Question 211.41

For those transients which result in the pressurizer being filled water solid, address the capacity of the quench tank to contain the water discharge and/or the radiological consequences of spillage of primary coolant water into the Containment.

Response [HISTORICAL INFORMATION]

The only transient that fills the pressurizer is the feedline rupture. The feedline rupture is analyzed with and without offsite power. The case with offsite power results in the highest water relief rates. A new analysis has been done assuming the reactor coolant pumps are on throughout the transient. The results of the analysis are as follows.

The pressurizer relief tank (PRT) cannot contain the water discharge associated with the feedline rupture. With the PRT initial level at the High Level Alarm Setpoint (resulting in the greatest discharge to the Containment), a total of 11,669 pounds (8800 pounds of steam and 2869 pounds of water) is discharged into the Containment.

The radiological consequences of spillage of primary coolant into the Containment are substantially less than that of a MSLB since no fuel failures are postulated. See UFSAR Section 15.2.8.

HISTORICAL INFORMATION

Question 211.43

Several of the analyses result in or have the potential for filling the pressurizer water solid. Discuss the potential for this causing a more severe transient, since the sizing of the safety valves was based on steam flow.

Response [HISTORICAL INFORMATION]

Although the safety valve capacity is based on steam relief, the water relief capacity of the valves is much larger than the amount of water relief required during a transient. Thus, a more severe transient would not occur.

More details are provided in response to Q211.45 on the capacity of relief and safety valves.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.44

Many of the transient descriptions refer to the Emergency Boration System which was deleted by a recent amendment. Remove references to this system from the analyses and verify that the analyses have been revised to no longer take credit for the high concentration boron from the EBS.

Response [HISTORICAL INFORMATION]

The Emergency Boration System (EBS) has been deleted from the STPEGS Units. Current analysis presented in Chapter 15 of the UFSAR no longer takes credit for the high concentration boron from the EBS.

HISTORICAL INFORMATION

Question 211.45 Deleted

TABLE Q211.45-1 .Deleted

Question 211.46

Confirm that during the preoperational or startup test phase you intend to verify the valve discharge rates and response times (such as opening and closing times for main feedwater, auxiliary feedwater, turbine and main steam isolation valves, and steam generator and pressurizer relief and safety valves) to show that they have been conservatively modeled in the Chapter 15.0 analyses.

<u>Response</u> [HISTORICAL INFORMATION]

<u>Valve Discharge Rates</u>

Valve discharge rates are confirmed during the preoperational test phase for the auxiliary feedwater valves.

Valve discharge rates are not confirmed during the preoperational or startup test phase for the following valves:

a. Main Feedwater, Turbine and Main Steam Isolation Valves - During the Phase III portion of the startup test program, the intent will be to confirm that the discharge rates for these valves are sufficient to control the various systems (within design values) for steady state operation (up to 100 percent of rated power) and during all Condition I events listed in Chapter 15.

b. Steam Generator and Pressurizer Relief Valves, and Steam Generator and Pressurizer Safety Valves - Testing of each pressurizer and steam generator power-operated relief valve (PORV) and safety valve (to demonstrate the discharge rates have been conservatively modeled) is neither practical or justified for the following reasons:

    1. There is no practical method of measuring steam flow rate from any of these valves after they are installed.

    2. Assuming that a method of measuring flow rate could be developed, testing of each valve would put the unit through numerous undesirable transients, because there are 2 pressurizer PORVs, 4 steam generator PORVs, 20 steam safety valves, and 12 steam dump valves. A relatively lengthy blowdown period would be required for each test in order to measure either steam flow rate or cooldown rate, which could be extrapolated to flow rate. Imposing a modified Condition II event on the unit is not justified.

    3. Testing of the unit's full load rejection capability adequately demonstrates that the capacities of the PORVs and steam dump valves are consistent with design. (See Phase IV startup test description 23, Section 14.2.12.3.)

Response (Continued)

4. The safety valves are ASME Section III components and have been tested by the manufacturer in accordance with the code requirements. The other relief/steam dump valve capacities have been verified by the respective manufacturers to be in accordance with design flow rates. These verifications are based on standard industry practices, which include obtaining flow characteristics by testing and/or calculating flow capacities based on specified conditions. The present test program verifies the valve stroke length to be in accordance with the manufacturers' specifications for each valve, thus ensuring that the specified valve opening is not exceeded.

Valve Response Times

Valve response times are confirmed during the preoperational or startup test phase for the following valves:

a. Main Feedwater Valves

b. Auxiliary Feedwater Valves

c. Turbine Valves

d. Main Steam Isolation Valves

e. Steam Generator Power-Operated Relief Valves

f. Pressurizer Power-Operated Relief Valves

Valve response times are not confirmed during the preoperational or startup test phase for the Steam Generator and Pressurizer Safety Valves - The safety valves are ASME Section III Components and as such have been tested by the manufacturer in accordance with the code requirements.

HISTORICAL INFORMATION

Question 211.48

Based on recent operating experience, provide an evaluation of the "Loss of Instrument Air" event, in particular as it relates to the potential for causing and compounding other more serious events.

Response [HISTORICAL INFORMATION]

"Loss of Instrument Air" would not result in the loss of any safety-related control functions and would not prevent shutdown of the reactor. The instrument air system is not required for safe shutdown during any design basis accident or transient. The loss of instrument air does not jeopardize plant safety.

The loss of instrument air during RHR operation would result in the loss of the ability to control the flow rate through the RHR heat exchanger. In this situation a controlled cooldown can be accomplished by starting and stopping the RHR pumps as required.

