QUESTION 211.1

It appears that portions of the recirculation pump seal cooling water are not seismic Category I (Regulatory Guide 1.29). The staff requires additional information to show that a complete loss of pump seal cooling water would not lead to unacceptable consequences.

RESPONSE:

Two non seismic Category 1 sources of cooling are available to the recirculation pump seals: recirculation pump seal cooling water supplied by RBCLCW and recirculation pump seal injection water supplied by the CRD system.

General Electric's Licensing Topical Report, NEDO-24083, Recirculation Pump Shaft Seal Leakage Analysis, provides an analytical basis for recirculation pump seal leakage, assuming a failure of both cooling water systems. This generic analysis predicts a bounding leakage rate well under 100 gpm. The generic analysis is applicable to Susquehanna. The report also documents test results, demonstrating that pump seal integrity will be maintained if any one of the two cooling water systems is out of operation at a given time.

QUESTION 211.2

The FSAR states that missiles from pressurized component failures are not credible. Valve stem, valve bonnet, and temperature element assemblies are examples of sources of missiles that should be addressed.

RESPONSE:

See revised FSAR Subsection 3.5.1.2.2.

QUESTION 211.3

The description or reference to the Standby Liquid Control System should be presented in Section 4.6. Address the requirements of Standard Review Plan (SRP) 4.6.

RESPONSE:

The Standby Liquid Control System is described in Subsection 9.3.5. Section 4.6 has been revised to include this reference.

Issuance of the Standard Review Plans (SRP) post-dates the Susquehanna construction permit by more than 2 years. Therefore, no attempt was made to design the plant to the requirements of the SRPs. The Susquehanna FSAR was prepared using Revision 2 of Regulatory Guide 1.70 as much as practical for a plant of its vintage, with assurance from NRC management that compliance with this Regulatory Guide assured submittal of all necessary licensing information.

As documented in a letter of August 5, 1977 from G. G. Sherwood to E. G. Case of NRC, the SRPs constitute a substantial increase in the information required just to describe the degree of compliance of various systems. This increase in turn represents a substantial resource expenditure which is unjustified and which could cause project delays if required of these projects. As stated in the reference letter, General Electric believes that SRPs should be applied to FSARs only to the extent they were required in the PSARs.

General Electric believes the above position, which is the essence of a directive from Ben C. Rusche, Director of Nuclear Reactor Regulation, to the NRC Staff dated January 31, 1977, is the appropriate procedure for review of the Susquehanna FSAR.

QUESTION 211.4

Acceptance Criterion II.2.b of SRP 5.2.2 states that, "All system and core parameters are at the values within the normal operating range, including uncertainties and technical specification limits, which would result in the highest transient pressure." Insufficient information is presented in the FSAR to determine that this acceptance criterion will be met. The applicant should confirm that the overpressure analysis will be based on an initial operating pressure (up to the Technical Specification limit) which will result in the most limiting peak pressure. The applicant should also confirm that the overpressure analysis will include the effects of the ATWS reactor recirculation pump trip on higher reactor pressure.

Acceptance Criterion II.2.c of SRP 5.2.2 states that, "The reactor scram is initiated either by the high pressure signal or by the second signal from the reactor protection system, whichever is later." The applicant has stated that the safety valve sizing analyses can take credit for the first indirect scram, which is the high neutron flux scram. The neutron flux scram occurs before the high pressure scram and results in a lower calculated peak pressure. The applicant should confirm that the safety valve sizing analyses will be based on the SRP acceptance criterion for reactor scram initiation.

RESPONSE:

The overpressure analysis shown in Chapter 5 of the FSAR assumed the plant is initially operating at 105% steam flow condition with a maximum vessel dome pressure of 1020 psig. The expected maximum operating pressure at 100% power is expected to be 1005 psig, therefore the assumed initial operating pressure of 1020 psig is expected to be conservative relative to expected actual operation. In addition, the nominal high pressure scram set point is expected to be set at 1040 psig. An analysis has been performed for a BWR-3 to investigate the effects of increasing the initial reactor pressure relative to the initial value used in the overpressure protection analysis on the peak system pressure. The conclusion was that increasing the initial operating pressure results in an increase of the peak system pressure, which is less than half the initial pressure increase as shown in Fig. 211.4-1 for the overpressure design transient (i.e., all MSIV closure with indirect high neutron flux scram). The same general trend is expected to exist for Susquehanna. For the Susquehanna project, the proposed technical specification limit on the high reactor pressure scram is 1050 psig. Therefore, the maximum increase in the initial pressure would be limited to only 30 psi and the maximum peak system pressure increase during the overpressure design transient would be limited to less than 15 psi. Thus the overpressure criteria would still be satisfied.

The overpressure analysis shown in Chapter 5 of the FSAR does not include the effects of the ATWS recirculation pumps trip on high reactor pressure. However, a sensitivity study performed on a BWR-4 shows that the peak vessel bottom pressure will increase by 2-4 psi when the effects of the ATWS recirculation pump trip on high reactor pressure are included. This conclusion is expected to be applicable to the Susquehanna project.

General Electric's position on the ASME Code Overpressure Protection is expressed in the attached copy of the letter from I. F. Stuart to the Director of Nuclear Reactor Regulation. The design of S/R valves for GE reactors is based on the requirements of Section III, Nuclear Vessels of the ASME Boiler and Pressure Vessel Code, which has also been adopted by the NRC as part of the requirements in the Code of Federal Regulations (10 CFR 50.55a). It is GE's interpretation that this code does not require the failure of qualified scram signals such as the direct safety-grade position scram. GE therefore considers the failure of the direct scram signal and relies on flux scram to terminate the event to be an appropriate basis for reactor vessel overpressure protection compliance. Analyses show adequate margin, however, does exist in the design of the S/R system that even if the flux scram signal failed and the event was terminated by pressure scram (clearly an emergency event), the peak vessel pressure would be less than the emergency and upset ASME code limits.

GENERAL ELECTRIC

NUCLEAR ENERGY

PROGRAMS DIVISION

GENERAL ELECTRIC COMPANY 175 CURTNER AVENUE SAN JOSE CALIFORNIA 95125
Mail Code 680 Phone (408) 297-3000 TWX NO 910-338-0116

December 23, 1975

Director of Nuclear Reactor Regulation
ATTN: Mr. Victor Stello, Jr.
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

SUBJECT: CODE OVERPRESSURE PROTECTION ANALYSIS - SENSITIVITY OF PEAK VESSEL PRESSURES TO VALVE OPERABILITY

Dear Mr. Stello:

Attached for your information as requested by Mr. Roy Woods of your staff is a study showing the sensitivity of peak vessel pressure to valve operability. This study is typical for a high power density BWR.

It should be noted that the design of safety/relief valves for General Electric Nuclear reactors is based on the requirements of Section III, Nuclear Vessels of the ASME Boiler and Pressure Vessel Code, which has also been adopted by the NRC as part of the requirements in the code of Federal Regulations (10CFR50.55a). It is General Electric's interpretation that this code does not require the failure of a qualified safety/relief valve in addition to the failure of the direct safety-grade position scram and is therefore not considered to be the Licensing basis for reactor vessel overpressure protection. Even further, consideration of the failure of the direct safety-grade position scram by itself, requires multiple equipment failures. The probability of an overpressurization event with these multiple equipment failures is so low, General Electric considers that such an event should be considered, as a minimum, as an "emergency" condition. Therefore, application of the "emergency" limit under these assumed failure conditions would be considered more appropriate.

In determining the required safety/relief valve capacity, General Electric conservatively assumes failure of all direct safety-grade position scrams in the analysis. Further the G.E. analysis conservatively relies upon indirectly derived signals (high neutron flux) from the reactor protection system and although this condition could appropriately be classified as an "emergency" condition, G.E. further conservatively applies the "upset" code requirements rather than the more appropriate "emergency" limits.

In summary, the attached sensitivity study shows that several valves have to fail in order to violate the "emergency" limit. General Electric considers the failure of the direct position scram and subsequent shutdown by high neutron flux scram, with all safety/relief valves operable to satisfy the code requirements and to be an appropriate G.E. licensing basis for reactor vessel overpressure protection.

GENERAL ELECTRIC

If you have any further questions, please contact me.

Sincerely,

Ivan F. Stuart, Manager
Safety and Licensing

SAFETY VALVE SIZING SENSITIVITY TO VALVE FAILURE

Figure 1 characteristics the sensitivity of the peak vessel bottom pressure to safety/relief valve capacity for a typical high power density BWR for an MSIV closure with both direct and flux scram. Although a specific plant sensitivity to valve capacity may vary from that shown in Figure 1 the general trends shown in the figure are considered typical for all BWR's. The conditions assumed in the analysis of the information depicted in Figure 1 are given in Table 1. The results in Figure 1 clearly show the peak vessel pressures are below the ASME upset limit for the case of trip scram over a large range of safety/relief capacity. Similarly the peak pressures are also considerably below the ASME "emergency" and "faulted" limits for the case of flux scram.

TABLE 1	
Vessel Dome Pressure - psig	1020
Steam Flow - lbs/hr	10.96×10^6
- % NBR	105.
Doppler Coefficient - c/°F	0.1817
Void Coefficient = c/% Rated Voids	-13.0
Rated Void Fraction - %	41.60
Scram Reactivity Curve	Figure 2
Scram Rod Drive	Figure 2
Safety/Relief Valve Setpoint - psig	1091 to 1111
Typical Valve Capacity - % NBR Steam flow	5 - 10 per valve
Typical Total Relief Valve Capacity (% NBR Steam flow)	75 - 78

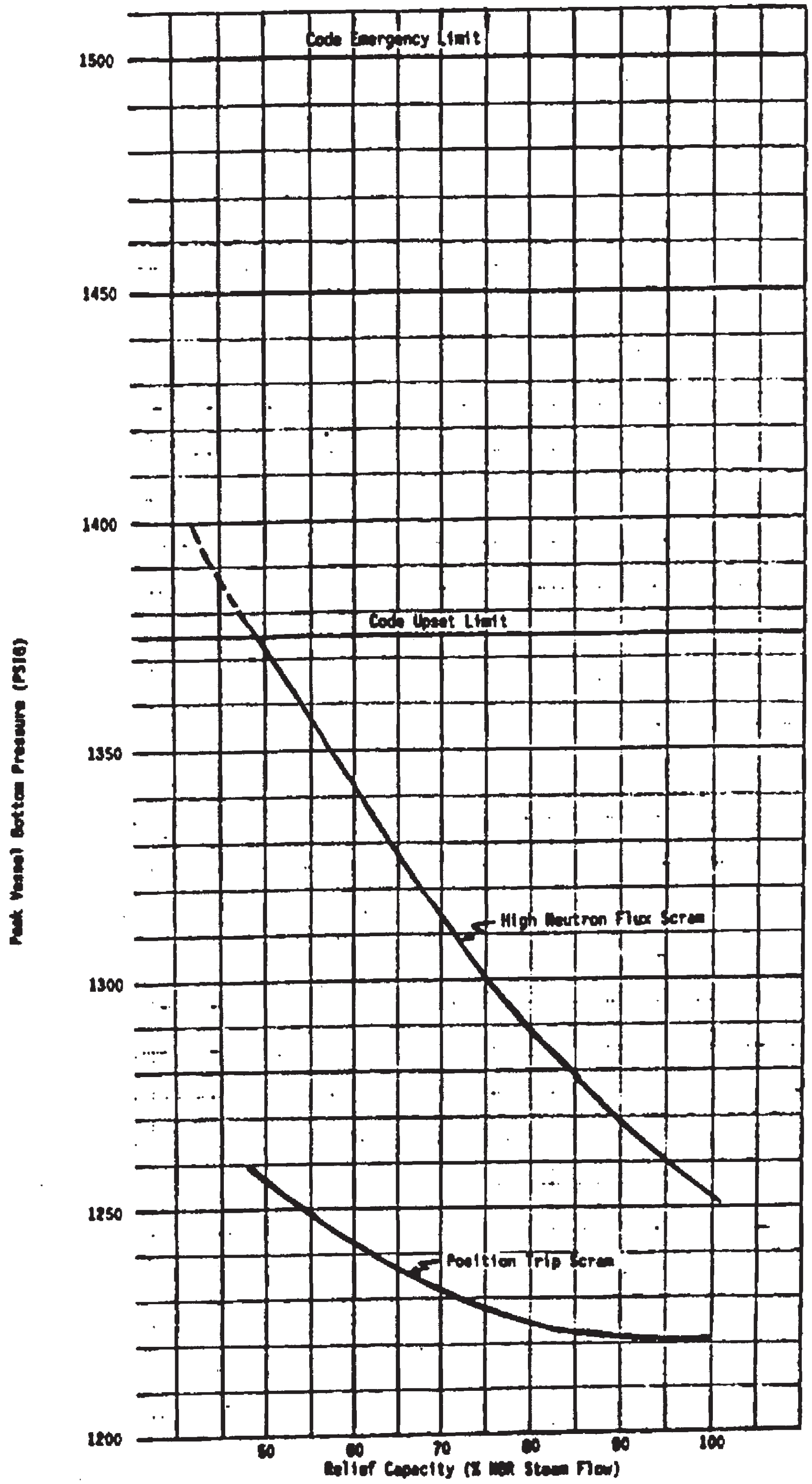
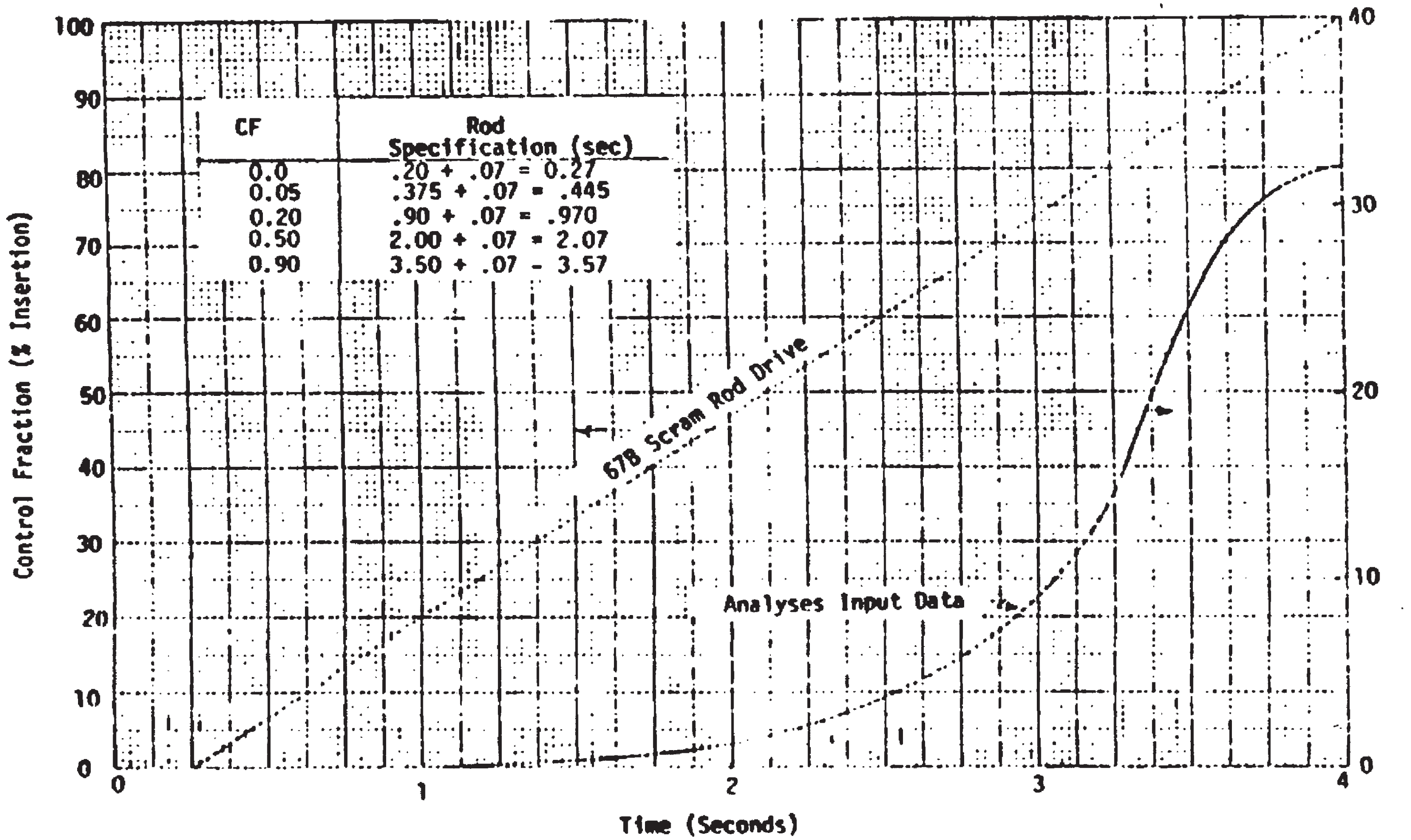
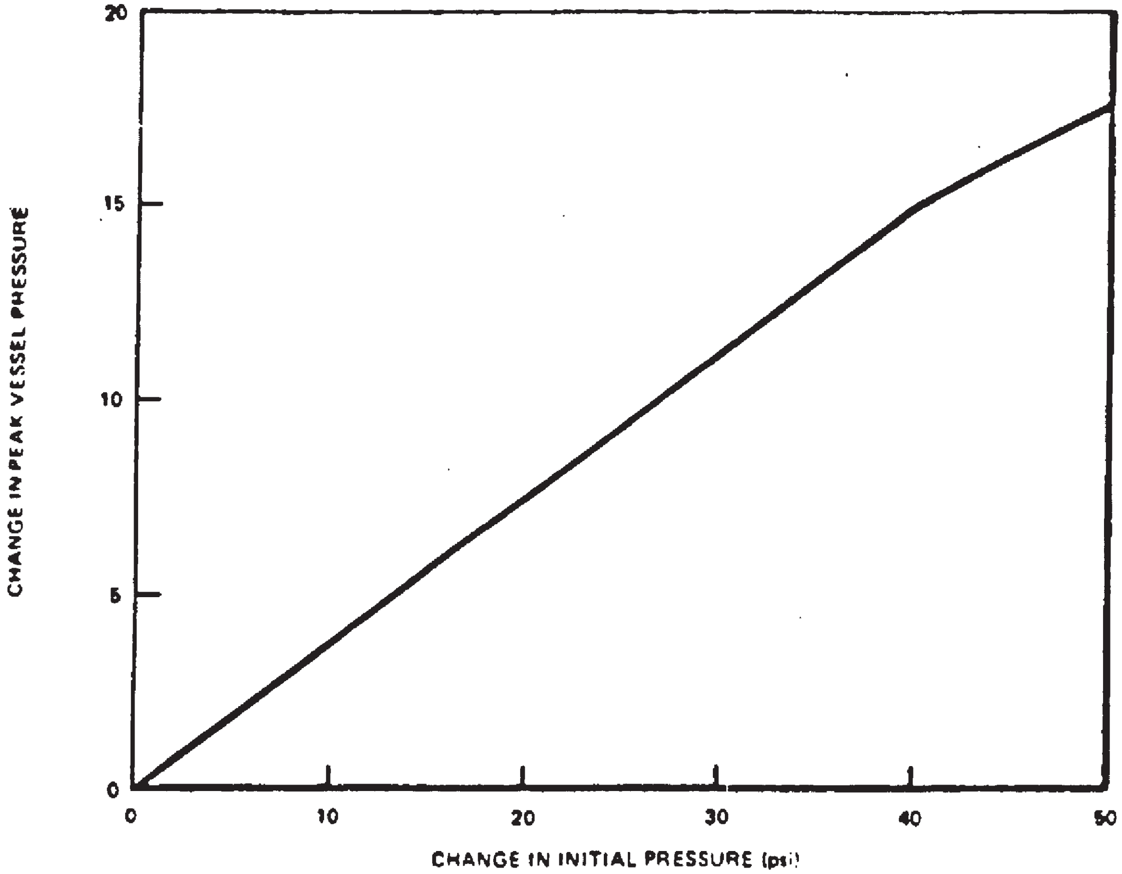


Figure 1 Peak Vessel Pressure vs. Relief Valve Capacity Closure of All MSIV's

Figure 2 - Scram Reactivity





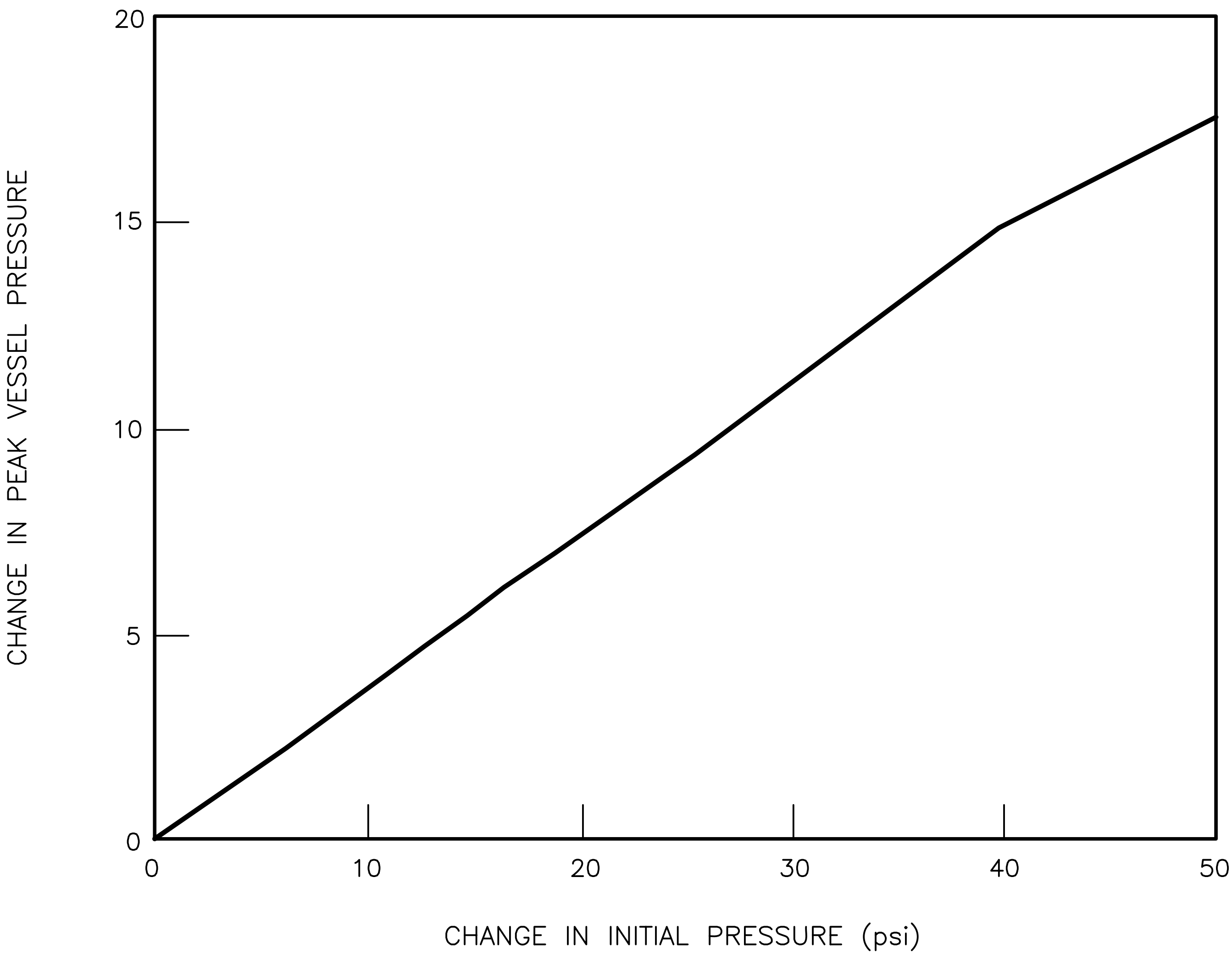
FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

BWR FLUX CHARACTERISTIC
MSIV CLOSURE FLUX SCRAM

FSAR FIGURE 211.4-1

PP&L DRAWING



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

BWR FLUX CHARACTERISTIC
MISV CLOSURE FLUX SCRAM

FIGURE 211.4-1, Rev 47

AutoCAD: Figure Fsar 211_4_1.dwg

QUESTION 211.5

The Reactor Coolant Pressure Boundary (RCPB) leakage detection system should be presented in Section 5.2.5 of the FSAR to show how you meet the requirements of SRP 5.2.5.

RESPONSE:

The Reactor Coolant Pressure Boundary (RCPB) Leakage Detection System is described in Subsection 5.2.5 of the FSAR.

QUESTION 211.6

The process diagram for the RCIC should contain system design parameters for the steam condensing mode of operation.

RESPONSE:

Steam for the steam condensing mode originates in the HPCI system. However, steam condensing steam flow is not a design basis for pipe sizing and is therefore not presented on its process diagram.

Steam for the steam condensing mode is shown on Dwg. M1-E11-3, Sh. 1 and M1-E11-3, Sh. 2, the RHR Process Diagram.

NOTE: The steam condensing mode has been eliminated since the original response to this question. See FSAR Section 5.4.7.1.1.5.

QUESTION 211.7

The acceptance criteria of SRP 5.4.6 (page 5.4.6-3) state that, "As a system which must respond to certain abnormal events, the RCIC system must be designed to seismic Category I standards, as defined in Regulatory Guide 1.29." The condensate storage tank which is the normal suction supply for the RCIC is not seismic Category I. The suppression pool provides a seismic Category I backup source of water, but the switchover requires operation action.

You should confirm that the Susquehanna design will conform to the above acceptance criterion. Either of the following alternatives would be acceptable approaches for meeting the acceptance criteria: (1) seismic Category I supply, or (2) safety-grade switchover to a seismic Category I supply, or (3) manual switchover to a seismic Category I supply if appropriately justified. You should discuss the approach to be used for Susquehanna.

RESPONSE:

Issuance of the Standard Review Plans (SRP) post-dates the Susquehanna construction permit by more than 2 years. Therefore, no attempt was made to design the plant to the requirements of the SRPs. The Susquehanna FSAR was prepared using Revision 2 of Regulatory Guide 1.70 as much as practical for a plant of its vintage, with assurance from NRC management that compliance with this Regulatory Guide assured submittal of all necessary licensing information.

As documented in a letter of August 5, 1977 from G. G. Sherwood to E. G. Case of NRC, the SRPs constitute a substantial increase in the information required just to describe the degree of compliance of various systems. This increase in turn represents a substantial resource expenditure which is unjustified and which could cause project delays if required of these projects. As stated in the reference letter, General Electric believes that SRPs should be applied to FSARs only to the extent they were required in the PSARs.

General Electric believes the above position, which is the essence of a directive from Ben C. Rusche, Director of Nuclear Reactor Regulation, to the NRC Staff dated January 31, 1977, is the appropriate procedure for review of the Susquehanna FSAR.

The Susquehanna design will conform to the acceptance criteria in SRP 5.4.6 by using a manual switchover to a seismic Category I supply. This approach is based on the evaluation of a similar question for the Hatch 2 FSAR, question 212.74. This evaluation assumes a concurrent abnormal transient (i.e., loss of offsite power), seismic failure of the condensate storage tank and HPCI taken as the worst single failure. In addition it allows for operator action to switch over the RCIC suction to the suppression pool. The results of this evaluation were much less severe than other accidents reported in Chapter 15. As this event is categorized as an accident and is less severe than other accidents with acceptable results, the approach to allow for manual switchover is considered justifiable.

QUESTION 211.8

The SRP 5.4.7 states the residual heat removal system (RHRS) should meet the requirements of General Design Criterion (GDC) 34 of Appendix A to 10 CFR Part 50. The RHR by itself cannot accomplish the heat removal functions as required by GDC 34. To comply with the single failure criterion the FSAR describes an alternate method of achieving cold shutdown in Section 15.2.9. Insufficient information is provided to allow an adequate evaluation of this alternate method. In particular, we have recently approved Revision 2 to SRP 5.4.7 (containing Branch Technical Position RSB 5-1) which delineates acceptable methods for meeting the single failure criterion. This Branch Technical Position requires testing to demonstrate the expected performance of the alternate method for achieving cold shutdown. You should describe plans to meet this requirement. In addition, we require that all components of the alternate system be safety grade (seismic Category I).

As a result of this requirement, the air supply to the automatic depressurization system (ADS) valves, including the system upstream of the accumulators, must be safety grade. This air supply must be sufficient to account for air consumption necessary for valve operation plus air loss due to system leakage over a prolonged period with loss of offsite power.

RESPONSE:

As discussed in Subsection 9.3.1.5.1, the gas supply to the ADS values and the backup gas supply to the ADS accumulators is safety grade. Codes covering the design and construction of these components are discussed in Subsection 9.3.1.5.1.

All components that are a part of the alternate shutdown loop see Subsection 15.2.9 and Figures 15.2-14 and 15.2-15 are routinely tested as required by technical specifications. Testing of the total alternate shutdown system would not provide any additional pertinent information and would result in introducing lower quality (suppression pool) water into the vessel. Based on the above, we do not feel that testing of the total loop is necessary or desirable.

This issue was tentatively resolved with the NRC on the Shoreham docket (BWR/4) by an agreement to test one safety relief valve in San Jose simulating the alternate shutdown condition. The rationale for acceptance of this plan was that the SRV is the only component in the loop which has not been demonstrated to be suitable for alternate shutdown conditions.

This test was successfully completed in December 1979. See Subsection 18.1.23.3 for a discussion of the results of the tests on the SRV's.

QUESTION 211.9

The SRP Section 6.3 does not allow credit for operator action for 20 minutes following a loss-of-coolant accident (LOCA). The FSAR states no operator action is required for at least 10 minutes. You should confirm that no operator action is required until 20 minutes after the LOCA, or provide technical justification and associated data based to support a time less than 20 minutes. You should identify the manual actions which must be performed to prevent safety criteria from being exceeded following a LOCA over the break spectrum, including single failures. It should also be shown that adequate alarms, instrumentation, and time will be available to the operator to perform manual actions necessary to prevent safety criteria from being exceeded.

RESPONSE:

In Subsection 6.3.3 of the FSAR, the only analysis affected by the 10 minute vs. 20 minute operator action assumption is the outside steam line break (OSLB). Based on GE experience with 20 minutes operator action, the resulting peak cladding temperature for the Susquehanna OSLB is estimated to be <1500°F.

Issuance of the Standard Review Plans (SRP) post-dates the Susquehanna Construction permit by more than two years. Therefore, no attempt was made to design the plant to the requirements of the SRPs. The Susquehanna FSAR was prepared using Revision 2 of Regulatory Guide 1.70 as much as practical for a plant of its vintage, with assurance from NRC management that compliance with this Regulatory Guide assured submittal of all necessary licensing information.

As documented in a letter of August 5, 1977 from G.G. Sherwood to E. G. Case of NRC, the SRPs constitute a substantial increase in the information required just to describe the degree of compliance of various systems. This increase in turn represents a substantial resource expenditure which is unjustified and which could cause project delays if required of these projects. As stated in the reference letter, General Electric believes that SRPs should be applied to FSARs only to the extent they were required in the PSARs.

General Electric believes the above position, which is the essence of a directive from Ben C. Rusche, Director of Nuclear Reactor Regulation, to the NRC Staff dated January 31, 1977, is the appropriate procedure for review of the Susquehanna FSAR.

QUESTION 211.10

Review procedure III.20 of SRP 6.3 requires that a long-term cooling capacity following a LOCA should be adequate in the event of failure of any single active or passive component of the ECCS. Insufficient information is presented in the FSAR to determine that this requirement will be satisfied with regard to passive failures. The ECCS should retain this capability to cool the core in the event of a passive failure during the long-term recirculation cooling phase following an accident. We will require you to address the following:

Detection and alarms must be provided to alert the operator passive ECCS failures during long-term cooling which allow sufficient time to identify and isolate the faulted ECCS line. The leak detection system should meet the following requirements:

(1) Identification and justification of maximum leak rate should be provided.

(2) Maximum allowable time for operator action should be provided and justified.

(3) Demonstration should be provided that the leak detection system will be sensitive enough to initiate (by alarm) operator action, permit identification of the faulted line, and isolation of the line prior to the leak creating undesirable consequences such as flooding of redundant equipment. The minimum time following initiation of an alarm before operator action is permitted is 30 minutes.

(4) It should be shown that the leak detection system can identify the faulted ECCS train and that the leak is isolable.

(5) The leak detection system must meet the following standards:

a) Control Room Alarm

(b) IEEE-279, except single-failure requirements.

In addition, determine that the effects on ECCS of passive failures such as pump seals, valve seals, and measurement devices. This analysis should address the potential for ECCS flooding and ECCS inoperability that could result from a depletion of suppression pool water inventory. The analysis should include consideration of (1) the flow paths of the radioactive fluid through floor drains, sump pump discharge piping, and the auxiliary building; (2) the operation of the auxiliary systems that would receive this radioactive fluid; (3) the ability of the leakage detection system to detect the passive failure; and (4) the ability of the operator to isolate the ECCS passive failure, including the case of an ECCS suction valve seal failure.

RESPONSE:

The ECCS equipment is located at the lowest elevation in the Reactor Building (Dwg. M-240, Sh. 1). Each train of the ECCS systems is physically separated from the other in watertight compartments. Each system within a train is further separated into watertight compartments. To protect from common mode flooding, the floor and equipment drain lines for each ECCS train has a normally closed valve in the line to the sump.

To alert the operator to any flooding occurring in an ECCS component room, a wall-mounted flooding sensor is provided in each room. These monitors alarm in the main control room when 3.25 inches of flooding has occurred. The sensors are seismic Category I and meet the requirements of IEEE-279, except single-failure requirements, and are shown on Dwg. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3, M-151, Sh. 4, M-155, Sh. 1 and Figure 7.4-1. In addition, the HPCI and RCIC compartments are provided with area leak detection systems consisting of area temperature monitors. During the post-accident long-term cooling phase, the RHR and CS systems are operating. The boundary condition for suppression pool inventory loss would be passive failure in the largest of the ECCS rooms (Core Spray Room). Approximately 5000 gallons would be lost before the operator would be alerted by the room flooding monitors. The operator would secure the affected Core Spray train and start the physically separated redundant train within 10 minutes of receipt of the room flooding alarm (refer to Question 211.236. Assuming a leak rate of 50 gpm and accounting for retention of recirculation water above the diaphragm slab, the suppression pool water level will still be adequate for proper operation of the remaining ECCS pumps. Refer to Section 6.3.6. The ECCS pump rooms are designed to accommodate flooding up to a level of 23 feet without affecting any redundant safety-related equipment or structures. Appropriate actions would be undertaken to drain the water from the room and repair or replace the passive failure. Any ECCS system leak can be isolated, including packing failure on any ECCS pump suction valve. This packing can be isolated since the valves are double-seat, wedge knife gate design.

In the reactor building elevations above the ECCS rooms,the worse case pipe rupture evaluated was found to be the 24" GBB-109/209 RHR piping in the piping/penetration rooms on elevation 683' with a maximum crack flow of 1360 gpm. The crack is postulated with the RHR system in shutdown cooling mode with the reactor cavity flooded. The analysis demonstrates that adequate alarms and instrumentation are available to detect the break in a timely matter and that sufficient time remains for operator action to terminate the event such that no unacceptable flooding results. Credit is taken for operator actions to terminate the event within 45 minutes. In this scenario, the sump room on elevation 645' in the basement of the reactor building is flooded due to the reactor building sumps backing up into this area. Watertight doors between the sump room and connected division 1 RHR/core spray pump rooms prevent water from entering these rooms and these systems remain operable during the flooding event. Water intrusion through equipment hatches above the ECCS/RCIC room is conservatively assumed in this evaluation, even though these hatches have been sealed with caulk. The analysis shows that the resulting inleakage through the equipment hatches would not adversely affect operation any ECCS/RCIC systems. Adequate core cooling systems remain available to maintain safe shutdown, assuming an additional single failure as required in BTP MEB-3-1.

QUESTION 211.11

Review procedure III.5 of SRP Section 6.3 requires that prior to installation, representative active components used in the ECCS will be proof-tested under environmental conditions and for time periods representative of the most severe operating conditions to which they may be subjected.

Insufficient information is presented in the FSAR to determine that proof testing has been performed for ECCS pumps which must function during the long term following a loss-of-coolant accident. Demonstrate that the design of the ECCS pumps which must function during the long term following a loss-of-coolant accident have been qualified by representative testing.

RESPONSE:

The RHR & CS pumps are designed for the life of the plant (40 years) and tested for operability assurance and performance as follows:

A. In-shop tests including (1) hydrostatic tests of pressure retaining parts of 150% times the design pressure, (2) performance tests while the pump is operated with flow to determine the total developed heat at zero flow and design flow, (3) net positive suction head (NPSH) requirements.

B. After the pump is installed in the plant, it undergoes the (1) system hydro tests, (2) functional tests, (3) the required periodic inservice inspection of once a month for an hour during normal plant operation, and one month of operation each year for shutdown (RHR pumps only).

C. In addition, the pumps are designed for a postulated single operation of 100 days for one accident during the unit's 40-year life.

The following table shows the maximum expected accumulated operating time for the life of the plant (40 years).

Mode of Operation	RHR	CS
1. In-shop test	4 (hours)	4 (hours)
2. Pre-Operation	168	168
3. Monthly Testing	480	480
4. Yearly Testing	40	40
5. Post LOCA	2400	2400
6. Shutdown	28800	N/A
	31892	3092

QUESTION 211.12

The initial MCPR assumed for the LOCA analysis is higher than the proposed plant operating limit MCPR. This assumption should be corrected to be below the operating limit MCPR.

RESPONSE:

The initial MCPR for the LOCA analysis was erroneously given as 1.31. The actual value used in the calculation was 1.2. The initial MCPR value in Table 6.3-2 has been corrected to 1.2. (Note that this is less than the value of 1.25 shown in Table 4.4-1 as the steady state MCPR.)

QUESTION 211.13

Provide analyses to show that diversion of ECCS to containment cooling at 10 minutes after a LOCA will not result in exceeding any safety criteria for the entire break spectrum, with consideration of single failure.

RESPONSE:

The effect on the standard ECCS analysis of diverting up to 2 LPCI pumps at ten minutes has been investigated for another BWR/4 with LPCI modification. The analysis showed that diverting LPCI flow at ten minutes can increase the temperatures for some small breaks (less than approximately 0.2 $ft.^2$). However, this increased PCT was still significantly less than the 2200°F limit. The single failure for Susquehanna has been reviewed in light of the previous analysis and it was determined that a Susquehanna analysis would yield similar results.

QUESTION 211.14

Table 6.3-7 should be clarified to show what ECCS equipment is available for core cooling with the assumed single failures.

RESPONSE:

Table 6.3-7 is intended to show the ECCS systems assumed available for reflooding the vessel after a LOCA. The first column lists the assumed single failures. The second column lists the corresponding ECC systems available for a recirculation suction line break. The third column lists the corresponding ECC systems available for recirculation discharge line break. (Note: No credit is taken for LPCI flow into the broken discharge line). The references to "loop" signify LPCI injection into the recirculation loop. For example: "Two LPCI (1 loop) " means "2 LPCI pumps injecting into 1 recirculation loop."

QUESTION 211.15

The staff notes that certain components upstream of the break in the recirculation line influence the total break area assumed in a LOCA calculation. Provide these components and their values of area that comprise the design basis area used for suction and discharge breaks in the LOCA calculation.

RESPONSE:

The component areas that comprise the suction and discharge break areas in the LOCA analysis are as follows:

Suction Break

Recirculation Suction Line Nozzle/Safe End	3.541 ft^2
RWCU Line Minimum Area	.080 ft^2
Jet Pump Discharge Nozzles -	.538 ft^2
Total	4.159 ft^2

Discharge Break

Recirculation Pump Minimum Area	1.389 ft^2
Jet Pump Discharge Nozzles - One Bank	.538 ft^2
Total	1.927 ft^2

QUESTION 211.16

Address the inadvertent closure of the recirculation line suction valve as a single-failure in the ECCS analysis break spectrum.

RESPONSE:

This is not a standard ECCS analysis. However, in response to this question, we have investigated the consequences of this improbable single failure throughout the break spectrum and for various times when failure is postulated to occur. Under all conditions, the resulting PCT is at least 100°F below the current maximum Appendix K PCT of 1874°F. Furthermore, except as noted below, the resulting worst-case PCT for each break size falls well below the current PCT vs. break area plot.

At a discharge break size of 1.0 ft^2 and valve closure beginning at the instant of the LOCA, the resulting PCT is 1767°F, which is 12°F above the current Appendix K PCT for 1.0 ft^2 break. Delaying the time of the postulated beginning of inadvertent valve closure at this break size by as little as 5 seconds or changing the break size by $\pm$ 0.1 ft^2 decreases the PCT to less than that previously calculated. Thus, this small perturbation to the current PCT vs. break area plot occurs within a very narrow range of discharge break size and a very narrow range (< 5 seconds) of times when this single failure is postulated to occur.

We feel that this single failure need not be reported in the standard Appendix K analysis because it represents a highly improbable event, and it is far from the limiting case.

QUESTION 211.17

Provide an analysis of "The Loss of Instrument Air" transient.

RESPONSE:

Recent operating experience indicates that complete loss of instrument air is a remote possibility, since there is enough instrument air stored to provide backup for safety-related air-operated equipment. However, reports of partial loss of instrument air appears to have had no serious effects on reactor components, although it occurs with a moderate frequency.

The Compressed Air Systems are described in FSAR Subsection 9.3.1; with the Instrument Air System in Subsection 9.3.1.1, the Service Air System in Subsection 9.3.1.2, the Radwaste Building Low Pressure Air System in Subsection 9.3.1.3, the Intake Structure Compressed Air System in Subsection 9.3.1.4, and the Containment Instrument Gas System in Subsection 9.3.1.5. The systems of interest are the Instrument Air and Containment Instrument Gas Systems.

The Containment Instrument Gas System consists of two, 100% capacity compressors augmented with nitrogen bottles for the ADS accumulators. The Instrument Air System consists of two, 100% capacity compressors.

However, in the event instrument air is lost from these redundant sources, the following events would occur (in a sequence dependent on the location and type of failures):

(1) Control Rod Drive System - The scram inlet and outlet valves will open, shutting down the reactor. The CRD flow control valve will close to approximately 2% open. The drain and vent valves for the Scram Discharge Volume will close.

The main turbine pressure control system will maintain reactor pressure after the reactor is shutdown until the turbine control valves are closed. If the mode switch is still in the "Run" mode the main steam isolation valves will close and produce a scram signal as the reactor pressure decreases below 850 psi.

(2) Reactor Cleanup System - All air-operated cleanup filter demineralizer valves and the reject valve to radwaste or the main condensers will close upon loss of air.

(3) Standby Liquid Control - The level indication for the storage tank will decrease to zero.

(4) Main steamline isolation valves will close. (Accumulators have sufficient volume for one-half cycle of operation, open to close.)

(5) Main steam safety relief valves will remain closed for the same reason as the main steamline isolation valves. However, there is sufficient air in each relief accumulator to provide one actuation of each relief valve following MSIV failure.

(6) Containment atmosphere control valves and containment ventilation isolation valves fail closed on loss of instrument air.

(7) Drywell and containment ventilation cooling water valves fail closed on loss of instrument air.

(8) Spent fuel pool cooling and cleanup system - The only air operated valve is the demineralized makeup to the pool skimmer surge tank which fails closed and is provided with a manual bypass valve.

(9) The ventilation supply isolation dampers to the secondary containment fail closed.

(10) The standby gas treatment system - only the fire protection water to the charcoal filter would be lost.

(11) The RCIC steamline drain and RHR heat exchanger steam supply valves will close.

(12) Loss of instrument air has no effect on HPCI.

(13) All testable check valves in the systems - Testability, not operability, would be lost to those testable check valves supplied by the Containment Instrument Gas or Instrument Air Systems.

The following is the sequence of operator actions expected during the course of the event. The operator should:

(1) Confirm that the reactor has become subcritical.

(2) Initiate a scheduled surveillance of the standby liquid control storage tank to confirm proper water level and add water manually as required from the clean demineralized water system.

(3) Operate RCIC and/or HPCI according to normal procedures to maintain normal reactor water level.

(4) Continue the cooldown of the reactor with the RHR system, after reactor pressure and temperature have decreased to the operating limits of RHR.

(5) Confirm normal operation of the standby gas treatment system.

(6) Manually makeup water to the closed cooling water system and the fuel pool system from the clean demineralized water system as required.

(7) Manually adjust the control room ventilation heating and cooling system to maintain comfortable conditions.

Loss of the instrument air system will result in the shutdown of the reactor due to the opening of the control rod scram valves and the closing of the main steamline isolation valves. The failure of instrument air will not interfere with the safe shutdown of the reactor since all equipment using instrument air is designed to fail to a position that is consistent with the safe shutdown of the plant.

QUESTION 211.18

We note that some analyzed transients take credit for non-safety-grade systems or components. The concern is that these events are analyzed using less reliable systems to show that the acceptance criteria are met. Confirm that the criteria would not be exceeded for each transient if credit is not allowed for these nonsafety systems.

RESPONSE:

Additional failures over and above those presented in the analyzed transients are considered to be accident conditions. The consequences of these accident conditions are considered to be less limiting than other analyzed accidents.

QUESTION 211.19

In the analyses for the generator load rejection and turbine trip transients, credit is taken for immediate reactor scram and recirculation pump trip obtained from a valve closure signal (turbine control valve for load rejection and turbine stop valve for turbine trip). Analyze these transients without taking credit for immediate reactor scram and recirculation pump trip. Take credit only for safety-grade, seismic Category I equipment and assume loss of offsite power. What is the effect of the failure of a single safety-grade component?

Present curves similar to those of Figures 15.2-2 and 15.2-4 and give values of maximum vessel pressure and minimum MCPR with the times at which these values occur. Evaluate the percent of fuel rods which would reach boiling transition. Since this event is not an anticipated transient, limited fuel failure can be allowed if dose consequences are acceptable.

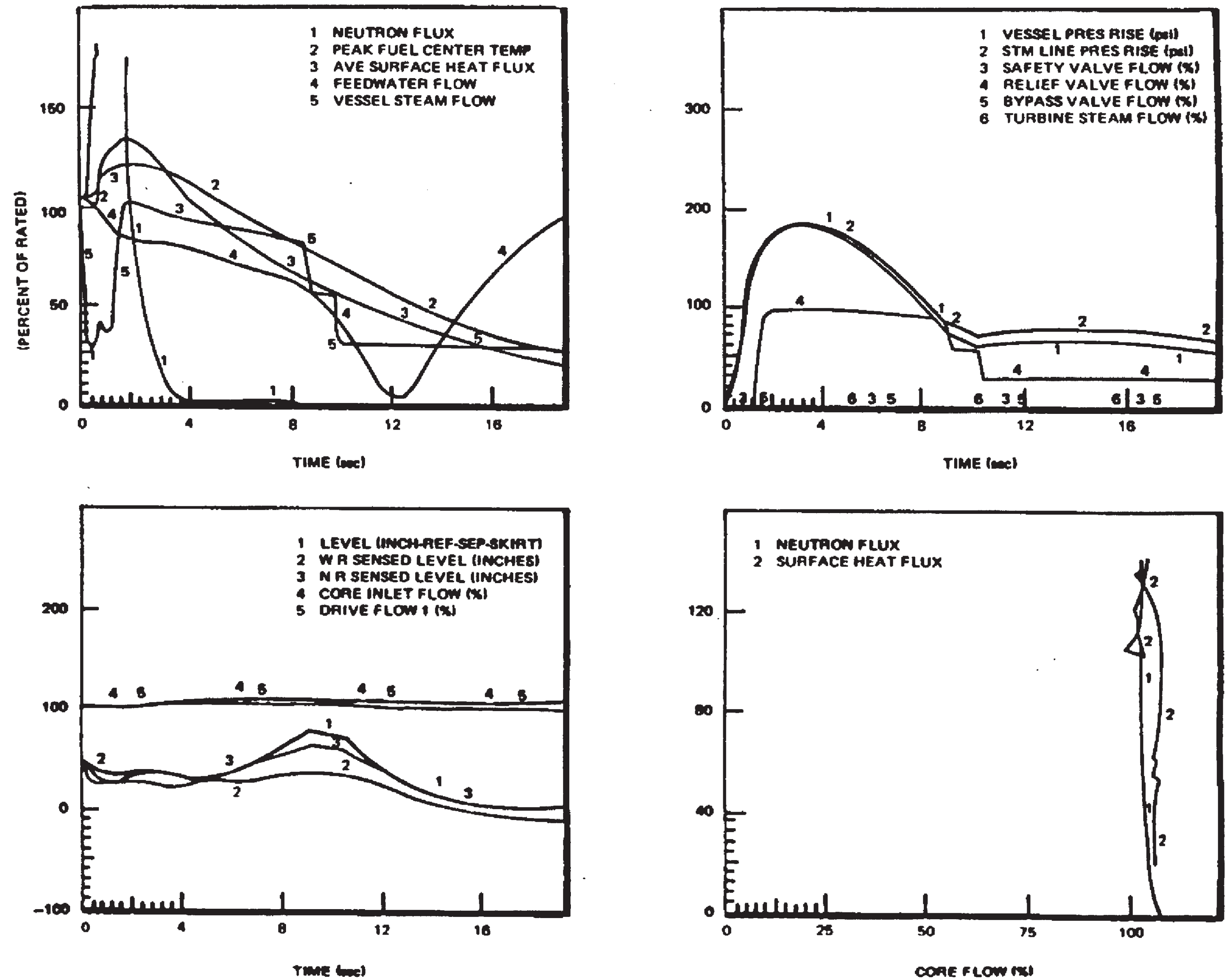
RESPONSE:

A study was performed for Hatch 2 plant (BWR/4) analyzing the generator load rejection transient with concurrent failures of direct scram, RPT function, and bypass function. The results are represented in the attached Table 211.19-1 and Figures 211.19-1 and 211.19-2. Combining the results of the table of peak clad temperatures with the conclusions reached in the Letter Report "Transient Reclassification"[1], it was concluded that there will be no calculated fuel failures. This is based on experimental evidence and calculational studies given in the above document for conditions similar to those used in Hatch 2 analysis. The conclusions of the Hatch 2 study which considered single failures of safety-grade components are also applicable to Susquehanna.

A loss of offsite power would improve the results of the above transient since the only additional effect would be a slow coastdown (in comparison to the RPT function) of the recirculation pumps.

[1] This report was submitted to the NRC as an attachment to a letter to R.C. DeYoung from E.A. Hughes, "Turbine Trip Without Bypass Analyzed as an Infrequent Event," October 5, 1976.

TABLE 211.19-1 SUMMARY OF RESULTS	
	HATCH 2
1. Maximum Vessel Pressure (psig) at t(sec) =	1245. 2.8
2. Minimum Transients MCPR at t(sec) =	 0.89 1.7
3. % Rods in Boiling Transition	6.7
4. Peak Cladding Temperature	<1420°F



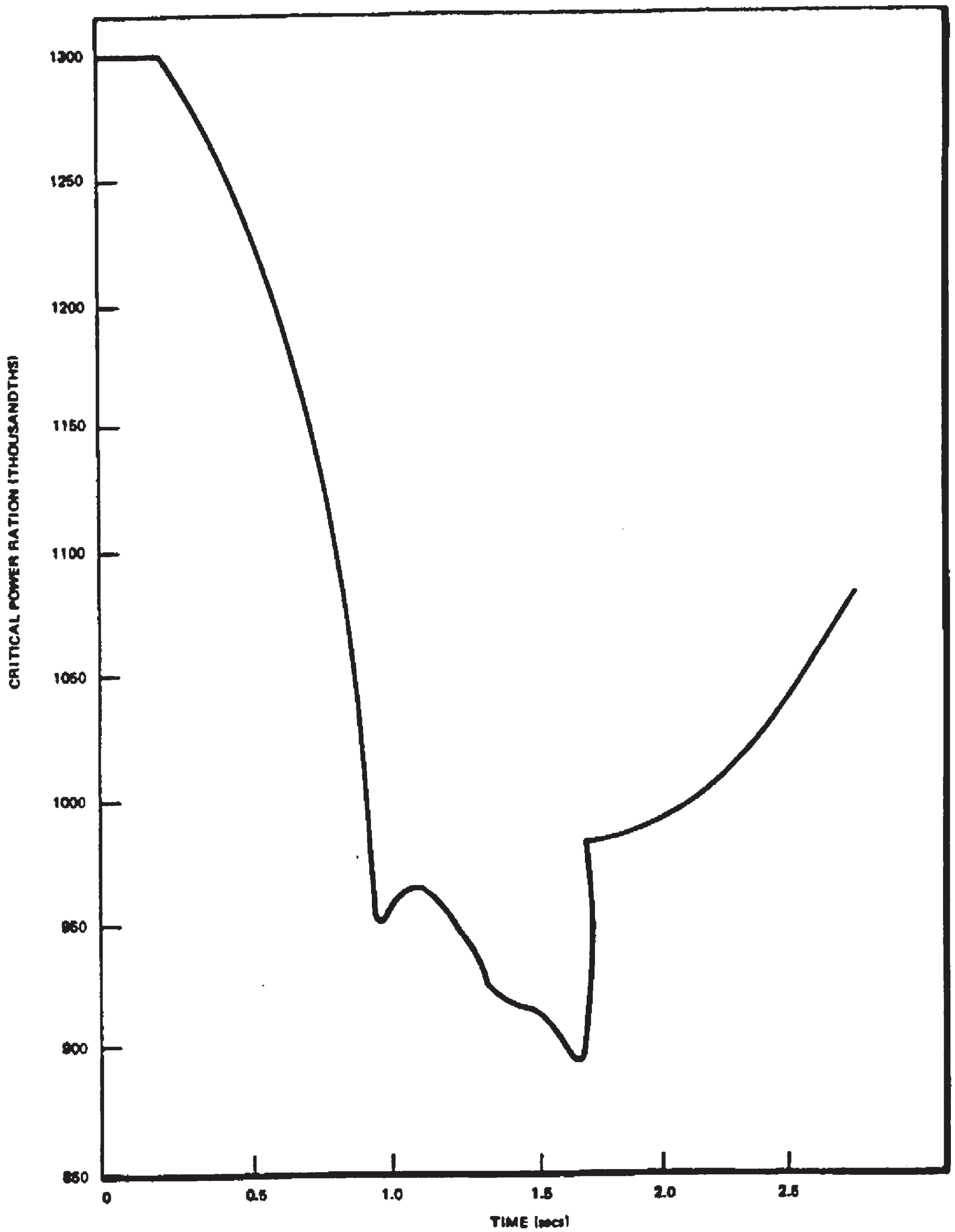
FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

GENERATOR LOAD REJECTION
WITHOUT BYPASS

FSAR FIGURE 211.19-1

PP&L DRAWING



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CRITICAL POWER RATIO
VS.
TIME

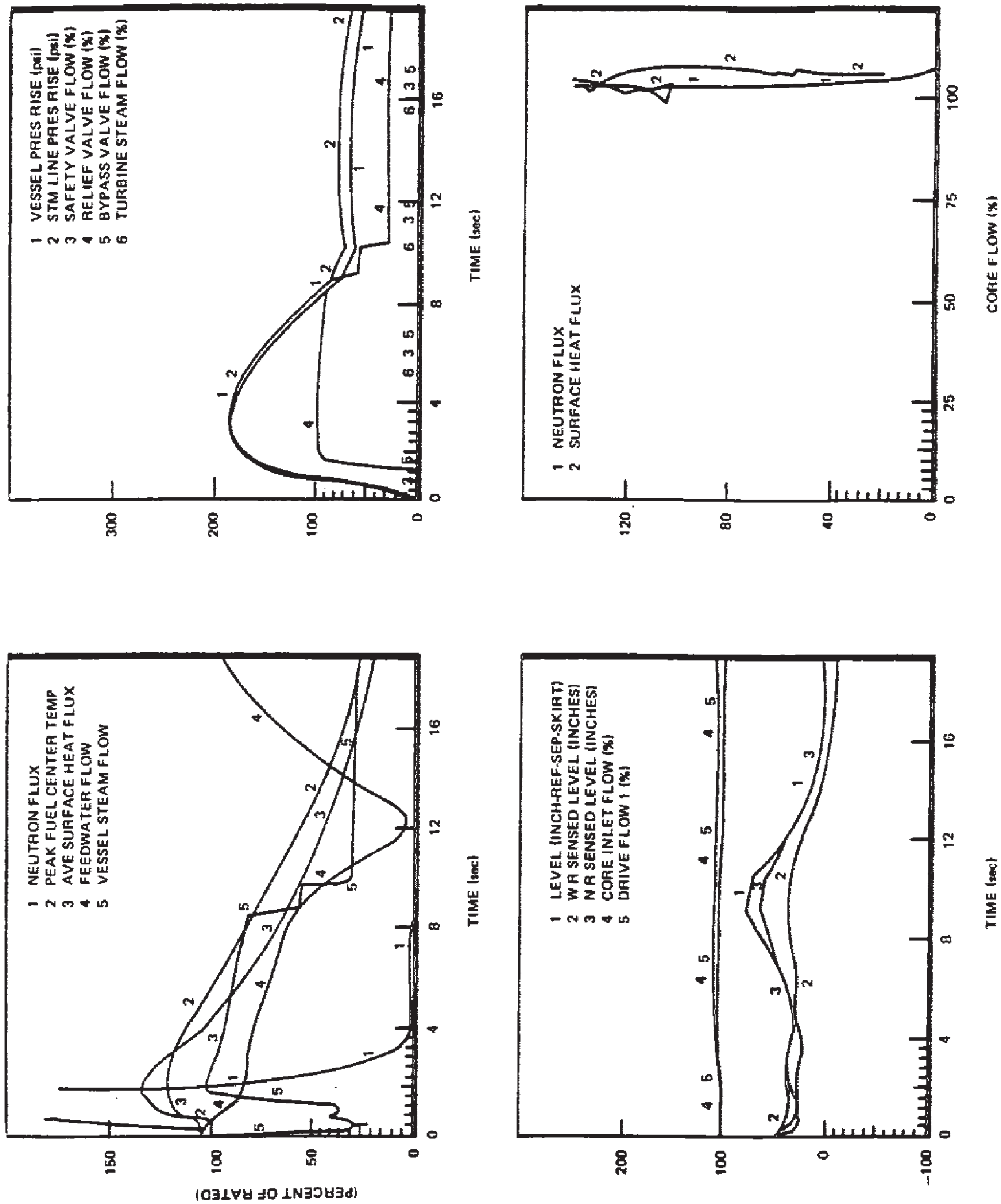
FSAR FIGURE 211.19-2

PP&L DRAWING

TABLE 211.19-1

SUMMARY OF RESULTS

	HATCH 2
1. Maximum Vessel Pressure (psig) at t(sec) =	1245. 2.8
2. Minimum Transients MCPR at t(sec) =	 0.89 1.7
3. % Rods in Boiling Transition	6.7
4. Peak Cladding Temperature	<1420°F



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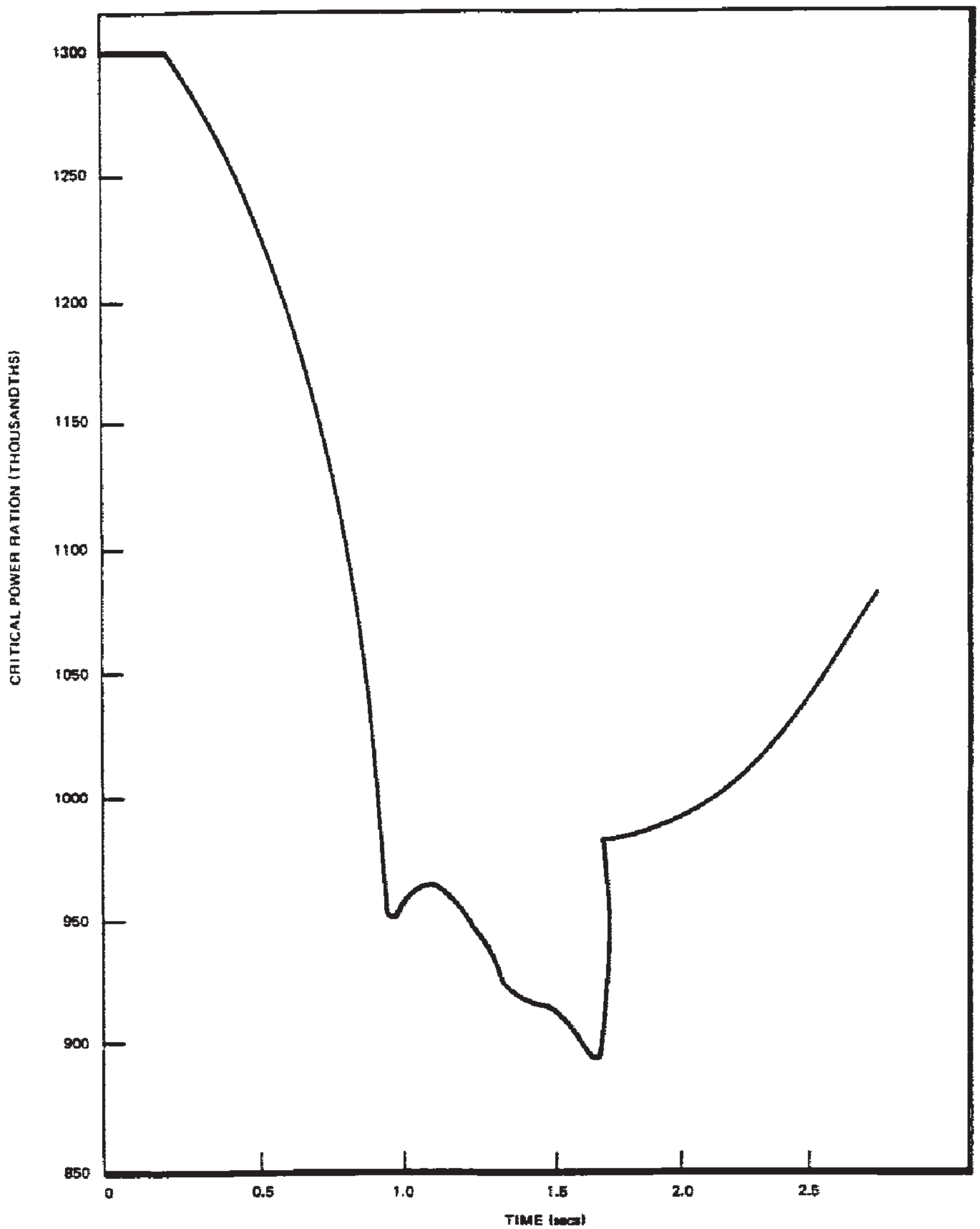
FINAL SAFETY ANALYSIS REPORT

GENERATOR LOAD REJECTION
WITHOUT BYPASS

FIGURE 211.19-1, Rev 47

AutoCAD: Figure Fsar 211_19_1.dwg



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UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

CRITICAL POWER RATIO
VS.
TIME

FIGURE 211.19-2, Rev 47

AutoCAD: Figure Fsar 211_19_2.dwg

QUESTION 211.20

The frequency category in Table 15.0-1 should be defined and be consistent with the frequency classification discussion in the text of Section 15.0.3.

