 1 loads 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.

430.124 (SRP 8.3.1) Section 8.3.2.2.5 of the FSAR indicates that the Class 1E dc system is in compliance with Regulatory Guides 1.128 and 1.129. Confirm and identify in the FSAR that

(1) Ventilation system in the battery area will limit hydrogen concentration per position 1 of the regulatory guide,

(2) The additional two items of instrumentation and alarm are provided per position 5(f),

(3) Battery mounting, location, unpacking, storage are in accordance with the applicable positions of Regulatory Guide 1.128.

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.

430.126 (SRP 8.3.1) Section 8.3.1.4.4.7 of the FSAR lists certain raceway types and configuration to be acceptable as an alternate to a physical barrier when installed in accordance with IEEE 384, Figure 2. With the exception of rigid steel conduit, all other listed raceways require additional information as follows.

(A) Aluminum sheathed cable and copper sheathed cable should be reevaluated to comply with position 2 of Regulatory Guide 1.75 and justified for acceptance.

(B) Enclosed metal wireways (gutters) and flexible metal conduit should satisfy IEEE-384 definition of "barrier." Test results for the worst case configuration should be submitted for staff review to substantiate the capabilities of these raceways for limiting damages to Class 1E circuits to an acceptable level.

(C) One inch separation between redundant divisions is for enclosed raceways. A solid bottom steel cable tray without solid steel cover, as shown in Figure 2 of IEEE 384, shall qualify for one inch separation only if it is on top of a redundant division tray with a solid steel cover as a qualified, totally enclosed raceway. Any other configuration of the subject tray with respect to its redundant division tray, should follow figures 3, 4 and 5 of IEEE 384 or should be analyzed and justified with test results. The same guidelines are applicable to steel ventilated cable trays with solid steel covers installed only at the top or the bottom of the tray.

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.

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.

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.

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.

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 V dc, 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.

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.

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.

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.

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.

430.136 (SRP 8.3.2) IE 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.

Confirm that the above 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.

ENCLOSURE

SOUTH TEXAS PROJECT (STP)

REQUEST FOR ADDITIONAL INFORMATION

440.14 (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.

440.15 (5.1, 5.2 & 5.4) 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.

440.16 (5.2 & 5.4) 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.

440.17 (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?

440.18 (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.

440.19 (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?

440.20 (5.2 & 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.

440.21 (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.

440.22 (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.

440.23 (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 sources 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.

440.24 (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.

440.25 (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.

440.26 (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.

440.27 (5.4.7) 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 examples, 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.

440.28 (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 purposes, discuss the suitability of the valve capacity and setpoint for this purpose.

440.29 (5.4.7) 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.

440.30 (5.4.7) 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.

440.31 (5.4.7) Provide RHR pump performance curves.

440.32 (5.4.7) 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.

440.33 (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 5.4A-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.

440.34 (5.4.7) Describe the preoperational test program for the RHR system.

440.35 (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 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.

440.36 (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.

440.37 (5.4.15) State what provisions have been made for pressurizer and RCS loop venting.

440.38 (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 thru 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 no 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.

440.39 (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.

440.40 (6.3) 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.

440.41 (6.3) Provide and justify the allowable temperature range for the RWST. Discuss what provisions are made to maintain the RWST temperature within this range.

440.42 (6.3) State how unacceptable HHSI and LHSI pump runout conditions are prevented during ECCS operation at low RCS pressures.

440.43 (6.3) 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.

440.44 (6.3) 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.

440.45 (6.3) 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.

440.46 (6.3) 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.

440.47 (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).

440.48 (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.

440.49 (15.0) Your response to our Question 211.7 regarding provision of a summary table of transient and accident analysis results for DNBR, 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.

440.50 (15.0) Your responses 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 reseat 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.

440.51 (15.0) 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 (AOOs). 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 the are less than those recommended in draft ANSI N-660.

440.52 (15.0) Clarify whether the STP AOO 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.

550.53 (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.

440.54 (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.

440.55 (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.

440.56 (15.0) The staff can not 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 anayses 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.

440.57 (15.0, 15.1.4 & 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.

440.58 (15.0) 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.

440.59 (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.

440.60 (15.1.5) Provide plots of DNBR versus time for the 1.4 ft^2 steam line break analysis, for both "offsite power available" and "offsite power not available" cases.

440.61 (15.1.5) State what assurance is provided that the MSIVs will close under the dynamic blowdown loads of a main steam line break.

440.62 (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.

440.63 (15.2.7) Figure 15.2-10 "S.G. Water Volume Transient for Loss of Normal Feedwater" shows the secondary volume curve as peaking at 6000 ft^3. 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 440.67b.).

440.64 (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 state 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.

440.65 (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)

440.66 (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.

440.67 (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 intend 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 CV0198 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.

440.68 (15.4.6) 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.

440.69 (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.

440.70 (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 reseat 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;
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 anlaysis 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.

440.71 (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.

440.72 (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.