The loss of instrument air may cause plant transients as a result of main steam isolation valve (MSIV) and feedwater control valve (FCV) and feedwater bypass control valve (FBCV) closure. The most immediate effect of the loss of instrument air will be the closure of the FCV thereby eliminating feedwater flow to the steam generators. The loss of feedwater transient, a Condition II event, is discussed in Section l5.2.7. The results of the analysis show that a loss of feedwater transient does not adversely affect plant safety. No fuel damage occurs and the steam release from the secondary system does not result in a release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators.

HISTORICAL INFORMATION

Question 211.49 Deleted

Question 211.50 Deleted

Question 211.51

For Chapter 15 accident events, provide the number of fuel rods calculated to be in DNB.

Response [HISTORICAL INFORMATION]

For Condition II events, it is demonstrated that DNBR remains greater than the limiting value; thus, the number of rods calculated to be in DNB corresponds to the criteria set forth in Section 4.4.1.

For large and small LOCAs, uncovering of the core results in DNB for all rods. For the steam line break events (Section 15.1.5), the feedwater line break events (Section 15.2.8), and the complete loss of forced reactor coolant flow events (Section 15.3.2), the DNBR does not fall below the limiting value as indicated in the appropriate sections of Chapter 15. Therefore, the criteria for rods in DNB presented in Chapter 4 applies to these events also.

As stated in Section 15.4.3, the number of fuel rods with DNBR less than the limiting value for the single RCCA withdrawal event is less than 5 percent of the rods in the core. For an improper fuel loading event, undetected errors will cause sufficiently small perturbations to be acceptable within calculational uncertainties, as stated in Section 15.4.7; thus, the effect due to improper loading on rods in DNB for transient event will be negligible.

The RCCA ejection analysis presented in Section 15.4.8 conservatively assumes that 10 percent of the rods in the core go into DNB and fail. For the locked rotor event presented in Section 15.3.3, the maximum number of fuel rods in DNB is conservatively calculated to be less than 10 percent of the rods in the core. As stated in Section 15.3.4, the consequences of an reactor cooling pump shaft break will be less severe than those for a locked rotor event.

Evaluation of the steam generator tube rupture indicates that no clad damage would be expected in this transient. The RCS depressurization due to flow out of the tube rupture presents the possibility of obtaining a low DNBR. However, the depressurization in a tube rupture is much less severe than the depressurization transient analyzed in Section 15.6.1. In this accident, it was determined that the DNBR is always greater than the limiting value, and thus no clad damage is expected. From this, it is concluded that no clad damage is expected in the steam generator tube rupture accident. For all other events discussed in Chapter 15, DNBR remains above the limiting value.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.52 Deleted

CN-2970

Question 211.53Q

A change in the Westinghouse fuel rod internal pressure design criteria is in the process of being approved. This change will permit the internal fuel rod pressure to exceed system pressure. For some Condition III and IV overpower events, this will result in an increase in the number of rods normally expected to fail as a result of these events. This is due to the probability of a rod simultaneously being in DNB and exceeding system pressure. Subsequent ballooning and touching the adjacent rods follows, thereby causing more rods to go into DNB and fail. Therefore, for the Chapter 15 analyses of Condition III and IV events, confirm if this change in the fuel rod internal pressure design criteria has been factored into the number of rods predicted to fail.

Response [HISTORICAL INFORMATION]

The NRC staff has completed its review of the revised Westinghouse fuel rod internal pressure design criteria and has decided on an acceptable amended criterion.

"The internal pressure of the lead fuel rod in the reactor will be limited to a value below that which could cause (1) the diametrical gap to increase due to outward cladding creep during steady-state operation and (2) extensive DNB propagation to occur."

WCAP-8963, "Safety Analysis for the Revised Fuel Internal Design Basis", was found to be acceptable to support the conclusion that an insignificant number of additional DNB events would occur during transients and accidents as a result of operating with fuel rod pressure (1) greater than nominal system pressure and (2) limited by the above criterion.

For all Condition III and IV overpower events, the number of rods that are assumed to fail is less than 10 percent. Therefore, the analyses for STPEGS are bounded by the analysis presented in the WCAP. The results presented in the WCAP are based on the detailed probability analysis performed to determined the maximum extent of core damage that could lead to DNB propagation. It was shown that the propagation mechanism causes only a small incremental increase in the percentage of rods in DNB. In view of the conservative nature of the failure propagation scheme and the small percentage increase in the number of failed rods, the potential increase in site release is inconsequential.

Although this effect resulting from the revised fuel rod internal pressure design criterion is small, it was factored into the number of rods predicted to fail.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.54 Deleted

Figure Q211.54-1 (Deleted)

Figure Q211.54-2 (Deleted)

Figure Q211.54-3 (Deleted)

HISTORICAL INFORMATION

Question 211.56

Question 211.8 addressed an error in a Westinghouse evaluation model and the response was that the reanalysis was provided in revised Sections 15.6.5 and 6.2.1.5. For other Chapter 15 transients which are predicted to experience DNBR, verify that the corrected analysis has been used or is not applicable.

Response [HISTORICAL INFORMATION]

The subject error discussed in the answer to Question 211.8 is the correction to the zirconium-water heat of reaction in the large LOCA models. It is not applicable to any accidents except large break LOCA.

Question 211.57

Provide or reference analyses for all transients which show that the acceptance criteria are met for initial operation with less than four loops.