RESPONSE:

Please see revised Table 15.0-1. The frequency categories are defined at the end of the table.

QUESTION 211.21

Identify the limiting transient for each category in Section 15.0.2. For MCPR limiting transients, provide the MCPR versus time plots. Larger scale time plots of those parameters presented in Chapter 15.0 should be presented for the limiting transient in each category.

RESPONSE

The limiting transient for each category may be identified on Table 211.21-1. The concept and derivation of a safety limit is such that its validity is transient or path independent.

Heat flux is the main contributor to the CPR circulation. Since the heat flux peaks and then decreases in a short period of time, the CPR will also attain its minimum value and return to is initial position rather rapidly. For this reason plots will not be provided.

TABLE 211.21-1

LIMITING TRANSIENTS

ANALYTICAL CATEGORY	TRANSIENT EVENT	ΔCPR	FREQUENCY CLASS	% RODS IN BOIL. TRANS.	NOTES
1. Decrease in core coolant temperature	Feedwater control failure max demand	0.16*	Moderate	< 0.1	Limiting event
	Loss of feedwater heater manual flow control (100°F)	0.12	Moderate	< 0.1	
2. Increase in reactor pressure	Generator load rejection bypass on	0.11	Moderate	< 0.1	
	Turbine trip, bypass on	0.09	Moderate	< 0.1	
	Generator load rejection bypass off	0.19*	Moderate	< 0.1	Limiting event
	Turbine trip, bypass off	0.17*	Moderate	< 0.1	
3. Decrease in reactor coolant system flow rate	Trip of both recirculation pump motors	~ 0.0*	Moderate	0.0	Transient is inconsequential for this analytic category
4. Reactor and power distribution anomalies	RWE - at power	0.18	Moderate	< 0.1	Limiting event
5. Increase in reactor coolant inventory	Inadvertent HPCI pump start	0.11	Moderate	< 0.1	Limiting event

* ODYN results without adjustment factors.

QUESTION 211.22

Provide assurance that the pressure time plots in Chapter 15 are consistent with the initiation logic for the safety-relief valves. For example, modifications may have been made to the safety/relief system to prevent subsequent reopening of these valves during pressure increase transients to meet containment design bases loadings.

RESPONSE:

The pressure time plots in Chapter 15 are in fact consistent with the initiation logic for the safety/relief valves. No modifications have been incorporated to the safety/relief system to prevent subsequent reopening of these valves during pressure increase transients to meet containment design basis loadings.

QUESTION 211.23

Provide the number of rods that are expected to be in boiling transition for the events that go below the safety limit MCPR.

RESPONSE:

For transient events, refer to the response provided to Question 211.21

For events classified as accidents, the number of rods in boiling transition is not the applicable criterion on which to base acceptability but rather an amount of failed fuel as given in Table 15.0-1a. Therefore the number of rods in boiling transition is not explicitly calculated for accidents.

QUESTION 211.24

Provide assurance that the limiting pump trip is assumed in analyzing decrease in reactor coolant system flow rate transients. The trip initiated from a loss of power may be different than a trip initiation from the recirculation pump trip (RPT) system since the location of the electrical breakers may be different and, thereby, cause different coastdown characteristics.

RESPONSE:

The limiting pump trip is assumed in analyzing decrease in reactor coolant system flow rate transients. The two pumps are tripped or the one pump is seized at time zero with corresponding flow coastdown, which are conservative assumptions in simulating the transients.

QUESTION 211.25

Provide a list of normal and maximum expected leakage rates and activity concentrations from identified and unidentified sources (e.g., CRD flange leaks, vent cooler drains, etc.) that are directed to the drain sumps.

RESPONSE:

For response see revised Subsections 5.2.5.1.2.4.3, 5.2.5.3.2, and 5.2.5.4.1 and Tables 5.2-11 and 5.2-12.

QUESTION 211.26

The drywell equipment drain sump receives two types of reactor coolant leakage--hot and cold. Leakage from "hot" sources such as the reactor vessel head flange, vent drain, and valve packings may flash into steam which must be condensed to reach the sump. What assurance is there that the steam will be condensed for leak detection monitoring purposes? For leakage from "cold" sources, the floor drain system is employed.

Thus, the floor drain system should be tested periodically for blocked lines. Discuss the surveillance program planned to minimize the potential for drain system blockage.

RESPONSE:

For response see Subsections 5.2.5.1.2.4.1 and 5.2.5.1.2.4.3.

QUESTION 211.27

In conformance with Regulatory Guide 1.45, the radioactivity monitoring channels are stated to be qualified for operation following an SSE. Confirm that all of the remaining leakage detection methods (systems) are qualified for operation following an OBE. (This includes the drywell equipment and the floor drain sumps, sump coolers, and associated instrumentation and piping.)

RESPONSE:

See Subsections 5.2.5.1.2.4.6, 7.6.1b.1.1.2, and 7.6.1b.1.2.2.

QUESTION 211.28

With regard to the sensitivity and response times of the containment airborne radiation monitoring systems, provide a detailed discussion on the capability of these monitors to detect a 1 gpm leak in 1 hour for varying containment background activity levels. The background activity levels should be considered for the plant containing fresh, irradiated, and permissible amounts of failed fuel, and the presence of normal expected leakage rates. Also, include the assumptions used in determining response times, such as the preset alarm level for higher background leakage and the plateout factor. Note that in Section 7.6.1b no information has been provided regarding sensitivity and response times, and reliability of the airborne radioactivity monitoring systems as was stated to be in Section 5.2.5.1.2.3.

RESPONSE:

For response see revised Subsection 5.2.5.1.2.3.1 and Table 5.2-13.

QUESTION 211.29

Clarify that the calibration of the level sensors is performed during normal plant operation. Note that per SRP 5.2.5, the leakage detection systems should be equipped with provisions to permit calibration and operability tests during plant operation. Also, the testing and calibration should be in compliance with IEEE Standard 279-1971. Discuss how you intend to comply with the above requirements.

RESPONSE:

This information is supplied in revised subsections 5.2.5.1.2.4.1 and 5.2.5.1.2.4.7.

QUESTION 211.30

Section 5.2.5.1.2.4.1 and Figure 9.3-11 indicate that the drywell floor drain sumps collect overflow from the drywell equipment drain tank in which the latter is used for collection of unidentified leakage. This type of design feature appears to preclude separate monitoring of identified and unidentified leakage.

Show that measures will be taken to prevent a small unidentified leakage that is of concern from being masked by a larger acceptable identified leakage.

RESPONSE:

For response see Subsections 5.2.5.1.2.4.1 and 5.2.5.1.2.4.3.

QUESTION 211.31

Explain why the piping from the valve stem packing leakoff connections (of the power-operated valves in the HPCI, CS, RCIC, RHR, etc.) to the equipment drain sump contain normally closed manual valves. Shouldn't these valves be normally opened?

RESPONSE:

For response see Subsection 5.2.5.2.

QUESTION 211.32

In conformance to Regulatory Guide 1.45 you state that provisions will be made to monitor systems connected to the RCPB for signs of intersystem leakage. Provide a detailed discussion that includes identification of all potential intersystem leakage paths (including detecting leakage from primary coolant system to the RHR and ECCS injection line) and the instrumentation used in each path to provide positive indication of intersystem leakage in the affected system.

RESPONSE:

Provision has been made to monitor systems connected to the RCPB for signs of intersystem leakage.

Specifically, radiation detectors are provided on the downstream piping of each RHR heat exchanger to detect primary coolant leakage into the RHR service water system (see Subsection 11.5.2.1.14); the radiation monitoring in the reactor building closed cooling water system (see Subsection 11.5.2.1.15) detects leakage from the reactor water cleanup system non-regenerative heat exchangers.

Additionally, radioactive material leakage to the service water from the fuel pool heat exchanger is monitored by the service water discharge radiation monitoring system (see Subsection 11.5.2.1.10).

QUESTION 211.33

BWR operating experience has shown that the HPCI and RCIC systems have been rendered inoperable because of inadvertent leak detection isolations caused by equipment room area high differential temperature signal. The events occurred when there was a relatively sharp drop in outside temperature. As noted in Section 5.4.6.1.1.1 and Table 5.2-8, Susquehanna incorporates this type of HPCI, RCIC and RHR (steam) isolation. Provide a discussion of the modifications that have been or will be made to prevent inadvertent isolations of this type which affect the availability and reliability of the HPCI, RCIC and the RHR systems.

Secondly, provide the trip settings for isolation of the HPCI, RHR and RCIC systems due to high area temperature in terms of degrees above ambient temperature.

Also, discuss the method of specification that would be applied. Show that the setting could not be set too low and cause inadvertent isolation when the system is needed.

RESPONSE:

For response see Subsection 5.2.5.1.3.

QUESTION 211.34

In Section 7.6.1a.4.3.9.2.1 you state that the HPCI high ambient area temperature switch will start the timer and initiate (after a delay period) the HPCI isolation valve closure. Provide this time delay period and justify its selection.

RESPONSE:

The time delay is provided to allow the operator the opportunity to differentiate between HPCI or RCIC pipe routing tunnel leakage and once identified isolate the source of the leakage while not allowing plant safety to be compromised.

The HPCI/RCIC common pipe routing area temperature switches activate a timer which is set for a 15-minute delay. This delay provides time for the operator to determine which system is leaking, and manually isolate that system from the Control Room before the leak detection logic automatically isolates both systems. The maximum temperature limitations of the HPCI/RCIC isolation valves will not be exceeded given this time delay and a 5 GPM leak rate.

See Revised Subsection 7.6.1a.4.3.9.2.1

QUESTION 211.35

Describe the provisions used for protection of the RCIC, HPCI and the RHR systems from cold weather in order to assure satisfactory operational performance. Also, in the assessment include the standby liquid control and the control rod drive hydraulic systems and sources of water (e.g., CST standby service water) for all the above systems.

RESPONSE:

All safety related portions of the RCIC, HPCI, RHR, Standby Liquid Control and CRD Systems (except CST level instrumentation which is described in Section 6.3.2.2.1) are located within heated portions of the Reactor Building whose temperature will not go below 40°F. Additionally the Standby Liquid Control System is provided with storage tank heaters and heat tracing for the piping and pumps to assure adequate elevated temperatures to prevent solution plateout.

None of the above systems require an external supply of water (condensate storage tank) in order to perform the safety related function. However, the RHR System requires RHR Service Water to be supplied to the RHR heat exchangers. This supply of water came from the Ultimate Heat Sink which is located outside and subject to outside temperatures. Subsection 9.2.7 discusses the protection of this cooling water supply system from winter temperatures.

QUESTION 211.36

In the consideration of potential missiles, justify why other pressurized components such as blank flange assemblies and pressurized vessels or bottles (e.g., safety/relief valve air accumulators and nitrogen accumulator tanks) have been omitted from the evaluation.

RESPONSE:

See Subsection 3.5.1.1.2 for response.

QUESTION 211.37

Discuss the potential for missiles inside the containment due to gravitational effects (of such components as electrical hoists or any unrestrained equipment) during maintenance times, reactor operation, and following a LOCA.

RESPONSE:

See Subsections 3.5.1.2 and 3.5.1.2.3 for this response.

QUESTION 211.38

With regard to rotating component failure missiles, show by analysis that the impeller fragments resulting from recirculation pump overspeed condition during a LOCA will not penetrate the pump case. Secondly, provide or reference a study that shows the probability for significant damage to occur within the containment from impeller missiles being ejected out the open end of the broken pipe is acceptably low. If a similar study for another plant is to be referenced, justify its appropriateness to your plant design.

RESPONSE:

The analysis that demonstrates that impeller fragments resulting from a recirculation pump overspeed condition does not penetrate the pump case was documented in the GE Letter Report, "Analysis of the Recirculation Pump Under Accident Conditions" Rev. 2 which was transmitted to the NRC on March 30, 1979. The relevant calculations below were extracted from pages 14a and 14b of that report.

"The analysis provided below calculates the energy of a 90° section of a complete impeller (this missile possesses the maximum translational kinetic energy). The translational energy in the missile is compared to that required to penetrate the pump case.

Missile Kinetic Energy

WK^2 for impeller = 900 lb ft^2

$$I = \frac{WK^2}{g} = \frac{900}{32.2} = 27.95 \text{ lb ft sec}^2$$

$$K.E._{TOTAL} = \frac{1}{2} I\omega^2 = \frac{1}{2}(27.95)(550)^2 = 4.23 \times 10^6 \text{ ft lbs}$$

$$K.E._{90^\circ \text{ SECTOR}} = \frac{4.23 \times 10^6}{4} = 1.06 \times 10^6 \text{ ft lbs}$$

Penetration Energy

$$D = \frac{2tl}{t+\ell} = \frac{(2)\ (\frac{\pi d}{4})\ (\ell)}{\frac{\pi d}{4} + \ell} = 20.84\ in.$$

where:

D = effective missile diameter (in)

d = impeller diameter (in)

ℓ = height of impeller (in)

Using the Stanford missile equation

$$E_S = \frac{(20.84)(70000)}{46500}\ [16000\ (3.5)^2 + 1500\ (\frac{33.5}{4})\ (2.5)]$$

$E_S = 6.15 \times 10^6$ ft lbs

Since E_s > K.E. no penetration of the pump case is probable."

A study showing the extremely low probability for significant damage within the containment from an escaping pump impeller missile was submitted to the NRC as Attachment 3 to the above-mentioned Letter Report. This bounding analysis is applicable to the Susquehanna plant.

QUESTION 211.39

Based on the review of nuclear power plant piping system design integrity, past history has shown several failures of safety valve headers resulting in the valves becoming missiles (NUREG-0307).

Since you address only the credibility of valve bonnets and stems, justify why the safety valve header and valve is not considered as a credible missile. Also, your statement that bonnet ejection is highly improbable and not considered credible missiles for valves of ANSI 900 psig rating and above is not supported. Show that should a large valve component become a missile, containment penetration would not occur. Discuss protection, such as equipment separation and redundancy, to preclude damage to the systems necessary to achieve and maintain a safe plant shutdown.

RESPONSE:

For response see revised Subsection 3.5 and 3.5.1.2. For a discussion of the effects of a large valve component missile or other missile generated inside the containment on the containment structure itself, see Section 3.8.

QUESTION 211.40

Provide a listing of the systems and equipment inside containment necessary to achieve and maintain a safe plant shutdown.

RESPONSE:

Subsection 3.2.1 discusses plant systems and equipment necessary to achieve and maintain a safe plant shutdown. Refer to Table 3.2-1.

QUESTION 211.41

Provide information demonstrating that loss of the operating CRD pump at low reactor pressure (less than 500 psig) will not result in accumulator depressurization and loss of scram capability. If the accumulator check valves leak following loss of the operating CRD pump, provide estimated time and basis before reactor scram capability becomes marginal. Also, present a testing program or procedure that would assure that operation of these check valves is acceptable over the plant lifetime.

RESPONSE

The failure of a CRD pump will not affect the capability to scram all control rods if required. Scram is achieved on either HCU accumulator pressure or a combination of accumulator pressure and reactor pressure. Flow from the CRD pump is not required to successfully scram the plant. Each of the 185 control rod drives has its own HCU which operates independently of any others. Each HCU is safety grade and has its own accumulator. The condition of the accumulators is continuously monitored by the Reactor Manual Control System. Loss of pressure and/or leakage from any of the 185 accumulators is detected by PSL-130 and LSH-129 respectively for each accumulator, as shown in Figure 4.6-5. Both occurrences are annunciated and a light signal identifies the particular control rod drive.

If a CRD pump fails the operator will bring the second pump on-line. If that pump is unavailable the operator can initiate a manual scram. If the pressure in a scram accumulator drops and approaches a pressure level below which control rod scram capability is impaired, an alarm is triggered and a light signal will identify the particular control rod drive. The operator will initiate a manual scram depending on the number of drives in this state.

If an accumulator check valve were to leak at the maximum allowable rate against which it has been designed, the minimum time available before scram capacity of an individual drive becomes marginal is at least 20 minutes. This, however, does not mean that the total core scram capability becomes impaired due to the leakage from one check valve.

The core is designed to be shutdown from all operating conditions with the most reactive control rod fully withdrawn.

BWR reactor experience indicates there has been no failure to scram in over 200 reactor years that can be attributed to the reactor scram mechanical system of which the HCUs are a part.

No more than three failures of individual drives to scram have occurred in over 270,000 individual drive scrams.
Several failures to scram of individual drives would have to occur simultaneously to prevent reactor shutdown.

In summary, as previously mentioned, accumulator pressure is continuously monitored and a pressure decrease is alarmed to the operator; therefore, further analysis of the reliability and duration of the check valves to hold scram accumulator pressure is not needed.

Operational experience has shown that a testing program or procedure that would assure acceptable check valve operation is unnecessary.

The applicant's position is that it is unreasonable and unjustified to postulate simultaneously the loss of the CRD pump and, in addition, the standby CRD pump; the common mode failure of the accumulator check valves; and reactor pressure too low to drive the control rods into the reactor.

The events postulated utilize accident assumptions applied to normal operational events and assumes failure of non-safety grade equipment (CRD pump and CRD standby pump).

QUESTION 211.42

Confirm whether the newly revised collet retainer design will be incorporated into the CRD mechanism.

RESPONSE:

The revised collet retainer tube will be used on both Susquehanna plants. Materials as given in Subsection 4.5-1 for the Outer Tube, Tube, and Spacer are correct.

QUESTION 211.43

In response to Question 112.7 regarding radial cracks in the reactor vessel feedwater nozzles and the CRD return line you stated that you are eliminating the CRD return line. Discuss the impact of this modification on the plant. In particular, include information covering, but not limited to, the following areas:

(1) Compare reactor vessel makeup capability for one and two CRD pump operation before and after the proposed modification. Commit to preoperational testing to verify the modified flow capability.

(2) Commit to preoperational testing to verify individual performance of modified CRD components and other aspects of the CRD system potentially affected by eliminating the CRD return line (equalizing valves, filters, scram times, settling function, etc.).

(3) Should new equalizing valves be added, discuss the potential lifetime effect on drive speeds; in particular, evaluate the vulnerability of the CRD system to a voiding of the drive exhaust header after a single failure.

(4) Evaluate the lifetime effect of the added flow through such components as the drive exhaust header and stabilizing lines; in particular, discuss the increased potential of corrosion products from carbon steel piping to deposit additional foreign matter in the drives.

(5) Discuss the potential for, and effect on, flow reversal through the directional control solenoid valve over the plant lifetime.

(6) Discuss the expected effect of the CRD modifications on the ΔP settling function across drives to ensure latching after withdrawal.

RESPONSE:

(1) The Control Rod Drive (CRD) system provides water to

a) maintain the CRD scram accumulators in a charged condition,

b) drive the control rods in and out of the core, and

c) cool the CRD mechanisms.

Verification of functional requirements including control room flow and pressure indications, is confirmed during preoperational testing.

The CRD return line was designed to provide a reactor pressure reference to the CRD system and to return to the reactor vessel water exhausted from CRD movement or for water in excess of system demands. In response to the discovery of cracking in the CRD return line nozzle, some BWRs under construction chose to modify the CRD system by total removal of the CRD return line and capping of the CRD return line nozzle. Although no credit has been taken for the CRD system high pressure inventory make-up capability in any previous safety analyses, the NRC staff believed the CRD coolant makeup capability of the system was a necessary redundant core cooling system and therefore made the recommendations outline in NUREG-0619. Section 8.1 of NUREG-0619 recommends that those BWR's without a dedicated return line piped to the reactor vessel demonstrate system capacity equivalent to the vessel coolant make-up required forty minutes following a reactor scram.

The CRD pumps were designed to simultaneously: 1) deliver a high discharge head for maintaining the scram accumulator charged and 2) deliver a relatively low coolant flow rate to the CRDs at operating reactor pressure. Performing as a high pressure make-up system was not a criterion considered when the CRD pump performance characteristics were specified.

The CRD system discharge piping was sized based on a maximum pump discharge flow rate of approximately 100 GPM. At the increased flow rates necessary to meet the recommendations of NUREG-0619, the piping pressure losses can increase as much as 300%. The impact of the increased flow rate recommended by NUREG-0619 is most evident when compared to the increase in piping pressure losses. While the system piping is capable of meeting the system functional requirements, it will not have the capability to meet the vessel make-up inventory recommendations of NUREG-0619.

In summary, the CRD system meets its functional requirements and this is verified during preoperational testing. The pumps and piping were not designed to provide core cooling makeup flow. No significant differences in flow capability exists with or without CRD return line. Therefore, the two pump testing is shown to be unnecessary. Although PP&L recognizes the CRD system as a potential source for reactor coolant make-up, it is meager when compared to HPCI, RCIC and feedwater make-up flow rates. No credit is taken for the CRD system coolant make-up capability in any plant safety analysis, but the Emergency Procedure Guidelines employ this system and all other potential inventory make-up systems if demanded by emergency operating symptoms.

The above text was excerpted from a "white paper" submitted by the Licensing Review Group to the NRC on March 26, 1982. The staff subsequently withdrew its recommendation for a CRD make-up flow test per Section 8.1 of NUREG 0619 on June 23, 1982 (Memorandum, Rubenstein to Tedesco).

(2) The control rod drive preoperational test will demonstrate that the system is fully operational and that all components including the hydraulic drive mechanisms, pumps, and flow control valves function properly. The CRD system will be configured with the modifications noted in the NRC concern.

(3) In order to assure satisfactory system operation with the single failure of an equalizing valve, the proposed design modification will include the addition of two equalizing valves installed in a parallel configuration. The failure of either valve will not impair CRD operation for any foreseen operating or accident condition.

(4) The CRD return line modification engendered no changes in flow of long term significance through components such as the drive exhaust header and stabilizing lines. Also, since the Susquehanna CRD hydraulic system components and lines are exclusively stainless-steel downstream of the drive water filters, the potential for depositing foreign material in the drives from this source is negligible.

(5) General Electric has completed lifetime testing of the subject directional control valves in response to the concern of pressurization and flow in the reverse direction. It is concluded from these tests that no adverse effects on the test valves resulted from the reverse flow mode of operation. (A copy of the report on these valve tests has been sent to Messrs. V. Stello and R. J. Mattson of the NRC by G. G. Sherwood of G. E. Licensing on April 9, 1979.)

(6) In the new system configuration, the exhaust water header is essentially isolated from the rest of the CRD hydraulic system and maintained at nearly reactor pressure. During periods of rod motion and subsequent rod settling, the flow discharged from the drive to the exhaust water header is readily dissipated to adjacent drives (i.e., via reverse flow through the -121 directional control valves of adjacent HCUs) and briefly

causes the pressure in the exhaust water header to increase only a few psi. Thus no detrimental effects on rod settling performance is expected to result from this CRD system modification. Furthermore, evidence of satisfactory drive settling will be established during preoperational testing with the return line eliminated. CRD drive operation within acceptable defined margins must be demonstrated by this testing prior to plant operation.

QUESTION 211.44

Provide assurance that the essential portions of the control rod drive system, namely, the 1-inch supply and return piping located inside the containment are protected from the effects of a high or moderate energy line breaks such as the high pressure core spray system, or high pressure core injection feedwater system, or high pressure core injection feedwater system, reactor coolant pressure boundary, etc. In support of the above information request, provide or reference equipment location or layout drawings to assure that no high or moderate energy piping systems are close to the control rod drive system or that protection is provided from the effects these pipe breaks. The concern is whether pipe whip and/or jet impingement can impair the capability to scram. In addition to the above requested evaluation, assess damage to the cluster of CRD return and supply lines, and scram capability by postulating rupture of a single CRD supply or return line.

RESPONSE:

The CRD insert (1" - SCH 80 piping) and withdraw lines (3/4" - SCH 80 piping) are routed such that half of the lines are on either side of the reactor vessel. Appropriate design considerations were given to the effects of postulated recirculation pipe breaks which would lead to pipe whip and/or jet impingement:

1. Pipe Whip Restraints

   The potential for pipe whip due to postulated rupture of the recirculation piping was considered and an adequate pipe whip restrain system is provided.

   The design provisions and criteria used to assure that the reactor and all essential equipment within primary containment are adequately protected against pipe whip are discussed in detail in Section 3.6. Figure 3.6-14 shows the location of pipe whip restraints as well as breaks considered in the design. Breaks will be selected in accordance with the intent of Regulatory Guide 1.46 and ANS 58.2. The pipe whip analysis will demonstrate that the restraint system will prevent the recirculation piping from impacting the CRD insert and withdraw lines. Table 3.6-2 summarizes essential systems and components in close proximity to high energy fluid system piping in the containment and from which it is confirmed that no CRD line is located close enough to the recirculation piping to be contacted during pipe whip.

2. Jet Impingement

The evaluation of jet impingement was also a design consideration. Jet loads should not cause inoperability of the CRD lines since no total crimping is possible from the jet effects on the CRD bundles.

A minimum of 3 gpm is required to accomplish scram and the piping would have to be completely sealed to prevent flow. Thus, it is physical impingement or pipe whip against the CRD piping.

3. CRD Piping Rupture

The CRD design is such that, if CRD piping should rupture, reactor pressure will act upon the drive piston causing rod insertion. Neither jet impingement nor pipe whip (because of restraints) could cause a pipe rupture, however.

QUESTION 211.45

The RHR system shall be capable of bringing the reactor to a cold shutdown using only safety-grade systems. Confirm that this requirement is met. Include in your assessment the air supply system used to operate the RCIC (or HPCI) steam and condensate control valves located at the RHR heat exchanger when the RHR system is in the steam condensing mode.

RESPONSE:

If the non-safety grade main condenser is not available for reactor shutdown, the safety-grade safety-relief valves are used to depressurize the reactor to 100 psig (nominal) while the safety-grade RCIC system supplies make-up water. Below 100 PSIG (nominal) the safety-grade RHR shutdown cooling mode is used to continue the reactor shutdown to the cold shutdown condition.

The RHR steam condensing mode and therefore the A.O. RHR steam regulating and condensate regulating valves were not used for safety-grade reactor shutdown.

In conclusion, the BWR provides a means to bring the reactor to cold shutdown using safety-grade systems.

NOTE: The steam condensing mode has been eliminated since the original response to this question. See FSAR Section 5.4.7.1.1.5 and the response to Question 211.46.

QUESTION 211.46

The RHR system shall be capable of bringing the reactor to a cold shutdown with only onsite or offsite power available and with the most limiting single failure. Figures 15.2-10 and -11 show available success paths to achieve a cold shutdown condition; however, vessel depressurization via the RHR system in the steam condensing mode is not shown. For completeness, provide a corrected figure or justify this omission. If vessel depressurization were to be achieved via manual relief valve actuation, how many valves would be required? Describe your plans for testing the alternate shutdown cooling modes of operation. Demonstrate that adequate passage of water through the safety/relief valves can be achieved and maintained when the alternate method is in use. Include the quantity of air supplied, the source, and the time before the air is exhausted.

RESPONSE:

The omission of utilizing the steam condensing mode of the RHR system operation to achieve cold shutdown conditions is justified because there is no requirement to do so and the current design of the plant is not compatible due to flow path requirement. Additionally, the steam condensing mode of RHR system operation was not a safety grade means for depressurizing the reactor because a safety grade air supply is not available to the steam regulating valve.

Plans for testing alternate shutdown modes of operation are based on the technical specifications.

Achieving and maintaining vessel depressurization through manual relief valve actuation requires a maximum of five (5) valves being actuated to pass sufficient steam and water.

The air supply for ADS valves is discussed in the response to Question 211.67.

NOTE: The steam condensing mode has been eliminated since the original response to this question. See FSAR Section 5.4.7.1.1.5.

QUESTION 211.47

During the shutdown cooling mode, the "flush water" valves are opened and closed outside the control room. Specifically identify the operated local flush water valves and the source of flush water. Discuss the consequences assuming the operator would omit this procedure and/or forget to close a local flush water valve and continue shutdown operations. Include available interlocks in the discussion.

RESPONSE:

Flush water is provided by the condensate transfer system to the RHR system piping at several locations through locally operated valves, specifically:

1) Head spray line via normally closed valves F081 and F082.

2) LPCI injection lines via normally open fill lines.

3) Shutdown cooling suction line via normally closed valves F064 and F083.

4) RHR pump suction line via normally closed valves HV15186 and 51-083.

Consequences of omitting the flushing procedure and/or not closing a local flush water valve and continuing shutdown operations is discussed in revised Subsection 5.4.7.2.6.

QUESTION 211.48

In Section 5.4.7.1.3 you identify the RHR relief valves and the RHR design pressure used as the sizing basis for the relief valves. Expand your discussion by providing the set point tolerance and ASME class rating of the valves and lines.

In addition, discuss the vulnerability of the RHR system to malfunctions which could result in overpressurization of low pressure piping. Support your evaluation by providing an outline of all operating procedures required to bring the plant to a cold shutdown condition from hot standby and procedures for plant startup from cold shutdown.

RESPONSE:

The set point tolerances for safety-related relief valves procured by Bechtel are in accordance with the ASME B&PV code.

The ASME class ratings of the valves and lines are as shown on Dwg. M-151, Sh. 1.

The RHR system is connected to higher pressure piping at shutdown, suction, shutdown return/LPCI injection, head spray, and heat exchanger steam supply. The vulnerability to overpressurization of each location is discussed in the following paragraphs.

Shutdown suction has two gate valves, F008 & F009, in series which have independent pressure interlocks to prevent opening of each valve at high inboard pressure. No single active failure nor operator error will result in overpressurization of the lower pressure piping.

The shutdown return/LPCI injection line has a swing check valve, F050, to protect it from higher vessel pressures. Additionally, a gate valve, F015, is located in series and has a pressure interlock to prevent opening at high inboard pressures. No single active failure nor operator error will cause overpressurization of the lower pressure piping.

The head spray line has a swing check valve, F019, to protect from higher vessel pressure. Additionally, a globe valve, F023, is located in series and has pressure interlocks to prevent opening at high inboard pressure. No single active failure nor operator error will cause overpressurization of the lower pressure piping.

The heat exchanger steam supply line has two pressure regulating globe valves. The operator sets the pressure regulating valves, F052 & F051, to limit heat exchanger pressure. A relief valve, F055, is provided downstream of F052 and F051 to protect the low pressure piping should the regulating valves fail open. No single active failure nor operator error will cause overpressurization of the low pressure piping.

OUTLINE OF OPERATING PROCEDURE AND RHR OVERPRESSURIZATION SAFEGUARD		
1. Plant Shutdown to cold shutdown from hot Standby* with safety grade systems.		
reactor condition	**OPERATING MODE USED**	**rhr overpressurization safeguard**
Depressurization from hot standby to ~100 psig	main steam relief valve discharge to the suppression pool depressurizes vessel	RHR isolated
	initiate and operate pool cooling mode of RHR system	low pressure mode, no safeguards required
Cooldown from ~100 psig to cold shutdown	initiate and operate shutdown cooling mode of RHR system	redundant pressure on inter-F008, F009 and F017 close valves above pressure interlock setpoint.
2. Plant Startup From Cold Shutdown		
Reactor Coolant below 125° & RPV head replacement	terminate shutdown cooling and isolate RHR	redundant pressure interlock on F008, F009 and F017 close valves above pressure interlock setpoint.
Remainder of Startup	standard	RHR isolated
~220° F vent and pressure RPV	vessel recirculation system and RWCU	RHR isolated
~920 psi	open steam bypass to main condenser, vessel recirculation, and RWCU	RHR isolated
above ~920 psi	admit steam to turbine and synch to grid, vessel recirculation, and RWCU	RHR isolated
* Normally, the main condenser is the heat sink during hot standby.		

QUESTION 211.49

Provide more detailed information regarding the actuation of the automatic minimum flow valves used for RHR pump protection against damage from a closed discharge valve. For example, specify flow rate quantities that signal minimum flow valve opening and closure on low main line flow and high main RHR line flow,respectively. Also, state whether the control system meets IEEE-279 standards. Confirm that the minimum flow line valve restrictors are designed to safety-grade standards (e.g., seismic Category I, ASME Code Section III).

Also, provide the design pressure of the minimum flow line.

RESPONSE:

The minimum flow valve opens at main line flows of less than 2000 gpm; this allows flow to return to the suppression pool through the low resistance low flow bypass line which branches off the main line upstream of the flow element.

The minimum flow valve closes at main line flows greater than 2000 gpm; this closes the low resistance low flow bypass to the suppression pool and forces the entire pump discharge flow through the main line.

The minimum flow-valve valve control meets IEEE-279 requirements on the ECCS network level.

The minimum flow line restricting orifice is Quality Group B (i.e. Seismic Category I, ASME Code Section III). The piping is rated at 300 psig.

QUESTION 211.50

Per Table 5.4-3, the RHR isolation valves F008 and F009 are signaled to close on reactor low water level. Clarify whether this valve isolation signal is based on the same signal as the RHR pump actuation in the LPCI mode, which is a water level of 1.0 foot above the active core. If not, provide vessel water level that isolates the RHR suction valves and show that core cooling can be maintained assuming a pipe break outside the containment. Hence, provide the following additional information assuming a pipe break outside containment in the RHR system when the plant is in a shutdown cooling mode:

(1) Identification of systems available for maintaining core cooling.

(2) Maximum discharge rate resulting from the break and the time frame available for recovery based on the discharge rate and its effect on core cooling.

(3) Identify the alarms available to alert the operator to the event, assurance that recovery procedures are available, and show that adequate time is available for operator action.

(4) Following the moderate energy line break, single failure criterion should be applied consistent with SRP 3.6.1 and BTP APCSB 3-1.

RESPONSE:

F008 and F009 isolate at reactor water level 3 which is approximately 15 feet above the top of the active fuel. Should a pipe failure occur in the shutdown suction piping, outside the containment, in the RHR system when the plant is in shutdown cooling, acceptable core cooling would be achieved by the core cooling systems. The following core cooling systems would be available to maintain core cooling when applying SRP 3.6.1 and BTP APCSB 3-1:

Note that HPCI would not be available when in shutdown cooling since it isolates @ 105 psi reactor pressure and the shutdown cooling interlock is @ 98 psi reactor pressure.

- If the single active failure is LPCS the following are available: 4 LPCI Pumps and 1 core spray loop
- If the single active failure is LPCI (not shutdown cooling loop) the following are available: 2 core spray loops and 2 LPCI pumps (in 1 loop)

The following signals automatically isolate F008 and F009 as a result of a pipe failure outside containment:

- RPV water level low - level 3

- RPV pressure high

- High Pump Suction Flow

The RPV water level low level 3 isolation signal will isolate the failed RHR line. The operator would be alerted to the failed pipe outside the containment by:

- High Pump Suction Flow

- Equipment Area Temperature High

- RPV Water Level Low (Level 3)

- Sump Operation Monitor (i).

- Equipment Room Radiation High. (not class 1E)

Appropriate action could be determined and alternate shutdown cooling could be established in accordance with off normal procedures. If the break occurs between the containment penetration and the RHR equipment room, there is no flooding level alarm, but there is an equipment area high temperature alarm. If the break occurs in the RHR equipment room, it will be detected by the room flooding detection system and the area high temperature alarm in the RHR equipment room. As a worst case, the low pressure systems would inject when level reaches – 129 inches.

From a flooding standpoint, the worst case pipe rupture in the reactor building was found to be the 24” GBB-109/209 RHR piping in the piping/penetration rooms on elevation 683’, with a maximum crack flow of 1360 gpm. The crack is postulated with the RHR system in shutdown cooling mode with the reactor cavity flooded. Although slightly higher pressures exist during operation of shutdown cooling with the vessel pressurized, these periods are of very limited duration. In addition, during these periods, adequate plant protection from a pipe rupture is provided by the level 3 shutdown cooling isolation function, as described above.

The analysis demonstrates that adequate alarms and instrumentation are available to detect the break in a timely manner and that sufficient time remains for operator action to terminate the event such that no unacceptable flooding results. Credit is taken for operator actions to terminate the event within 45 minutes. In this scenario, the sump room on elevation 645’ in the basement of the reactor building is flooded due to the reactor building sumps backing up into this area. Watertight doors between the sump room and connected division 1 RHR/core spray pump rooms prevent water from entering these rooms and these systems remain operable during the flooding event. Water intrusion through equipment hatches above the ECCS/RCIC rooms is conservatively assumed in this evaluation, even though these hatches have been sealed with caulk. The analysis shows that the resulting inleakage through the equipment hatches would not adversely affect operation any ECCS/RCIC systems. The analysis demonstrates that adequate core cooling systems remain available to maintain safe shutdown, assuming an additional single failure as required in BTP ASB 3-1.

QUESTION 211.51

Discuss system design provisions to prevent damage to the RHR (LPCI) pumps against pump runout conditions during ECCS and test modes of operation.

RESPONSE:

RHR pump damage due to high runout flows during ECCS modes is prevented as follows:

The LPCI injection piping has a restricting orifice, F015100, to prevent excessively high runout flow rates.

The Containment Spray piping has higher frictional and elevational losses than the LPCI injection piping; therefore, RHR flow to containment spray will always be less than the above LPCI injection flow rate and, as a result, will have an acceptable runout flow rate.

The pool cooling piping has the same restricting orifice as LPCI injection, F015100, plus the added resistance of the HX's and a smaller diameter pool return line.

These added resistances more than compensate for the lower elevation head of the pool cooling mode and, therefore, result in a flow less than LPCI injection, which is an acceptable runout flow rate.

RHR pump damage due to high runout flows during testing is prevented by the system resistance described above and by operator action to throttle flow as needed.

QUESTION 211.52

Figure 5.4-13 of the FSAR shows the labeling of the orifices in the discharge lines as "FO." Clarify whether this is a restricting orifice, normally labeled as "RO."

RESPONSE:

As shown on Dwg. M-100, Sh. 1, "FO" stands for flow restrictor.

QUESTION 211.53

Explain the apparent discrepancy between Figure 5.4-14a and Table 1.3-3 which identifies three RHR pumps and four RHR pumps, respectively.

RESPONSE:

Both Dwg. M1-E11-3, Sh. 1, and Table 1.3-3 correctly indicate that there are four RHR pumps.

QUESTION 211.54

Provide a more detailed description and location of the RHR pump suction strainer inside the suppression pool. Include pipe bends and the minimum height of the suppression pool water level above the suction strainer. Show that the NPSH at the center line of the RHR pump will be met at the pump's design condition as well as at the most limiting operating condition.

Also, discuss the size of particles that could pass through the strainer and continue to the RHR pump passages. How much material blockage would it take to significantly affect RHR pump suction flow from the suppression pool following a LOCA?

RESPONSE:

For response refer to revised Subsection 5.4.7.2.2d.

QUESTION 211.55

Provide pressure interlock set points used in the prevention of opening the RHR isolation valves F008 and F009 to the low pressure suction piping, and for the initiation of valve closure on increasing reactor pressure.

RESPONSE:

The pressure interlock set point for RHR shutdown suction isolation valves F008 and F009 is nominally 135 psig plus elevation head. The set point for opening and closing is the same.

QUESTION 211.56

Confirm that all valves performing an isolation function between the high pressure and low pressure boundary in the RHR system (e.g., check valves and motor-operated valves) meet the leak testing and inspection requirements of the ASME Section XI code for Category A valves. A combination of two or more check or motor-operated valves in series should have design provision for individual leak testing of any two valves.

RESPONSE:

As stated in revised Subsection 5.4.7.1.2, Reactor Coolant Pressure Boundary valves are subject to inservice leakage testing requirements as provided in 10CFR50.55a.

The pump and valve testing program, including specification of leakage testing requirements will be provided in the response to FSAR Question 110.47.

QUESTION 211.57

Commit to providing a means for pressure relief between the two RHR isolation valves F008 and F009 or show by analysis that piping integrity would be maintained assuming a LOCA or steam line break would occur and the trapped water between the valves would thermally expand.

RESPONSE:

Dwg. M-151, Sh. 1 shows relief valve F126 between F008 and F009. This valve will provide pressure relief.

QUESTION 211.58

Operation of the RHR system in the steam condensing mode involves partial draining of one or both RHR heat exchangers and introduction of reactor steam into initially cold lines and heat exchangers. Describe the methods (e.g., valve operation, air introduction, etc.) and provisions to be used to prevent occurrence of water hammer during the initiation of operation in this mode, and the change to the pool cooling mode. When the RHR is used in the steam condensing mode with one or both heat exchangers, can the jockey pump system fill the lines to the injection valve in the core spray and RHR lines? If not, what procedures would be used to prevent water hammer following startup of the core spray or RHR pumps?

Pressure relief valves and lines designed to overpressurization of the RHR system are routed outside containment before being returned to the suppression pool. Discuss design provisions made to mitigate possible water hammer in these lines. Secondly, confirm that these relief lines are capable of taking the seismic and dynamic blowdown loads without loss of piping integrity.

RESPONSE:

Initiation of the steam condensing mode was previously described in Subsection 5.4.7.2.6.b. The functions intended to prevent water hammer during initiation of this mode of generation include:

1) Lowering of heat exchanger water level to provide expansion volume for steam

2) Opening of heat exchanger non-condensable vent before steam is admitted to provide a discharge path

3) Initially admitting steam at a low pressure and slowly increasing steam pressure to 200 PSIG to avoid high pressure surges

4) Opening all valves slowly to avoid sudden flow surges.

The functions intended to prevent the occurrence of water hammer following steam condensing termination and change to pool cooling are:

1) Closing the heat exchanger condensate discharge and letting continuing condensation raise the water level until the rate of increase becomes very slow.
2) Opening valves connecting the heat exchanger to the main RHR loop.

3) Opening high point vent and filling heat exchanger shell and connecting piping using the condensate transfer system.

When the RHR system was used for steam condensing, the LPCI injection loop was isolated from the heat exchanger steam flow by closing valves F003 and F047. (see RHR P&ID Figure 5.4-13). During steam condensing the RPV injection lines of the core spray and the RHR system were kept full by the condensate transfer system. The use of the steam condensing mode had no effect on the condensate system's ability to fill the injection lines, since the fill connections were outside the steam condensing loop. Startup of the RHR or core spray pumps did not cause water hammer since there were no voids in the injection lines. Please note that Susquehanna SES is not equipped with a jockey pump system, and that the Core Spray System was not associated with steam condensation.

Discharge lines connecting to the pressure relief valves in each RHR loop are continuously sloping towards the suppression pool and, therefore, are normally empty. A vacuum relief valve is provided near the discharge of each line to prevent below atmospheric pressure surges in the line and thereby mitigate the potential for water hammer.

Each discharge line is designed to withstand the seismic and dynamic blowdown loads without loss of piping integrity.

NOTE: The steam condensing mode has been eliminated since the original response to this question. See FSAR Section 5.4.7.1.1.5 and the response to Question 211.46.

QUESTION 211.59

Discuss the procedures for minimizing the potential for exceeding the allowable cooldown rate (greater than 100 degrees Fahrenheit/hour) of the RHR and the reactor coolant system when placing the plant in a shutdown cooling mode following planned normal conditions or an emergency.

RESPONSE:

When either the normal shutdown cooling mode or the alternate shutdown cooling mode (SRV return to pool and suction from pool) is used, the operator controls the cooldown rate via valves F017 (total flow), F048 (heat exchanger bypass flow), F047 (heat exchanger inlet flow) and F003 (heat exchanger outlet flow). The operator determines the cooldown rate by monitoring reactor coolant temperature change with time.

QUESTION 211.60

Discuss the RHR pump reliability for long-term operation. Long-term reliability should be demonstrated by either operational experience or testing. If previous operational experience are be cited as the basis for qualifying the pumps, state any pump design differences and conditions from previous pump operations.

RESPONSE:

Operational experience is the bases for demonstrating long-term reliability of the RHR pumps, i.e., over 3000 hrs. of total operation (not continuous on only one pump) with no reported problems. Based on this operating experience and past experience on similar pumps in non-nuclear service it can be expected that the Susquehanna RHR pumps will operate as required.

QUESTION 211.61

Leakage of steam from the HPCI steam line past the normally closed valves F051 and F052 can and has caused steam bubble formation in the RHR heat exchangers with resultant water hammer following startup of the RHR pumps. Describe the provisions (e.g., sensors with alarms) and procedures you plan to use in preventing such an occurrence due either to leakage or inadvertent valve opening.

RESPONSE:

If inadvertent valve opening or leakage causes system pressure to exceed relief valve F025 set point, a high pressure alarm off pressure switch N022 will occur. Also, if a steam bubble is forming in the heat exchanger or steam supply piping, temperature element N004 will indicate abnormally high temperatures and will alarm at set point.

QUESTION 211.62

Provide an RCIC pump performance curve that depicts flow rate versus reactor vessel pressure. Also, identify the most limiting operating condition and specify the NPSH margin under this condition.

RESPONSE:

The RCIC system, when operating, provides constant make-up at a flow rate of 600 gpm independent of reactor vessel pressure.

The most limiting operating condition occurs during the initial start-up with a closed discharge valve. For this condition, a minimum by-pass flow of 75 gpm will be maintained to prevent pump damage.

For minimum NPSH available see revised Subsection 5.4.6.2.2.2.

QUESTION 211.63

It appears that it is possible for some steam condensate to remain in the lines leading to the RCIC steam turbine. (This occurs when the steam isolation valves would be temporarily closed for maintenance.) Discuss whether the amount of liquid can cause damage to the RCIC turbine so that the system is incapable of delivering water to the reactor vessel as required. Also, describe the design modifications you propose to prevent water hammer effects at the turbine exhaust.

RESPONSE:

If the steam isolation valves were temporarily closed for maintenance, administrative control and specific operating procedures precludes the possibility of thermal shock or water hammer to the steamline, valve seats, and discs. Keylock switches are provided as part of the administrative control. Operating procedures involve opening the outboard isolation valve, warming the steamline by gradually opening the warm-up valve located on a pipeline bypassing the inboard isolation valve and then opening the inboard isolation valve.

A vacuum breaker system is installed close to the RCIC turbine exhaust line suppression pool penetration to avoid siphoning water from the suppression pool into the exhaust line as steam in the line condenses during and after turbine operation. The vacuum breaker line runs from the suppression pool air volume to the RCIC exhaust line through two normally open motor operated gate valves and two swing check valves arranged to allow air flow into the exhaust line, precluding steam flow to the suppression pool air volume.

During turbine operation, condensate buildup in the turbine exhaust line is minimized by the installation of a drain pot in a low point of the line near the turbine exhaust connection. The condensate collected in the drain pot drains to the barometric condenser through a restricting orifice.

There is also a steam supply drain pot which controls condensed steam in the RCIC turbine steam supply line.

QUESTION 211.64

An isolation signal closes a number of valves in the RCIC system. In particular, the affected valves are F063 and F064, F007 and F008 located inside and outside containment, branched off the main steam line. However, the P&ID shows that these valves are keylocked open Justify this apparent discrepancy and evaluate the consequences of a postulated pipe break downstream of the first or second isolation valve for steam flow rates less than or greater than the 300 percent of the steady-state steam flow indicated in this section.

RESPONSE:

FO63 and FO64 check valves are both located outside the containment and do not branch off the main streamline. The RCIC, P&ID, Dwg. M-149, Sh. 1 shows these valves without keylocks and without an isolation signal input.

The following discussion pertains to containment isolation valves F007 and F008.

The isolation signal is automatic and bypasses the keylock when the valves must be closed in the case of an RCIC line break. For other accidents, it is more desirable to have steam available for RCIC operation than to preclude its operation because of a containment automatic isolation valve closure signal. If the isolation valves were closed, operator action would be required to reopen the valves to avoid water hammer and thermal shock. An isolation signal is given for a large pipe break by detecting flow rates greater than 300 percent of the steady-state steam flow. For leakage with flow rates less than 300 percent of steady-state steam flow, an isolation signal is signaled by use of area temperature sensors provided by the leak detection system.

If the steam isolation valves were temporarily closed for maintenance, operating procedures provide specific directions on opening the steam isolation valves and the warm-up line. This administrative control relieves the possibility of thermal shock or water hammer to the steam line, valve seats, and discs.

Keylock switches on the steam isolation valves provide positive administrative control of the opening procedures.

QUESTION 211.65

For the failure of the normal RHR shutdown cooling event analysis, provide the reactor vessel temperature and pressure time traces and the suppression pool temperature time trace for the alternate shutdown cooling modes--activity C1 and C2 as described in Figure 15.2-11. Include the assumed initial pool and service water temperatures.

RESPONSE:

Revision 1 to the FSAR contains an update of this transient and provides this information. See Figures 15.2-12 and 15.2-13.

QUESTION 211.66

Provide estimated times to achieve a cold shutdown condition for the alternate cooling paths Activity C1 and C2 as described in Figure 15.2-11.

RESPONSE:

FSAR Revision 1 contains an update of this transient and provides this information in the "Notes for Figure 15.2-11".

QUESTION 211.67

The FSAR states that the accumulator sizing for the power-operated relief valves is sufficient for one actuation; and for the automatic depressurization system (ADS) valves it is sufficient for two actuations. A "noninterruptable" safety-grade source of air for the ADS valves is required to terminate certain postulated transient and accident events without loss of the ADS function. Show that an adequate supply of air will exist to operate the ADS valves for the following conditions:

(1) The alternate method of achieving and maintaining a cold shutdown following a loss of offsite power with a worst single failure in the RHR system;

(2) For a small LOCA with failure of high pressure ECCS where the ADS valves would be used for reactor vessel depressurization and maintaining long-term cooling. Include a discussion and procedures to be used to replenish coolant inventory; and

(3) For a small steam line break disabling the RCIC concurrent with a single failure of the HPCS and HPCI that would require ADS function to depressurize the reactor vessel. Consider the air supply needs for long-term cooling (e.g., how would reactor vessel inventory be maintained when decay heat repressurizes the vessel above the shutoff head of the low pressure cooling system?)

RESPONSE:

The pneumatic supply to operate the ADS valves is described in Subsection 9.3.1.5. The ADS system itself is described in Sections 5.2 and 7.3.

The ECCS performance evaluation, which includes the ADS, is presented in Subsection 6.3.3. Table 6.3.5 identifies core cooling modes that are utilized following completion of ADS operation. For example, if failure of the HPCI is assumed, the reactor pressure vessel is depressurized by the ADS to a pressure suitable for use of the Core Spray Systems or any of the available LPCI Systems.

The normal source of air for actuation of the SRV's is the Containment Instrument Gas System. Although the majority of the system is designed and constructed in accordance with quality group D specifications, all piping and components required for proper long term operation of the ADS valves are safety grade. Associated with each ADS valve is an accumulator capable of opening the valve at least once against a drywell pressure of 45 psi; two actuations against 31.5 psig drywell pressure. When normal pressure or power is lost, the ADS valves are supplied by a backup source of high pressure nitrogen gas: the safety related nitrogen storage system provides an adequate supply of gas for long term operation of ADS. The nitrogen bottles have a 3 day storage capacity based on the system design leakage rate. After 3 days, the storage bottles can be recharged indefinitely since the charging connections for the bottles are located in areas of the plant that are accessible under post-accident conditions.

To achieve vessel depressurization by manual actuation of relief valves, three valves would need to be actuated to pass sufficient steam flow to depressurize the vessel. Three to five valves would be necessary to pass sufficient water to keep the vessel depressurized as necessary. Thus a maximum of five ADS valves are required to perform the shutdown cooling function.

In the event that ADS valves are employed assuming either failure of the normal RHR shutdown cooling function (condition 1) or the small LOCA's (conditions 2 and 3) inquired of, the safety grade pneumatic supply ...accumulator/high pressure nitrogen... assures that the valves will open on demand and remain open continuously during the postulated post-accident period.

While the ADS valves remain open, the reactor vessel will not repressure and all low pressure ECCS pumps will be able to maintain cooling flow to the vessel.

QUESTION 211.68

The analyses presented to show conformance to the ASME Boiler and Pressure Vessel Code for overpressure protection references NEDO-10802 as the analytical model for plant transient evaluation. General Electric has submitted to the staff an updated analytical model (ODYN) to evaluate plant transients. Reanalyze the overpressure sizing transient using the ODYN code unless assurance can be provided that the NEDO-10802 analysis is bounding with regard to predicting peak pressure. The analysis must include the effects of the high pressure recirculation pump trip (RPT) and the turbine stop valve/control valve closure recirculation pump trip where applicable. Provide analysis to justify that the closure of all main steam isolation valves (MSIV) is the most severe overpressure transient when considering the new code, the second safety-grade scram and the effects of RPT.

RESPONSE:

The ODYN/REDY (NEDO-10802) comparisons performed have supported the conservatism of the REDY analysis for this category of events. Additionally, the ODYN code has not been shown to result in any modification of the relative severity of the pressurization events such that the MSIV closure with flux scram is expected to remain the limiting event.

Consideration of the high pressure trip of the recirculation pumps has been considered on a generic basis previously. This is covered in the response to Question 211.4.

Additional discussion of the analytical basis for overpressure protection analyses is provided in the response to Question 211.4.

QUESTION 211.69

Sensitivity studies showing the effect of initial operating pressure on the peak transient pressure attained during a limiting overpressure event have not been provided. Therefore, either:

(1) provide a sensitivity study which shows that increasing the initial operating pressure (up to the maximum permitted by the high pressure trip set point) will have negligible effect on the peak transient pressure, or

(2) propose a technical specification which will assure that the reactor operating pressure will not exceed the initial pressure assumed in the overpressure analysis.

RESPONSE:

The response to this question part (1) has been provided earlier as part of the response to Question 211.4; specifically, Paragraph 1 of the response and Figure 211.4-1.

QUESTION 211.70

The performance of essentially all types of safety/relief valves has been less than expected for a safety component. Because of reportable events involving malfunctions of these valves on operating BWRs, the staff is of opinion that significantly better safety/relief valve performance should be required of new plants. Provide a detailed description of improvements between your plant and presently operating plants in the areas listed below. In addition, explain why the noted differences will provide the required performance improvement.

(1) Valve and valve operator type and/or design. Include discussion of improvements in the air actuator, especially materials used for components such as diaphragms and seals. Discuss the safety margins and confidence levels associated with the air accumulator design. Discuss the capability of the operator to detect low pressure in the accumulator(s).

(2) Specifications. What new provisions have been employed to ensure that valve and valve actuator specifications include design requirements for operation under expected environmental conditions (esp. temperature, humidity, and vibration)?

(3) Testing. Prior to installation, safety/relief valves should be proof-tested under environmental conditions and for time periods representative of the most severe operating conditions to which they may be subjected.

(4) Quality Assurance. What new programs have been instituted to assure that valves are manufactured to specifications and will operate to specifications? For example, what tests are performed by the applicant to assure that the blowdown capacity is correct?

(5) Valve Operability. Provide your surveillance program to monitor the performance of the safety/relief valves. Identify the information that will be obtained and how these data will be utilized to improve the operability of the valves. For example, how will this program reduce the malfunctions that have occurred in operating reactors?

(6) Valve Inspection and Overhaul. The FSAR states that one half of the safety/relief valves will be bench checked and visually inspected every refueling outage. However, depending on operating cycle length, this may result in several years between inspections.

Operating experience has shown that safety/relief valve failure may be caused by exceeding the manufacturer's recommended service life for the internals of the safety/relief valve or air actuator. At what frequency do you intend to visually inspect and overhaul the ADS portion of the safety/relief valve? For both safety/relief and ADS modes, what provisions exist to ensure that valve inspection and overhaul are in accordance with the manufacturer's recommendations and that the design service life is not exceeded for any component of the safety/relief valve?

RESPONSE:

(1) See attached Table 211.70-1 for SRV Improvements as compared to present operating plants.

With regard to the air accumulators as a design requirement for overpressure protection, each safety relief valve has a relief accumulator that is sized to allow one actuation against normal drywell pressure with reactor pressure at 1000 psig, should the air supply to the valve fail. The ADS valves each have a separate accumulator that is sized to allow one actuation against maximum drywell pressure with the reactor at 0 psig, should the ADS air supply fail.

All pneumatic lines supplying the air to the relief and ADS accumulators should have a check valve to prevent leakage of the air out of the accumulator in the event of a pneumatic supply failure.

There is no GE specified instrumentation to allow the operator to detect low pressure in the accumulators.

(2) The GE Safety Relief Valve Equipment Specification(s) identifies and includes all the design requirements necessary for operation of the valve and valve actuator assembly in its expected normal and postulated abnormal environments. Verification of the design for safety relief valve acceptability is and has been demonstrated by life cycle testing, environmental testing in accordance with IEEE 323-1971, and seismic testing in accordance with IEEE 344-1975.

(3) The design of the safety relief valve has successfully demonstrated compliance with performance requirements when subjected to the following qualification test programs:

(a) Life Cycle Test(s)

This test program consist of subjecting production tested safety relief valve assembly of the design to be used to 300 relief (power) and safety (pressure) actuations in order to demonstrate acceptability of the valve design to meet (1) set pressure, (2) opening and closing response times, (3) blowdown, (4) seat tightness, (5) flow rated capacity lift (ASME) during each actuation, (6) reclosure (after each actuation) without demonstrating a tendency to stick open, chatter or disc oscillation, and emergency operability requirements. Conditions such as environmental temperature, pressure ramp rates, pneumatic operating pressure, solenoid voltage and backpressure were varied, consistent with test facility capabilities, to assure valve operability under the limits of the normal expected conditions to which the safety relief valve may be subjected. This test program establishes the qualified service life of the safety relief valve.

(b) Environmental Test(s)

This test program consist of subjecting a production tested pneumatic actuator assembly (includes air cylinder with electrically operated solenoid valve assemblies) unit of the design to be used on the safety relief valve to the environmental influences of radiation, thermal aging, mechanical aging, negative pressure and the postulated LOCA steam environment in order to demonstrate acceptability of the actuator design to meet operability requirements. The test program is in accordance with IEEE 323-1971 requirements and establishes the qualified service life of the actuator assembly.

(c) Seismic Test(s)

This test program consist of subjecting a safety relief assembly of the design to be used to seismic tests in accordance with IEEE 344-1975 to demonstrate acceptable functionality and structural integrity of the design when static moments are applied to the inlet and outlet flanges and dynamic and seismic OBE and SSE loads are imposed separately and combined.

(4) The GE safety relief valve specification incorporates all of the required performance, structural, interface, test, and regulatory guide requirements specified for the plant.

To assure that safety relief valves are manufactured and will perform to the requirements specified by the GE safety relief valve specification, the following types of actions are taken with the valve supplier:

(a) Valve supplier is evaluated for capability in complying with specification requirements.

(b) A qualified design is established that demonstrates compliance with specification requirements.

(c) The details and manufacturing process of the qualified design is frozen.

(d) Each safety relief valve assembly is manufactured to the approved design freeze list and manufacturing procedures.

(e) Each safety relief valve and actuator assembly is production tested to GE approved procedures to assure a high degree of confidence that the delivered equipment will perform as required.

(f) Quality Assurance inspection points are instituted throughout the process along with both general and random GE surveillance and periodic audits.

For example, to verify that the SRV flow capacity is correct, the following is verified or performed:

(a) Design is ASME certified for flow capacity.

(b) Nozzle bore diameter is dimensionally inspected.

