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SUBJECT: Forwards draft responses to Reactor Sys Branch questions which will be discussed during 800821 meeting.Responses to Questions 211.201,211.266,211.267,211.268 & 211.269 will be provided on 800821. See Report

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August 1, 1980

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Mr. B. J. Youngblood, Chief
Licensing Branch No. 1
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Docket Nos. 50-387
50-388

SUSQUEHANNA STEAM ELECTRIC STATION
RESPONSES TO REACTOR SYSTEMS BRANCH QUESTIONS
ER 100450 FILE 841-2
PLA 518

Dear Mr. Youngblood:

Attached are PP&L's draft responses to the Reactor Systems Branch questions which will be discussed during the meeting on August 21, 1980.

The following questions are not enclosed; however, an answer will be provided on August 21, 1980.

211.201
211.266
211.267
211.268
211.269

If you have any questions, please call.

Very truly yours,

N W Curtis

N. W. Curtis
Vice President - Engineering and
Construction - Nuclear

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Attachments

cc: T. Collins - Nuclear Regulatory Commission
H. Reeve - Savannah River Plant

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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 assureance 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 operaton band for ths parameter.

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QUESTION 211.137:

Uncertainty exists on the correct value of APRM neutron flux scram setpont 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%).

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 NSQA 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. RHRS-shutdown cooling operation action would consist of adjusting the RHRS to and from steam condensing mode to water/water heat removal mode.

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 initiaes 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 is to be an issue which will be 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 sytem variables and how the various plant systems would interact and function. 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 thich 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 Flor	Recirculation runback, (2) Relief valves
15.3.1	Trip of Both Recirc-ulation Pumps	Level 8 turbine trip, turb-ine 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

TABLE 211.139-1 (CONTINUED)

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" of Table 7.2-5 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?

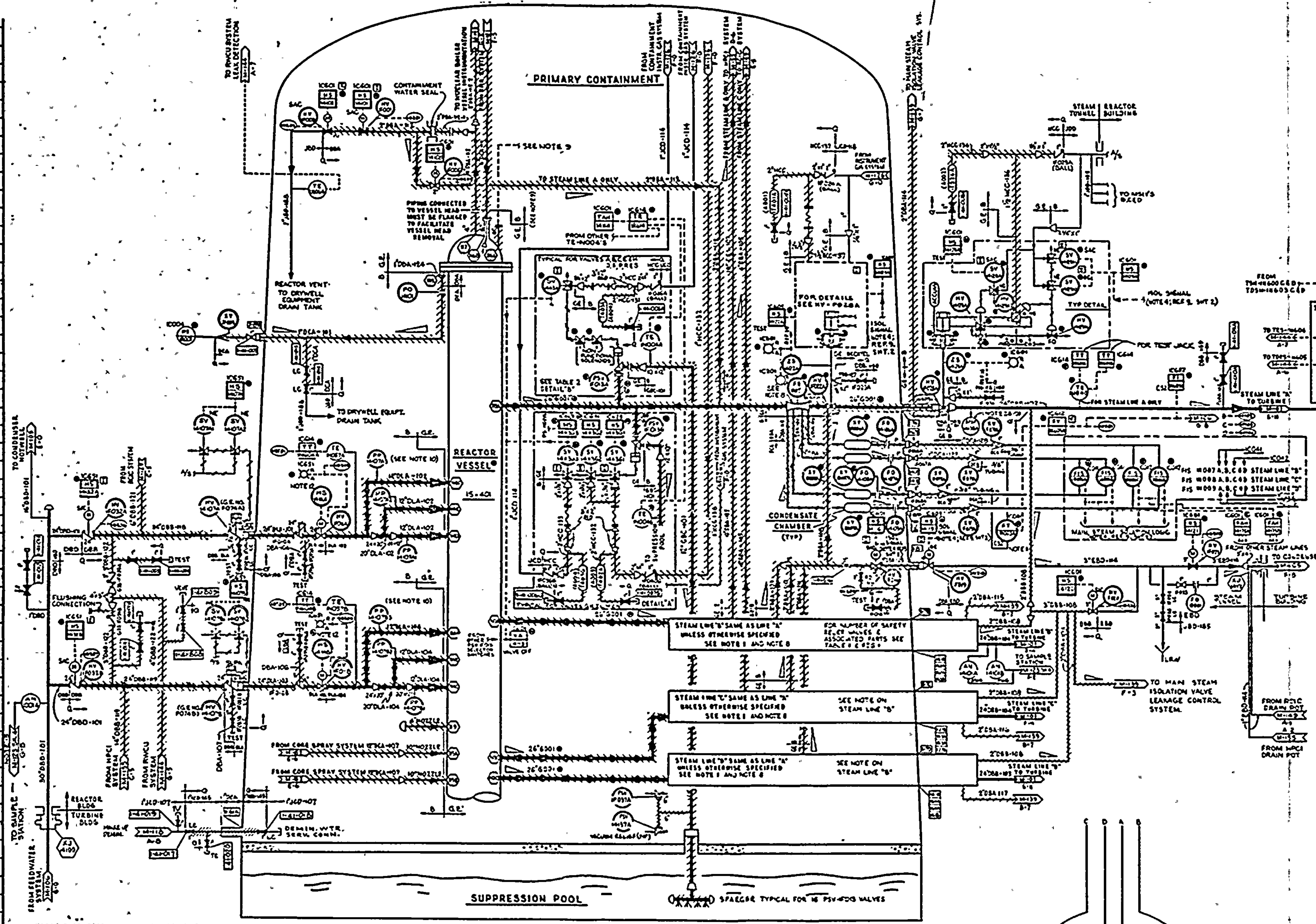
  2) Are all equipment and components required for safety/relief valve actuation in the relief mode safety grade?

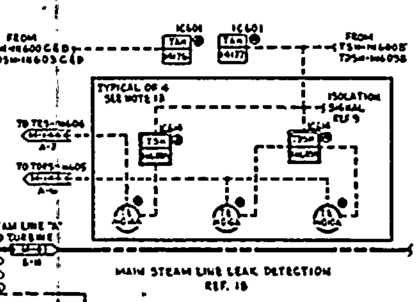
RESPONSE:

a) The correct, up-to-date, set points for valves B and E are 1146 psig. Table 1 of Figure 5.1-3a has been corrected.

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.





MAIN STEAM LINE LEAK DETECTION
REF. 18

NOTES:

1. STEAM LINES & ASSOCIATED EQUIPMENT ENCLOSED IN BOXES SHALL HAVE PART NOS. CORRESPONDING TO THEIR RESPECTIVE LINE LETTER UNLESS OTHERWISE NOTED.
   EXAMPLE: XXXXXB IS ON LINE B, YYYYYC IS ON LINE C.
2. THE G.E. MPL NUMBER FOR THIS SYSTEM IS B21.
3. LOCATE PRESSURE TEST POINTS PPW-30 A,B,C,D AS CLOSE AS POSSIBLE TO VALVES F028 A,B,C,D.
4. MAIN STEAM LINE ISOLATION IS INITIATED BY ONE OF THE FOLLOWING CONDITIONS:
   A. REACTOR LOW WATER LEVEL.
   B. MAIN STEAM LINE HIGH RADIATION.
   C. MAIN STEAM LINE HIGH FLOW.
   D. LOW TURBINE INLET PRESSURE.
   E. HIGH STEAM LINE TUNNEL TEMPERATURE.
   F. REACTOR HIGH WATER LEVEL.
5. AUTO DEPRESSURIZATION FUNCTION (ADF) IS INITIATED BY THE FOLLOWING SIMULTANEOUS SIGNALS:
   A. DRYWELL HIGH PRESSURE.
   B. REACTOR WATER LOW LEVEL.
   C. RHR OR CORE SPRAY PUMP MOTOR RUNNING.
6. MISCELLANEOUS VALVE NUMBERS USED ARE 1-41-001 THRU 1-41-020.
7. DELETED
8. FLOW ELEMENT FOR MAIN STEAM LINES B,C,D ARE N052, N053, AND N054 RESPECTIVELY.
9. GE SUPPLIES MATING FLANGE, EITHER NOZZLE 6A OR 6B MAY BE CONNECTED TO THE HEAD SPRAY LINE
10. PRESSURE TAPS TO CONFORM TO ASME PTC 6, 1964, PARA 4 74
11. FT C32-N005 A&B ARE ON 1C004, AND FT C32-N005 C&D ARE ON 1C015.
12. THE VALVE CONTROL SWITCH IS LOCATED ON THE VALVE OPERATOR
13. THE SECOND ELEMENT IS ONLY USED ON STEAM LINE "A" AND IS A SPARE ON LINE B, C & D.
14. SEE DESIGN SPEC. FOR NUCLEAR PIPING 8856-M-175 SECTION 4.3, FOR ADDITIONAL DYNAMIC SEISMIC-SYSTEM ANALYSIS REQUIREMENTS ON LINES DBD-101, 102, 103, 104 & 105.
15. INSTALL ROOT VALVES (TWO 1" CCD-GB PER ANALYSIS NOZZLE) ON AN-B21-1D014 TO COMPLY WITH GE-NED SPEC.# 22A2706.

TABLE 2 CONTROL SWITCH ARRANGEMENT FOR DETAIL "D"

TYPICAL FOR 1F013A, B & C

PSV-1F013	1C601 CONTROL SWITCH	1C631 TRANSFER SWITCH	1C631 CONTROL SWITCH	SOLENOID VALVE
A	HS-141113A2	HSS-141113A	HS-141113A1	SV-141113A
B	HS-141113B2	HSS-141113B	HS-141113B1	SV-141113B
C	HS-141113C2	HSS-141113C	HS-141113C1	SV-141113C

TYPICAL FOR 1F013 D, E, F, H, P, R & S

PSV-1F013	1C601 CONTROL SWITCH			SOLENOID VALVE
D	HS-141113D			SV-141113D
E	HS-141113E			SV-141113E
F	HS-141113F			SV-141113F
H	HS-141113H			SV-141113H
P	HS-141113P			SV-141113P
R	HS-141113R			SV-141113R
S	HS-141113S			SV-141113S

TABLE 1. SAFETY / RELIEF VALVE LOCATION, SUFFIX ASSIGNMENT & ASSOCIATED EQUIPMENT

SAFETY / RELIEF VALVES 1F013		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
RELIEF VALVE SPRING SET PRESSURE (PSIG)		1175	1146	1175	1175	1146	1185	1205	1175	1195	1205	1195	1205	1195	1185	1185	1185
ACCUMULATORS	(ADS) 1T402(X) 150 PSIG							A		B	C	D	E	F			
	1T403(X) 90 PSIG	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
TEMPERATURE ELEMENT N016		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
CHECK VALVES	1F036(X)	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
	1F040(X)(ADS)							G		J	K	L	M	N			
VACUUM BREAKER 1F037(X) & 1B137(X)		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
PRESSURE SWITCH N022 (REF. 8 F-2)		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
PRESSURE SET POINT OF N022 (PSIG)		1086	1076	1086	1086	1076	1096	1116	1086	1106	1116	1106	1116	1106	1096	1096	1096
SOLENOID VALVES 4113 ASSIGN. FUNCTION	ADS (A)							A		A	A	A	A	A			
	ADS (A)							A		A	A	A	A	A			
	1A113X3 PRESS RELIEF (Y)	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

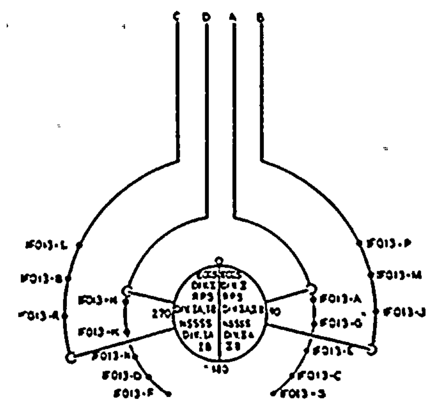


FIG. 1
SAFETY/RELIEF VALVE LOCATION AND SEPARATION ASSIGNMENT OF VESSEL INSTRUMENTATION

Rev. 16, 7/80

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

P & ID
NUCLEAR BOILER

FIGURE 5.1-3a

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.

b) The peak pressure values given in Table 15.0-1 for event 15.1-2 are correct. The text in Section 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.

15.1.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2.

The same void reactivity coefficient used for pressurization transients is applied since a more negative value conservatively increases the apparent severity of the power increase. End of cycle (all rods out) scram characteristics are assumed. The safety-relief valve action is conservatively assumed to occur with higher than nominal set points. The transient is simulated by programming an upper limit failure in the feedwater system such that 135% feedwater flow occurs at a system design pressure of 1060 psig.

15.1.2.3.3 Results

The simulated feedwater controller transient at 105% NBR rated steam flow is shown in Figure 15.1-3. The high water level turbine trip and feedwater pump trip are initiated at approximately 10 sec. Scram occurs simultaneously from stop valve closure, and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. MCPR remains above 1.06 (the safety limit) and peak fuel center temperature increases less than 59°F. The turbine bypass system opens to limit peak pressure in the steam line near the safety valves to 1138 psig and the pressure at the bottom of the vessel to about 1175 psig. The nuclear system process barrier pressure limit is not endangered.

The bypass valves subsequently close to re-establish pressure control in the vessel during shutdown. The level will gradually drop to the Low Level isolation reference point, activating the RCIC/HPCI systems for long term level control.

15.1.2.3.4 Consideration of Uncertainties

All systems utilized for protection in this event were assumed to have the most conservative allowable response (e.g., relief setpoints, scram stroke time and work characteristics). Plant behavior is, therefore, expected to lead to a less severe transient.

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. 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.

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 211.147:

On page 4-7 of NEDO-10802, it is stated that the difference in trend of flow coastdown versus initial powre 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 simualted for the 1 and 2 RPT transient cases (using miniumum 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.

TABLE 15.1-2

SEQUENCE OF EVENTS FOR FIGURE 15.1-2

Time-sec	Event
0	Initiate a 100°F temperature reduction into the feedwater system.
2	Initial effect of unheated feedwater starts to raise core power level and steam flow, (Transport delay in feedwater piping is neglected).
40	APRM high neutron flux alarm sounds.
≃ 60	Reactor variables settle into new steady state, (Below SCRAM trip point).
600	Operator begins to insert control rods (in normal sequence) to restore plant operation within normal power-flow conditions.

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.

15.1 DECREASE IN REACTOR COOLANT TEMPERATURE

15.1.1 LOSS OF FEEDWATER HEATING

15.1.1.1 Identification of Causes and Frequency Classification

15.1.1.1.1 Identification of Causes

A feedwater heater can be lost in two ways:

(1) Steam extraction line to heater is closed,

(2) Steam is bypassed around heater.

The first case produces a relatively gradual cooling of the feedwater. In the second case, the steam bypasses the heater and no heating of that feedwater occurs. In either case the reactor vessel receives cooler feedwater. The maximum number of feedwater heaters which can be tripped or bypassed by a single event represents the most severe transient for analysis considerations. This event has been conservatively estimated to incur a loss of up to 100°F of the feedwater heating capability of the plant and causes an increase in core inlet subcooling. This increases core power due to the negative void reactivity coefficient. The event can occur with the reactor in either the automatic or manual control mode. In automatic control, some compensation of core power is realized by modulation of core flow, so the event is less severe than in manual control.

15.1.1.1.2 Frequency Classification

The probability of this event is considered low enough to be categorized as an infrequent incident. However, because of the lack of a sufficient frequency data base, this transient disturbance is analyzed as an incident of moderate frequency.

This event is analyzed under worst case conditions of a 100°F loss and full power although a reduction of feedwater temperature of 100°F at high power has never been reported.

15.1.1.2 Sequence of Events and Systems Operation

15.1.1.2.1 Sequence of Events

Tables 15.1-1 and 15.1-2 list the sequence of events for this transient; its effect on various parameters is shown in Figures 15.1-1 and 15.1-2.

15.1.1.2.1.1 Identification of Operator Actions

In the automatic flux/flow control mode, the reactor settles out at a lower recirculation flow with no change in steam output. An average power range monitor (APRM) neutron flux alarm will alert the operator that he must insert control rods to return to the rated flow control line, or that he may reduce flow if in the manual mode. The operator must determine from existing tables the maximum allowable T-G output with a feedwater heater out of service. If reactor scram occurs, although it is not predicted in either automatic manual flow control mode, the operator must monitor the reactor water level and pressure controls and the T-G auxiliaries during coastdown.

15.1.1.2.2 Systems Operation

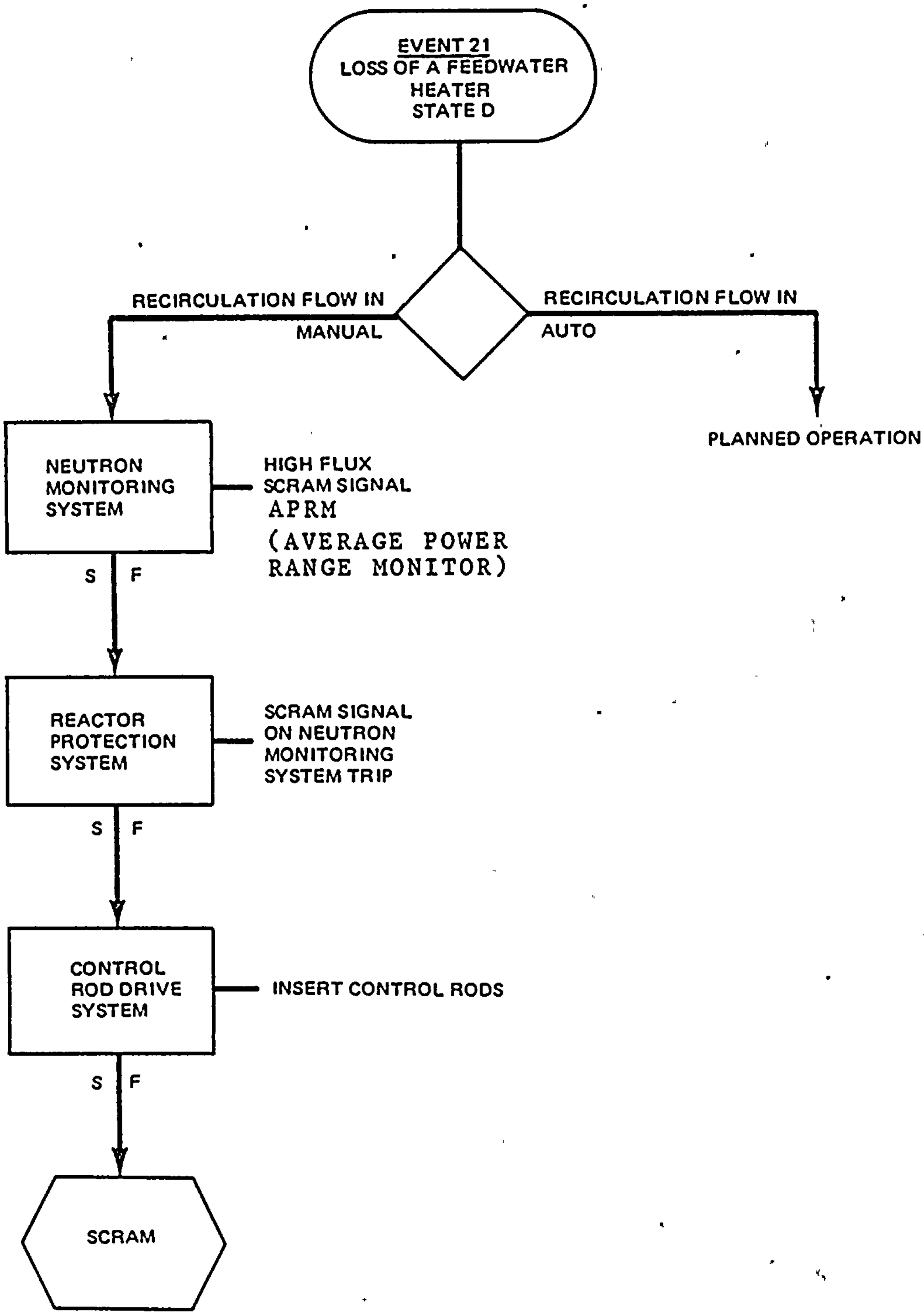
In establishing the expected sequence of events and simulating the plant performance, it was assumed that the plant instrumentation and controls, plant protection and reactor protection systems functioned normally.

The average power range monitor (APRM) provides the alarm to the operator, but no protection system trip is expected or required to mitigate the predicted consequences of this event.

Required operation of Engineered Safeguard Features is not expected for either of these transients.

15.1.1.2.3 The Effect of Single Failures and Operator Errors

These two events generally lead to an increase in reactor power level. The APRM alarm alerts the operator, however, the reactor requires no automatic trip. Therefore, single failures are not expected to result in a more severe event than analyzed. See Appendix 15A.



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

PROTECTION SEQUENCE FOR LOSS OF A FEEDWATER HEATER

FIGURE 15A.6-21

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.

15.1.1.3 Core and System Performance

15.1.1.3.1 Mathematical Model

The predicted dynamic behavior has been determined using a computer simulated, analytical model of a generic direct-cycle BWR. This model is described in detail in Reference 15.1-1. This computer model has been improved and verified through extensive comparison of its predicted results with actual BWR test data.

15.1.1.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

The plant is assumed to be operating at 105% of NB rated steam flow and at thermally limited conditions. Both automatic and manual modes of flow control are considered.