Response [HISTORICAL INFORMATION]

The STPEGS UFSAR analyses are not intended to cover N-1 loop operation. Currently, STPEGS intends to operate the plant with four loops in operation only. Therefore, no analysis for operation with less than four loops is required.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.85

STPEGS indicated in a previous amendment that the Emergency Boration System would be deleted. Please provide complete justification for this deletion. For each transient that relies on the EBS, or any of its functions, justify its deletion and show that the safety margin has not been reduced.

Response [HISTORICAL INFORMATION]

Westinghouse has developed improved analytical techniques which allow a deletion of the Emergency Boration System (EBS). The sole function of the EBS is to provide concentrated boric acid to the reactor coolant to mitigate the consequences of postulated steam line break accidents. The cases which serve as the Westinghouse steam line break licensing basis are the main steam system depressurization accident (Section 15.1.4) and the main steam line rupture accident (Section 15.1.5).

The effect of deleting the EBS on the main steam depressurization accident analysis is that the reactor returns to criticality. Historically, Westinghouse's criterion for this Condition II event had been to show that no return to criticality occurs. However, Westinghouse has adopted a new criterion, whereby the reactor may return to criticality, but no fuel damage may occur. This new criterion is in compliance with the criteria used by the NRC and ANS, which require that radiation releases during Condition II steam line breaks remain within the limits set forth in 10CFR Part 20. This limit can be met with a return to criticality, if it is assured that there is no consequential fuel damage.

The effect of EBS deletion on the main steam line rupture analysis is that the reactor returns to a higher power level after the rupture. For this accident, Westinghouse demonstrates that the DNB design basis is met and, therefore, the radiation releases limits of this Condition IV event set forth in 10CFR Part 100 are not violated.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.86

As part of the NRC review of the licensees submitted of South Texas Unit 2, the staff will conduct an independent audit of the limiting small break LOCA and Chapter 15 transients. In order to conduct our audit, we require the information listed in the attachment. In order to conclude our evaluation within the time frame of the requested license, we require the applicant to provide the requested information within 6 weeks of receipt of this request for additional information.

Response [HISTORICAL INFORMATION]

In a letter dated June 16, 1982 from D. G. Eisenhut (U.S. NRC) to E. P. Rahe (Westinghouse), the NRC agreed to request RESAR-41 generic data rather than STPEGS plant-specific information; detailed information will be required at some future time prior to licensing of STPEGS

HISTORICAL INFORMATION

Question 440.47N Deleted

Question 440.48N

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 STPEGS technical specification limits.

Response **(HISTORICAL INFORMATION)**

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.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 440.50N

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 reseat properly after prolonged relieving of liquid or two 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 **(HISTORICAL INFORMATION)**

HISTORICAL INFORMATION

Only two events predict the pressurizer will fill during or as a result of the transient, Chemical and Volume Control Systems malfunction and Feedwater System Pipe Break. 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 water solid, 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. For the Feedwater System Pipe Break refer to revised Sections 15.0.9 and 15.2.8 which show that the pressurizer does not become water solid due to a feedwater line break.

HISTORICAL INFORMATION

Note:
Q&Rs 211.43 and 440.50N are considered historical information. Q&R 211.45 has been deleted from the UFSAR and the response has been partially incorporated into UFSAR text (Section-15.0.8.2).

Question 440.51N

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&R 15.0-18 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.

<u>Response</u> [HISTORICAL INFORMATION]

a. Following an Anticipated Operational Occurrence (AOO), the plant should be able to return to power operation given that the initiating fault has been corrected. No operator action has been assumed for any of the AOO, except for the boron dilution event. In Section 15.4.6, the Standard Review Plan requires that, for operator action to terminate the transient, at least 15 minutes (30 minutes for refueling) be shown available between the time when an alarm announces an unplanned moderator dilution and the time of loss of all shutdown margin. Refer to Section 15.4.6 for details concerning alarms, delay times, actions and equipment for use in mitigating the boron dilution event. No other analysis of an AOO assumes (i.e., requires) operator action.

b. The response to Question 211.52 has been revised to reflect safety analysis assumptions concerning times of operator action for the steam line break, feedwater line break, and LOCA events.

The steam generator tube rupture (SGTR) has been reanalyzed in accordance with the methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A. The methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A has been accepted by the NRC. Section 15.6.3, WCAP-12369-P, and letter ST-HL-AE-3236, dated October 13, 1989, contains STP specific details of the reanalysis.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 440.52N Deleted

Question 440.53N Deleted

Question 440.54N Deleted

Question 440.55N

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 table 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:

1. Low reactor coolant flow in more than one loop

2. Undervoltage

3. Underfrequency

4. Pressurizer low pressure

5. Pressurizer high level

For STPEGS, 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 Reactor Coolant System (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 ten 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 440.56N

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 STPEGS 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 440.57N

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

See the response to Question 440.80N.

Question 440.58N Deleted

Section 15.1

Question 032.23

Describe the Emergency Boration System's (EBS) redundant heat tracing system. Identify and justify any deviation from your preliminary design presented in the PSAR. In the Safety Evaluation Report related to construction of STPEGS (NUREG-75/075) the staff requested that the applicant provide a design feature or perform a test that would assure that during switching from one ESF power source to the other, a fault which may exist on one system would not be transferred over to the redundant system, thereby compromising the independence of redundant Class 1E power systems. Provide this information. Also provide the design details for EBS temperature monitoring system indicating how the requirements of IEEE-279 are satisfied.

<u>Response</u>

As a result of analyses performed after FSAR submittal, the EBS is no longer required at STPEGS and has been deleted.

Question 211.58

Provide the basis for the different flow rates for the full power and zero load conditions (i.e., 14 percent vs. 200 percent) and verify that the lower value is appropriate for the full power case.