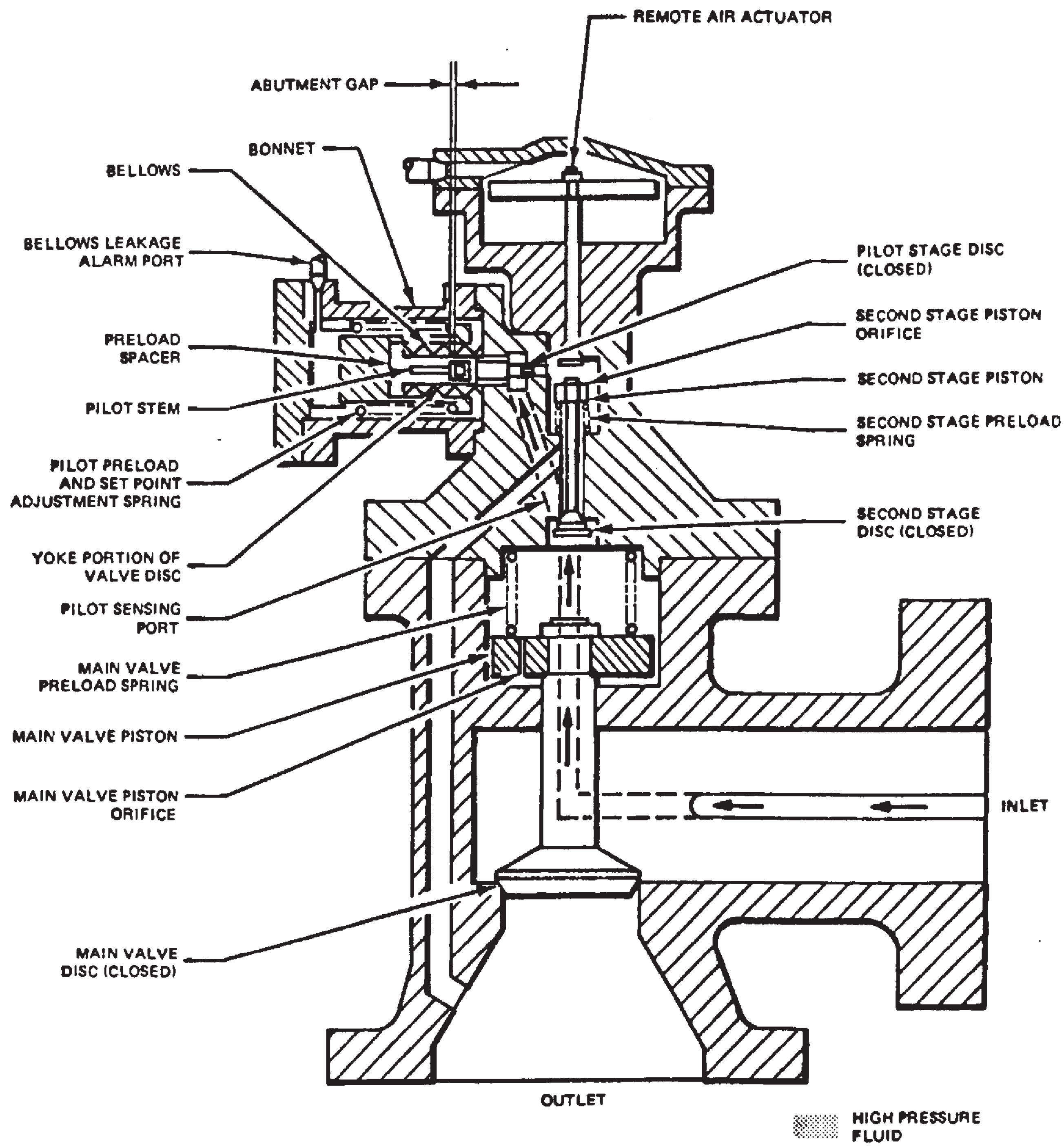
(c) Each valve is checked to assure that it opens to flow capacity lift position by use of an LVDT and O-Graph readout.

Details for the surveillance and testing of safety relief valves are included in Section 3/4.4.2 of the Technical Specification and in the pump and valve in-service inspection program.

TABLE 211.70-1

COMPARISON OF SRV IMPROVEMENTS

DESCRIPTION	OTHER PLANT(S)	SUSQUEHANNA SES	REMARKS
Valve Manufacturer	Target Rock Corporation	Crosby Valve & Gage Co.	
Valve Type	Reverse Seated, Pilot Operated, Dual Function	Direct Acting, Spring Loaded, Dual Function	See Figures 211.70-1 and 2 for cross-section views.
Valve Model/Style	67F	HV-65-BP	
Valve Size	6 inch inlet 10 inch outlet	6 inch inlet 10 inch outlet	
Performance Anomalies	Excessive pilot leakage resulting in plant blowdown.	No pilot used	Steam leakage past the Crosby type SRV nozzle and disc interface does not result in inadvertent SRV opening to cause a plant blowdown. SRV opening will result due to a system pressure exceeding SRV spring set or if the actuator cylinder is actuated.
	Air operator diaphragm failure due to use of inadequate diaphragm design and incorrect lubrication.	No diaphragms used	The Crosby type of SRV utilizes a standard type (direct acting) pneumatic cylinder which contains proven static and dynamic seals which have been properly lubricated. The design and materials used has been successfully subjected to life cycle and environmental tests.



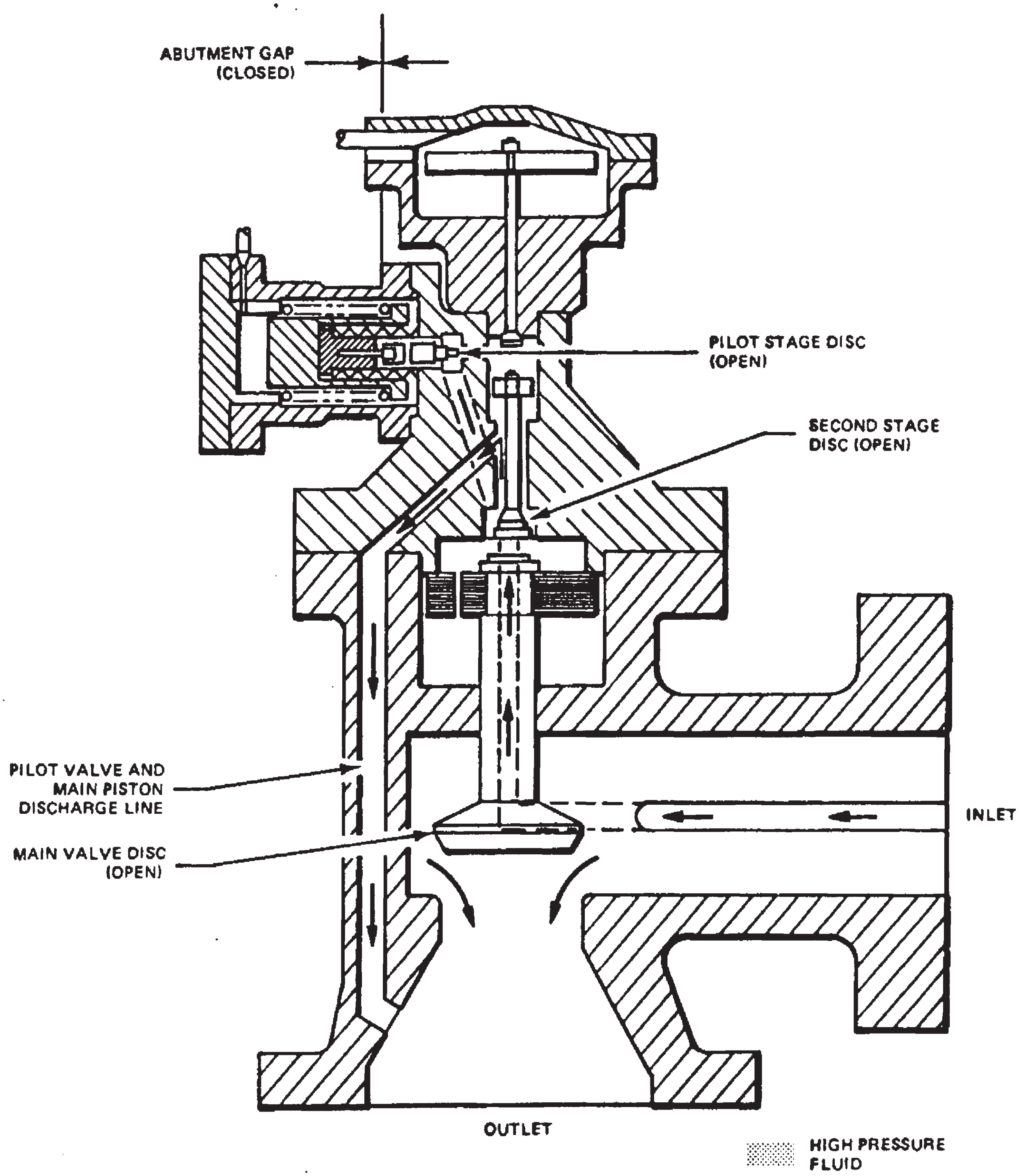
FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

VALVE SCHEMATIC (CLOSED)

FSAR FIGURE 211.70-1

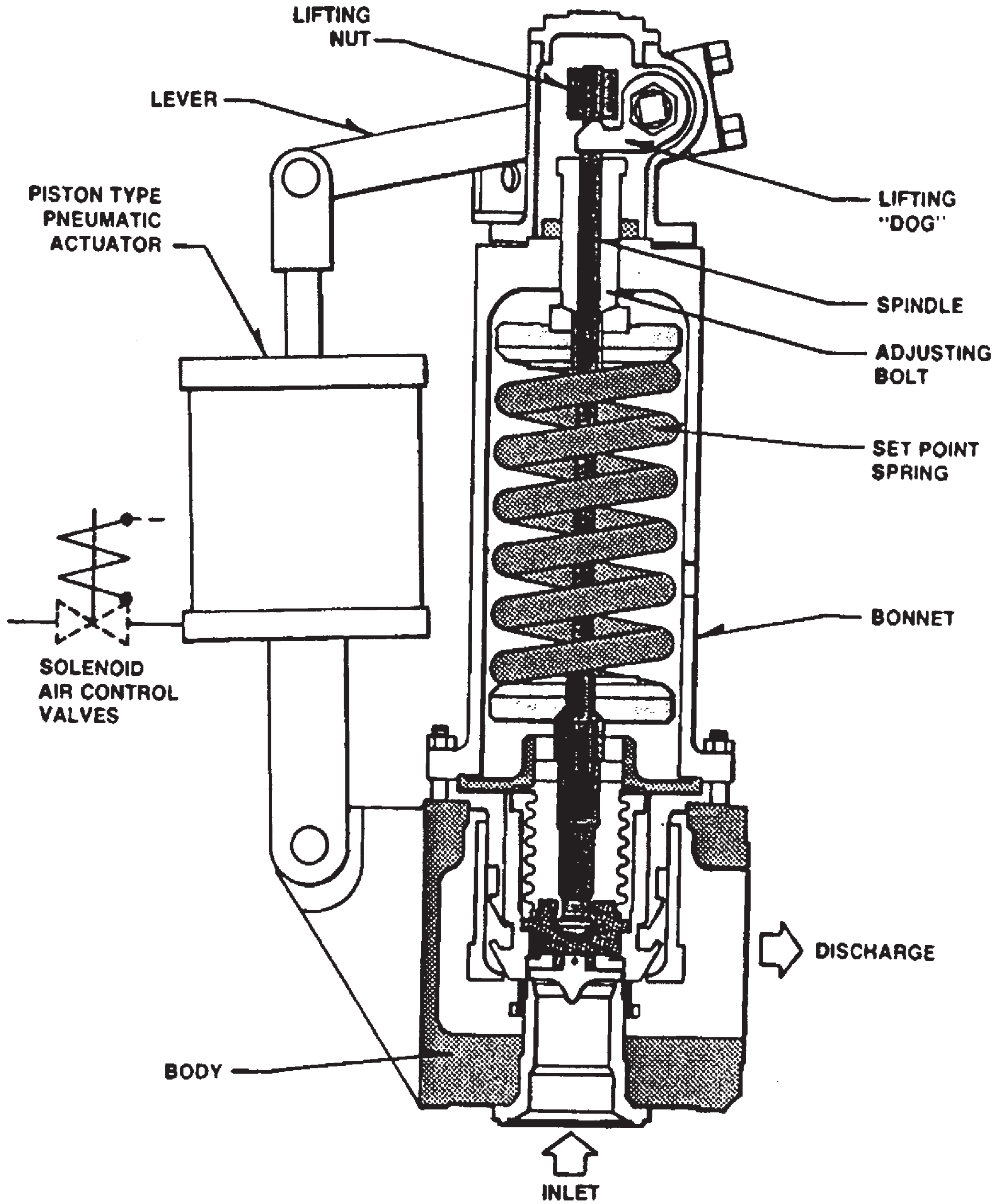
PP&L DRAWING



FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
VALVE SCHEMATIC (OPEN)
FSAR FIGURE 211.70-1a

PP&L DRAWING



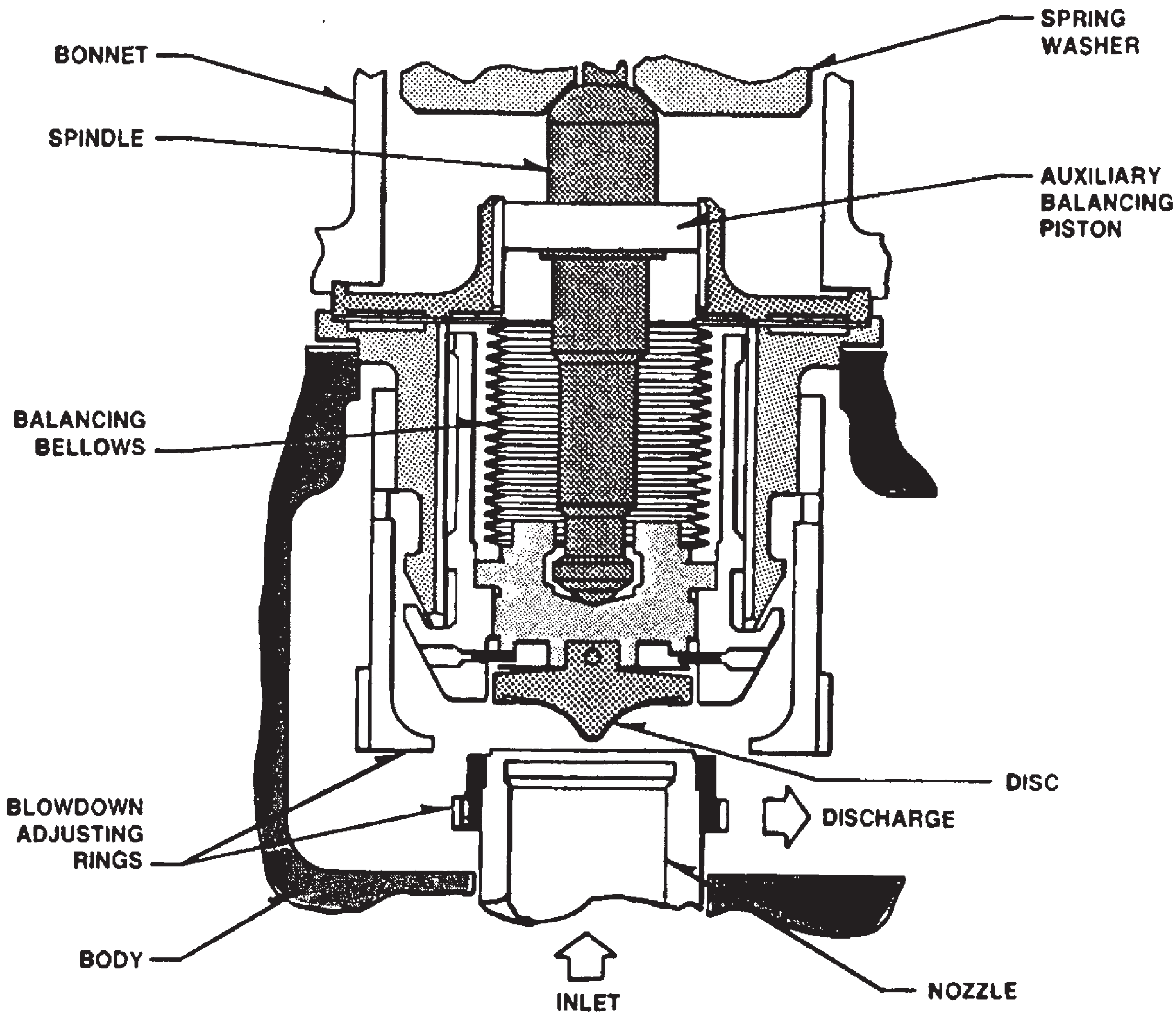
FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CROSBY VALVE

FSAR FIGURE 211.70-2

PP&L DRAWING



FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

INTERNAL DETAILS OF
CROSBY VALVE

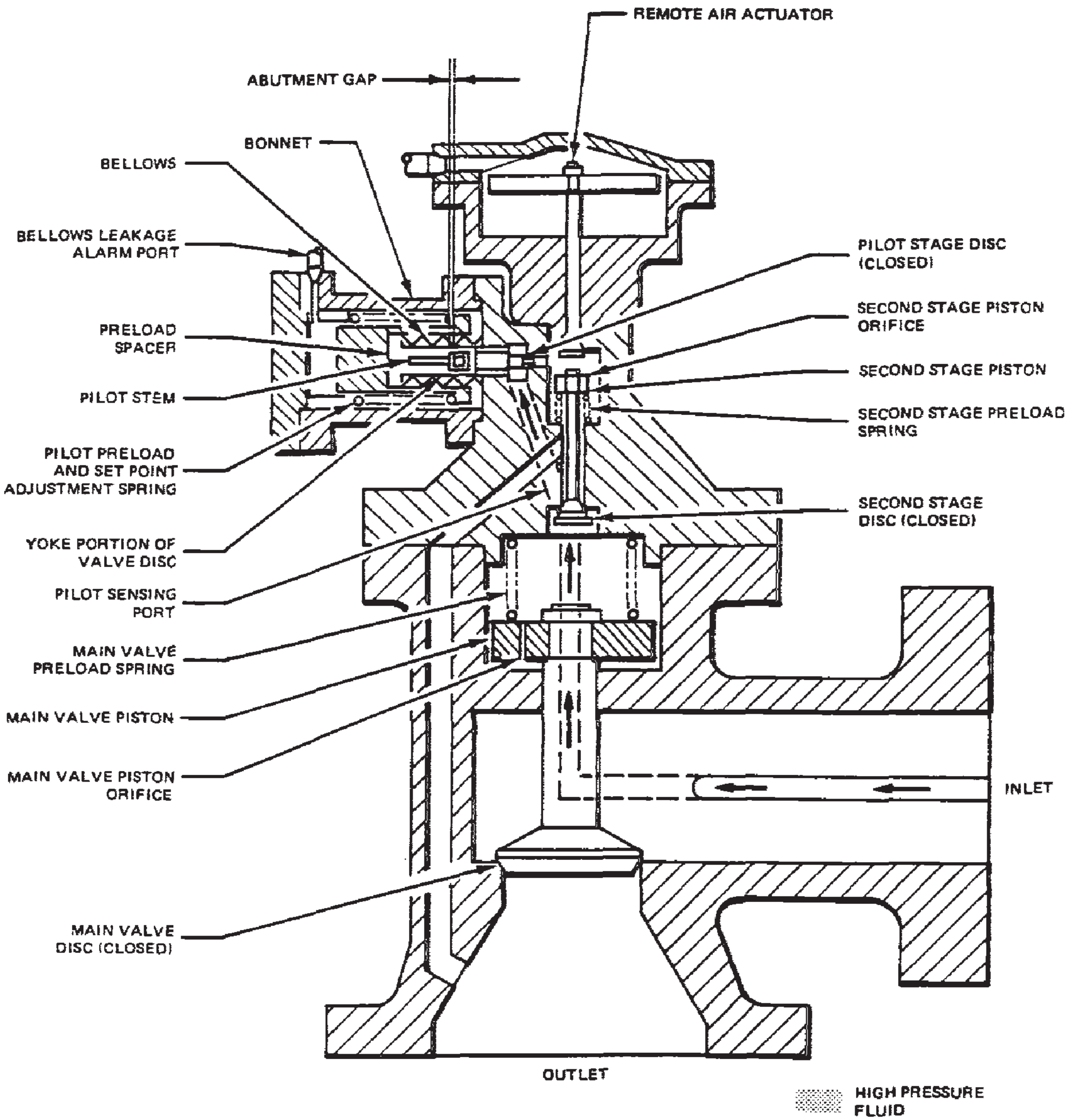
FSAR FIGURE 211.70-2a

PP&L DRAWING

TABLE 211.70-1

COMPARISON OF SRV IMPROVEMENTS

DESCRIPTION	OTHER PLANT(S)	SUSQUEHANNA SES	REMARKS
Valve Manufacturer	Target Rock Corporation	Crosby Valve & Gage Co.	
Valve Type	Reverse Seated, Pilot Operated, Dual Function	Direct Acting, Spring Loaded, Dual Function	See Figures 211.70-1 and 2 for cross-section views.
Valve Model/Style	67F	HV-65-BP	
Valve Size	6 inch inlet 10 inch outlet	6 inch inlet 10 inch outlet	
Performance Anomalies	Excessive pilot leakage resulting in plant blowdown.	No pilot used	Steam leakage past the Crosby type SRV nozzle and disc interface does not result in inadvertent SRV opening to cause a plant blowdown. SRV opening will result due to a system pressure exceeding SRV spring set or if the actuator cylinder is actuated.
	Air operator diaphragm failure due to use of inadequate diaphragm design and incorrect lubrication.	No diaphragms used	The Crosby type of SRV utilizes a standard type (direct acting) pneumatic cylinder which contains proven static and dynamic seals which have been properly lubricated. The design and materials used has been successfully subjected to life cycle and environmental tests.



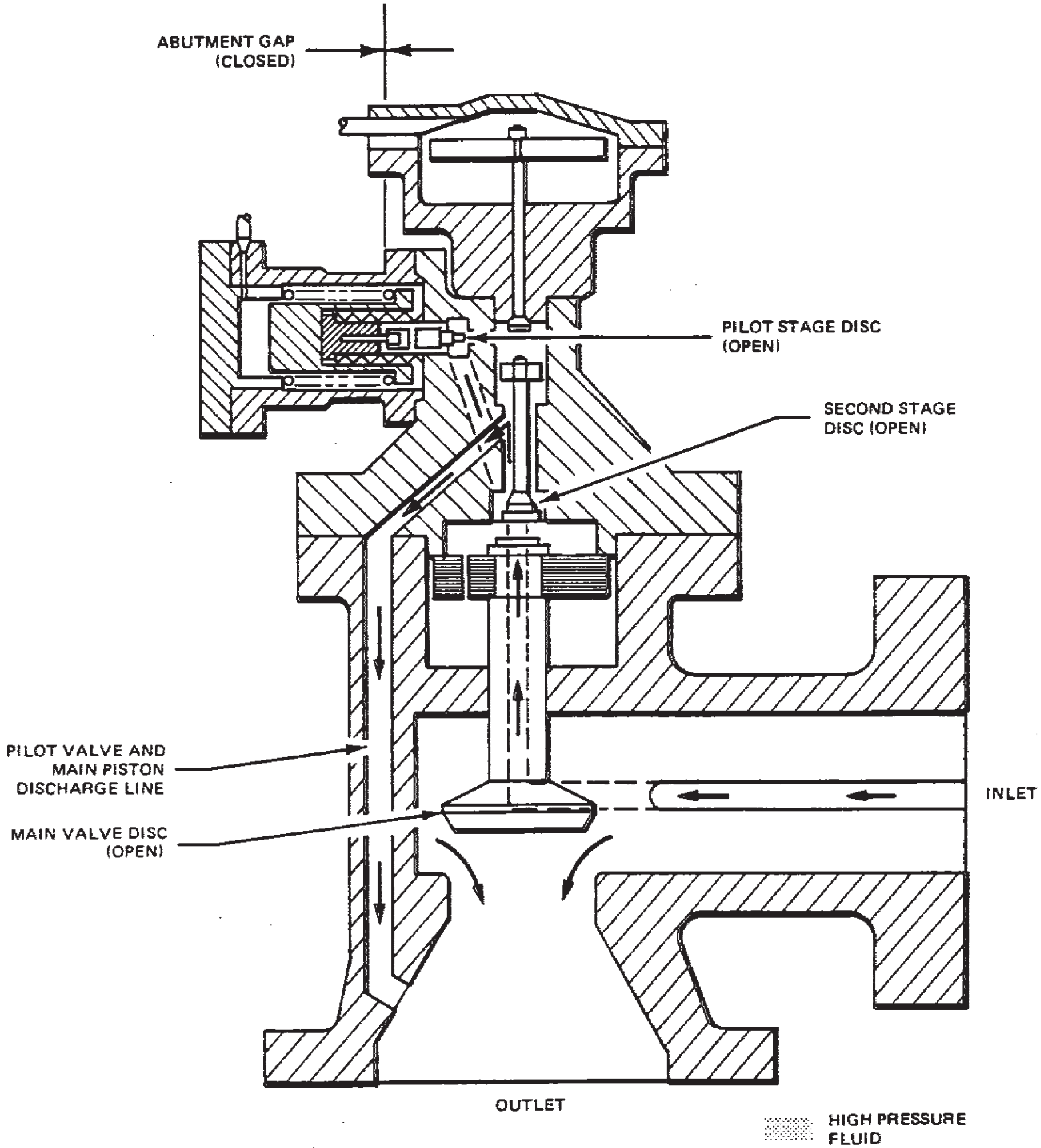
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

VALVE SCHEMATIC (CLOSED)

FIGURE 211.70-1, Rev 47

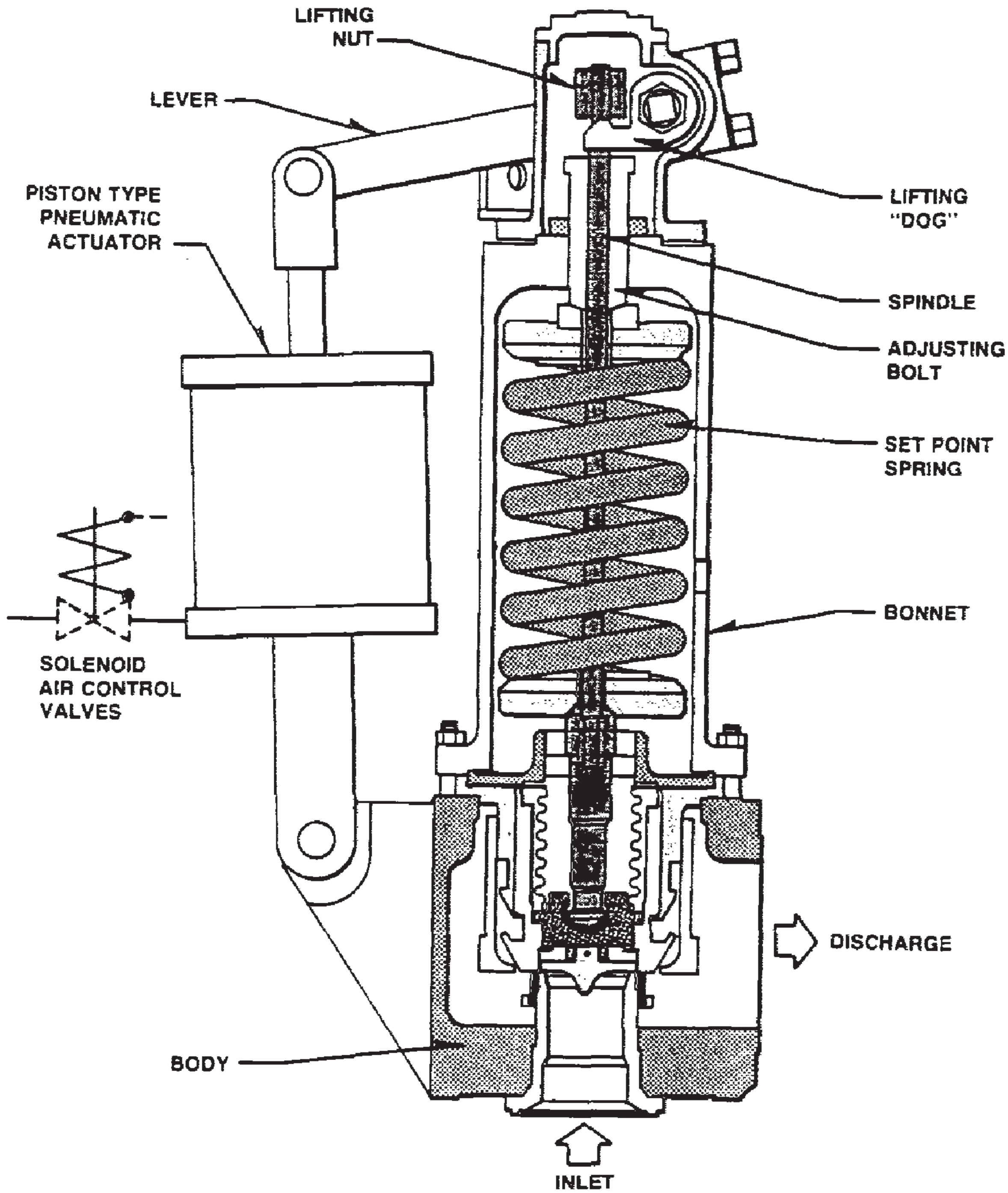
AutoCAD: Figure Fsar 211_70_1.dwg



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
VALVE SCHEMATIC (OPEN)
FIGURE 211.70-1A, Rev 47

AutoCAD: Figure Fsar 211_70_1A.dwg



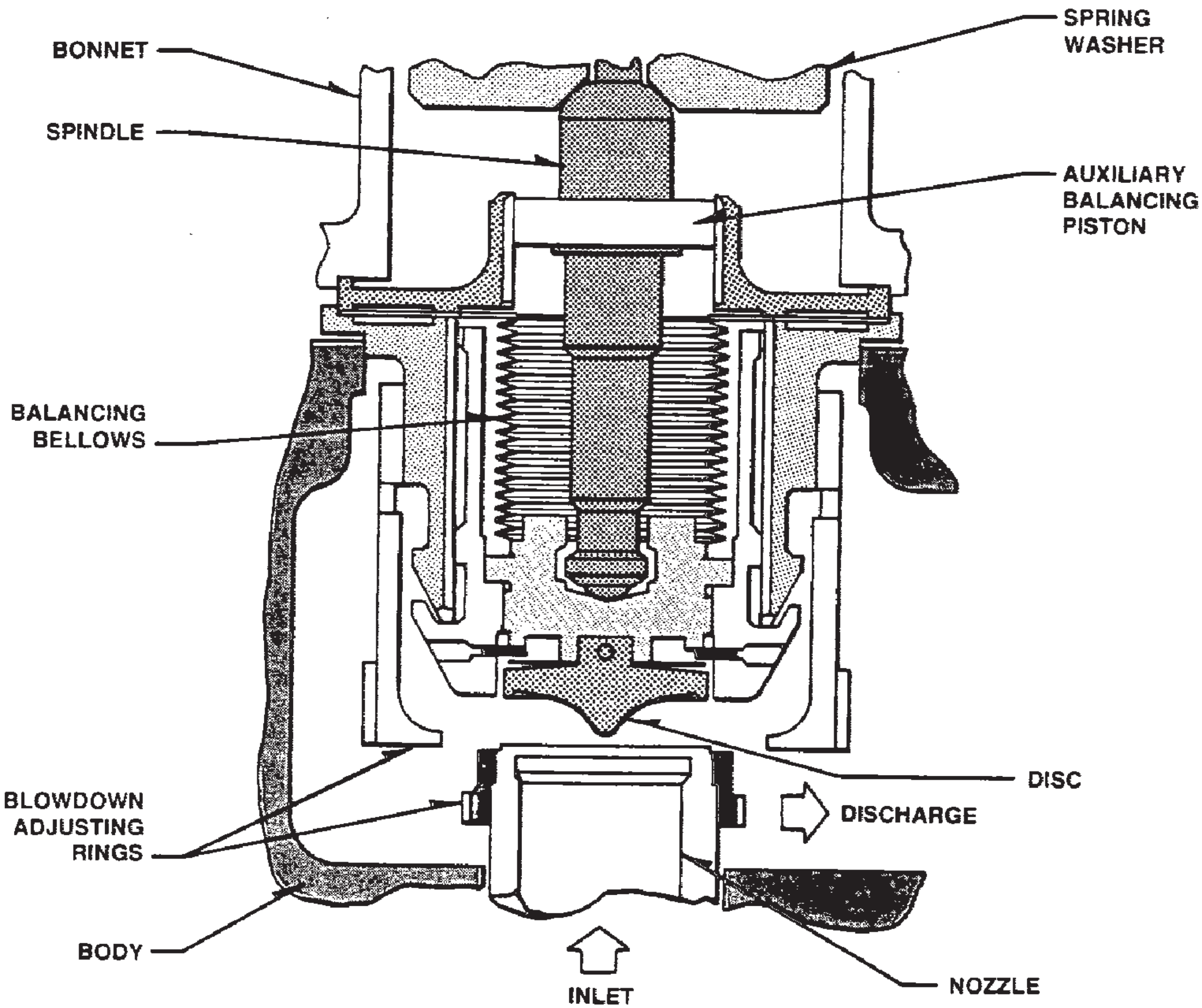
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

CROSBY VALVE

FIGURE 211.70-2, Rev 47

AutoCAD: Figure Fsar 211_70_2.dwg



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INTERNAL DETAILS OF
CROSBY VALVE

FIGURE 211.70-2A, Rev 47

AutoCAD: Figure Fsar 211_70_2A.dwg

QUESTION 211.71

The response to Question 211.4 is insufficient to allow an adequate evaluation.

Provide all system and core parameter initial values assumed in the overpressure analyses. Include their nominal operating range with uncertainties and technical specification limits.

RESPONSE:

The initial values of system and core parameters assumed in the overpressure analysis are listed in Subsection 5.2.2.2.2.1. They are:

		Analysis Value	Nominal Value
(a)	Operating Power		
	- MWT	3439	3293
	- % NBR	104.4	100.0
(b)	Steam Flow		
	- 10^6lb/hr	14.153	13.479
	- % NBR	105.0	100.0
(c)	Dome Pressure		
	- psig	1020	1005

The operating power and steam flow are limited by the operating license to their nominal values. The technical specification on the operating dome pressure is provided in Chapter 16. However, the effect of different operating dome pressures on the overpressure protection is shown in the response to question 211.4 which concludes that the assumption of the operating dome pressure leads to conservative analysis. Therefore, the overall assumptions of initial system and core conditions are conservative.

QUESTION 211.72

Does your design incorporate a fast scram system? Correct the time scale on figure 15.0-2.

RESPONSE:

A fast scram system is not incorporated in the design. The time scale on Figure 15.0-2 should be revised as shown on revised Figure 15.0-2.

QUESTION 211.73

Identify the safety/relief valve manufacturer.

RESPONSE:

The safety/relief valve manufacturer for the valves used on the Susquehanna SES plant is Crosby Valve Company.

QUESTION 211.74

Provide the calculations to support your relief valve discharge coefficients and flow capacities.

RESPONSE:

The requested information is provided in the following letter and enclosure.

The National Board of Boiler and Pressure Vessel Inspectors

S. F. HARRISON, Executive Director

1155 N. HIGH ST.
COLUMBUS, OHIO 43201
Phone 614-[illegible]

L. SULLIVAN, Chairman
Trenton, N. J.

R. BARTOSCH, 1st Vice Chm.
[illegible], Oregon

N. ALLISON, 2nd Vice Chm.
Nashville, Tenn.

EXECUTIVE COMMITTEE

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Wilmington, Delaware

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Des Moines, Iowa

STANLEY SMITH
Vancouver, B.C., Canada

April 27, 1972

Crosby Valve & Gage Co.
Mr. J. L. Corcoran
Senior Staff Engineer
Wrentham, Mass. 02093

SUBJECT: Capacity Certification
Crosby Style HB Valve
Per ASME Code Section III

Dear Mr. Corcoran:

We have examined the capacity certification charts submitted with your letter of March 20, 1972 for the subject valve and find them to be in order. We are enclosing a signed copy for your record.

Yours very truly,

W. L. Garvin

W. L. GARVIN
Asst. Executive Director

WLG:JW
encs.
cc: O. E. Buxton

The National Board of ... Pressure Vessel Inspectors

Columbus, Ohio

(6XRX10)

Name of Manufacturer: CROSBY VALVE & GAGE COMPANY

...e of Valve: STYLE HB - Section III, Nuclear

Average Coefficient Established by Test: .966 (Formula: W = 51.5 x .966 x AP x .90)

Accumulation 3% per Section III.

Inlet Size 6 in.

Seat Dia. ... in.

Bore Dia.: 4.530
Area: 16.117

Popping Press. Lbs.	Blowdown Lbs.	Capacity Lift Inch	Capacity Lbs. Per Hour	Capacity S.C.F.M.
50	2.5	1.134	47,789	
100	5.0	1.134	84,966	
200	10.0	1.134	159,321	
300	15.0	1.134	233,675	
500	25.0	1.134	382,365	
1000	50.0	1.134	754,158	
1500	75.0	1.134	1,125,931	

Inlet Size ... in.

Seat Dia. ... in.

Popping Press. Lbs.	Blowdown Lbs.	Capacity Lift Inch	Capacity Lbs. Per Hour	Capacity S.C.F.M.

Inlet Size ... in.

Seat Dia. ... in.

Popping Press. Lbs.	Blowdown Lbs.	Capacity Lift Inch	Capacity Lbs. Per Hour	Capacity S.C.F.M.

I, the undersigned, hereby certify that the capacities of safety valves shown in column headed Capacity Lbs. Per Hour, have been determined in accordance with the rules formulated by The A. S. M. E. Boiler Code Committee.

Date ... N... /71

... Executive Director

QUESTION 211.75

Page 5.2-6 states that the spring safety mode in the analysis is assumed to be 1177 to 1217 psig; Table 5.2-2 states 1146 to 1205 psig for spring set pressure. Explain the differences and how these values are used in the overpressure analysis. Define the transient analysis specification of valve groups and how they are used in the analysis.

RESPONSE:

The following specification of valve groups and spring safety mode setpoints, as indicated in Subsection 5.2.2.2.2.4 were used in the overpressure analysis.

a. valve groups - spring-action safety mode - 5 groups

b. pressure set point (maximum safety limit)
spring-action safety mode -1177 - 1217 psig

"The set points are assumed at a conservatively high level above the nominal set points. This is to account for initial set point errors and any instrument set point drift that might occur during operation. Typically the assumed set points in the analysis are 1 to 2% above the actual nominal set points."

The values shown in Table 5.2.2 represent nominal set points. The S/RV capacity in the safety mode used in the overpressure analysis is shown in Figure 5.2-12 as a function of steam line pressure.

QUESTION 211.76

Provide the power-operated pressure relief set points and capacities used in the transient analyses of Chapter 15.

RESPONSE:

The power-operated pressure relief set points used in the analysis of Chapter 15 are 1091, 1101, 1111, 1121, and 1131 psig, respectively, for the five groups of valves, as indicated in Table 15.0-2 of the FSAR. The total capacity of the valves at the first relief set point of 1091 psig is 99% NBR steam flow.

QUESTION 211.77

Confirm that adequate NPSH will exist if operator action is not initiated prior to 20 minutes after a LOCA. Provide your detailed NPSH calculation to demonstrate conformance to Regulatory Guide 1.1 for the ECCS pumps. Provide on Figures 6.3-3 and 6.3-6 the information on pages 6.3-7 and 6.3-14. Provide a discussion of the significance of Figure 6.3-7 with regard to NPSH margin.

RESPONSE:

For response see new Figures 6.3-3a and 6.6-6a, new Subsection 6.3.2.2.3.1, revised Subsections 6.3.2.2.4.1 and 6.3.2.2.4, and Dwg. M1-G33-1, Sh. 1 and M1-G33-1, Sh. 2.

QUESTION 211.78

Discuss the consequences of not performing operator actions until 20 minutes after a LOCA. Discuss all actions that are required by the operator to place the plant in the long-term cooling mode subsequent to a LOCA.

RESPONSE:

The only LOCA requiring operator action is a break outside the containment in a line directly connected to the reactor pressure vessel. The outside steam line break is representative of this class of breaks. The response to Question 211.90 addresses this subject in more detail.

Actions that are required by the operator to place the plant in long-term cooling mode subsequent to a LOCA are discussed in Subsection 6.2.2.2. Refer to this subsection for further discussion.

QUESTION 211.79

Item 5 on page 6.3-2 is not clear. Identify the ECCS line break as well as the single failure assumed to yield the available operating ECCS equipment shown.

RESPONSE:

The last paragraph of Item 5 indicates the ECCS line break to yield the available operating equipment shown.

The assumed failure for condition c is also indicated.

QUESTION 211.80

Page 6.3-9 of your SAR states that the HPCI is automatically shutdown on RPV high water level signal. What provisions are incorporated in the design to prevent premature termination of the HPCI flow. Are any interlocks provided, such as a LOCA signal, that prevent automatic shutoff?

RESPONSE:

Only the turbine is tripped when HPCI is automatically shut down on an RPV high water level signal. The steam supply line isolation valves are not closed in the turbine trip mode, and the turbine trip initiating signal is not sealed in. Consequently, the turbine trip solenoid will remain energized only so long as the trip-initiating condition lasts. Cycling of the HPCI system will occur when the turbine is tripped by high vessel water level and a high drywell pressure signal is present.

QUESTION 211.81

When the water level in the condensate storage tanks (CST) drops to a predetermined level, the HPCI pump switches automatically to the suppression pool. Provide assurance that adequate NPSH exist up to switchover. In addition, show that the minimum suction piping submergence in the CST will preclude undesirable vortex formation. Describe preoperational testing that will be performed to demonstrate that such vortex formation will not occur.

RESPONSE:

See revised Subsection 6.3.2.2.1, and new Subsections 6.3.2.2.1.1 and 6.3.2.2.1.2.

QUESTION 211.82

Figure 6.3-6 shows a core spray head flow curve as used in the LOCA analysis.

Credit for core spray heat transfer is not used until rated core spray is achieved (approximately 75 seconds for DBA), even though flow begins to enter the core at approximately 50 seconds. Is this flow included in the inventory calculation for reflood time? How are CCFL effects considered in the calculation in this earlier time frame?

RESPONSE:

Core spray flow is included in the inventory calculation for reflood time from the time of core spray initiation even though core spray heat transfer credit is conservatively not used until rated core spray is achieved.

CCFL effects are accounted for from the time of core spray initiation and uncovery of the top of the fuel bundles. The CCFL calculation is the same before and after rated core spray is achieved. A more complete description of the modeling of the CCFL effects is contained in NEDO-20566, "General Electric Company Analytical Model for Loss of Coolant Analysis in Accordance with 10CFR50 Appendix K."

QUESTION 211.83

Provide the Figure 6.3-8c that is discussed in Section 6.3.2.2.4 (page 6.3-15).

RESPONSE:

Subsection 6.3.2.2.4 has been revised to delete the incorrect reference to Figure 6.3-8c. The process diagram consists of: Dwgs. M1-E11-3, Sh. 1 and M1-E11-3, Sh. 2.

QUESTION 211.84

A recent CE report, "DC Power Source Failure for BWR 3 and BWR 4," dated 11/1/78, provides a generic response to staff concerns relative to loss of DC power sources on peak cladding temperature (PCT). For smaller break sizes, this failure yields higher PCT's than failure of HPCI. Provide assurance that this failure has been properly taken into account in your single failure analysis. In this regard, Table 6.3-5 should be clarified. For example, a loss of a diesel generator would cause a loss of a core spray pump plus an LPCI pump. Also, it is not clear what is being presented in the column headed, "Effect on Safety Function." Is Table 6.3-5 intended to agree with Table 6.2-7? Is break location considered? Define the asterisk used on DC power failure.

RESPONSE:

The PCT versus break size curves (Figures 2 and 6 in the report of 11/1/78) bound the effects of any DC power source failure for Susquehanna.

Table 6.3-5 was revised and clarified in Rev. 4 to the FSAR.

QUESTION 211.85

Provide assurance that adequate NPSH exists for an ECCS passive failure in a water-tight pump room. Address the possibility of vortex formation at the suction of the remaining ECCS pumps with the lowered pool level. Discuss preoperational tests to be performed to demonstrate that there is not impairment of ECCS function due to lowered suppression pool level.

RESPONSE:

See Subsection 6.3.6 for discussion of NPSH availability with ECCS passive failure and of vortex formation in the suppression pool.

Testing for pump operation at minimum NPSH margin is provided by preoperational tests.

QUESTION 211.86

Confirm that the LPCI system does not perform any other function, such as containment cooling, during the short term portion of the LOCA recovery? If so, this feature must be taken into account in your LOCA analyses. See Question 211.105.

RESPONSE:

The LPCI mode of the RHR system is initiated by the LOCA signal. The LPCI mode will continue until the operator determines that another mode of operation is needed (such as containment cooling) and takes action to initiate another mode. No operator actions are needed during the short-term portion of the LOCA recovery. (See also Subsection 6.3.2.8).

QUESTION 211.87

The discussion of the LPCI system is not complete. Discuss the status of valves (open or closed) in the LPCI system and the recirculation system during the LOCA. Provide the initiation signals, interlocks, and time delays associated with each valve movement during the LOCA.

RESPONSE:

The RHR system valve positions in LPCI mode are indicated in Dwg. M1-E11-3, Sh 1, Table 1. Dwg. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh 3 and M-151, Sh. 4 indicate RHR valve positions in standby mode, i.e., during normal power operation. A comparison indicates that valve F015 is the only motor-operated valve which changes position from standby mode to LPCI mode. The LPCI mode initiation signal and interlocks for valve F015 are indicated in Dwg. M1-E11-5, Sh. 1, M1-E11-5, Sh. 2, M1-E11-5, Sh. 3, M1-E11-5 Sh. 4 and M1-E11-5, Sh. 5.

Both recirculation system discharge valves and discharge bypass valves are signalled to close given both an LPCI initiation signal and reactor pressure reduction to 240 psia. The valves stroke closed in 30 seconds. The signal to close is independent of other initiation signals such as core spray or LPCI injection valve opening.

QUESTION 211.88

Provide the assumed values that comprise the total break area for the steam line break; feedwater line break; and core injection spray line break.

RESPONSE:

The maximum steam line break inside the containment is based on the safe end area (3.05 ft^2); the maximum outside steam line break area (3.75 ft^2) is based on the flow limiter area for each steam line (0.94 ft^2).

The feedwater line break area (0.36 ft^2) is based on the inside area of the feedwater sparger pipe (0.18 ft^2).

The maximum core spray line break area is based on the limiting area of the core spray line safe end (0.52 ft^2).

QUESTION 211.89

Correct Figure 6.3-64 or discuss why the initial PCT for the core spray line break is 1700°F.

RESPONSE:

The correct PCT figure for the core spray line break (redesignated Figure 6.3-58) was provided in Rev. 4 to the FSAR.

QUESTION 211.90

What are the differences between steam line breaks inside and outside containment with regard to break area? The analyses suggest that core uncovery could occur if no operator action took place before 20 minutes. Provide the effect on peak clad temperature of no action prior to 20 minutes and discuss all assumptions.

RESPONSE:

See response to Question 211.88 for differences in steam line break area inside and outside the containment.

See response to Question 211.9 (Rev. 1 8/78 to the FSAR) for General Electric's position with respect to the 20 minute operator action assumption. The conclusion that the peak cladding temperature will be < 1500°F for the Susquehanna OSLB is valid, assuming operation action at 20 minutes, and is not inconsistent with limited core uncovery proceeding the operator action.

QUESTION 211.91

Section 6.3.3.4 (page 6.3-23) states that operator action is not required during the short term cooling mode following a LOCA. Since the short term mode may extend past ten minutes for smaller breaks, discuss in detail what operator actions are required in view of what is stated in Section 6.3.2.8 (page 6.3-19) regarding throttling requirements. In your discussion include the instrumentation that the operator has available, what actions he must perform, and the instructions available to the operator in the emergency procedures. Also include a plot of NPSH margin versus time for the worst case break.

RESPONSE:

Subsection 6.3.2.8 covers a DBA response and there the short term cooling mode encompasses the period required to recover vessel water level. The HPCI system is designed to inject water into the reactor vessel for small breaks which do not depressurize the vessel.

If a small break occurs and the HPCI system does not function, the automatic depressurization system (ADS) will cause vessel blowdown and the low pressure systems will then act to restore vessel water level. In either case, no operator action is required to restore reactor water level.

Satisfactory long-term response requires that the core remain covered and that the core decay heat be transferred to a heat sink.

Operation action is required to establish the long-term cooling function as follows:

Case I

If automatic blowdown has occurred, considerable energy will have been released to the suppression pool. The energy released to the pool will cause a pool temperature rise. Subsequent to the accident, fission product decay heat will result in a continuing energy dump to the pool. Unless this energy is removed from the primary containment system, the suppression pool and primary containment will attain unacceptably high temperature and pressure. Therefore, planned operator actions will be initiated to maintain adequate suppression pool water temperature.

Operator Actions for Case (I)

Realign the RHR system to change from the low-pressure coolant injection mode to the suppression pool cooling mode.

1. Switch closed the LPCI injection valve E11-F017.

2. Switch open the pool return valves E11-F028 and F024 in chosen loop, and regulate flow to 10,000 gpm for one pump or 15,000 gpm for two pump in one loop.

3. Switch the RHR service water pumps (if not already running) to start position.

4. Switch closed the RHR heat exchanger bypass valve E12-F048 in the chosen loop.

Manual control switches (for valves E11-F017, E11-F024, E11-F028 and E11-F048 and service water pump) and RHR and service water flow indications should be accessible to the operator to accomplish the foregoing manual actions. All of the foregoing control switches and indicators are located on H12-P601 panel. Operator proximity to H12-P601 panel is required to perform the above manual action.

Throttle valve E21-F005 in each operating core spray loop to obtain a maximum flowrate of 6350 gpm for long-term cooling. Manual control switches for valves E21-F005 A & B are located on control room panel H12-P601, as are flow indicators for both core spray loops.

The preceding paragraphs present a means for the operator to maintain the core covered and cool the containment.

Case II

If automatic blow has not occurred.

Operator Actions for Case II

Due to the fact that HPCI or feedwater have recovered vessel water level, the operator can trip the automatic depressurization system or blow the vessel pressure down by actuating less than the entire complement of ADS valves. High drywell pressure would have initiated all ECSS equipment as it did in Case I, and these systems maintain vessel water level as vessel pressure decreases and HPCI and feedwater are isolated. Controls for the ADS valves are located on control Room panel H12-P601.

From the point, the operator actions are the same as in Case I. The preceding writeup has been prepared on the basis that all standard accident assumptions are valid, i.e., the loss of normal power sources and a single failure has occurred.

NPSH available and NPSH required for the worst case break at any time are discussed in the following subsections:

System	FSAR Subsection
CS	6.3.2.2.3.1
LPCI	6.3.2.2.4.1
HPCI	6.3.2.2.1.1

QUESTION 211.92

The SSES design uses a swing bus arrangement. In accordance with the staff policy discussed in NUREG-0138, provide an ECCS calculation for the suction line break assuming no LPCI injection.

RESPONSE:

Due to the improved swing bus design used for Susquehanna, it is inappropriate to assume the complete loss of LPCI. The response to Question 040.23 confirms that the LOCA analysis presented in Subsection 6.3.3 is acceptable.

QUESTION 211.93

Identify all ECCS valves that may be potentially submerged or subject to spray impingement following a LOCA. Discuss environmental qualification of these valves for these conditions.

RESPONSE:

See revised Subsection 6.3.1.1.4 and additional Table 6.3-10 for a listing of all safety-related valves subject to spray impingement or submergence.

QUESTION 211.94

The references provided for the ECCS analysis must include references for the latest model changes and corrections.

RESPONSE:

Three (3) additional reference are required for the latest model changes. See revised Subsections 6.3.6 and 6.3.3.7.1.

QUESTION 211.95

Demonstrate that HPCI failure from 1.0 ft^2 to the DBA is not more limiting than the LPCI D/G failure.

RESPONSE:

For large breaks (1.0 ft^2 to the DBA) the HPCI is not as effective at supplying coolant to the vessel as the low pressure ECC systems because the rapid depressurization of the vessel limits the amount of time the HPCI operates. Because of this the HPCI is less limiting for large breaks than the failure of a low pressure ECC system.

The HPCI pump is powered by a turbine drawing steam from the reactor pressure vessel and operates only while the vessel pressure is above 165 psia. The rapid depressurization characteristic of large breaks quickly brings the vessel pressure below this minimum operating pressure and the HPCI system stops injecting coolant into the vessel. For the large recirculation discharge break the HPCI operates for about 30 seconds for the DBA and about 60 seconds for the 1.0 ft^2 break during the blowdown phase of the event. Also the effectiveness of the HPCI is limited for large breaks because the rated flow of the HPCI system is only about one half of one of the low pressure ECC systems. Therefore, the effect of the HPCI system on large break LOCA analysis is minimal. The low pressure systems are more effective in reflooding the core for large breaks, therefore the limiting single active failure for large breaks is the failure that disables the greatest number of low pressure systems. For Susquehanna, this is the LPCI injection valve failure, which combined with the recirculation discharge break, disables both LPCI loops. The ECC systems that remain operational are the HPCI system, the two LPCS systems, and the ADS.

Given the failure of the HPCI combined with the recirculation discharge break the LOCA analysis would take credit for the two LPCS systems, the two LPCI systems, and the ADS. This failure is clearly less limiting for large breaks.

QUESTION 211.96

There have been damaging water hammer occurrences in the turbine supply or exhaust lines of HPCI systems that were attributed to steam driven slugs of water. Contributing causes included a) water drawn into the exhaust line from the suppression pool, b) inadequate draining of the steam supply line, and c) trapping of water slugs upstream of the supply line isolation valves during maintenance. Also, check valves in the turbine exhaust lines of the HPCI system which serve a containment isolation function have been damaged as the result of intermittent closures which arise from flow oscillations in the exhaust line associated with formation and collapse of steam bubbles in the suppression pool. One type of corrective action involved the use of a sparger to reduce the oscillations. What design features are used at Susquehanna to prevent these types of damage?

RESPONSE:

In addition to the condensing sparger, a vacuum breaker system is installed to reduce pressure oscillations.

A vacuum breaker system is installed close to the HPCI turbine exhaust line wetwell penetration to avoid siphoning water from the suppression pool into the exhaust line, as steam in the line condenses during and after turbine operation. The vacuum breaker line runs from the wetwell air volume to the HPCI exhaust line through two normally open motor-operated gate valves and two swing check valves arranged to allow air flow into the exhaust line, and preclude steam flow to the wetwell air volume.

During turbine operation, condensate buildup in the turbine exhaust line is minimized by the installation of a drain pot in a low point of the line near the turbine exhaust connection. The condensate collected in the drain pot drains to the barometric condenser through a restricting orifice.

QUESTION 211.97

Check valves in the discharge side of the HPCI, LPCI/RHR, LPCS systems perform an isolation function in that they protect low pressure systems from full reactor pressure. The staff will require that these check valves be classified ASME IWV-2000 Category AC, with the leak testing for this class of valve being performed to code specifications. It should be noted that a testing program which simply draws a suction on the low pressure side of the outermost check valves will not be acceptable. This only verifies that one of the series check valves is fulfilling an isolation function. The necessary testing frequency will be that specified in the ASME Code, except in cases where only one or two check valves separate high to low pressure systems. In these cases, leak testing will be performed at each refueling after the valves have been exercised.

Identify all ECCS check valves which should be classified Category AC as per the position discussed above. Verify that you will meet the required leak testing schedule, and that you have the necessary test lines to leak test each valve.

Provide the leak detection criteria that will be proposed for the Technical Specification.

RESPONSE:

The response to question 110.47 will provide the complete in service inspection pump and valve program submittal, all information concerning the program will be included in that submittal.

QUESTION 211.98

What provisions are made to protect level instrumentation for the condensate storage tank and the lines from this tank leading to the HPCI systems from the effects of cold weather.

RESPONSE:

For response see Subsection 6.3.2.2.1.

QUESTION 211.99

Some relief valve discharge lines on ECCS penetrate primary containment and have outlets below the surface of the suppression pool. Since these lines form part of the primary containment, the concern is that excessive dynamic loads resulting from water hammer during relief valve actuation may cause line cracking or rupture. Identify these lines penetrating containment and provide information concerning measures taken to prevent line damage.

RESPONSE:

See revised Subsection 6.3.2.6.

QUESTION 211.100

The ECCS contains manual as well as motor-operated valves. Consideration must be given to the possibility that manual valves might be left in the wrong position and remain undetected when an accident occurs. Provide a list of location and type of all manually operated valves in the safety systems and discussion of the methods used for each valve to minimize the possibility of such an occurrence. The staff will require remote indication in the control room for all critical ECCS valves (manual or motor-operated).

RESPONSE:

A discussion of the methods used to minimize the possibility that manual valves in the ECCS might be left in the wrong position is given in revised Subsection 6.3.2.9. Table 6.3-9 provides a listing of each manually-operated valve in the ECCS.

QUESTION 211.101

Recent operating experience identified a potential common mode flooding of ECCS equipment rooms. The problem involved the equipment drain lines (see 1E Circular No. 78-06, May 25, 1978). Verify that the specific design for floor and equipment drains are such that flooding in any one room or location will not result in flooding of redundant ECCS equipment in other rooms. If isolation valves or limit switches are used to prevent common flooding, identify these valves and switches and discuss provisions to be included in the Technical Specifications to assure adequate surveillance.

RESPONSE:

See response to Question 211.10 for a detailed discussion of specific design for the floor and equipment drains, including isolation washers and instrumentation used to prevent common flooding of ECCS equipment rooms. The measures described will be assured by the use of administrative controls. No Technical Specification provisions are contemplated.

QUESTION 211.102

The discussion in Section 6.3.2.2.5 of the fill system used to prevent water hammer due to empty discharge lines in the RHR and ECC systems is inadequate. Since there have been about fifteen damaging water hammer events resulting from empty discharge lines of core spray and RHR systems, the adequacy of fill systems, including instrumentation and alarms is a matter of concern. Please respond to the following:

(1) Provide a detailed description of the fill system including instrumentation and alarms with appropriate references to a P&ID.

(2) Level transmitters apparently are not used to detect trapped air bubbles upstream of injection valves. Pressure read downstream of a pump discharge check valve that is greater than the gravity head corresponding to the highest point in the system does not necessarily indicate the absence of trapped air pockets? What provisions are made to avoid trapping of air pockets? In the discussion include consideration of leaking valves in bypass test lines.

(3) If maintenance is required on a particular loop (e.g., in RHRs) requires draining, how does the fill system protect the other loop and systems (e.g., CS)?

(4) What surveillance testing will be required to demonstrate that the fill system instrumentation is capable of performing the desired function?

(5) How are surveillance tests made to determine if the discharge lines for the RHR and CS systems are full as required in the Standard Technical Specifications?

(6) Assuming the jockey pump does not maintain full lines, water hammer could occur during surveillance tests of the RHR and CS pumps. If damage occurred, the event would be reported in a LER. However, if special fill and vent procedures were used prior to these tests, water hammer would not occur, but the inadequacies of the jockey pump system might not be evident. Discuss the procedures to be used in surveillance tests involving startup of RHR and CS pumps and the reporting procedures to be used if special filling and venting procedures are used and indicate partially empty lines.

RESPONSE:

For response, see revised Subsection 6.3.2.2.5.

QUESTION 211.103

During long-term cooling following a small LOCA, the operator must control primary system pressure to preclude overpressurizing the pressure vessel after it has been cooled off.

(1) Describe the instructions given the operator to perform long-term cooling.

(2) Indicate and justify the time frame for performing the required action.

(3) List the instrumentation and components needed to perform this action and confirm that these components meet safety grade standards.

(4) Discuss the safety concerns during this period and the design margins available.

(5) Provide temperature, pressure, and RCS inventory graphs that would show the important features during this period.

The above discussion should account for the following:

(1) Loss of offsite power.

(2) Operator error or single failure.

RESPONSE:

During long term cooling following a small LOCA there are no operator actions required to control system pressure to preclude overpressurization of the pressure vessel after it has been cooled off. The system is always protected by relief valves that are more than adequate to handle decay heat generation. If the small LOCA caused reactor water level to drop to level 3 or drywell pressurization the plant would scram. If water level drops to level 2 then HPCI (and RCIC) would come on automatically to re-establish water level for the postulated LOCA and would automatically control water level between levels 2 and 8. If the small LOCA had caused high drywell pressure and water level dropped to level 1 then all ECC systems would come on to re-establish water level. ADS would automatically come on to depressurize the vessel if the HPCI system is insufficient to maintain reactor vessel water level.