The same void reactivity coefficient conservatism used for pressurization transients is applied since a more negative value conservatively increases the severity of the power increase. The values for both the feedwater heater time constant and the feedwater time volume between the heaters and the spargers are adjusted to reduce the time delays since they are not critical to the calculation of this transient. The transient is simulated by programming a change in feedwater enthalpy corresponding to a 100°F loss in feedwater heating.

15.1.1.3.3 Results

In the automatic flux/flow control mode, the recirculation flow control system responds to the power increase by reducing core flow so that steam flow from the reactor vessel to the turbine remains essentially constant. In order to maintain the initial steam flow with the reduced inlet temperature, reactor thermal power increases above the initial value and settles at about 115% NBR power (111% of initial power), below the flow-referenced APRM neutron flux scram setting, and core flow is reduced to approximately 97% of rated flow. The MCPR reached in automatic control mode is greater than for the more limiting manual flow control mode.

15.1.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2.

The same void reactivity coefficient used for pressurization transients is applied since a more negative value conservatively increases the apparent severity of the power increase. End of cycle (all rods out) scram characteristics are assumed. The safety-relief valve action is conservatively assumed to occur with higher than nominal set points. The transient is simulated by programming an upper limit failure in the feedwater system such that 135% feedwater flow occurs at a system design pressure of 1060 psig.

15.1.2.3.3 Results

The simulated feedwater controller transient at 105% NBR rated steam flow is shown in Figure 15.1-3. The high water level turbine trip and feedwater pump trip are initiated at approximately 10 sec. Scram occurs simultaneously from stop valve closure, and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. MCPR remains above 1.06 (the safety limit) and peak fuel center temperature increases less than 59°F. The turbine bypass system opens to limit peak pressure in the steam line near the safety valves to 1138 psig and the pressure at the bottom of the vessel to about 1175 psig. The nuclear system process barrier pressure limit is not endangered.

The bypass valves subsequently close to re-establish pressure control in the vessel during shutdown. The level will gradually drop to the Low Level isolation reference point, activating the RCIC/HPCI systems for long term level control.

15.1.2.3.4 Consideration of Uncertainties

All systems utilized for protection in this event were assumed to have the most conservative allowable response (e.g., relief setpoints, scram stroke time and work characteristics). Plant behavior is, therefore, expected to lead to a less severe transient.

15.1.3.3.2 Input Parameters and Initial Conditions

This transient is simulated by setting the controlling regulator output to a high value, which causes the turbine admission valves to open fully and the turbine bypass valves to open partially. Since the controlling and backup regulator outputs are gated by a high value gate, the effect of such a failure in the backup regulator would be exactly the same. A regulator failure with 115% steam flow was simulated as a worst case since 110% is the normal maximum flow limit.

A 5-second isolation valve closure instead of a 3-second closure is assumed when the turbine pressure decreases below the turbine inlet low pressure set point for main steam line isolation initiation. This is within the specification limits of the valve and tends to aggravate the results of the analysis.

This analysis has been performed, unless otherwise noted, with the plant conditions listed in Table 15.0-2. |Δ

15.1.3.3.3 Results

Figure 15.1-4 shows the response of important nuclear system variables for this transient. The turbine inlet pressure decreases to the low pressure trip set point in 19 sec and initiates trip of the MSIV's. Closure of the MSIV's initiates scram, and subsequent loss of steam to the main turbine and the feedwater turbines.

Reactor low turbine pressure trip limits the duration and severity of the depressurization so that no significant thermal stresses are imposed on the nuclear system process barrier. After the rapid portion of the transient is complete the nuclear system safety/relief valves operate intermittently to relieve the pressure rise that results from decay heat generation. No significant reductions in fuel thermal margins occur. Because the rapid portion of the transient results in only momentary depressurization of the nuclear system and because the safety/relief valves operate only to relieve the pressure increase caused by decay heat, the nuclear system process barrier is not threatened by high internal pressure for this pressure regulator malfunction.

satisfy single failure criterion and credit is taken for these protection features.

The pressure relief system which operates the relief valves independently when system pressure exceeds relief valve instrumentation set points is assumed to function normally during the time period analyzed.

All plant control systems maintain normal operation unless specifically designated to the contrary.

15.2.2.2.2.2 Generator Load Rejection with Failure of Bypass

Same as Subsection 15.2.2.2.2.1 except that failure of the main turbine bypass valves is assumed for the entire transient.

15.2.2.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase is accomplished by the reactor protection system functions. Turbine control valve trip scram and RPT are designed to satisfy the single failure criterion. An evaluation of the most limiting single failure (i.e., failure of the bypass system) was considered in this event. Details of single failure analysis can be found in Appendix 15A.

15.2.2.3 Core and System Performance

15.2.2.3.1 Mathematical Model

The computer model described in Subsection 15.1.1.3.1 was used to simulate this event.

15.2.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2.

The turbine electrohydraulic control system (EHC) power/load imbalance device detects load rejection before a measurable speed change takes place.

The closure characteristics of the turbine control valves are assumed such that the valves operate in the full arc (FA) mode

15.2.3.2.3 The Effect of Single Failures and Operator Errors

15.2.3.2.3.1 Turbine Trips at Power Levels Greater Than 30%NBR

Mitigation of pressure increase is accomplished by the reactor protection system functions. Main stop valve closure scram trip and RPT are designed to satisfy single failure criterion.

15.2.3.2.3.2 Turbine Trips at Power Levels Less Than 30% NBR

Same as Subsection 15.2.3.2.3.1 except RPT and stop valve closure scram trip is normally inoperative. Since protection is still provided by high flux, high pressure, etc., these will also continue to function and scram the reactor should a single failure occur.

15.2.3.3 Core and System Performance

15.2.3.3.1 Mathematical Model

The computer model described in Subsection 15.1.1.3.1 was used to simulate these events.

15.2.3.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

Turbine stop valves full stroke closure time is 0.1 second.

A reactor scram is initiated by position switches on the stop valves when the valves are less than 90% open. This stop valve scram trip signal is automatically bypassed when the reactor is below 30% NB rated power level.

Reduction in core recirculation flow is initiated by position switches on the main stop valves, which actuate trip circuitry which trips the recirculation pumps.

15.2.4.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase is accomplished by initiation of the reactor scram via MSIV position switches and the protection system. Relief valves also operate to limit system pressure. All of these aspects are designed to single failure criterion and additional single failures would not alter the results of this analysis. Closure of one MSIV plus a single active component failure (the second MSIV) results in a situation no worse than the analysis of the four closed MSIVs.

Failure of a single relief valve to open is not expected to have any significant effect. Such a failure is expected to result in less than a 20 psi increase in the maximum vessel pressure rise. The peak pressure will still remain considerably below 1375 psig. The design basis and performance of the pressure relief system is discussed in Chapter 5.

15.2.4.3 Core and System Performance

15.2.4.3.1 Mathematical Model

The computer model described in Subsection 15.1.1.3.1 was used to simulate these transient events.

15.2.4.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

The main steam isolation valves close in 3 to 5 seconds. The worst case, the 3-second closure time, is assumed in this analysis.

Position switches on the valves initiate a reactor scram when the valves are less than 90% open. Closure of these valves inhibits steam flow to the feedwater turbines terminating feedwater flow.

Valve closure indirectly causes a trip of the main turbine and generator.

Because of the loss of feedwater flow, water level within the vessel decreases sufficiently to initiate trip of the recirculation pump and initiate the HPCI and RCIC systems.

15.2.5.3.2 Input Parameters and Initial Conditions

This analysis was performed with plant conditions tabulated in Table 15.0-2 unless otherwise noted. Turbine stop valves full stroke closure time is 0.1 second.

A reactor scram is initiated by position switches on the stop valves when the valves are less than 90% open. This stop valve scram trip signal is automatically bypassed when the reactor is below 30% NB rated power level.

The analysis presented here is a hypothetical case with a conservative .8 inches Hg per second vacuum decay rate. Thus, the bypass system is available for several seconds since the bypass is signaled to close at a vacuum level of about 10 inches Hg less than the stop valve closure.

15.2.5.3.3 Results

Under this hypothetical .8 inches Hg per second vacuum decay condition, the turbine bypass valve and main steam isolation valve closure would follow main turbine and feedwater turbine trips about 12 seconds after they initiate the transient. This transient, therefore, is similar to a normal turbine trip with bypass. The effect of main steam isolation valve closure tends to be minimal since the closure of main turbine stop valves and subsequently the bypass valves have already shut off the main steam line flow. Figure 15.2-6 shows the transient expected for this event. It is assumed that the plant is initially operating at 105% of Nuclear Boiler rated steam flow conditions. Peak neutron flux reaches 168% of NB rated power while average fuel surface heat flux reaches 105% of rated value. Safety/relief valves open to limit the pressure rise, then sequentially reclose as the stored energy is dissipated.

15.2.5.3.4 Considerations of Uncertainties

The reduction or loss of vacuum in the main turbine condenser will sequentially trip the main and feedwater turbines and close the main steamline isolation valves and bypass valves. While these are the major events occurring, other resultant actions will include scram (from stop valve closure) and bypass opening with the main turbine trip. Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is directly dependent upon the rate at which the vacuum pressure is lost. Normal loss of vacuum due to loss of cooling water pumps or steam jet air ejector problem valves closed, causes a scram and initiates recirculation pump trip (RPT) (already tripped at reference time t=0).

15.2.6.2.3 The Effect of Single Failures and Operator Errors

Loss of the auxiliary power transformer in general leads to a reduction in power level due to rapid pump coastdown with pressurization effects due to turbine trip occurring after the reactor scram has occurred. Additional failures of the other systems assumed to protect the reactor would not result in an effect different from those reported. Failures of the protection systems have been considered and satisfy single failure criteria and as such no change in analyzed consequences is expected. See Appendix 15A for details on single failure analysis.

15.2.6.3 Core and System Performance

15.2.6.3.1 Mathematical Model

The computer model described in Subsection 15.1.1.3.1 was used to simulate this event.

Operation of the RCIC or HPCI systems is not included in the simulation of this transient, since startup of these pumps does not permit flow in the time period of this simulation.

15.2.6.3.2 Input Parameters and Initial Conditions

15.2.6.3.2.1 Loss of Auxiliary Power Transformer

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2 and under the assumed systems constraints described in Subsection 15.2.6.2.2.

15.2.6.3.2.2 Loss of All Grid Connections

Same as Subsection 15.2.6.3.2.1

adequate core coverage and will provide long-term inventory control.

15.2.7.3 Core and System Performance

15.2.7.3.1 Mathematical Model

The computer model described in Subsection 15.1.1.3.1 was used to simulate this event.

15.2.7.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

15.2.7.3.3 Results

The results of this transient simulation are shown in Figure 15.2-9. Feedwater flow terminates at approximately 5 seconds. Subcooling decreases causing a reduction in core power level and pressure. As power level is lowered, the turbine steam flow starts to drop off because the pressure regulator is attempting to maintain pressure for the first 8 seconds or so. Water level continues to drop until the vessel level (L3) scram trip set point is reached whereupon the reactor is shut down. Main steam line isolation occurs at 13 seconds due to vessel water dropping to the L2 trip. Also at this time, the recirculation system is tripped and HPCI and RCIC operation is initiated. MCPR remains considerably above the safety limit since increases in heat flux are not experienced.

15.2.7.3.4 Considerations of Uncertainties

End-of-cycle scram characteristics are assumed.

This transient is most severe from high power conditions, because the rate of level decrease is greatest and the amount of stored and decay heat to be dissipated are highest.

Operation of the RCIC or HPCI systems is not included in the simulation of the first 50 seconds of this transient since startup of these pumps occurs in the latter part of this time period and therefore these systems have no significant effects on

15.4.4.3 Core and System Performance

15.4.4.3.1 Mathematical Model

The nonlinear dynamic model described briefly in Subsection 15.1.1.3.1 is used to simulate this event.

15.4.4.3.2 Input Parameters and Initial Conditions

This analysis has been performed unless otherwise noted with plant conditions tabulated in Table 15.0-2.

One recirculation loop is idle and filled with cold water (100°F). Normal procedure when starting an idle loop with one pump already running requires heating the idle recirculation loop to within 50°F of core inlet temperature prior to loop startup.

The active recirculation loop is operating with about 50% of normal rated diffuser flow going across the active jet pumps.

The core is receiving 38% of its normal rated flow. The remainder of the coolant flows in the reverse direction through the inactive jet pumps.

Reactor power is 55% of NBR power conditions. Normal procedures require startup of an idle loop at a lower power.

The idle recirculation pump suction valve is open, but the pump discharge valve is closed.

The idle pump fluid coupler is at a setting which approximates 50% generator speed demand.

15.4.4.3.3 Results

The transient response to the incorrect startup of a cold, idle recirculation loop is shown in Figure 15.4-6. Shortly after the pump begins to move, a surge in flow from the standard jet pump diffusers causes the core inlet flow to rise sharply.

A short-duration neutron flux peak reaches the flow referenced APRM flux set point at 10 seconds and reactor scram is initiated. The neutron flux peaks at 323% of NB rated. Surface heat flux follows the slower response of the fuel and peaks at 135% of NB of initial value. Nuclear system pressures do not increase significantly

15.4.5.3 Core and System Performance

15.4.5.3.1 Mathematical Model

The nonlinear dynamic model described briefly in Subsection 15.1.1.3.1 is used to simulate this event.

15.4.5.3.2 Input Parameters and Initial Conditions

This analysis has been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2. For this event the most severe transient results when initial conditions are established for operation at the low end of the rated flow control rod line. Specifically, this is 65% NB rated power and 50% core flow.

Maximum change in speed control occurs with failure of one of the motorgenerator set speed controllers. A rapid swing of the coupler is simulated at its maximum rate of 25% per second.

15.4.5.3.3 Results

Figure 15.4-7 shows the results of the transient. The changes in nuclear system pressure are not significant with regard to overpressure. Pressure decreases over most of the transient. The rapid increase in core coolant flow causes an increase in neutron flux, which initiates a reactor APRM high flux scram.

The peak neutron flux rise reaches 265% of NBR flux, and the accompanying transient fuel surface heat flux reaches 130% of initial. The MCPR remains above the safety limit of 1.06, and fuel center temperature increases only 407°F. Reactor pressure is discussed in Subsection 15.4.5.4. Therefore, the design basis is satisfied.

15.4.5.3.4 Considerations of Uncertainties

Some uncertainties in void reactivity characteristics, scram time and worth are expected to be more optimistic and will therefore lead to reducing the actual severity over that which is simulated herein.

15.5.1.2.2 System Operation

To properly simulate the expected sequence of events the analysis of this event assumes normal functioning of plant instrumentation and controls, specifically, the pressure regulator and the vessel level control which respond directly to this event.

Required operation of engineered safeguards other than what is described is not expected for this transient event.

The system is assumed to be in the manual flow control mode of operation.

15.5.1.2.3 The Effect of Single Failures and Operator Errors

Inadvertent operation of the HPCI results in a mild pressurization. Corrective action by the pressure regulator and/or level control is expected to establish a new stable operating state. The effect of a single failure in the pressure regulator will aggravate the transient depending upon the nature of the failure. Pressure regulator failures are discussed in Subsections 15.1.3 and 15.2.1.

A single failure in the level control system causes level rise or fall by improper control of the feedwater system. Increasing level will trip the turbine and automatically trip the HPCI system off. This trip signature is already described in the failure of feedwater controller with increasing flow. Decreasing level will automatically initiate scram at the L3 level trip and will have a signature similar to loss of feedwater control - decreasing flow.

15.5.1.3 Core and System Performance

15.5.1.3.1 Mathematical Model

The detailed nonlinear dynamic model described briefly in Subsection 15.2.2.3.1 is used to simulate this transient.

15.5.1.3.2 Input Parameter and Initial Conditions

This analysis has been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

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.

TABLE 15.1-3

SEQUENCE OF EVENTS FOR FIGURE 15.1-3

Time-sec	Event
0	Initiate simulated failure of 135% upper limit on feedwater flow.
10.064	L8 vessel level set point trips main turbine and feedwater pumps. Turbine bypass operation initiated.
10.064 (est.)	Reactor scram trip actuated from main turbine stop valve position switches.
10.074	Recirculation pump trip (RPT) actuated by stop valve position switches.
10.249 (est.)	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
12.0	Relief group 1 actuated due to high pressure.
21.0	Relief group 1 closed.
45+ (est.)	Turbine bypass valves close (not simulated) causing vessel pressure to recover and depress water level.
650(est.)	Low water level trip attained causing isolation with closure of the MSIV's and initiation of HPCI and RCIC systems.

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 inadervent 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.

15.1.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2.

The same void reactivity coefficient used for pressurization transients is applied since a more negative value conservatively increases the apparent severity of the power increase. End of cycle (all rods out) scram characteristics are assumed. The safety-relief valve action is conservatively assumed to occur with higher than nominal set points. The transient is simulated by programming an upper limit failure in the feedwater system such that 135% feedwater flow occurs at a system design pressure of 1060 psig.

15.1.2.3.3 Results

The simulated feedwater controller transient at 105% NBR rated steam flow is shown in Figure 15.1-3. The high water level turbine trip and feedwater pump trip are initiated at approximately 10 sec. Scram occurs simultaneously from stop valve closure, and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. MCPR remains above 1.06 (the safety limit) and peak fuel center temperature increases less than 59°F. The turbine bypass system opens to limit peak pressure in the steam line near the safety valves to 1138 psig and the pressure at the bottom of the vessel to about 1175 psig. The nuclear system process barrier pressure limit is not endangered.

The bypass valves subsequently close to re-establish pressure control in the vessel during shutdown. The level will gradually drop to the Low Level isolation reference point, activating the RCIC/HPCI systems for long term level control.

15.1.2.3.4 Consideration of Uncertainties

All systems utilized for protection in this event were assumed to have the most conservative allowable response (e.g., relief setpoints, scram stroke time and work characteristics). Plant behavior is, therefore, expected to lead to a less severe transient.

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, re-analyze 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, and

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

Table 15A2-2 has been modified to delete the reference to "Low Power."

TABLE 15A.2-2 (Continued)

ANTICIPATED (EXPECTED) OPERATIONAL TRANSIENTS

Cross-Correlation References

NSOA Event No.	Event Description	NSOA Event Figure No.	Safety Analysis Section No.
19	RHRS - Shutdown Cooling Failure Increased Cooling	15A.6-19	15.1.6
20	Loss of All Feedwater Flow	15A.6-20	15.2.7
21	Loss of Feedwater Heater	15A.6-21	15.1.1
22	Feedwater Controller Failure Maximum Demand	15A.6-22	15.1.2
23	Pressure Regulator Failure - Open	15A.6-23	15.1.3
24	Pressure Regulator Failure - Closed	15A.6-24	15.2.1
25	Main Turbine Trip With Bypass System Operational	15A.6-25	15.2.3
26	Loss of Main Condenser Vacuum	15A.6-26	15.2.5
27	Main Generator Trip (Load Rejection) With By-pass System Operational	15A.6-27	15.2.2
28	Loss of Plant Normal On-Site AC Power - Auxiliary Transformer Failure	15A.6-28	15.2.6
29	Loss of Plant Normal Off-Site AC Power - Grid Connection Failure	15A.6-29	15.2.6

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 18 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.

15.1.3.3.2 Input Parameters and Initial Conditions

This transient is simulated by setting the controlling regulator output to a high value, which causes the turbine admission valves to open fully and the turbine bypass valves to open partially. Since the controlling and backup regulator outputs are gated by a high value gate, the effect of such a failure in the backup regulator would be exactly the same. A regulator failure with 115% steam flow was simulated as a worst case since 110% is the normal maximum flow limit.

A 5-second isolation valve closure instead of a 3-second closure is assumed when the turbine pressure decreases below the turbine inlet low pressure set point for main steam line isolation initiation. This is within the specification limits of the valve and tends to aggravate the results of the analysis.

This analysis has been performed, unless otherwise noted, with the plant conditions listed in Table 15.0-2.

15.1.3.3.3 Results

Figure 15.1-4 shows the response of important nuclear system variables for this transient. The turbine inlet pressure decreases to the low pressure trip set point in 19 sec and initiates trip of the MSIV's. Closure of the MSIV's initiates scram, and subsequent loss of steam to the main turbine and the feedwater turbines.

Reactor low turbine pressure trip limits the duration and severity of the depressurization so that no significant thermal stresses are imposed on the nuclear system process barrier. After the rapid portion of the transient is complete the nuclear system safety/relief valves operate intermittently to relieve the pressure rise that results from decay heat generation. No significant reductions in fuel thermal margins occur. Because the rapid portion of the transient results in only momentary depressurization of the nuclear system and because the safety/relief valves operate only to relieve the pressure increase caused by decay heat, the nuclear system process barrier is not threatened by high internal pressure for this pressure regulator malfunction.

15.1.3.3.4 Consideration of Uncertainties

If the maximum flow limiter were set higher or lower than normal, a faster or slower loss in nuclear steam pressure would result. The rate of depressurization may be limited by the bypass capacity, but it is unlikely. For example, the turbine valves will open to the valves wide-open state admitting slightly more than the rated steam flow, and with the limiter in this analysis set to fail at 115%, we would expect something less than 15% to be bypassed. This is therefore not a limiting factor on this plant. If the rate of depressurization does change it will be terminated by the low turbine inlet pressure trip set point.