Response [HISTORICAL INFORMATION]

The feedwater flow rates used in full load and zero load excessive feedwater transients are different because the number of steam generators receiving feedwater is different.

At full load conditions, the feedwater flow is divided between all four steam generators. The faulted steam generator receives 140 percent of its nominal full load flow rate. The unaffected steam generators each receive the nominal full load flow rate.

At zero load conditions during an excessive feedwater transient, one steam generator receives all the feedwater flow (200 percent of nominal full load flow). The other three steam generators are assumed not to receive any feedwater flow.

NOTE: The feedwater flow rates assume bounding values. Flow rates for the current analyses are provided in UFSAR Section 15.1.2.

Question 211.60 Deleted

Question 211.61

Figure 15.0-9 indicates operator termination of safety injection to limit RCS pressure and pressurizer level. Address the time frame associated with this action and/or the consequences of failure to perform the action or premature termination of SI flow.

Response

Operation action is not assumed for at least 10 minutes following a depressurization of the main steam system. If the operator fails to terminate SI at the appropriate time, no adverse consequences will occur. The SI pumps have a maximum shut off head approximately 1600 psia. Thus, no overpressurization of the RCS can occur due to the SI system. If the operator prematurely terminates SI and criticality is attained, the core power will increase until it reaches equilibrium with steam demand.

Further information is provided in the response to Q211.52.

Question 211.64 Deleted

Question 211.67 Deleted.

Question 211.69 Deleted

Question 211.70

Figures 15.1-13, 15.1-16, and 15.1-19 indicate that the pressurizer is emptied during the safety valve and steam line break transients. Discuss the potential effects of this conditions, including the potential for and recovery from void formation in the RCS. Also address the applicability of the models during the period when the pressurizer is empty.

HISTORICAL INFORMATION

Reponse [HISTORICAL INFORMATION]

Figure Q211.70-1 and Q211.70-2 show the void volume in the reactor vessel upper head and the and the pressurizer as a function of time for the 1.4 ft^2 steam line ruptures presented in Section 15.1.5 of the UFSAR. The figures show that voids never completely fill the reactor vessel head, thus no steam flow out of the head will occur. The fluid in the reactor coolant loops remains subcooled throughout the transient, therefore no voiding will occur in the loops. The void in the reactor head is removed once the coolant temperature decreases below the saturation temperature for the equilibrium pressure (approximately 1,000 psia).

The inadvertent opening of a relief valve presented in Section 15.1.4 had no void formation in the reactor vessel head. The fluid in the reactor coolant loops remained subcooled, thus no voiding will occur in the loops.

LOFTRAN will model transient conditions where voids are formed in the reactor vessel upper head. As a steam void in the reactor vessel upper head increases, water is assumed to be pushed out of the reactor vessel using a slug flow model. This model is applicable as long as no voiding occurs in the reactor coolant loops. Therefore, the analysis is independent of the pressurizer level. If the steam void completely fills the reactor vessel upper head, then steam flow from the reactor vessel would occur. The South Texas units showed only small amounts of void formation in the upper head and the reactor coolant loops remained subcooled. The situation where voids occur in the reactor coolant loops need not be considered.

Figure Q211.70-1

Figure Q211.70-2

Question 440.1N

In response to our previous question (2ll.85) regarding deletion of the emergency boration system (EBS) from the STPEGS design, you have indicated that EBS deletion was justifiable, since, in the event of a main steam line break, the DNB design bases are met and the radiation releases are within the limits set forth in l0 CFR Part l00. We have reviewed the system aspects of the revised steam line break analysis in FSAR Section l5.l.5. Based on our review we have determined that the following additional information is required. If this information has been included elsewhere in your FSAR, appropriate references in Section l5.l.5 will suffice. Likewise, if the information has been provided in the form of other documentation (e.g., Westinghouse topical reports), reference to such documentation (please be specific) is appropriate.

a. Clarification of the methodology for calculating reactivity feedback, including the effect of nonuniform core inlet temperatures from the reactor coolant loops; justification of the conservatism in the methodology with regard to the peak power obtained.

b. Clarification of the methodology used in calculating DNBR and verification that the power distributions used for DNBR calculations reflect the effect of nonuniform core inlet temperatures from the reactor coolant loops.

c. With respect to ESF actuation functions for an SLB, describe and justify the differences between the protection functions at the STPEGS and the actuation functions in NUREG-0452, "Standard Technical Specifications for Westinghouse PWR's". Describe the "excessive cooldown protection" function, which, in accordance with the FSAR, provides safety injection in the event of an SLB. Identify the actuation set points.

<u>Response</u>

a) See revised Section 15.1.5.

b) See revised Section 15.1.5.

c) With respect to Engineered Safety Features (ESF) actuation functions for a SLB, the current differences between the protection functions at STPEGS and NUREG-0452 are as follows:

   1. For safety injection (SI) actuation, the function of low compensated steamline pressure has been added. The functions of high differential pressure between steam lines and high steam flow in two steam lines coincident with low-low T_{avg} or low steam line pressure have been deleted.

   2. For steamline isolation, the function of high steam flow coincident with low steamline pressure or low-low T_{avg} has been deleted. In addition, the functions of high steam pressure rate has been added.

Response (Continued)

The excessive cooldown protection logic has been deleted from the STPEGS protection system. This system, first described in RESAR-41, is not taken credit for in the STPEGS plant specific licensing basis analysis.

The actuation setpoints are given in the Technical Specifications.

Question 440.59N Deleted

Question 440.60N

Provide plots of DNBR versus time for the 1.4 ft² steam line break analysis, for both "offsite power available" and "offsite power not available" cases.