The ADS valves stay open once actuated until the high drywell pressure and low reactor water level signals have cleared and resetting is accomplished by depressing both timer reset pushbuttons and both drywell high pressure reset pushbuttons. The ADS valves are designed to stay open for at least 100 days thereby precluding any significant repressurization of the reactor vessel. If the pressure vessel were cooled off following the hypothetical small LOCA then the ADS valves would be open and would prevent repressurizing the pressure vessel. Points 1 through 5 above then can be responded to in summary as follows:

(1) No operator actions are required following a small LOCA to preclude overpressurizing the vessel after it has been cooled-off. Operator actions to establish long-term cooling are discussed in Section 6.2.2.

(2) No actions are required.

(3) No actions are required. Safety grade instrumentation is described in Chapter 7.

(4) Limiting safety concerns are addressed in Sections 6.2 (Containment Barrier); 6.3 (Peak Clad Temperature Calculations); and Chapter 15 (Radiological Releases). The postulated event is not a limiting event for designing to assure the health and safety of the public.

(5) System characteristics for the more severe design basis events are shown in Sections 6.2 and 6.3.

The above discussion accounts for loss of offsite power and operator action or single failure.

QUESTION 211.104

The answer to 211.10 is not complete. Explain how the leakage detection system meets the requirements of IEEE-279. Provide the minimum time available before operator action is taken after initiation of an alarm. Examine auxiliary system piping in the location of ECCS equipment and address the potential break of a non-safety grade pipe that may cause flooding.

RESPONSE:

Revisions 7 and 17 to the FSAR revised the response to Question 211.10, and fully explain the leakage detection system's conformance to IEEE 279.

See revised Subsections 3.6.1.1 (Flooding) and 6.3.6.

QUESTION 211.105

Your response to 211.13 requires supplemental discussion. Demonstrate that for all sizes of breaks in a recirculation loop or in ECCS lines requiring ECCS actuation, the core is covered sufficiently so that LPCI diversion to wetwell spray after 10 minutes is acceptable and the ECCS systems continue to satisfy the requirements of GDC 35 and 10 CFR 50.46. Consideration should be given to the full spectrum of potential single failure and break locations. Confirm that no operator action affecting ECCS performance is required prior to 20 minutes after the initiation of the accident.

Discuss the effects of the following on core cooling and provide the necessary information to show that the requirements of GDC 35 and 10 CFR 50.46 are not violated.

(1) Justify that the system provided for diversion of LPCI flow meets single failure criteria so that diversion before 10 minutes need not be considered.

(2) Provide a sensitivity study showing peak clad temperature as a function of break size for small break LOCA's assuming diversion will be initiated at 10 minutes. Perform this study for ECCS and recirculation line breaks. For the most limiting break, provide the following figures:

   (a) Water level inside the shroud as a function of time during the LOCA
   (b) Reactor vessel pressure vs. time
   (c) Convective heat transfer coefficient vs. time
   (d) Peak clad temperature vs. time
   (e) ECCS flow rate vs. time

(3) Justify that diversion at times greater than 10 minutes will have less severe consequences than diversion at 10 minutes (considering appropriate break size for later diversion).

(4) Provide a discussion which balances the need for LPCI diversion for this limiting break size with the need for abundant core cooling (GDC 35). For example, this discussion could relate to the likelihood of LPCI diversion for this size break.

RESPONSE:

The Susquehanna plant, as demonstrated in Subsection 6.2.1.1.3, does not require automatic LPCI diversion and no system has been provided. Equipment, controls and instrumentation associated with the containment spray cooling mode of the RHR system are classified in Table 3.2-1 and are discussed in Subsections 5.4.7 and 7.3.1.1a.1.6.

The effect on the standard LOCA analysis of diverting LPCI flow to wetwell spray cooling was investigated in detail for another BWR/4 with LPCI modification, namely Shorham (see LILCO Letter SNRC-696, Enclosure 2, Item 5, dated June 9, 1978). The results and discussion of the Shorham analysis are directly applicable to Susquehanna.

The results of the above analysis showed that the break location and size most affected by LPCI diversion is the core spray (CS) line break for which the LPCI would start injecting into the vessel at 600 seconds (i.e., the assumed time of the LPCI diversion). The limiting failure assumed with this break is the failure of the DC source common to the HPCI, one CS system and one LPCI pump. This break/failure combination was specifically determined for Susquehanna to be an 0.026 $ft.^2$ CS line break with a resultant calculated PCT of 1644°F with diversion.

For breaks smaller than the above and with a diversion time of greater than 600 seconds, calculated PCT will be lower since core uncovery will be for a shorter time period and decay heat at the time of uncovery will be lower. Breaks larger than the above get some reflooding benefit from the LPCI pumps before the assumed diversion and this results in lower PCT; later diversion simply increases this benefit. Consequently, diversion at times greater than 10 minutes will have less severe consequences than diversion at 10 minutes.

Based on the discussion and analysis in Subsection 6.2.1.1.5, the conditions that might require some operator action, e.g., LPCI diversion, would result from a small primary system leak in the drywell being simultaneously accompanied by an open bypass path between the drywell and the suppression chamber. The calculated break area that maximizes the containment pressure following this very unlikely combination of events is of the same order of magnitude as the break area of the small break that, even with diversion, resulted in PCT well below the Appendix K limit. This significant margin (456°F) demonstrates that the Susquehanna design has a well-balanced capability for contending with postulated "competing" events.

The ECCS design basis for Susquehanna assumed no operator intervention prior to 10 minutes after the initiation of the LOCA (see Subsection 6.3.2.8), while a complete re-analysis assuming no operator action prior to 20 minutes has not been performed, it has been determined that the outside steam line break accident (OSLB) is representative of that class of breaks where manual action, namely actuation of ADS, is required due to reactor isolation. As indicated in our response to Questions 211.9, and reconfirmed in our response to Question 211.90, for this bounding event operator action at 20 minutes after the break results in a calculated peak cladding temperature of < 1500°F.

QUESTION 211.106

Your response to 211.11 indicates that your ECCS pumps are designed to operate 100 days for any one accident during the 40 year plant lifetime. Provide information that demonstrates that your ECCS pumps will function for that time period as well as any maintenance assumed to occur during that time period.

RESPONSE:

GE operating experience of Ingersoll Rand (IR) ECCS pumps is as follows:

Hatch	RHR Pump	2A	864 hours
		2B	1112 hours
		2C	629 hours
		2D	569 hours
	LPCS Pump	2A	13.5 hours
		2B	11.8 hours
Chinshan 1	RHR Pump		100 hours
	Core Spray Pump		30 hours
Chinshan 2	RHR Pump		75 hours
	Core Spray Pump		20 hours

Maintenance was not required or performed during the running times listed above.

No problems have been reported on these pumps.

Based on our own limited operating experience and past operating experience of similar IR pumps in non-nuclear service, we feel confident that the Susquehanna ECCS pumps will operate as required.

QUESTION 211.107

Your break spectrum analysis is insufficient to allow an adequate evaluation. To confirm that a sufficient number of breaks have been analyzed to generate Figure 6.3-10, provide the tabulated values of peak cladding temperature (PCT) and break area used. Provide small break calculations of approximately 0.02 ft^2 and 1.0 ft^2 with an HPCI failure to verify that these break sizes remain non-limiting (see more complete curve in WPPSS-2 FSAR, Figure 6.3-13). Also, submit a large break model calculation for a 1.0 ft^2 break with HPCI failure to similarly verify that the worst break has been properly identified. Provide a discussion on why the 0.68 discharge DBA yields the limiting PCT for Susquehanna. The discussion should include transition boiling time, hot node uncovery time, rated core spray time, and reflood time. This discussion should also describe the trend in suction line breaks (i.e., does this trend also exist for smaller than the largest suction break area, with perhaps a smaller suction break yielding the highest PCT).

RESPONSE:

Table 211.107-1 shows the values of calculated PCT and break areas used to generate the small-break-model curves of Figure 6.3-10.

The results of the 0.02 ft^2 small break calculation with an HPCI failure are shown in Figure 6.3-10 and the back-up table. With regard to the 1.0 ft^2 break, as discussed in the response to Question 211.95, the HPCI failure is less limiting than the failure of a low-pressure ECC system for large breaks (approximately 1.0 ft^2 and greater) because the HPCI system injects coolant into the vessel for only a short period of time. Because the HPCI is not effective for large breaks, the HPCI failure case need not be analyzed. The HPCS failure is analyzed for large breaks on BWR/5's and BWR/6's because, unlike the turbine-driven HPCI system, the motor-driven HPCS system injects coolant into the vessel continuously and contributes significantly to core reflooding.

The 0.68 discharge DBA yields the limiting calculated PCT for Susquehanna due to characteristics such as (1) time of boiling transition, (2) hot node uncovery, (3) rated core spray time, and (4) reflooding time which is determined by the number and combination of available ECCS systems. The time of calculated boiling transition increases with decreasing break size since the jet pump suction uncovery (which leads to boiling transition) is determined primarily by break size. The calculated hot node uncovery time also increases with decreasing break size, as it is primarily determined by the inventory lost through the break during the blowdown. The later boiling transition time and uncovery time tend to make smaller breaks less limiting because more stored energy can be removed from the fuel during the blowdown period following the accident. The hot note reflooding time is determined by a number of interacting phenomenon such as depressurization rate, countercurrent flow limiting (CCFL), vessel inventory loss, and the combination of available ECCS.

The fewest ECC systems available for reflooding the vessel result in the longest reflooding times.

As shown in Table 6.3-5, the recirculation discharge break coupled with the LPCI injection valve failure results in the fewest ECC systems available to reflood the core. As the HPCI operates for a short period of time, only the two LPCS systems are left for reflooding.

The CCFL effect is a significant factor for determining reflooding time when core spray (CS) systems are utilized; calculated LPCI reflooding effectiveness is unaffected by CCFL.

Smaller breaks result in slower depressurization rates. The major effects of slower depressurization rate on reflooding are:

a) Smaller inventory depletion which results in earlier reflooding and hence a lower PCT.
b) Later low pressure ECC injection which results in later reflooding and later credit for core spray cooling and hence a higher PCT.
c) Less severe restriction of core spray downflow at the CCFL plane (upper tie plate) due to the higher pressure, which results in earlier reflooding and hence a lower PCT.
d) Longer periods of steam generation by flashing from the lower plenum, which results in more CCFL restriction and later reflooding.

Due to the complex interactions of the above, a detailed break search is performed to determine the break size resulting in the longest hot node uncovered time (see Figure 6.3-70); this time is the most significant factor in determining PCT. Other factors, such as time of rated core spray are of secondary importance.

As a result of this break search, the 0.68 discharge DBA was determined to be the most limiting break size. For this break size the combination of effects b) and d) were more dominant than effects a) and c), compared to the DBA or any other break.

The same phenomena discussed above for the discharge break are present in the break spectrum for the suction break (see Figure 6.3-71). For the suction break, however, two LPCI pumps are also available (see Table 6.3-5). Unhindered by the effects of CCFL, the LPCI rapidly refloods the vessel and this results in a shorter total uncovered time for smaller break sizes as demonstrated in Figure 6.3-71.

QUESTION 211.108

For BWR-4's with the LPCI modification (no loop selection logic) the potential exists for isolating a recirculation break with the core uncovered before the pressure has decreased sufficiently to permit the low pressure ECCS to enter the core. In particular, the single failure considered is an inadvertent closure of the recirculation suction valve with a break between the discharge and suction valves. Analyze the consequences of this failure for the Susquehanna ECCS.

RESPONSE:

The response to Question 211.16 discusses the consequences of this highly improbable event and demonstrates the inadvertent closure of the recirculation suction valve as a single failure as being less severe than the maximum Appendix K case.

QUESTION 211.109

Provide the missing footnote on Table 6.3-3.

RESPONSE:

The reference to footnote (3) is no longer applicable to Table 6.3-3, and is being deleted.

See revised Table 6.3-3.

QUESTION 211.110

Correct Figure 15A.6-31, "Protection Sequences Main Turbine Trip--Without Bypass:"

(1) For the event to occur at <30% power, protection sequences should be the same as for generator trip without bypass as shown in Figure 15A.6-30.

(2) Delete HPCI that is connected with incident detection circuitry.

Also, confirm that subsequent to initial core cooling the sequence of operations to extended core cooling would be the same as shown in Figure 15A.6-26, "Protection Sequences for Loss of Main Condenser Vacuum."

RESPONSE:

The above corrections to Figure 15A.6-31 have been incorporated.

The protection sequence subsequent to initial core cooling to achieve extended core cooling would be the same as indicated on Figure 15A.6-26.

QUESTION 211.111

Per your response to Q211.19 regarding the analyses for generator load rejection and turbine trip transient, explain your statement that "... a loss of offsite power would improve the results of the above transient since the only additional effect would be a slow coastdown (in comparison to the RPT function) of the recirculation pumps," particularly since the RPT was intended to improve thermal margin.

RESPONSE:

The analysis for the response to Question 211.19 assumed, among others, a failure of the RPT function. With loss of offsite power, the recirculation pumps will be tripped at time 0 with a coastdown due to loss of power to the pumps. Obviously, this case is less severe than the transient shown in the response to Question 211.19 since the RPT is intended to improve thermal margin.

QUESTION 211.112

Since the reclassification of the generator and turbine trip without bypass transients has not been accepted by the staff and is still under generic review, reanalyze the above events for determination of the operating limit MCPR in which the results would not violate the safety limit MCPR of 1.06. Also, it is our position that the limiting transient be reanalyzed with the ODYN code.

RESPONSE:

Reanalyzes of potentially limiting pressurization transients with the ODYN[1] code have been accomplished, and results reported into Chapter 15. This includes turbine trip and generator load rejection transients without bypass analyzed as events of moderate frequency. None of these ODYN transients violate the safety limit MCPR of 1.06.

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1 NEDO-24154, Volume 1, 2, NEDE-24154-P, Volume 3, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors", dated October 1978. Submitted to NRC Attn.: O.D. Parr, 12/15/78, Letter from J.F. Quirk.

QUESTION 211.113

Modify NSOA drawings to include benefits of nonsafety-grade equipment which mitigate transients and accidents. Such equipment includes relief valves, turbine bypass valves, and vessel level (high) trip.

RESPONSE:

Each transient and accident discussed in Chapter 15 corresponds to one protection sequence of an event in Appendix 15A. The NSOA drawings (protection sequences) are consistent with the analytical bases of 15A.3 and the measures of safety (unacceptable results) of 15A.2.7, and are primarily directed at system level response requirements. Certain Chapter 15 events assume, following the initiating single-failure, the normal operation of some non-safety-grade equipment functions; these instances are identifiable from the text.

QUESTION 211.114

During recent meeting with General Electric the staff has discussed the use of nonsafety-grade equipment for anticipated transient analyses. It is our understanding that one of the more limiting events is the feedwater controller failure (maximum flow demand). For this transient, the plant operating equipment that have a significant role in mitigating this event are the turbine bypass system and the reactor vessel high water level (Level 8) trip that closes the turbine stop valves. To assure an acceptable level of performance, it is the staff's position that this equipment be identified in the plant Technical Specifications with regard to availability, set points, and surveillance testing. Submit your plan for implementing this requirement along with any system modifications that may be required to fulfill the requirements.

RESPONSE:

In discussions between GE and the NRC on November 20 and 21, 1978, GE reported on the results of transient analysis when performed to design basis accident conditions assumptions, and equipment availabilities, that failure to give credit to the Level 8 Turbine Trip and the Main Turbine By-Pass system could respectively result in CPR's of 0.02 and 0.08. In no manner could these postulated accident events result in unacceptable impacts on the health and safety of the public as GDC criteria #29 requires.

Level 8 Technical Specification

The Level 8 instrumentation is already subject to technical specifications requirements associated with the HPCI. Such a requirement can be accommodated by the present design.

Main Turbine By-Pass System Technical Specification

The turbine bypass system and stop valves Technical Specification are provided in Chapter 16.

QUESTION 211.115

With regard to your response to Q211.24, you state that the limiting pump trip is assumed in analyzing decrease in reactor coolant system flow rate transients. Identify what trip signal (e.g., RPT on turbine control valve fast closure or stop valve closure; reactor vessel water level L2 set point, motor branch circuit over-current protection, etc.) can be expected to produce the most severe pump coastdown.

RESPONSE

The limiting pump trip is assumed in analyzing decrease in reactor coolant system flow rate transients. The trip of the electrical breaker at pump motor, along with minimum specified pump inertia time constant assumed in the analysis leads to the most limiting pump trip transient. Examples of this type of trip are RPT on turbine stop/control valve fast closure and water level L2 trip.

QUESTION 211.116

It is not evident that the assumed drop of 100°F in feedwater temperature gives a conservative result of this transient with manual recirculation flow control. For example, a feedwater temperature drop of about 150°F occurred at one domestic BWR resulting from a single electrical component failure. The electrical equipment malfunction (circuit break-trip of a motor control center) caused a complete loss of all feedwater heating due to total loss of extraction steam. Accordingly, either (1) submit a sufficiently detailed failure modes and effects analysis FMEA) to demonstrate the adequacy of a 100°F feedwater temperature reduction relative to single electrical malfunctions or (2) submit calculations using a limiting FW temperature drop which clearly bounds current operating experience.

Also, temperature drops of less than 100°F can occur and involve more realistic slow changes with time. Assuming all combinations result in slow transients with the surface heat flux in equilibrium with the neutron flux at the occurrence of scram, a smaller temperature drop than 100°F that still causes scram could result in a larger ΔCPR. Please evaluate this transient and justify that the assumed values of the magnitude and time rate of change in the feedwater temperature are conservative.

RESPONSE:

No single electrical component failure will cause the loss of more than one train of feedwater heaters as separate power sources are supplied to each of the feedwater control panels. Each feedwater heater train consists of five (5) feedwater heaters plus a drain cooler. SSES does not have a feedwater heater train bypass line.

The GE feedwater heater system design specification requires that the maximum temperature decrease which can be caused by bypassing feedwater heater(s) by a simple valve operation will be less than or equal to 100°F. This is the basis of the assumed drop of 100°F in feedwater temperature in the analysis. Loss of one (1) feedwater heater train at SSES will actually result in significantly less than a 100°F temperature drop.

It should be pointed out that a steady state (i.e., the surface heat flux in equilibrium with the neutron flux) is assumed in determining the MCPR during the transient. Therefore, a temperature loss smaller than 100°F is not expected to result in any more severe a transient than that analyzed.

QUESTION 211.117

Closure times from partially open to fully closed position are not addressed in the FSAR. For full-stroke closure, the assumed closure time would appear to be conservative in terms of the supplied information. However, for operation in the full arc (full throttling) mode, the closure times may be significantly less than 0.150 second for typical cases where the control valves are only partially open. With respect to this transient, there are two concerns. The first concern is that minimum closure times for part-stroke may be less than those assumed in the analysis. The second concern is that the analysis, which is based on 105% NBR steam flow and valves wide open initial conditions, may give a less conservative result than an initial condition at a somewhat lower power with control valves partially open as expected. Demonstrate that control valve closure times smaller than 0.150 second do not result in unacceptable increases in MCPR and reactor peak pressure or provide either (1) justification that smaller closure times cannot occur or (2) a minimum closure time to be incorporated in the Technical Specifications.

RESPONSE:

The generator load rejection transient discussion in Subsection 15.2.2 is presented on a worse case basis. For this reason it is assumed that the turbine control valves are operated in the full arc mode rather than in the partial arc mode. In the full arc mode the turbine control valves are all partially open. The closure times are assumed to be a conservative .07 second. By utilizing this closure time and the 105% NBR steam flow we are evaluating the worst case. The transient performed in that manner provides a bounding case analysis in which the partial arc response will be less severe. Tables 15.2-1 and 15.2-2 have been revised to reflect the 0.07 second closure time used in the analyses.

To establish a steam flow of 105% NBR there has to be a minimum flow area. In order to attain smaller closure times the control valves would have to be closed further. This would reduce the steam flow, thus reducing the severity of the transient. The 0.07 second closure time is the most conservative closure time which still permits the maintenance of a 105% NBR steam flow.

QUESTION 211.118

For the loss of feedwater heating transient in the manual flow control mode the thermal power monitor (TPM) is used to scram the reactor. Explain the need for the TPM and provide specific transients for which this trip signal initiates scram. Discuss how surveillance testing of the TPM is incorporated in the station technical specifications.

RESPONSE:

The Susquehanna SES plant does not have the thermal power monitor, and hence, was not included in the analysis. See Subsection 15.1.1.3.3 of the FSAR.

QUESTION 211.119

For the recirc flow control failure with increasing flow transient (Section 15.4.5) provide the initial operating MCPR determined at 65% NB rated power and 50% core flow. In addition, provide the K_f factors as a function of core flow for the automatic and manual flow control modes of operation. Furthermore, provide the maximum flow control set point calibration limit (e.g., 100% or 105% of rated flow) for the recirc loop flow control valves used in the transient analysis.

Provide recirculation pump M-G set points for the manual flow control mode assumed in the analysis. Also, you reference the GE topical report NEDO-10802 as the dynamic model to simulate this event. Since NEDO-10802 does not describe the complete event, discuss in greater detail the overall method used to calculate the CPR.

RESPONSE:

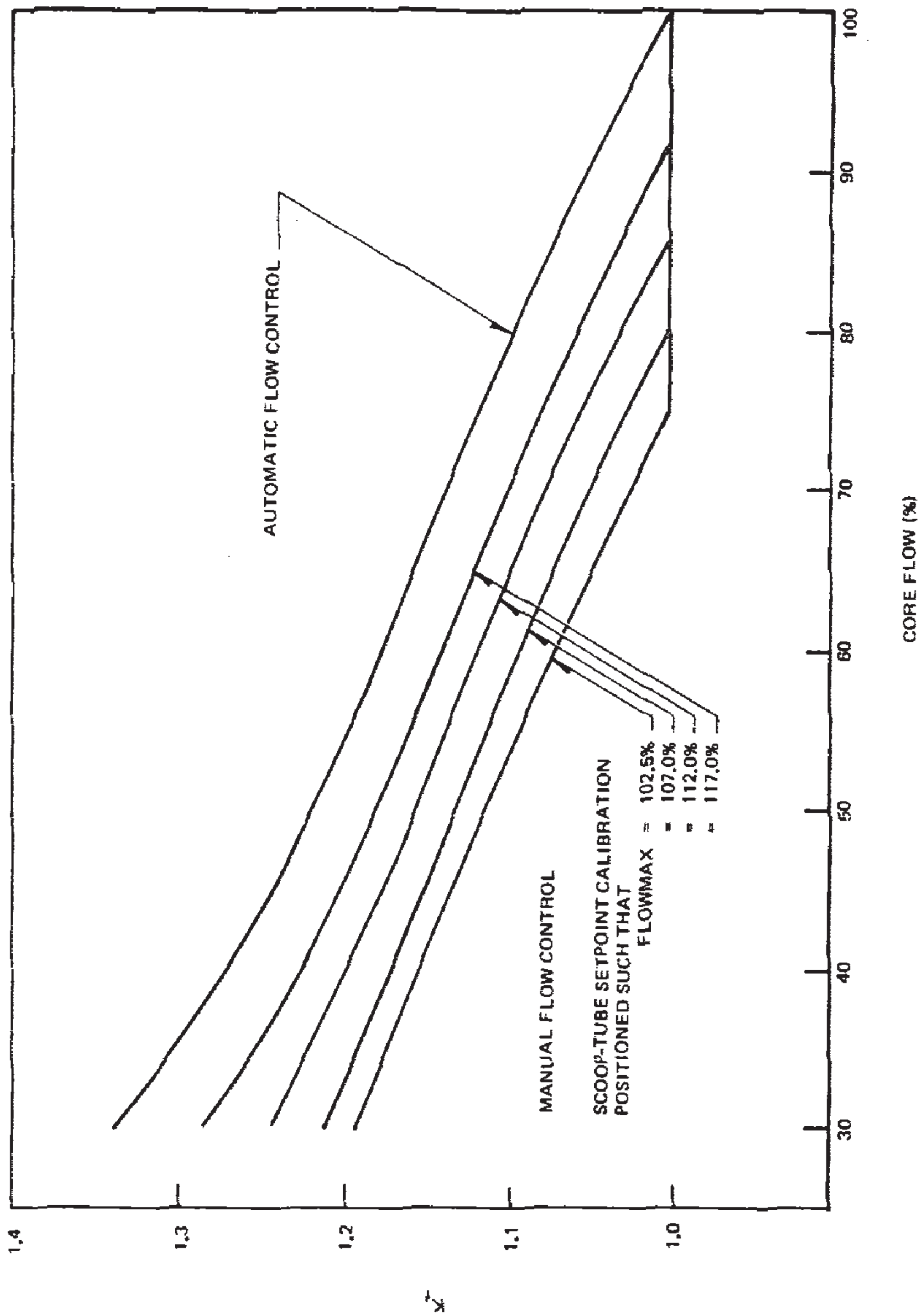
The initial operating MCPR at 65% nuclear boiler rated power (initial core, before power uprate) and 50% core flow was 1.23, assuming slow runout to 102.5% of rated flow.

A plot of K_f factors versus core flow is shown on Figure 211.119-1. Note that the M-G set points for the manual flow control mode are shown on the figure; because flow control is provided by M-G sets there are no flow control valves and thus no flow control set points.

The overall method used to calculate the ΔCPR for recirculation pump runout is as follows:

1) The hot channel is set on the MCPR safety limit at the pump runout value (e.g. 102.5%) on the 105% steam flow power-flow line by appropriately changing the radial power distribution.

2) Using the same power distribution, MCPR's are evaluated all along the 105% power-flow line. These MCPR's represent the limits for each particular off-rated condition. Slow runout (i.e. steady-state analysis) is assumed in this calculation since it is conservative with respect to fast runout.



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PLOT OF K_f FACTORS
VS.
CORE FLOW FOR THE
AUTOMATIC AND MANUAL
FLOW CONTROL MODES

FIGURE 211.119-1, Rev 47

AutoCAD: Figure Fsar 211_119_1.dwg

QUESTION 211.120

For the recirculation pump seizure accident we note in Table 15.3-3 that credit is taken for nonsafety-grade equipment to terminate this event. Section 15.3.3 of the Standard Review Plan, Revision 1, requires use of only safety-grade equipment and that the safety functions be accomplished assuming the worst single failure of an active component.

Reevaluate this accident with the above specific criteria, and provide the resulting CPR and percentage of fuel rods in boiling transition.

RESPONSE:

The recirculation pump seizure event, assuming the operation of specific non-safety grade equipment, has a mild impact in relation to the design-basis double-ended recirculation line break in Sections 6.3 and 15.6. Failure of such equipment would not make the core performance and/or radiological consequences of this highly improbable pump seizure (rapid core flow decrease) event more limiting than the maximum DBA-LOCA addressed in the FSAR. Therefore, no additional evaluations are considered necessary. The FSAR text has been revised regarding frequency classification by deleting references to infrequent incident classification in Subsections 15.3.3.1.2 and 15.3.4.1.2, recirculation pump seizure and recirculation pump shaft break respectively.

QUESTION 211.121

With a sudden increase in feedwater flow, there will be a drop in the feedwater temperature which contributes to the reactivity increase during the first part of the transient. For example, the combination of feedwater temperature drop and a smaller maximum flow rate could lead to a level 8 trip with the surface heat flux close to the flux scram set point. If the feedwater temperature at the reactor vessel has been assumed constant, the transient should be analyzed to include the effect of this temperature variation on MCPR. The basis for determining the time variation in FW temperature at the reactor vessel should be provided. Also show that a smaller increase in feedwater flow rate in conjunction with the change in feedwater temperature does not give a lower MCPR.

RESPONSE:

It is true that there will be a drop in the feedwater temperature with an increase in feedwater flow. However, the feedwater heater usually has a large time constant (in minutes, not in seconds). So the feedwater temperature change is very slow.

In addition, there is a long transport delay time before the cold feedwater reaches the vessel. Therefore, it is expected that the feedwater temperature change during the first part of the feedwater controller failure (maximum demand) transient is insignificant, and its effect on the transient severity is minimal so a smaller increase in feedwater flow rate does not give a lower MCPR.

QUESTION 211.122

Figure 15.5-1 (Inadvertent startup of HPCI) is inconsistent with the text described in Section 15.5.1.3.3. For example, the figure shows no change in drive and core inlet flow after 20 seconds when the turbine is tripped nor are there any changes shown for such parameters as steam line pressure rise and bypass flow. Please correct these inconsistencies. Also, based on the text, the sequence of events shown in Table 15.5-1 in incomplete. Finally, the assumption that the HPCI temperature is 40°F does not appear to be conservative if the text description of the course of this transient is correct. A higher HPCI temperature could result in a level 8 trip of the turbine at neutron flux just below scram set point, with a resultant lower MCPR than that obtained using the 40°F value. Provide a reanalysis using more conservative temperatures or justify present results.

RESPONSE:

The text previously described in Subsection 15.5.1.3.3 was incorrect. Contrary to the text, the APRM scram setpoint is not reached at approximately 16 seconds, and the high level trip setpoint is not reached at approximately 20 seconds initiating turbine trip and the trip of the recirculation and feedwater pumps. The Neutron Flux reaches a peak of only 118.2% NBR, and the water level remains considerably below the L8 setpoint. Higher temperatures are not expected to lead to L8 trip, and actually result in lower increase in heat flux. Studies show that using 40°F temperature is conservative for this transient.

See revised Subsection 15.5.1.3.3.

QUESTION 211.123

In the analysis of inadvertent opening of a safety/relief valve, it is stated that a plant shutdown should be initiated if the valve cannot be closed. How much time does the operator have to initiate plant shutdown before exceeding Technical Specification limits for suppression pool temperature?

RESPONSE:

The following discussion, combined with revised pages 15.1-14 and 15.1-15 and Table 15.1-5, comprise the response to the above question.

Prior to the initiation of the postulated stuck-open safety/relief valve event, the operator would receive an alarm indicating an open (or leaking) valve from thermocouples in the relief valve discharge line, and another alarm when the suppression pool temperature rose to 95°F. At an anticipated Technical Specification limit of 110°F, the operator will receive a second alarm and will be required to scram the plant. The scram is a procedural requirement based on Technical Specification limits. The technical specification limits are reached assuming maximum pool operating temperature, minimum pool operating volume, and no pool cooling systems in operation when the valve first opens, the time for the suppression pool temperature to increase from the design basis 90°F (max.) to the 110°F level is conservatively calculated to be more than nine (9) minutes. Assuming inaction until 10 minutes, the resultant pool temperature would increase by 4°F. This is well below the upper limit pool temperature of 200°F, which is the safety limit.

QUESTION 211.124

The transient analysis for loss of all grid connections shows main steam line isolation valve (MSIV) closure at 36.8 seconds, due to loss of condenser vacuum. A concern is that the MSIV's may close at an earlier time in the transient and result in higher system pressures. Apparently, credit is taken for MSIV air accumulator operation since the normal air supply to the MSIV's would trip at the start of this transient. Discuss design provisions and verification testing which demonstrate that MSIV performance is qualified to the extent assumed in the analysis.

Related to the same potential for faster MSIV closures, is the design such that a loss of all grid connections may result in an isolation signal which would close the MSIV's? What sources of electrical power are used for MSIV isolation logic and isolation actuators? Would these sources of power be available following a loss of all grid connections? Do the logic and actuators fail safe to cause an MSIV isolation signal on loss of electrical power?

RESPONSE:

The transient analyses of Loss of All Grid Connections and Loss of Auxiliary Power Transformer transients have been revised. The following discussion is based on the updated information.

During the loss of all grid connections transient, the MSIV's start to close two seconds after loss of power. As load rejection is initiated at time zero, MSIV closure does not result in higher system pressures and has negligible effect on the transient. Verification testing which demonstrates the assumed MSIV performance is accomplished during start-up (see Chapter 14).

Susquehanna had no direct isolation signal due to loss of all grids; the MSIV's do close, however, because of loss of all electric power to the fail-safe MSIV logics and actuators. Power sources used for MSIV logics and actuators as follows:

1) Inboard valves logic and AC Pilot Solenoid, 120 V, 60 Hz RPS Bus "A."
2) Inboard valves DC Pilot Solenoid, 125 V, DC Bus "A."
3) Outboard valves logic and AC Pilot Solenoid, 120 V, 60 Hz RPS Bus "B."
4) Outboard valves DC Pilot Solenoid, 125 V, DC Bus "B."

On loss of electrical power they de-energize and cause closure of the MSIV's.

The isolation signal due to loss of condenser vacuum at about 28 seconds after the loss of power becomes irrelevant because the MSIV's have closed earlier, as described above.

QUESTION 211.125

Operation of Susquehanna with partial feedwater heating might occur during maintenance or as a result of a decision to operate with lower feedwater temperature near end of cycle. Justify that this mode of operation will not result in (1) greater maximum reactor vessel pressures than those obtained with the assumption used in Section 5.2.2, or (2) a more limiting ΔMCPR than would be obtained with the assumptions used in Section 15.0. The basis for the maximum reduction in feedwater heating considered in the response should be provided (e.g., specific turbine operational limitations).

RESPONSE:

Lower feedwater temperature increases the core intel subcooling and results in a corresponding decrease in both the core average void fraction and the steam production. The feedwater temperature of 250°F is considered as the lower limit based on the conclusion that plants with improved interference fit spargers can be run in this mode (250°F FFWT) without adverse consequences. Typically, the core average void fraction is reduced by ~ 16% when the feedwater temperature is reduced from 420°F to 250°F. The lower steam production rate reduces the peak pressures which occur during a transient (Table 211.125).

The use of feedwater temperature reduction to extend the cycle beyond normal EOC is not expected to result in more severe transients. The lower void fraction (~ 16% lower at 250°F FFWT) reduces the dynamic void coefficient and the severity of the transient (i.e., the Δ CPR due to the transient) is less. Table 211.125 provides the typical ΔCPR numbers for two transients analyzed. Although the scram reactivity response is somewhat degraded due to the less bottom peaked power shape, the overall response is dominated by the void feedback effects and the resulting transient is less severe. Reducing the feedwater temperature before EOC will not result in more severe plant transient either. The peak pressures will be less due to the reduced steam production. The Δ CPR will be less due to the smaller void coefficient. Due to the presence of a significant number of control rods inserted into the core for this condition, the scram response is not appreciably affected by the feedwater temperature reduction. In addition, the transient response at points in the cycle other than EOC is consistently less than EOC.

If operation in the reduced feedwater temperature mode is utilized, prior to operation an analyses will be performed to show this mode of operation will not violate MCPR safety limits, given the events in Chapter 15.

TABLE 211.125-1 TRANSIENT ANALYSIS RESULTS*				
REACTOR CYCLE	TRANSIENT	EXPOSURE POINT	PEAK VESSEL PRESSURE	ΔCPR
BWR4 251-764 Equil. cycle	Load rejection w/o bypass	Rated EOC (104.2% power)	1235	.17
	(Reduced Feedwater Heating)	Extended EOC (100% power)	1219	0.16
	Feedwater Controller failure	Rated EOC (104.2% power)	1202	0.12
	(Reduced Feedwater) Heating	Extended EOC (100% power)	1060	0.05
* ODYN ANALYSIS RESULTS				

TABLE 211.125-1 TRANSIENT ANALYSIS RESULTS*				
REACTOR CYCLE	TRANSIENT	EXPOSURE POINT	PEAK VESSEL PRESSURE	ΔCPR
BWR4 251-764 Equil. cycle	Load rejection w/o bypass	Rated EOC (104.2% power)	1235	.17
	(Reduced Feedwater Heating)	Extended EOC (100% power)	1219	0.16
	Feedwater Controller failure	Rated EOC (104.2% power)	1202	0.12
	(Reduced Feedwater) Heating	Extended EOC (100% power)	1060	0.05
* ODYN ANALYSIS RESULTS				

QUESTION 211.126

Since systems such as the HPCI and RCIC are initially aligned to the condensate storage tank (CST) and switch to the suppression pool on low water level in the CST, the CST water level should be included in Table 7.5-1, entitled "Safety Related Display Instrumentation," add the above for display in Table 7.5-1 or justify its omission.

RESPONSE:

Systems such as the HPCI and RCIC are initially aligned to the condensate storage tank (CST) and automatically switch to the suppression pool on low water level in the CST. The switch from the suppression pool to the CST on high suppression pool level is automatic for HPCI, but is manual for RCIC. The CST water level should not be included in Table 7.5-1, entitled "Safety Related Display Instrumentation" because the important safety parameter is the HPCI flow or the RCIC flow. Only important parameters, such as flow, are included in Table 7.5-1.

QUESTION 211.127

For the safety-related display instrumentation shown in Table 7.5-1, identify which parameters serve a post-accident tracking or monitoring function.

RESPONSE:

Safety-related display instrumentation shown in Table 7.5-1 which serve a post-accident tracking or monitoring function are described in Subsections 7.5.1a.4.2.1 thru 7.5.1a.4.2.4.

QUESTION 211.128

In Table 7.5-1 you identify the range of the reactor vessel pressure to be from 0 to 1500 psig. Since the design pressure is 1250 psig, justify the upper bound of the instrumentation range when considering potential accidents that may cause large pressure excursions (i.e., ATWS).

RESPONSE:

The reactor pressure instrument range of 0 to 1500 psig is prudent for this device. This range envelopes the anticipated pressure transients while providing adequate resolution at mid-instrument range for normal operating conditions.

QUESTION 211.129

Display instrumentation for the condensate storage tank level should be provided on the remote shutdown control panel. Secondly, you state that the RHR flow indicator will be located on the remote shutdown panel. Verify that flow indication will be provided for both RHR systems (A and B), and that the flow range will be the same as that shown in Table 7.5-1.

RESPONSE:

For response, see revised Subsections 7.4.1.4.2.2 and 7.4.1.4.2.3, as well as revised Table 7.4-3.

QUESTION 211.130

Table 7.4-3 identified certain valves actuated by the transfer switches. Why are recirculation suction valves F023B and F023A actuated closed? What is the status of the remaining recirculation suction valves? Discuss when the closure of these valves would be initiated and clarify why valve "A" is closed in Unit 2 while valve "B" is closed in Unit 1.

Relate the above discussion to the potential for pump cavitation.

RESPONSE:

For response, see revised Subsections 7.4.1.4.2.2 and 7.4.1.4.2.3, and revised Table 7.4-3.

QUESTION 211.131

Per Section 7.4.1.4.3, transfer switches on the remote shutdown panel are operated to transfer control to the remote shutdown panel. Provide a list of valves in the nuclear boiler, RHR, and RCIC systems, if any, that would be actuated to the "safe condition" by a signal from the transfer switches.

RESPONSE:

For response, see revised Subsections 7.4.1.4.2.2. and 7.4.1.4.2.3, and revised Table 7.4-3.

QUESTION 211.132

Add to Table 3.11-3* the Control Rod Hydraulic System (portions of system necessary for scram) and its component operability under abnormal environmental conditions. Clarify whether the RHR steam isolation valves are included in item 4 of Table 3.11-3. Also, provide the basis for selecting an abnormal temperature of 148°F for component operability.

RESPONSE:

Condition 5, which is applicable to portions of the Control Rod Hydraulic System necessary for scram, has been added to Table 3.11-3*.

RHR steam isolation valves are not included in item 4 of Table 3.11-3*.

The 148°F (65°C) temperature is a standard NEMA Power House Grade environment. Equipment is, therefore, available without special design.

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* Section 3.11 has been rewritten since the original response to this question, and Table 3.11-3 has been eliminated.

QUESTION 211.133

The following questions pertain to our review of Table 3.9-1 which shows the number of plant cycles (events) considered for reactor assembly design and fatigue analysis.

(1) Explain the events in Item 9 and relate to the transients analyzed in Chapter 15.0. Also, provide the number of cycles for safety or relief valve blowdown.

(2) In Table 3.9-1, item 16b is the indicated automatic blowdown feature related to the ADS function:

(3) Explain event item 15a and relate to Chapter 15.0 or Section 5.2.2 analyses. Justify omission of a reactor overpressure with flux scram and isolation valves stay closed under "Emergency Conditions."

RESPONSE:

(1) The scram events listed occur from various causes as follows:

Turbine Generator Trip, Feedwater On, Isolation Valves Stay Open - 40 Events

These events correspond to the "Generator Load Rejection - Turbine Control Valve (TCV) Fast Closure" and "Turbine Trip" described in Chapter 15, Section 15.2, without other failures assumed, such as bypass failure. The same condition with bypass failure is included with the Loss of Feedwater Pump scram events.

Other Scrams - 140 Events

These scram events are caused by conditions other than rapid turbine admission or main steam isolation valve closures at full power. Other scram causes include low reactor water level and reactor protection system trips, some of which result from the remaining accidents discussed in Chapter 15.

There are 8 single relief valve or safety valve blowdown events which completely depressurize the reactor due to failure of a safety, relief, or turbine bypass valve to reclose automatically after pressure has dropped below its design setting. The 8 events do not include the large number of valve actuations which are expected to occur where the valves function normally without completely depressurizing the reactor.

(2) See revised Table 3.9-1. The automatic blowdown feature indicated in 16.b is related to ADS. It assumes a complete reactor depressurization due to unintended operation of the ADS system or an assumed failure of several safety or relief valves to reclose automatically at their reset pressure.

(3) The "Reactor Overpressure with Delayed Scram" event assumes closure of main turbine admission valves assuming that scram is delayed so that power and pressure are initially limited by safety valve operation and reactor recirculation pump tripoff. A similar condition is discussed under the study of the "Anticipated Transient Without Scram" (ATWS) event in Chapter 15, Section 15.8. This delayed scram event results in more severe pressure and power transient conditions than a "Flux Scram with Isolation Valve Closure" which is covered under the "Loss of Feed Pump, Isolation Valves Closed" event of Table 3.9-1, Item 16c.

QUESTION 211.134

In Table 15.0-2, item 32, provide the correct units (or value) for recirculation pump trip inertia for transient analysis.

RESPONSE:

The correct unit for recirculation pump trip inertia time constant is "seconds". Refer to Table 15.0-2.

QUESTION 211.135

In Table 15.0-2, item 28, you show the high flux trip set point of 120% as an input value for transient analysis. Justify for not using 122% instead of 120% set point which accounts for calibration error, instrument accuracy, and transient overshoot as shown in Table 7.2-4.

RESPONSE:

Instrument trip setpoints are in the Technical Specifications and consistent with the plant's safety analyses. The safety analysis is performed using justified conservative setpoints that include provision for instrument errors and transient overshoots. The information in Table 7.2-4 was preliminary, and the table is being deleted from the FSAR since the appropriate information is part of the Technical Specifications for Susquehanna.

QUESTION 211.136

Provide a realistic range and permitted operation band for the exposure dependent parameters in Tables 4.4-1 and 15.0-2. In Table 15.0-2, provide assurance that values of parameters selected yield the most conservative results.

RESPONSE:

None of the thermal and hydraulic design characteristics shown in Table 4.4-1 are exposure dependent. Instead, they reflect the rated power and flow limits which characterize the core design.

In Table 15.0-2, the only exposure dependent parameters are the doppler coefficient, the void coefficient, and the scram reactivity. If the parameter is assumed not to vary during exposure, the value is assumed to be constant. While doppler and void reactivity effects impact transient performance, the scram reactivity dominates the transient response. Transient performance evaluations are not performed utilizing the worst combination of void, doppler, and scram characteristics. Instead, to provide assurance that the transient evaluations yield the most conservative results, the evaluations are performed at core exposure conditions expected to occur with the worst scram reactivity characteristic. The minimum scram reactivity for projected operation in BWR's occurs at the end of cycle exposure point, when the control rods are completely withdrawn from the core at rated power/flow conditions.

The scram reactivity characteristic varies slightly with exposure, but is most strongly affected by the core power distribution and the associated control rod configuration prior to a scram. The scram reactivity of Curve 2 in Figure 15.0-2 presents a conservative but realistic lower bound on the minimum scram reactivity for Susquehanna, and also defines the minimum scram characteristic for permitted operation.

The doppler coefficient varies slowly with exposure and is expected to be valued from -.1483 to -.2358 cents/°F during rated power operation. There is no defined operation band for this parameter. The void coefficient varies slightly with exposure and is expected to fall in the range of -6.32 to -9.07 cents/% (rated voids). Except for requiring that the void coefficient is negative, there is no defined operation band for this parameter.

QUESTION 211.137

Uncertainty exists on the correct value of APRM neutron flux scram setpoint to be used in transient analyses. The value indicated as input for transient analysis in Table 15.0-2 is 125% NBR. However, a value of 120% NBR is indicated in Table 7.2-4 and 7.6-5. Explain this discrepancy. For the correct value of setpoint used in transient analyses, provide a breakdown of any uncertainty allowances that are added to the nominal value.

RESPONSE:

The discrepancy of the APRM scram setpoint arises because of the conservatism allowed for the transient analysis. The scram setpoint is 120% of NBR thermal power. The analyses assume the plant is operating at 104.4% of NBR thermal power for conservatism. Therefore, the APRM neutron flux scram setpoint is 125% NBR (104.4 x 120%).

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QUESTION 211.138

Provide a listing of the transients and accidents in Chapter 15 for which operator action is required in order to mitigate the consequences. In the Chapter 15 time sequence of events or NSOA tables, provide the times of, and manual actions or automatic system changes that are required to place the plant in the final stabilized condition (cold shutdown).

RESPONSE:

For Loss of Coolant Accident (LOCA) events inside the containment, all short term (t = 0 through 10 minutes) safety functions are automatically initiated and controlled. All the necessary NSSS-ESF systems would continue to provide long term (t = 10 minutes to 30 days) automatic safety action. Thus, no operator actions are required for these cases to provide for adequate core cooling. Extended long term NSSS-ESF manual actions would be centered around RHRS-shutdown cooling aspects.

For LOCA's outside the primary containment, operator action is required to provide short term core cooling under the severely degraded conditions assumed in the LOCA analysis. Operator action is required for these breaks because there will be no high drywell pressure signal to activate the automatic depressurization system (ADS). Given LOCA analysis assumptions, no credit is taken for the feedwater system and the reactor core isolation cooling (RCIC) system. Also, the high-pressure coolant injection (HPCI) system is assumed to fail (worst single failure). With no credit for the above systems, the operator must manually initiate the ADS to depressurize the vessel below the shutoff head of the low-pressure ECC systems, allowing these systems to terminate the transient. Once the operator initiates the ADS, no further operator actions other than those previously identified for a LOCA inside the containment are required to provide long term cooling. As shown in response to 211.90, the operator has at least 20 minutes to manually depressurize via ADS to assure you result in acceptable consequences.

For anticipated operational transient events, no operator action is assumed in less than 10 minutes to mitigate the consequences of the mode. Most events involve automatic process control systems (e.g., feedwater or pressure controls which are usually in operation). Some events allow operator manual control adjustments (e.g., control rod insertion) prior to an automatic protection action. But in no case will the failure or error of the operator manual action negate any protection function or cause a radiological safety problem. Operator actions may improve the course of a transient, but no credit is taken (ahead of 10 minutes) in the current safety evaluation analyses.

However, control of the suppression pool thermal response inevitably relies on positive operator action. Failure of the operator to adjust the RHRS to a water/water heat removal mode will result in suppression pool overheating which has no automatic control. In summary, operator action is not required to maintain core cooling capability, but is required to control containment overheating.

QUESTION 211.139

The response to question 211.113 does not provide sufficient detail on non-safety grade equipment and components which mitigate transients and accidents. Provide a table of the non-safety grade equipment and components assumed to mitigate consequences for each transient and accident in Chapter 15. For those events where non-safety grade systems are used; provide the change in consequences or results when taking credit for safety grade equipment only.

RESPONSE:

The use of non-safety grade equipment for transient analysis was an issue which was addressed in detail by the Licensing Review Group. To enhance interim evaluation a description of the role of non-safety grade equipment is included here. Table 211.139-1 highlights transients which utilize non-safety grade equipment.

It is important to note that the analysis for each of the transients in Table 211.139-1 is based on the single-failure criterion associated with moderate frequency events (i.e., abnormal transients are defined as events which occur as a result of equipment malfunctions as a result of a single active component failure or operator error). Following this single failure, the resulting transient is simulated in a conservative fashion to show the response of primary system variables and how the various plant systems would interact and function. In these transients, the consideration of any additional failures is not considered appropriate within the realm of the abnormal transient definition, but shifts them to infrequent events. Although certain transient events assume the operation of specific non-safety grade equipment to provide a realistic transient signature, failures of such equipment would not make these events more thermally or pressure limiting than the limiting accidents already addressed in the FSAR Chapters 5 and 15. In fact, many of the events which have a level 8 turbine trip (a non-safety grade trip) would be less severe if the level 8 trip were assumed not to function.

Failure of the relief valve function of the safety-relief system for any event will not result in a transient which exceeds the peak pressure response of the limiting event presented in Chapter 5.0. Failure of the level 8 turbine trip of failure of the bypass to open when the level 8 trip does occur were studied for a BWR similar to the Susquehanna design. The increase in CPR was about 0.02 for a delay in the turbine trip and 0.08 for failure of bypass. Although thermal margins are reduced, no significant (if any) fuel damage is expected.

The offsite doses (if any) would be negligible, and therefore no impact from a health and safety viewpoint. The loss of feedwater event is analytically about the same with or without the recirculation runback ahead of the level 2 trip. In summary, the thermal and pressure safety limits are not compromised by inclusion of the simulated response of non-safety grade systems.

Table Q211.139-1 shows which non-safety grade systems or components were assumed to actuate in the FSAR analysis.

TABLE 211.139-1

NON-SAFETY GRADE SYSTEMS/COMPONENTS ASSUMED IN FSAR ANALYSES
MODERATE FREQUENCY EVENTS

FSAR SECTION	TRANSIENT	NON-SAFETY GRADE SYSTEM OR COMPONENTS
15.1.2	Feedwater Controller Failure, Max Demand	Level 8 turbine and feedwater trip, Turbine bypass, Relief valves
15.1.3	Pressure Regulator Failure, Open	Relief valves
15.2.2	Load Rejection	Turbine bypass, Relief valves(1)
15.2.3	Turbine Trip	Turbine bypass, Relief valves(1)
15.2.4	Closure of all MSIV's	Relief valves
15.2.5	Loss of Condenser Vacuum	Turbine bypass, Relief valves
15.2.6	Loss of AC Power	Turbine bypass, Relief valves
15.2.7	Loss of all Feedwater Flow	Recirculation runback, (2) Relief valves
15.3.1	Trip of Both Recirculation Pumps	Level 8 turbine trip, turbine bypass, Relief valves
15.3.2	Recirculation Control Failure, Decreasing Flow	Level 8 turbine trip, turbine bypass, Relief valves
15.4.1	Rod withdrawal error-low Power	Rod Sequencing Control System (RSCS)
15.4.2	Rod Withdrawal error-at Power	Rod Block Monitor (RBM)
15.4.5	Recirculation Control Failure-Increasing Flow	Level 8 turbine trip, turbine bypass
	INFREQUENT EVENTS	
15.2.3	Turbine Trip w/o Bypass	Relief valves
15.2.2	Load Rejection w/o Bypass	Relief Valves

(1) Level 8 (high water level) trip potentially activated following the initial part of these events, but it is not a significant factor in fuel or vessel overpressure protection evaluation.

(2) Neglected in the analysis.

TABLE 211.139-1

NON-SAFETY GRADE SYSTEMS/COMPONENTS ASSUMED IN FSAR ANALYSES
MODERATE FREQUENCY EVENTS

FSAR SECTION	TRANSIENT	NON SAFETY GRADE SYSTEM OR COMPONENTS
15.1.2	Feedwater Controller Failure, Max Demand	Level 8 turbine and feedwater trip, Turbine bypass, Relief valves
15.1.3	Pressure Regulator Failure, Open	Relief valves
15.2.2	Load Rejection	Turbine bypass, Relief valves(1)
15.2.3	Turbine Trip	Turbine bypass, Relief valves(1)
15.2.4	Closure of all MSIV's	Relief valves
15.2.5	Loss of Condenser Vacuum	Turbine bypass, Relief valves
15.2.6	Loss of AC Power	Turbine bypass, Relief valves
15.2.7	Loss of all Feedwater Flow	Recirculation runback, (2) Relief valves
15.3.1	Trip of Both Recirculation Pumps	Level 8 turbine trip, turbine bypass, Relief valves
15.3.2	Recirculation Control Failure, Decreasing Flow	Level 8 turbine trip, turbine bypass, Relief valves
15.4.1	Rod withdrawal error-low Power	Rod Worth Minimizer
15.4.2	Rod withdrawal error-at Power	Rod Block Monitor (RBM)
15.4.5	Recirculating Control Failure-Increasing Flow	Level 8 turbine trip, turbine bypass
INFREQUENT EVENTS		
15.2.3	Turbine Trip w/o Bypass	Relief valves
15.2.2	Load Rejection w/o Bypass	Relief valves

(1) Level 8 (high water level) trip potentially activated following the initial part of these events, but it is not a significant factor in fuel or vessel overpressure protection evaluation.

(2) Neglected in the analysis.

QUESTION 211.140

The analysis of transients and accidents in Chapter 15.0 does not state which of the RPS time response delays in Table 7.2-5 is used in the REDY computer code model (NEDO-10802). For each transient and accident in Chapter 15.0, specify whether the sensor or overall delay time is used in the analysis and why the specified delay time is conservative.

RESPONSE:

In all Chapter 15 events, the maximum overall time delay is utilized for each scram encountered and reported in each event scenario. This allows for maximum specified sensor and logic delays.

QUESTION 211.141

Confirm the following items for all transients in Chapter 15.0 which require control rod insertion to prevent or lessen plant damage.

a) All calculations were performed with the conservative scram reactivity curve No. 2 in Figure 15.0-2.

b) The slowest allowable scram insertion speed was used.

RESPONSE:

The scram time characteristics shown in curve 2 of Figure 15.0-2 are derived from the Technical Specification scram time. The expected scram time is faster than what is used in the FSAR analysis. This scram reactivity characteristic is used in all total plant transient analyses that call for scram. Control rod motion events utilize unique, conservative scram shape appropriate for the situation, but also base their rate on the scram speed technical specification.

QUESTION 211.142

a) In Table 1 of Figure 5.1-3a (Nuclear Boiler), the relief valve spring set pressure at 1130 psig for safety/relief valves B and E does not agree with a corresponding value of 1146 psig in Table 5.2-2 of the FSAR and in Table 1 of Drawing M-141, Rev. 9. Correct this setpoint discrepancy for safety mode (mechanical) actuation.

b) For transient analysis, credit has been taken for safety/relief valve actuation in the relief mode. A more conservative approach would be to take credit for safety/relief valve actuation in the safety mode, resulting in higher peak vessel pressures.

   1) What effect on MCPR and peak vessel pressure does credit for safety/relief valve actuation in the safety mode have on transients analyzed in Chapter 15?

   2) Are all equipment and components required for safety/relief valve actuation in the relief mode safety grade?

RESPONSE:

a) The correct, up-to-date, set points for valves B and E are 1146 psig. See Table 1 of Dwg. M-141, Sh 2.

b) The relief action mode has appropriately been applied to Chapter 15 transient pressurization events. There is no previous or current requirement to assume simultaneous failure of these valves for the transient assessment. No detrimental effect on MCPR would be expected since it is dominated by the scram protection. Any increase in peak pressure is addressed by the bounding, worst ASME code case analysis presented in Chapter 5 and the Vessel Overpressure Protection Report.

   That analysis shows that completely acceptable overpressure protection is provided even for the worst cases when credit is only taken for accepted ASME valve operation.

   All equipment and components required for initial safety relief valve actuation in the relief mode are safety grade but not single failure proof. The overpressure protection analysis (in Section 5) only took credit for ASME code credited valve action, and showed the very significant protection margin even if a single additional failure is assumed.

QUESTION 211.143

Modify Table 15.0-1 as follows:

a) Give calculated values of MCPR instead of the entry 1.06.

b) For the "feedwater controller failure at maximum demand" transient, correct the discrepancy in values for maximum vessel pressure, maximum steam line pressure, and MCPR that exists between Table 15.0-1 and Section 15.1.2.3.3.

RESPONSE:

a) Where significant risk of approaching MCPR limits exists, specific calculations have been done and recorded in the table. Events such as 15.1-4 show virtually no power increase (or any other parameter change that challenges thermal margin) and they indeed are much greater than the 1.06 safety limit and need not be calculated. To provide assurance the safety limit is maintained for all transients where the MCPR entry is greater than 1.06, Table 15.0-1 has been modified. A threshold value of 1.10 will be used in place of 1.06. Comparison of "Maximum Neutron Flux" and "Maximum Core Average Surface Heat Flux" for all the transients (whose entry has changed) with the "Generator Load Rejection, Bypass-on" transient (15.2.2) shows we are being conservative with respect to the 1.10 MCPR value.

   The two exceptions are start of "Idle Recirculation Loop" and "Recirculation Flow Control Failure-Increasing Flow" transients. These transients, however, start at a lower power and hence have a much higher initial CPR value (1.48 and 1.40 respectively). The MCPR is expected to be greater than 1.10, because the increase of heat removal due to core flow increase (up to 130% of initial value) can accommodate the increase of the surface heat flux.

b) The peak pressure values given in Table 15.0-1 for event 15.1-2 are correct. The text in Subsection 15.1.2.3.3 has been corrected from 1110 to 1138 and 1128 to 1175. All values are psig. The MCPR in this case just reaches the 1.06 safety limit. Subsection 15.1.2.3.3 has been revised to state the MCPR just reaches 1.06.

QUESTION 211.144

For transients and accidents in Chapter 15 in which it is stated that the operator initiates some corrective action, provide justification for any corrective actions by the operator prior to 20 minutes.

RESPONSE:

Virtually all required protection is provided by automatic functions. Chapter 15 analyzes the transients and accidents to the point where the event has been mitigated. The sequence of events shows time frames of all automatic and operator actions required to mitigate those events. The design and protection basis for the few situations where operator action is involved is and has been the 10 minute period. We believe that lapse times of 10 minutes for those situations remains appropriate. The 10 versus 20-minute operator action time frame is being addressed under the post TMI concerns.

QUESTION 211.145

Discuss how the pre-operational and startup tests will be used to confirm flow parameters used in Chapter 15 analyses. Provide details of any previous test of components in test facilities conducted to show satisfactory performance of the recirculation and feedwater flow control systems and respective pumps. Describe how this information was used in Chapter 15 analyses.

RESPONSE:

Preoperational tests confirm proper erection and performance values for flow rate and pressure of the hydraulic subsystems. These tests also validate the control system function related to both automatic and manual valving of the hydraulic lines. Startup tests ST-30 (Recirculation System Test) and ST-23 (Feedwater System Test) confirm the transient responses of the recirculation system/feedwater system. Expected performance estimates are based on component development test results and on qualification performance tests for the safety-related pumps and valves. Actual plant instrumentation is first calibrated and then used in preoperational tests for flow measurements, pressure measurements, and as sensor inputs for control circuitry. Final performance is validated during the above cited startup tests.

QUESTION 211.146

Analyze the turbine trip and generator load rejection transient from a safe shutdown earthquake event. Credit should not be taken for non-seismically qualified equipment or any equipment contained in a non-seismic structure.

RESPONSE:

Use of seismically qualified equipment to provide protection in the postulated design basis accidents is considered adequate and bounding from the viewpoint of seismic impact.

In response to a similar NRC request on the Hatch 2 docket (Question 212.64), an analysis of the load rejection transient was performed assuming the following additional failures:

1. Failure of direct trip scram
2. Failure of recirculation pump trip (RPT)
3. Failure of bypass systems

A summary of results of this analysis for Hatch 2 is as follows:

Maximum vessel pressure (psig)	1245
Time of maximum pressure (seconds)	2.8
Minimum critical power ratio (MCPR)	0.89
Time of MCPR (seconds)	1.7
Rods in boiling transition (%)	6.7
Peak cladding temperature (°F)	1420
Peak value of fuel average temperature (°F)	1544

If the above transient were analyzed with a direct trip scram, the results would be bounded by the flux scram trip presented here.

It is not anticipated that any single active component failure, in addition to failures of the direct trip scram, RPT and the bypass system, would significantly increase the severity of this event due to its brief duration.

QUESTION 211.147

On page 4-7 of NEDO-10802, it is stated that the difference in trend of flow coastdown versus initial power between the analytical and experimental coastdown curves for Dresden Unit No. 2 (a BWR/3) in Figure 4-11 was due in part to differences between actual and computed jet pump efficiencies.

a) How has this effect been treated in analysis of SSES transients involving flow coastdown with two recirculation pump trip (RPT)?

b) Is this treatment applicable to Susquehanna which is a BWR/4? If so, explain how.

RESPONSE:

a) Simulation of the recirculation system is matched to the operating flow, etc. for the Susquehanna unit. The coastdown characteristic is simulated by the equations given in NEDO-10802, but conservative (rapid) flow reduction is simulated for the 1 and 2 RPT transient cases (using minimum specified inertia). In the turbine and generator trip events where the RPT is part of the protection sequence conservative (slow) flow reductions are simulated for the RPT characteristic using upper limits on inertia. The minor differences sometimes seen between coastdowns at various power levels are covered for the limiting, full power, full flow cases by this conservative approach.

b) No significant differences in recirculation system behavior is expected, nor has it been observed, between BWR/3 and BWR/4 plants.