Depressurization rate has a proportional effect upon the voiding action of the core. If it is large enough, the sensed vessel water level trip set point (L8) may be reached initiating a turbine and feedwater pump trip early in the transient. Turbine trip will initiate reactor scram and shut down the reactor. Thermal margins will be better than a typical turbine trip event because of the power reduction initially experienced due to increased core holds in this event. Since the pressure regulator failure continues to signal the bypass to remain fully open, the turbine inlet pressure will drop below the low pressure isolation set point and the expected transient signature will conclude with an isolation of the main steam lines.

15.1.3.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which fuel, pressure vessel or containment are designed; therefore, these barriers maintain their integrity and function as designed. Peak pressure in the bottom of the vessel reaches 1123 psig which is below the ASME code limit of 1375 psig for the reactor coolant pressure boundary. Vessel dome pressure reaches 1092 psig, just slightly below the set point of the second pressure relief group. Minimum vessel dome pressure of 845 psig occurs at about 20 seconds.

15.1.3.5 Radiological Consequences

While the consequence of this event does not result in fuel failure it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not

TABLE 15.1-4

SEQUENCE OF EVENTS FOR FIGURE 15.1-4
PRESSURE REGULATOR FAILURE - OPEN
INITIAL STEAM FLOW CONDITION - 105% NBR

Time-sec	Event
0	Simulate maximum limit on steam flow to main turbine.
0.2	Main turbine bypass partially open.
19	Main steamline isolation on low turbine inlet pressure.
19.3	Main steam isolation valves reach 90% open position and initiates reactor scram trip.
48 (est)	Lowest relief valve starts cycling to remove decay heat.

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 relatively insignificant.

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 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:

See response to Question 211.117 for the response to this question.

QUESTION 211.162:

Explain why vessel steam and bypass flows in Figure 15.2-1 drop to zero at approximately 37 seconds instead of zero at 45-plus seconds from a 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 distrubance 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.

safety limit for the incidents of moderate frequency. MCPR reaches 1.01 for this event.

15.2.2.3.4 Consideration of Uncertainties

The full stroke closure rate of the turbine control valve of 0.15 seconds is conservative. Typically, the actual closure rate is more like 0.2 seconds. Clearly the less time it takes to close, the more severe the pressurization effect.

All systems utilized for protection in this event were assumed to have the poorest allowable response (e.g., relief set points, scram stroke time and work characteristics). Plant behavior is, therefore, expected to reduce the actual severity of the transient.

15.2.2.4 Barrier Performance

15.2.2.4.1 Generator Load Rejection

Peak pressure remains within normal safety range and no threat to the barrier exists.

15.2.2.4.2 Generator Load Rejection with Failure of Bypass

Peak pressure at the valves reaches 1160 psig. The peak nuclear system pressure reaches 1193 psig at the bottom of the vessel, well below the nuclear barrier transient pressure limit of 1375 psig.

15.2.2.5 Radiological Consequences

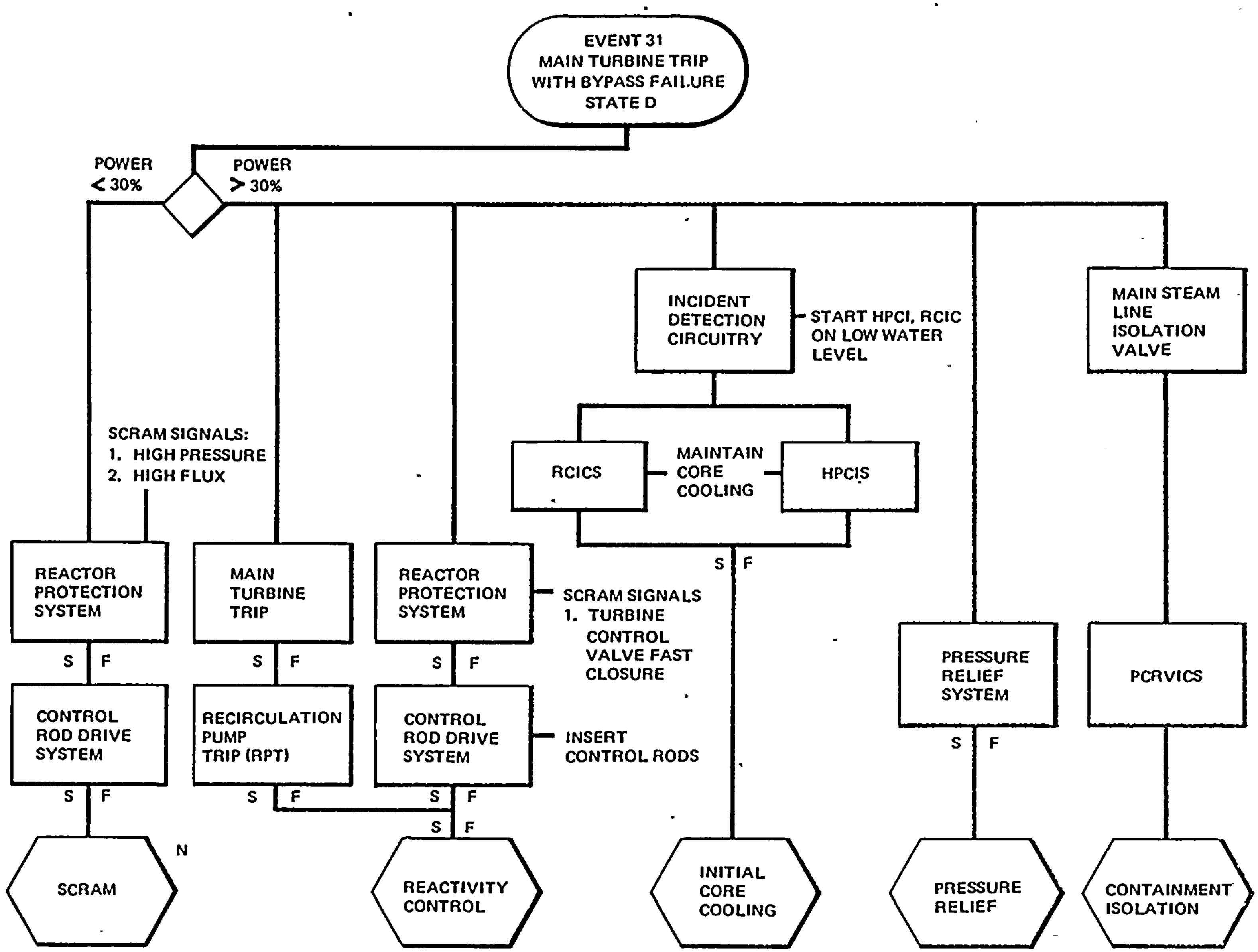
While the consequence of this event does not result in fuel failures, it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will have to be in accordance with established technical specifications; therefore, this event, at the worst, would only

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.



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

PROTECTION SEQUENCES MAIN TURBINE TRIP - WITH BYPASS FAILURE

FIGURE 15A.6-31

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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.

15.2.3.2.3 The Effect of Single Failures and Operator Errors

15.2.3.2.3.1 Turbine Trips at Power Levels Greater Than 30%NBR

Mitigation of pressure increase is accomplished by the reactor protection system functions. Main stop valve closure scram trip and RPT are designed to satisfy single failure criterion.

15.2.3.2.3.2 Turbine Trips at Power Levels Less Than 30% NBR

Same as Subsection 15.2.3.2.3.1 except RPT and stop valve closure scram trip is normally inoperative. Since protection is still provided by high flux, high pressure, etc., these will also continue to function and scram the reactor should a single failure occur.

15.2.3.3 Core and System Performance

15.2.3.3.1 Mathematical Model

The computer model described in Subsection 15.1.1.3.1 was used to simulate these events.

15.2.3.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

Turbine stop valves full stroke closure time is 0.1 second.

A reactor scram is initiated by position switches on the stop valves when the valves are less than 90% open. This stop valve scram trip signal is automatically bypassed when the reactor is below 30% NB rated power level.

Reduction in core recirculation flow is initiated by position switches on the main stop valves, which actuate trip circuitry which trips the recirculation pumps.

QUESTION 211.167:

During the "turbine trip with bypass" transient, explain why vessel steam and bypass flows in Figure 15.2-3 drop to zero at approximately 37 seconds insteam of zero at 45-plus seconds from a 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.

(3) Minimum specified valve capacities are utilized for over-pressure protection.

(4) Set points of the safety/relief valves are assumed to be 1% higher than the valve's nominal set point.

15.2.4.4 Barrier Performance

15.2.4.4.1 Closure of All Main Steam Isolation Valves

The nuclear system relief valves begin to open at approximately 2.7 seconds after the start of isolation. The SRVs close sequentially as the stored heat is dissipated but continue to discharge the decay heat intermittently. Peak pressure at the vessel bottom reaches 1187 psig, clearly below the pressure limits of the reactor coolant pressure boundary. Peak pressure in the main steamline is 1146 psig.

15.2.4.4.2 Closure of One Main Steam Isolation Valve

If closure of the valve occurs at an unacceptably high operating power level, a flux or pressure scram will result; therefore, no significant effect is imposed on the RCPB. The main turbine bypass system will continue to regulate system pressure via the other three "live" steamlines.

15.2.4.5 Radiological Consequences

While the consequence of this event does not result in fuel failure it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release condition. If purging of the containment is chosen, the release will have to be in accordance with established technical specifications; therefore this event, at the worst, would only result in a small increase in the yearly integrated exposure level.

The activity released to the suppression chamber can be contained for some period of time. If it is assumed that the activity airborne above the suppression pool will be released

under controlled conditions. The operator can choose to release the activity after decay has reduced the amount of activity to levels where the offsite dose consequence is minimal. For example, consider the case when the activity is released through the containment purge at an assumed time of 4 hours after the blowdown is complete (8 hours after the transient begins).

The containment airborne activity is discharged via the SGTS, which has a filter efficiency of 99 percent for the iodine activity. For this example, the airborne activities above the suppression pool and the activity released to the environs are listed in Tables 15.2-6 and 15.2-7 respectively.

The offsite radiological doses are presented in Table 15.2-8.

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 sec. 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.

TABLE 15.2-5

SEQUENCE OF EVENTS FOR FIGURE 15.2-5

Time-sec	Event
0	Initiate closure of all main steam line isolation valves (MSIV).
0.3	MSIVs reach 90% open.
0.3	MSIV position trip scram initiated.
2.8	All relief valves open due to pressure relief set point action.
19.4	All pressure relief valves reclose.
23.0	Group 1 pressure relief valves reopen.
29.0	Group 1 pressure relief valves reclose.
36.0	Group 1 pressure relief valves reopen.
40.0	Group 1 pressure relief valves reclose.

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.

15.2.5.3.2 Input Parameters and Initial Conditions

This analysis was performed with plant conditions tabulated in Table 15.0-2 unless otherwise noted. Turbine stop valves full stroke closure time is 0.1 second.

A reactor scram is initiated by position switches on the stop valves when the valves are less than 90% open. This stop valve scram trip signal is automatically bypassed when the reactor is below 30% NB rated power level.

The analysis presented here is a hypothetical case with a conservative .8 inches Hg per second vacuum decay rate. Thus, the bypass system is available for several seconds since the bypass is signaled to close at a vacuum level of about 10 inches Hg less than the stop valve closure.

15.2.5.3.3 Results

Under this hypothetical .8 inches Hg per second vacuum decay condition, the turbine bypass valve and main steam isolation valve closure would follow main turbine and feedwater turbine trips about 12 seconds after they initiate the transient. This transient, therefore, is similar to a normal turbine trip with bypass. The effect of main steam isolation valve closure tends to be minimal since the closure of main turbine stop valves and subsequently the bypass valves have already shut off the main steam line flow. Figure 15.2-6 shows the transient expected for this event. It is assumed that the plant is initially operating at 105% of Nuclear Boiler rated steam flow conditions. Peak neutron flux reaches 168% of NB rated power while average fuel surface heat flux reaches 105% of rated value. Safety/relief valves open to limit the pressure rise, then sequentially reclose as the stored energy is dissipated.

15.2.5.3.4 Considerations of Uncertainties

The reduction or loss of vacuum in the main turbine condenser will sequentially trip the main and feedwater turbines and close the main steamline isolation valves and bypass valves. While these are the major events occurring, other resultant actions will include scram (from stop valve closure) and bypass opening with the main turbine trip. Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is directly dependent upon the rate at which the vacuum pressure is lost. Normal loss of vacuum due to loss of cooling water pumps or steam jet air ejector problem

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 is being revised and will be available by the fourth Quarter of 1980.

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.

TABLE 15.2-13

SEQUENCE OF EVENTS FOR FIGURE 15.2-8

Time-sec	Event	
(-)0.015 (approx.)	Loss of Grid causes turbine-generator to detect a loss of electrical load.	
0	Control valve fast closure.	15
0	Turbine-generator PLU trip initiates main turbine bypass system operation.	
0	Recirculation system pump motors are tripped.	
0	Fast control valve closure (FCV) initiates a reactor scram trip.	
0	Initiation of stanby AC power systems.	16
0.1	Turbine bypass valves open.	15
0.15	Turbine control valves closed.	
1.2	Group 1 relief valves actuated.	
1.4	Group 2 relief valves actuated.	
1.5	Group 3 relief valves actuated.	
1.7	Group 4 relief valves actuated.	15
2.0	MSIV's start to close.	
4.0	Feedwater turbines tripped off.	
18.7	Group 1 safety relief valves close.	
37.2	Initiate Containment Isolation, HPCI and RCIC operation, (L2) (not simulated).	16

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 15.0-1 (1091, 1101, 1111, 1121, 1131 psig). The safety function of SRV is used in the vessel overpressure protection section (see Question 211.142), 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:

In response to NUREG 0578, requirement 2.1.2, the BWR Owners Group has initiated tests to demonstrate the ADS valves are qualified for a spectrum of conditions. These tests will include a low pressure liquid test to simulate alternate shutdown viability of the ADS valves. Valve hydraulic losses will be determined as a result of those tests. Therefore, system hydraulic losses can be readily compared to available pump head. The BWR Owners Group has committed to the NRC to have the tests completed by July of 1981.

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.

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.

TABLE 15.3-3

SEQUENCE OF EVENTS FOR FIGURE 15.3-3

Time-sec	Event
0	Single pump seizure was initiated.
0.7	Jet pump diffuser flow reverses in seized loop.
1.9	Vessel level (L8) trip initiates turbine trip.
1.9	Feedwater pumps are tripped off.
1.9	Turbine trip initiates bypass operation.
2.1	Turbine trip initiates reactor scram trip.
4.0	Group 1 pressure relief valves open.
10.0	Group 1 pressure relief valves close.
35	Bypass closes, steam flow shuts off-zero flow.
41.7	L2 vessel level set point isolation of main steam line.
72+ (est)	HPCI/RCIC flow enters vessel (not simulated)

QUESTION 211.180:

The narrative on page 15.4-13 discussing the "abormal 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 scram will again occur. Table 15.4-3 has been modified.

a) Table 15.3-3 indicates L4 near 11 seconds. This is verified by Figure 15.4-6.

b) Table 15.3-3 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 econds level rate is definitely flattening out under normal feedwater level control.

above initial. The water level does not reach the high set point.

15.4.4.3.4 Consideration of Uncertainties

This particular transient is analyzed for an initial power level that is much higher than that expected for the actual event. The much slower thermal response of the fuel mitigates the effects of the rather sharp neutron flux spike and even in this high range of power, no threat to thermal limits is possible.

15.4.4.4 Barrier Performance

No evaluation of barrier performance is required for this event since no significant pressure increases are incurred during this transient. See Figure 15.4-6.

15.4.4.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released from the fuel. Figure 15.4.4-1 Abnormal Startup of Idle Recirculation Loop Pump.

TABLE 15.4-3

SEQUENCE OF EVENTS FOR FIGURE 15.4-6

Time-sec	Event
0	Start pump motor.
9.0	Startup loop flow starts to increase significantly.
10.0	Reactor high flux scram initiated.
11.0	Vessel level reaches (L4) Low Level Alarm
23.5	Vessel level reaches (L3) Low Level Scram Trip.
35.0	Diffuser flows and pressures begin to stabilize.
50.0	Vessel level begins to stabilize.

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 i=0 dive 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 th 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 the 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.

TABLE 15A.6-2

PLANT EVENTS APPLICABLE IN EACH BWR OPERATING STATE

ANTICIPATED (EXPECTED) OPERATIONAL TRANSIENTS

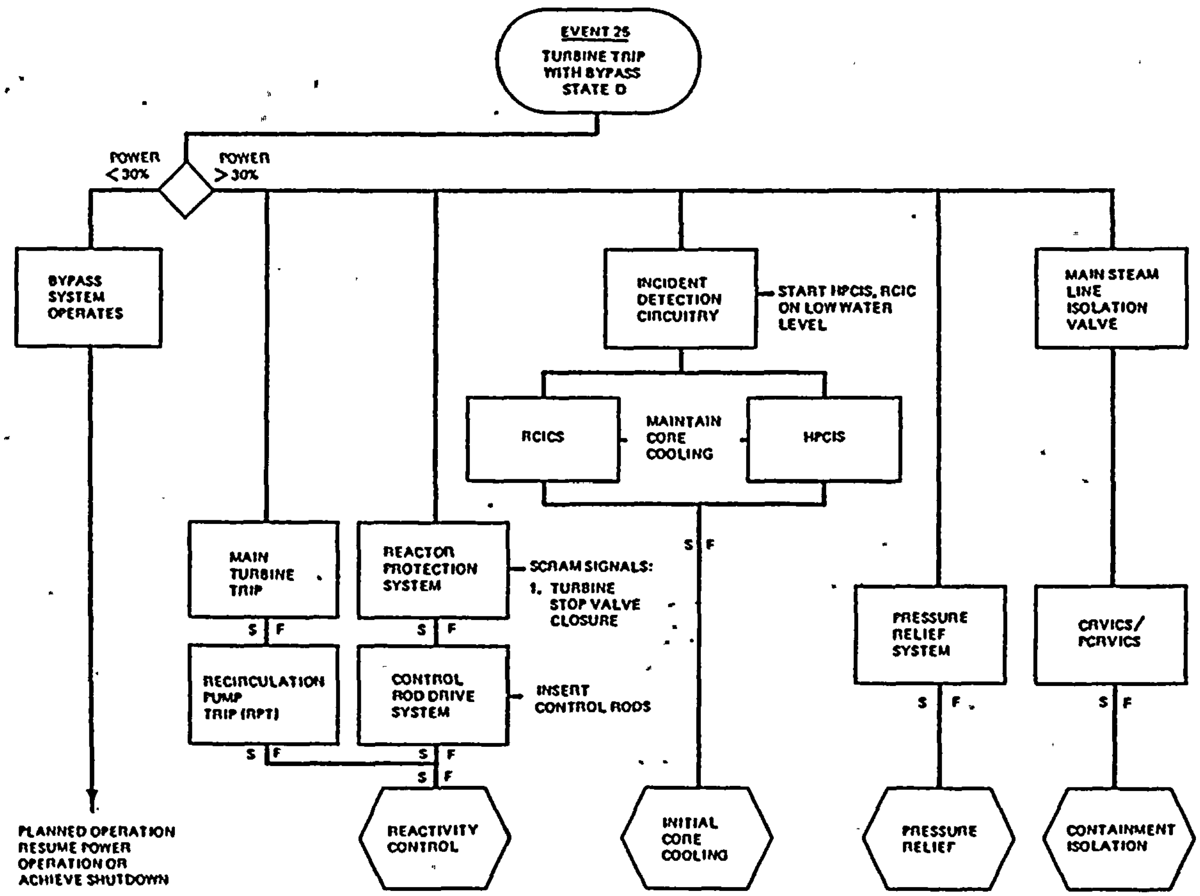
Types of Operation and Events	BWR Operating States A	B	C	D
7. Manual or Inadvertant SCRAM	X	X	X	X
8. Loss of Plant Instrument/ Service Air System			X	X
9. Inadvertant Start-Up of HPCI Pumps	X	X	X	X
10. Inadvertant Start-up of Idle Recirculation Loop Pump	X	X	X	X
11. Recirculation Loop Flow Control Failure-Increasing			X	X
12. Recirculation Loop Flow Control Failure-Decreasing			X	X
13. Recirculation Loop Pump Trips - One or Both			X	X
14. Inadvertant MSIV Closure - One or Four Valves			X	X
15. Inadvertant Operation of One Safety/Relief Valve			X	X
16. Continuous Control Rod Withdrawal Error - During Start-up		X		
- During Refuleing	X			
17. Continuous Control Rod Withdrawal Error - At Power			X	X
18. RHRS-Shutdown Cooling Failure - Loss of Cooling	X	X	X	X
19. RHRS-Shutdown Cooling Failure - Increased Cooling	X	X	X	X
20. Loss of All Feedwater Flow			X	X
21. Loss of One Feedwater Heater				X
22. Feedwater Controller Failure - Maximum Demand	X	X	X	X

TABLE 15A.6-2 (Continued)