Response

Transient plots of the 1.4 ft² steam line break analysis are illustrated in Figures 15.1-15 through 15.1-20 of the STPEGS UFSAR. Historically, departure from nucleate boiling ratio (DNBR) versus time plots have never been presented in Chapter 15 of the FSAR. The main steam line break is a Condition IV event and, consequentially, must meet the radiological dose release requirements of l0CFRl00. Limited fuel damage is permitted as long as the above criteria are met.

Based on previous steam line 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 steam line 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 state-points, 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 STPEGS was above the design basis limit and no fuel was calculated to fail.

Question 440.61N

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 main steam isolation valves (MSIVs) of STPEGS 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 (RG) 1.48, i.e., full scale prototype testing. This test was the first ever performed on a valve as large as a 26-in. valve.

   The purpose of the Sonic Flow Test was to show that the Atwood and Morrill MSIV 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-in. production valve modified to represent an even larger 32-in. 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 pressurized water reactor (PWR) plants, and conforms to ASME Class 2 requirements.

Question 211.71 Deleted

. Figure Q211.71-1 Deleted

Question 211.73

Provide the time frame assumed for operator isolation of the break in the feedwater line break analysis. Provide justification and a list of all assumptions used to determine this time frame.

Response

The feedwater system pipe break analysis presented in Section 15.2.8 does not assume the operator isolates the break.

Question 440.62N Deleted

Question 440.63N

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 440.70b.).

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

A steam generator (SG) water volume of 6000 ft^3 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^3 will fill the SGs. The Loss of Normal Feedwater analysis presented in Section 15.2.7 assumes that the operator terminated (AFW) auxiliary feedwater 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 anticipated operational occurence (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.

NOTE: Plant operators are trained to perform actions specified in the emergency operating procedures (EOPs). The EOPs instructs operators to take specific actions to prevent flooding of the steam generators.

HISTORICAL INFORMATION

Question 440.64N

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 440.58N regarding automatic feedwater isolation). If credit is taken for operator action, please justify why it can be taken.

<u>Response</u>

a. The analyses assumptions regarding the initial steam generator (SG) 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 (SG) level in both the faulted and intact SGs on the peak Reactor Coolant System (RCS) temperatures are provided in Table 5.1-1. As demonstrated, the peak RCS temperature reaches the highest value when the initial SG level in the faulted loop is (+)5 percent of nominal level and the initial SG 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.

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

Response (Continued)

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

c. The STPEGS Auxiliary Feedwater System (AFWS) is designed such that the operator is not required to take manual action to ensure the minimum required auxiliary feedwater (AFW) flow is injected into the intact SGs even assuming the worst single active failure is one AFW pump. However, the transient analyses provided in Section 15.2.8.2 of the STPEGS UFSAR assume the operator takes action following the feedline rupture to isolate the AFW 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 AFW flow spilling out the rupture is assumed in order to conserve the plant condensate quality water supply to the AFW pumps. Should this action not be taken by the operator, the first required action by the operator would be to terminate the SI flow within a minimum of 30 minutes in the accident analysis following the initiation of the rupture.

   All main feedwater flow to the SGs is isolated on receipt of a SI signal on 2/3 low steam line pressure in the faulted SG. AFW flow is automatically initiated on a SI signal or on low-low SG level in any SG.

Question 211.55

Deleted

Question 211.75

Provide an analysis for the loss of flow from two or more reactor coolant pumps or provide a justification, with bases, why this condition is not credible.

Response

The types of loss of forced reactor coolant flow cases analyzed are based on the reactor coolant pump power supply configuration.

STPEGS has four different reactor coolant pump power supplies (one for each pump). Only the complete loss of flow and the loss of flow from one reactor coolant pump are analyzed. With this power supply arrangement, loss of flow from two or three reactor coolant pumps is not considered credible because multiple faults would have to be postulated.

Question 211.76 Deleted.

Question 211.77

Section 15.3.2.1 of the FSAR states that the reactor trip on reactor coolant pump undervoltage is blocked below 10 percent power. Discuss what reactor trip provides protection on a decrease in reactor coolant flow below 10 percent power. Discuss what analyses have been conducted to verify the adequacy of this trip.

<u>Response</u>

For a decrease in reactor coolant flow during operation below approximately 10 percent power (interlock P-7), there is no immediate reactor trip function required. Natural circulation flow in the RCS provides adequate core cooling capability.

Question 211.78

The Standard Review Plan, Section 15.3.3/4 classified the RC pump rotor seizure and RC pump shaft break as infrequent transients. Provide a justification for your classification of the transient results meet the acceptance criteria for an infrequent event as required by the SRP.

Response

The reactor coolant pump seizure and reactor coolant pump shaft break events are classified according to the ANS as Condition IV events - limiting faults. Westinghouse follows this classification in the Chapter 15 safety analysis. However, the results of the analysis for this event meet the safety analysis for a Condition III event. The peak RCS pressure is maintained below 2750 psig. The peak clad temperature is well below 2700°F.

Question 211.79 Deleted

Section 15.4

Question 211.80

Discuss the uncertainty in the calculations for the nuclear power transient during the startup of an inactive loop. Of primary concern is the possibility that the loop flow may have exceeded the low reset point before the P-8 setpoint has been reached, resulting in the loss of the trip function assumed in the analysis. Also, confirm that the 15 second startup time for the inactive pump is conservative and that a faster startup would not make the transient more severe.