QUESTION 211.148

For the "loss of feedwater heating" transient, the sequence of events in Table 15.1-2 for the limiting manual flow control mode is not described in sufficient detail to permit evaluation of transient results in Figure 15.1-2 and comparison with NSOA events in Figure 15A.6-21. No detail is presented in Table 15.1-2 between 2 and 40 plus seconds. Revise Table 15.1-2 to include NSOA events in Figure 15A.6-21 and additional detail between 2 and 40 plus seconds.

RESPONSE:

The sequence of events in Table 15.1-2 has been revised. The table reflects the fact that no scram is expected, and simple insertion of some rods will restore the plant to normal, planned operation. To address the concern expressed on 8/21/80 meeting by the NRC of why 100°F temperature loss is assumed instead of 150°F, the following is provided. The GE feedwater system design requirements are that the maximum temperature decrease which can be caused by bypassing feedwater heating by any equipment single failure or operator error be less than or equal to 100°F. An analysis, however, was performed for a BWR 5/Mark II in which a 150°F temperature loss was simulated. In this particular analysis, an APRM scram occurred approximately 2 seconds earlier for the 150°F loss case compared to the 100°F loss case. The peak thermal power was no higher and the minimum CPR value no lower. The results found are applicable to the Susquehanna design.

QUESTION 211.149

The thermal power monitor (TPM) is not included in the Susquehanna design per response to question 211.118. However, it is indicated as the primary protection system trip for mitigating the consequences of the "loss of feedwater heating" transient in Section 15.1.1.2.2. What was used to scram the reactor in the manual mode? Modify Figure 15A.6-21 and Sections 15.1.1.2.2. and 15.1.1.2.3 accordingly.

RESPONSE:

The "loss of feedwater heating" transient does not reach nor require scram for either the automatic or manual mode of flow control. Subsections 15.1.1.2.1.1, 15.1.1.2.2, 15.1.1.2.3 and Figure 15A.6-21 have been revised to be consistent with the design of the Susquehanna units.

QUESTION 211.150

This section states that input parameters and initial plant conditions for the "loss of feedwater heating" transient are in Table 15.0-1. This should be changed to Table 15.0-2 in this section and in the corresponding sections of the remaining transients in Chapter 15 where this discrepancy occurs.

RESPONSE:

Chapter 15.0 has been revised to correct this discrepancy.

QUESTION 211.151

Correct discrepancies between events in Table 15.1-3 and NSOA Figure 15A.6-22 for the "feedwater controller failure at maximum demand" transient. Table 15.1-3 does not include the initial core cooling and reactor vessel isolation events indicated in Figure 15A.6-22.

RESPONSE:

Table 15.1-3 has been modified to reflect vessel isolation and HPCI and RCIC utilization.

QUESTION 211.152

Explain the basis for the assumed feedwater flow controller failure at 135% flow. Is the indicated failure initiated at 0 seconds or does the failure begin at 0 seconds and increase to 135% flow at a later time. If the former is true, correct Figure 15.1-3 accordingly.

RESPONSE:

The feedwater controller failure event is initiated by assuming the plant to be running at steady state then failing the demand signal into the demand controller output limiter set at 135%. The feedwater responds by increasing flow as indicated in Figure 15.1-3. The increased flow increases water level until Level 8 trip is attained in near 10 sec. as stated in Table 15.1-3 and initiates the sequence of events indicated.

In most designs the feedwater system has 115 to 135% capacity. This event was run at 135% as being a conservative analysis. Smaller capacities or limits in the system would provide milder results.

QUESTION 211.153

Correct the inadvertent combination of Section 15.1.2.3.2, beginning on page 15.1-7, with Section 15.1.2.3.1.

RESPONSE:

The numbering sequence for Subsection 15.1.2.3 has been revised.

QUESTION 211.154

Provide justification that analysis of the "feedwater controller failure-maximum demand" transient at 105% NBR steam flow is more restrictive than at low power. If so, delete reference to "low power" for NSOA event No. 22 in Table 15A.2-2. If not, reanalyze and make appropriate corrections.

RESPONSE:

A feedwater controller failure-maximum demand at 105% NBR steam flow is more restrictive than at lower powers for two reasons:

1) The magnitude of the power rise decreases with lower initial power level. The cause of this is a pressurization event due to the turbine trip. The void content is proportional to the power level. Pressurization collapses the voids which in turn increases the power. Therefore, the magnitude of the power rise will decrease with a lower initial power.

2) The initial operating MCPR is higher with lower initial power level and core flow.

Table 15A.2-2 has been modified to delete the reference to "Low Power."

QUESTION 211.155

a) It is not apparent from the text whether the "pressure regulator failure-open" transient is terminated by a low turbine-inlet pressure trip or a L8 trip. Trips indicated in various sections of the text are summarized below:

Section	Trip
15.1.3.2.1.1	Low pressure at the turbine inlet
15.1.3.3.2	Low pressure at the turbine inlet
15.1.3.3.3	L8 trip
Table 15.1-4	Low pressure at the turbine inlet

Specify which trip is most restrictive on thermal margins and revise applicable tables, sections, and figures of the FSAR.

b) It appears that less than the assumed 115% NBR steam flow in Section 15.1.3.3.2 was simulated at the beginning of the transient in Figure 15.1-4. Explain this discrepancy and make corrections, if necessary.

c) Safety/relief valve (SRV) actuation for this transient in the relief mode is not included in Tables 15.0-1 and 15.1-4 and Figure 15.1-4 for decay heat removal. Please explain.

RESPONSE:

a) Low turbine inlet pressure closure of the MSIV's is correct. Sections 15.1.3.3.3, 15.1.3.3.4 and Table 15.1-4 have been modified.

b) The regulator is failed to a demand signal 15% beyond that which gives 100% NBR steam flow to the turbine generator. The logic opens the bypass valves in addition to the turbine control valves and allows a small bias to prevent bypass opening during normal plant operation. This gives the sum of the two steam flow paths a value less than the full 115% NBR steam flow.

c) The beginning of single-valve response to handle decay heat will occur near 48 seconds. Table 15.1-4 has been modified to reflect this.

QUESTION 211.156

In Table 15.1-4,

a) Include safety/relief valve actuation times for the "pressure regulator failure-open" transient.

b) Indicate the value of steam flow simulated at time = 0.

RESPONSE:

a) This transient is a depressurization event, not a pressurization event. Pressure only rises after the MSIV's have been tripped some 20 seconds into the transient. Vessel pressure rises slowly and may attain the first relief set point about 30 seconds after the reactor has already scrammed. Consequently, this series of events has no significance from an overpressure protection viewpoint.

b) Initial steam flow was 105% NBR.

QUESTION 211.157

Specify the assumed operating mode (manual or automatic) of the recirculation flow control system for the "pressure regulator failure-open" transient and provide justification that the most conservative results on core thermal margins are obtained with the assumed operating mode.

RESPONSE:

The analysis as presented in the FSAR was performed in the manual mode of operation, which is conservative. If the pressure regulator failure-open transient were analyzed in the automatic mode of the recirculation system, the following would occur: The output of the pressure regulator is used as the "equivalent load" for load following. Therefore, if the output of the pressure regulator goes high, a negative load error results. The master controller will respond by decreasing demand to the speed controller so the recirculation pump speed will decrease. With a lower recirculation flow the power would decrease at a faster rate in this automatic mode condition that the rate in which the power decreased in the manual mode. This would cause a more rapid depressurization and a main steam isolation on low turbine inlet pressure would occur at an earlier time. These conditions would produce insignificant differences from MCPR considerations when compared to the manual mode transient.

QUESTION 211.158

A qualitative presentation of results for the "inadvertent safety/relief valve opening" transient is given because analyses from earlier FSAR's indicated this event is not limiting from a thermal margin standpoint.

a) Provide supporting data that justifies this condition (i.e., referenced plant and MCPR).

RESPONSE:

Inadvertent safety/relief valve opening transient is inconsequential from a thermal margin standpoint. The small, abrupt steam flow increase leads to an initial decrease in pressure and generated power, giving decrease in surface heat flux. The steam flow disturbance is only 6.25% of the total rate flow, a very minor disturbance corrected quickly by the pressure regulator. The change in MCPR is less than 0.02.

QUESTION 211.159

For the "pressure regulator failure-closed" transient, correct the discrepancy that exists between the 5 psi setpoint difference for the backup pressure regulator in Sections 15.2.1.1.1 and 15.2.1.2.1 and a corresponding 10 psi setpoint difference in Section 10.3.2.

RESPONSE:

The smaller value in Section 15.2 is more realistic of the increment maintained during plant operation. This value allows for continued plant operation without scram or any outage of the unit occurring. The basis is to analyze the situation should it occur during plant operation. Assuming a wider set point difference (i.e., 10 psi), the result is essentially like a spurious scram with steam flow continuing under the control of the backup regulator. A larger set point difference would not cause a more severe event than the turbine trip where stop valve closure occurs (Subsection 15.2.3).

QUESTION 211.160

It is stated that the pressure disturbance in the reactor vessel from failure of the primary pressure regulator in the closed mode is not expected to exceed flux or pressure scram trip setpoints. Explain the bases for this conclusion.

RESPONSE:

See response to 211.159

QUESTION 211.161

In the evaluation of the "generator load rejection" transient, a full-stroke closure time of 0.15 seconds is assumed for the full-stroke closure time of 0.15 seconds is assumed for the turbine control valves (TCV). Section 15.2.2.3.4 states that the assumed closure time is conservative compared to an actual closure time of more like 0.20 seconds. However, in Figure 10.2-2, Turbine Control Valve Fast Closure Characteristic, an acceptable TCV closure time of 0.08 seconds is implied. Explain this apparent non-conservative discrepancy and the effect it has on analyses in Chapter 15 requiring TCV closure.

RESPONSE:

The 0.08 seconds shown in Figure 10.2.2 is an acceptable value whereas the .07 seconds TCV closure time in Tables 15.2-1 and 15.2-2 is the bounding value.

See response to Question 211.117 for further clarification to this question.

QUESTION 211.162

Explain why vessel steam and bypass flows in Figures 15.2-1 drop to zero at approximately 37 seconds instead of zero at 45-plus seconds from an L2 vessel level isolation in Table 15.2-1.

RESPONSE:

Figure 15.2-1 indicates that by 37 seconds the bypass closes terminating all steam flow (turbine valves closed, relief valves closed). This essentially isolates the reactor as it automatically attempts to regain continuous pressure control. Loss of FW, however, (conservatively assumed here) depresses vessel water level to L2 at which point an MSIV trip is initiated. However, this event introduces no disturbance as the vessel was essentially isolated at approximately 37 seconds.

QUESTION 211.163

During the "generator load rejection with bypass" transient, it is stated that peak pressure remains within normal operating range. Explain how this is accomplished since safety/relief valve actuation in the relief mode occurs from the pressure increase.

RESPONSE:

The statement is intended to imply well within normal "safety" range - not normal "operating" range. The peak of less than 1150 psi in the dome is clearly within the pressure boundary limits, below the design pressure of the primary system. Subsection 15.2.2.4.1 has been revised.

QUESTION 211.164

Correct NSOA Figure 15A.6-31, Protection Sequence Main Turbine Trip - With Bypass Failure, by reversing the indicated power levels. This error occurred during revision of this figure per Question 211.110.

RESPONSE:

Figure 15A.6-31 has been corrected.

QUESTION 211.165

Would a turbine trip coupled with failure of the operator to put the mode switch in the startup position before reactor pressure decays to 850 psig (action (5)) be more restrictive on thermal margins than the "turbine trip with bypass failure" transient analyzed in Section 15.2.3.3.3.2?

RESPONSE:

No. Avoidance of the low pressure isolation is primarily for convenience of plant recovery. No safety thermal margin protection is involved.

QUESTION 211.166

This section addresses the effect of single failures and operator errors for turbine trips at power levels 67%.

(a) What is the basis for power levels 67%?

(b) Explain the discrepancy with NSOA Figures 15A.6-26 and 15A.6-31 which refer to power levels 30%.

RESPONSE:

Section 15.2.3.2.3.1 has been modified to read turbine trip at power greater than 30%. Above 30%, the turbine trip supplies an automatic scram signal. Below 30%, the scram signal is not needed, allowing the bypass system to handle low power turbine or generator trips without scram.

QUESTION 211.167

During the "turbine trip with bypass" transient, explain why vessel stream and bypass flows in Figure 15.2-3 drop to zero at approximately 37 seconds instream of zero at 45-plus seconds from an L2 vessel level isolation in Table 15.2-3.

RESPONSE:

See the response to Question 211.162.

QUESTION 211.168

This section includes a detailed discussion of activity above the suppression pool, activity releases to the environs, and offsite radiological doses for MSIV closure transients. Explain why this information was not included in corresponding sections of other events in Chapter 15 requiring SRV actuation. For instance, the "generation load rejection with bypass failure" transient clearly has a higher peak vessel pressure and longer blowdown.

RESPONSE:

As indicated in the appropriate FSAR sections, fourteen accidents require SRV actuation with blowdown into the suppression pool (FSAR Subsections 15.1.2, 15.1.3, 15.1.4, 15.2.2, 15.2.3, 15.2.4, 15.2.5, 15.2.6, 15.2.7, 15.2.9, 15.3.1, 15.3.2, 15.3.3, and 15.3.4). None of these accidents involves uncontrolled activity releases to the environment. Controlled releases will have to be in accordance with established technical specifications; therefore, at the worst, releases from these accidents would result in small increases in the yearly integrated doses. One example of controlled release activities is given in Subsection 15.2.4.5.

QUESTION 211.169

Table 15.2-5 does not list all significant events up to 40 seconds for the "closure of all MSIV" transient. Include the following items:

(a) Significant actions associated with attainment of applicable vessel setpoints.

(b) Recirculation pump runback if it was simulated in the analysis.

RESPONSE:

Table 15.2-5 has been updated to indicate the sequence as indicated in Figure 15.2-5.

Recirculation pump runback was not simulated as it occurs some 7.5 seconds into the transient and is tripped off entirely at approximately 13 seconds. This is well after neutron and surface heat flux have peaked and therefore is of no consequence to fuel thermal integrity.

QUESTION 211.170

Include the time at which the turbine stop valves are closed in Table 15.2-10.

RESPONSE:

Since turbine stop valve closure is the first action to reach the reactor after loss of vacuum, time zero of the event is simulated to be the start of valve closure. The same 0.1 second closure time used for all stop valve closure events was also utilized here. Table 15.2-10 has been modified to reflect this discussion.

QUESTION 211.171

This section states that the turbine bypass valve and main steam isolation valve closure would follow the main turbine and feedwater turbine trip about 5 seconds after they initiate during the "loss of condenser vacuum" transient. Based on this, the bypass valves should close at approximately 5.01 seconds instead of 12.1 seconds in Table 15.2-10 and Figure 15.2-6. Explain this apparent discrepancy.

RESPONSE:

Table 15.2-10 and Figure 15.2-6 are correct. Loss of vacuum occurred at the rate of 0.8 in/sec giving the 12.1 seconds indicated. Subsections 15.2.5.3.2 and 15.2.5.3.3 have been modified to reflect this discussion.

QUESTION 211.172

Add the following items to Table 15.2-12 to be consistent with Figure 15A.6-28 for the "loss of auxiliary power transformer" transient:

a) Safety/relief valve actuation

b) Reactor vessel and containment isolation

RESPONSE:

Table 15.2-12 has been revised.

QUESTION 211.173

Add the following items to Table 15.2-13 to be consistent with Figure 15A.6-29 for the "loss of all grid connections" transient:

a) Reactor vessel and containment isolation

b) Initiation of the standby AC power system

RESPONSE:

Table 15.2-13 has been modified.

QUESTION 211.174

It is indicated in the "loss of feedwater transient" that credit is taken for safety/relief valve operation with "low setpoints" to remove decay heat since bypass valves become ineffective with MSIV isolation. Specify the value of the low set points used in the analyses.

What are the consequences if the safety function of SRV is used? (See Q211.139).

RESPONSE:

The low set points used in the analysis are from Table 15.0-2 (1091, 1101, 1111, 1121, 1131 psig). The safety function of SRV is used in the vessel overpressure protection section (see Question 211.142B), but this case is not a limiting event from that viewpoint, therefore more normal relief action is shown for the purposes of Chapter 15.

QUESTION 211.175

For the "failure of RHR shutdown cooling" transient, the FSAR considers alternate shutdown cooling methods in the event the residual heat removal (RHR) system in the suction line may not be used because of valve failure. In the analysis, valves in the automatic depressurization system (ADS) were used to transfer fluid (steam, water or a combination of these) from the reactor vessel to the suppression pool. The RHR system removes the added heat by removing cooling water from the suppression pool and injecting it into the reactor vessel. We require that you perform a test or cite previous test results to demonstrate that the ADS valves can discharge the fluid under the most limiting conditions when the fluid is all water. Show that the alternate method is a viable means of shutdown cooling by comparing the system hydraulic losses with the available pump head. Hydraulic losses should be provided for each system component and, wherever possible, should be derived from experimental results.

RESPONSE:

See Subsection 18.1.23 for discussion of SRV tests.

QUESTION 211.176

Table 15.3-2 indicates that zero vessel steam flow does not occur until after 46 seconds for the "trip of both recirculation pump motors" transient. However, Figure 15.3-2 indicates zero steam flow occurs at approximately 36 seconds. Explain this discrepancy.

RESPONSE:

Table 15.3-2 indicates time of bypass closure under pressure control.

QUESTION 211.177

In the analysis of one and two recirculation pump trip events in Sections 15.3.1, a minimum design rotating inertia was used to obtain a predicted rate of decrease in core flow greater than expected. Specify the inertia value used for each transient in Chapter 15 and the basis for selection. In the selection basis, include the effect on MCPR and reactor vessel pressure.

RESPONSE:

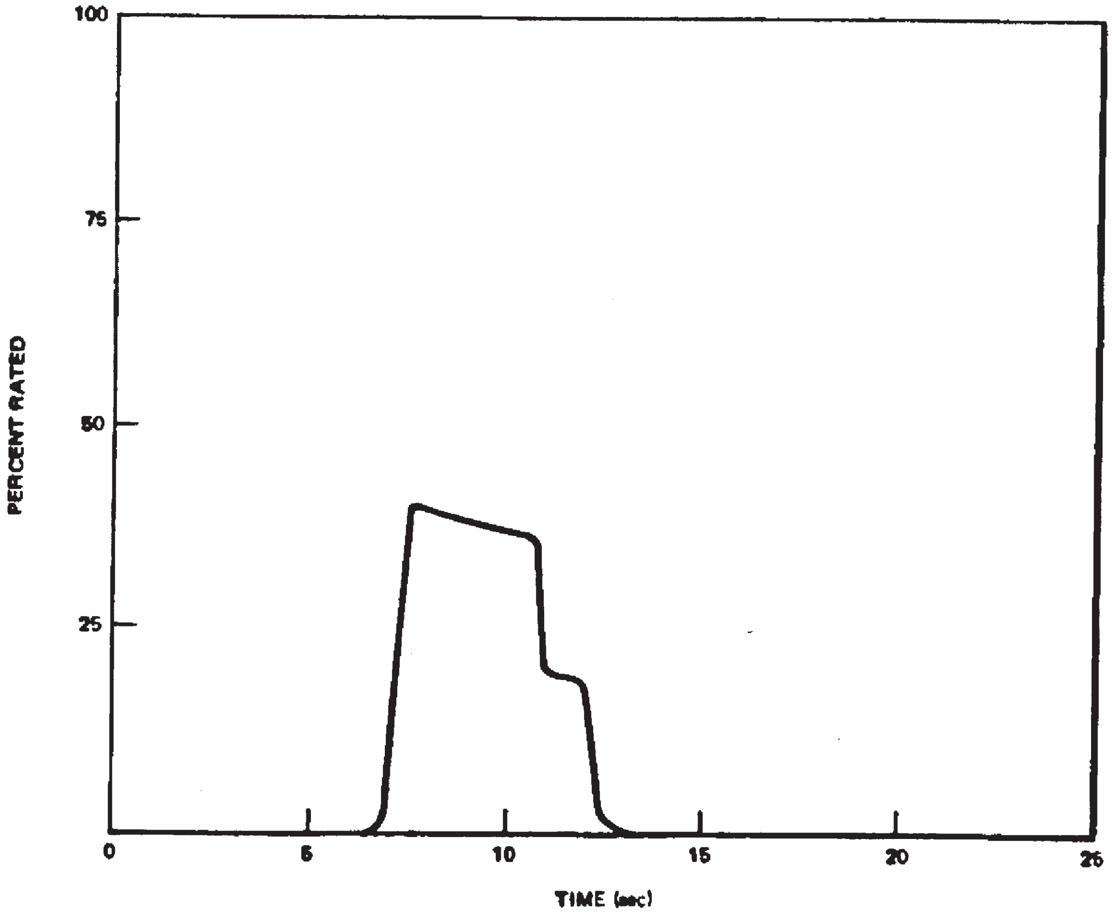
The inertial characteristic assumed is given in Table 15.0-2, Item 32. The inertial time factor for the purchased pump-motor units is 3.82 seconds and the rest of the equipment in the string of recirculation supply (drive motor, generator, coupler) more than double the total coast down characteristic expected. This characteristic was assumed to be 4.5 seconds for the direct RPT transients (which produce no reduction of CPR margin) and the turbine-generator trip events in which a slower pump coast down conservatively represents the protective action of the pump-motor trip. This approach gives worse results for the CPR and peak pressure evaluations of the turbine-generator trip type events, yet has virtually no impact on the direct RPT events, which have no reduction in CPR. Thus, the 4.5 second time constant was used for all transients.

QUESTION 211.178

Include relief valve flow in Figure 15.3-2.

RESPONSE:

Relief valve flow is included in Figure 15.3-2. The upper left quadrant indicates total steam flow, upper right quadrant indicates bypass flow. Since the turbine has been tripped the difference between these flows is the safety relief valve flow. Relief valve flow is shown in Figure 211.178-1.



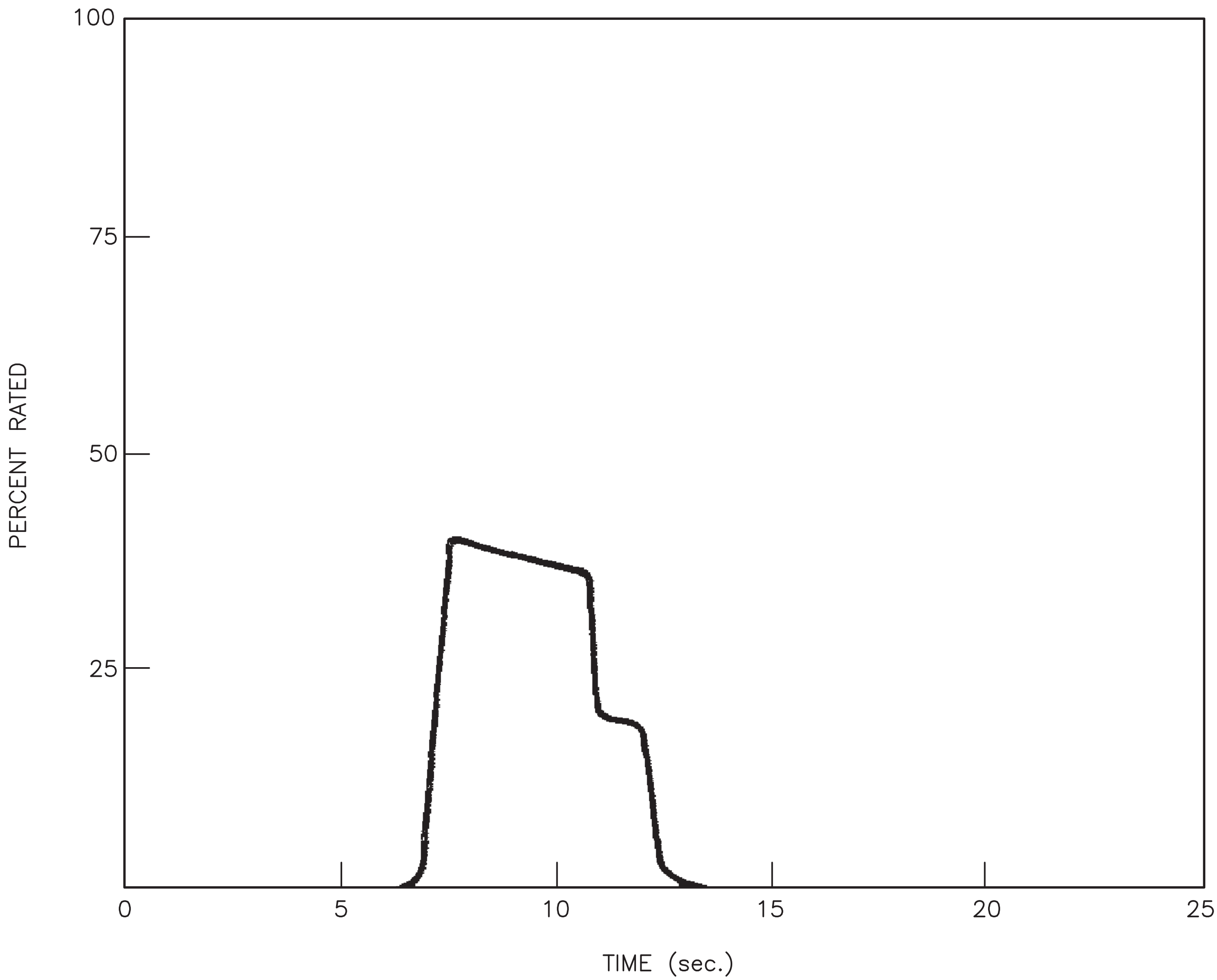
FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SRV STEAM FLOW
(TRIP OF BOTH RECIRCULATION
PUMP MOTORS)

FSAR FIGURE 211.178-1

PP&L DRAWING



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

SRV STEAM FLOW
(TRIP OF BOTH RECIRCULATION
PUMP MOTORS)

FIGURE 211.178-1, Rev 47

AutoCAD: Figure Fsar 211_178_1.dwg

QUESTION 211.179

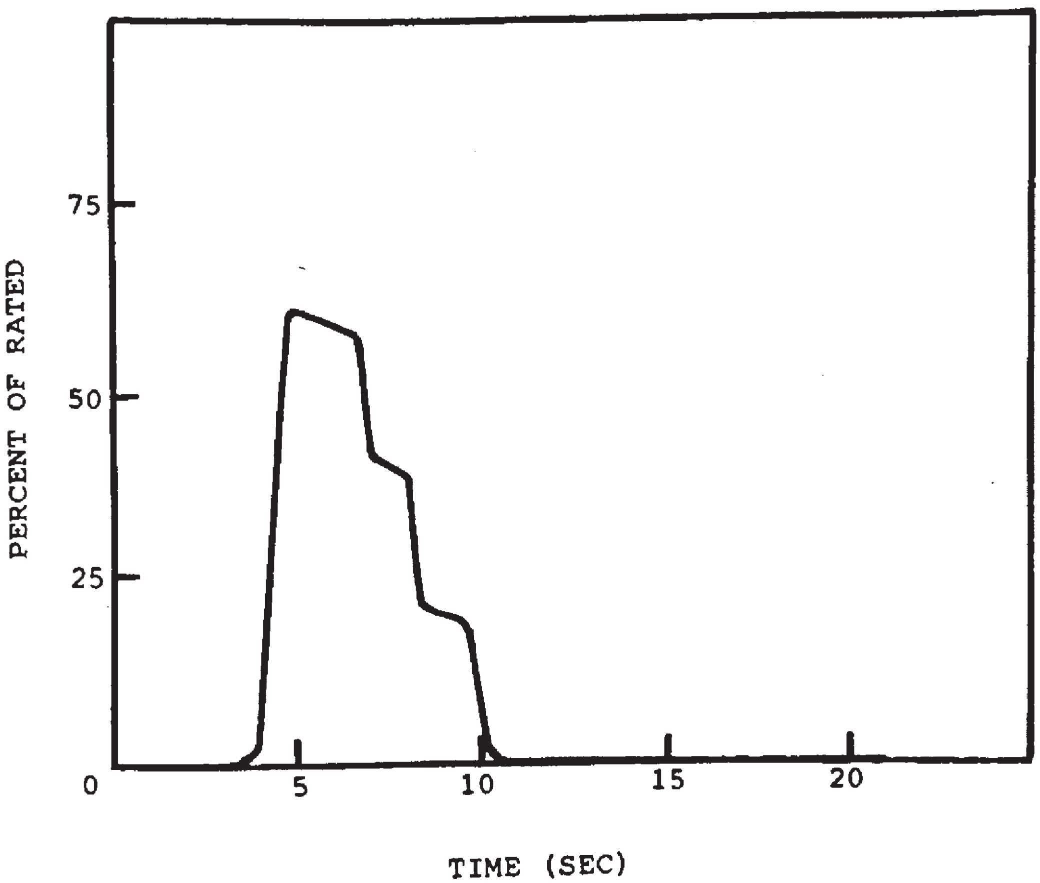
a) Table 15.3-3 indicates that zero steam flow should not occur until after 41.7 seconds for the "seizure of one recirculation pump" transient. However, Figure 15.3-3 indicates zero steam flow at approximately 35 seconds. Explain this discrepancy.

b) Include relief valve flow in Figure 15.3-3.

RESPONSE:

a) Table 15.3-3 is modified to indicate zero steam flow at 35 seconds when bypass valve closes under control of the pressure regulator.

b) Relief valve flow is indicated in Figure 15.3-3. The upper left quadrant indicates total steam flow and the upper right quadrant indicates total bypass flow after the turbine valve has been closed. Therefore, the difference is safety/relief valve flow. Relief valve flow is shown in Figure 211.179-1.



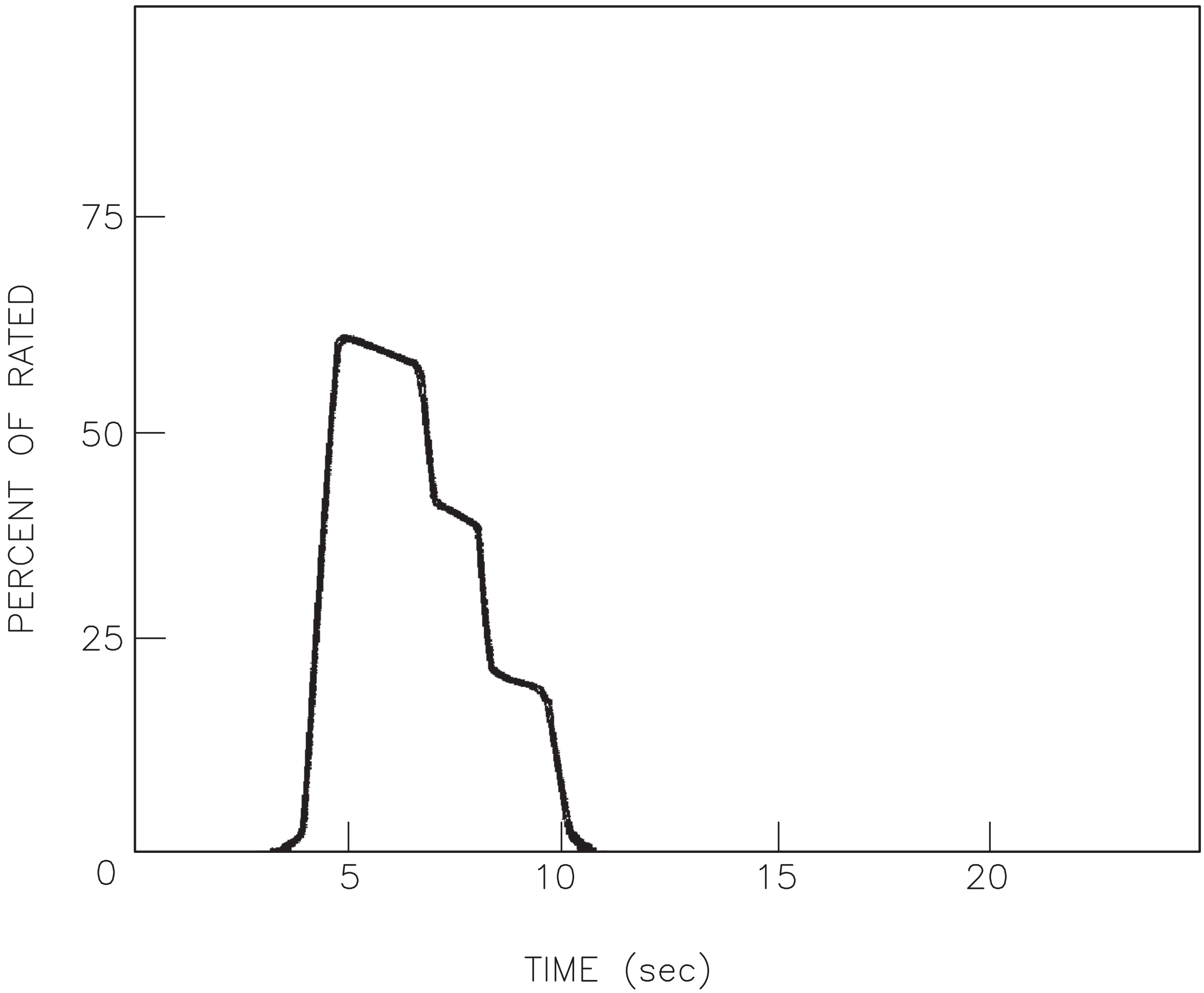
FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SRV STEAM FLOW
(SEIZURE OF ONE
RECIRCULATION PUMP)

FSAR FIGURE 211.179-1

PP&L DRAWING



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

SRV STEAM FLOW
(SEIZURE OF ONE
RECIRCULATION PUMP)

FIGURE 211.179-1, Rev 47

AutoCAD: Figure Fsar 211_179_1.dwg

QUESTION 211.180

The narrative on page 15.4-13 discussing the "abnormal startup of an idle recirculation pump" transient states, "The water level does not reach either the high or low level set points." Table 15.4.3 indicates a low level trip occurs 22.0 seconds after pump start. Figure 15.4-6 indicates a low level trip occurs approximately 23.5 seconds after pump start. Further:

a) Table 15.4-6 indicates a low level alarm 10.5 seconds after pump start while Figure 15.4-6 indicates this alarm occurs about 11.5 seconds after the pump starts.

b) Table 15.4-6 indicates vessel level beginning to stabilize 50.0 seconds after the pump starts. Figure 15.4-6 shows no such indication.

Resolve these discrepancies.

RESPONSE:

The sequence in Table 15.4-3 starts out with a scram at 10 seconds following the improper pump start. Figure 15.4-6 confirms this. At 23.5 seconds (rather than 22) level fails to L3 which also issues a redundant scram signal to a system which has already scrammed. It is the intent of Table 15.4-3 to show this, not to imply that the scram will occur again. Table 15.4-3 has been modified.

a) Table 15.4-6 indicates L4 near 11 seconds. This is verified Figure 15.4-6. The narrative in Subsection 15.4.4.3.3 has been modified to be consistent with Table 15.4-3.

b) Table 15.4-6 indicates that vessel level is beginning to stabilize at 50 seconds. This appears to be correct. Actually, level recovered from L3 at about 41 seconds and from 30 to 40 seconds level is changing at the rate of 2.5 in./sec. From 50 to 60 seconds level rate is definitely flattening out under normal feedwater level control.

QUESTION 211.181

Identify the diffuser flow units in Figure 15.4-6 (and also in Sector 2 of Figure 15.4-7). If this is % flow, explain why diffuser flow 1 drops to zero about 30 seconds after the pump starts.

RESPONSE:

In Figures 15.4-6 and 15.4-7 the units of diffuser flow is % of rated diffuser flow. The lower left plot indicates core flow (initial) at about 37%. Consequently with 1 recirculation loop operating the diffuser flows and core flow are:

76% on the "live" side,
-2% on the tripped side,
and core flow = (76-2)/2 = 37%

where 2% is indicated as reverse flow in the upper right plot (Item 4). At t=0 drive flow of 1 is zero and at approximately 8.5 seconds it rises sharply to about 40% then decays off to about 18%. It decays to 18% as the pump speed settles out from its 100% rated speed at the beginning of the transient to about 20% of rated speed. This causes the diffuser flow 1 to increase (item 4 upper right quadrant) and settle out following the pump characteristics. As the pump settles out at 20% reference speed the head created by the pump is insufficient to overcome the reverse head generated by the live loop following scram and so the diffuser flow decays to zero and again reverses.

QUESTION 211.182

The narrative of page 15.5-3 discussing inadvertent HPCI startup and Table 15.5-1 both indicate full HPCI flow is established at approximately 19% of rated feedwater flow in one second. Explain why the curve of feedwater flow in Figure 15.5-1 does not show this change.

RESPONSE:

The feedwater flow indicated in Figure 15.5-1 will not show the same response characteristics as that which is indicated by the HPCI input flow. This is due to the fact that feedwater flow is monitored upstream of the HPCI injection point and that the level control signal calls for shutdown of the feedwater flow as the added HPCI flow is added to the reactor vessel. The time response in feedwater flow is accounted for by the delay required for the level signal to attain steady state at a condition in which the reduction in feedwater exactly balances the HPCI flow. Figure 15.5-1 shows exactly this result.

QUESTION 211.183

The FSAR indicates that the inadvertent relief valve opening transient is analyzed in Subsection 15.1.4. However, no analytical data (curves) are provided in Subsection 15.1.4. Supply necessary information so that this transient can be evaluated concerning a decrease in reactor coolant inventory.

RESPONSE:

The qualitative analysis presented covers the very small nature of this disturbance on the reactor. See also response to question 211.158. Reactor feedwater flow maintains normal water level easily as the total flow leaving the vessel is restored to the initial value by the closure of the turbine control a compensating amount under normal action of the control valves. No threat to significant loss of inventory exists.

QUESTION 211.184

A number of inconsistencies exist among narrative descriptions, tables, and figures in Appendix 15A relative to the control rod drive system. Please resolve the following:

a) Table 15A.6-2 indicates that Event 7 can occur in States C & D. Figure 15A.6-7 indicates applicability to States A, B, C, D. The narrative on Page 15A-35 indicates any state.

b) Table 15A.6-2 indicates Event 16 can occur in States A, B & C. The narrative and Figure 15A.6-16 indicate applicability in States A & B only.

c) Figure 15A.6-17 and the narrative on Page 15A-39 indicate Event 17 is applicable in States C & D. The definition indicates that it is not applicable in State C.

d) Figure 15A.5-25 does not indicate Event 25 is applicable to State D only.

e) Figure 15A.6-28, Table 15A.6-2 and the narrative on Page 15A-44 for Event 28 are inconsistent for applicable states.

f) The narrative on Page 15A-50, Table 15A.6-4 and Figure 15A.6-40 for Event 40 are inconsistent for applicable state.

RESPONSE:

a) Table 15A.6-2 is in error. The table has been revised.

b) Table 15A.6-2 is in error. The table has been revised.

c) The definition of operating state being discussed is the starting point. The reactor is shutdown initially but planned operation in this state is achieving critically. Therefore you can theorize a rod withdrawal error.

d) State D is listed as the only operating state in the event title.

e) Figure 15A.6-28 has been revised.

f) Table 15A.6-4 has been revised.

QUESTION 211.185

Regulatory Guide 1.29, Section C.1.3, specifies that portions of the steam systems of boiling water reactors extending from the outermost containment isolation valve up to but not including the turbine stop valve, and connected piping of 2-1/2 inches or larger nominal pipe size up to and including the first valve that is either normally closed or capable of automatic closure during all modes of normal reactor operation, be classified Seismic Category I. You state on page 3.13-10 that your equivalent portion of the steam system is non-Seismic Category I. Justify your design deviation from the above requirements.

RESPONSE:

See revised Subsections 3.13.1 and 10.3.3.

QUESTION 211.186

a) Item (5) on page 3.13-11 discusses those portions of structures, systems, or components (SSC) whose continued function is not required but whose failure could reduce the functioning of items important to safety. Provide a list of these SSC.

b) Regulatory Guide 1.29, Section C.4, requires that Appendix B of 10 CFR 50 should be applied to the above SSC.

Provide justification for not including such items in the 10 CFR 50 Appendix B Quality Assurance Program.

RESPONSE:

a) These components, called "safety impact items" on Susquehanna SES, have grown in number since the inception of the project. Hence, the list of safety impact items will be final when construction is nearly 100% completed. The following are a sampling of safety impact items on Susquehanna SES:

I PIPING AND VALVES

Drywell	All small, large non-"Q" piping
Wetwell	All small, large non-"Q" piping
	Note: "Q"=essential

Fire Protection System

Diesel-gen. rooms piping	All FPS pipe
Control structure CO_2 piping	over certain "Q" cabinets, trays
Control structure portable water piping inside battery rooms	-

Drainage System

Drain pipe over cooler 1V-222A, Area 29, elev 739'-7"	4"XBD

II DUCTWORK

Reactor Building Unit 1	All "Q" & "A" duct shown on ref dwgs
Reactor Building Unit 2	All "Q" & "A" duct shown on ref dwgs
Control Structure	All ductwork shown on ref.dwgs.,except elevs. 676', 686', and 687'.
Turbine Building and Radwaste Building	Exhaust ductwork within the reactor building superstructure.
Containment Unit 1	-
Containment Unit 2	-

III ELECTRICAL RACEWAYS

All Non-Class IE Cable Trays in Reactor Building and Inside containment	-
All Non-Class IE Cable Trays in Control Structure, Except Elev. 656' and 676'	-

IV OTHER MECHANICAL ITEMS

RPV insulation framework, (except top head frame-work).	-
Drywell Coolers	1V&2V-411A&B 1V&2V-412A&B 1V&2V-413A&B 1V&2V-417A&B

V CONTROL SYSTEMS ITEMS

BOP auxil relay cabinet	0C665A, B, A3, B3
Environmental monitoring panel	0C671
Earthquake monitoring panel	0C696
BOP auxil relay cabinets	2C665A, B
Off-gas recombiner panel	0C673
Transducer panels	1C680A,B,C,D,E,F
Transducer panels	2C680A,B,C,D,E,F
Transducer panels	2C661A1, B1
Span prot switchyard control and display	0C658
500 and 230 kV switch yard control and display	0C659
Startup transfer protection	0C657
Transducer panels	1C661A1, B1

VI CIVIL ITEMS

Turbine building	Main structural framework as needed to ensure that the building will not collapse only.
Radwaste building	Main structural framework as needed to ensure that the building will not collapse only.

Platform, catwalks, stairs, ladders	All within Containment
Grating	All within Containment
Handrail/toeplate	All within Containment
Stair support structural steel	All within Containment
Monorails	All within Containment

VII ARCHITECTURAL ITEMS

Control Structure

Viewing gallery windows overlooking control room (bullet-resisting glass windows)	Struct framing (tubing) is seismic Category I. Attachment of window framing to structural turbine is safety impact.

b. The pertinent criteria of 10 CFR 50, Appendix B, have been applied to the design and design control of such ("safety impact") items, as noted in Subsection 3.13.1. The justification for not including these components under a more extensive program is based on their relative importance to safety and their conservative treatment in design. Safety impact items, unlike Quality group A, B, and C components, have no direct safety function. Hence, they are treated in relative order of importance. This same manner of reasoning is apparent in the relative treatment of Quality Group A, B, and C components. Each of these are directly related and therefore essential to safety. However, acceptable methods of design, fabrication and examination can vary among them considerably. This can be seen when comparing ASME Section III Class 1, 2, and 3 component code requirements.

The second justification, conservative design treatment, is based on the fact that safety impact items are typically analyzed, like essential items, to Code allowables which are well below yield values for the material. However, the only function safety impact items generally have is not fail completely so they will not collapse. Thus safety impact item component supports could actually be allowed to go into the plastic deformation range, short of complete failure (i.e., ultimate strength). Since safety impact items are not designed to go into permanent deformation, this gives us a significant added safety margin for steel supports. As an example, A-36 (SA-36) steel, typically used for pipe and component supports, reaches its ultimate strength (i.e., failure) at 58,000 psi minimum. Its minimum yield point is 36,000 psi. Moreover, A-36 pipe support materials are analyzed to a Code allowable of 12,600 psi. For pipes which are safety impact items, one can see then that the supports are not only analyzed so they do not deform but actually could sustain a 460% increase in stress before failure. This is typical of the inherent conservatism in the design of safety impact items.

QUESTION 211.187

a) Provide a list of those structures, systems and components which form interfaces between Seismic Category I and non-seismic Category I features.

b) Provide justification for not adhering to 10 CFR 50, Appendix B for such items (item (6), page 3.13-11).

RESPONSE:

a) As described in Subsection 3.13.1, "Regulatory Guide 1.29," paragraph 6, only piping systems form interfaces between Seismic Category I and non-seismic Category I features. Such piping is limited to that between the Seismic Category I boundary and the first point which can be treated as an anchor. This arrangement exists at all Seismic Category I piping boundaries and is so noted by the crosshatched liner and "Q" flags on the P&IDs already provided in this FSAR. No structures, systems, or other components form such interfaces.

b) Regulatory Guide 1.29, Rev. 3, paragraph C.3 & 4 states that only the pertinent portions of 10CFR 50 Appendix B should be applied to these components. The discussion in Section 3.13 on Regulatory Guide 1.29 states which portions were applied. The application of these portions of Appendix B is consistent with the relative importance of these components.

QUESTION 211.188

In Table 3.2-1, fill in the following information, where missing:

(1) Principal construction codes and standards (most pages).

(2) Page 18, Main Steam System: Pressure vessels, heat exchangers (all information).

(3) Page 1, Nuclear Boiler System: Air supply check valves (safety class).

RESPONSE:

Table 3.2-1 has been revised (see attached pages), to show the principal construction codes and standards.

The main steam system: pressure vessels, heat exchangers information has been deleted from page 18. Information on pressure vessels has been added in the condensate and feedwater section of the table.

The safety class of the nuclear boiler system: air supply check valves is shown on page 1 of the revised Table 3.2.1.

QUESTION 211.189

The RHR pump return line as shown on P&I Diagram M-151 (Figure 5.4-13) penetrates into the Suppression Chamber as a Safety Class 2, Quality Group B line (pipe 18"-GBB-109). After penetration, the quality group classification is changed to D. Standard Review Plan Section 3.2.2 states that changes in quality group classification are usually permitted only at valve locations, with the valve assigned the higher classification. Demonstrate that the safety function of the system is not impaired due to the fact that quality group classification changes at a point where no valve was located.

RESPONSE:

As shown on Dwg. M-151, Sh. 1, 18"-GBB-109 changes classification to 18"-HBD-185 after penetrating the containment. The purpose of the HBD-185 line is to return low energy water to the suppression pool when the RHR system is in pump test or suppression pool cooling mode. Because the classification change occurs inside the suppression pool, the function of this line will not be impaired even if the line sustains a crack or break. Also, note that this line is seismically analyzed and thus, will not fail during a seismic event. The containment function of the RHR system is not degraded by this classification change because the containment penetration assembly is quality group B, and the RHR system is a closed loop, quality group B, system outside containment. Therefore, the safety function of the system is not impaired due to the fact that quality group classification changes at a point where no valve is located.

QUESTION 211.190

The RHR containment spray line piping (within isolation valve) is listed as Quality Group A, Safety Class I, Seismic Category I (Table 3.2-1, page 4). In Figure 5.4-13 (P&ID M-151), this line is indicated as 12" GBB-118, i.e. Quality Group B. Resolve this inconsistency.

RESPONSE:

The listing of the RHR containment spray line piping in FSAR Table 3.2-1, page 4, has been changed in accordance with the classification of the 12" GBB-118 line shown in Dwg. M-151, Sh. 1.

QUESTION 211.191

Table 3.2-1, page 10, lists piping and valves forming a part of containment boundary of the Reactor Building Closed Cooling Water System as Quality Group B, Safety Class 2, Seismic Category I. Penetration of primary containment for this piping is not shown on any of the relevant P & I diagrams. Show the above piping and valves on appropriate P & I diagrams and indicate the classification of this piping.

RESPONSE:

Piping and valves forming a part of containment boundary of the reactor building closed cooling water system are shown on the revised FSAR Dwg. M-113, Sh. 1. Penetration of primary containment is through the 4"-HBB-157 and 4"-HBB-158 lines which are shown on revised Dwg. M-113, Sh. 1.

QUESTION 211.192

Since the initial discovery of cracking in boiling water reactor (BWR) control rod drive return line (CRDRL) nozzles, General Electric (GE) has proposed a number of solutions to the problem. One solution GE has proposed is a system modification that involves total removal of the CRDRL and cutting and capping of the CRDRL nozzle. It appears from your response to 211.7 that SSES plans this modification.

The staff asked for more information on the impact of this modification on your plant and also required an SSES commitment to preoperational testing to verify performance of the modified CRD system in Question 211.43. When you respond to 211.43, you should address the applicable items and staff concerns specified in the letter from D. Eisenhut, NRC, to R. Gridley, GE, dated January 28, 1980, on the subject of control rod drive return line (CRDRL) removal and capping CRDRL nozzles.

RESPONSE:

The referenced letter from D. Eisenhut, NRC, to R. Gridley, GE, dated January 28, 1980, essentially documents the NRC position on the CRD return line deletion. Pages 3 and 4 of that letter provide a summary of the NRC conclusions on this subject. In their final conclusion, 251" BWR/4 plants (such as Susquehanna) are accepted for return deletion contingent upon the Utility performing some demonstration tests (these tests are performed as part of normal performance and preoperational testing). The second and third conclusions do not pertain to the Susquehanna design. The fourth conclusion places the requirements for the installation of the GE-recommended pressure equalizing valves between the cooling water and exhaust water headers, the installation of flush ports on carbon steel exhaust water headers, and the replacement of any carbon steel pipe in the flow stabilizer loop. Referring to the CRD system P&ID (Dwgs. M-146, Sh. 1 and M-147, Sh. 1) for Susquehanna, all these requirements are met in the GE-designed system; redundant pressure equalizing valves are installed between the cooling water and exhaust water headers; the exhaust water header is constructed of stainless steel and therefore does not require flush ports; and there is no carbon steel pipe in the CRD system downstream of the main drive water filters. The fifth NRC conclusion requires the utility to develop procedures for optimizing the CRD system flow to the reactor pressure vessel. The CRD system preoperational test verifies proper CRD system operation with one pump. Plant procedures also address normal CRD system operation, i.e. one pump available. Plant emergency procedures delineate systems available for cooling makeup to the RPV in an emergency. CRD is among the systems listed. The last conclusion is the sixth in the list and is not applicable to the CRD system design for Susquehanna.

The revised response to Q211.43 item (1) delineates the LRG and PP&L position concerning two pump CRD operation for core cooling as not required.

QUESTION 211.193

In 3.5.1.2.3, you state that, "Equipment which is not necessary for operation or safety is removed from containment or secured in place prior to operation of the reactor to ensure that it will not become a missile." Are all the supports for the above equipment capable of surviving during an SSE?

RESPONSE:

See revised section 3.5.1.2.3

QUESTION 211.194

Discuss the possibility of the CRD mechanism becoming a missile inside containment.

RESPONSE:

The response to this question is given in Subsection 4.6.1.2.3, 4.6.2.1.2.2.1, 4.6.2.1.2.2.3, 4.6.2.1.2.2.4, 4.6.2.1.3, and revised Section 3.5.

QUESTION 211.195

Your response to Question 211.39 in reference to bonnet ejection of ANSI 900 trip-rated valves in revised Subsections 3.5 and 3.5.1.2 is qualitative. Supply a mathematical analysis supporting your contention that bonnet ejection of ASME, Section III, pressure seal bonnet-type valves, is improbable.

RESPONSE:

See revised Section 3.5.1.1.2(b).

QUESTION 211.196

You assign low probabilities (although no numerical values are given) to pressurized components or rotating equipment parts becoming primary missiles. In the event such a missile does occur, however:

(a) What specific barricades are provided to prevent failure of safety equipment within containment due to the impact of the missile?

(b) What secondary missiles might be generated by the primary missile, and how will their effects be mitigated?

RESPONSE:

See revised Sections 3.5 and 3.5.1.1.2(d). Low-probability missiles are considered as credible missiles.

No barricades or barriers have been found to be required to prevent damage to or failure of safety equipment within the containment. Secondary missiles were not considered as credible missiles.

QUESTION 211.197

Estimate the damage or failure caused in safety-related equipment within containment due to impact by credible primary or secondary missiles.

RESPONSE:

See response to Question 211.196

QUESTION 211.198

In Subsection 5.2.2.2.3.1 of the FSAR, you state that the required safety valve capacity is determined by analyzing the pressure rise from an MSIC closure with flux scram transient. Figure 5.2-1 shows curves produced by this analysis.

(a) In Figure 5.2-1, the curves for vessel pressure rise and steamline pressure rise exceed the scale of the graph so that it is unclear what the maximum pressure is and when it occurs. Provide a plot with appropriate scales so that the maximum pressures are clearly shown.

(b) In your response to Q211.4, you state that analyses show that adequate margin exists in the design of the S/R valve system, so even if the flux scram signal failed and the event was terminated by a pressure scram, the peak vessel pressure would be less than the ASME code limits. Provide the results of these analyses and indicate the % relief capacity needed to keep peak vessel bottom pressure less than the ASME code limit.

RESPONSE:

With regard to the curves for vessel pressure rise and steamline pressure rise which exceed the scale presented, Figure 5.2-5 of the FSAR shows the vessel pressure time response. The steamline pressure rise parallels the vessel pressure time response mismatched by only a fraction of a second, and reaches a peak value of about 40 psi less than the vessel bottom pressure shown in the figure.

The peak vessel pressure attained from an MSIV closure with pressure scram and 16 S/R valves and with a total spring action safety capacity of 102.1% NBR steam flow is 1320 psig (4.2 seconds), which is below the ASME code limit of 110% of vessel design pressure (i.e., 1250 x 1.10 = 1375).

QUESTION 211.199

What is the pressure safety margin calculated for the MSIV closures with flux trip?

RESPONSE:

The pressure safety margin calculated for the MSIV closure with flux trip is 75 psi.

QUESTION 211.200

On page 5.2-14, it is stated that it is not feasible to test the safety/relief valve setpoints while the valves are installed. It would appear that improper setpoints (due to such faults as erroneous setpoint calculation) would be credible common failure mode which can result in degradation of he pressure relief systems. Provide assurance that a credible common failure mode in the failure-to-open direction has been properly considered. Provide the results of a data search of operating reactors indicating the frequency with which this type of failure has occurred (improper setpoint).

RESPONSE:

Improper safety/relief valve set points as a result of erroneous set point calculations are very unlikely due to internal GE procedures which are implemented in accordance with the requirements of 10CFR50, Appendix B, criterion III. These design verification procedures require that the set points established through the normal design and analysis practices be verified by independent calculations. Each valve is individually tested on steam with calibrated instruments for proper set point prior to installation on the reactor. This pre-installation set point testing is conducted with quality controlled procedures and test instrumentation which meet the requirements of Appendix B to 10CFR50. The adequacy of the calculations and pre-installation set point test are supported by a review of BWR operating experience that identified that no failure of a safety/relief valve attributable to improper set point has been recorded.

QUESTION 211.201

Provide the results of the hydraulic calculations that show the Mach number, pressure, and temperature at various locations from upstream of the safety/relief valves to the suppression pool at maximum flow conditions.

The concern is related to the potential for the development of damaging shock waves to the discharge piping. Include the effects of suppression pool swell variations on the operation of the safety relief valves.

RESPONSE:

The mach number, pressure, and temperature at various locations downstream of the safety/relief valves to the suppression pool at maximum flow conditions have been calculated and compared to test results.

The NRC question indicated upstream of the safety/relief valves, but we assumed it to be downstream of the safety/relief valve since the question is concerned with the effects of shock waves on the discharge piping and suppression pool.

The mach numbers, pressures, and temperatures at various locations in the longest SRV discharge line are included in Table 211.201-1. Also included are the KWU measured and calculated values. The measured values have been corrected to a reactor pressure of 1276 psia (88 bar) for consistency. The resulting calculated pressures are higher than the measure values but lower than the values calculated by KWU. The analysis indicates one shock is present immediately downstream of the SRV. The results for the shortest SRV line would be similar with the shock occurring further downstream in the expander (i.e., upstream of point A attached Table 211.201-1). The reason the calculated values are higher than the measured values is due to the idealization of the flow being one dimensional, especially at the exit of the valve.

Since the critical pressure at the quencher outlet is 116 psia, and the backpressure from the suppression pool is 63 psia, critical flow will remain at the quencher outlet and hence the effects of the suppression pool swell variations will have no effect on the operation of the safety relief valves. This is assuming the reactor pressure remains at 1276 psia.

TABLE 211.201-1

SUMMARY OF RESULTS

SYSTEM LOCATION	CALCULATED AT 127.6 PSIA (88 BAR) REACTOR-PRESSURE				TEST
	BECHTEL			KWU	KWU
	Mach No.	Temp. °F	Pressure Psia	Pressure Psia	Pressure* Psia
A Valve Exit	.38	1025	370	540	319
B U/S of Schedule Change	.45	1021	311	356	
C D/S of Schedule Change	.53	1016	299	344	
D Quencher Inlet	.40	1024	294	312	203
E Quencher Outlet	1.0	970	115	149	

* Corrected for 88 bar (1276 psia) Reactor Pressure

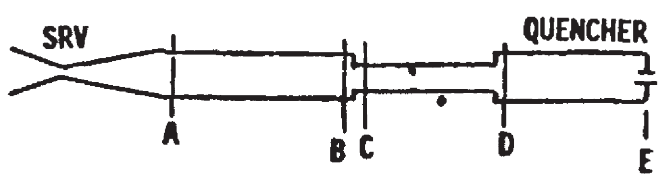


TABLE 211.201-1

SUMMARY OF RESULTS

SYSTEM LOCATION	CALCULATED AT 127.6 PSIA (88 BAR) REACTOR-PRESSURE				TEST
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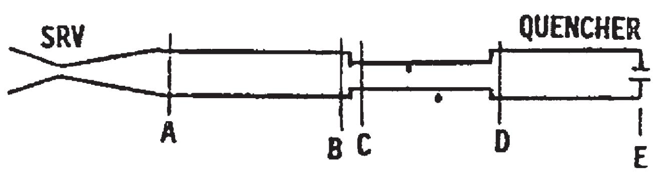


QUESTION 211.202

Referring to Subsection 5.2.2.4.1, on page 5.2-9 in the FSAR, you state that the pneumatic accumulator provided for each safety/relief valve has sufficient capacity to provide one safety/relief valve actuation. It appears from Figure 5.1-2 Nuclear Boiler, that the air supply line upstream of the ball inlet check valve for non-ADS safety/relief valves is not safety grade. If an airline break occurred upstream of the check valve, would there be indication in the control room of this break and the status of the accumulator? If indication is given, what operator action would be required?

RESPONSE:

The air supply line upstream of the ball inlet check valve is not safety grade. However, the pneumatic accumulator will preserve its pressure integrity and provide one safety/relief valve actuation.

The non-safety grade pipe from the gas compressor to the ball inlet check valve is not required for safe operation or shutdown of the plant. If a significant leak developed, it would be indicated in the control room by PI-12642. (See Dwg. M-126, Sh. 1 and M-126, Sh. 2).

Operator action would be determined by the location of the leak and its affect on system operation. Normally, if the break is outside containment and it does not affect system operation it would be repaired with the reactor at power. However, if the break were inside containment the reactor would normally be placed in the hot standby mode for repair to the line.

QUESTION 211.203

In the Susquehanna analyses, what capacity is assumed for each group of valves that are actuated at their power-operated relief setpoint?

RESPONSE:

In the Susquehanna SES overpressure analysis, no credit is taken for valves that are operated in the power-operated relief mode. All values are assumed to operate in their spring action (safety) mode. The capacity of each safety/relief valve group is simulated in the analysis to be one-fifth of the total specified flow.

For the overpressure analysis, the safety/relief valve setpoints for the 5 assumed valve groups are 1177, 1187, 1197, 1207, and 1217 psig. Each valve group is assumed to have one-fifth of the total valve capacity at setpoint. Consequently, when 1177 psig is reached, a blowdown corresponding to 20% of the total valve capacity of 105% NBR Steam flow is assumed to take place, etc. According to Figure 5.2-5 of the FSAR, these setpoints will be reached about 2 seconds after the onset of the transient.

For actual valve operation, safety valve spring setpoints are in the range 1146 to 1205 psig. This would result in valve opening times of about 2 seconds but at a slightly earlier time than for the assumed valve setpoints.

QUESTION 211.204

Submit an overpressure report as required by the ASME Boiler and Pressure Vessel Code, Section III which is referenced in Section 5.2.2 of the Standard Review Plan.

RESPONSE:

The applicable overpressure report has been submitted under separate cover (PLA-544, dated 9/12/80).

QUESTION 211.205

Were the curves in Figure 5.2-5 which shows the pressure at the vessel bottom versus time for the MISIV transients based on 105% of rated steam flow? In not, provide these curves.

RESPONSE:

The curves in Figure 5.2-5 are based on 105% NBR steam flow.