PLANT EVENTS APPLICABLE IN EACH BWR OPERATING STATE

ANTICIPATED (EXPECTED) OPERATIONAL TRANSIENTS

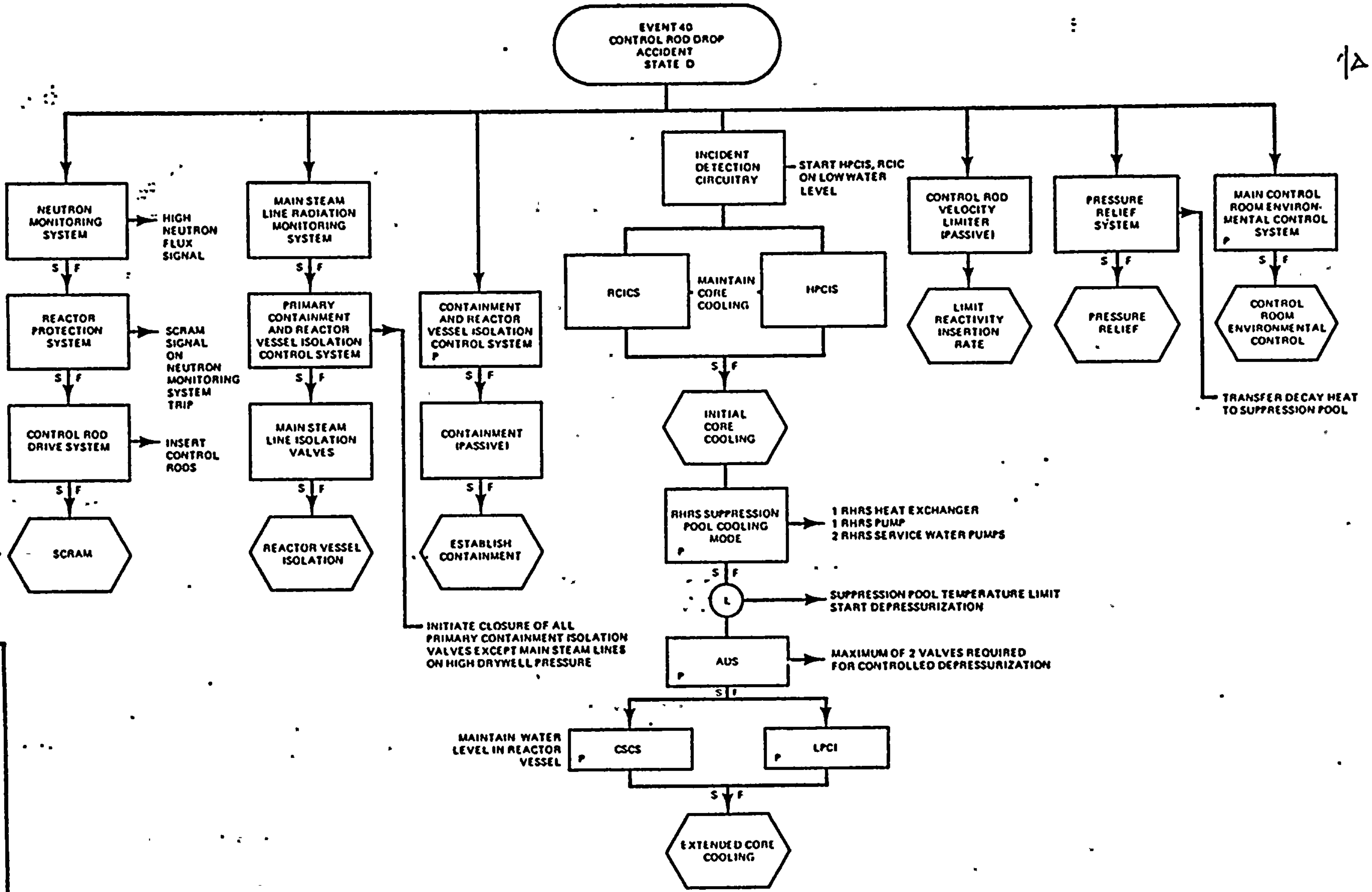
Types of Operation and Events	BWR Operating States A	B	C	D
23. Pressure Regulator Failure - Open			X	X
24. Pressure Regulator Failure - Closed			X	X
25. Main Turbine Trips - With Bypass				X
26. Loss of Main Condenser Vacuum			X	X
27. Main Generator Trip (Load Rejection) With Bypass				X
28. Loss of Plant Normal On-site AC Power - Auxiliary Transformer Loss	X	X	X	X
29. Loss of Plant Norman Off-site AC Power - Grid Connection Loss	X	X	X	X



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

PROTECTION SEQUENCES FOR MAIN TURBINE TRIP WITH BYPASS

FIGURE 15A.6-25



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

PROTECTION SEQUENCES FOR CONTROL ROD DROP ACCIDENT

FIGURE. 15A.6-40

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 , to show the principal construction codes and standards.

The main steam system: pressure vessels, heat exahngers 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.

TABLE 3.2-1

SSES DESIGN CRITERIA SUMMARY

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Reactor System	4,5		C							
Reactor vessel		GE	C	A	1	III-A	I	Y		
Reactor vessel support skirt		GE	C	NA	1	III-A	I	Y		
Reactor vessel appurtenances, pressure retaining portions		GE	C	A	1	III-A	I	Y		
CRD housing supports		GE	C	NA	2	X	I	Y		15
Reactor internal structures, engineered safety features		GE	C	NA	2	X	I	Y		
Reactor internal structures, other		GE	C	NA	Other	X	N/A	Y		
Control rods		GE	C	NA	2	X	I	Y		
Control rod drives		GE	C	NA	2	III-2	I	Y		
Core support structure		GE	C	NA	2	X	I	Y		
Power range detector hardware		GE	C	B	2	III-2	I	Y	10	
Fuel assemblies		GE	C	NA	2	X	I	Y		15
Nuclear Boiler System	4,5									
Vessels, level instrumentation condensing chambers		GE	C	A	1	III-1	I	Y	10	15
Vessels, air accumulators		P	C	C	3	III-3	I	Y		
Air supply check valves, piping downstream of air supply check valve		P	C	C	3	III-3	I	Y		16
Piping, relief valve discharge		P	C	C	3	III-3	I	Y		
Piping, main steam, within outermost isolation valve		GE	C	A	1	III-1	I	Y		15
Pipe supports, pipe restraints, main steam		P	C	A	1	III	I	Y		
Piping, other within outermost isolation valves		P	C	A	1	III-1	I	Y	10	
Piping, instrumentation beyond outermost isolation valves		P	R,T	B	2	III-2	Note 20	N		15
Safety/relief valves		GE	C	A	1	III-1	I	Y		
Valves, main steam isolation										

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

 4

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Piping, water return line within isolation valves		P	C	A	1	III-1	I	Y	8	
Piping, scram discharge volume lines		P	C	B	2	III-2	I	Y		
Piping, insert and withdraw lines		P	C,R	B	2	III-2	I	Y		
Piping, other		P	C,R	D	Other	B31.1.0	N/A	N		
Hydraulic control unit		GE	C	NA	2	N/A	I	Y	12	
Electrical modules, with safety function		GE	C	NA	2	IEEE-279/ 323	I	Y		15
Cable, with safety function		P	C,R	NA	2	IEEE-279/ 323/383	NA	Y	15	15
Engineered Safety Features										
Standby Liquid Control System	9.3.5									
Standby liquid control tank		GE	R	B	2	III-C & API-650	I	Y		15
Pump		GE	R	B	2	NP & V-II	I	Y		
Pump motor		GE	R	NA	2	X	I	Y		
Valves, explosive		GE	R	A	2	NP & V-II	I	Y		
Valves, isolation and within		P	C	A	1	III-1	I	Y	10	
Valves, beyond isolation valves		P	C	B	2	III-2	I	Y	10	
Piping, within isolation valves		P	C	A	1	III-1	I	Y	10	
Piping, beyond isolation valves		P	C	B	2	III-2	I	Y	10	
Electrical modules, with safety function		GE	C	NA	2	IEEE-279/ 323	I	Y		15
Cable, with safety function		P	C	NA	2	IEEE-279/ 323/383	NA	Y	15	16
RHR System	5.4.7									
Heat exchangers, primary side		GE	R	B	2	III-2	I	Y		15
Heat exchangers, secondary side		GE	R	C	3	III-3	I	Y		
Piping, within outermost containment isolation valves		P	C	A	1	III-1	I	Y	10	

* Refer to the General Notes at the end of this table.

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
valve; gland exhaust piping from RCIC turbine										
RCIC barometric condenser		GE	R	D	Other	B31.1.0	NA	N		
RCIC condensate pump and condenser vacuum pump		GE	R	D	Other	X	NA	N		15
Pumps		GE	R	B	2	NP & V-II	I	Y		
Valves, containment isolation and within containment		P	C	A	1	III-1	I	Y	10	
Valves, other		P	R	B	2	III-2	I	Y	10	
RCIC turbine		GE	R	NA	2	X	I	Y	11	
Electrical modules, with safety function		GE	R	NA	2	IEEE-279/ 323	I	Y		15
Cable, with safety function		P	R	NA	2	IEEE-279/ 323/383	NA	Y	15	
Fuel Storage and Handling	9.1									
Storage Equipment	9.1.1, 9.1.2									
New fuel storage vault		P	R	NA	Other	AWS D1.1	I	Y		
New fuel storage racks		GE	R	NA	Other	AWS D1.1	I	Y		
Spent fuel storage racks		P	R	NA	2	III-2	I	Y		16
Defective fuel storage racks		P	R	NA	2	III-2	I	Y		
Control rod storage racks		P	R	NA	2	III-2	I	Y		
Liner for spent fuel pool, RX well, dryer-sep. pool, and cask pit		P	R	NA	2	AISI/AWS D1.1	I	Y		15 16
Channel storage racks		GE	R	NA	Other	AWS D1.1	NA	N		
In vessel racks		GE	R	NA	Other	AWS D1.1	I	Y		
Defective fuel storage containers		GE	R	3		AWS D1.1	NA	Y		
Fuel Servicing Equipment	9.1.4									
Fuel preparation machine		GE	R	NA	Other	X	NA	Y		
New fuel inspection stand		GE	R	NA	Other	X	NA	N		15
General purpose grapple		GE	R	NA	Other	X	I	Y		
Irradiated fuel shipping cask		P	R	NA	Other	49CFR 173.393 49CFR 173.396	I	Y		16

* Refer to the General Notes at the end of this table.

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Piping, other		P	O,R,SW	C	3	III-3	I	Y		4
RHR SW Pumps		P	SW	C	3	III-3	I	Y		
Pump motors		P	SW	NA	3	IEEE-323/ 344	I	Y		
Valves, isolation		P	C,R	B	2	III-2	I	Y		
Valves, other		P	O,R,SW	C	3	III-3	I	Y		
Electrical modules, with safety function		P	O,R,SW	NA	3	IEEE-279	I	Y		
Cable, with safety function		P	O,R,SW	NA	3	IEEE-279/ 323/383	NA	Y	15	
Heat exchangers		P	O,R,G	C	3	II-3/TEMA C	I	Y		
Piping drain pumps		P	O	NA	Other	HYD.I	NA	N		
<u>Emergency Service Water System</u>	9.2.7									
Piping up to RHR SW system		P	O,G,R, T,CS, SW	C	3	III-3	I	Y		4
Pumps		P	SW	C	3	II-3	I	Y		
Pump motors		P	SW	NA	3	IEEE-323/ 344	I	Y		
Valves		P	O,G,R, T,CS, SW	C	3	II-3	I	Y		
Electrical modules with safety function		P	O,G,R, T,CS SW	NA	3	IEEE-279	I	Y		
Cable, with safety function		P	O,G,R, T,CS, SW	NA	3	IEEE-279/ 323/383	NA	Y	15	16
Heat exchangers		P	R,T,G, CS	C	3	II-3	I	Y		
<u>Reactor Building Closed Cooling Water System</u>	9.2.2									
Piping and valves forming part of containment boundary		P	R,C	B	2	III-2	I	Y		

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

 4

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *
Piping and valves, fuel oil system		P	O,G	C	3	III-3	I	Y	
Transfer pumps, fuel oil system		P	O,G	C	3	III-3	I	Y	
Pump motors, fuel oil system		P	O,G	NA	3	IEEE-323/344	I	Y	
Diesel generators		P	G	NA	2	IEEE-387	I	Y	
Electrical modules with safety functions		P	G	NA	3	IEEE-279	I	Y	
Cable, with safety functions		P	G	NA	3	IEEE-279/323/383	NA	Y	15
Diesel fuel storage tanks		P	O	C	3	III-3	I	Y	
Diesel lube oil system piping and valves		P	G	C	3	B31.1	I	Y	
Heat exchangers, jacket water, and lube oil		P	G	C	3	III-3/TEMA C	I	Y	
Filter housings		P	G	C	3	VIII/B31.1	I	Y	
Lube oil heater		P	G	NA	Other	NONE	NA	N	
Lube oil circulating pump		P	G	D	Other	Hyd. I	NA	N	24
Diesel starting air system piping and valves from receiver to diesel		P	G	C	3	III-3	I	Y	
Piping and valves, other		P	G	D	Other	B31.1.0	NA	N	
Air receivers		P	G	C	3	III-3	I	Y	
Compressors		P	G	D	Other	NA	NA	N	
Cooling jacket water heater		P	G	NA	Other	NA	NA	N	
Cooling jacket water heater pump		P	G	D	Other	Hyd. I	NA	N	24
Dirty lube oil drain tank		P	G	D	Other	NONE	NA	N	
Heating, Ventilating and Air Conditioning Systems									
Control Structure	9.4.1								
Control Room & Computer Room HVAC									
Motors		P	CS	NA	3	NEMA MG1 IEEE-344	I	Y	
Instrumentation		P	CS	NA	3	IEEE-279	I	Y	

16

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Fans		P	CS	NA	3	AMCA	I	Y		
Prefilters		P	CS	NA	3	UL Class I	I	Y		
HEPA filters		P	CS	NA	3	MIL-F-51068C MIL-F-51079	I	Y		
Adsorber units		P	CS	NA	3	AACC CS-8 RDT M-16-1T	I	Y		
Dampers, isolation		P	CS	NA	3	AMCA	I	Y		16
Dampers, flow distribution		P	CS	NA	3	AMCA	I	Y		
Ductwork		P	CS	NA	3	AISI	I	Y		
Coils, cooling		P	CS	NA	3	ARI	I	Y		16
Chilled water system		P	CS	D	3	B31.1	I	Y		
Electric heating coils		P	CS	C	3	NEC,NEMA	I	Y		
Centrifugal water chillers (except condenser)		P	CS	D	3	VIII	I	Y		16
Centrifugal water chillers - condenser		P	CS	C	3	III-3	I	Y		
<u>Relay Room, Cable Spreading, Battery Room HVAC, and HVAC Equipment Room</u>										
Motors		P	CS	NA	3	NEMA MG1 IEEE-344	I	Y		
Fans		P	CS	NA	3	AMCA	I	Y		16
Prefilters		P	CS	NA	3	UL Class 1	I	Y		
Coils, heating, electric		P	CS	NA	3	NEC,NEMA	I	Y		
Coils, cooling - chilled water		P	CS	NA	3	ARI	I	Y		16
Dampers		P	CS	NA	3	AMCA	I	Y		
Ductwork		P	CS	NA	3	AISI	I	Y		
Piping & valves		P	CS	C	3	B31.1	I	Y		
Instrumentation		P	CS	NA	3	IEEE-279	I	Y		16
<u>SGTS Equipment Room H&V</u>										
Motors		P	CS	NA	3	NEMA MG1 IEEE-344	I	Y		
Fans		P	CS	NA	3	AMCA	I	Y		
Heaters, electric		P	CS	NA	3	NEC 424 NFPA 90A&90B	I	Y		

* Refer to the General Notes at the end of this table.

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Dampers		P	CS	NA	3	AMCA	I	Y		
Ductwork		P	CS	NA	3	AISI	I	Y		
Instrumentation		P	CS	NA	3	IEEE-279	I	Y		16
Reactor Building										
Reactor Building HVAC (Zone I)	9.4.2									
Motors		P	R	NA	Other	NEMA MG 1	NA	N		
Fans		P	R	NA	Other	AMCA	NA	N		
Prefilters		P	R	NA	Other	UL Class 1	NA	N		
HEPA filters		P	R	NA	Other	MIL-F-51068C, MIL-F-51079	NA	N		16
Adsorber units		P	R	NA	Other	AACC CS-8 RDT M-16-1T	NA	N		16
Coils, cooling		P	R	NA	Other	ARI	NA	N		
Coils, heating		P	R	NA	Other	NEC,NEMA	NA	Y		16
Ductwork		P	R	NA	Other	SMACNA,AISI	NA	N		
Dampers, isolation		P	R	NA	3	AMCA	I	Y		16
Dampers, other		P	R	NA	Other	AMCA	NA	N		
Piping										
Connected to SGTS		P	R	C	3	NFPC	I	Y		
Remainder		P	R	D	Other	B31.1	NA	N		
Valves										
Isolation, chilled water to primary containment		P	R	C	3	III-2	I	Y		
Remainder		P	R	D	Other	B31.1	NA	N		
ECCS Pump Rooms	9.4.2									
Motors		P	R	NA	3	IEEE-323/344	I	Y		
Fans		P	R	NA	3	AMCA	I	Y		
Filters		P	R	NA	3	NA	I	Y		
Coils, cooling		P	R	NA	3	ARI	I	Y		16
Ductwork		P	R	NA	3	AISI	I	Y		
Piping and valves		P	R	C	3	III-3	I	Y		

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Emergency SWGR and Load Center Rooms										
Motors		P	R	NA	3	NEMA MG1 IEEE-344	I	Y		
Fans		P	R	NA	3	AMCA	I	Y		
Prefilters		P	R	NA	3	UL Class 1	I	Y		
Coils, cooling (ESSW)		P	R	C	3	III-3	I	Y		
Coils, chilled water		P	R	NA	3	ARI	I	Y		
Dampers		P	R	NA	3	AMCA	I	Y		
Ductwork		P	R	NA	3	AISI	I	Y		
Piping & valves, ESSW		P	R	C	3	III-3	I	Y		
Piping & valves, chilled water		P	R	NA	3	B31.1	NA	N		|16
Instrumentation		P	R	NA	Other	IEEE-279	I	Y		
Refueling Floor HVAC (Zone III)	9.4.6.									
Motors		P	R	NA	Other	NEMA MG1	NA	N		
Fans		P	R	NA	Other	AMCA	NA	N		
Prefilters		P	R	NA	Other	UL Class 1	NA	N		
HEPA filters		P	R	NA	Other	MIL-F-51079 MIL-F-51068C	NA	N		
Adsorber units		P	R	NA	Other	RDT M-16-1T AACC CS-8	NA	N		
Coils, cooling & heating		P	R	NA	Other	ARI	NA	N		
Ductwork		P	R	NA	Other	SMACNA	NA	N		
Dampers		P	R	NA	Other	AMCA	NA	N		
Piping & valves		P	R	NA	Other	B31.1	NA	N		
Drywell Cooling System	9.4.5									
Motors		P	C	NA	Other	IEEE-334 NEMA MG1	NA	Y		
Fans		P	C	NA	Other	AMCA 210	I	Y		
Coils, cooling		P	C	NA	Other	ARI	I	Y		
Ductwork		P	C	NA	Other	AISI	I	Y		
Dampers		P	C	NA	3	AMCA	I	Y		
Piping and valves		P	C	NA	Other	B31.1	NA	N		|16

* Refer to the General Notes at the end of this table.

 4

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *
Combustible Gas Control System									
Hydrogen recombiners inside containment		P	C	NA	2	NA	I	Y	
Primary Containment Atmosphere monitoring system (PCAMS)		P	C, R	B, D	2	III-2	I	Y	10, 41
Standby Gas Treatment System	9.4.1								
Motors		P	CS	NA	3	IEEE-323/ 344	I	Y	16
Fans		P	CS	NA	3	AMCA	I	Y	16
Prefilters		P	CS	NA	3	UL Class 1	I	Y	16
Demisters		P	CS	NA	3	MSAR 71-45	I	Y	16
HEPA filters		P	CS	NA	3	MIL-F-51079 MIL-F-51068C	I	Y	16
Adsorber units		P	CS	NA	3	AACC CS-8 RDT M-16-1T	I	Y	16
Ductwork		P	CS	NA	3	AISI	I	Y	16
Dampers		P	CS	NA	3	AMCA	I	Y	16
Piping		P	CS	C	3	NFPC	I	Y	16
Valves		P	CS	C	3	B31.1	I	Y	16,14
Electric heaters		P	CS	NA	3	NEMA & NEC	I	Y	
Radwaste Building HVAC	9.4.3								
Motors		P	RW	NA	Other	NEMA MG1	NA	N	
Fans		P	RW	NA	Other	AMCA	NA	N	
Prefilters		P	RW	NA	Other	UL Class 1	NA	N	
HEPA filters		P	RW	NA	Other	MIL-F-51079A MIL-F-51068C	NA	N	
Coils, cooling & heating		P	RW	NA	Other	ARI & UL	NA	N	
Adsorber units		P	RW	NA	Other	MIL-C-17605 RDT M-16-1T	NA	N	
Ductwork		P	RW	NA	Other	SMACNA	NA	N	

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* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Dampers		P	RW	NA	Other	AMCA	NA	N		
Electric heating coil		P	RW	NA	Other	NEC	NA	N		
Diesel Generator Building HVAC	9.4.7									
Motors		P	G	NA	3	NEMA MG-1	I	Y		16
Fans		P	G	NA	3	AMCA	I	Y		
Ductwork		P	G	NA	3	AISI	I	Y		
Dampers		P	G	NA	3	AMCA	I	Y		
Turbine Building HVAC	9.4.4									
Motors		P	T	NA	Other	NEMA MG1	NA	N		
Fans		P	T	NA	Other	AMCA	NA	N		
Filters		P	T	NA	Other	NA	NA	N		
Coils, cooling		P	T	NA	Other	ARI	NA	N		
Ductwork		P	T	NA	Other	SMACNA	NA	N		
Dampers		P	T	NA	Other	AMCA	NA	N		
Chilled water system		P	T	D	Other	B31.1	NA	N		
Electric heating coil		P	T	NA	Other	NEC,NEMA	NA	N		
Emergency Service Water Pumphouse Ventilation	9.4.8									
Motors		P	SW	NA	3	NEMA MG1	I	Y		
Fans		P	SW	NA	3	AMCA	I	Y		16
Ductwork		P	SW	NA	3	AISI	I	Y		
Dampers		P	SW	NA	3	AMCA	I	Y		
Administration Building HVAC										
Motors		P	O	NA	Other	NEMA MG1	NA	N		
Fans		P	O	NA	Other	AMCA	NA	N		
Prefilters		P	O	NA	Other	UL Class 1	NA	N		
Dampers		P	O	NA	Other	AMCA	NA	N		
Coils, cooling		P	O	NA	Other	ARI	NA	N		
Coils, heating		P	O	NA	Other	NEC,NEMA	NA	N		16
Ductwork		P	O	NA	Other	SHACNA	NA	N		

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *
Main Steam and Power Conversion System									
Main Steam System	10.3								
Main steam piping to turbine stop valves and branch line piping up to and including first valve		P	R,T	B	2	III-2	NA	N	20
Main steam piping from and including the turbine stop valve to turbine casing and branch line piping up to and including first valve		P	T	D	Other	B31.1.0	NA	N	9,18,33
Steam piping and valves		P	T	D	Other	B31.1.0	NA	N	
Main Steam Isolation Valve Leakage Control System									
Piping and valves up to first isolation valve of the inboard subsystem		P	R	A	1	III-1	I	Y	
Piping and valves, other		P	R	B	2	III-2	I	Y	
Blowers		GE	R	N/A	2	NEMA-MG1 IEEE-328/344	I	Y	
Main Condenser Evacuation System	10.4.2								
Piping and components		P	T,RW	D	Other	B31.1.0	NA	N	
Heat exchangers		P	T	D	Other	VIII-1	NA	N	
Air ejectors		P	T	D	Other	B31.1.0	NA	N	
Condensate and Feedwater System	10.4.7								
Reactor feedwater piping and valves, RPV to outermost isolation valve		P	C,R	A	1	III-1	I	Y	32
Reactor feedwater, piping and valves, other		P	R,T	D	Other	B31.1.0	NA	N	
Steam piping to feedwater		P	T	D	Other	B31.1.0	NA	N	

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* Refer to the General Notes at the end of this table.