Response [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

Generic studies of the startup of an inactive loop have been performed. Table Q211.80-1 lists results of these studies where pump startup times were varied from 7.5 seconds to 30.0 seconds. In all cases examined, nuclear flux reached the P-8 interlock setpoint (reset for 3 loop operation) before loop flow increased above the low reactor coolant flow trip setpoint. In all cases examined, the DNBR remained well above the limit. These case with a 7.5 second startup time yielded the lowest DNBR. Startup times of approximately 7.5 seconds were considered unrealistic. Pump startup times less than 30 seconds are conservatively faster than actual plant values. Thus, for UFSAR analysis purposes, startup times of approximately 20 seconds were selected.

Figure Q211.80-1 shows the nuclear flux and RCS loop flow transients corresponding to the case presented in Section 15.4.4. The case presented uses a startup time of approximately 18 seconds. The P-8 interlock setpoint is reached approximately 7 seconds before loop flow increases above the low reactor coolant flow trip setpoint.

HISTORICAL INFORMATION

TABLE Q211.80-1

INACTIVE LOOP START RESULTS

[HISTORICAL INFORMATION]

Pump Start Time (sec)	Time of Reactor Trip (sec)	Time of Loop Flow Reaching Low Reactor Coolant Flow Trip Setpoint (sec)
30.0	7.77	25.87
22.4	6.40	19.66
16.8	5.12	14.94
11.9	3.86	10.79
7.5	2.51	6.67

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Figure Q211.80-1

Question 211.81 Deleted

Question 211.82

Recently, an operating PWR experienced a boron dilution incident due to the inadvertent injection from the NaOH tank into the Reactor Coolant System while the reactor was in the cold shutdown condition. This event occurred due to a single failure - misposition of the isolation valve of the NaOH tank while the decay heat removal system was lined up for reactor coolant recirculation. Discuss the potential for a boron dilution incident caused by dilution sources other than the CVCS.

Response [HISTORICAL INFORMATION]

Other than the CVCS, the only sources with water of a boron concentration which could be less than the RCS boron concentration are the Recycle Holdup Tanks (RHTs) in the Boron Recycle System. There are also reactor makeup water connections to the Boron Recycle System; but, as the only path between them and the RCS is via the RHTs, they do not constitute a separate dilution source. No single failure can allow flow from the RHTs to enter the RCS or the refueling canal, so dilution of the RCS from the RHT need not be considered.

HISTORICAL INFORMATION

HISTORICAL INFORMATION 73

Question 232.7 Deleted

Question 232.8 Deleted

Question 312.14 Deleted

Figure Q312.14-1 Deleted

Figure Q312.14-2 Deleted

Question 440.66N

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 percent. 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 Technical Specification value for the maximum allowable cold leg temperature difference.

Question 440.67N Deleted

Question 440.68N Deleted.

Section 15.6

Question 211.84 Deleted

Question 312.9 Deleted

CN-2970

HISTORICAL INFORMATION

Question 312.10

Provide figures showing (1) primary and secondary system temperature and pressure and (2) liquid level in the affected steam generator for the time period between tube failure and the time when primary system and secondary system pressures equilibrate.

Response [HISTORICAL INFORMATION]

The steam generator tube rupture (SGTR) has been reanalyzed in accordance with the methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A. The methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A has been accepted by the NRC. Section 15.6.3, WCAP-12369-P, and letter ST-HL-AE-3236, dated October 13, 1989, contains STP specific details of the reanalysis.

Analyses performed for the Δ94 replacement steam generators are documented tin WCAP-15136 South Texas Unit 1 Replacement Steam Generator Program Safety Analysis and Licensing Report, November 1998, which provides the details of the analysis. The replacement steam generator analysis follows the methodology of WCAP-10698 and Supplement 1 of WCAP-10698. Consistent with the approach taken in WCAP-12369 for STP, the effect of iodine scrubbing of steam bubbles as they rise from the rupture site to the water surface has been conservatively neglected in the analysis. The Model Δ94 analysis therefore does not include a figure showing the liquid level in the affected steam generator.

HISTORICAL INFORMATION

Question 440.2N

Verify that the reflood heat transfer model utilized for the double ended cold leg guillotine (DECLG) break LOCA analysis is acceptable for the STPEGS 14 foot core. (Refer to the attached SER on the 1981 version of the Westinghouse large break ECCS model.)

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

The DECLG break LOCA analysis was recalculated utilizing the Westinghouse 1981 ECCS evaluation model in conjunction with BART (WACP-9561). Therefore, use will no longer be made for the FLECHT correlation to calculate heat transfer coefficients. A SER for BART was issued in December 1983. Since BART has no restriction on the applicability to 14 foot cores, this question is no longer relevant for STPEGS. The results of this analysis will be presented in Section 15.6.5.

HISTORICAL INFORMATION

Question 440.3N

HISTORICAL INFORMATION

Verify that the STP large break ECCS model incorporates the revised staff requirements for cladding swelling and rupture models described in NUREG-0630, "Cladding Swelling and Rupture Models for LOCA Analysis", April 1980. (See also attached SER.)

On October 14, 1980, Houston Lighting & Power Company received a letter from the NRC requesting additional information concerning the application of the cladding swelling and rupture models for the Loss-of-Coolant Accident (LOCA) analysis. Specifically, the request was made that HL&P provide supplemental information which utilized the materials model of draft NUREG-0630. In response, HL&P submitted an evaluation of the potential impact of using fuel rod models presented in draft NUREG-0630 on the LOCA analysis for STPEGS, Units 1 and 2. That evaluation was contained in a letter from J. H. Goldberg to D. G. Eisenhut dated February 27, 1981. Use of the NRC fuel rod models caused a ΔF_Q penalty of 0.0364, which was offset by NRC credit of 0.20.