QUESTION 211.206

In your response to Question 211.4 in Table 1 on page 211.4-5, you state:

a) Safety/relief Valve Setpoint - psig 1091 to 1111

b) Typical Valve Capacity - % NBR Steam Flow - 5-10 per valve

c) Typical Total Relief Valve Capacity (% NBR Steam Flow) 75-85

In Chapter 15 and in your response to Question 211.76, you give the power-operated relief setpoints used in your transient analysis as 1091 - 1131 psig.

In your response to Question 211.76, you state the total capacity of the valves at the first relief setpoint of 1091 psig to be 99% NBR steam flow.

At 1091 psig, two (2) valves open according to the groups defined in Table 5.2-2. If each valve has 5-10% NBR steam flow capacity, how can the total capacity at 1091 psig by 99% of NBR steam flow? Clarify all the above inconsistencies involving setpoints and capacities.

RESPONSE:

The power-operated pressure relief setpoints used in the analysis of Chapter 15 are 1091, 1101, 1111, 1121 and 1131 psig respectively for the five groups of valves, as indicated in Table 15.0-2 of the FSAR. The total capacity of all the valves (quoted as if they all opened at the first relief setpoint of 1091 psig) is 99% NBR steam flow. The analytical simulation in Chapter 15 assumes that one-fifth of the valves open effectively at each setpoint. The first group therefore opens at the first group upper limit setpoint of 1091 psig with 19.8% NBR capacity. Each subsequent group similarly opens at its setpoint with equal capacity (corrected only to represent the increase in flow due to the slightly higher pressure).

Regarding any discrepancies, it should be noted that Table 1 of Q.211.4, as referenced in the letter attachment to that question, represents a generic BWR calculation and is not unique to Susquehanna. Therefore, the values of setpoints and capacities in Chapter 15 and in the response to Q.211.76 are the correct values for Susquehanna.

QUESTION 211.207

Nominal spring mode safety/relief valve setpoints are given in Table 5.2-2 and again in Table 1 of Figure 5.1-3a. The lowest setpoint in Table 5.2-2 is given as 1146 psig whereas in Figure 5.1-3a it is shown to be 1130 psig. Resolve this inconsistency. Also, what is the basis for the pressure setpoint increments between groups?

RESPONSE:

The safety/relief valve spring set pressure of 1146 psig in Table 5.2-2 is the correct valve for this parameter. Dwg. M-141, Sh. 2 has been corrected.

The increments between the setpoint groups are based on vessel overpressure protection design analysis which has historically used a 10 psi difference between setpoints for safety/relief valves.

QUESTION 211.208

In Table 5.2-2, five safety/relief valve groups are identified with the nominal spring mode pressure setpoints given for each group. Table 15.0-2 identifies five power actuated relief mode setpoints. Do the latter correspond to the same groupings given in Table 5.2-2? That is, are there two valves set at 1091 psig, four at 1101 psig, etc.? If not, provide the proper power actuated mode groups.

RESPONSE:

The setpoints presented in Table 15.0-2 do correspond to the five spring set pressure settings. For example, the two valves of 1146 psig (spring) will have a 1091 psig (power actuated relief mode) set pressure.

QUESTION 211.209

In Table 15.0-1, the number of relief valves involved in the first blowdown following various transients is given.

In the case of pressure regulator fail-open, the maximum steam line pressure is indicated as 1092 psig. With the first group of safety/relief valves set at 1091 psig, two valves should blowdown, not zero as indicated by Table 15.0-1.

In the case of the loss of auxiliary power transformer, the maximum steam line pressure is indicated at 1105 psig. If the valve groupings are the same as in Table 5.2-2, this should cause blowdown of the first two groups of valves (6), not the 10 indicated in Table 15.0-1.

Resolve these apparent discrepancies.

RESPONSE:

Table 15.0-1 lists the number of relief valves involved in the first blowdown following the given transients. Valve actuation is accounted for in this table whenever the vessel dome pressure reaches the relief valve setpoint. The nominal relief valve settings are:

1076 psig
1086 psig
1096 psig
1106 psig
1116 psig

Table 5.2-2 gives the spring setpoint, not the air-actuated, relief mode setpoints.

To conservatively predict peak pressures the transients assume at least a value 1% higher than the nominal relief valve settings (See Table 15.0-2).

a) The case of pressure regulator failure-open should have shown the first group opening. Table 15.0-1 has been revised. No safety relief valve flow is assumed in this transient.

b) This transient was reanalyzed showing actuation of 16 relief valves as was documented by FSAR Revision 16 in Table 15.0-1.

Setpoint listings are as follows:

Nominal relief (psig)	Analysis relief (psig)
1076	1091
1086	1101
1096	1111
1106	1121
1116	1131

Nominal spring (psig)	Analysis spring (psig)
1146	1177
1175	1187
1185	1197
1195	1207
1205	1217

QUESTION 211.210

Expand the discussion in Section 6.3 to describe the design provisions that are incorporated to facilitate maintenance (including draining and flushing) and continuous operation of the ECCS pumps, seals, valves, heat exchangers, and piping runs in the long-term LOCA mode of operation considering that the water being recirculated is potentially very radioactive.

RESPONSE:

The Susquehanna equipment for long-term cooling following a postulated LOCA includes two complete core spray systems and two RHR systems. These two systems consist of a total of eight pumps capable of providing water to the reactor pressure vessel. The piping and instrumentation diagrams of these systems are shown in Dwg. M-152, Sh. 1, M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3 and M-151, Sh. 4. Long-term cooling water can be provided to the core by one RHR (LPCI mode) pump or one CS loop (both pumps), while heat can be rejected to the ultimate heat sink via either of the two RHR heat exchangers using one of four RHR pumps. Thus a maximum of three pumps would be required for post-LOCA core cooling. All of these components are designed to remain operable during and following a Loss of Coolant Accident, and the redundancy provided is such that maintenance is not expected to be required during the long-term core cooling period following a LOCA. However, the RHR and Core Spray systems are designed with provisions for flushing as shown in Dwg. M-152, Sh. 1 M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3 and M-151, Sh. 4.

QUESTION 211.211

Severe water hammer occurrence in the ECCS discharge piping during startup of the ECCS pumps is avoided by ensuring that the discharge pipes are maintained full of water. The condensate transfer system is used to achieve this function for all ECCS piping. Since the condensate transfer system also supplies water to numerous other systems, the following areas require clarification:

a) Justify the use of a common filling system for all ECCS discharge piping versus independent jockey pumps.

b) Identify the expected demands on the condensate transfer system and what effects, if any, would be expected on the makeup required to keep the discharge pipes full of water?

c) Can individual "fill lines" be isolated to permit maintenance on one ECCS system without affecting the other system?

d) The discharge piping "fill system" is apparently considered to be an auxiliary system. Are any priority interlocks provided to ensure that the "filling system" will be given priority over the other uses of the condensate transfer system water?

e) The individual fill lines apparently do not have instrumentation to monitor low pressure. Provide assurance that when the condensate transfer pumps are operating that the individual ECCS discharge lines are full of water.

f) What is the history of water hammer events at other plants employing this design?

RESPONSE:

a) The pump fill system adopted for Susquehanna SES utilizes the existing condensate system and is relatively simple. It is believed to have a higher system overall reliability than a system requiring individual pumps, or so-called jockey pumps, to perform the fill function. However, there is no known operating experience with a common discharge line fill system.

The condensate transfer system has been designed to be reliable insomuch as it is required for plant operation. Therefore complete failure of this common filling system for the ECCS would require that the plant be brought to a shutdown condition.

b) At standby pressures substantially below valve rated pressures, the estimated makeup for the ECCS systems is less than 1 (one) gpm. See revised Subsection 6.3.2.2.5.

c) The individual fill lines can be isolated to permit maintenance on ECCS systems and individual loops of a system without affecting the other loops. See revised Subsection 6.3.2.2.5.

d) Due to the very small amount of continuous make-up required no interlocks are provided to give priority to "keep-full" function of the Condensate Transfer System's ECCS fill lines.

e) See revised subsection 6.3.2.2.5.

f) The water hammer events which have occurred in BWR plants with ECCS fill systems are documented and transmitted to the NRC as Licensing Event Reports (LER). These are kept on file at the NRC. See Table 211.211-1 for a tabulation of water hammer events based on LER information on file with the General Electric Company.

TABLE 211.211-1

LER WATER HAMMER EVENTS

PLANT	DATE	SYSTEM
Dresden 2	4/21/71	Core spray
Oyster Creek I	5/25/71	Core spray
Quad Cities	4/04/72	RHR
Fitzpatrick	4/10/74	RHR
Duane Arnold	4/10/74	Core spray
Brunswick 1	3/15/77	RHR steam condensing inlet line to HXGR
Brunswick 2	4/13/77	RHR Loop B
Brunswick 1	11/09/77	RHR steam condensing inlet line to HXGR
Brunswick 1	12/20/77	RHR steam line condensing line
Millstone 1	2/20/78	Core spray
Brunswick 2	3/28/78	HPCI

TABLE 211.211-1

LER WATER HAMMER EVENTS

PLANT	DATE	SYSTEM
Dresden 2	4/21/71	Core spray
Oyster Creek I	5/25/71	Core spray
Quad Cities	4/04/72	RHR
Fitzpatrick	4/10/74	RHR
Duane Arnold	4/10/74	Core spray
Brunswick 1	3/15/77	RHR steam condensing inlet line to HXGR
Brunswick 2	4/13/77	RHR Loop B
Brunswick 1	11/09/77	RHR steam condensing inlet line to HXGR
Brunswick 1	12/20/77	RHR steam line condensing line
Millstone 1	2/20/78	Core spray
Brunswick 2	3/28/78	HPCI

QUESTION 211.212

The description of the filling system for ECCS discharge piping in Section 6.3.2.2.5 of the FSAR addresses system operation for the RHR and core spray piping. The HPCI discharge piping is not discussed in this Section or Section 6.3.2.2.1 but Dwg. M-155, Sh. 1 shows a "filling line" for the HPCI discharge piping. Resolve this apparent discrepancy.

RESPONSE:

For response see revised subsection 6.3.2.2.5.

QUESTION 211.213

The results presented in the FSAR for Section 6.3.3.7.5, 6.3.3.7.6, and 6.3.3.7.7 are supposedly taken from "typical" or the "lead plant" analysis for this product line. Identify the typical and/or lead plant and justify the selection in view of the criteria specified in Topical Report NEDO-20566, Vo. II, page III-33.

RESPONSE:

The Susquehanna plant is a BWR/4 with LPCI modification with the core plate leakage holes plugged. In accordance with the Licensing Topical Report NEDO-20566 Volume II the lead plant for the above classification is the Fitzpatrick plant which is a 218/BWR 4.

The text incorrectly stated that the results in Subsections 6.3.3.7.5 and 6.3.3.7.6 were from a lead plant analysis. This statement has been deleted from Subsections 6.3.3.7.5 and 6.3.3.7.6. The results presented in these two sections were obtained from calculations performed specifically for Susquehanna and only the results in Subsection 6.3.3.7.7 were taken from the lead plant analysis.

The lead plant analysis is used primarily to identify the limiting failures and breaks. It also defines the LOCA characteristics for similar reactor designs. Individual plant specific analyses are then performed to provide specific plant responses for the limiting breaks and failures. This technique was adopted for the Susquehanna analysis and only the less limiting lead plant cases (i.e. break location where the PCT was significantly less than the limiting case) were used in the Susquehanna FSAR (refer to Subsection 6.3.3.7.7).

The justification for selecting a 218 BWR as the lead plant for the BWR 4 plants with a LPCI modification is based on those criteria discussed below:

Criterion 1. Typical Blowdown and Reflood Characteristics

This criterion is important because it ensures that the break spectrum characteristics will be typical for all the plants in a particular class. The shape of the break spectrum is generally dominated by the complement of ECCS equipment available given a single failure. Since every BWR 4 plant with a LPCI modification will have the same complement of ECCS equipment for the worst single failure, any plant in this class will satisfy Criterion 1. However, from a peak cladding temperature standpoint the 218-BWR/4 yields the highest results and thus is the preferred lead plant.

Criterion 2. <u>Typical Reactor Power</u>

This criterion - establishes the degree to which the lead plant analysis can be considered "generic". The thermal power of the 218 BWR/4 reactor design is approximately 35% higher than the smaller BWR/4 design and 35% lower than the larger BWR/4 reactor designs. Hence, the 218 BWR provides the most typical results for reactors in this class.

Criterion 3 <u>Number of Reactor Types</u>

This criterion also establishes the degree to which the lead plant analysis can be considered "generic". Since the number of 218 and 251 BWR 4 plants with a LPCI modification are approximately equal, either reactor sizes could be chosen as typical. However, since the other criteria favored the choice of the 218 BWR as "typical" or "lead plant", the 218 BWR is the preferred choice for the lead plant for the BWR 4 plants with a LPCI modification.

QUESTION 211.214

NPSH considerations require clarification in the following areas:

a) Provide calculations or other evidence to show how the ECCS suction lines in the suppression pool are designed to prevent formation of vortices and air ingestion when the ECCS is in operation. Section 6.3.6 states that NPSH calculations, assuming the worst case passive failure in an ECCS pump and the subsequent drop in the suppression pool level, show adequate margin to assure proper pump operation. Justify the use of a minimum suppression pool level to prevent vortices formation versus providing mechanical vortex barriers for the ECCS suction lines in the suppression pool.

b) Section 6.3.2.8 of your FSAR states that "10 minutes following the accident, the operator is required to throttle the CS and LPCI pumps to rated CS and LPCI flow rate in order to ensure that adequate NPSH is available to the pumps." Evaluate the consequences of delaying the throttling action until 20 minutes after the accident. Provide manufacturer's pump test data which demonstrates the required NPSH for each ECCS pump.

c) Provide new Figures 6.3-3a and 6.3-6a referenced in the response to Question 211.77.

RESPONSE:

a) Any vortexes that may form in the flow approaching the intake in the suppression pool are expected to break-up at the strainers prior to entering the pump suction lines. The presence of such vortexes in the approach flow and any related effects of such vortexes on pump performance and pump noise will be verified during preoperational testing.

The use of the minimum suppression pool water level will not, as stated in the question, prevent vortex formation. See revised Subsection 6.3.6.

b) Ten-minute operator action time is justified to mitigate the consequences of design basis limiting events as described in the FSAR. The ANS 58.8 Subcommittee, composed of representatives from industry and the NRC, is developing a standard to define acceptable operator action times. Preliminary results of this study indicate that 10 minutes are justified.

New Figures 6.3-72, 6.3-73, 6.3-74 and 6.3-75 are the ECCS pump data which demonstrates the required NPSH for each ECCS pump.

Subsection 6.3.2.8 has been revised to include the following:

The NPSH requirements of the CS pump and the LPCI (RHR) pump are shown in Figure 6.3-6A and 5.4-15, respectively.

c) Figures 6.3-3a and 6.3-6a have been included in the FSAR.

QUESTION 211.215

Provide the minimum required capacity of the condensate storage tank and the suppression pool.

Assuming no makeup to the CST or to the suppression pool and considering NPSH requirements, provide the calculations which show how long the ECCS could operate under the worst conditions.

RESPONSE:

There is no minimum required capacity for the condensate storage tank. The minimum reserve storage capacity in the condensate storage tank, which has been reserved for HPCI or RCIC systems operation, is 135,000 gallons. The minimum required suppression pool water volume is 122,410 $ft.^3$

In the event of a LOCA, the primary containment will be isolated. The water content in the suppression pool will remain essentially unchanged minus the quantity retained in the drywell, and with heat rejection, will not limit ECCS pump operation. The RHR pump, for instance, will still have adequate NPSH at the maximum accident water temperature of 203°F. NPSH calculations for the RHR pump are presented in Subsection 6.3.2.2.4.1. NPSH calculations for CS pump are presented in subsection 6.3.2.2.3.1. The calculations account for suppression pool water retention in the drywell and minimum allowable water level in the suppression pool.

QUESTION 211.216

Valves in the Safeguards systems are interlocked to minimize the potential for operational malfunctions (e.g., to ensure valving changes are performed in a proper sequence, and to ensure that two separate modes of equipment operation cannot occur simultaneously).

Present a tabulation of all electrical interlocks for all electrically-controlled pneumatically or hydraulically operated or motor operated valves of the systems that are shown on the FSAR figures listed below. The tabulation should:

1. Identify all other valves (by valve number and electrical division) that are interlocked with each valve shown in the listed figures.

2. List the required position (open, closed, or intermediate position) of these other valves that will permit motion of the valves shown on the listed figures.

3. List any permissives (interlocks) that each valve shown provides to any other valve(s) and to control circuits for pumps.

FSAR Figure	System Description
6.3-1	HPCI System
6.3-4	Core Spray System
5.4-13	RHR System

RESPONSE:

Electrical interlocks for all electrically-controlled pneumatically or hydraulically operated or motor operated valves of the HPCI, Core Spray and RHR Systems are discussed in Chapter 7 of the Susquehanna FSAR. High pressure/low pressure system interlocks, system bypasses and interlocks, logic and sequencing, as well as Functional Control Diagrams (FCD's) which show in graphic form the permissives necessary for system operation are all provided in FSAR Section 7.3. The specific information provided is as follows:

High Pressure Coolant Injection System (HPCI)

1. Bypasses and Interlocks - Section 7.3.1.1a.1.3.5.

2. Logic and Sequencing - Section 7.3.1.1a.1.3.4.

3. HPCI Functional Control Diagram –Dwg. M1-E41-6, Sh. 1, M1-E41-6, Sh. 2, M1-E41-6, Sh. 3, M1-E41-6, Sh. 4 and M1-E41-6, Sh. 5.

Core Spray System (CS)

1. Bypasses and Interlocks - Section 7.3.1.1a.1.5.5.

2. Logic and Sequencing - Section 7.3.1.1a.1.5.4.

3. Core Spray Functional Control Diagram – Dwg. M1-E21-3, Sh. 1,M1-E21-3, Sh 2 and M1-E21, Sh. 3.

LPCI Mode of RHR

1. Bypasses and Interlocks - Section 7.3.1.1a.1.6.5.

2. Logic and Sequencing - Section 7.3.1.1a.1.6.4.

3. RHR Functional Control Diagram – Dwg. M1-E11-5, Sh. 1, M1-E11-5, Sh 2, M1-E11-5, Sh. 3, M1-E11-5, Sh. 4, M1-E11-5, Sh. 5.

The high pressure/low pressure interlock equipment which is provided is given in Subsection 7.6.1a.3.3. This section has been revised to include the second motor operated valve (E11-F022) in the RHRS Head Spray. The reference to E51-F066 (the check valve for the Head Spray) is incorrect and has been replaced by the above mentioned motor operated valve.

QUESTION 211.217

Discuss the design provisions that permit manual override on the ECCS subsystems once they have received an ECCS initiation signal. Also include a discussion of any lockout devices or timers that prevent the operator from prematurely terminating ECCS functions. For example, if offsite power is not available, the operator must wait until the core is flooded, and thus secure several of the ECCS pumps, to permit the manual starting of the RHR service water pumps without overloading the diesel generators. Discuss the design provision that permits the operator to shutdown these ECCS pumps after they have been automatically started.

RESPONSE:

The HPCI pump turbine driver can be stopped after starting automatically by: (1) closing the steam supply isolation valves, (2) tripping the turbine by using the remote turbine logic then closing the steam supply isolation valves, or (3) tripping the turbine by using the manual isolation switch (logic B). The HPCI turbine auxiliary oil pump must be stopped with each of the alternatives. The third of the alternatives is the preferred method as the system can be easily started again without delay. See Dwg. M1-E41-6, Sh. 1, M1-E41-6, Sh. 2, M1-E41-6, Sh. 3, M1-E41-6, Sh. 4 and M1-E41-6, Sh. 5 for the logic diagram. Provisions in the control logic of the RHR and core spray pumps permit the operator to stop any pump after an automatic initiation. No time delays exist in the pump control circuitry. In addition the core spray injection valve and LPCI outboard throttling valves can be closed or throttled in the presence of a LOCA signal to control pump flow or isolate the system as necessary. The LPCI outboard throttling valve cannot be controlled by the operator until 5 minutes after the initiation signal.

No such delay timer exists in the core spray valve logic. Refer to Dwg. M1-E21-3, Sh. 1, M1-E21-3, Sh. 2, M1, E21-3, Sh. 3, M1-E11-5, Sh. 1, M1-E11-5, Sh. 2, M1-E11-5, Sh 3, M1-E11-5, Sh. 4 and M1-E11-5, Sh. 5 for logic diagrams.

In the absence of offsite power, it is necessary to stop 2 RHR pumps and 2 core spray pumps in order to establish long-term cooling in one plant while a forced shutdown is required in the second plant. Placing the core spray pump switch or RHR pump switch momentarily in the "stop" position will cause that pump to stop and block the incoming auto start signal.

QUESTION 211.218

Provide piping isometric drawings that show the relative elevations and physical locations of the valves, suppression pool, primary containment, pumps, heat exchangers, and the lengths of piping for the entire ECCS. The locations and valve numbers of all valves should be shown on the isometric drawings. The valve nomenclature should be identical to that used on the P&ID's presented in the FSAR.

RESPONSE:

The drawings listed below provide the required information for the LPCI injection and shutdown cooling modes of the RHR system, the HPCI system and the CS system. The referenced drawings also include isometrics of the "keep full" lines for the RHR, HPCI and CS systems. These drawings were transmitted to NRC via PLA-522 dated 8/1/80.

LPCI and Shutdown Cooling Mode of RHR

SK-M-950	HBB-110-2	SK-M-5077
DBB-107-1	HBB-110-3	SK-M-5078
DBB-107-2	HBB-110-4	SK-M-5101
DCA-108-1	HBB-111-1	SK-M-5102
DCA-110-1	HBB-111-2	SK-M-5139
DCA-110-2	HBB-111-3	SK-M-5140
GBB-104-1	HBD-174-1	SK-M-5142
GBB-104-2	HBD-174-2	SK-M-5747
GBB-104-3	HCD-105-1	SK-M-5748
GBB-104-4	HCD-9-1	SK-M-5801
GBB-105-1	HCD-9-2	SK-M-5802
GBB-105-2	HCD-11-1	SK-M-6089
GBB-106-1	HCD-11-2	SK-M-6090
GBB-106-2	HCD-112-1	
GBB-116-1	HCD-112-2	
GBB-116-2	SK-M-5053	
GBB-117-1	SK-M-5055	
HBB-110-1	SK-M-5057	

HPCI

DBB-112-1	HCB-101-1	HCD-11-1
DBB-117-1	HCB-103-1	HCD-11-2
DBB-119-1	HCB-104-1	HCD-105-1
DBB-120-1	HCD-9-1	HCD-114-1
DBB-120-2		HCD-114-2
DBB-121-1		SK-M-5349
DBB-121-2		SK-M-5387
DBB-121-3		SK-M-5401

DLA-103-1
DLA-104-1
DLA-104-2
DLA-104-3
DLA-105-4
EBB-102-1
EBB-102-2
HBB-107-1
HBB-109-1
HCB-1-2
SK-M-5423
SK-M-5424
SK-M-5606
SK-M-6102
SK-M-6103

CORE SPRAY

DBB-113-1
DBB-113-2
DCA-107-1
DCA-107-2
DCA-109-1
DCA-109-2
GBB-101-1
GBB-101-2
GBB-101-3
GBB-101-4
GBB-102-1
GBB-102-2
GBB-102-3
GBB-103-1
GBB-103-2
HBB-104-1
HBB-104-2
HBD-183-1
HBD-183-2
HCB-1-2
HCB-101-1
HCB-102-1
HCD-9-1
HCD-9-2
HCD-11-1
HCD-11-2
HCD-105-1
HCD-111-1
HCD-115-1
SK-M-5007
SK-M-5168
SK-M-5263
SK-M-5264
SK-M-5265
SK-M-5266
SK-M-5393
SK-M-5395

QUESTION 211.219

Section 6.3, III, 24 of the Standard Review Plan recommends that periodically ECCS pumps and valves are to be operated (on normal and emergency power) to demonstrate that the system can respond to a LOCA. These tests are to be completed during plant operation. During refueling outages, the ECCS systems are tested to verify proper coolant flow to the reactor vessel. The FSAR indicates that "flow test" lines are provided for the CS, LPCI, and the HPCI systems, but the type, the duration, and the frequency of the testing is not clear. Provide additional information to specify the "periodic system surveillance" programs for each of the ECCS systems.

RESPONSE:

Technical Specification Section 3/4.5 (Chapter 16 of the FSAR) provides details of the periodic system surveillance programs for each of the ECCS systems.

QUESTION 211.220

Your response to Question 211.70 requires additional clarification. Parameters such as environmental temperature, pressure ramp rates, operating pressure, solenoid voltage, and backpressure were varied consistent with test facility capabilities to establish safety relief valve service life. Provide assurance that the worst anticipated operating conditions were simulated in this test program.

In response to Question 211.70, you state that the accumulator capacity will provide air for one actuation while Section 5.2.2.4.1 states that the accumulator capacity is adequate for two actuations.

In 7.3.1.12.1.4.2, you state that a dual solenoid-operated pilot valve controls the pneumatic pressure applied to the "bellows actuator" which controls the safety/relief valve directly. In Figure 211.70-2, you show a cross-section of a Crosby valve which has a piston type pneumatic actuator. Also, in Table 211.70-1, you state that the SSES safety/relief valves have no pilot valves but in Section 7.3.1.1a.1.4.2, you state that the air accumulator is sized to provide air for five actuations of the pilot valve following a failure of the pneumatic supply. Resolve these discrepancies.

RESPONSE:

Based on existing system specifications the worst anticipated operating conditions were simulated in the relief valve testing program.

Subsection 5.2.2.4.1 calls for one SRV actuation for overpressure protection which is correct for accumulators provided for the relief function. That section calls for two accumulator actuations against 31.5 psig drywell pressure, one actuator against 45 psig in ADS. The response to Question 211.67 further describes these relief valves.

The pilot valve referred to in Subsection 7.3.1.1a.1.4.2 is in the pneumatic supply system and the words "bellow actuator" has been replaced by "piston type pneumatic actuator." Regarding the last sentence, the Crosby SRV does not have a steam pilot valve but instead it has solenoid valves for control of the pneumatic supply to the pneumatic actuator. The air accumulator is sized to provide 5 actuations of the ADS piston type pneumatic actuator via the solenoid valves.

QUESTION 211.221

Recent event reports from operating BWRs have shown that multiple relief valve failures may occur from a common failure mode. Provide assurance that your relief valve design is qualified (including testing after being subjected to a environment representative of an extended time period at normal operating conditions) to support your assumption that 5 of the 6 ADS valves will operate. A history of safety/relief valve operation, including similar valves in other plants, should be included in this evaluation. Both satisfactory and unsatisfactory operation should be included, noted as the number of times the valve opened or failed to open, the number of times the valve closed or failed to close.

RESPONSE:

History on Crosby Type SRVs

Presently valves of a similar but earlier design are installed and have been operated in Chinshan 1&2 and 2 SRVs of a modified design are in Browns Ferry 3 with satisfactory operating results. No unsatisfactory performance has been experienced except for a spare SRV which was installed into Chinshan 1. The spare SRV was reported to have failed to fully reclose after a relief operation.

Although the SRV did reclose with no further anomalies noted, a question exists as to whether gross leakage due to foreign material existed or if in fact the SRV did not fully reclose. A direct means of determining SRV position was not used. The design of the SRVs to be installed into Susquehanna 1&2 is a modified version of that installed in Chinshan 1&2.

Qualification of the Safety Relief Valve Design

Three test units of the modified design of the safety/relief valve were subjected to the following qualification test programs in order to demonstrate compliance with the performance requirements under the specified conditions.

1. Life Cycle Tests - These tests consisted of subjecting each of the prequalification production units to approximately 300 safety and relief actuations in order to verify acceptability of the design to meet the requirements for (a) set pressure, (b) opening and closing response time, (c) blowdown, (d) seat tightness, (e) achievement of flow rated capacity lift (ASME) during each actuation, (f) proper reclosure after each actuation without sticking open or a

tendency thereto, chatter or disc oscillation, and (g) opening of the SRV without any inlet pressure applied which simulates an emergency operability condition. Conditions such as environmental temperature, pressure ramp rates, induced dynamic and static back-pressures, pneumatic operating pressure and solenoid voltage were varied to assure valve operability under normal and transient operating conditions to which the safety relief valve may be subjected. Upon completion of the tests, test units were disassembled and inspected. This test program established the qualified service life of the safety relief valve.

2. Environmental and Seismic Tests - In order to demonstrate acceptability of the design for either an upset, emergency or faulted condition, a test unit was subjected to the tests described in the following paragraphs.

   The test unit subjected to the seismic test was one which had been subjected to the life cycle tests except that the electro-pneumatic actuator assembly used on the safety relief valve had been subjected to the following environmental tests.

   - Environmental Tests

     Prior to seismic testing of the safety/relief valve, the electro-pneumatic actuator assembly was separately subjected to a qualification aging test which consisted of: 1) a reference frame test prior to testing to determine leakage, response timing and solenoid electrical characteristics for subsequent comparison purposes, 2) radiation aging to a cumulative radiation dosage of 3×10^7 RADS, 3) a post radiation reference frame test, 4) thermal aging to a temperature of 343 + 9°/-0°F for a duration of 96 continuous hours (four days) in an air atmosphere with uncontrolled humidity and with 90 psig operating air pressure applied to the inlet side of the solenoid pilot seat, 5) post thermal reference frame tests, 6) mechanical aging in a normal environment by mechanically cycling the actuator assembly 500 times with each solenoid air valve assembly against an equivalent load of 250 psig and with the maximum permitted pneumatic air supply source pressure of 200 psig, and 7) a post mechanical aging reference frame test. The environmentally and mechanically aged electro-pneumatic actuator assembly was then attached to a safety valve which had completed the life cycle tests. This complete test unit was then subjected to the seismic tests as described below.

- Seismic

The test unit was subjected to seismic tests to simulate the normal, upset, emergency and faulted conditions. The seismic test program consisted of 1) resonant frequency determination, 2) nozzle loading, 3) Operating Basis Earthquake, 4) Safe Shutdown Earthquake, and 5) reference frame tests. The resonant frequency determination test was performed using a dynamic evaluation test technique in which the test unit was fixed to a reaction mass with a force input provided by a lightweight armature shaker. The input force and acceleration were monitored to determine the resonant frequencies of the test unit. Resonance was defined as those frequencies where the input force and acceleration have a 90 degree phase relationship.

In the event that a resonant frequency was determined below 33 Hz, a sine dwell test would have been required to show structural integrity. However, the lowest natural frequencies were 33 Hz in all planes and the test was therefore not required.

Testing was also performed to determine the effect of nozzle loads on the test unit. The loads induced into the inlet and outlet flanges represent combined static and dynamic loads anticipated at the piping interfaces when installed in the plant for either normal or abnormal conditions.

The range of nozzle loads was from zero to a maximum of 1,100,000 and 800,000 inch-pounds on the inlet and outlet flanges, respectively. The moments were applied simultaneously by a loading arm and a hydraulic cylinder attached to the outlet flange. Inlet and outlet flange studs were instrumented with strain gages to monitor the effects of the applied moments on the studs.

The moments were applied in incremental steps and the test unit was relief operated at each step and operability characteristics recorded.

The test unit was then subjected to a series of Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE) simulations in each of two test orientations to demonstrate operability assurance during upset conditions. The OBE test consisted of 30-second duration simultaneous biaxial horizontal and vertical phase incoherent inputs of random motion. The horizontal and vertical inputs consisted of frequency bandwidths spaced one-third octave apart over the required frequency range. The amplitude of each one-third octave bandwidth was independently adjusted in each axis until the Test Response Spectra enveloped the Required Response Spectra. The resulting table motion was analyzed by a spectrum analyzer using one-sixth octave bandwidths at 5% damping. The test conditions and operability during each of the OBE tests were varied as shown in Table 211.221-1.

The test unit was then subjected to a Safe Shutdown Earthquake (SSE) simulation. The test and operability conditions during the SSE test are also shown in Table 211.221-1.

Post-OBE and post-SSE reference frame tests were performed to determine the operability effects due to repeated combinations of seismic simulations, nozzle loadings, temperature and pressure.

These reference frame tests consisted of set pressure determination during safety actuation, response time determination during relief actuation, valve leakage, and an emergency operability test. These reference frame tests were performed with induced nozzle loads applied.

In order to evaluate the design capability of the test unit, the OBE and SSE tests were repeated using a higher input level. The test conditions during these tests are shown in Table 211.221-1.

A reference frame test was performed at the conclusion of the high level OBE and high level SSE tests to determine the effects of the simulation.

- Post-Seismic Environmental Tests

  Subsequent to the seismic tests, the electro-pneumatic actuator assembly was removed from the test unit and subjected to post seismic reference frame tests, a negative pressure test, post negative pressure reference frame tests, a postulated Loss of Coolant Accident (LOCA) environment test, and a post LOCA reference frame test and inspection.

Conclusions

The qualification test results (A) verified, by demonstration, that the SRV design will be operable and is structurally sound under the various normal and abnormal environmental and dynamic conditions to which the valve may be subjected either separately or in combination when placed in service, (B) established the basis for confirming the installed and qualified life of the valve, and (c) provided information necessary to enhance the established Quality Assurance program to ensure that new valves are equivalent to the qualified design, are properly installed, operated, maintained and inspected.

TABLE 211.221-1

TEST CONDITIONS

TEST	ORIENTATION	NOZZLE LOADS (IN-LBS) INLET	NOZZLE LOADS (IN-LBS) OUTLET	TEST UNIT TEMPERATURE	INLET PRESS. (PSIG)	OPERABILITY CONDITION
REFERENCE FRAME TEST						
OBE 1	Longitudinal/Vertical	0	0	Ambient	0	Closed
OBE 2	Longitudinal/Vertical	400,000	300,000	Ambient	0	Closed
OBE 3	Longitudinal/Vertical	400,000	300,000	Operating	1,000	Closed
OBE 4	Longitudinal/Vertical	400,000	300,000	Operating	1,000	Relief
OBE 5	Longitudinal/Vertical	400,000	300,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
SSE	Longitudinal/Vertical	400,000	300,000	Operating	1,000	Relief
REFERENCE FRAME TESTS						
OBE 1	Lateral/Vertical	0	0	Ambient	0	Closed
OBE 2	Lateral/Vertical	400,000	300,000	Ambient	0	Closed
OBE 3	Lateral/Vertical	400,000	300,000	Operating	1,000	Closed
OBE 4	Lateral/Vertical	400,000	300,000	Operating	1,000	Relief
OBE 5	Lateral/Vertical	400,000	300,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
SSE	Lateral/Vertical	400,000	300,000	Operating	1,000	Relief

TABLE 211.221-1

TEST CONDITIONS

TEST	ORIENTATION	NOZZLE LOADS (IN-LBS)		TEST UNIT TEMPERATURE	INLET PRESS. (PSIG)	OPERABILITY CONDITION
		INLET	OUTLET			
REFERENCE FRAME TESTS						
*OBE 1	Lateral/Vertical	750,000	560,000	Ambient	0	Closed
*OBE 2	Lateral/Vertical	1,000,000	750,000	Ambient	0	Closed
*OBE 3	Lateral/Vertical	1,000,000	750,000	Operating	1,000	Closed
*OBE 4	Lateral/Vertical	1,000,000	750,000	Operating	1,000	Relief
*OBE 5	Lateral/Vertical	1,000,000	750,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
*SSE	Lateral/Vertical	1,000,000	750,000	Operating	1,000	Relief
REFERENCE FRAME TESTS						
*OBE 1	Longitudinal/Vertical	750,000	560,000	Ambient	0	Closed
*OBE 2	Longitudinal/Vertical	1,000,000	750,000	Ambient	0	Closed
*OBE 3	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000	Closed
*OBE 4	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000	Relief
*OBE 5	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
*SSE	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000	Relief
REFERENCE FRAME TESTS						
* High Level Inputs						

TABLE 211.221-1

TEST CONDITIONS

Page 1 of 2

TEST	ORIENTATION	NOZZLE LOADS (IN-LBS)		TEST UNIT TEMPERATURE	INLET PRESS. (PSIG)	OPERABILITY CONDITION
		INLET	OUTLET			
REFERENCE FRAME TEST						
OBE 1	Longitudinal/Vertical	0	0	Ambient	0	Closed
OBE 2	Longitudinal/Vertical	400,000	300,000	Ambient	0	Closed
OBE 3	Longitudinal/Vertical	400,000	300,000	Operating	1,000	Closed
OBE 4	Longitudinal/Vertical	400,000	300,000	Operating	1,000	Relief
OBE 5	Longitudinal/Vertical	400,000	300,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
SSE	Longitudinal/Vertical	400,000	300,000	Operating	1,000	Relief
REFERENCE FRAME TESTS						
OBE 1	Lateral/Vertical	0	0	Ambient	0	Closed
OBE 2	Lateral/Vertical	400,000	300,000	Ambient	0	Closed
OBE 3	Lateral/Vertical	400,000	300,000	Operating	1,000	Closed
OBE 4	Lateral/Vertical	400,000	300,000	Operating	1,000	Relief
OBE 5	Lateral/Vertical	400,000	300,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
SSE	Lateral/Vertical	400,000	300,000	Operating	1,000	Relief

TABLE 211.221-1

TEST CONDITIONS

TEST	ORIENTATION	NOZZLE LOADS (IN-LBS)		TEST UNIT TEMPERATURE	INLET PRESS. (PSIG)	OPERABILITY CONDITION
		INLET	OUTLET			
REFERENCE FRAME TESTS						
*OBE 1	Lateral/Vertical	750,000	560,000	Ambient	0	Closed
*OBE 2	Lateral/Vertical	1,000,000	750,000	Ambient	0	Closed
*OBE 3	Lateral/Vertical	1,000,000	750,000	Operating	1,000	Closed
*OBE 4	Lateral/Vertical	1,000,000	750,000	Operating	1,000	Relief
*OBE 5	Lateral/Vertical	1,000,000	750,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
*SSE	Lateral/Vertical	1,000,000	750,000	Operating	1,000	Relief
REFERENCE FRAME TESTS						
*OBE 1	Longitudinal/Vertical	750,000	560,000	Ambient	0	Closed
*OBE 2	Longitudinal/Vertical	1,000,000	750,000	Ambient	0	Closed
*OBE 3	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000	Closed
*OBE 4	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000	Relief
*OBE 5	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000+	Safety
REFERENCE FRAME TESTS						
*SSE	Longitudinal/Vertical	1,000,000	750,000	Operating	1,000	Relief
REFERENCE FRAME TESTS						
* High Level Inputs						

QUESTION 211.222

Section 6.3.3.7.3 of the FSAR states that Figure 6.3-13 is a graphical representation of the break spectrum calculations presented in Table 6.3-3. Figure 6.3-13 is a graphical representation of lower plenum enthalpy versus time. Resolve this discrepancy. The title for Figure 6.3-13 incorrectly identifies the curve as core flow versus time for the 68% DBA recirculation discharge break. Correct the title of the figure.

Figure 6.3-31 appears to be mislabeled as a curve for a DBA recirculation "Discharge" break instead of a suction break. Correct the title of the figure.

RESPONSE:

The reference to Figure 6.3-13 in Section 6.3.3.7.3 is incorrect. The correct figure reference is Figure 6.3-10. The title for Figure 6.3-13 has been corrected to include the figure information presented. The title of Figure 6.3-31 has been changed to read "recirculation suction break" instead of "recirculation discharge break."

QUESTION 211.223

A timer is used in each ADS logic. The basis for the time delay before ADS actuation is to ensure that the HPCI system has time to operate, but yet short enough to ensure that the LPCI or the CS systems can adequately cool the fuel should NPCI fail to start. Manual reset circuits are provided for the ADS initiation signal and primary containment high pressure signals.

Discuss in detail any criteria to be given to the operator (e.g., emergency procedures or operator training) that would form the bases for the operator's decision to use the manual reset circuits to delay or prevent ADS actuation.

RESPONSE:

Instructions for resetting the ADS system are as follows:

1. ADS logic shall not be reset prior to system initiation unless spurious initiation is verified.

2. ADS logic may be reset after system initiation if reactor vessel level is greater than Level 1 and sufficient water delivery capability exists to maintain this level.

Operator Guidelines for Emergency Procedures have been forwarded to the NRC in response to TMI item 1.6.8 submitted under separate cover (PLA-650).

QUESTION 211.224

Section 5.2.2.4.2.1 states that cyclic testing has demonstrated that the safety/relief valves are capable of at least 60 actuation cycles between required maintenance. Are the actuations of the safety/relief valves recorded? If so, how are these data recorded and reported to the NRC?

RESPONSE:

Whenever an SRV is actuated, the actuation is recorded in the process computer providing a record of actuations of each SRV. There are no plans to report SRV actuation data to the NRC as these records are for maintenance purposes.

QUESTION 211.225

Initiation of the HPCI system automatically occurs for a "low water level." Table 6.3-2 of your FSAR indicates that this occurs at or less than 131.6 inches above the top of the active fuel. Figure 5.3-2 indicates that the "low water level" initiation of HPCI occurs at level, L2 or 123.2 inches above the top of the active fuel. Resolve this inconsistency.

RESPONSE:

The value of $\leq$ 10.97 feet above the top of the active fuel in Table 6.3-2 in the Susquehanna FSAR is a typographical error. The correct value is $\leq$ 10.27 feet about the top of the active fuel. This value is consistent with the elevation of the low water level trip, level 2, and the ECCS analysis. Table 6.3-2 has been corrected.

QUESTION 211.226

Provide data to verify that representative HPCI active components (in particular, the pump) have been "proof-tested" under the most severe operating conditions that are anticipated. The service life and the maximum expected operating time accumulated during the service life of that HPCI pump should be specified.

RESPONSE:

The HPCI pump for Susquehanna SES is similar in design and fabrication to pumps that have been installed and operated in BWR plants for several years.

While they have never been called upon to function during a A, these pumps are periodically tested in operating plants and have been shown to perform satisfactorily.

Each pump is tested at the vendor's plant for hydraulic performance and freedom from vibration. This is in addition to the tests and inspections performed during the fabrication of the pumps.

The severe operating conditions to which the pumps are exposed are temperatures to 148°F ambient, maximum expected post-DBA radiation levels and dynamic loads due to the safe shutdown earthquake and hydrodynamic effects associated with the DBA. The pumps are mainly fabricated of metallic materials which will not be degraded by the expected post-DBA temperature and radiation environment. The non-metallic gaskets and seals are made of materials with a demonstrated resistance to the post-DBA environment. The dynamic load inputs are addressed analytically and evaluated against appropriate criteria to assure operation of the pump while undergoing dynamic loading.

The above assures that the expected service life will exceed the expected operating time of approximately 550 hours.

A breakdown of expected operating hours for several events during the life of the pump is provided below:

Event	Operating Time (Hours)
Shop Testing	2
Preoperational Testing	10
Monthly Testing	480
Yearly Testing	40
Post-LOCA	12
Shutdown	N/A

The assumed operating time for post-LOCA is 12 hours for the HPCI pump. The low pressure RHR and CS systems take up the core cooling within 12 hours after incipient LOCA event and maintain the long-term core cooling of post-LOCA subsequent to 12-hour period.

GE stated that the ECCS pump motors meet the environmental qualification requirements of the DOR guidelines and IEEE 323-1971. Prior to June 30, 1982, further qualification work will be preformed to bring these items up to at least the level of IEEE 323-1971 per NUREG 0588 Category II.

QUESTION 211.227

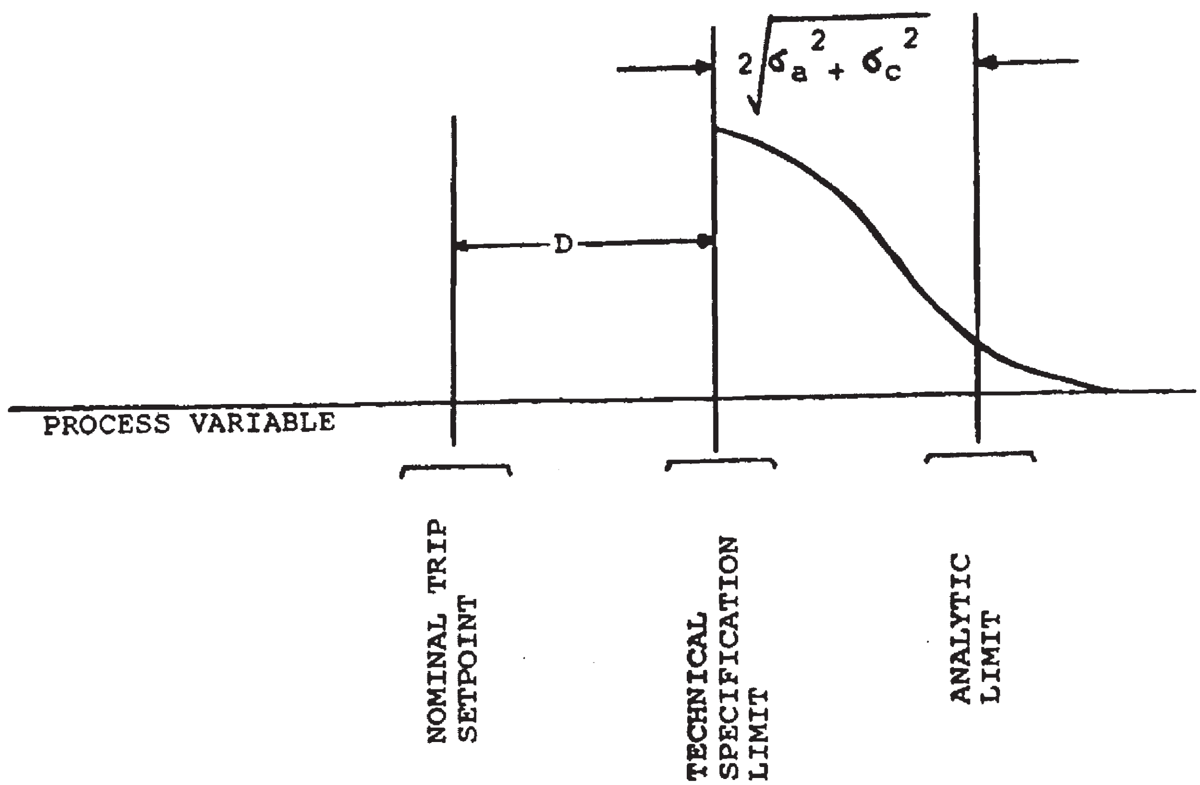
Provide the trip settings and setpoint ranges for the RCIC system isolation instrumentation. Indicate the method of specification of these settings and the provisions for minimizing the potential for inadvertent isolation of RCIC.

RESPONSE:

RCIC system isolation instrumentation trip setting and setpoint ranges are provided in the plant Technical Specifications. The trip setpoints are established from the analytic limit by allowing for instrument drift and accuracy and calibration capability (see Figure 211.227-1).

The indicated allowance for accuracy is that of the sensor as established by the purchase specification. The calibration capability shown is compatible with the instrument accuracy and resolution. The design drift allowance has been chosen to enable the effective trip setpoint to remain within the allowable value over the period between surveillance (calibration) tests, and is based on cumulative field experience derived from virtually identical applications and environmental conditions. The differential between the allowable value and the analytic limit is obtained as twice the square root of the sum of the squares of the sensor accuracy and overall calibration capability (see Figure 211.277-1) Twice the square root was used to give a two sigma value for the combination, based on the accuracy and calibration allowances being conservatively considered as one sigma values. The differential between the trip setpoint and the allowable value is equal to the design drift allowance.

To minimize the potential for inadvertent isolation, the RCIC is field tested (initial startup testing per the startup test program and surveillance tested per the technical specifications) to verify that these setpoints are properly set. For example, the RCIC steam line flow-high is checked and set during initial startup testing of the system to verify adequate margin between the operating value of steam flow (indicated by Δp) and the trip setpoint.



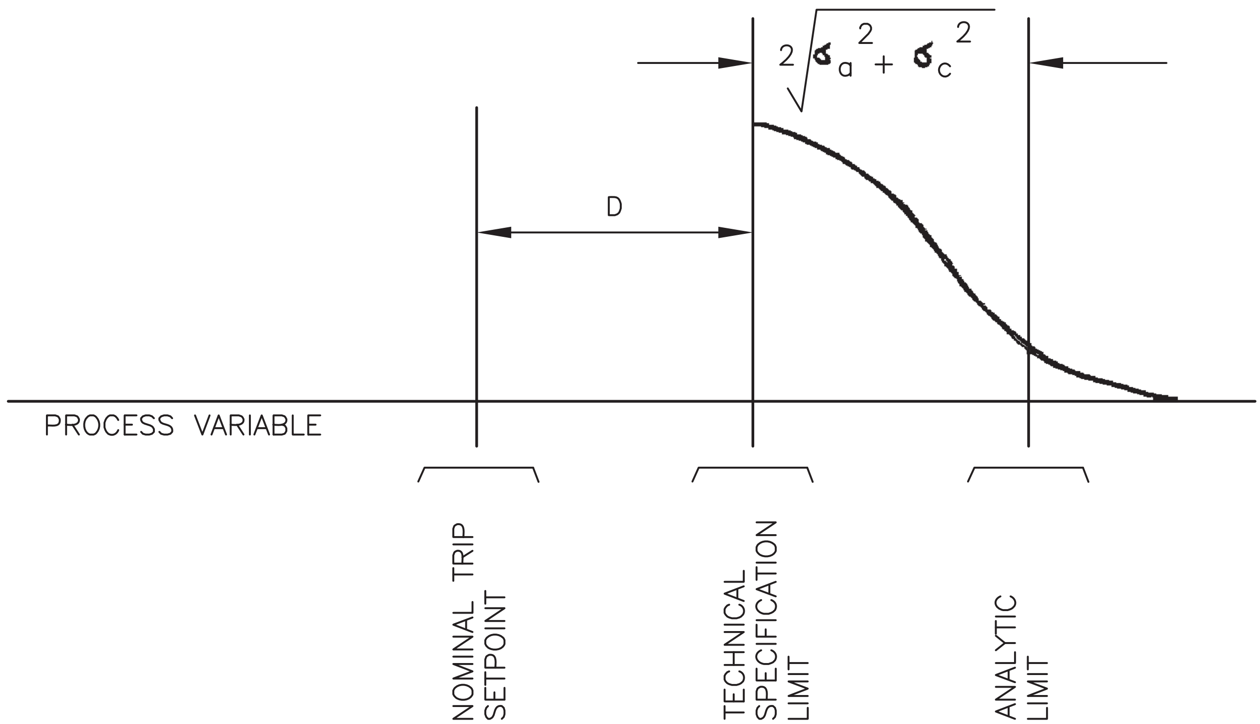
FSAR REV. 46, 06/93

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

TRIP SETPOINT CALCULATION

FSAR FIGURE 211.227-1

PP&L DRAWING



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

TRIP SETPOINT CALCULATION

FIGURE 211.227-1, Rev 47

AutoCAD: Figure Fsar 211_227_1.dwg

QUESTION 211.228

The response to Questions 211.13 and 211.105 require additional clarification.

Reference was made to another BWR/4 with LPCI modification (Shoreham) and the results of an analysis for LPCI diversion at Shoreham was identified as applicable to Susquehanna. Does Susquehanna have an interlock similar to that at Shoreham which would prevent LPCI diversion prior to reflooding the reactor core to the 2/3 level? If not, justify the use of the Shoreham analysis for LPCI diversion at Susquehanna.

Describe operator requirements to activate LPCI diversion. Can the diverted LPCI loop be returned to provide additional core flooding, if required? What instructions, if any, are provided to the operator to ensure that the operable LPCI loop is not prematurely diverted to containment cooling in the event that one LPCI loop is disabled?

RESPONSE:

The Susquehanna Plant, unlike the Shoreham Plant has no level interlock on the LPCI diversion logic. However, for the Shoreham LPCI diversion analysis no credit was taken for the level interlock device.

In that analysis LPCI diversion was always assumed to occur at 10 minutes subsequent to the LOCA initiation signals. Both Susquehanna and Shoreham are BWR/4 plants with LPCI modification and thus have the same complement of ECC systems. Therefore, the Shoreham LPCI diversion analysis results are representative of the expected results for Susquehanna.

Before the LPCI flow can be diverted to either the pool cooling mode or containment spray (wetwell/drywell) mode, the operator has to close the LPCI throttling valve (F027) and then initiate the "manual" switch of the desired diversion mode and open the appropriate valve.

In order to return the diverted LPCI loop to provide additional core flooding, the operator merely needs to close the diversion valve, and manually open the LPCI throttling valve.

Instructions to the operator ensuring that the LPCI flow is not prematurely diverted to the other modes are contained in the "Emergency Procedures Guidelines." Extracts of the guidelines pertinent to LPCI diversion are given below:

- do not secure an ECCS unless there are at least two independent indications that adequate core cooling is assured.

- do not divert RHR pumps from the LPCI mode unless adequate core cooling is assured.

In addition, the Operation and Maintenance Instructions for the RHR system specifies that when the water level in the reactor has been restored to the two-thirds level, and if the drywell pressure has increased to at least 2 psig, only then can the operator make use of the containment spray/cooling operation to depressurize the drywell and/or cool the suppression pool water.

There are no interlocks on the LPCI other than those described above that would prevent the operator from diverting LPCI to drywell or containment sprays. However, in the short term following a loss-of-coolant accident, the operators primary concern will be assuring adequate inventory in the core. In addition, from FSAR Tables 6.2-1 and 6.2-5 and Figure 6.2-2, it is seen that the peak containment pressure for the recirculation line break is well below the design limit with no credit for containment sprays. Consequently, there would be no reason for the operator to divert LPCI to containment spray, since no violation of containment design pressure limits would occur anyway.

QUESTION 211.229

The LPCI head flow characteristics shown in Figure 6.3-7 are incomplete. Provide horsepower, NPSH, and other normal pump characteristics.

RESPONSE:

Figure 6.3-7 shows pressure vessel head over drywell as a function of flow as input into the LOCA analysis. The actual performance parameters of the RHR pump, such as total head, efficiency, brake horsepower, and NPSHR, are depicted in Figure 5.4-15, which is entitled: "RHR Pump Characteristic Curves."

Subsection 6.3-224 has been revised to include the following statement; "The LPCI pump characteristics are shown in Figure 5.4-15."

QUESTION 211.230

Section 7.3.1.1a.1.4.11.2 states that ADS safety/relief valve operability will be monitored by a temperature element installed on the valve discharge piping. Operating experience has shown that a "false" temperature increase may be indicated even though the valve has not operated. Justify use of the temperature element over a direct valve position indication to assure safety/relief valve operability.

RESPONSE:

The temperature element on the SRV discharge piping is used primarily to detect SRV leakage. However, even if a SRV is leaking, the temperature element will measure a temperature increase when the SRV opens initially during an overpressure transient, thus indicating valve operability. In addition, positive valve position indication monitors will be addressed in our response to item 2.1.3.a of NUREG-0578.

QUESTION 211.231

The flow rate from each core spray loop is stated to be 6,350 gpm in figure 6.3-5 and Table 1.3-3. Table 6.3-2 and Table 6.2-2 state that the flow rate per core spray loop is 6,250 gpm. Resolve this discrepancy.

RESPONSE:

The rated flow rate for each core spray loop, as given in Dwg. M1-E21-15, Sh. 1 and Table 1.3-3, is 6350 gpm. For analysis purposes, a flow rate of 6250 gpm, as given in Tables 6.2-2 and 6.3-2, is used.

This accounts for a 100 gpm leakage in the piping connection between the vessel nozzle and the shroud. A note has been added to tables 6.2-2 and 6.3-2 to reflect this.

QUESTION 211.232

Provide assurances that the pre-operational and initial startup test programs outlined in Section 14.2.12.1 and 14.2.12.2 conform to Regulatory Guide 1.68. The statement that "The system performance characteristics are in accordance with applicable design documents" is not acceptable.

Compliance with the criteria outlined in Appendix A of Regulatory Guide 1.68 is not readily apparent. No pre-operational or initial startup test programs for the LPCI (RHR) system were found in the FSAR.

RESPONSE:

Conformance of test programs with Regulatory Guide 1.68 is discussed in Subsection 14.2.7.

Subsections 14.2.12.1 and 14.2.12.2 provide general preoperational and startup test descriptions.

The preoperational test description for the RHR system (including LPCI) is contained in test abstract P49.1.

QUESTION 211.233

Section 6.3.2.9 of he FSAR refers to Table 6.3-9 for a listing of all manual ECCS valves and the methods for assuring correct valve position. Provide Table 6.3-9.

RESPONSE:

Table 6.3-9 was provided in Revision 14 to the Susquehanna SES FSAR.

QUESTION 211.234

The low pressure systems of the ECCS are provided with relief valves to prevent the components and piping from inadvertent overpressurization. Provide justification to support the relief valve capabilities and setpoints that are stated in the FSAR for the Core Spray and Low Pressure Coolant Injection system. The isolation pressure for the low pressure systems should be included in this discussion.

RESPONSE:

The ECCS relief valve setpoints given in the FSAR were chosen to assure that the maximum expected pressure from the worst-case overpressure event does not exceed the ASME code allowable pressure for the ECCS piping. The relief valve capacities will more than accommodate the worst case pressurization event due to either backleakage from the reactor vessel or thermal expansion. The isolation pressure (permissive) for the low pressure systems is stated in the Technical Specifications.

QUESTION 211.235

Tables 6.3-1 and 6.3-2 do not agree on the time delay between initiation signal to HPCI injection valve opening and the HPCI pump at rated flow. Table 6.3-1 states this delay is 35 seconds while Table 6.3-2 states that the delay is 30 seconds. Resolve this discrepancy. Provide the basis for the time delay before the HPCI pump is at rated flow.

RESPONSE:

For design basis accident analysis purposes, the initiating signal for HPCI operation in Table 6.3-1 is conservatively chosen to be the second signal. Consequently, the 35 second time presented in Table 6.3-1 for HPCI injection represents the time required to reach low-low water level plus the 30 second maximum time delay from the initiation signal as presented in Table 6.3-2.

Thirty seconds is the maximum allowable design basis delay time of the HPCI system from the initiation signal to injection at rated flow. This delay time is factored into all ECCS analyses requiring HPCI injection.

QUESTION 211.236

The answers to Questions 211.10 and 211.104 are incomplete. The leak detection system has been described in generalities, but the maximum leak rate and the allowable time for operator action have not been identified. Provide a scenario for the response of the leak detection system and the operator response for the maximum anticipated leak rate. Included in this scenario should be quantitative values for the leak rate and the response times.

RESPONSE:

The responses to Questions 211.10 and 211.104 have been revised.

Refer to revised Subsection 6.3.6 for the worst-case scenario for a passive failure of an ECCS component during the long-term recirculation cooling phase following an accident. There it was assumed that the operator will respond by isolating the affected ECCS train 10 minutes after receiving a flooding alarm. However, NRC Question 211.10 specifies that an operator response time of 30 minutes should be assumed, which is 20 minutes longer than that assumed by PP&L. Consequently, preoperational testing to verify pump NPSH adequacy and absence of suppression pool vortex formation was done at a suppression pool water level low enough to account for the additional 20-minute response time.

A leakage rate of 50 gpm was conservatively assumed as the passive failure. This figure is significantly larger than seal failure leak rates observed in operating plants. The RHR and core spray pump shaft seals are designed such that much lower leakage rates would be expected.

QUESTION 211.237

Section 6.3.3.2 states that conformance to criterion 3 of 10 CFR 50.46, Maximum Hydrogen Generation, is shown in Table 6.3-4. However, Table 6.3-6 shows oxidation fraction versus PCT and MAPLHGR. Provide the maximum hydrogen generation for these conditions.

RESPONSE:

Table 6.3-6 has been revised to include the maximum hydrogen generation (core wide metal water reaction).

QUESTION 211.238

Discuss what monitors are available to identify the source of leakage between such components as the pump seals, valve stem packing, and the equipment warming drains and all other compartment sources drained to the drywell equipment drain tank.

RESPONSE:

For a discussion of detection of leakage past the reactor recirculation pump seals, please refer to revised Subsections 5.2.5.2(2) and 5.2.5.3.2.

Source identification of normally-expected leakage is discussed in Subsection 5.2.5.3.2. Valve stem packing leakage is discussed in Subsection 5.2.5.2(4)

Detection of abnormal leakage outside the primary containment is discussed in Subsection 5.2.5.1.3. Flood detectors are provided in all ECCS pump rooms (RHR, Core Spray, HPCI and RCIC). In addition rooms which could see a steam environment following a pipe break (RHR, HPCI & RCIC) are provided with a steam break detection system.

QUESTION 211.239

With respect to leak detection, provide the following additional information:

1. What is the quantitative relationship between the drainage flow and sump level to the leakage rate from any source?

2. Provide assurance that all leakage within the drywell and reactor building will flow directly to the sumps and that there are no reservoirs which must be filled before any sump drain flow occurs.

3. Provide a schematic of the drywell and the drywell area showing the locations and elevations of leakage detection instrumentation.

4. Are all the components in the leakage detection system qualified for the post-LOCA environment long-term cooling mode of the ECCS?