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
pump turbine										
Crossover (low pressure) piping		P	T	D	Other	B31.1.0	NA	N		
Bypass (high pressure) piping, downstream of first isolation valve										
Condensate piping and valves		P	T	D	Other	B31.1.0	NA	N		
Heat exchangers		P	T	D	Other	VIII-1/ TEMA C	NA	N		
Pressure Vessels		P	T	D	Other	VIII-1	NA	N		16
Pumps, feedwater and condensate		P	T	D	Other	B31.1.0/ Hyd.I	NA	N	24	
<u>Condensate Cleanup System</u>	10.4.6									
Piping and valves		P	T	D	Other	B31.1.0	NA	N		
Pressure vessels		P	T	D	Other	VIII-1	NA	N		
<u>Condensate Storage and Transfer System</u>	9.2.10									
Tanks		P	O	D	Other	D100	NA	N		
Piping and valves		P	O,T	D	Other	B31.1.0	NA	N		
Pumps		P	T	D	Other	B31.1.0/ Hyd.I	NA	N	24	
<u>Turbine Gland Sealing System</u>	10.4.3									
Steam seal evaporator		P	T	D	Other	VIII-1	NA	N		16
Gland steam condenser		P	T	D	Other	VIII/TEMA C	NA	N		
Piping and valves		P	T	D	Other	B31.1.0	NA	N		
<u>Auxiliary Steam System</u>	10.4.11									
Auxiliary boilers		P	T	D	Other	VIII	NA	N		
Piping and valves		P	T	D	Other	B31.1.0	NA	N		
<u>Main Chlorination System</u>	9.2.8									
Pumps		P	CA	D	Other	B31.1.0/ Hyd.I	NA	N	24	

* Refer to the General Notes at the end of this table.

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Non-Nuclear Instrumentation										
All portions that input to the reactor protection system		GE	C,R	NA	2	IEEE-279	I	Y		
All portions that input to the engineered safety feature actuation system		P/GE	C,R	NA	2	IEEE-279	I	Y		
Engineered Safety Features Actuation System	7.3									
All portions		GE	C,R	NA	2	IEEE-279	I	Y		
Engineered Safety Features Systems (controls and instrumentation required for safety associated with each actuated system)	7.3									
Emergency core cooling system		GE	C,R	NA	2	IEEE-279	I	Y		
Containment isolation system		P	C,R	NA	2	IEEE-279	I	Y		
Containment purge systems		P	C,R	NA	2	IEEE-279	I	Y		
Emergency diesel generator systems		P	G	NA	2	IEEE-279	I	Y		
Main steam line break detection system		P	C,R,T	NA	2	IEEE-279	I	Y		
Controls and Instrumentation Associated with Safe Shutdown Systems	7.4									15
Control room habitability system		P	CS	NA	2	IEEE-279	I	Y		
PCAMS		P	C,R	B,D	2	IEEE-279	I	Y		15
Instrumentation Associated with Other Systems Required for Safety	7.6									
Spent fuel pool cooling system		P	R	NA	2	IEEE-279	I	Y		16
Fuel handling area ventilation isolation system		P	R	NA	2	IEEE-279	I	Y		

* Refer to the General Notes at the end of this table.

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Control room panels		P/GE	CS	NA	2	IEEE-279	I	Y		16
Local instrument racks associated with safety related equipment		P	ALL	NA	2	IEEE-279	I	Y		
Instrumentation Associated with Systems Not Required for Safety	7.7									
Seismic instrumentation		P	ALL	NA	Other	NA	I	Y		16
Area radiation monitoring		P	ALL	NA	Other	NA	NA	N		
Leak Detection System										
Temperature elements		GE	C,R,T	N/A	2	IEEE-323	I	Y	39	15
Differential temperature switch		GE	C,R	N/A	2	IEEE-323	I	Y	39	
Differential flow indicator		GE		N/A	2	IEEE-323	I	Y	39	
Pressure switch		GE	C,R	N/A	2	IEEE-323	I	Y	39	
Differential pressure indicator switch		GE		N/A	2	IEEE-323	I	Y	39	
Differential flow summer		GE		N/A	2	IEEE-323	I	Y	39	
Process Radiation Monitors										
Electrical modules, main steam line and reactor building ventilation monitor		GE	R	N/A	2	IEEE-323	I	Y		15
Cable, main steam line and reactor building ventilation monitors		P	R	N/A	2	IEEE-279/323/383	I	Y		
Electric Systems	8									
Engineered Safety Features AC Equipment	8.3									
4.16 kV switchgear		P	O	NA	2	IEEE-308/323/344	I	Y		
480 V load centers		P	O	NA	2	IEEE-308/323/344	I	Y		
480 V motor control centers		P	O	NA	2	IEEE/308/344	I	Y		

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Compressed Air and Instrument Gas Systems	9.3.1									
Compressors		P	T	NA	Other	NONE	NA	N		
Pressure vessels, for safety related equipment		P	C,R	C	3	III-3	I	Y		
Pressure vessels, not for safety related equipment		P	ALL	D	Other	VIII-1	NA	N		
Piping and valves forming part of containment boundary		P	C,R	B	2	III-2	I	Y		
Piping and valves, safety related		P	C,R	C	3	III-3	I	Y		
Piping and valves, other		P	ALL	D	Other	B31.1.0	NA	N		
Nitrogen storage bottles		P	R	NA	Other	DOT	I	N		16
Sampling Systems	9.3.2									
Sample coolers		P	All	D	4	VIII-1 TEMA C	NA	N		16
Piping and valves on III-1 systems		P	C	A	1	III-1	I	Y	10	
Piping and valves on III-2 systems		P	C,R	B	2	III-2	I	Y	10	
Piping and valves on III-3 systems		P	R,T,RW	C	3	III-3	I	Y	10	
Piping and valves, other systems		P	R,T,RW	D	Other	B31.1.0	NA	N	10	
Piping and valves, containment penetration, isolation		P	C	B	2	III-2	I	Y	10	
Fire Protection System	9.5.1									
Tanks		P	O	D	Other	API-650/ D100	NA	N		
Pumps, piping and water system components		P	ALL	NA	Other	NFPA/NEPIA	NA	N		
Gas system components (CO and Halon 1301)		P	CS	NA	Other	NFPA/NEPIA	NA	N		
Fire and smoke detection and alarm system		P	ALL	NA	Other	NFPA/NEPIA	NA	N		

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Generator External Hydrogen System										
Vessels		P	T	D	Other	VIII-1	NA	N		
Piping		P	T	D	Other	B31.1.0	NA	N		
Valves		P	T	D	Other	B31.1.0	NA	N		
Nitrogen System										
Vessels		P	O	D	Other	VIII-1	NA	N		
Piping		P	O	D	Other	B31.1.0	NA	N		
Valves		P	O	D	Other	B31.1.0	NA	N		
Plant Chilled Water System	9.2.12									
Chillers		P	ALL	D	Other	B9.1	NA	N		
Chilled water heat exchangers		P	ALL	D	Other	VIII-1/ TEMA C	NA	N		
Pumps		P	ALL	D	Other	VIII-1/ Hyd.I	NA	N	24	
Piping		P	ALL	D	Other	B31.1.0	NA	N		
Valves		P	ALL	D	Other	B31.1.0	NA	N		
Safety Related Chilled Water System										
Chillers		P	CS	D	3	ARI/B9.1	I	Y		
Heat exchangers		P	CS	D	3	VIII-1/ TEMA C	I	Y		
Pumps		P	CS	D	3	VIII-1/L Hyd.I	I	Y		
Motors		P	CS	NA	3	IEEE-323/ 344	I	Y		
Piping		P	CS	D	3	B31.1	I	Y		
Valves		P	CS	D	3	B31.1	I	Y		
Equipment and Floor Drains	9.3.3									
Piping, radioactive		P	All	D	Other	B31.1.0	NA	N		16
Piping, nonradioactive		P	ALL	D	Other	B31.1.0	NA	N		
Demineralized Water Makeup System	9.2.9									

* Refer to the General Notes at the end of this table.

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *
Tanks		P	CW	D	Other	VIII-1	NA	N	
Pumps		P	CW	D	Other	B31.1.0/ Hyd.I	NA	N	24
Motors		P	CW	NA	Other	NEMA MG1	NA	N	
Piping and valves		P	ALL	D	Other	B31.1.0	NA	N	
Buildings									
Reactor Building		P	R	B	2	ACI/AISC	I	Y	
Primary Containment		P	C	B	2	ACI/AISC/ III	I	Y	27,30
Access hatches/locks/doors		P	C	B	2	III-MC	I	Y	
Liner plate		P	C	B	2	III-MC	I	Y	
Penetration assemblies		P	C	B	2	III-MC	I	Y	29
Vacuum relief valves		P	C	B	2	III-2	I	Y	
Diesel generator building		P	G	NA	2	ACI/AISC	I	Y	
Control structure		P	CS	NA	2	ACI/AISC	I	Y	
Radwaste and offgas building		P	RW	NA	Other	ACI/AISC	NA	N	22
Turbine building		P	T	NA	Other	ACI/AISC	NA	N	21
Administration building		P	O	NA	Other	ACI/AISC	NA	N	
Circulating water pump house		P	O	NA	Other	ACI/AISC	NA	N	
ESSW pumphouse		P	O	NA	3	ACI/AISC	I	Y	|16
Structures									
Spray pond		P	O	NA	3	ACI	I	Y	
Condensate storage tank		P	O	D	Other	D100	NA	N	
Spent fuel pool		P	R	NA	2	ACI/AISC	I	Y	
Spent fuel pool liner		P	R	NA	Other	ACI/AISC	NA	N	
Refueling water storage tank		P	O	D	Other	D100	NA	N	

* Refer to the General Notes at the end of this table.

TABLE 3.2-1 (Continued)

NEC	National Electrical Code
NEMA	National Electrical Manufacturer's Association
NEMA MG1	National Electrical Manufacturers' Association, NEMA-MG-1, 1971 "Motors and Generators"
NEMA SM22	National Electrical Manufacturers' Association, NEMA-SM-22, 1970, "Single Stage Steam Turbine for Mechanical Drive Service"
IEEE-279	IEEE-279, Criteria for Protection Systems for Nuclear Power Generating Stations - 1971.
IEEE-308	IEEE-308, Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations - 1974
IEEE-317	IEEE-317, Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations - 1972
IEEE-323	IEEE-323, General Guide for Qualifying Class IE Electric Equipment for Nuclear Power Generating Stations - 1974
IEEE-344	IEEE-344, Guide for Seismic Qualification of Class IE Electric Equipment for Nuclear Power Generating Stations - 1971
IEEE-383	Type Test of Class IE Electrical Cables, Field Splices, and Connections for Nuclear Power Generating Stations
IEEE-387	IEEE-387, Criteria for Diesel Generator Units applied as Standby Power Supplies for Nuclear Power Generating Stations - 1972
HSI-306	Health and Safety Information, USAEC, Revised Minimal Specification for the High Efficiency Particulate Air Filter. Issue No. 306
NFPA	National Fire Protection Association
NEPIA	Nuclear Energy Property Insurance Association
ARI	Air Conditioning and Refrigeration Institute
DOT 7A	Department of Transportation - Shipping Container Specification 49CFR178.350.
AWS D1.1	American Welding Society, Structural Welding Code. 16

NA None Applicable 16

X Manufacturer's Standards 15

6) I - The equipment shall be constructed in accordance with the seismic requirements for the Safe Shutdown Earthquake, as described in Section 3.7.

NA - The seismic requirements for the Safe Shutdown Earthquake are not applicable to the equipment or structure.

7) Y - Requires compliance with the requirements of 10CFR50, Appendix B in accordance with the quality assurance program described in Chapter 17.

N - Not within the scope of 10CFR50, Appendix B.

8) The classification of the control rod drive water return line from the reactor vessel through the third isolation valve will be Group A. Beyond the third valve will be Group D, except as noted in Table 3.2-1.

9) The following qualification shall be met with respect to the certification requirements:

1. The manufacturer of the turbine stop valves, turbine control valves, turbine bypass valves, and main steam leads from turbine control valve to turbine casting shall use quality control procedures equivalent to those defined in General Electric Publication GEZ-4982A, "General Electric Large Steam Turbine-Generator Quality Control Program".

2. A certification shall be obtained from the manufacturer of these valves and steam leads that the quality control program so defined has been accomplished.

10) 1. Instrument and sampling piping from the point where they connect to the process boundary and through the process shutoff (root) valve(s), isolation valve(s), and excess flow check valve, when provided, will be of the same classification as the system to which they connect. The process system classification applies to all pressure boundary components.

2. All instrument lines which are connected to the reactor coolant pressure boundary and are utilized to actuate safety systems shall be Group B from the process shutoff (root) valve(s), isolation valve(s), or excess flow check valve, when provided, to the sensing instrumentation.

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 classificaiton. 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 FSAR Figure 5.4-13, (P&ID M-151), 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 FSAR Figure 5.4-13 (P&ID M-151).

TABLE 3.2-1 (Continued)

Principal Components (34*)	FSAR Section	Source of Supply (1)*	Location (2)*	Quality Group Classification (3)*	Safety Class (4)*	Principal Construction Codes and Standards (5)*	Seismic Category (6)*	Quality Assurance Requirement (7)*	Comments *	
Piping, beyond outermost containment isolation valves		P	R	B	2	III-2	I	Y	10	16
Containment spray line piping within isolation valve		P	C,R	B	2	III-2	I	Y		
Containment spray line piping beyond isolation valve		P	R	B	2	III-2	I	Y		
Pumps		GE	R	B	2	NP & V-II	I	Y		15
Pump motors		GE	R	NA	2	NEMA/NEC	I	Y		
Reactor vessel head spray line piping inside second isolation valve		P	C	A	1	III-1	I	Y		
Reactor vessel head spray line piping beyond second isolation valve		P	R	B	2	III-2	I	Y		
Valves, isolation LPCI line		P	C,R	A	1	III-1	I	Y		
Valves, isolation, other		P	C,R	B	2	III-2	I	Y	10	
Valves, beyond isolation valves		P	R	B	2	III-2	I	Y	10	
Mechanical modules		GE	R	NA	2	X	I	Y		15
Electrical modules, with safety function		GE	R	NA	2	IEEE-279/ 323	I	Y		
Cable, with safety function		P	C,R	NA	2	IEEE-279/ 323/383	NA	Y	15	
Core Spray	6.3									
Piping, within outermost isolation valves		P	C	A	1	III-1	I	Y	10	
Piping, beyond outermost isolation valves		P	R,C	B	2	III-2	I	Y	10	16
Pumps		GE	R	B	2	NP & V-II	I	Y		15
Pump motors		GE	R		2	NEMA/NEC	I	Y		
Valves, containment isolation and within containment		P	C	A	1	III-1	I	Y	10	
Valves, beyond outermost containment isolation valves		P	R	B	2	III-2	I	Y	10	
Electrical modules with safety function		GE	R	NA	2	IEEE-279/ 323	I	Y		15
Cable, with safety function		P	R	NA	2	IEEE-279/	NA	Y	15	

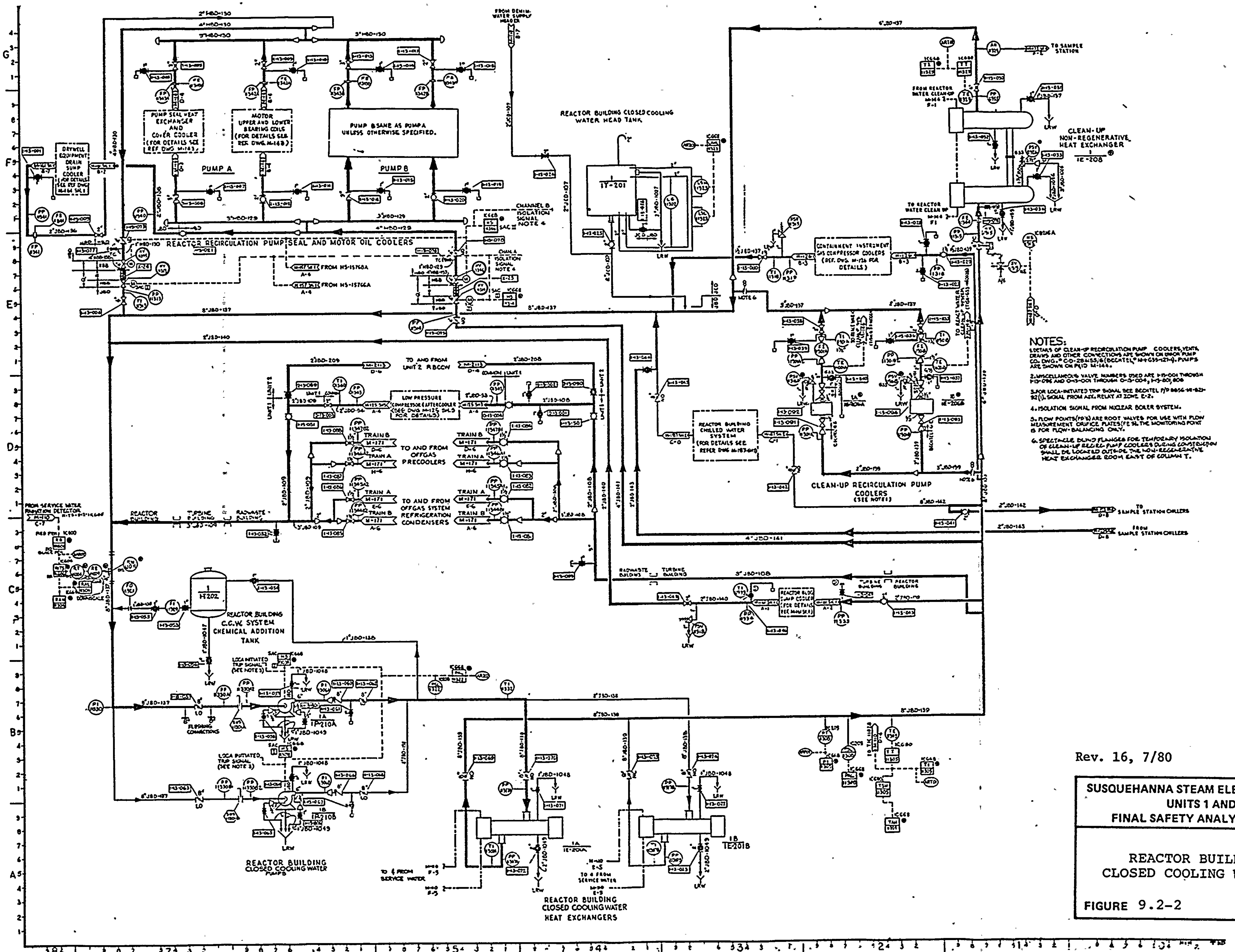
* Refer to the General Notes at the end of this table.

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 Figure 9.2-2. Penetration of primary containment is through the 4"-HBB-157 and 4"-HBB-158 lines which are shown on revised Figure 9.2-2.