HISTORICALINFORMATION

Question 440.5N

Clarify which Westinghouse ECCS evaluation model is utilized for the STPEGS DECLG break analysis, the 1978 model (as stated on page 15.6-17) or the 1975 model (as stated on page 15.6-18).

Response [HISTORICAL INFORMATION]

The 1978 Westinghouse ECCS model is utilized for the STPEGS DECLG break analysis. The reference to the 1975 model has been deleted.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 440.6N

Verify that the LOCA analyses utilize the correct upper head fluid temperature.

Response [HISTORICAL INFORMATION]
The upper head cooling spray nozzle flow is 0.4 percent of the total flow. This small spray nozzle flow rate indicates that the upper head fluid temperature should be conservatively modeled as being equal to the vessel outlet temperature. A review of the analysis for STPEGS showed that the upper head fluid temperature was modeled as being equal to the vessel outlet temperature.

HISTORICAL INFORMATION

Question 440.7N

The STPEGS ECCS design appears to be unique in that only 3 of the 4 RCS loops are connected to the ECCS. Discuss whether the STPEGS DECLG break LOCA utilized split downcomer nodalization. Provide justification for the nodalization method for the split downcomer in light of the fact that STPEGS has one loop without ECCS and the 1981 model justification did not have such an arrangement. If STPEGS did not use a split downcomer provide justification. (Note: See also page 6 of the attached SER.)

Response [HISTORICAL INFORMATION]

STPEGS was analyzed using the 1978 Westinghouse ECCS evaluation model which utilizes a non-split downcomer.

Although the ECCS is asymmetric, it is modeled in such a way as to minimize injection into the RCS and maximize spill to containment, i.e., the break occurs in a loop equipped with ECCS. In addition, during the blowdown portion of the transient the bypass region has been modeled as consisting of three intact loops plus the annulus region. This is in contrast to the actual case in which only two intact loops contain injection. This larger bypass region extends the time required to fill the region and delays the end of bypass. A conservation amount of water is calculated to be lost because of the requirement for 100 percent bypass.

During the reflood portion of the transient, a penalty for steam-water mixing is taken in all three intact loops instead of only two. This penalty increases the loop pressure drop and reduces the core flooding rate below that which is actually expected for the postulated break location.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 440.8N   Deleted

Question 440.69N

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 440.39N). 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.

<u>Response</u> [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

a. The acceptance criteria for this event as described in the Standard Review Plan (SRP) are different from that of the small break Loss-of-Coolant Accident (LOCA) event. For this reason, only the plots of nuclear power, pressurizer pressure, core average temperature, and departure from nucleate boiling ratio (DNBR) are provided in the UFSAR, 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 <u>W</u> NSSS", Section 3.0. Two cases of break size were analyzed representing one small power-operated relief valve (PORV) and three large PORVs 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 SI is available, there is voiding in the core and hot legs, but no core uncovery. The clad temperature remains below steady state operating temperatures, and decay heat is removed via natural circulation. If maximum safeguards SI 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 UFSAR are the worst small breaks.

HISTORICAL INFORMATION

Response (Continued)

b. Figure 15.6-4 was deleted in Amendment 45 of the STPEGS 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 Engineered Safety Features (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 SI 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.

HISTORICAL INFORMATION

Question 440.70N

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 STPEGS 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

Question 440.70N (Continued)

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 STPEGS 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 [HISTORICAL INFORMATION]

The steam generator tube rupture (SGTR) has been reanalyzed in accordance with the methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A. The methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A has been accepted by the NRC. Section 15.6.3, WCAP-12369-P, and letter ST-HL-AE-3236, dated October 13, 1989, contains STP specific details of the reanalysis.

Analyses performed for the Δ94 replacement steam generators are documented in WCAP-15136 South Texas Unit 1 Replacement Steam Generator Program Safety Analysis and Licensing Report, November, 1998, which provides the details of the analysis. The replacement steam generator analysis follows the methodology of WCAP-10698 and Supplement 1 of WCAP-10698.

HISTORICAL INFORMATION

Question 440.72N

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 two 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 [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Based upon the calculated containment pressures, sump temperatures, safety injection (SI) and Residual Heat Removal (RHR) heat exchanger (HX) performance curves, one RHR HX 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 low-head safety injection (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 Emergency Core Cooling System (ECCS) model used in large break LOCA calculations assumed that only one LHSI/high-head safety injection (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 refueling water storage tank (RWST) for the entire 300 second 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.

CN-3131

Question 440.80N

a. In Question 440.57N the staff requested information regarding the effect of the STPEGS design for MSIV closure on mitigation of steam generator tube rupture (SGTR) or small break LOCA. It is our understanding that the MSIVs would automatically close on low RCS pressure SI actuation, while the Westinghouse emergency response guidelines (ERGs) are based on use of the condenser for steam dump when it is available and thus assume that the MSIVs for intact SGs remain open. Your response indicated that for this type of event the MSIVs would be reopened, and that the time required for reopening the MSIVs would be offset by the time it takes to isolate a ruptured SG in the event of SGTR. You concluded that automatic closure of the MSIVs on any SI signal would not adversely affect recovery. We do not concur with this conclusion for the reason discussed below.
In our conference call of December 3, 1985, on this subject, you stated that several operations are required prior to reopening the MSIVs, including SI reset and equalization of MSIV upstream and downstream pressures. First, it is not clear that SI Reset would be possible at the times when MSIV opening is necessary. Second, it is not clear whether the STPEGS emergency operating procedures (EOPS) for SGTR and small break LOCA mitigation reflect these additional steps for re-establishment of steam dump to the condenser, and whether this will be part of operator training, including simulator runs. It is not clear that this mode of plant operation is consistent with our approval of generic Westinghouse ERGs. Please address the above concerns.