RESPONSE:

For the responses to Parts 1 and 2 of Question 211.239, please refer to revised Subsection 5.2.5.1.2.4.1.

For Part 3, the location of the leakage detectors is not a significantly useful parameter, because the drywell HVAC system effectively mixes the air, steam and radioactivity throughout the drywell, unless a temperature sensor or monitor sample point is located next to a leak. Estimates of leakages are based on uniform mixing assumptions, hence leaks near detectors will alarm at leak rates lower than those actually necessary to comply with the Technical Specifications on total leakages.

Nevertheless, the locations of the drywell leakage detection monitors are given in Table 5.2-14 for informational purposes. The pressure monitors are not listed, because they are located outside containment.

For the response to Part 4 of the Question, please refer to revised Subsection 5.2.5.1.2.

QUESTION 211.240

On page 5.2-49, in Subsection 5.2.5.1.2.4.1, you state "The drywell equipment drain tank is equipped with two (2) 50 gpm transfer pumps. Either one of these pumps will be capable of preventing the drywell equipment drain tank from overflowing the drywell floor drain sump during conditions of acceptable identified leakage rates." State quantitatively what constitutes acceptable identified leakage rates and discuss the consequences of exceeding these rates.

RESPONSE:

The two 50 gpm transfer pumps have recently been deleted. See revised FSAR Subsection 5.2.5.1.2.4.1. See Technical Specification 3.4.3.2 for acceptable leakage rates and action to be taken if these rates are exceeded. See also revised subsections 9.3.3.1, 9.3.3.5 and Table 9.3-10.

QUESTION 211.241

In Subsections 5.2.5.2, on page 5.2-54, you state:

(a) "The recirculation valve packing leakoff connections are piped to the drywell equipment drain through normally closed isolation valves." Show this on P&I diagram M-143.

(b) "The main steam isolation valve packing leakoff piping is provided with a normally closed isolation valve, and is capped." "Keeping these leakoff connections isolated provides two sets of packings for limiting steam leakage." Estimate the increase in unidentified leakage as a result of the above feature.

RESPONSE:

In Subsection 5.2.5.2 the sentence, "the recirculation valve packing leakoff connections are piped to the drywell equipment drain through normally closed isolation valves," has been deleted. As stated in FSAR Subsection 5.2.5.2, each recirculation valve packing leakoff connection is provided with a normally closed isolation valve, and is capped.

This is shown on revised Dwg. M-143, Sh. 1 and M-143, Sh. 2. Also, revised M-161, Sh. 1, no longer indicates recirculation valve seal drainage to the drywell equipment drain tank.

The increase in unidentified leakage from the main steam isolation valve packing as a result of the normally closed valve packing leakoff isolation valve and cap has not been quantified, however, the design value for steam valve seal leakage is 400 gallons per day (0.28 gallons per minute) for 4 main steam isolation valves inside containment during normal operation. Dwg. M-141, Sh. 1, has been revised to show that the main steam isolation valve packing leakoff connections are each provided with a normally closed isolation valve; and are each capped.

QUESTION 211.242

Sections III.7 and III.8 of Standard Review Plan 5.2.5 state that:

(1) The control room operators shall have a chart or graph that permits rapid conversion of count rate into gpm, that the conversion procedures shall take into account the isotope being monitored and the activity of the primary coolant, and that the plant will maintain a running record of background leakage, so that its effect may be subtracted from any sudden increases in leak detection, which may be "unidentified" leakage and require prompt action. If monitoring is computerized, backup procedures should be available to the operator.

(2) The radiation monitoring systems shall have a radioactive source built into the system to permit system test and calibration during operation, and that the flow of "identified" leakage, which may amount to as little as .05 gpm or as much as 0.25 gpm representing a total daily flow of between 72 and 360 gallons, will be used to provide an operability check during operation for the sump monitoring systems and the containment air cooler condensate flow monitors. The directly measured quantity of flow thus obtained from the sump and air cooler monitors can be used to calibrate the radiation monitoring systems.

Provide verification that the leak detection systems comply with the above requirements. Include a list of all indications available to the above requirements. Include a list of all indications available to the control room operator for evaluating and detecting unidentified leakage of concern. Show how the operator will determine the amount of leakage by observing the indications available to him and how he will maintain a record of background leakage. In addition, discuss the procedures used by the operator to convert all leak detection indications in the control room to a common leakage equivalent; e.g., gpm.

RESPONSE:

For the response to parts 1 and 2 of this question, please see revised Subsection 5.2.5.1.2.3.1C(6). As indicated in FSAR Subsection 5.2.5 in response to Q211.238, the ability of the drywell leak detection system, as a whole, to function effectively is dependent upon many complex, varying and unpredictable factors. Any single part of the system (e.g., Noble Gas concentration, particulate concentration, etc.) may not necessarily work effectively for all kinds of leaks. Thus, the operator will be required to evaluate all available monitors and to use his judgment as to which ones would be applicable to a given situation.

QUESTION 211.243

Section 5.2.5.1.2.3 states that radioactivity monitor alarm setpoints will be set significantly above background to prevent nuisance alarms. Provide an indication of how high above background these alarms will be set and an indication of what size leak these monitor alarms would detect assuming the sump level monitor fails to alarm.

RESPONSE:

Please see the response to Questions 211.238 and 211.242 and refer to Subsection 5.2.5.1.2.3.1C(6).

QUESTION 211.244

Confirm that the RCIC electro-hydraulic system integrated with the turbine governing valve is of safety Class 2, and Seismic Category I design.

RESPONSE:

The RCIC electro-hydraulic system integrated with the turbine governing valve is a safety grade design, specified for Seismic Category I design. A similar turbine assembly has been tested for qualification in accordance with IEEE 344-1975. The electro-hydraulic control system was in its operational modes (start-up, no-load steady state operation, and shutdown) during the test program.

QUESTION 211.245

The ASME Boiler and Pressure Vessel Codes, Section III, Article NB-7000 requires that individual pressure relief devices be installed to protect lines and components that can be isolated from normal system overpressure protection. With reference to the appropriate P&ID, discuss compliance with the above code for the RCIC pump discharge line.

RESPONSE:

The RCIC process diagram recommends that the design pressure for this line be either 1500 psig or dependent on feedwater system shut-off head if this condition exceeds 1500 psig. Since the pump discharge line is designed to the maximum pressure to which it may be subjected to, no pressure relief devices need to be installed.

QUESTION 211.246

In Subsection 7.4.1.1.3.1, you state that one of the two testable check valves on the pump discharge line is located inside the drywel1. According to P&ID Diagrams M-149 and M-141, the RCIC pump discharge line connects to the feedwater line outside the drywel1. Please explain the above inconsistency.

RESPONSE:

The RCIC system discharges to the vessel via the feedwater discharge line. The check valve inside the drywell which is on the feedwater discharge line, discussed in Section 7.4.1.1.3.1 is shown on the feedwater system P&ID. (Dwg. M-106, Sh. 1).

QUESTION 211.247

Some relief valve discharge lines (e.g., for RHR system) penetrate primary containment and have outlets below the surface of the suppression pool. Since these lines form part of the primary containment, the concern is that excessive dynamic loads during relief valve actuation may cause line cracking or rupture. Identify these lines penetrating containment and provide information concerning measures taken to prevent line damage. Of particular concern in this regard are water slugs in lines discharging steam (e.g., RHR head exchangers). Such water slugs would be drawn up from the suppression pool as the result of low pressures with steam condensation or result from inadequate draining of low point.

RESPONSE:

This question was answered previously. Please refer to our responses to Questions 211.99 and 211.58.

QUESTION 211.248

In the evaluation of the turbine trip transients, 0.10 second is assumed for full-stroke closure time of the turbine stop valve. Demonstrate that turbine stop valve closure times smaller than 0.10 second do not result in unacceptable increases in MCPR and reactor peak pressure or provide either (1) justification that smaller closure time cannot occur or (2) a minimum closure time to be incorporated in the Technical Specifications.

RESPONSE:

This historical stop valve closure time has been upheld by all plant operating experience to date as a realistic bound. Sensitivities to this closure time are not great, and the potential uncertainties are conservatively bounded by the generator load rejection event analysis. It assumes a very conservative effective control valve closure time (near 0.07 seconds) based on partially-open, parallel operating turbine admission valves (full arc mode).

That analysis bounds this stop valve closure event without need for additional specifications.

QUESTION 211.249

Provide results of an analysis to demonstrate that no single failure will result in over-pressurization of the RHR system. Provide the design basis used to determine the capacity of the relief valves of the RHR system.

RESPONSE:

The design basis for overpressure protection in the RHR system is that the entire system shall comply with the applicable portions of the ASME Boiler & Pressure Vessel Code Section III Subsections NA, NB, NC and ND as applicable.

RHR low-pressure piping is connected to the reactor coolant pressure boundary of the RHR shutdown suction and discharge connections to the recirculation system, to the main steam piping via the HPCI/RHR steam supply line, and to the vessel head spray. Overpressure protection of each of these lines is discussed in turn in the following paragraphs:

a. RHR suction from the recirculation system and RHR connection to the vessel head spray line: These lines have an inside containment isolation valve and an outside containment valve. Each valve, per line, is interlocked with a separate pressure switch which prohibits opening of the associated valve if the recirculation pressure exceeds the shutdown range. The valve controls are in two separate electrical divisions. The design complies with General Design Criterion 55.

b. RHR shutdown return and LPCI injection line (one line provides both functions): This one contains an inside containment testable check valve which functions automatically to prevent outflow from the vessel. In addition, there are two outside containment isolation valves, viz E11-F015 which is a normally closed gate valve and E11-F017 which is a normally open throttling type angle globe valve. Opening of these two valves in the automatic initiation mode is controlled by four pressure switches connected in a two-out-of four configuration. The switches prevent opening of the two outboard valves when the vessel pressure is too high. In the manual mode either outboard valve can be opened if the other valve is fully closed (testing purposes) or both valves can be manually opened if the vessel pressure is below the setpoint of one of the above mentioned pressure switches. The design complies with GDC 55.

c. Thermal expansion within the RHR system, and reactor system isolation valve leakage, are accommodated by one-inch relief valves. This size valve is considered large enough to accommodate any postulated leakage. Valves E11-F126 and E11-F029 relieve shutdown line thermal expansion or leakage pressure; valve E11-F025 relieves discharge line thermal expansion or leakage pressure. The heat exchangers contain their own thermal expansion relief valves, and the suction piping is relieved by valve E11-F030 whenever the pool suction valves are closed.

QUESTION 211.250

Complete the RHR process flow diagram in Figure 5.4-14 to include the pressures at various locations in the system. For example, the service water outlet and primary coolant inlet pressures at the RHR head exchanger are required in the assessment of the provisions to monitor heat exchanger tube leakage.

RESPONSE:

M1-E11-3, Sh. 1 has been revised to show pressures in the RHR heat exchanger.

The RHR service water pressure is lower than primary coolant pressures. Heat exchanger tube leakage will be from the primary coolant to the RHR Service Water. This leakage will be monitored with a radiation monitor in the RHR service water line downstream of each RHR heat exchanger. A High activity in the RHR service water will be detected by the radiation monitor which in turn will actuate an alarm in the main control room. Operator action will be required to isolate the faulty heat exchanger to prevent the flow of contaminated RHR service water to the spray pond. Prior to isolating the faulty RHR heat exchanger, the operator will have the option of bringing the second RHR heat exchanger on line to maintain the cooling function.

QUESTION 211.251

In Hatch 2, it is possible to discharge reactor coolant into the suppression pool when performing shutdown cooling with the RHR system. Identify any modes of equipment operation that permit such a flow path in Susquehanna. If such paths exist, what design features or instrumentation will be used to monitor this flow?

RESPONSE:

There are no "modes" of operation in the Susquehanna design that are similar to that available at Hatch as referenced in the question. This is due to the fact that in the Susquehanna RHR system the shutdown cooling suction valves (F006) are interlocked with the RHR test line valves (F028) so that the suction valves cannot be opened unless the test line, which returns to the suppression pool, is valved closed. In addition, the shutdown cooling suction valves are also interlocked with the suppression pool suction valves (F004) so that a direct drainage path is not available.

However, there does exist a condition, i.e. the low flow bypass, which will permit reactor water to be directed to the suppression pool. If the shutdown cooling flow should drop too low ($\leq$ 10% of rated) the pump low flow bypass (F007) will open directing the flow to the suppression pool. The bypass valve will close once the minimum flow setpoint has been exceeded. This feature protects the RHR pumps from possible damage caused by a closed discharge valve and will result in a flow from the reactor to the pool of about 1000 gpm. This flow is controlled by the orifice (D001) installed upstream of the bypass valve.

SUPPLEMENT:

Unit 1 and Unit 2 have been modified to prelude valve pressure locking of the RHR suction valves (F004). This modification will install 1" and smaller pressure equalization piping (which includes two 1/8" orifice plates) on each of the RHR HV-151F004A/B/C/D and HV-251F004A/B/C/D valves between their bonnet stuffing boxes and the 24" HBB110 and HBB210 suppression pool side piping (i.e., containment side) to preclude valve pressure locking while in Shutdown Cooling Mode. This modification results in the potential for leakage back to the suppression pool when in Shutdown Cooling Mode. This leakage is estimated to be 10 gpm (Worst Case Design, 2 loops, 98 psi) which is well within the bounding analysis of 1000 gpm. This flow is controlled by orifices FO-15120A/B/C/D FO-25120A/B/C/D, FO-15121A/B/C/D and FO-25121A/B/C/D, and can be manually isolated if required.

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QUESTION 211.252

On previous occasions, leakage of steam past valves in the steam supply lines to RHR heat exchangers has resulted in steam bubble formation and the occurrence of damaging water hammer following startup of the RHR pumps. Describe the provisions (e.g., sensors with alarms) and procedures to be used for Susquehanna to prevent such an occurrence due either to leakage or inadvertent valve opening.

RESPONSE:

Start Historical Section

If inadvertent valve opening or leakage causes system pressure to exceed relief valve F025 setpoint, a high pressure alarm off pressure switch N022 will occur. During normal power operation if a steam bubble is forming in the heat exchanger or steam supply piping, temperature element N004 indicates abnormally high temperatures and causes an alarm to annunciate in the control room. In addition, high temperature on the RHR side of the heat exchanger produces a high temperature in the RHR service water. TE NOO5, located between the heat exchanger and the isolation valves, during normal power operation, cause an alarm in the control room to annunciate on detection of high temperature. Both TE N004 and TE N005 provide inputs to recorder R601 mounted in the control room which can be used in determining the presence and/or the extent of a leak.

Provided as part of the RHR Steam Condensing mode, the steam lines to the RHR Heat Exchangers directly connect to the normally pressurized HPCI Turbine steam supply line. The steam lines are isolated from their respective heat exchanger by two pressure control valves, PV-1F051A and PV-1F052A(B). If alarms are received indicating steam leakage into a heat exchanger, a preliminary action would be to check for closure of the pressure control valves. For those situations where actual leakage past both pressure control valves is experienced, further action would be dictated by the magnitude of the leakage involved. To maintain the heat exchanger and piping filled with water, venting through HV-1F111A(B) or through HV-1F103A(B) and HV-1F104A(B) may be attempted. To reduce the leakage past the isolation valves, a steam trap might be placed on the drain line between the valves. If measures such as these are ineffectual in preventing steam bubble formation, ultimately the HPCI steam supply line would have to be isolated, rendering that system inoperable. At that point, the Technical Specification LCO on HPCI operability would dictate plant operations while attempts were made to repair the leaking pressure control valves.

Response procedures for the specified alarms are available. These procedures will discuss the source of the alarm, the probable cause, automatic actions to be expected and immediate operator actions to be performed.

End Historical Section

QUESTION 211.253

Discuss the procedures for minimizing the potential for exceeding the allowable cooldown rate (greater than 100 degrees Fahrenheit/hour) of the RHR and the reactor coolant system when placing the plant in a shutdown cooling mode following planned normal conditions or an emergency.

RESPONSE:

When either the normal shutdown cooling mode or the alternate shutdown cooling mode (SRV return to pool and suction from pool) is used, the operator controls the cooldown rate via valves F017 (total flow), F048 (heat exchanger bypass flow), F047 (heat exchanger inlet flow) and F003 (heat exchanger outlet flow).

The operator determines the cooldown rate by monitoring reactor coolant temperature change with time. When the process computer is available, the operator is capable of displaying temperature/time information graphically on a convenient CRT to monitor the cooldown rate. A backup to the computer display is manual charting of the temperature information versus time. Either or both of these methods may be utilized by the operator to help maintain the cooldown rate within limits. Recorders will provide the permanent record of cooldown transient information.

QUESTION 211.254

Specify and justify your selection of the core burnup that yields the most limiting combination of moderator temperature coefficient, void coefficient, Doppler coefficient, axial power profile, and radial power distribution which was used in the analytical model for all transients analyzed.

RESPONSE:

As stated in the response to Question 211.136, the nuclear parameters which influence most transient events in Chapter 15 are most limiting of end-of-cycle, all-rods-out conditions. This occurs due to the minimum scram reactivity shape (Figure 15.0-2) which occurs that dominates the power and/or pressure increase transient protection. Some non-limiting events (e.g. recirculation pump trips) are analyzed with smaller void coefficients to represent the beginning, of cycle characteristics. These coefficients are more severe for the transient. Table 15.0-2 provides the values that were utilized and the text for each event discussed the selection of appropriate conditions for that case.

The power shapes utilized in the thermal hydraulic analysis are selected to provide the limiting operating MCPR allowed for the hot channel. The power shape involved in the nuclear parameter selection is based on the design basis, Haling distribution. Expected operation will provide better characteristics (e.g. more favorable scram reactivity shape) throughout the cycle.

QUESTION 211.255

Explain why the transient resulting from recirculating flow control failure with increasing flow is more severe at the low end of the rated flow control line, specifically at 65% NB rated power and 50% rated core flow.

RESPONSE:

At 105% steam flow the recirculation system is operating just below the recirculation system design rating. Consequently, failure of the flow control at this power level introduces negligible power demand upon the system as recirculation flow is already at its maximum. As power level decreases, flow control failure in the increase mode introduces a corresponding larger increase in power demand. 65% power, 50% core flow is also the power point at the end of the auto flow control range and consequently represents the maximum disturbances that is anticipated.

QUESTION 211.256

Explain how Event 11 in Recirculation Loop Flow Control Failure to Maximum Demand (in Appendix 15A) is a planned operation in state C and also in state D with mode switch not in run. (Figure 15A.6-11).

RESPONSE:

The mode switch, when it is not in the run position, will not allow movement of the flow controller. Failure of the controller unit will not result in variation in recirculation flow.

Therefore failure of the controller is not analyzed in this mode and is true for both operating states (C and D).

QUESTION 211.257

In reference to Figure 15.4-7:

a) Explain why the level curves do not show identical traces. Are the traces in percent of level instead of in inches? (This also applies to Figure 15.4-6).

b) Explain why diffuser flow #2, decreases between time T = 2 and T = 3 seconds.

c) Explain why the curves do not show an L-8 trip at approximately 36 seconds, when the narrow range level reaches the trip setpoint. Also explain why Table 15.4-4 indicates an L-8 trip does not occur until 50+ seconds.

d) Explain why vessel steam flow, and turbine steam flow, increase between T = 20 seconds and T = 27 seconds.

RESPONSE:

a) There are three different levels that are presented in Figures 15.4-6 and 7. They are;

1) Level: average actual, "top-of-the mixture" vessel level, inches

2) Wide range instrument level, inches

3) Narrow range instrument level, inches

The vessel internal level is the actual, top-of-the-mixture level, in the vessel bulk-water region outside the separators, the narrow range and wide range levels are instrument measurements of the actual level. These levels always are different because they represent "collapsed" level height with reference column density. Instrument legs for the two sensor ranges are different, giving different readings. They also "see" the effects of variations in dryer pressure drop.

These comments apply to all Chapter 15 level plots of this format. The curves are in inches -- referenced to the location of the bottom of the separator skirt.

b) Figure 15.4-7 shows the Recirculation Flow Control Single Loop Failure with Increasing Flow. Failure of Loop #1 controller to the upper limit causes Loop #1 drive flow to increase with resulting increase in diffuser #1 flow. The resulting positive power excursion is sufficient to scram the reactor. The core inlet flow increases with diffuser #1 flow, initially increasing core pressure drops. Since the demand signal in the second loop remains constant, the second loop diffuser flow drops as it "sees" the increasing core pressure drop during the first few seconds. When scram occurs, the core pressure drop is again reduced, and diffuser flow #2 increases somewhat, then settles out at a slightly below its initial value as the system flow transients approach a steady state condition with total core flow near 90%, but the individual recirculation loop flows still unequal.

c) The curves do not show an L-8 trip at 36 seconds as the trip at this point is of little analytical importance. The reactor has already been scrammed - 2.5 seconds - and no thermal margins are threatened. Steam flow to the turbine is shown to be essentially zero. Level has been brought to its normal/high range and feedwater has been shut off by its normal controls. The exact time of the L-8 trip (if it occurs) is not a key parameter.

d) There is a slight amount of turbine steam flow from 20 to 27 seconds because core inlet flow is in the last stage of settling out to steady state. As the inlet flow decreases slightly, vessel pressure responds by rising slightly due to increased steaming. With increased pressure rise, the turbine control valve is opened slightly to pass steam. Core flow settles out at steady state and the turbine control valve close. A small amount of steam flow (generated by decay heat) is expected to occur. This will automatically be passed through the turbine bypass (or control valves until the turbine is shutdown) when pressure reaches the regulator setpoint.

QUESTION 211.258

The assumed pressure regulator failure at 115% NBR steam flow appears low compared to a failure value of 130% NBR steam flow used in other plant safety analyses. Explain the basis for the assumed pressure regulator failure at 115% NBR steam flow.

RESPONSE:

Current specifications require the limiter to be set at the 115% steam flow demand limit. This is the value assumed for the Susquehanna unit. It should be noted that changing the flow limit from 115% to 130% will have an approximate change of CPR of less than or equal to 0.05.

QUESTION 211.259

Table 15.0-2 does not contain all of the input parameters used in the REDY computer code. For the transients analyzed in Chapter 15.0, provide the following:

a) A list of all input parameters for each transient.

b) Justification that these input parameters for each transient are suitable.

RESPONSE:

Table 15.0-2 was provided to summarize the principal key parameters related to the transient analyses. Qualification of the REDY code is documented in NEDO 10802.

QUESTION 211.260

Identify the Failure Mode and Effect Analysis for evaluating the control rod drive system which you state is provided in Appendix 15A.

RESPONSE:

Subsection 4.6.2 has been revised to state that The Nuclear Safety and Operational Analysis is presented in subsection 15A.6.5.3.

QUESTION 211.261

GE calculations performed for decrease in reactor coolant temperature (Section 15.1) and for reactor pressure increase (Section 15.2) events using the proposed ODYN licensing basis model (NEDO-24154) have shown that in some cases a more limiting CPR is predicted than by the current REDY licensing bases model (NEDO-10802).

Based on a letter to Glen C. Sherwood dated 1/23/80 from Richard P. Denise, the staff's ODYN licensing position is that GE can proceed with ODYN analysis of transients described in Chapter 15 of licensing application Safety Analysis Reports. Provide an ODYN analysis of the applicable events listed in Tables 2-1 and 2-2 of NEDO-24154-P.

RESPONSE:

See revised response to Question 211.112.

QUESTION 211.262

For the "recirculation pump seizure" accident, coincident loss of offsite power is not simulated with the assumed turbine trip and coastdown of the undamaged pump. Reanalyze this transient assuming coincident loss of offsite power and incorporate this reanalysis with that previously requested in Q211.120.

RESPONSE:

The event severity of a coincident loss of offsite power with the postulated recirculation pump seizure accident is bounded by the analysis of "Loss of AC Power" as shown in Section 15.2.6. The only difference between these two events is the core flow coastdown rate. The flow coastdown rate during the pump seizure event coincident with a loss of offsite power is faster than that during the loss of AC power transient. The loss of AC power causes this event to become a pressurization event. The faster flow coastdown for pressurization events are less severe because of negative void reactivity coefficient. If the loss of offsite power were coincident with the high water level turbine trip, the resulting accident would be less severe than the one analyzed in the FSAR. This is due to the fact that the recirculation pump trip will occur earlier in the former accident.

To discuss the effect of core coastdown rate on CPR, the following is presented. Core coastdown rate has an effect on the change in CPR. This effect has two critical components which vary inversely with each other. The inverse relationship exists between the heat generation rate (neutron flux) and the heat dissipation rate (thermal hydraulics). The faster the coastdown rate, the faster the neutron flux drops; but, the slower the residual heat in the fuel is dissipated.

The events in Chapter 15 are analyzed to conservatively account for this relationship with regard to the change in CPR.

QUESTION 211.263

Table 6.3-3 specifies that the limiting break is a 1.5 square foot (0.80 DBA) break in a recirculation discharge pipe with a peak cladding temperature of 1874°F. The same peak cladding temperature (1874°F) is shown for the 0.68 DBA case shown in Table 6.3-6.

Section 6.3.3.7.4 indicates that the most limiting case is obtained by combining the LAMB/SCAT results for the 0.80 DBA case with the SAFE/REFLOOD results for the 0.68 DBA case.

Explain the bases for selecting 0.8 DBA rather than a larger break for use in the LAMB/SCAT analysis since larger breaks generally decrease the time to boiling transition.

Are the values listed in Table 6.3-3 for the 1.5 square foot recirculation break the results of combining the 0.68 and the 0.80 DBA results?

Discuss the reasons for the 0.68 DBA having the longest period for which the hot node is uncovered.

Provide curves to show the results of the 0.80 DBA analyses and curves of the composite analyses used to identify the limiting break.

RESPONSE:

In determining the peak clad temperature the (PCT) for large breaks, LAMB/SCAT calculations are generally performed for selected breaks (i.e. 1.0 ft^2, 60% DBA, 80% DBA and the 100% DBA break).

For the PCT calculation for a particular break size the LAMB/SCAT analysis results of the next largest calculated break size are conservatively used. Hence, the SAFE/REFLOOD results of the .68 DBA break size were combined with the LAMB/SCAT results of the 0.8 DBA break size. This procedure is expedient and results in a conservative calculation of PCT because an earlier time of boiling transition is combined with the longest duration of hot node uncovery (i.e. SAFE/REFLOOD results). It follows from the above discussion that to combine the SAFE/REFLOOD results of the .68 DBA with the LAMB/SCAT results for a 100% DBA break size would introduce additional, unwarranted conservatisms into the PCT calculations. Hence, the use of the current procedure is justified.

Table 6.3-3 has a typographical error. The break size yielding a PCT of 1874°1F should be 1.3 ft^2 (not 1.5 ft) which corresponds to a 68% DBA discharge break. Table 6.3-3 has been corrected. This correction now makes Table 6.3-3 consistent with Section 6.3.7.4 and Figure 6.3-70. Therefore, the PCT of 1874°F presented in Table 6.3-3 is the result of combining the 0.68 and 0.80 DBA results as described above.

The total period for which the hot node remains uncovered (refer to Figure 6.3-70) is determined by the difference between the recovery and uncovery time of the hot node for each break analyzed. The uncovery time generally increases with decreasing break size due to reduced break flow. The recovery time has a tendency to get shorter with decreasing break size in the intermediate break region. However, as the reflooding time is determined by a number of interrelated phenomena such as break flow, depressurization rate, counter current flow limiting (CCFL) effect the reactor coolant inventory at the time of ECCS injection, and the combination of available ECCS. Some of these factors, like depressurization rate, can result in an increase or a decrease in reflooding time because of competing effects like the impact of CCFL, flashing and ECCS injection time. The impact of the complex interaction between the competing effects on the calculated reflooding time is then determined by performing the detailed break spectrum calculation, as was done for Susquehanna. Based on these calculations, it can be concluded per the .68 DBA that the impact on the reflooding time of the various negative effects for intermediate breaks, like delayed ECCS injection, more than offset the positive effects, like less break flow.

From Figure 6.3-70 it is observed that the duration of hot node uncovery is considerably smaller (i.e., approximately 30 seconds less) for the .80 DBA break than for the .68 DBA break. Therefore, based on the reasoning discussed earlier, no PCT analysis was necessary for the .80 DBA.

QUESTION 211.264

You state that the quantitative analyses of the spectrum of pipe breaks is covered in Section 6.2, 7.1, 7.3, 8.3, and Appendix 15A. However, most of the information provided applies only to the DBA line break. Provide a list of the pipe size and break locations that were analyzed for LOCA inside containment.

RESPONSE:

The plant specific analyses performed for FSAR Table 6.3-3 are discussed below. Lead plant analyses results (FitzPatrick) were used for the feedwater line, core spray line, and inside the containment steamline breaks. In the lead plant analysis a double-ended, guillotine break was analyzed for each line.

1. Large Breaks

In the large break region (i.e. breaks 1.0 ft^2) a substantial amount of the vessel inventory is lost out the break and has to be made up by the ECC system. Therefore the limiting single failure is the one which eliminates the largest amount of ECCS reflooding flow. For Susquehanna (i.e. a BWR/4 with the LPCI modification) this limiting single failure is the failure of the LPCI injection valve.

a. Recirculation Discharge Breaks

Failure of the LPCI injection valve in the unbroken loop eliminates 2 LPCI. Also no credit is taken for the 2 LPCI which inject into the broken loop. Therefore the systems remaining are 2 LPCS (low pressure core sprays) + HPCI (high pressure coolant injection) + ADS (automatic depressurization system).

Although the HPCI is available, it is not very effective for large breaks, which rapidly depressurize the vessel. This is so because the HPCI has a minimum operating pressure of 165 psia.

The following break sizes were analyzed with the SAFE and REFLOOD codes to determine the total hot node uncovered time and hence the limiting breaks:

1.936 ft^2 (100% DBA), 90% DBA, 80% DBA, 70% DBA, 69% DBA, 68% DBA, 67% DBA, 66% DBA, 65% DBA, 60% DBA, 1.0 ft^2

These results are summarized in Figure 6.3-73 of the FSAR.

b. <u>Recirculation Suction Breaks</u>

Failure of the LPCI injection valve in the unbroken loop eliminates 2 LPCI.

Also, no credit is taken for the injection of the 2 LPCI in the broken loop until the recirculation discharge valve closes. This valve does not begin closing until the system pressure is approximately below 200 psia. It also has maximum closing time of approximately 33 seconds.

Therefore, though some LPCI flow is available, its injection is significantly delayed. The following break sizes were analyzed with the SAFE and REFLOOD codes to determine the total hot node uncovered time and hence the limiting breaks:

4.159 ft^2 (100% DBA), 90% DBA, 80% DBA, 70% DBA, 60% DBA, 50% DBA, 40% DBA, 30% DBA, 1.0 ft^2

These results are summarized in Figure 6.3-74 of the FSAR. They clearly show that for this break location the 100% DBA is the limiting point. This point was analyzed with the large break method as described in Section 6.3.3.7.4. The results showed that the recirculation suction breaks were less limiting than the discharge breaks previously discussed (refer to Table 6.3-3).

2. <u>Small Breaks</u>

In the small break region (i.e. breaks 1.0 ft^2) there are several competing effects which determine the PCT. These effects include depressurization rate, break size, break flow, and counter current flow limiting (CCFL) effects. These effects in combination with the available ECCS determine the limiting break/failure combinations. A list of the plant specific

Susquehanna analyses performed in this region are given below and are summarized on Table 6.3-3 and in Figure 6.3-10 of the FSAR.

a. Recirculation discharge Breaks

1. HPCI failure (2 LPCI + 2 LPCS + 2 ADS remaining)

   Breaks (ft^2) analyzed:

   .5, .4, .3, .2, .16, .14, .12, .10, .09, .08, .07, .06, .05, .0 4, .02

2. Diesel generator failure (HPCI + 1 LPCI +1 LPCS + ADS remaining)

   Breaks (ft^2) analyzed:

   1.0, .7, .6, .5, .45, .4, .35, .3

3. LPCI injection valve failure (HPCI + 2 LPCS + ADS remaining)

   Breaks (ft^2) analyzed:

   1.0, .9, .8, .7, .6, .5

   For recirculation discharge line breaks no credit is taken for the LPCI flow into the broken loop.

b. Recirculation Suction Breaks

1. HPCI failure (4 LPCI + 2 LPCS + ADS remaining)

   Breaks (ft^2) analyzed:

   0.1, .08, .06, .04, .02

2. Diesel generator failure (HPCI + 3 LPCI + 1 LPCS + ADS remaining)

   Breaks (ft^2) analyzed:

   1.0, .9, .8, .7, .6, .5, .4, .3, .25, .2

3. LPCI injection valve failure (HPCI + 2 LPCI + 2 LPCS + ADS remaining)
   Breaks (ft^2) analyzed:

   1.0, .9, .8, .7

QUESTION 211.265

In several transient and accident analyses (e.g., loss of offsite power, rod drop accident) RCIC is credited as the backup system to HPCI for providing initial core cooling. RCIC normally takes suction on the condensate storage tank (CST) but must be manually switched to the suppression pool should CST water be unavailable. Since the CST and its piping are not qualified structures, consideration must be given to a delay in the cooling function. What is the effect on the consequences for each event of a 20 minute delay in the switchover of RCIC to the suppression pool assuming HPCI has been incapacitated by a single failure (see Q211.144).

RESPONSE:

The combined likelihood of the particular initiating event, unavailability of normal feedwater, total failure (simultaneous) of the CST, and failure of the HPCI system is considered to be very small. Even if manual action were required, we believe the 10-minute design basis remains appropriate but see no situation with high enough likelihood or significant sensitivity to pursue any further.

QUESTION 211.266

The response to Q211.21 is not sufficient. Provide the CPR for the limiting transient in analytical category 3 (Table 211.21-1).

RESPONSE:

Table 211.21-1 which is originally contained in the response to Staff Question 211.21 has been revised. Any one of the transients in category 3 (section 15.3) is initiated by core flow reduction which then causes core power to drop quickly. The core power and core flow are the major parameters affecting the thermal margin. For the transients concerned, the gain of thermal margin due to core power reduction is at least comparable to the loss of thermal margin due to core flow reduction. The impact on the thermal margin of the vessel pressure variation is insignificant.

Therefore, the change of CPR for the transients in category 3 is insignificant. The 0.02 of CPR is estimated to be large enough to bound the CPR for the limiting transient in category 3.

QUESTION 211.267

The response to Q211.113 is not acceptable. Modify NSOA figures in Appendix 15A to include nonsafety-grade systems or components which mitigate event consequences.

RESPONSE:

Appendix 15A figures have been modified to include nonsafety-grade systems or components. The table provided with the response to Question 211.139 was used as the primary source of data for the 15A figure modifications.

QUESTION 211.268

The response to Q211.19 needs further clarification. Provide justification that results of Hatch 2 (a BWR 4/218-560) are applicable to Susquehanna (a BWR 4/251-764).

RESPONSE:

The study analyzing the generator load rejection transient with concurrent failure of the direct scram, the RPT function and the bypass function was performed for the lead plants of BWR/4, 5 and 6. This study has shown similar results for all the plants analyzed, which have different reactor vessel sizes and different design characteristics. Susquehanna and Hatch 2 are both BWR/4 with similar plant characteristics. The transient responses are similar. Therefore, the results and conclusion of the generator load rejection with concurrent failure of the direct scram, the RPT function and the bypass function for Hatch 2 plant are applicable to the same transient combination for Susquehanna plant.

QUESTION 211.269:

The response to Q211.110 is not complete. The "system bypass failure" safety system block should be added as in Figure 15A.6-30 (Item (1) of Q211.110).

RESPONSE:

Per Question 211.110 (Item 1) Figure 15A.6-31 has been revised to agree with the Protection Sequence for Main Generator Trip without bypass at < 30% power depicted in Figure 15A6.30.

QUESTION 211.270

Review of the "loss of all feedwater flow" transient indicates the feedwater flow decreases to zero in 5 seconds. For the analyses presented in the FSARs indicated below, the reactor vessel water level decreases to the L3 scram trip setpoint as follows:

FSAR	Time at which L3 trip occurs sec	Vessel ID, in./no of Fuel Assemblies	Rated Power, MWt
Susquehanna	4.6	251/764	3293
Fermi-2	6.8	251/764	3293
Grand Gulf	4.1	251/800	3833
WNP-2	7.36	251/764	3323

Based on power level and vessel size only, the L3 setpoint for Susquehanna should be attained at approximately the same time as Fermi-2 and WNP-2. Explain why there is a difference between the times that the L3 trip is attained for Susquehanna and the other reactors. Include appropriate design considerations (differences in piping design, level setpoints, etc) in the response.

RESPONSE:

Although the power level and vessel size for the Susquehanna plant are approximately the same as those for Fermi-2, Grand Gulf, and WNP-2, the "loss of all feedwater flow" transient analyzed in Susquehanna is done without taking credit for the recirculation flow reduction logic at the early stage of the transient. The effect of bypassing this recirculation runback is to keep core power high and reduce level quicker than if the recirc runback had been initiated. (Note that value for Grand Gulf is 6.7 sec. - not 4.1 sec.)

To address the effect on CPR with and without credit for the recirculation runback, the following is presented. The transient as analyzed for Susquehanna is the most conservative approach to stimulate the event. The effect of bypassing the recirculation system runback allows the recirculation system to continue to operate at the same speed instead of slowing down. Continuing at the same speed maintains the core injection flow at the same rate thereby causing the core water level to drop faster. The sequence of events occur much more rapidly and the effect on CPR is to increase as compared to the CPR with taking credit for recirculation runback.

The impact on MCPR however is small and the resultant MCPR remains above 1.10 for either case.

QUESTION 211.271

For each transient and accident analyzed in Chapter 15, identify each normally operating system for which credit has been taken.

RESPONSE:

Abnormal operational transients are defined as events which are results of single equipment failures or single operator errors that can be reasonably expected during any normal or planned mode of plant operations. Following the assumed single failure, which is assumed to fail in the worst direction, the resulting transient is simulated in a conservative fashion to show the response of primary system variables and how the various plant systems would interact and function. In the analysis, the plant instrumentation and controls, plant protection and reactor protection systems, except the assumed failure, are assumed to maintain normal operation unless specifically designated to the contrary in order to provide a realistic transient signature. The effects of single failures and operator errors on the transients are also discussed and presented in Chapter 15 of FSAR. In these transients, the consideration of any additional failure is not considered appropriate within the realm of abnormal transient definition.

Nevertheless, the worst plant control mode is assumed in the transient simulation to provide a conservative safety evaluation to cover all possible plant operation modes. For example, manual flow control mode is assumed in the transient analysis. Furthermore, some control systems are saturated during the transient (e.g., pressure control is saturated during pressurization events) and, consequently, there is no effect on thermal or pressure margin during transients. In addition, most of transients analyzed are mitigated by reactor scram. Thus, the effect of control system operation on the thermal and pressure margin is insignificant and minimal. Therefore, it is concluded that although control systems operation is assumed in transient simulations to provide realistic transient signatures, additional failures assumed in these systems would generally not make the transient significantly more severe than the events already presented in the FSAR.

QUESTION 211.272

It is indicated that the "pressure regulator-closed" transient with failure of the backup pressure regulator is less severe than the "turbine trip with bypass" transient in Section 15.2.3. This agrees with GESSAR 238. As a result, only a qualitative evaluation of the transient was provided.

However, quantitative results from the Grand Gulf FSAR indicate the opposite.

The staff's concern is that quantitative results for this transient may be similar to those for Grand Gulf. Provide a quantitative analysis of the "pressure regulator-closed" transient with the ODYN mode assuming failure of the backup pressure regulator and revise Section 15.2.1.2.3 accordingly. This request should be coordinated with the ODYN request via the 211.160 question.

RESPONSE:

This transient is included in the ODYN reanalysis for Susquehanna.

QUESTION 211.273

Revise Table 15.2-15 to indicate the time that suppression pool alarms are received, the Technical Specification limit of 130°F is exceeded, and the maximum value of the suppression pool temperature is attained.

RESPONSE:

Table 15.2-15 has been revised to show the time of which Technical Specification temperatures at:

1) 90°F-normal operating limit

2) 110°F-SCRAM the reactor if not already SCRAMED

3) 120°F-begin manual depressurization, if not already begun

The Suppression pool reached a temperature of 120°F at 24 minutes. The Suppression pool reached a temperature of 130°F at 48 minutes. However, the basis for the questioned Technical Specification at 130°F is unknown. Technical specification limit to depressurize is at 120°F.

QUESTION 211.274

Specific input parameters for the models used to evaluate blowdown rate and suppression pool temperature are shown in Table 15.2-16 along with the analytical results in Figures 15.2-12 and -13. In connection with this, provide the following information:

a) Identify the analytical models used to evaluate blowdown rate and suppression pool temperature.

b) Provide justification that the input parameters used are conservative, by reference to approved topical reports, or other documentation.

RESPONSE:

a) The analytical computer codes used to evaluate blowdown rate and suppression pool temperature response are described in NEDO-10320 and NEDO-10320 supplement 1, "General Electric Pressure Suppression Containment Analytical Model," and in NEDE-20877, "Long Term Containment Response for BWR."

b) Table 15.2-16 has been provided to show the key parameters which relate to the transient analysis. The short and long term responses were obtained from the models referenced in a) above.

Parameters in which variations might have significant effect upon the results were selected conservatively (i.e. minimum suppression pool mass) to bound the design values and maximize the containment pressure and temperature response.

See revised subsection 15.2.9.3.

QUESTION 211.275

The response to Q211.122 indicates that studies show use of a 40°F HPCI temperature is conservative. Provide a reference to these studies.

RESPONSE:

The introduction of high-pressure core injection (HPCI) into the feedwater sparger, during which the nuclear reactor is operating at some steady state condition, produces an increase in core inlet subcooling. The effect of this subcooling is to decrease the core void fraction and increase the positive void reactivity feedback. In fact, the lower the HPCI injection temperature, the less voiding in the core. This tends to increase the rate of power production and therefore makes the transient more severe.

The design basis water temperature for HPCI ranges from 40°F to 140°F, depending on the water supply source temperature. Therefore, 40°F is the lowest temperature required for HPCI, which represents the most conservative situation.

QUESTION 211.276

From the discussion of single failures for the "inadvertent HPCI startup" transient, it is indicated that a single failure of the pressure regulator or level control will aggravate the transient, resulting in reduced thermal margins. Provide the MCPR and peak vessel pressure values that result for this event with the most limiting of the above single failures considered in the analysis.

RESPONSE:

In the event of the "inadvertent HPCI startup" transient, neither the pressure regulator nor the level controller is expected to fail because both systems are in normal continuous operation at the time of the hypothesized event, and no significant change in their function is demanded by the event. They should simply continue their normal function.

Inadvertent startup of the HPCI results in a mild pressurization. Upon pressurization due to the addition of cooler water into the feedwater sparger, the pressure regulator tends to regulate the vessel pressure by adjusting the position of the turbine control valve. When an active failure of the regulator system is considered, such that the turbine control valves would not open, further pressurization would result which would lead to an event similar to the "pressure regulator failure-close "transient (15.2.1). No significant change in thermal margin protection would occur (< .01 CPR change).

Because of the addition of the cooler water in feedwater sparger, the level control system tends to reduce the feedwater flow to maintain the normal water level. When an active failure of the level control system is considered, the water level would continue to rise. This situation is similar to the "feedwater controller failure-maximum demand" transient (15.1.2) and results in a similar CPR change.

Since the HPCI startup does not challenge these control systems significantly, beyond their normal control functions, the independent simultaneous failure of either is considered extremely unlikely.

Note: The word "aggravate" used in the text does not mean a worse thermal margin. It rather implies an undesirable action (e.g. turbine trip) which may result in reactor scram and shutdown.

QUESTION 211.277

The response to Question 221.3 indicates that 8x8 fuel bundles with two water rods will be used at Susquehanna instead of the 8x8 fuel bundles with one water rod.

a) Have the transients and accidents in Chapter 15 been evaluated with 8x8 fuel bundles using one or two water rods.

b) If the transients and accidents in Chapter 15 were analyzed with the one water rod fuel bundles, would any significant changes in MCPR, peak vessel pressure, percent of rods experiencing boiling transition, and the radiological consequences be expected if the two water rod design was used in the analysis? Discuss any changes to the above event parameters in quantitative terms.

RESPONSE:

The transients and accidents submitted in Section 15 of the FSAR were analyzed with 8x8 retrofit fuel bundles using two water rods.

Subsequent reload analyses have also incorporated Siemens 9x9 fuel bundles with two water rods, as incorporated in each reload core.

QUESTION 211.278

In the description of event sequences for LOCA inside containment, confirm that the zero reference time for Tables 6.3-1 and 6.2-8 are the same.

RESPONSE:

The zero reference time for both tables 6.3-1 and 6.2-8 is the same (i.e. the time of the pipe break).

QUESTION 211.279

The thermal power of 3439 MWt used in Chapter 15 analyses (Table 15.0-2) is indicated as 104.4% NBR. For LOCA calculations inside containment, the thermal power value of 3434 in Tables 6.2-4 and 6.3-2 is indicated as a design overpower of 105%. Explain the discrepancy in the thermal power values specified.

RESPONSE:

In Tables 6.2-4, 6.3-2, and 15.0-2, the conditions are based on 105% of rated steam flow, not an over power of 105%. Table 6.2-4 has been corrected to note that the basis is 105% of rated steamflow. The difference in the thermal power values specified is because transient analyses (Table 15.0-2) are performed assuming a steam dome pressure of 1020 psig (1035 psia), with a corresponding thermal power of 3439 MWt or 104.4% NBR. LOCA and containment analyses (Tables 6.2-3 and 6.3-2 respectively), are performed assuming a steamdome pressure of 1055 psia with a corresponding power of 3434 MWt or 104.3% NBR. Both of these sets of conditions are documented in the heat balance sheet for 105% of rated steamflow. The higher pressure assumed for LOCA and containment analyses provides additional conservatism for these calculations by maximizing the mass and energy released to the containment. The slight difference in power (about 0.1%) has a negligible effect on both transient and LOCA/containment analyses.

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TABLE 9.2-8
SUSQUEHANNA POND WATER ALLOWANCES

LOSS DESCRIPTION	WATER ALLOWANCE ($x10^6$ GAL.)
a) Evaporation due to heat dissipation duty for maximum water loss case.	8.70
b) Drift from wind for maximum water loss case.	5.41
c) System charging volume.	Negligible
d) Maximum solar evaporation losses.	1.06
e) Losses resulting from wave action.[1]	0
f) Losses resulting from sedimentation.[2]	1.0
g) Fuel pool makeup and boundary valve leakage[5]	5.9
TOTAL POND VOLUME REQUIRED	22.1
TOTAL POND VOLUME PROVIDED[4]	22.2

(1) Based on design provisions for protection from this loss.

(2) Negligible sedimentation is anticipated. The value given corresponds to 6 in. of pond depth, which is a conservative allowance between cleaning periods.

(3) Deleted

(4) Based on the Technical Specification low level limit.

(5) A conservative value of 70 gpm over the 30-day transient is used to account for potential boundary valve leakage in the ESW system.

QUESTION 211.281

The response to Q211.3 is unacceptable. Address the requirements of Standard Review Plan 4.6 with regard to the standby liquid control system and the recirculation flow control system.

RESPONSE:

The recirculation flow control system is evaluated against the general design criteria as follows:

a) Criteria 20, 21, 23 and 25: Criteria 20, 21, 23 and 25 are applicable to protection systems only. The recirculation flow control system is a reactivity control system but is not a protection system.

b) Criterion 26: The recirculation flow control system is the second reactivity control system required by this criterion. The requirements of this criterion do not apply within the system itself.

c) Criterion 27: The recirculation flow control system is not intended to control reactivity following an accident. Consequently, this criterion does not apply.

d) Criterion 28: The transient analyses in Chapter 15 evaluate the consequences of reactivity events involving changes in reactor coolant temperature and pressure and cold water addition. The results of these analyses indicate that none of these postulated events causes damage to the reactor coolant pressure boundary. In addition, the integrity of the core, its support structures and other reactor pressure vessel internals are maintained so that the capability to cool the core is assured.

See revised Section 4.6.

The SLC System is evaluated against the general design criteria as follows:

a) GDC 20, 21, 23 and 25: These criteria are applicable to protection systems only. By definition of the protection system described in the GDC 20, the SLC System is not a protection system and, therefore, does not have to meet these GDC's.

b) GDC 26: Although the SLC System is a backup system to the normal reactivity control system, the control rods, the system does not have the capability of reliably controlling the rate of reactivity changes resulting from planned, normal power changes. The SLC System is capable of holding the reactor core subcritical under cold condition in the event the control rod system fails to function.

c) GDC 27: Although the SLC System is capable of injecting the boron into the vessel when all the control rods are fully in, the system is neither intended to be initiated when the control rods are capable of shutting down the reactor, nor designed to inject boron solution into the emergency core cooling system to shutdown the reactor during an accident.

d) GDC 28: This criteria applies to reactivity control system transients which result in an increase in reactivity. The actuation of the SLC system results in a decrease in reactivity and therefore this criteria does not apply.

See subsection 9.3.5.3.

QUESTION 211.282

The text indicates all components of the RCIC system are capable of individual functional testing during normal plant operation. Table 1.3-8 indicates each component, except the flow controller, is capable of functional testing. Resolve the discrepancy with respect to functional testing of the RCIC flow controller.

RESPONSE:

The design flow functional test capability of the RCIC system permits functional testing of all components of the RCIC system including the flow controller as described in subsections 5.4.6.1.2.1 and 5.4.6.2.4. Table 1.3-8 has been corrected.

QUESTION 211.283

Specify the common mode failure probability value for both the control rod drive system (CRDS) and the Standby Liquid Control System (SLCS).

RESPONSE

A Fault Tree Analysis (GE letter dated 8/18/80, McSherry to Buchholz, "Technical Analysis of Probability of Failure to Scram") was completed for both of these systems, and the calculated unreliability is 10^{-7}/reactor year. This unreliability is an estimate of the failure to fully insert at least 50% of the control rods into the core (assuming all rods were initially out); combined with a failure to inject boron into the vessel by the SLCS.

QUESTION 211.284

Is the 12" exhaust pipe shown in Figure 5.4-9a installed as a sparger to prevent flow oscillations which have been known to damage check valves in the turbine exhaust line of the RCIC system? If not, are there other design features used at Susquehanna to prevent this type of damage?

RESPONSE:

The 12-inch exhaust pipe shown in Dwg. M-149, Sh. 1 is installed as a sparger to prevent flow induced oscillations due to steam bubble formation and collapse in the suppression pool. There is no other design feature used at Susquehanna to prevent this type of damage since the sparger will adequately resolve the problem.

QUESTION 211.285

Resolve the following items relating to filtration of condensate water for the CRD hydraulic system.

a) The text description and Figure 4.6-5a indicate that normal filtration of condensate water on the suction side of the CRD water pump is accomplished by a single 25-micron disposable filter. Explain why no filter is provided in the bypass line to allow for servicing of the pump suction filter.

b) Describe provisions in the SSES design and operating procedures to protect CRD hydraulic system components and instruments from pluggage due to inadvertent failure of either the pump suction filter or the drive water filters. If none exist, provide justification that inadvertent failure of either type filter will not cause pluggage and result in failure of the system to perform its function.

RESPONSE:

a) The primary source of CRD system water is the condensate treatment system. The water from the condensate system is of a controlled high quality and not laden with particulate matter. If it is necessary to service the pump suction filter with the CRD drivewater pump in operation, the 250-micron Y-strainer upstream of each pump provides adequate filtration.

b) The pressure drop across the pump suction filter and the pressure drop across the in-service drive water filter are monitored by pressure switches. Both switches provide an alarm in the control room on high differential pressure, indicating a need to remove the related filter from service to prevent inadvertent failure. Annunciators response procedures detail immediate operator actions. As indicators of filter failure, a conductivity switch at the discharge of the drive water filters and a pressure switch on the charging water header also provide control room alarms for which appropriate alarm response procedures are written.

QUESTION 211.286

Identify the layout studies done to assure that no interference exists which will restrict the passage of control rods and the pre-operational test(s) that are used to show acceptable performance.

RESPONSE:

During initial pre-operational testing, an observer who is in direct communication with the control room will observe the operation of each individual control rod and verify that there is no binding or restriction to rod motion and will listen for any scraping or binding noises which may signify rod misalignment. In addition, the function of each CRD drive line will be measured as indicated by the differential pressure developed across the CRD piston during notch withdrawal. These differential pressure traces will be compared to reference traces to assure proper operation and the absence of abnormal friction.

The clearance study that was generically applied to all BWR's 4 & 5 "C" lattice plants with 0.100" channels was issued in Oct. 1975 (reference GE 767E667 Rev. 0). Susquehanna's use of 0.080" channels for the initial fuel load basically means the control rod gap is increased by 0.040." A separate study for C-lattice plants with 0.080" channels was not performed.

QUESTION 211.287

Section 5.4.6.2 of Regulatory Guide 1.70 requires that significant design parameters for all components of the RCIC system be identified and that all components be shown on appropriate P&I diagrams. Design parameters for only a portion of the RCIC components are included in Section 5.4.6.2.2.2. Some of the more important components omitted are the:

a) Water leg (jockey) pump
b) Vacuum pump
c) Vacuum tank
d) Condensate pump
e) Turbine and steam supply drain pots
f) Turbine governing and trip throttle valves
g) Pump suction strainers in the suppression pool

Provide the significant design parameters for all RCIC components not included already in Section 5.4.6.2.2.2 and verify that each component can be identified on Figures 5.4-9a and 5.4-9b.

RESPONSE:

Information taken from turbine instruction manual, VPF 2757-309-1 Susq. 1 VPF 2757-310-1 Susq. 2 & Calculations, VPF 2757-33-4 & 34-2

a) There is no jockey pump system per se. However, there is a discharge line keep fill system shown on Figure 7.4-1 and described in revised Subsection 6.3.2.2.5.

b) Vacuum pump
design pressure 50 psig
temperature 650°F
capacity 17 CFM @10 "Hg vac, 70°F, 15 psig disc.

c) Vacuum tank
design pressure 15 psig
temperature 212°F

Condenser
design pressure 50 psig
temperature 650°F

d) <u>Condensate pump</u>
design pressure 50 psig
temperature 650°
23GPM @10 "hq, vac, 70°F, 50 psig disc.

e) <u>Turbine and Steam Supply Drain Pots</u>

<u>Turbine</u> ASME Section III, Class 2 piping to barometric condenser. See existing write-up

<u>Steam Supply</u> As above with 600 lb/hr steam trap rated @ 1120 psig inlet and 1130 psid differential pressures

Also condensate high level switch which opens 1" bypass of steam trap

f) <u>Turbine governor and trip/throttle valves</u>
design pressure 1250 psig
temperature 575°F
normal operating pressure, 1105 psig

g) <u>Pump Suction Strainers in Suppression Pool</u>
Rated flow 600 gpm each @ ΔP of 4.0 psid with 2 strainers

Rejects particles over .125"

Fabricated of type 316 SS

Significant design parameters for the RCIC System components are defined on the system Piping and Instrumentation Diagram (Dwgs. M-149, Sh. 1 and M-150 Sh. 1) and the Process Diagram (Dwg. M1-E51-81, Sh 1). The primary intent of these system level documents is to define system functional performance parameters and design conditions.

Table 211.287-1 provides a list of the individual items in the RCIC system which corresponds to the items shown on Dwgs. M-149, Sh. 1 and M-150, Sh. 1 (does not include instruments). Part numbers are from the GE parts list for this system. All RCIC components identified in Table 211.287-1 appear on Dwgs. M-149, Sh. 1 and M-150, Sh. 1.

The RCIC Process Diagram (Dwg. M1-E51-81, Sh. 1) defines design pressure, maximum and minimum design temperatures, system flow rates, and operating pressure and temperatures for any particular component or location in the system.

TABLE 211.287-1

RCIC SYSTEM COMPONENT LIST

ITEMS	DESCRIPTION	SUPPLIER
C001	RCIC Pump	G.E.
C002	Turbine Aux Stm Turbine Drives	G.E.
D001	Rupture Disc W/Vac Supp, Turbine Exhaust Line Rupture Disc with the Vacuum Support	A.E.
D002	Rupture Disc W/Vac Supp, Turbine Exhaust Line Rupture Disc with the Vacuum Support	A.E.
D003	Steam Supply Drain Pot Trap	A.E.
D004	Restricting Orifice, Turbine Exhaust Drain Pot Discharge Line	A.E.
D005	Restricting Orifice, Pump Discharge Minimum Flow Line	A.E.
D006	Restricting Orifice, Pump Discharge to CST Line	A.E.
D008	Restricting Orifice, Turbine Exhaust Overpressure Vent Line	A.E.
D009	Restricting Orifice, Pump Discharge to Lube Oil Cooler	A.E.
D010	Restricting Orifice, Trip Throttle Valve Seal Leak Line	A.E.
F004	Diaph. Valve w/Pilot Solenoid Cond Pump Discharge Isol. Valve	A.E.
F005	Diaph. Valve w/Pilot Solenoid Cond Pump Discharge Isol. Valve	A.E.
F007	Gate Valve MO, Steam Supply Line Inboard Isolation	A.E.
F008	Gate Valve MO, Steam Supply Line Outboard Isolation	A.E.
F009	Manual Valve, CST Discharge to Pump Suction Line	A.E.
F010	Motor Operated Valve, CST Discharge to Pump Suction Line	A.E.
F011	Check Valve, CST Discharge to Pump Suction Line	A.E.
F012	Gate Valve MO, Pump Discharge Line	A.E.
F013	Gate Valve MO, Pump Discharge Line	A.E.
F014	Check Valve, Pump Discharge	A.E.
F015	Press Cont Valve, Pump Discharge to Lube Cooler Line	A.E.
F016	Manual Valve, Pump Suction Line	A.E.
F017	Relief Valve, Pump Suction Line	A.E.

TABLE 211.287-1

RCIC SYSTEM COMPONENT LIST

ITEMS	DESCRIPTION	SUPPLIER
F018	Relief Valve, Pump Discharge to Lube Cooler Line	A.E.
F019	Globe Valve MO, Pump Minimum Flow Discharge Line	A.E.
F021	Check Valve, Pump Discharge Min Flow Line	A.E.
F022	Globe Valve MO, Pump Discharge to CST Line	A.E.
F023	Check Valve, Pump Discharge to CST Line	A.E.
F025	Diaph. Valve w/Pilot Solenoid, Steam Supply Line Drain Line Isolation	A.E.
F026	Diaph. Valve w/Pilot Solenoid, Steam Supply Line Drain Line Isolation	A.E.
F028	Check Valve, Vacuum Pump Discharge Line	A.E.
F030	Check Valve, Pump Suction From Suppression Pool	A.E.
F031	Motor Operated Valve, Pump Suction From Suppression Pool	A.E.
F032	Globe Manual Valve, Test Line of Pump Suction from Suppression Pool	A.E.
F033	Relief Valve, Barometric Condenser	A.E.
F034	Manual Globe Valve, Test Line of Pump Discharge Line	A.E.
F035	Manual Globe Valve, Test Line of Pump Discharge Line	A.E.
F036	Manual Globe Valve, Test Line of Steam Supply Line	A.E.
F037	Manual Globe Valve, Test Line of Steam Supply Line	A.E.
F038	Manual Gate Valve, Steam Supply Drain Line	A.E.
F039	Manual Gate Valve, Steam Supply Drain Line	A.E.
F040	Check Valve, Turbine Exhaust Line	A.E.
F041	Manual Globe Valve, Test Line for Turbine Exhaust Line	A.E.
F043	Manual Globe Valve, ΔP Instrument Line for Steam Supply Line	A.E.
F044	Excess Flow Check Valve, ΔP Instrument Line for Steam Supply Line	A.E.
F045	Globe Valve MO, Steam Supply Line	A.E.

9 5 0 3 2 7 0 3 0 7 0

TABLE 211.287-1

RCIC SYSTEM COMPONENT LIST

ITEMS	DESCRIPTION	SUPPLIER
F046	Motor Operated Valve, Pump Discharge to Lube Oil Cooler Line	A.E.
F047	Check Valve, Cond Pump Discharge Line to Pump Suction	A.E.
F048	Manual Globe Valve, Test Line for Cond Pump Discharge to Pump Suction	A.E.
F049	Manual Globe Valve, Cond Pump Discharge to Pump Suction	A.E.
F050	Manual Globe Valve, Pump Vent Line	A.E.
F051	Manual Globe Valve, Pump Internal Discharge Line	A.E.
F052	Manual Globe Valve, Steam Supply Drain Line Test Line	A.E.
F053	Manual Globe Valve, Steam Supply Drain Line Test Line	A.E.
F054	Diaph. Valve w/Pilot Solenoid, Steam Supply Drain Line Trap Bypass Line	A.E.
F055	Manual Globe Valve, Vacuum Pump Discharge Line Test	A.E.
F057	Manual Globe Valve, Pump Discharge Min. Flow Test Line	A.E.
F058	Manual Globe Valve, Pump Discharge Min Flow Test Line	A.E.
F059	Gate Valve MO, Turbine Exhaust Line	A.E.
F060	Gate Valve MO, Vacuum Pump Discharge Line	A.E.
F062	Gate Valve MO, Turbine Exhaust Line Vacuum Breaking Line	A.E.
F063	Check Valve, Turbine Exhaust Line Vacuum Breaking Line	A.E.
F064	Check Valve, Turbine Exhaust Line Vacuum Breaking Line	A.E.
F065	Manual Globe Valve, Turbine Exhaust Vacuum Breaking Line Test Lines	A.E.
F082	Manual Globe Valve, Turbine Exhaust Vacuum Breaking Line Test Lines	A.E.
F083	Manual Globe Valve, Turbine Exhaust Vacuum Breaking Line Test Lines	A.E.
F084	Gate Valve MO, Turbine Exhaust Line Vacuum Breaking Line	A.E.
F088	Globe Valve MO, Steam Supply Bypass Line	A.E.