Rev. 16, 7/80

M-113

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

REACTOR BUILDING
CLOSED COOLING WATER

FIGURE 9.2-2

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 RCDRL 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 a 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 will be 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 stablizer loop. Referring to the CRD system P&ID (Figures 4.6-5a and 4.6-5b) 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 drivewater filters. The fifth NRC conclusion requires the Utility to develop procedures for optimizing the CRD system flow to the reactor pressure vessel. The last conclusion is the sixth in the list and is not applicable to the CRD system design for Susquehanna.

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.

(3) The Motor as a Potential Missile:

Since bolting is capable of carrying greater torque loads than the pump shaft, pump bolt failure is precluded. Since pump shaft failure decouples the rotor for the overspeed driving blowdown force, only those cases with peak torques less than that required to fail the pump shaft (five times rated) will have the capability to drive the motor to overspeed. When missile generation probabilities are considered along with a discussion of the actual load bearing capabilities of the system, it is evident that these considerations support the conclusion that it is unrealistic that the motor would become a missile.

It is concluded that the other rotating components inside the containment such as fans and chillers do not have sufficient energy to move the masses of their rotating parts through the housings in which they are contained.

In addition, redundant safety related components are located in different areas of the containment, so that a rotating component failure missile will not damage both redundant components.

3.5.1.2.2 Pressurized Component Failure Missiles 1

A discussion of the potential for missile generation from the failure of pressurized components, e.g. valve stems, valve
bonnets, and temperature element assemblies, is presented in 1
Subsection 3.5.1.1.2. That discussion is also applicable to pressurized components inside containment.

3.5.1.2.3 Gravitationally Generated Missiles

Components necessary for the operation and safety of the reactor are designed to remain in place and functioning during all design basis conditions. Equipment which is not necessary for operation, startup testing, or safety is removed from the
containment or seismically supported and secured in place prior 10 16
to operation to ensure that it will not become a missile during plant operation or during a safe shutdown earthquake. Therefore, during reactor operation and following a LOCA all equipment inside containment is secured. During maintenance when such equipment is returned to the containment or made operational administrative and procedural methods will be used to ensure that significant damage is not caused to safety equipment even when the reactor is in the shutdown condition.

QUESTION 211.194:

Discuss the possibility of the CRD mechanism becoming a missile inside containment.

RESPONSE:

The response to this question is given in section 4.6.1.2.3, 4.6.2.3.2.2.1, 4.6.2.3.2.2.3, 4.6.2.3.2.2.4 and 4.6.2.3.3.

of these components is incredible because of the conservative design, material characteristics, inspections, quality control during fabrication and erection, and prudent operation as applied to the particular component.

It has been concluded that large, massive rotating components, such as the various ECCS pumps and motors, fans, and compressors outside the primary containment, do not have sufficient energy to move the masses of their rotating parts through the housings in which they are contained.

Similarly, it is concluded that the HPCI and RCIC turbines cannot generate missiles. Overspeed tripping devices ensure that the HPCI and RCIC turbines will not reach runaway speed where component failure could take place.

However, even with this conservative design, the RCIC and HPCI turbines are located in separate compartments so that any turbine missile will affect only one division of equipment.

This is also true for other large rotating safety related equipment, such as pumps, fans, and compressors. Redundant equipment is normally located in different areas of the plant or separated by walls, so that a single missile from a rotating mass will not damage both redundant systems.

3.5.1.1.2 Pressurized Component Failure Missiles

The following potential internal missile donors from pressurized equipment were investigated:

10 a) High Energy Piping

Pressurized components in systems where service temperature exceeds 200°F or service pressure exceeds 275 psig were evaluated as to their potential for becoming missiles. Pipe whip restraints were provided at possible breakpoints of these high energy lines, which may impact on safety related equipment or structures (see Section 3.6).

Additional attention has been given to ensure that safety relief valves and valve headers are not credible missiles. All SRV headers are restrained in accordance with the pipe whip criteria described in Section 3.6 to ensure that in the event of a circumferential type break of the header, no
10 missile would result.

The safety relief valves are attached to welded, Schedule 160 sweepolet fittings on the headers. The design of this attachment includes all dynamic loads that may be associated with the SRV discharge. This attachment is not a postulated

break location in accordance with the criteria stated in
Section 3.6.2. Verification of this will be available upon 10
completion of the stress report. The SRV header is designed
and built to the conservative requirements of the ASME
Section III, Class 1, Code and as such is subject to the ASME 16
Section XI Inservice Inspection requirements. This
inspection plus the RCPB leak detection capability would
provide early indication of any possible failure in this 16
area.

Therefore, it is concluded that the likelihood of missiles
from high energy piping, which may impact on safety related
equipment, is remote.

b) Valve Bonnets 10

Valves of ANSI 900 psig rating and above, constructed in
accordance with Section III of the ASME Boiler and Pressure
Vessel Code, are pressure seal bonnet type valves. For
pressure seal bonnet valves, valve bonnets are prevented from
becoming missiles by the retaining ring, which would have to 10
fail in shear, and by the yoke, which would capture the
bonnet or reduce bonnet energy.

The bonnet bolts preload the pressure seal gasket so the
valve will be sealed when it is not under pressure. When 10
pressurized, the valve is sealed by process fluid pressure
and the bonnet bolts are under no load. All ASME III Class
I, 900 # bonnet-seal type valves were analyzed per ASME B &
PV Code, Section III. Standard calculation pressure used in
these analyses was given by Figure NB-3545.1-2 for weld-end 16
valves. Using the typical pressure seal valve shown in
Figures 3.5-9 and 3.5-10 as an example, the total thrust load
on the retaining ring and valve body was calculated. The
results are listed in Table 3.5-7. The results show both the
retaining ring and valve body meet the NB-3227 requirement
while using a calculation pressure which is much higher than
the normal operating pressure of the valve.

The majority of valves inside containment have massive valve
operators which are supported by the yoke. For these valves, 10
the valve operators act as an additional limitation to the
yoke becoming a missile.

For a yoke clamp to fail, one would have to assume that the
retaining ring fails completely and instantaneously so that 16
the bonnet could strike the yoke. The yoke is normally under
no load and complete failure of the yoke clamp is not
considered credible.

Because of the highly conservative design of the retaining
ring of these valves, bonnet ejection is highly improbable
and hence bonnets are not considered credible missiles.

TABLE 3.5-7

CALCULATED STRESS FOR BONNET-SEAL TYPE VALVES

Bearing Stress

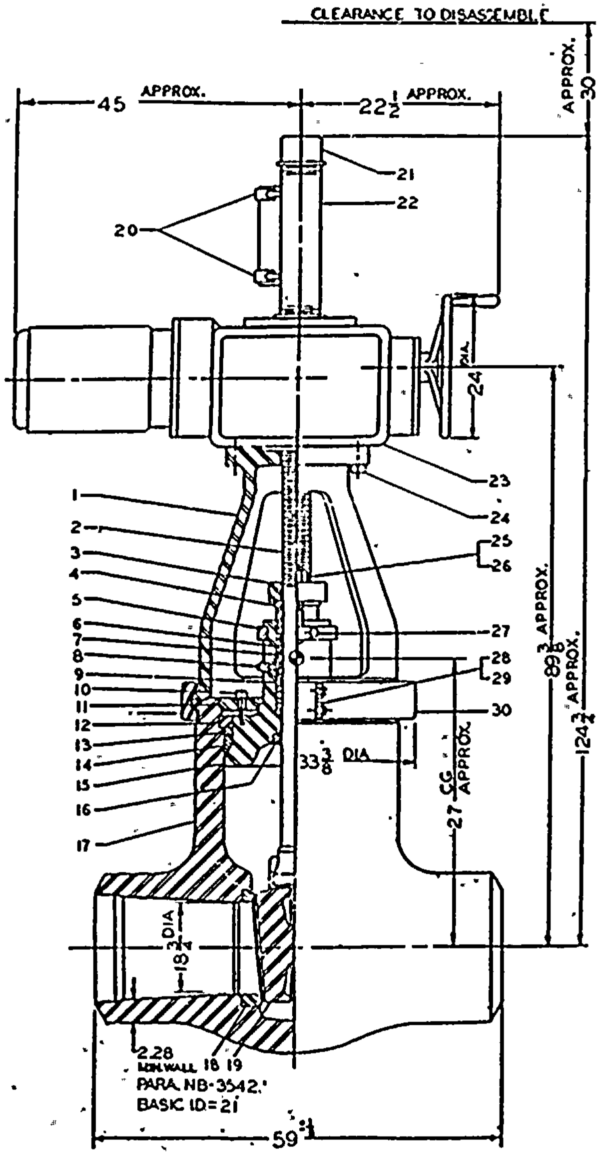
Zone[3]	Calculated Stress	Stress Limit
b-c	17.05 ksi	28.3 ksi
d-e	19.54 ksi	30.7 ksi

Shearing Stress

Zone	Calculated Stress	Stress Limit
a-b	7.60 ksi	11.34 ksi
c-f	10.83 ksi	12.3 ksi

Note:

1. Above results are based on calculation pressure - 2425 psi.
2. Valve design pressure = 1500 psi
3. Refer to Figure 3.5-10.



1. Valve design and manufacture in accordance with ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class I with addenda up to and including the Winter 1972 Addenda, Bechtel Design Specification 8856-P-17 and Code Cases 1334-2, 1516-1, 1534 and 1535-2.

2. Hydrostatic Tests
   a. Shell in accordance with ASME Code Paragraph NB-6000 to 3850 psig. Test duration - 36 minutes minimum.
   b. Seat leakage in accordance with MSS-SP-61 to 2200 psig. Test duration - 4 minutes minimum. Allowable leakage rate 2 cc/hr./inch of nominal valve size.

3. Nondestructive testing and repair of pressure boundary parts shall be in accordance with the applicable paragraphs under Section NC-2000 of Section III and reference thereto except as modified by Bechtel Design Specification 8856-P-17

4. Material certification per ASME Code: Para. NB-2130.

5.

Cert. of Tests	Body	Bonnet	Disc	Seat Ring
Radiography	YES		YES	
Ultrasonic		YES		
Mag. Particle				
Liquid Penetrant	YES	YES	YES	
Charpy-V-Notch				
L.P. Hardfacing		YES	YES	YES
Wall Thickness	YES	YES	YES	

6.

Bechtel Item No.	Valve Mark No.	A.DV Co. Serial No.	OPER. POS. NO	STEM POSITION
1.1	24-DCA-GT-MO-F015A	E5855-1-1	2	HORIZ.
1.1	24-LCA-GT-MO-F015B	E5855-1-2	4	HORIZ.
1.2	24-DCA-GT-MO-F015A	E5855-15-1	2	HORIZ.
1.2	24-DCA-GT-MO-F015B	E5855-15-2	4	HORIZ.

7. Valve assembly weight 12,950 lbs. with operator.
8. Motor operator weight 1,950 lbs.
9. Cv =31,000 gpm
10. Limitorque Motor Operator Dwg. 02-408-0372-3
11. Limitorque Wiring Diagram Dwg. 15-477-5124-3

PARTS LIST

Part No.	Qty.	Description	Material
1	1	Yoke	A216-WCB
2	1	Stem	A564-630-1075
3	1	Follower Flange	A36
4	1	Follower Gland	A276-316
5	1	Gland Clamp	A36
6	1 Set	Upper Packing	John Crane 187I
7	1	Lantern Gland	A276-316
8	1	Pipe Plug	316 STAINLESS STEEL
9	1 Set	Lower Packing	John Crane 187I
10	12	Bonnet Cap Screws	Commercial Steel
11	1	Bonnet Clamp Ring	A182-F316
12	1	Gasket Retaining Ring	SA182-F316
13	1	Spacer Ring	A240-316
14	1	Pressure Seal Gasket	304L STAINLESS
15	1	Bonnet	SA182-F316
16	1	Stop Ring w/Stellite	SA240-316
17	1	Weld Ends Body	SA351-CF8M
18	2	Seat Rings w/Stellite	SA182-F316
19	1	Disc w/Stellite	SA351-CF3M
20	2	POSITION SWITCHES	NAMCO D2400X
21	1	Pipe Cap	Commercial Iron
22	1	Stem Protector	Commercial Steel
23	1	Limitorque	Commercial
24	8	Limitorque Cap Screws	A574-67
25	2	Follower BOLTS	A193-B7
26	2	Follower Nuts	A194-2H
27	2	Gland Cap Screws	A574-67
28	4	Yoke Clamp Studs	A193-B7
29	8	Yoke Clamp Nuts	A194-2H
30	1	Yoke Clamp	A36

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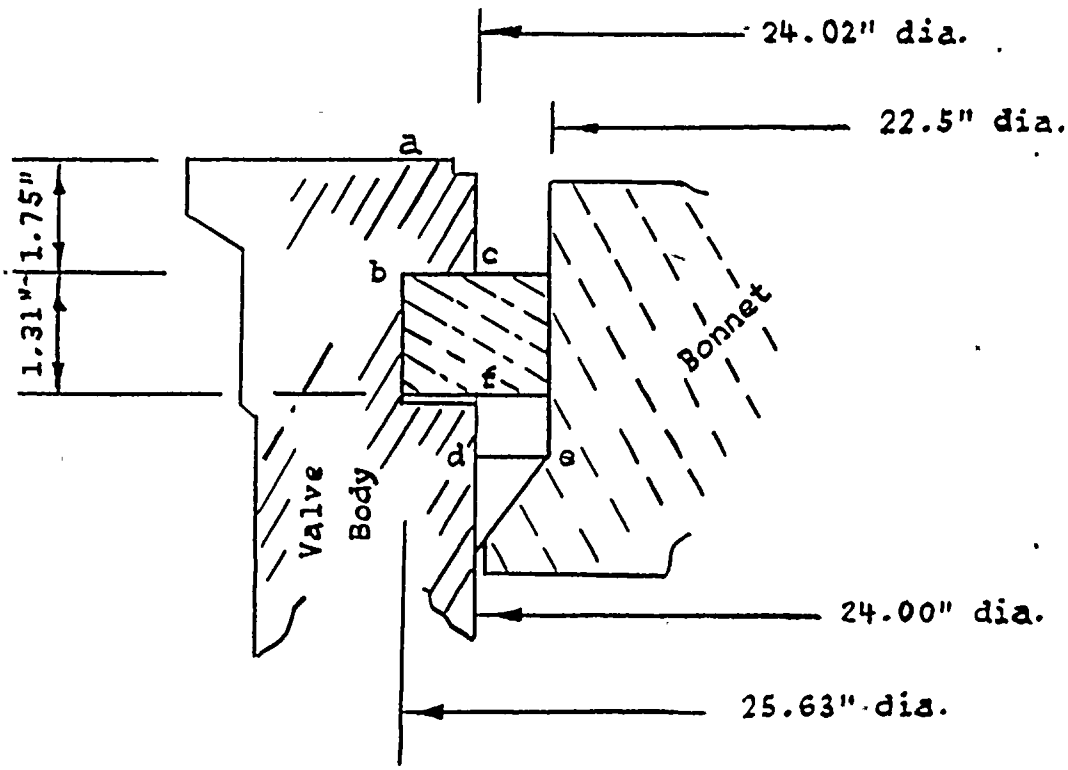
TYPICAL 900# BONNET SEAL TYPE VALVE

FIGURE 3.5-9



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RETAINING RING DESIGN
FOR 900# BONNET - SEAL
TYPE VALVE

FIGURE 3.5-10

3.5 MISSILE PROTECTION

Where possible, the Seismic Category I and safety related structures, equipment, and systems are protected from missiles generated by internal rotating or pressurized equipment through basic station component arrangement so that, if equipment failure occurs, the missile does not cause the failure of these structures, equipment, or systems. Where it is impossible to
provide protection through plant layout, suitable physical 16
barriers will be provided to isolate the credible missiles or to shield the critical system or component. Also, redundant Seismic Category I components are suitably protected so that a single missile cannot simultaneously damage a critical system component and its backup system. Table 3.2-1 provides a tabulation of safety related structures, systems, and components, along with their applicable seismic category and quality group classification.

Section 3.12 - Separation Criteria for Safety Related Mechanical and Electrical Equipment provides a detailed discussion of
protection from missles, such as equipment separation and 10
redundancy, to preclude damage to the systems necessary to achieve and maintain a safe plant shutdown.

3.5.1 MISSILE SELECTION AND DESCRIPTION

3.5.1.1 Internally Generated Missiles (Outside Primary Containment)

There are two general sources of postulated missiles outside the primary containment:

a) Rotating component failure missiles

b) Pressurized component failure missiles

3.5.1.1.1 Rotating Component Failure Missiles

The systems located outside the primary containment have been examined to identify and classify potential missiles. The basic approach is to ensure design adequacy against generation of missiles, rather than to allow missile formation and then containing their effects.

Catastrophic failure of rotating equipment, such as pumps, turbines, fans, and compressors leading to the generation of missiles, is not considered credible. Massive and rapid failure

Subsection 3.5.1.1.2

Most valves of ANSI rating 600 psig and below are valves with bolted bonnets. Valve bonnets are prevented from becoming missiles by limiting stresses in the bonnet-to-body bolting material by requirements set forth in the ASME Boiler and Pressure Vessel Code, Section III, and by designing flanges in accordance with applicable code requirements. Even if bolt failure were to occur, the likelihood of all bolts experiencing simultaneous complete severance failure is remote. The widespread use of valves with bolted bonnets and the low historical incidence of complete severance failure of bonnets confirm that bolted valve bonnets need not be considered as credible missiles.

10 c) Valve Stems

Valve stems are not considered potential missiles if at least one feature in addition to the stem threads is included in their design to prevent ejection. Valves with backseats are prevented from becoming missiles by this feature. In addition, air or motor operated valve stems will be effectively restrained by the valve operators.

10 d) Temperature detectors

Temperature or other detectors installed on piping or in wells are evaluated as potential missiles if a single circumferential weld would cause their ejection. This is highly improbable, since a complete and sudden failure of a circumferential weld is needed for a detector to become a missile. In addition, because of the spatial separation of redundant safety related equipment, a small missile such as a detector, assuming the circumferential weld fails completely, is not likely to hit redundant safety related equipment.

10 e) Nuts and Bolts

Nuts, bolts, nut and bolt combinations, and nut and stud combinations have little stored energy and thus are of no concern as potential missiles.

f) Blind Flanges

Bolted blind flanges are not considered credible missiles because of the extremely unlikely occurrence of all bolts experiencing simultaneous complete severence failure as discussed in (b) above.

10

g) Safety Relief Valve and Main Steam Isolation Valve Accumulators.

Pressurized ASME III vessels such as SRV and MSIV accumulators are not considered credible missiles. These accumulators are operated at a maximum pressure and

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 a MSIV 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 steam line 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 limit. 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 steam line pressure rise which exceed the scale presented, Figure 5.2-5 of the FSAR shows the vessel pressure time response. The steam line 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 sec.), 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 211.202:

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 FSAR Figure 9.3-5).

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.

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

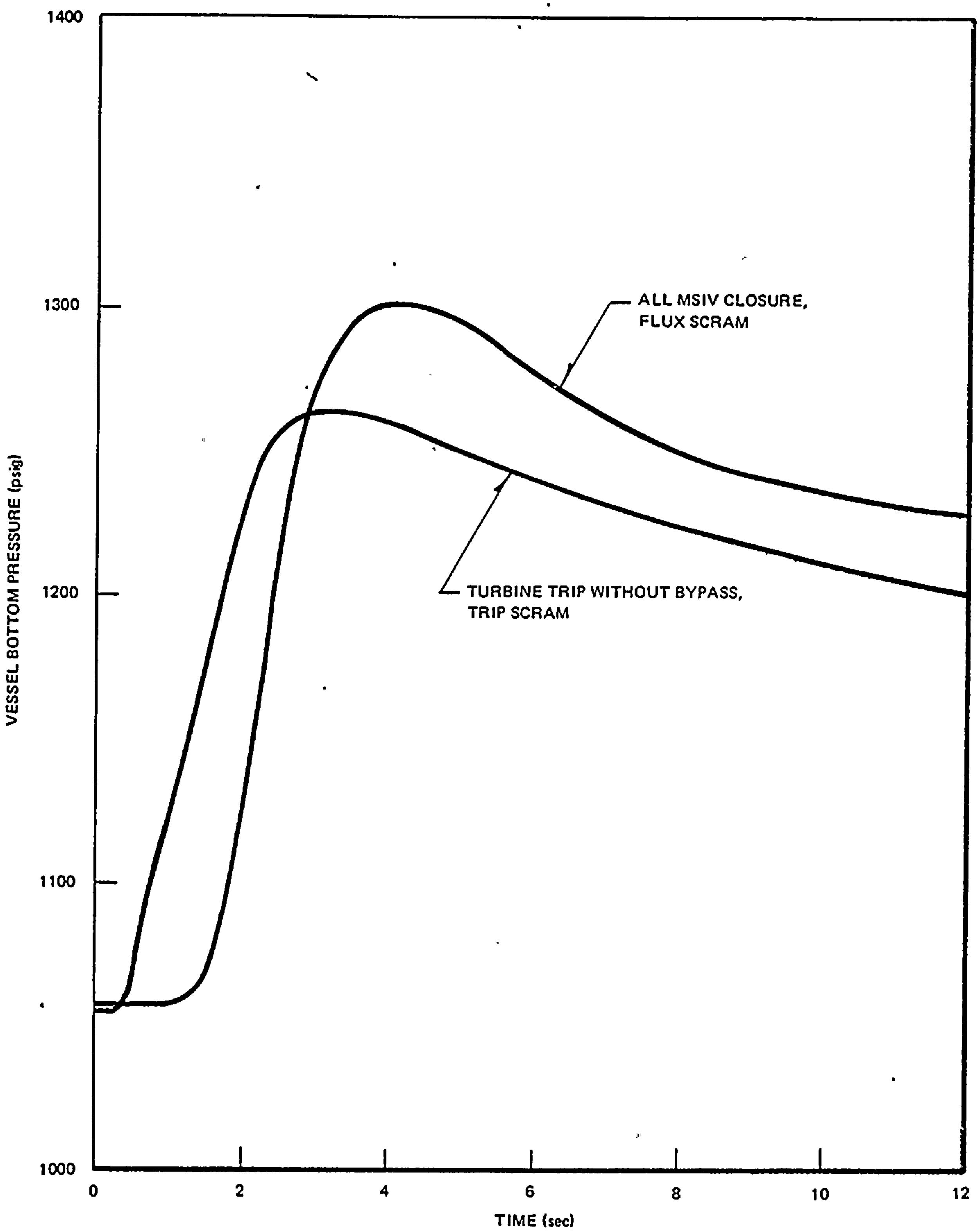
The applicable overpressure report will be submitted under a separate cover.