b. Please provide detailed information on the effect of STPEGS design for MSIV closure on the frequency of challenges to the MSIVs, steam generator safety valves (SVs) and atmospheric dump valves (ADVs). Consider the possible effect of more frequent challenges on the reliability of these valves. For SVs consider previous operating incidents during which a SV was actuated and then did not reseat properly, thus causing excessive steam leakage (e.g., Ginna SGTR event). Can the number of lifetime design cycles for these components be exceeded as a result of this design? Your response should consider operating history during various modes of operation, including testing and spurious actuations.

c. The evaluations currently conducted by the Westinghouse Owners Group (WOG) to address SGTR accident mitigation do not assume closure of the MSIVS on SI signal. The operator action times assumed in these analyses are based on typical MSIV closure actuation systems, which are not the same as for STPEGS. Thus, it is not apparent that these analyses are representative of the STPEGS plant. Therefore, unless it can be demonstrated that the WOG analyses clearly apply to STPEGS, provide the results of plant specific analyses that address the spectrum of SGTR concerns being addressed by the WOG. These include but are not limited to, the required time to stop the primary-to-secondary break flow and the time margin to overfill.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

The Main Steamline Isolation Valve (MSIV) closure logic has been modified to be consistent with that of other Westinghouse plants. The MSIV closure on manual and high steam pressure rate signals will be maintained. The MSIV closure on a safety injection signal has been modified to MSIV closure only on a HI-2 containment pressure signal and on a low steam line pressure signal.

HISTORICAL INFORMQTION

Section 15.7

Question 211.42

For each event in Chapter 15, provide a discussion of the potential for and impact of incorrect operator action. The discussion should include incorrect actions during normal procedures as well as actions resulting from an incorrect identification of a transient.

Response

Refer to Section 15.7 for postulated events.

1. Liquid-Containing Tank Failures

   The rupture of a Recycle Holdup Tank (RHT) in the Boron Recycle System (BRS) is considered as the most limiting event. The description and analysis of a liquid-containing tank failure is provided in Section 15.7.3.

   For the analysis of the radiological consequences of this event, a tank filled to 80 percent capacity (64,000 gal) is assumed to be released. High level alarms are provided in the RHT, ensuring the influent to the tank will be terminated at approximately 80 percent of tank capacity.

   If the RHT ruptures while it is being filled, it is unlikely that the combined release of the liquid in the tank and the influent (flowing at a low rate of 100 gal/min) released prior to isolation of the tank will exceed 64,000 gallons. The required operator action is to terminate the influent upon receipt of a high RHT sump level alarm and low RHT level alarm. Incorrect operator action, resulting in delayed isolation of the RHT, will not significantly impact the offsite dose consequences of a RHT failure.

Response (Continued)

If the RHT ruptures when it is not receiving influent, incorrect operator actions have no impact on the offsite dose consequences. An operator error during recovery from this accident does not result in equipment malfunctions.

2. Design Basis Fuel Handling Accidents

For the design basis fuel handling accidents, all actions which minimize the offsite dose consequences are automatic, except for a scenario where the Personnel Airlock is open during a fuel handling accident in Containment. Inside the Containment, a high activity signal from the RCB Purge Isolation Monitors initiates Containment ventilation isolation. If the Personnel Airlock is open an operator action is required to close the door. The impact of an incorrect operator action (failure to close the Containment Personnel Airlock) was not considered in the licensing amendment which allows the airlock to remain open during refueling since the potential for an incorrect operator identification of a fuel handling accident is considered very low. It is considered low because Technical Specifications require an individual to be assigned the responsibility of closing the airlock if the door is left open during refueling and a fuel handling accident occurs. This was found to be acceptable to the NRC as evident in the approved licensing amendment for this change (Reference 1).

For a fuel handling accident in the Fuel Handling Building, a high activity signal from the spent fuel pool ventilation monitors diverts the building exhaust through carbon filter units. Thus, incorrect operator actions will have no impact on the offsite dose consequences of a design basis fuel handling accident.

References

1. ST-AE-HL-94116, South Texas Project, Units 1 and 2 - Amendment Nos. 69 and 58 to Facility Operating License Nos. NPF-76 and NPF-80, (TAC Nos. M90796 and M90797).

3. Spent Fuel Cask Drop Accident

The design of the wet cask handling system incorporates features to limit cask drops to 30 feet. Thus, no radiological consequences are expected, and incorrect operator actions will have no impact on the offsite dose consequences.

Note: Additional discussion is provided in the response to Q211.52.

Question 450.2N

Please provide the basis for using the dilution volumes shown in Table 15.7-9 of the FSAR in the analyses of the radiological consequences of fuel handling accidents inside containment and in the fuel handling building.

Response

For the fuel handling accident inside the Fuel-Handling Building (FHB) the dilution volume is the volume directly above the fuel pool serviced by the HVAC. Thus the surface area of the pool was multiplied by the height from the surface of the water to the exhaust ducts. This results in a volume of 53,000 ft^3. Thus a value of 50,000 ft^3 was conservatively used in the analysis.

A similar methodology was assumed in the Reactor Containment Building (RCB). The southeast corner (closest approach) of the refueling water pool is 45 ft from the exhaust duct of the Containment purge. In addition the purge exhaust duct is 17.5 ft above the surface of the water. A cylinder with a radius of 45 ft and a height of 17.5 ft was assumed. This results in a dilution volume of approximately 111,000 ft^3.