TABLE 211.287-1

RCIC SYSTEM COMPONENT LIST Page 4 of 4

ITEMS	DESCRIPTION	SUPPLIER
Sub List of C002 (Aux. Steam Turbine Devices)		
	Vacuum Pump	G.E.
	Condensate Pump	G.E.
	Vacuum Tank	G.E.
	Barometric Condenser	G.E.
	Lube Oil Cooler	G.E.
	Turbine Trip Throttle Valve	G.E.
	Turbine Governing Valve	G.E.
	Press Control Valve on Vacuum Pump Discharge Line	G.E.
	Check Valve on Cond Pump Discharge Line	G.E.

QUESTION 211.288

Describe the design features and operating procedures that preclude water hammer effects at the pump discharge of the RCIC system.

RESPONSE:

A keep full system is used to preclude water hammer in the RCIC pump discharge piping. Refer to revised Subsection 6.3.2.2.5 (PL: See attached)

QUESTION 211.289

Section 14.2.12.5 (P50.1) does not provide sufficient details of the RCIC pre-operational and initial startup test program to determine whether the RCIC system meets the requirements of Regulatory Guide 1.68. Provide this information.

RESPONSE:

The description of pre-operational and startup testing of the RCIC are described by the Abstracts for P50.1 and ST-14 in Chapter 14.

Testing to verify that ESF pumps operate within their design pump-head curves and with adequate NPSH will be done. This testing will be addressed in the response to Question 423.32.

Conformance of test programs to Regulatory Guides is discussed in subsection 14.2.7.

QUESTION 211.290

For the majority of events analyzed in Section 15, the recirculation flow control mode (automatic or manual) assumed in the analysis is not specified. Our concern is that the mode selected may not result in the most severe margins on MCPR and peak vessel pressure.

a) Specify the recirculation flow control mode assumed for each event analyzed in Section 15.

b) Specify the change in MCPR and peak vessel pressure for each event if the opposite recirculation flow control mode had been assumed in the analysis.

RESPONSE:

All of the major transient events are simulated with the manual recirculation flow control mode. The analysis evaluated with this mode of operation is more severe in transient results because of the following:

By using the manual flow control option in a hypothesized transient, the recirculation speed controller would lose its communication with the master controller; therefore unable to adjust the core flow as effective as otherwise the master controller would have demanded. As a consequence, the core flow response time will lengthen before a new stable flow condition can be re-established. This delay tends to worsen the simulated transient.

QUESTION 211.291

The intent of Question 211.264 is to have the applicant provide a list of all plant-specific break sizes and locations analyzed. In addition to this request, provide the peak cladding temperature and peak local oxidation associated with each plant-specific break size.

RESPONSE:

Tables 211.291-1 thru 211.291-4 list the peak cladding temperature and peak local oxidation associated with each plant specific break size. The peak local oxidation is only given for the limiting cases; all other cases will be less than the limiting cases.

TABLE 211.291-1

LARGE BREAKS

As stated in the response to Question 211.264, the large break spectrum is analyzed using the SAFE and REFLOOD codes to identify the limiting points. These limiting points are then analyzed using the large breaks method described in Section 6.3.3.7.4. The results for the limiting points are given below.

RECIRCULATION SUCTION BREAKS, LPCI INJECTION VALVE FAILURE

Break (ft^2)	PCT Deg-F	Oxide Fraction
4.2	1688	3.1×10^{-3}

RECIRCULATION DISCHARGE BREAKS, LPCI INJECTION VALVE FAILURE

Break (ft^2)	PCT Deg-F	Oxide Fraction
1.9 (DBA)	1818	6.0×10^{-3}
1.0	1755	4.8×10^{-3}
1.3 (68% DBA)	1874	7.6×10^{-3}

TABLE 211.291-2

SMALL BREAKS

RECIRCULATION SUCTION BREAKS

HPCI FAILURE (4 LPCI + 2 CS + ADS REMAINING)

Break (ft^2)	PCT Deg-F
0.1	1395
0.08	1500
0.06	1386
0.04	1279
0.02	1119

D.G. FAILURE (HPCI + 3 LPCI + 1 CS + ADS REMAINING)

Break (ft^2)	PCT Deg-F
1.0	945
0.9	940
0.8	1089
0.7	1086
0.6	1092
0.5	1062
0.4	1206
0.3	1181
0.25	1036
0.2	883

LPCI INJECTION VALVE FAILURE

Break (ft^2)	PCT Deg-F
0.1	896
0.9	889
0.8	1049
0.7	1031

Note: CS, LPCI Quantity means pumps.
HPCI Quantity means systems.

TABLE 211.291-3

SMALL BREAKS

RECIRCULATION DISCHARGE BREAKS

HPCI FAILURE (2 LPCI + 2 CS + ADS REMAINING)

Break (ft^2)	PCT Deg-F	Peak Oxide Fraction
.5	1126	
.4	1101	
.3	1201	
.2	1299	
.16	1313	
.14	1313	
.12	1348	
.10	1423	
.09	1481	
.08	1531	1.695×10^{-3}
.07	1434	
.06	1369	
.05	1333	
.04	1271	
.02	111	

DG FAILURE (1 LPCI + 1 HPCI + 1 CS + ADS REMAINING)

Break (ft^2)	PCT Deg-F	Peak Oxide Fraction
1.0	1176	
0.7	1195	
0.6	1193	
0.5	1139	
0.45	1272	6.610×10^{-4}
0.4	1339	
0.35	1240	

LPCI INJECTION VALVE FAILURE (1 HPCI + 2 CS + ADS REMAINING)

Break (ft^2)	PCT Deg-F	Peak Oxide Fraction
1.0	1447	9.883×10^{-4}
.9	1379	
.8	1149	
.7	1140	
.6	1142	
.5	1095	

TABLE 211.291-4

STMO BREAKS (3.75 ft^2)

Failure	PCT °F	Oxide Fraction
LPCI IV	No uncovery	
DG	No uncovery	
HPCI	700	3.28×10^{-4}

QUESTION 211.292

Subsection 5.2.2.4.1 of the FSAR states that each safety/relief valve is provided with a device to counteract the effects of backpressure which results in the discharge line when the valve is open and discharging steam. What type of device is provided? What effects would be anticipated if the device were to fail?

RESPONSE:

Backpressure occurs in the discharge line only after the valve is opened and discharging steam. In order to counteract the effects of backpressure (eg-valve cycling and chatter with resulting setpressures variances) when the valve operates in the safety (pressure) mode of operation, the SRV design contains an internal part/feature capable of adjusting the SRV for proper blowdown/valve reclosure. The design feature of the SRV which provides this capability is called the blowdown adjusting ring. Once blowdown adjusted, the blowdown ring is located in place by use of a lockwired setscrew. Should the adjustment be changed or the adjusting ring fail, the valve would cycle or chatter after initial opening if the inlet pressure had not depressurized below the spring set point of the valve. Each valve is production tested and adjusted for proper blowdown that is compatible with the expected plant specific backpressure range to be realized under normal operating conditions.

See revised Subsection 5.2.2.4.1.

QUESTION 21.293

Subsection 5.2.5.3.2 of the FSAR implies that all identified leakage can be measured while the reactor is operating. It is not clear how the base data will be established to permit comparison with the 25 gpm identified leakage limit. Provide the frequency that these data will be recorded and indicate what procedural guidelines are to be used to record the magnitude of the base-identified leakage rate.

RESPONSE:

All identified leakage is piped to the drywell equipment drain tank as stated in Subsection 5.2.5.1.2.4.1. This section describes the operation of the drywell floor drain sumps and states that the operation of the drywell equipment drain tank is similar. The drain tank level is the measured variable used to calculate identified leakage rate. The level is recorded continuously in the control room. The leakage rate, calculated internally by the recorder using the level-rate of change is also recorded continuously, the only exception being during the interval the drain valves are open, at which time the leakage rate pen is reset to "0" gpm.

The operator will be able to monitor the identified leakage rate in three ways:

(1) directly, by reading the leakage rate pen,

(2) by interpreting the rate of change of the level pen,

(3) by noting the number of drain cycles per a given unit time.

This monitoring will be performed once per 12 hours to parallel the monitoring required of unidentified leakage.

QUESTION 211.294

It is unclear whether comparative "grab" samples of the continuously monitored containment atmosphere can and will be taken on a periodic basis. Resolve this ambiguity. If "grab" samples are not to be taken, justify omission of these comparative data.

RESPONSE:

The containment radiation detection system has redundant detector packages that can measure both the drywell and the suppression chamber atmospheres. Each package contains a sampling nozzle drawing from the main sample steam directly preceding the detectors.

The sampling nozzles can be used to obtain grab samples for laboratory analysis. Also, the post-accident sampling station can draw grab samples from two locations inside containment. However, the latter is not intended for use during normal operation.

This method of leak detection (containment atmosphere sampling), due to inherent uncertainties as discussed in Subsection 5.2.5.1.2.3, is only used for supporting information. This, along with the fact that these detectors will be calibrated using known sources, make grab samples on a routine basis during normal operation unnecessary as they will yield no additional information or benefit

Question 211.295

Our position on the emergency core cooling systems (ECCS) is that these systems should be designed to withstand the failure of any single active or passive component without adversely affecting their long-term cooling capabilities. In this regard, we are concerned that the suppression pool in boiling water reactors (BWR's) may be drained by leakage from isolation valves which may be rendered inaccessible by localized radioactive contamination following a postulated loss-of-coolant accident (LOCA). Accordingly, indicate the design features in the Susquehanna facility which will contain leakage from the first isolation valve in the ECCS lines taking water (suction lines) from the suppression pool during the long-term cooling phase following a postulated LOCA.

RESPONSE:

The ECCS is designed to withstand the failure of any single active or passive component without adversely affecting the long-term cooling capabilities. Any leakage from ECCS systems can be isolated and contained. The design features in Susquehanna that assure this capability are described in response to FSAR Question 211.10.

QUESTION 211.296

Calculations of NPSH available to ECCS pumps in BWRs are normally provided with reference to the pump suction. We are concerned that under certain post-accident conditions the potential may exist for damage to ECCS pumps from cavitation because of local flashing in the system suction lines. The potential can result for example from local elevation changes in the piping runs. Calculations of NPSH available at the pump suction may erroneously assume liquid continuity up to the point of pump suction. We require, therefore, that the applicants provide calculations demonstrating that all points in all safety-related suction piping, the NPSH available is adequate to preclude local flashing under the worst postulated conditions.

RESPONSE:

We have reviewed the suction piping for all ECCS pumps to determine if adequate NPSH is available to preclude local flashing in the pipe. Local flashing can occur if the absolute pressure at the point ($h_{a'}$) is less than the vapor pressure (h_{vpa}) of the fluid in the pipe. ($h_{a'} = h_{stat} + h_{atm} - h_{fic} > h_{vpa}$).

The suction piping for the core spray system is horizontal from the suction strainer to the outside of the suppression pool penetration and thereafter it slopes down continuously to the pumps without any vertical rises. In order to demonstrate that localized flashing would not occur under the worst case postulated accident conditions, an evaluation was performed for this section of piping. The following conservative inputs were used for this evaluation:

1) The worst case post-accident suppression pool level, corresponding to the 667.3' elevation;

2) The worst case Core Spray suction strainer differential pressure of 4.3 psid (or 10.31'), which corresponds to the fully fouled condition;

3) A vapor pressure of 29.52', which corresponds to the maximum post accident suppression pool temperature of 203°F; and finally,

4) To be consistent with the intent of Regulatory Guide 1.1, no credit was taken for suppression chamber over-pressurization.

These assumptions, along with the expected piping losses, were used to determine the absolute pressure at numerous points along the Core Spray pump suction pathway. The absolute pressure at each point in the piping was then compared to the vapor pressure of the fluid (29.52') to determine the "margin to flashing". It was concluded that a minimum margin of 2.4' is maintained at the most limiting location, which corresponds to the highest point in the suction piping. Considering that this margin is greater than the vender's specified NPSHr for the Core Spray pumps at the rated loop flow of 6350 GPM (2'), it is reasonable to conclude that liquid continuity in the Core Spray suction lines can be expected, and that the potential for localized flashing will not impact system performance, nor pose a threat to the integrity of piping and/or structures.

Similarly the suction piping for the RHR system is horizontal from the suction strainers to the outside of the suppression pool penetration and thereafter it slopes down continuously to the pump without any vertical rises. As with Core Spray, an evaluation was performed to demonstrate that localized flashing would not occur in this section of piping under the worst case postulated accident conditions. The following conservative inputs were used for this evaluation:

1) The worst case post-accident suppression pool level, corresponding to the 667.3' elevation was assumed;

2) The worst case RHR suction strainer differential pressure of 2.5 psid (or 6.0'), which corresponds to the fully fouled condition;

3) A vapor pressure of 29.52', which corresponds to the maximum post accident suppression pool temperature of 203°F, and finally,

4) To be consistent with the intent of Regulatory Guide 1.1, no credit was taken for suppression chamber over-pressurization.

These assumption, along with the expected piping losses, were used to determine the absolute pressure at numerous points along the RHR pump suction pathway. The absolute pressure at each point in the piping was then compared to the vapor pressure of the fluid (29.52') to determine the "margin to flashing". It was concluded that a minimum margin of 6.2' is maintained at the most limiting location, which corresponds to the highest point in the suction piping. Considering that this margin is greater than the vender's specified NPSHr for the RHR pumps at the rated pump flow of 10000 GPM (3'), it is reasonable to conclude that liquid continuity in the RHR suction lines can be expected, and that the potential for localized flashing will not impact system performance, nor pose a threat to the integrity of piping and/or structures.

The suction pipe for the HPCI pump takes a vertical rise of four feet inside the suppression pool, to the elevation of the suppression pool penetration, elevation 658' 1". Refer to the NPSH calculation presented in the FSAR section 6.3.2.2.1.2. For simplicity, conservatively assume that all 13.23 feet of friction loss (h_f) is between the suction strainer inlet and the high point.

Using the NPSHA numbers from this section, the available $h_{a'}$ would be:

$$h_{a'} = 668.5 - 658.08 + 33.16 - 13.23 = 30.35 \text{ feet}$$

The required pressure is the vapor pressure at 140°F: h_{vpa} = 6.8 feet. Since the $h_{a'} > h_{vpa}$ there is adequate pressure at this high point to prevent local flashing. The remainder of the piping from containment isolation valve to the pump does not go upward and therefore there is no local flashing.

Conclusion: There is adequate NPSH available to preclude local flashing in the ECCS suction piping.

HISTORICAL INFORMATION

QUESTION 221.1

The following information and commitments relative to a Loose Parts Monitoring Systems (LPMS) for the Susquehanna Steam Electric Station are required.

The LPMS manufacturer's sensitivity specifications shall be provided. The LPMS must be operational and capable of recording vibration signals for signature analysis at the time of initial startup testing.

A description of the monitoring equipment including location and basis for alarm settings shall be provided in the FSAR. Anticipated major sources of internal and external noise must be provided along with plans to minimize these sources. A description of precautions taken to insure the operability of the LPMS after operational basis earthquakes is required. A detailed discussion of the operator training program for operation of the LPMS, planned operating procedures, and record keeping procedures is required. Signature analysis records must be utilized and maintained for an appropriate period (e.g., three years).

RESPONSE:

We are unaware of any LPMS acceptable to the staff that has been proven in operation. Although we continue to monitor product developments in this area for possible consideration, we have no plans at this time to incorporate a LPMS due to the unavailability of an effective system.

HISTORICAL INFORMATION

QUESTION 221.2

Section 4.4 contains no discussion of crud and its effect on CPR and core pressure drop. Provide the assumptions used for amount of crud in design calculations and the sensitivity of CPR and core pressure drop to variations in the amount of crud present. Also provide data supporting the assumption on crud thickness and discuss how crud build-up in the core would be detected.

RESPONSE:

FSAR Subsection 4.4.2.11 has been added to provide this information.

QUESTION 221.3

The GEXL data base (for the approved correlation) is for 7x7 and 8x8 one water rod bundles. No substantial data base has been provided to support the 8x8, two water rod design. The GEXL correlation must be demonstrated to be applicable to the new 8x8 design, by comparison to applicable data, prior to issuance of an operating license for Susquehanna. Alternatively, the MCPR limit may be increased by 0.05 to accommodate GEXL uncertainties.

RESPONSE:

FSAR Subsection 4.4.2 has been updated to provide this information.

QUESTION 221.4

You state on page 4.4-6 that "There is reasonable assurance, therefore, that the calculated flow distribution throughout the core is in close agreement with the actual flow distribution of an operating reactor." Does this refer specifically to Susquehanna calculations? What operating reactor was used for the data comparison?

RESPONSE:

FSAR Subsection 4.4.2.5 has been updated to provide this information.

QUESTION 221.5

Your flow distribution discussion does not address uncertainties on the flow distribution or the effect of channel flow uncertainty, coupled with other uncertainties on the MCPR uncertainty. Also, Table 4.4-6 does not address flow distribution uncertainties. Provide this information.

RESPONSE:

FSAR Subsection 4.4.2.9 has been updated to provide this information.

QUESTION 221.6

Page 4.4-17 states "Analytical models of the individual flow paths were developed as an independent check of the tests. When using these models for hydraulic design calculations, nominal drawing dimension are used." Provide the assumptions and equations comprising the model and a comparison of model predictions with data.

RESPONSE:

FSAR Subsection 4.4.4.5.2 provides the required information.

QUESTION 221.7

What fraction of the fuel bundle flow is "water rod flow"?

RESPONSE:

FSAR Subsection 4.4.4.5.2 has been updated to provide this information.

QUESTION 221.8

Page 4.4-18 of the FSAR states that "the nominal expected bypass flow fraction is approximately 10 percent." What is the calculated bypass flow fraction for Susquehanna and what is its uncertainty?

RESPONSE:

FSAR Subsection 4.4.4.5.1 has been updated to provide this information.

QUESTION 221.9

What is the name of the computer program cited in this Section 4.4.4.5? Provide references which document the code.

RESPONSE:

The digital computer program used for thermal hydraulic analysis is a General Electric proprietary code which has not been documented in the form of a Licensing Topical Report to the NRC.

QUESTION 221.10

You state that the stability analyses performed in Section 4.4.4.6.6 and for Figure 4.4-6, were performed "at the most limiting condition that occurs at the end-of-cycle, with power peaked to the bottom of the core. . . ." Indicate which cycle is being referred to (i.e., first, second, or equilibrium). If it is other than equilibrium, provide results for the end of equilibrium cycle or justify why the results presented represent worst-case conditions. Provide the power profile and the void reactivity coefficient used for the analysis.

RESPONSE:

FSAR Subsection 4.4.4.6.6 has been revised to provide this information.

QUESTION 221.11

In discussing the FABLE code on page 4.4-23, you state that "As new experimental or reactor operating data are obtained, the model is refined to improve its capability and accuracy." This means that comparison of old versions of the model with data, as given in Figure 4.4-4, are meaningless for Susquehanna if it has been analyzed with an updated version. Are the comparisons of the model with data, as given in Figure 4.4-4, are meaningless for Susquehanna if it has been analyzed with an updated version. Are the comparisons of the model with data, as given in Figure 4.4-4, based on the same version of the model as was used for Susquehanna? If not, provide comparisons using the Susquehanna model. In addition, provide a description of the code or reference a prior licensing submittal (other than the KAPL reports on STABLE).

RESPONSE:

FSAR Subsection 4.4.4.6.5. has been revised to provide this information.

QUESTION 221.12

On page 4.4-23, the REDY code is referenced as the model used to perform system stability calculations. You also state that the model is periodically refined as new experimental or reactor operating data are obtained. Is the version of REDY used for Susquehanna described in NEDO-10802? If not, describe the changes.

RESPONSE:

FSAR Subsection 4.4.4.6.4 has been revised to provide this information.

QUESTION 221.13

BWR applications have traditionally included operational design guidelines for decay ratios and damping factors used in stability analyses. These design guides have been omitted from your discussion of stability. Are operational design guidelines no longer applicable? If not, explain why.

RESPONSE:

FSAR Subsection 4.4.4.6.3 has been provided to include this information.

HISTORICAL INFORMATION

QUESTION 221.14

Your response to Q221.1 is unacceptable. The staff believes that the state-of-the-art has progressed such that effective LPM systems can be installed in commercial LWRs. The rationale for this is documented in draft Regulatory Guide 1.133 (Loose-Part Detection Program for the Primary System of Light-Water-Cooled-Reactors). Additional rationale clarifying the staff position can also be found in a letter, Vassallo to J.E. Mecca (Pugent Sound Power and Light Company) "Skagit Nuclear Power Project, Units 1 & 2" dated July 20, 1978 (Docket Nos. 50-522/523) available in the NRC public document room. A number of LWR's, including BWR's, at the same stage of licensing as Susquehanna, have committed to the installation of a LPM system. In addition, it is required by the staff that a LPM system be installed and operational prior to startup of the reactor. Therefore, please provide the information requested in Q221.1.

RESPONSE:

The Susquehanna SES Loose Parts Monitoring System is discussed in Subsections 7.7.1.12 and 7.7.2.12.

HISTORICAL INFORMATION

QUESTION 221.15

Table 4.4-6 describes uncertainties used in the statistical analysis which is performed to establish the fuel cladding integrity safety MCPR limit. Provide a discussion of and reference where possible the experimental data bases used to derive the uncertainty values listed. In particular, describe the applicability of these values to the 8x8, two-water rod assembly design.

RESPONSE:

FSAR Subsection 4.4.2.9 references the required information.

QUESTION 222.1

Describe in detail how the feedwater line and recirculation line short-term mass and energy release rates, used in the annulus pressurization and loading calculations, were determined.

Provide, separately, as a function of time, the mass flux ($lbm/sec/ft^2$) and areas used for each side of the break (the reactor vessel side and the inventory or long pipe side). List all assumptions and conservatisms used. If a hand calculation was used for this analysis, document the work done.

RESPONSE:

Refer to Appendix 6A for response.

QUESTION 222.2

One second after a postulated steam line break, a quality less than 1.0 was assumed to exit the rupture.

This may provide the limiting containment pressurization, but may not provide the limiting containment temperature. Assuming 100% efficiency for the steam separators and dryers, provide the mass and energy release rates which would occur with a 1.0 break quality. Show that this would not provide the limiting condition for the drywell and suppression pool temperature.

RESPONSE:

FSAR Subsection 6.2.1.1.3.3.2 has been revised to provide this information.

QUESTION 230.1

The response to Question 221.9 is unacceptable. The applicant should commit to submit a report describing the computer program used for core thermal-hydraulic analysis prior to issuance of an operating license for Susquehanna. The report should provide the code description, the calculational methods and empirical correlations used, a sample application and code verification through comparison with experimental data.

RESPONSE:

The computer program cited in Subsection 4.4.4.5 is named ISCOR. Various versions of this code have been used by the General Electric Company for over a decade to perform detailed core, steady-state, thermal-hydraulic analysis.

The ISCOR computer program is used as the basis for the steady state thermal-hydraulic module in the GEBS/PANAC three-dimensional BWR core simulator. The models and non-proprietary correlations are described in Chapter 4 of the BWR Core Simulator Licensing Topical Report (NEDO-20953, May, 1976).

QUESTION 230.2

The response to Question 221.2 is unacceptable. Question 2 requested assumptions used for amount of crud used in design calculations and the sensitivity of CPR and core pressure drop to variations in the amount of crud present. Merely stating that "a conservative amount of crud is deposited on the fuel rods and fuel rod spacers" does not begin to answer this question. The question also asked for a discussion of how crud buildup in the core would be detected; no discussion is provided.

RESPONSE:

In general, the CPR is not affected as crud accumulates on fuel rods (References 1 and 2). Therefore, no modifications to GEXL are made to account for crud deposition. For pressure drop considerations, the amount of crud assumed to be deposited on the fuel rods and fuel rod spacers is greater than is actually expected at any point in the fuel lifetime. This crud deposition is reflected in a decreased flow area, increased friction factors, and increased spacer loss coefficients, the effect of which is to increase the core pressure drop by approximately 1.7 psi, an amount which is large enough to be detected in monitoring of core pressure drop. It should be noted that assumptions made with respect to crud deposition in core thermal hydraulic analyses are consistent with established water chemistry requirements. More detailed discussion of crud (service-induced variations) and its uncertainty is found in Section III of Reference 3.

References:

1. McBeth, R. V., R. Trenberth, and R. W. Wood, "An Investigation Into the Effects of Crud Deposits on Surface Temperature, Dryout, and Pressure Drop, with Forced Convection Boiling of Water at 69 Bar in an Annuler Test Section," AEEW-R-705, 1971.

2. Green, S. J., B. W. LeTourneau, A. C. Peterson, "Thermal and Hydraulic Effects of Crud Deposited on Electrically Heated Rod Bundles," WAPD-TM-918, September, 1970.

3. "General Electric Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application," General Electric Company, January, 1977, (NEDO-10958A).

QUESTION 230.3

Your response to question 221.13 is incomplete. Since the operational design guidelines are exceeded for some operating conditions, Figure 4.4-6 should be revised to show decay ratios as a function of rod position, recirculation flow and power. Figure 4.4-6 as currently presented is not sufficiently detailed for use in inferring operational boundaries.

RESPONSE:

The operational design guideline is not intended for use in defining operational boundaries. It is used to determine the range of optional operation in the automatic flow control mode. Current guideline is the decay ratio 0.5. It is clear from Figure 4.4-6 that most of the operating domain meet the guideline. It should be noted, however, that power/flow condition which has a decay ratio greater than the guideline can always be operated in the manual flow control mode.

Although GE does utilize design stability guides to optimize BWR operation and performance from an availability considerations, application of these guidelines is not considered to be a necessary requirement to demonstrate an acceptable and licensable configuration.

The criterion used with respect to safety is that the calculated decay ratio be less than 1.0 over the expected range of operation. This has been demonstrated for Susquehanna unit. Operational guides have been deleted from Figure 4.4-6.

QUESTION 230.4

Your response to Question 221.15 is unacceptable. You reference NEDO-10958-A for a discussion of the uncertainties and their bases. The staff evaluation of NEDO-10958 states "The estimated value of the uncertainties and the basis for the value depend on the specific design and equipment of each reactor and will be evaluated for each reactor at the time Technical Specifications are issued." Information to support the uncertainty values for Susquehanna must be submitted prior to issuance of a safety evaluation report for Susquehanna.

RESPONSE:

A general discussion of the bounding statistical analysis uncertainty shown in Table 4.4-6 is given in the GETAB Licensing topical report (Reference 1). Of these uncertainties, all except that of critical power are unaffected by the two water-rod assembly design. The GEXL critical power predictability for the 8 x 8 two water-rod design has been shown to be similar to the standard one water-rod design (see the response to Question 221.3); the value for this uncertainty cited in Reference 1 (1 = 3.6%) is conservative with respect to both one water-rod and two water-rod designs.

Additional information concerning the remaining uncertainties in Table 4.4-6 and the bases used in the derivation of those uncertainties is contained in the Licensing topical report "Process Computer Performance Evaluation Accuracy" (References 2, 3 and 4). As stated therein, "the analysis was performed ... for measurements systems typical of (or conservative with respect to) the BWR4-6," and is therefore directly applicable to Susquehanna.

References:

1. "General Electric Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application," General Electric Company, January, 1977 (NEDO-10958A).

2. J. F. Carew, "Process Computer Performance Evaluation Accuracy," General Electric Company, June, 1974 (NEDO-20340).

3. J. F. Carew, "Process Computer Performance Evaluation Accuracy Amendment 1," General Electric Company, December, 1974 (NEDO-20340).

4. J. F. Carew, "Process Computer Performance Evaluation Accuracy Amendment 2," General Electric Company, September, 1975 (NEDO-20340-2).

QUESTION 230.5:

The staff is performing a generic study of the hydrodynamic stability characteristics of LRWs under normal operation, anticipated transients, and accident conditions. The results of this study will be applied to the staff review and acceptance of stability analyses and analytical methods now in use by the reactor vendors. In the interim, the staff concludes that past operating experience, stability tests, and the inherent thermal-hydraulic characteristics of LWRs provide a basis for accepting the Susquehanna stability evaluation for normal operation and anticipated transient events. However, in order to provide additional margin to stability limits, natural circulation operation of Susquehanna will be prohibited until the staff review of these conditions is complete. Any action resulting from the staff study will be applied to Susquehanna.

RESPONSE:

PP&L does not plan to operate the Susquehanna units in the natural circulation mode. The plant technical specifications are consistent with your position, and require that appropriate actions be taken if no recirculation loops are in operation

QUESTION 230.6:

Because the Susquehanna stability analysis is for the first cycle only, a new analysis must be reviewed and approved by the staff prior to second cycle operation.

RESPONSE:

PP&L will perform a stability analysis for the second cycle of operation.

QUESTION 230.7:

No analysis has been presented for MCPR limits or stability characteristics for one long loop operation. One-loop operation will not be permitted until supporting analyses are provided and are approved by the staff.

RESPONSE:

PP&L does not plan to operate the Susquehanna units with only one recirculation loop in operation; therefore, no additional analysis is required. The plant technical specifications are consistent with your position, and require that appropriate actions be taken with one recirculation loop not in operation.

NOTE: Since the original response to this question, supporting analyses have been provided and approved by the staff, and the Susquehanna units are now licensed for single-loop operation (SLO).

QUESTION 230.8:

The steady-state operating limit for the Minimum Critical Power Ratio (MCPR) is 1.25. This value is calculated based on REDY model described in NEDO-10802. The results of three turbine trip tests performed at the Peach Bottom-2 have revealed that in certain cases the results predicted by REDY model are non-conservative. The General Electric Company's new ODYN for use in transient analyses has been approved. Accordingly, the applicant is required to reanalyze prior to criticality the following transients with ODYN: (1) generator load rejection/turbine trip, (2) feedwater controller failure-maximum demand, and (3) main steam isolation valve closure with position switch scram failure. If another event should be more limiting than those listed above, the other event should be reanalyzed with ODYN. The reanalyses should include CPR calculation and demonstrate that the operating limit for MCPR is not less than 1.25.

RESPONSE:

The Susquehanna SES ODYN submittal is scheduled for the second quarter of 1981.

QUESTION 231.1

Section 4.2 of the FSAR references NEDO-20944 as the sole input for fuel design. In our review of this GE topical, one further report was generated, "BWR/4 and BWR/5 Fuel Design, Amendment 1," NEDE-20944-1P, January, 1977. This report should be applicable to Susquehanna and should be referenced.

RESPONSE:

NEDE-20944-1P (Amendment One to NEDE-20944-P) is applicable to Susquehanna SES.

References have been added to Section 4.2 and Section 1.6.

QUESTION 231.2

Recently we questioned the validity of fission gas release calculations in most fuel performance codes including GEGAP-III for a burnup greater than 20,000 MWd/tU. General Electric Co. was informed of this concern on November 23, 1976 and was provided with a method of correcting gas release calculations for burnups greater than 20,000 MWd/tU. Since there was no question of the adequacy of GEGAP-III for burnups below 20,000 MWd/tU, your calculations are acceptable for operation early in life until the peak local burnup reaches 20,000 MWd/tU. For burnups in excess of that value, GEGAP-III calculations (and other affected analyses) must be redone using the correction method mentioned above or such modified methods that might be submitted by Pennsylvania Power and Light Co. or General Electric Co. and approved by us.

RESPONSE:

This information is provided in Subsection 4.2.3.2 of the Susquehanna SER (NUREG-0776).

QUESTION 231.3

Recently NRC has questioned the validity of fission gas release calculations in most fuel performance codes including GEGAP-III for a burnup greater than 20,000 MWd/tU. General Electric was informed of this concern on November 23, 1976 and was provided with a method of correcting gas release calculations for burnups greater than 20,000 MWd/tU. Since there was no question of the adequacy of GEGAP-III for burnups below 20,000 MWd/tU, the Susquehanna 1 and 2 calculations are acceptable for operation early in life until the peak local burnup reaches 20,000 MWd/tU. For burnups in excess of that value, GEGAP-III calculations (and other affected analyses) must be redone using the correction method mentioned above or such modified methods that might be submitted by Pennsylvania Power and Light or General Electric and approved by the NRC.

RESPONSE:

See response to Question 231.2.

QUESTION 231.4

Our requirement for routine fuel surveillance is discussed in paragraphs I.D and II.D of Section 4.2 (Revision 1) of the Standard Review Plan. Please refer to that document and submit a description of the on-line rod failure detection methods and a description of the post-irradiation fuel surveillance program planned for Susquehanna 1 and 2.

RESPONSE:

See FSAR Subsection 4.2 for a reference to the subject document and surveillance program. See FSAR Section 11.5 for on-line monitoring system descriptions.

QUESTION 231.5

The NRC staff has been generically evaluating three materials models that are used in ECCS evaluations. Those models predict cladding rupture temperature, cladding burst strain, and fuel assembly flow blockage. We have (a) discussed our evaluation with vendors and other industry representatives (Reference 1), (b) published NUREG-0630, "Cladding Swelling and Rupture Models for LOCA Analysis" (Reference 2), and (c) required licensees to confirm that their operating reactors would continue to be in conformance with 10 CFR 50.46 if the NUREG-0630 models were substituted for the present materials models in their ECCS evaluations and certain other compensatory model changes were allowed (References 3 and 4).

Until we have completed our generic review and implemented new acceptance criteria for cladding models, we will require that the ECCS analyses in your FSAR be accompanied by supplemental calculations to be performed with the materials models of NUREG-0630. For these supplemental calculations only, we will accept other compensatory model changes that may not yet be approved by the NRC, but are consistent with the changes allowed for the confirmatory operating reactor calculations mentioned above.

REFERENCES

1. Memorandum from R.P. Denise, NRC, to R. J. Mattson, "Summary Minutes of Meeting on Cladding Rupture Temperature, Cladding Strain, and Assembly Flow Blockage," November 20, 1979.

2. D. A. Powers and R. O. Meyer, "Cladding Swelling and Rupture Models for LOCA Analysis", NRC Report NUREG0630, April 1980.

3. Letter from D. G. Eisenhut, NRC, to all Operating Light Water Reactors, dated November 9, 1979.

4. Memorandum from H. R. Denton, NRC. to Commissioners, "Potential Deficiencies in ECCS Evaluation Models," November 26, 1979.

RESPONSE:

FSAR Subsection 6.3.3.7.1 provides a reference to a detailed evaluation which responds to this question.

QUESTION 232.1

General Electric Co. has performed a generic analysis of the consequences of continuous withdrawal of an out-of-sequence control rod during reactor startup. This analysis has been documented on the Hatch-2 docket (50-366). Please provide a reference or repeat the analysis on the Susquehanna docket.

RESPONSE:

FSAR Subsection 15.4.1.2.1 has been updated to provide this information.

QUESTION 232.2

In view of the fact that the dry fresh fuel storage racks are undermoderated and the flooded racks are overmoderated, has the case of optimum moderation been analyzed? Provide analysis to show that this configuration is safe or provide bases for concluding that low density moderation in the racks is precluded.

RESPONSE:

Refer to revised FSAR subsections 9.1.1.2 and 9.1.1.3.1.

QUESTION 232.3

Comment on the effect of a misoriented bundle on the CPR in view of the change in R-factor induced by the bundle tilt.

RESPONSE:

FSAR Subsection 15.4.7.3.3 has been updated to provide this information.

QUESTION 232.4

The information in Section 9.1.2 (including Revision 15) is not sufficient to permit the review of the criticality of the spent fuel storage racks. The following information will be required.

(1) A description of the racks including, in particular those features affecting their reactivity.

(2) A description of the assumptions made in the analysis, including those regarding the reactivity of the fuel to be stored, credit taken for absorbers in the fuel and racks, temperature of water in the pool, and placements of assemblies in racks.

(3) A description of the analytical methods used, including the results of code verifications and calculational biases and uncertainties.

(4) A discussion of the effect on the reactivity of uncertainties in material properties and geometry of the racks and fuel placement in the racks.

(5) A discussion of the effect of abnormal fuel distributions on the reactivity of the racks; for example, a dropped assembly lying across the racks, an assembly lowered into a non-designed location (if possible), and other abnormal configurations.

(6) The results of the criticality analysis should be presented for the nominal rack design and fuel placement; the various calculational and mechanical uncertainties should be given along with the total uncertainty.

RESPONSE:

See revised FSAR Subsection 9.1.2.

QUESTION 260.1

Section 17.1.2.2 of the standard format (Regulatory Guide 1.70) requires the identification of safety-related structures, systems, and components (Q-list) controlled by the QA program. You are requested to supplement and clarify the Q-list in Table 3.2-1 of the FSAR in accordance with the following:

a. The following items from the Q-list need expansion and/or clarification as noted. Revise the list as indicated or justify not doing so.

   1) Clarify that the Control Rod Drive System includes the scram accumulators.

   2) Clarify that discharge piping fill lines and jockey pumps are included in the HPCI, RCIC, RHR, and Core Spray Systems.

   3) Clarify that the Emergency Core Cooling and RCIC Systems include the mechanical vortex suppression devices.

   4) Identify the "equipment associated with a safety action" as regards the Leakage Detection System. For example, it is not clear that post-LOCA ECCS Leakage Detection Systems are included.

b. The following items do not appear on the Q-list. Add the following items to the list or justify not doing so.

   1) ESSW Spray Pond Emergency Spillway.

   2) Site grading.

   3) Roof scuppers and parapet openings.

   4) Pressure resisting doors.

   5) Meteorological data collection programs.

   6) Refueling Interlock System.

   7) Rod worth minimizer.

   8) Primary Containment Vacuum Relief System - instrumentation and controls.

   9) Standby Gas Treatment System - instrumentation and controls.

10) Missile barriers for safety related equipment.

11) Steam lines to the HPCI and RCIC turbines along with the associated valves and restraints.

12) Equipment and drain floor - piping and containment isolation valves.

13) Quencher and quencher support.

14) Downcomers and braces.

15) Primary Containment Purge System.

16) Primary Containment Ventilation System - piping and containment isolation valves.

17) Onsite Power Systems (Class 1E)

    a) transformers
    b) valve operators
    c) protective relays and control panels

18) Engineered safety features DC equipment - protective relays and control panels.

19) Biological shielding within primary containment, reactor building, and control building.

20) Nuclear boiler system instrumentation piping beyond the outermost isolation valve.

21) Drywell cooling system piping and valves for coolers V-414A and B, V-415A and B, and V-416A and B.

22) Mainsteam system piping to turbine stop valves and branch line piping up to and including first valve.

23) Spent fuel pool liner.

24) Radiation monitoring (fixed and portable).

25) Radioactivity monitoring (fixed and portable).

26) Radioactivity sampling (air, surfaces, liquids).

27) Radioactive contamination measurement and analysis.

28) Personnel monitoring internal (e.g., whole body counter) and external (e.g., TLD system).

29) Instrument storage, calibration, and maintenance.

30) Decontamination (facilities, personnel, and equipment).

31) Respiratory protection, including testing.

32) Contamination control.

33) Feedwater spargers.

34) Safety-related masonry walls (see 1E Bulletin No. 80-11).

35) Measuring and test equipment used for safety-related structures, systems, and components.

36) Expendable and consumable items necessary for the functional performance of safety-related structures, systems, and components (i.e., weld rod, fuel oil, boric acid, snubber oil, etc.).

c. Enclosure 2 of NUREG-0737, "Clarification of TMI Action Plan Requirements" (November 1980) identified numerous items that are safety-related and appropriate for OL application and therefore should be on the Q-list. These items are listed below. Add these items to the Q-list and/or indicate where on the Q-list they can be found. Otherwise justify not doing so.

	NUREG-0737 (Enclosure 2) Clarification Item
1) Plant-safety-parameter display console.	I.D.2
2) Reactor coolant system vents.	II.B.1
3) Plant shielding.	II.B.2
4) Post accident sampling.	II.B.3
5) Valve position indication.	II.D.3
6) Dedicated hydrogen penetrations.	II.E.4.1
7) Containment isolation dependability.	II.E.4.2

8)	Accident monitoring instrumentation.	II.F.1
9)	Instrumentation for detection of inadequate core-cooling.	II.F.2
10)	HPCI & RCIC initiation levels.	II.K.3(13)
11)	Isolation of HPCI and RCIC	II.K.3(15)
12)	Challenges to and failure of relief valves.	II.K.3(16)
13)	ADS actuation.	II.K.3(18)
14)	Restart of core spray and LPCI.	II.K.3(21)
15)	RCIC suction.	II.K.3(22)
16)	Space cooling for HPCI & RCIC.	II.K.3(24)
17)	Power on pump seals.	II.K.3(25)
18)	Common reference level.	II.K.3(27)
19)	ADS valves, accumulator, and associated equipment and instrumentation.	II.K.3(28)
20)	Emergency plans.	III.A.1.1/ III.A.2
21)	Emergency support facilities.	III.A.1.2
22)	Inplant I radiation monitoring.	III.D.3.3
23)	Control-room habitability.	III.D.3.4

d. The instrumentation and control systems and components must be identified on the Q-list (FSAR Table 3.2-1) to the same scope and level of detail provided in Chapter 7 of the FSAR.

<u>RESPONSE</u>:

<u>Introduction</u>

Table 3.2-1 (SSES Design Criteria Summary) of the FSAR is intended to provide identification of safety-related structures, systems, and components as required by Section 17.1.2.2 of the standard format (Regulatory Guide 1.70). The "Q List" for Susquehanna SES is not a part of the FSAR. The "Q-List" is just one of a series of

controlled QA program documents which serve to identify in expanded detail the quality classification of SSES items and related services in response to FSAR commitments. Quality classifications used include but are not limited to safety related, ASME Code Section III related, safety impact related, fire protection related, environmental monitoring related, etc. The SSES QA Manual and its implementing procedures prescribe the preparation and maintenance of these quality classification documents and defines the quality assurance controls that are to be applied to such items/services.

a-1 The scram accumulators are a part of the hydraulic control unit which is indicated as safety related in Table 3.2-1.

a-2 The discharge piping fill lines for HPCI, RCIC, RHR and core spray systems are included in Table 3.2-1 of the FSAR. These lines, between the main system piping and the condensate system outer isolation check valve, are included under the respective systems subsection's "Piping Beyond Outermost Containment Isolation Valves."

The line fill system adopted for SSES does not incorporate jockey pumps to perform the fill function. The fill function is performed by the condensate transfer system. See response to Question 211.211 and FSAR Section 6.3.

a-3 The SSES Suppression Pool has no vortex suppression devices. Testing is conducted to assure that vortices do not adversely affect ECCS systems. The condensate storage tank supply line is provided with a vortex breaker; however, it is not safety related inasmuch as the tank is not safety related. See response to NRC Question 211.214 for testing information.

a-4 See revised Note 39 to FSAR Table 3.2-1.

b-1 ESSW Spray Pond Emergency Spillway

The ESSW Spray Pond Emergency Spillway was installed as part of the spray pond concrete liner. The material used to construct the spillway (concrete and reinforcing steel) was controlled by the same quality requirements in effect for the concrete liner. Therefore, the listing on Table 3.2-1 for Spray Pond (Structures Page 26) applies to the ESSW Spray Pond Emergency Spillway as a safety-related structure.

b-2 Site grading which could impact the safety-related equipment and structures in the spray pond and the power block, i.e., reactor building, control structure and diesel generator building is limited to the periphery channel and cooling tower basin areas as described in the flooding scenarios of FSAR Section 2.4.2.3 for maximum probable precipitation and basin rupture.

The process for reviewing and approving future change to the periphery channel and the area between the cooling tower basin and the power block will be controlled by procedures which are responsive to the appropriate portion of the QA Program described in Section 17.2.

b-3 Future changes to the roof scuppers and parapet openings on safety-related buildings will be made in accordance with the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-4 Pressure-resisting doors classified as safety-related components have been added to Table 3.2-1 (Buildings).

b-5 Calibration and data collection of the meteorological system are controlled by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-6 The testing and surveillance requirements for the refueling interlock system are included in the technical specifications and are covered by the procedures which are responsive to appropriate portions of the Quality Assurance Program described in Section 17.2.

b-7 The testing and surveillance requirements for the rod worth minimizer are included in the technical specifications and are covered by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-8 The instrumentation and controls for the Primary Containment Vacuum Relief System have no safety-related function. They are only for testing and are not used post-LOCA.

b-9 See revised Table 3.2-1 under Standby Gas Treatment "and associated instrumentation" has been added to Control Panels.

b-10 Those missile barriers classified as safety-related structure are designed in accordance with the criteria shown in the revised section of Table 3.2-1 (Structures).

b-11 Piping and associated valves to the HPCI and RCIC turbines are included in Table 3.2-1 of the FSAR under the following subsections:

HPCI - "Piping beyond outermost containment isolation valve, other"

"Valves other"

RCIC - "Piping beyond outermost containment isolation valve, other"

"Valves other"

Associated restraints for the HPCI and RCIC turbine <u>piping</u> are not detailed in Table 3.2-1 of the FSAR as they are not principal components of systems. The restraints are covered by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-12 Table 3.2-1 of the FSAR has been revised to incorporate the safety related piping and isolation valves and applicable codes and standards associated with the containment penetrations.

b-13 See revised Table 3.2-1 (Nuclear Boiler System).

b-14 See revised Table 3.2-1 (Buildings).

b-15 The Primary Containment Purge System is not safety related with the exception of the piping and valving associated with the primary containment penetration boundary. See revised Table 3.2-1 under Combustible Gas Control System.

b-16 The Primary Containment Ventilation System should be referred to as the Dry Well Cooling System. The Dry Well Cooling System has no primary containment penetration.

b-17 Appropriate onsite power system components which are safety-related are listed in Table 3.2-1. Where the specific components are part of a safety-related (class 1E) system, they appear in Table 3.2-1 as subsets of the Onsite Power Systems. (Example: Load

Center Transformers are a subcomponent of Load Center, and Valve Operators are a subcomponent of Motor Operated Valves.)

b-18 Engineered safety features DC equipment listed under electric systems are safety-related. See Table 3.2-1. The protective relays and control panels are subsets of this system.

b-19 Biological shielding determined to be safety-related is designed in accordance with the criteria shown in the revised section of Table 3.2-1 (Structures).

b-20 Instrument lines are safety-related for all divisionalized loops all the way to the local instruments. These are included as a subset of the various systems identified in Table 3.2-1.

b-21 With the exception of cooling water piping and valves associated with the primary containment penetration boundary the reactor building chilled water system is not safety related. In Table 3.2-1 the components of the Drywell Coolers have been listed separately under Drywell Cooling System. The piping and valves are not required to the system to perform its safety-related function.

b-22 As indicated in Table 3.2-1, under Nuclear Boiler System, the piping beyond the outermost isolation valves up to the turbine casing is Quality Group "B" and as stated in Note 20, has been designed by the use of a dynamic seismic system analysis to withstand the OBE and SSE design loads in combination with other appropriate loads, within the limits specified for Class 2 pipe in the ASME Section 3 Code. Per ASME and PP&L's Quality Assurance Program, the same quality assurance requirements which were in effect during procurement and construction of this portion of the main steam line will be in effect during the operation of this line.

b-23 Spent fuel pool liner is addressed in Table 3.2-1 under "Structures."

b-24 This is not a "structure, system or component" requiring entry in Table 3.2-1. Control and calibration of radiation monitoring (fixed and portable) is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-25 This is not a "structure, system or component" requiring entry in Table 3.2-1. Control and calibration of radioactivity monitoring (fixed and portable) is provided by procedures which are responsive to the appropriate portions of Quality Assurance Program described in Section 17.2.

b-26 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of radioactivity contamination measurement and analysis is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-27 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of radioactive contamination measurement and analysis is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-28 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of personnel monitoring (e.g., while body counter) and external (e.g., TLD system) is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-29 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of instrument storage, calibration and maintenance is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-30 Decontamination equipment and facilities are not safety related. Decontamination piping and valves are a part of the "Liquid Radwaste Management Systems -- Liquid & Chemical Waste Piping and Valves" as described in Table 3.2-1 of the FSAR.

Personnel decontamination is not a "structure, system or component" requiring entry in Table 3.2-1. Control of personnel decontamination is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-31 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of respiratory protection, including testing is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2

b-32 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Contamination control is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

b-33 The feedwater spargers are a subset of "Reactor System--Reactor Internal Structures--Other" on Table 3.2-1.

b-34 Masonry walls designed as safety-related structures are designed in accordance with the criteria shown in the revised section of Table 3.2-1 (Structures).

b-35 Measuring and test equipment is not safety related. Calibration of these pieces of measuring and test equipment used to perform checks on safety functions of safety-related equipment are controlled by the operational QA program described in Section 17.2.

b-36 The classification of these items is beyond the definition of a "structure, system or component" requiring entry in Table 3.2-1. The quality classification of expendable and consumable items necessary for the functional performance of safety-related structures. systems or components is determined as part of the procurement process in accordance with the provisions of the QA program described in Section 17.2.

c. Introduction

Part C of the question invokes enclosure (2) to NUREG 0737 as the basis for modifying Table 3.2-1 to include certain items. NUREG 0737 does not impose this requirement in all cases. Many of the TMI action plan requirements are intangible in that they call for studies, documentation, administrative controls, etc. Our approach in responding to Part C of this question has been to identify major structural or hardware-related requirements of NUREG 0737, and to apply quality assurance to those items, if appropriate. Finally, for SSES, implementation of many of the identified sections of NUREG 0737 is not yet required per enclosure (2). For all modifications that are eventually required for SSES, safety-related classification will be determined. For more information, refer to PP&L's response to NUREG 0737.

c-1 The Safety Parameter Display System (SPDS) is not safety related and therefore will not be added to Table 3.2-1. However, it will be procured and maintained under procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

c-2 The various reactor coolant system vent paths are safety-related. They are designated in Table 3.2-1, as follows:

The RCS vessel head vent is a subset of "reactor vessel appurtenances, pressure retaining portions" under "Reactor System."

The main steam relief valves with their ADS function are a subset of "safety/relief valves" under "Nuclear Boiler System."

c-3 Shield walls identified as a result of the Plant Shielding Study (NUREG 0737 Item II.B.2) will be reviewed for classification as safety-related structures. Table 3.2-1 reflects the quality assurance requirements under "Structures" of those shield walls classified as safety-related.

c-4 The Post Accident Sampling Station (PASS), with the exception of its interfaces with safety related systems will not in itself be safety related. All PASS interfaces will be covered in the appropriate systems in their piping/valve descriptions. Specific description of the PASS in Table 3.2-1 will be incorporated upon completion of design.

PASS operations will not be a "structure, system or component" requiring entry in Table 3.2-1. Control will be provided by appropriate procedures in Chapter 17 of the FSAR and Section 6.8 of the technical specifications describing the QA program coverage of procedural controls.

c-5 Valve position indication is a subset of Safety Relief Valve under Nuclear Boiler System in Table 3.2-1.

c-6 Not applicable to SSES. Hydrogen recombiners are inside containment.

c-7 Containment isolation valves are safety-related as shown in Table 3.2-1. This subject was part of a study from which no changes to Table 3.2-1 resulted.

c-8 Accident monitoring has both safety and non-safety related listing as follows:

(a) Noble gas effluent radiological monitor is non-safety related per NUREG-0737. The calibration of the noble gas effluent radiological monitor is provided by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

(b) Continuous samples of plant effluents for radioactive iodine and particulate are non-safety related. Samples are controlled by procedures which are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

(c) Containment Hi-range radioactive monitors are safety related. See revised Table 3.2-1 under Post Accident Monitoring.

(d) Containment pressure monitor is safety related. See revised Table 3.2-1 under Post Accident Monitoring.

(e) Containment suppression pool water level instrumentation is safety related. See revised Table 3.2-1 under Post Accident Monitoring.

(f) Containment H_2O monitor system is safety related. See revised Table 3.2-1 under Post Accident Monitoring.

c-9 As a result of this study, no additional instrumentation was required, therefore there is no change required in Table 3.2-1.

c-10 As a result of these studies there was no change required of the HPCI and RCIC set points. There were no changes to Table 3.2-1 because of these studies.

c-11 The Quality Assurance requirements for HPCI and RCIC Systems are shown in Table 3.2-1.

c-12 Response to the TMI study is still in the evaluation phase. Table 3.2-1 will be modified as necessary.

c-13 The BWR owners group is still evaluating this requirement. If the study so indicates, Table 3.2-1 will be modified accordingly.

c-14 This study determined that no changes were required to Table 3.2-1.

c-15 The Quality Assurance requirements for the RCIC Systems are shown in Table 3.2-1.

c-16 Safety-related unit coolers are provided in these rooms as necessary to maintain temperature. See ECCS Pump Room in Table 3.2-1.

c-17 Response to the TMI issues is under evaluation between PP&L and the NRC staff. After the evaluation has been completed any changes to the Quality Assurance requirements will be reflected in Table 3.2-1 as appropriate.

c-18 This study resulted in no changes to SSES equipment. Entries in Table 3.2-1 are not required as they are included within the individual systems.

c-19 Response to this TMI issue is under study/evaluation. Any modifications to the SSES design will be evaluated to determine if they are safety related. Table 3.2-1 will be modified as deemed appropriate.

c-20 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of this activity is provided by appropriate procedures. Chapter 17 of the FSAR and Section 6.8 of the Technical Specifications describe the QA program coverage of procedural controls.

c-21 These items are not safety related. Justification is contained in NUREG 0696 paragraph 2.5 and 4.2 (Table 2 and footnotes). The Emergency Facilities and associated equipment are not required for safe shutdown or immediate or long term operation following a LOCA. The failure of these facilities or the associated equipment will not cause the release of radioactivity in excess of 10 CFR 100 limits or cause or increase severity of a DBA. The individual facilities will be designed and installed in accordance with quality plans set forth under Section I.D of NUREG 0696. For these reasons Emergency Support Facilities will not be added to Table 3.2-1.

The program for maintenance and independent audits of these facilities and equipment is described in the Susquehanna Emergency Plan and the Susquehanna Technical Specifications.

c-22 This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of this activity is provided by appropriate procedures. Chapter 17 of the FSAR and Section 6.8 of the Technical Specifications describe the QA program coverage of procedural controls.

c-23 Control room habitability is maintained by safety related equipment. This equipment is identified in Table 3.2-1 under the section heading HVAC System-Control Structure.

d. Instrumentation and Control system are identified only at the system level in Table 3.2-1 without providing information on the individual component level. The quality classification of individual components has been identified in expanded detail in controlled QA program documents (e.g., "Q-List" and the instrument index).

QUESTION 281.1

Establish and state appropriate limits for the conductivity of the purified condensate to the reactor vessel in accordance with Regulatory Position C.1 of Regulatory Guide 1.56, Revision 1.

Also, describe the sampling frequency, chemical analyses, and established limits for dissolved and suspended solids that will be performed and the basis for these limits.

RESPONSE:

General Electric specifies .1 micro MHO/cm @ 25°C for purified condensate conductivity to the reactor vessel. Additional limits and actions are listed in the Technical Specifications.

A design modification is undergoing engineering review to permit on line sampling. It is anticipated that suspended solids (defined as collectable on a 0.45 micron-pure-size-rated membrane filter paper) will be collected on an on-line filter paper which normally accumulates for a period of 1 to 7 days (7 day samples will check flow rate once per day). All filters collected during a 7 day period of normal sampling will be combined to determine an average weekly ppb. Total metal will be tested for one or more of the following: Fe, Cu, Ni, Cr.

Dissolved solids will be sampled once per week. Either a grab sample or caution exchange technique will be used to obtain a sample capable of detecting 2 ppb Cu and 5 ppb Fe.

Additionally, once per month a 24 hour composite sample will be collected on either cation exchange papers or cation exchange columns (after a change of 0.45 micron filter paper). The copper, nickel, chromium and iron concentrations will be determined from this composite sample.

Expected limits (ppb) for operations above 50% power are as follows:

Parameter	Normal	Max.	Time allowed above normal
Total suspended	$\leq$15.0	$\leq$50.0	14 days/12 mo. period
Suspended Fe	$\leq$15.0	NA	NA
Suspended Cu	$\leq$2.0	$\leq$2.0	NA
Total dissolved	$\leq$15.0	$\leq$50.00	14 days/12 mo. period
Dissolved Fe	$\leq$15.0	NA	NA
Dissolved Cu	$\leq$2.0	NA	NA
Total metals	$\leq$30.0	$\leq$100	14 days/12 mo. period
Total Fe	$\leq$30.0	NA	NA
Total Cu	$\leq$2.0	NA	NA

The basis for these limits are the prevention of crud build-up on fuel heat transfer surfaces and the minimization of transport of active corrosion products outside of the core as established by GE fuel warranties.

QUESTION 281.2

Establish and state sequential regeneration frequency in order to maintain adequate capacity margin in the condensate treatment system (Regulatory Position C.2 of Regulatory Guide 1.56, Revision 1). Include the basis for the resin regeneration frequency.

RESPONSE:

See revised Subsection 10.4.6.2.1.

QUESTION 281.3

Indicate that the initial total capacity of new demineralizer resins will be measured and describe the method to be used for this measurement (Regulatory Position C.3 of Regulatory Guide 1.56, Revision 1).

RESPONSE:

A representative sample of each batch of new resin will be taken and either sent to the manufacturer of the resin, sent to a laboratory that specializes in resin testing, or tested by PP&L. The methods used will be either those suggested by the resin manufacturer of by ASTM for total exchange capacity.

QUESTION 281.4

Describe the method of determining the condition of the demineralizer units so that the ion exchange resin can be regenerated or replaced before an unacceptable level of depletion is reached (Regulatory Position C.4 of Regulatory Guide 1.56, Revision 1). Describe the method by which (a) the conductivity meter readings for the condensate cleanup system will be calibrated, (b) the flow rates through each demineralizer will be measured, (c) the quantity of the principal ions likely to cause demineralizer breakthrough will be calculated, and (d) the accuracy of the calculation of resign capacity will be checked.

RESPONSE:

See response to Question 281.2. The following additional response is given for 281.4.

a) The conductivity cell will be checked with an in-line laboratory cell once per week.

b) Flow rates are measured by means of an annubar on the inlet to each demineralizer vessel and recorded at the local control panel.

c) and d) The system has been designed for conductivity endpoint as an indication of demineralizer breakthrough rather than by calculation as described in regulatory position 4.c of Regulatory Guide 1.56.

QUESTION 281.5

Indicate the control room alarm set points of the conductivity meters at the inlet and outlet demineralizers in the condensate and reactor water cleanup systems when either (Regulatory Position C.5 of Regulatory Guide 1.56, Revision 1):

a) The conductivity indicates marginal performance of the demineralizer systems.

b) The conductivity indicates noticeable breakthrough of one or more demineralizers.

RESPONSE:

Reactor water cleanup system controls room alarm set points of the conductivity meters at the demineralizer inlet and outlet are ≤1 micro MHO/cm and ≤.1 micro MHO/cm respectively (Modes 1, 2, and 3). Additional appropriate limits and actions are listed in SSES Technical Specifications Section 3.4.4.4. These set points accomplish a. and b. of the question and are consistent with Regulatory Position C.5 of Regulatory Guide 1.56, Revision 1.

See response to 281.2.

QUESTION 281.6

The reactor coolant limits and corrective action to be taken if the conductivity, pH, or chloride content is exceeded will be established in the Technical Specifications. Describe the chemical analysis methods to be used for their determination (Regulatory Position C.6 of Regulatory Guide 1.56, revision 1).

RESPONSE:

The conductivity of the reactor coolant is continuously monitored by an in-line plant instrument. The in-line instrument will be verified to be reading correctly once per week by a flow through lab cell.

The ph of the reactor coolant will be analyzed by using a grab sample when the conductivity exceeds one micro-mho. The electrode method will be used.

The chloride content will be determined from a grab sample by one of several approved plant procedures depending on the chloride concentration level.

QUESTION 281.7

Describe the water chemistry control program to assure maintenance of condensate demineralize influent and effluent conductivity within the limits of Table 2 of Regulatory Guide 1.56, Revision 1. Include conductivity meter alarm set points and the corrective action to be taken if the limits of Table 2 are exceeded.

RESPONSE:

See revised Subsection 10.4.6.3.

QUESTION 281.8

THIS QUESTION HAS BEEN DELETED

QUESTION 281.9

THIS QUESTION HAS BEEN DELETED

QUESTION 281.10

THIS QUESTION HAS BEEN DELETED

QUESTION 281.11

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QUESTION 281.29

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