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.



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PEAK VESSEL PRESSURE VERSUS TIME FOR SAFETY VALVE CAPACITY SIZING TRANSIENT (105% STEAM FLOW)

FIGURE 5.2-5

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.

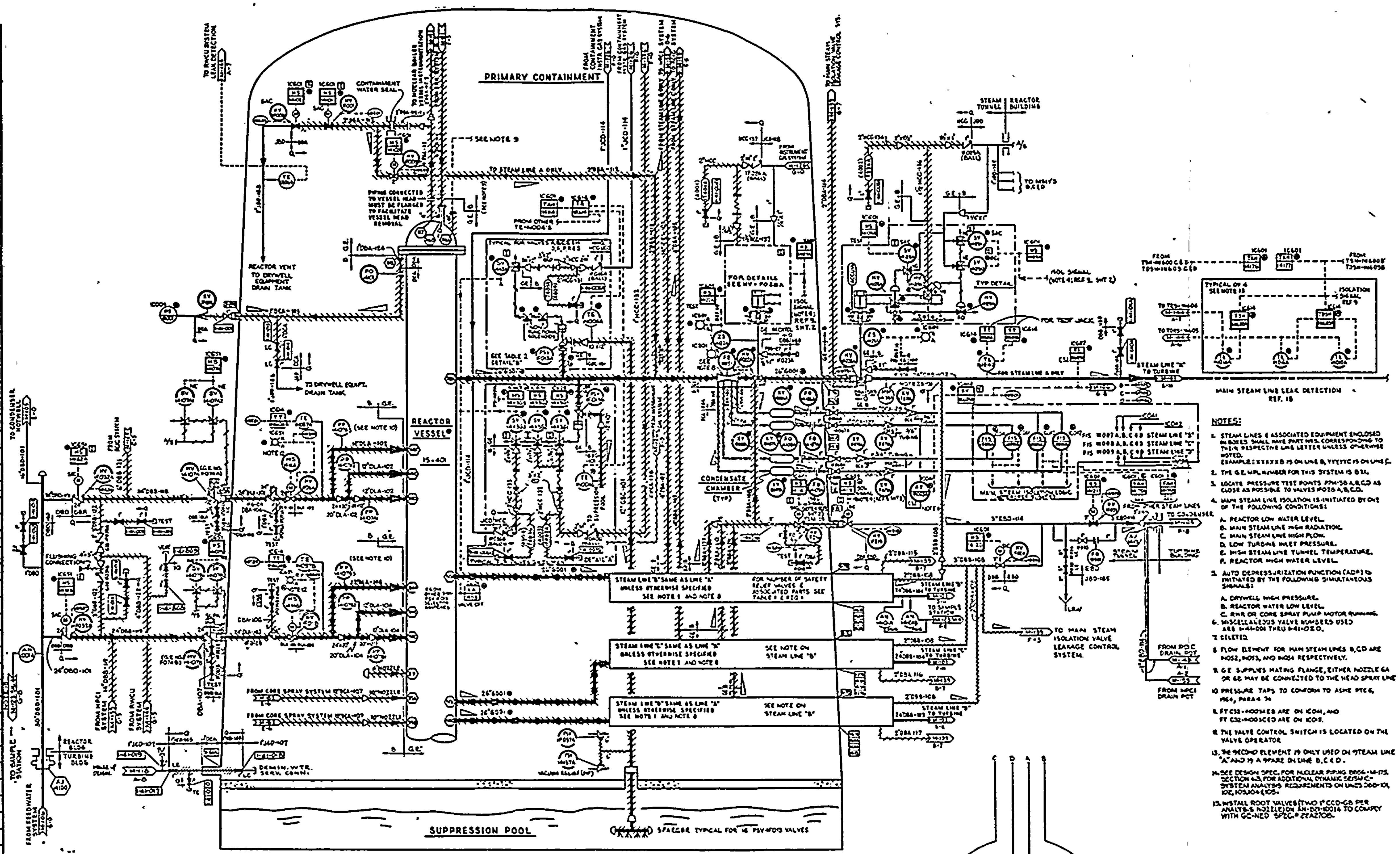
QUESTION 211.207:

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. Figure 5.1.3a has been corrected.

The increments between the setpoint groups are based on vessel overpressure protection design analysis which has historically used a 10 psi diffrence between setpoints for safety/relief valves.



NOTES:

1. STEAM LINES & ASSOCIATED EQUIPMENT ENCLOSED IN BOXES SHALL HAVE PART NOS. CORRESPONDING TO THEIR RESPECTIVE LINE LETTER UNLESS OTHERWISE NOTED.
   EXAMPLE: XXXXXB IS ON LINE B, YYYYYC IS ON LINE C.
2. THE G.E. MPL NUMBER FOR THIS SYSTEM IS B21.
3. LOCATE PRESSURE TEST POINTS PPM-38 A,B,C,D AS CLOSE AS POSSIBLE TO VALVES F028 A,B,C,D.
4. MAIN STEAM LINE ISOLATION IS INITIATED BY ONE OF THE FOLLOWING CONDITIONS:
   A. REACTOR LOW WATER LEVEL.
   B. MAIN STEAM LINE HIGH RADIATION.
   C. MAIN STEAM LINE HIGH FLOW.
   D. LOW TURBINE INLET PRESSURE.
   E. HIGH STEAM LINE TUNNEL TEMPERATURE.
   F. REACTOR HIGH WATER LEVEL.
5. AUTO DEPRESSURIZATION FUNCTION (ADS) IS INITIATED BY THE FOLLOWING SIMULTANEOUS SIGNALS:
   A. DRYWELL HIGH PRESSURE.
   B. REACTOR WATER LOW LEVEL.
   C. RHR OR CORE SPRAY PUMP MOTOR RUNNING.
6. MISCELLANEOUS VALVE NUMBERS USED ARE 1-41-001 THRU 1-41-020.
7. DELETED
8. FLOW ELEMENT FOR MAIN STEAM LINES B,C,D ARE N052, N053, AND N054 RESPECTIVELY.
9. G.E. SUPPLIES MATING FLANGE, EITHER NOZZLE 6A OR 6B MAY BE CONNECTED TO THE HEAD SPRAY LINE
10. PRESSURE TAPS TO CONFORM TO ASME PTC 6, 1964, PARA 4 74
11. FT C32-N003 A&B ARE ON 1C041, AND FT C32-N003 C&D ARE ON 1C043.
12. THE VALVE CONTROL SWITCH IS LOCATED ON THE VALVE OPERATOR
13. THE SECOND ELEMENT IS ONLY USED ON STEAM LINE "A" AND IS A SPARE ON LINE B, C & D.
14. SEE DESIGN SPEC. FOR NUCLEAR PIPING 8856-M-175, SECTION 6.3, FOR ADDITIONAL DYNAMIC SEISMIC SYSTEM ANALYSIS REQUIREMENTS ON LINES DBB-101, 102, 103, 104 & 105.
15. INSTALL ROOT VALVES (TWO 1" CCD-GB PER ANALYSIS NOZZLE) ON AN-B21-10014 TO COMPLY WITH GE-NED SPEC.# 22A2708.

TABLE 2 CONTROL SWITCH ARRANGEMENT FOR DETAIL "B"

TYPICAL FOR 1F013 A,B & C

PSV-1F013	1C601 CONTROL SWITCH	1C601 TRANSFER SWITCH	1C631 CONTROL SWITCH	SOLENOID VALVE
A	HS-141F013A2	[illegible]	[illegible]	[illegible]
B	HS-141F013B2	[illegible]	[illegible]	SV-141F013B
C	HS-141F013C2	[illegible]	[illegible]	SV-141F013C

TYPICAL FOR 1F013 D,E,F,H,P,R & S

PSV-1F013	1C601 CONTROL SWITCH			SOLENOID VALVE
D	HS-141F013D			SV-141F013D
E	HS-141F013E			SV-141F013E
F	HS-141F013F			SV-141F013F
H	HS-141F013H			SV-141F013H
P	HS-141F013P			SV-141F013P
R	HS-141F013R			SV-141F013R
S	HS-141F013S			SV-141F013S

TABLE 1. SAFETY / RELIEF VALVE LOCATION, SUFFIX ASSIGNMENT & ASSOCIATED EQUIPMENT

		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
SAFETY / RELIEF VALVES F013																	
RELIEF VALVE SPRING SET PRESSURE (PSIG)		1175	1146	1175	95	1146	1185	1205	1175	1195	1205	1195	1205	1195	1185	1195	1185
ACCUMULATORS	(ADS) 1T402(X) 150 PSIG							A		B	C	D	E	F			
	1T403(X) 90 PSIG	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
TEMPERATURE ELEMENT N004		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
CHECK VALVES	F036(X)	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
	F040(X)(ADS)							G		J	K	L	M	N			
VACUUM BREAKER F037(X) & M137(X)		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
PRESSURE SWITCH N022 (REF. 8 F-2)		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
PRESSURE SET POINT OF N022 (PSIG)		1086	1076	1086	1096	1076	1096	1116	1086	1106	1116	1106	1116	1106	1096	1096	1096
SOLENOID VALVES 4113 ASSIGN.	ADS (A)							A		A	A	A	A	A			
	ADS (B)							A		A	A	A	A	A			
	N1343 PRESS RELIEF (Y)	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

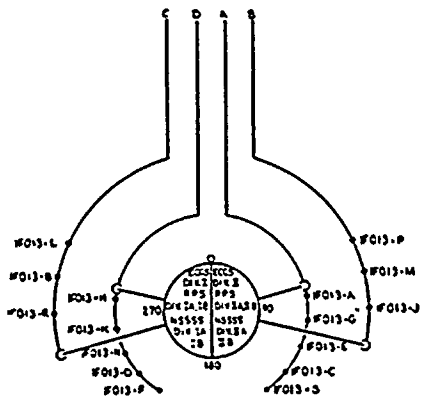


FIG. 1
SAFETY/RELIEF VALVE LOCATION AND SEPARATION ASSIGNMENT OF VESSEL INSTRUMENTATION

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UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

P & ID
NUCLEAR BOILER

FIGURE 5.1-3a

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 actualization of 16 relief valves as was documented by FSAR revision is in Table 15.0-1.

TABLE 15.0-1

RESULTS SUMMARY OF TRANSIENT EVENTS

Subsection I.D.	Figure I.D.	Description	Maximum Neutron Flux, NBR	Maximum Dome Pressure psig	Maximum Vessel Pressure psig	Maximum Steam Line Pressure psig	Maximum Core Average Surface Heat Flux % of Initial	Minimum CPR -	Frequency Category*	Duration of Blowdown: No. of Valves 1st Blowdown	Duration of Blowdown: Duration of Blowdown sec
15.1		DECREASE IN CORE COOLANT TEMPERATURE									
15.1.1	15.1-2	Loss of Feedwater Heater, Manual Flow Control	119.1	1023	1061	1004	112.8	1.13	a	0	0
15.1.2	15.1-3	Feedwater Cntl Failure, Max Demand	204.8	1150	1175	1138	109.4	1.06	a	16	9
15.1.3	15.1-4	Pressure Regulator Fail - Open	103.5	1092	1123	1092	100.2	>1.06	a	2	2
15.1.4		Inadvertent Opening of Safety or Relief Valve	See Text						a	--	--
15.1.6		RHR Shutdown Cooling Malfunction Decreasing Temp	See Text						a	--	--
15.2		INCREASE IN REACTOR PRESSURE									
15.2.1		Pressure Regulator Fail - Closed	See Subsections 15.2.2 and 15.2.3 with By Pass on						a	--	--
15.2.2	15.2-1	Generator Load Rejection, Bypass-On,	191.6	1144	1169	1134	102.9	1.14	a	16	9
15.2.2	15.2-2	Generator Load Rejection, Bypass-Off,	342.8	1174	1199	1160	110.3	1.01	b	16	20
15.2.3	15.2-3	Turbine Trip, Bypass-On	167.2	1143	1167	1132	101.4	1.16	a	16	8
15.2.3	15.2-4	Turbine Trip, Bypass-Off	294.4	1171	1196	1159	107.8	1.03	b	16	20
15.2.4	15.2-5	Inadvertent MSIV Closure	163.6	1151	1187	1146	100.2	>1.06	a	16	16

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 Figures 6.3-4 and 5.4-13. 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 passive 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 Figures 6.3-4 and 5.4-13.

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) At the time the plant was designed, the use of the Condensate Water Storage System to fill and keep full the ECCS discharge lines was common industry practice. The system adopted for Susquehanna SES is simple and thus 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.

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	4/4/72	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	11/9/77	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

Case 2

Mode A and C-2

Maximum suppression pool temperature for these modes is 200 °F.

Flow is 10,000 gpm.

H = 33.9 feet 4

H = 22.0 feet

H = (11.53)(2.395) = 27.6 feet

P = 0.8 psi = 1.9 feet

Strainer head loss = $9.4 \text{ Ft.} \times \frac{(10,000)^2}{(13,200)^2} = 5.4$ 15

NPSHA = 33.9 + 20.5 - 27.6 - 1.9 - 5.4

= 19.5 feet available.

6.3.2.2.5 ECCS Discharge Line Fill System

A requirement of the core cooling systems is that cooling water flow to the reactor vessel be initiated rapidly when the system is called on to perform its function. This quick-start system characteristic is provided by quick-opening valves, quick-start pumps, and standby ac power source. The time lag between the signal to start the pump and the initiation of flow into the RPV is minimized by the ECCS discharge line fill system which continuously keeps the core cooling pump discharge lines filled and simultaneously prevents water hammer during the rapid start transient of the ECCS pumps. 15

The ECCS discharge line fill system consists of fill liners which provide a continuous supply of condensate from the condensate transfer system to the high points of the ECCS discharge piping. Following initial venting and system fill, a pressure above atmospheric pressure is maintained at the system's high points to prevent air accumulation. A minor, but continuous inflow into the discharge lines is required primarily to make up for leakage across the check or stop check valves provided near the ECCS pumps. Past experience has shown that these valves will leak slightly, producing a small backflow. The estimated make-up for the ECCS pump discharge lines is less than 1 gpm. To ensure that the discharge lines are always filled, indication is provided in the Control Room as to whether the condensate transfer pumps are operating. Alarm PAL 0837 will indicate low condensate transfer 12 Δ

pump discharge pressure which can be verified on pressure indicator PI 00836 in the control room.

Two pressure switches PSL 00837A and PSL 00837B are provided to initiate this low pressure alarm. (Refer to FSAR Figure 9.2-9.) The pressure switches are primarily set to protect the condensate transfer pumps from operating at runout conditions. With one pump operation and approaching runout, tripping of the pressure switches will cause the second pump to start and thereby raise the pressure in the pump discharge header. The set point pressure for pump runout protection well exceeds the pump discharge pressure required for maintaining the ECCS injection lines pressurized. The fill lines for each ECC System, therefore, are provided with pressure regulators to control the fill pressure to 20 psig at the system's high points. With the ECCS injection lines properly filled, vented, and pressurized, maintaining an adequate pump discharge header pressure will assure that the injection lines will remain filled with water.

16 A 2" fill line is provided for the discharge line of the HPCI train, each of the two RHR trains and each of the two core spray trains. The individual fill lines can be isolated to permit maintenance on ECCS and on individual grains of a system without affecting the other train. Details are shown in the HPCI P&ID, Figure 6.3-1a, RHR P&ID. Figure 5.4-13 and C.S. P&ID, Figure 6.3-4. The condensate transfer pumps with associated instrumentation, including the low pressure alarm PAL 00837, are shown on the condensate and refueling water P&ID, Figure 9.2-9.

No Level transmitters are provided to detect air bubbles upstream of injection valves.

Air pockets will be prevented by proper venting and filling and by maintaining the discharge lines continuously pressurized such
12 that the pressure at the high points always exceeds atmospheric pressure. This will require a minor but continuous feed flow into the discharge lines to make up for valve leakage.

The presence of small, local air bubbles upstream of the injection valves will not be detrimental to the ECCS during the start transient.

Each RHR train has its own fill line and can be isolated from the other train. If one pump in an RHR train needs to be isolated for maintenance, the discharge line for the other pump will remain filled and pressurized to the isolation valve of that pump, allowing the pump to perform its function.

The pressure sensor at the discharge of the condensate transfer pumps and the associated pressure indicator and low-pressure alarm, PAL 00837, will be tested in accordance with standard

procedures for surveillance testing of instrumentation. The functional test will requie tripping the condensate transfer pump to initiate automatic transfer of operation to the 100% capacity standby pump on indication of low discharge pressure.

Surveillance tests to determine if the discharge lines for the RHR and CS systems are full are performed by momentarily opening the vents at the system's high points to confirm the water fill and pump flow. No special fill and vent procedures are required prior to surveillance testing of RHR and CS pumps. 12

Surveillance tests to determine if the pump discharge lines are full will be performed before testing any of the ECCS pumps. Detection of large amounts of air in the discharge piping will have to be reported on the test sheets. Such a test with significant amounts of air present in the discharge line would not be considered acceptable.

6.3.2.3 Applicable Codes and Classification

The applicable codes and classification of the ECCS are specified in Section 3.2. All piping systems and components (pumps,

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 Figure 6.3-1a shows a "filling line" for the HPCI discharge piping. Resolve this apparent discrepancy.

RESPONSE:

For response see revised subsection 6.3.2.2.5.

Case 2

Mode A and C-2

Maximum suppression pool temperature for these modes is 200 °F.

Flow is 10,000 gpm.

H = 33.9 feet 4

H = 22.0 feet

H = (11.53)(2.395) = 27.6 feet

P = 0.8 psi = 1.9 feet

Strainer head loss = 9.4 Ft. X $\frac{(10,000)^2}{(13,200)^2}$ = 5.4 15

NPSHA = 33.9 + 20.5 - 27.6 - 1.9 - 5.4

= 19.5 feet available.

6.3.2.2.5 ECCS Discharge Line Fill System

A requirement of the core cooling systems is that cooling water
flow to the reactor vessel be initiated rapidly when the system
is called on to perform its function. This quick-start system
characteristic is provided by quick-opening valves, quick-start
pumps, and standby ac power source. The time lag between the
signal to start the pump and the initiation of flow into the RPV 15
is minimized by the ECCS discharge line fill system which
continuously keeps the core cooling pump discharge lines filled
and simultaneously prevents water hammer during the rapid start
transient of the ECCS pumps.

The ECCS discharge line fill system consists of fill liners which
provide a continuous supply of condensate from the condensate
transfer system to the high points of the ECCS discharge piping.
Following initial venting and system fill, a pressure above
atmospheric pressure is maintained at the system's high points to
prevent air accumulation. A minor, but continuous inflow into
the discharge lines is required primarily to make up for leakage
across the check or stop check valves provided near the ECCS
pumps. Past experience has shown that these valves will leak
slightly, producing a small backflow. The estimated make-up for 12
the ECCS pump discharge lines is less than 1 gpm. To ensure that
the discharge lines are always filled, indication is provided in
the Control Room as to whether the condensate transfer pumps are
operating. Alarm PAL 0837 will indicate low condensate transfer

pump discharge pressure which can be verified on pressure indicator PI 00836 in the control room.

Two pressure switches PSL 00837A and PSL 00837B are provided to initiate this low pressure alarm. (Refer to FSAR Figure 9.2-9.) The pressure switches are primarily set to protect the condensate transfer pumps from operating at runout conditions. With one pump operation and approaching runout, tripping of the pressure switches will cause the second pump to start and thereby raise the pressure in the pump discharge header. The set point pressure for pump runout protection well exceeds the pump discharge pressure required for maintaining the ECCS injection lines pressurized. The fill lines for each ECC System, therefore, are provided with pressure regulators to control the fill pressure to 20 psig at the system's high points. With the ECCS injection lines properly filled, vented, and pressurized, maintaining an adequate pump discharge header pressure will assure that the injection lines will remain filled with water.

16 △ A 2" fill line is provided for the discharge line of the HPCI train, each of the two RHR trains and each of the two core spray trains. The individual fill lines can be isolated to permit maintenance on ECCS and on individual grains of a system without affecting the other train. Details are shown in the HPCI P&ID, Figure 6.3-1a, RHR P&ID. Figure 5.4-13 and C.S. P&ID, Figure 6.3-4. The condensate transfer pumps with associated instrumentation, including the low pressure alarm PAL 00837, are shown on the condensate and refueling water P&ID, Figure 9.2-9.

No Level transmitters are provided to detect air bubbles upstream of injection valves.

Air pockets will be prevented by proper venting and filling and
by maintaining the discharge lines continuously pressurized such
that the pressure at the high points always exceeds atmospheric
12 pressure. This will require a minor but continuous feed flow
into the discharge lines to make up for valve leakage.

The presence of small, local air bubbles upstream of the injection valves will not be detrimental to the ECCS during the start transient.

Each RHR train has its own fill line and can be isolated from the other train. If one pump in an RHR train needs to be isolated for maintenance, the discharge line for the other pump will remain filled and pressurized to the isolation valve of that pump, allowing the pump to perform its function.

The pressure sensor at the discharge of the condensate transfer pumps and the associated pressure indicator and low-pressure alarm, PAL 00837, will be tested in accordance with standard

procedures for surveillance testing of instrumentation. The functional test will requie tripping the condensate transfer pump to initiate automatic transfer of operation to the 100% capacity standby pump on indication of low discharge pressure.

Surveillance tests to determine if the discharge lines for the RHR and CS systems are full are performed by momentarily opening the vents at the system's high points to confirm the water fill and pump flow. No special fill and vent procedures are required prior to surveillance testing of RHR and CS pumps. 12

Surveillance tests to determine if the pump discharge lines are full will be performed before testing any of the ECCS pumps. Detection of large amounts of air in the discharge piping will have to be reported on the test sheets. Such a test with significant amounts of air present in the discharge line would not be considered acceptable.

6.3.2.3 Applicable Codes and Classification

The applicable codes and classification of the ECCS are specified in Section 3.2. All piping systems and components (pumps,

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 modificaiton. 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 Sections 6.3.3.7.5 and 6.3.3.7.6 were from a lead plant analysis. This statement has been deleted from Section 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 Section 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 Section 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. Typical Reactor Power

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 Number of Reactor Types

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.

(4) Minimum critical power ratio as a function of time from SCAT.

(5) Water level as a function fo time from SAFE/REFLOOD.

(6) Pressure as a function of time from SAFE/REFLOOD.

(7) Fuel rod convective heat transfer coefficient as a function of time from CHASTE.

(8) Peak cladding temperature as a function of time from CHASTE.

(9) Average fuel temperature as a function of time from CHASTE.

(10) PCT rod internal pressure as a function of time from CHASTE.

The maximum average planar linear heat generation rate, maximum local oxidation, and peak cladding temperature as a function of exposure from the CHASTE analysis of the 0.68 DBA are show in Table 6.3-6.

The DBA (the complete severence of the recirculation discharge piping) results are shown on Figures 6.3.3.21 through 6.3.3.28.

The second most limiting location for the LOCA is the recirculation suction line. Figure 6.3-74 shows the variation with break size of the calculated time the hot-node remains uncovered for a recirculation suction line break. Based on these calculations, the maximum recirculation suction line break was determined to be the suction line break which yields the highest peak cladding temperature. The results of the maximum berak in this piping are shown on Figures 6.3.3-29 through 6.3.3-36.

6.3.3.7.5 Transition Recirculation Line Break Calculations

Important variables from the analysis of the transition (1.0 ft^2) break are shown in Figures 6.3-37 through 6.3-48. These variables are:

1) Core average pressure (large break methods) as a function of time from LAMB.

(2) Core flow (large break methods) as a function of time from LAMB.

(3) Core inlet enthalpy (large break methods) as a function of time from LAMB.

4) Minimum critical power ratio (large break methods) as a function of time from SCAT.

5) Water level (large break methods) as a function of time from SAFE/REFLOOD.

6) Pressure (large break methods) as a function of time from SAFE/REFLOOD.

7) Fuel rod convective heat transfer coefficient (large break methods) as a function of time from CHASTE.

8) Peak cladding temperature (large break methods) as a function of time from CHASTE.

9) Water level (small break methods) as a function of time from SAFE/REFLOOD.

10) Pressure (small breaks methods) as a function of time from SAFE/REFLOOD.

11) Convective heat transfer coefficients (small break methods) as a function of time from REFLOOD.

12) Peak cladding temperature (small break methods) as a function of time from REFLOOD.

Δ

6.3.3.7.6 Small Recirculation Line Break Calculations

Important variables from the analysis of the small break yielding the highest cladding temperature are shown in Figures 6.3-49 thru 6.3-52 These variables are:

1) Water level as a function of time from SAFE/REFLOOD.

2) Pressure as a function of time from SAFE/REFLOOD.

3) Convective heat transfer coefficients as a function of time from REFLOOD.

4) Peak cladding temperature as a function of time from REFLOOD.

Δ The same variables resulting from the analysis of a less limiting small break are shown in Figures 6.3-53 thru 6.3-56.

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 vortice 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 6.3-67 thru 6.3-70 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.

Ten 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 CS and LPCI pumps. The NPSH requirements of the CS pump and the LPCI (RHR) pump are shown in Figure 6.3-6A and 5.4-15, respectively. A

During the long term cooling period (after 10 minutes), the operator will take action as specified in Subsection 6.2.2.2 to place the containment cooling system into operation. Throttling the CS and LPCI pumps and placing the containment cooling mode system into operation is the only manual action that the operator needs to accomplish during the course of the LOCA.

The operator has multiple instrumentation available in the control room to assist him in assessing the post-LOCA conditions. This instrumentation provides reactor vessel pressures and water levels; containment pressure and temperature and radiation levels as well as indicating the operation of the ECCS. ECC system flow indication is the primary parameter available to assess proper operation of the system. Other indications such as position of valves, status of circuit breakers, and essential power bus voltage are also available to assist him in determining system operating status. The electrical and instrumentation complement to the ECCS is discussed in detail in Chapter 7.3. Other available instrumentation is listed in the P&IDs for the individual systems. Much of the monitoring instrumentation available to the operator is discussed in more detail in Chapter 5 and Section 6.2.

6.3.2.9 Position Verification for Manual Valves

Consideration has been given to the possibility that manual valves in the ECCS might be left in the wrong position when an accident occurs. Table 6.3-9 lists all the manually-operated valves in the ECCS (ADS, LPCI, Suppression Pool Cooling Core Spray, and HPCI) and summarizes the methods for assuring correct valve position. The table lists only those manual valves which are related to the ECCS function of those systems. Thus, the only manual valves in the RHR system which were evaluated are those which comprise part of the LPCI and Suppression Pool Cooling modes. The boundaries of RHRS for this purpose include sidestreams and connecting systems out to the first normally-closed remotely operated valve or to two check valves in series.

Many of the manual valves in these systems are vent, drain, or test connection valves which are normally closed and capped. These valves are identified in the "Function" column of Table 6.3-9. Such valves are not critical to the ECCS function; administrative controls, such as pre-startup valve lineup checks, should suffice to reasonably assure that such valves will not degrade ECCS performance.

6.3.5 INSTRUMENTATION REQUIREMENTS

Design details including redundancy and logic of the ECCS instrumentation are discussed in Section 7.3.

All instrumentation required for automatic and manual initiation of the HPCI, CS, LPCI and ADS is discussed in Subsection 7.3.2 and is designed to meet the requirements of IEEE 279 and other applicable regulatory requirements. The HPCI, CS, LPCI and ADS can be manually initiated from the control room.

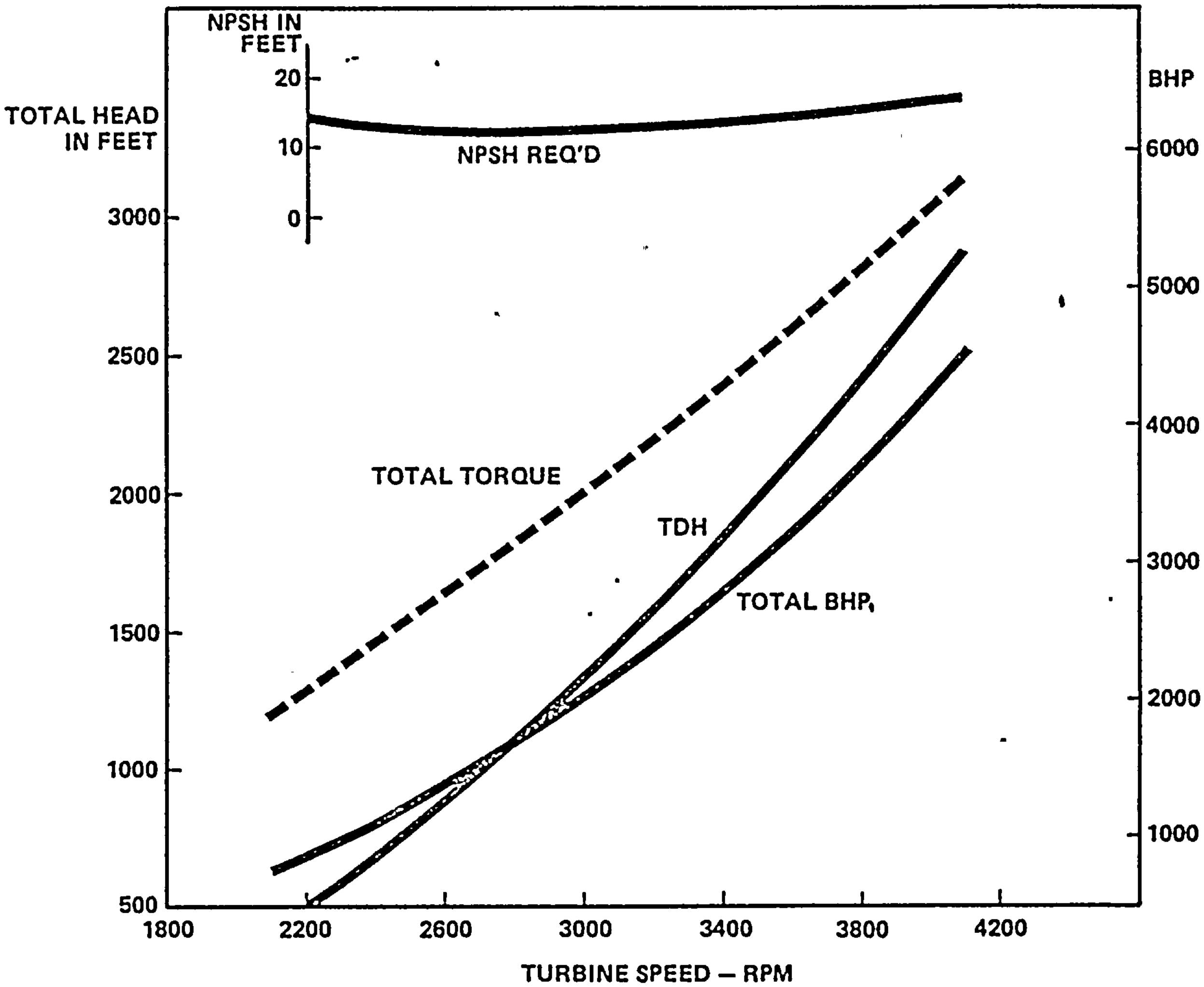
The HPCI, CS, and LPCI are automatically initiated on low reactor water level or high drywell pressure. (See Table 6.3-2 for specific initiation levels for each system.) The ADS is automatically actuated by sensed variables for reactor vessel low water level and drywell high pressure plus the indication that at least one LPCI pump or both CS pumps in the same loop are operating. The HPCI, CS and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The CS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure.

HPCI injection begins as soon as the HPCI turbine pump is up to speed and the injection valve is opened since the HPCI is capable of injecting water into the RPV over a pressure range from 150 psig to 1145 psig.

6.3.6 NPSH MARGIN AND VORTEX FORMATION AFTER A PASSIVE FAILURE IN A WATER TIGHT ECCS PUMP ROOM

NPSH calculations for ECCS pumps have shown adequate margin to assure capability of proper pump operation after a pool level drop due to a worst case passive failure in an ECCS water tight pump room. This capability will be verified during preoperational testing assuming a passive failure in the ECCS pump room resulting in the lowest pool level with subsequent operation of the ECCS pump with the smallest NPSH margin above NPSH required. ECCS pump data is presented in Figures 6.3-67 thru 6.3-70.

The pool level drop has been determined assuming a passive failure in a ECCS water tight pump room with operator action 10 minutes after an alarm in the room indicating high water level. This lowest suppression pool water level will also be used during preoperational testing to verify the absence of vortex formation in the flow approaching the suction strainers in the pool during ECCS pump operation. Pump performance and pump noise will be monitored during these tests to determine if pumps are sensitive to suction flow conditions in the suppression pool.



CONTSTANT 5000 GPM WITH 100 GPM BOOSTER BY-PASS

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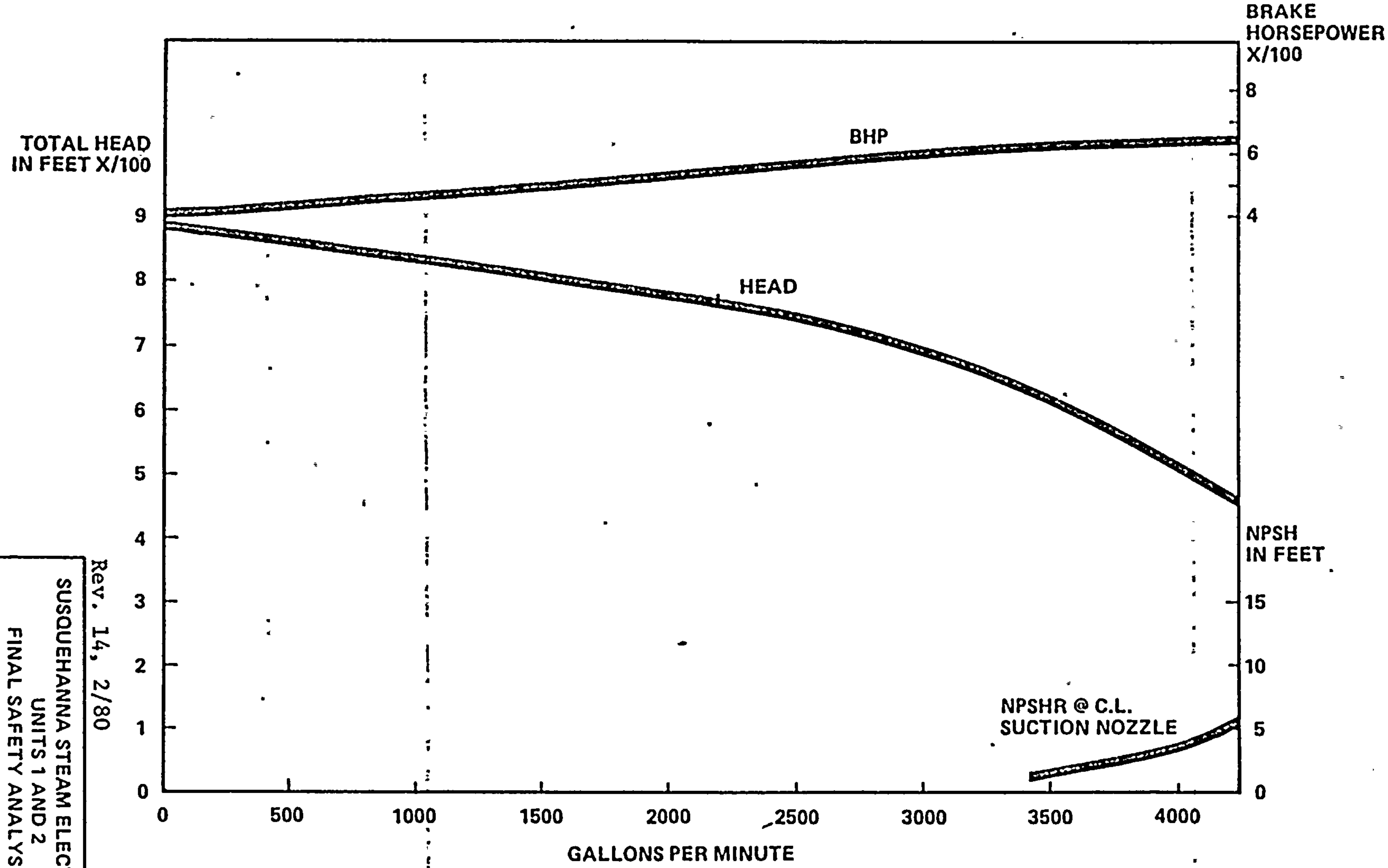
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

HIGH PRESSURE COOLANT INJECTION PUMP CHARACTERISTICS

FIGURE 6.3-3A



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UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CORE SPRAY PUMP
CHARACTERISTICS

FIGURE 6.3-6A

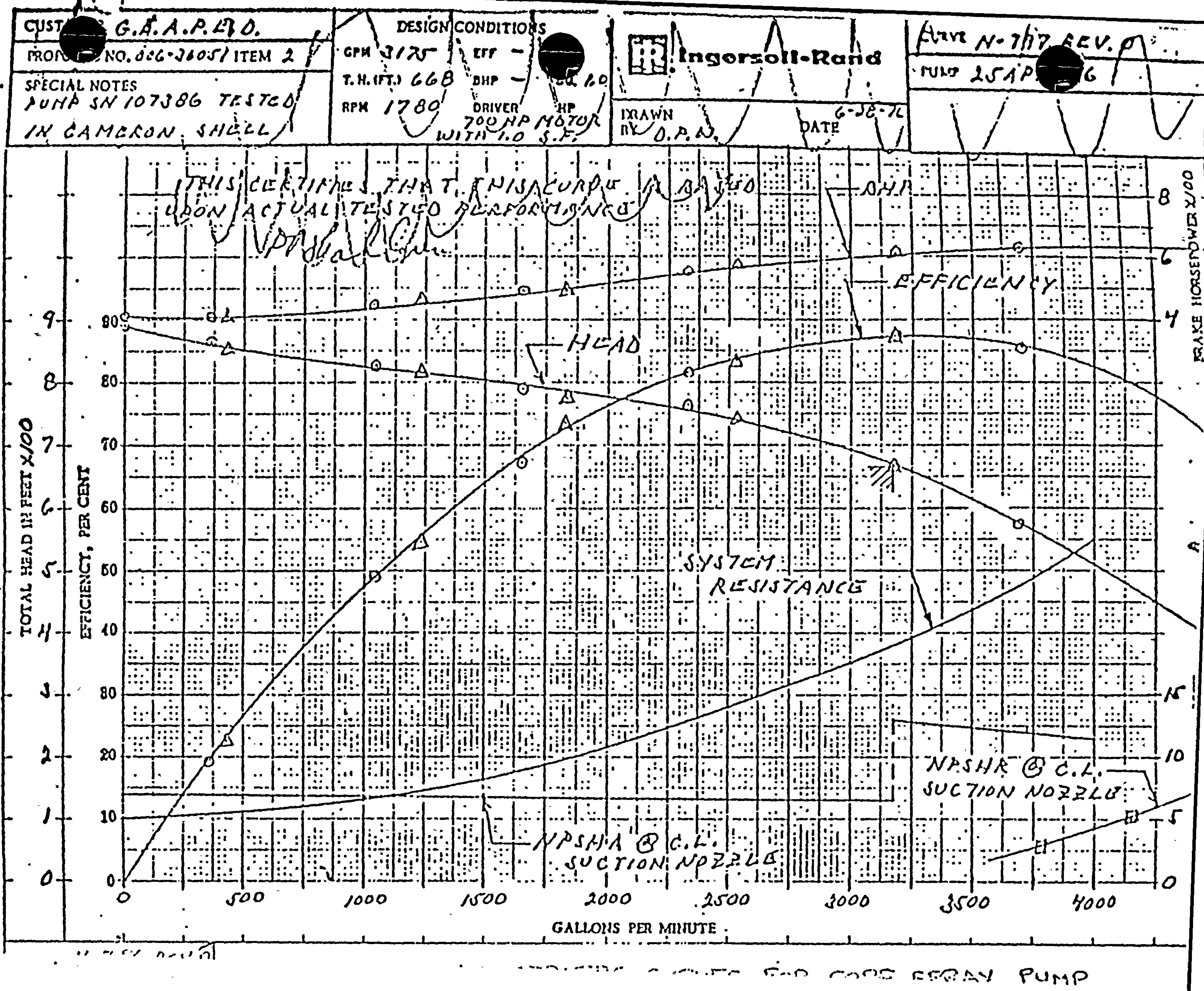

CUSTOMER G.A.A.P. LTD.
PROPOSAL NO. 066-36051 ITEM 2
SPECIAL NOTES
PUMP SN 107386 TESTED IN CAMERON SHELL
DESIGN CONDITIONS
GPM 3175
T.H.(FT.) 668
RPM 1780
EFF —
BHP —
DRIVER HP 700 HP MOTOR WITH 1.0 S.F.
Ingersoll-Rand
DRAWN BY D.P.N.
DATE 6-30-72
PUMP 25APKD-6
THIS CERTIFIES THAT THIS CURVE IS BASED UPON ACTUAL TESTED PERFORMANCE
BHP
EFFICIENCY
HEAD
SYSTEM RESISTANCE
NPSHR @ C.L. SUCTION NOZZLE
NPSHA @ C.L. SUCTION NOZZLE
TOTAL HEAD IN FEET X/100
EFFICIENCY, PER CENT
BRAKE HORSEPOWER X/100
GALLONS PER MINUTE
0
500
1000
1500
2000
2500
3000
3500
4000
CURVES FOR CORE SPRAY PUMP

Figure 6.3-67

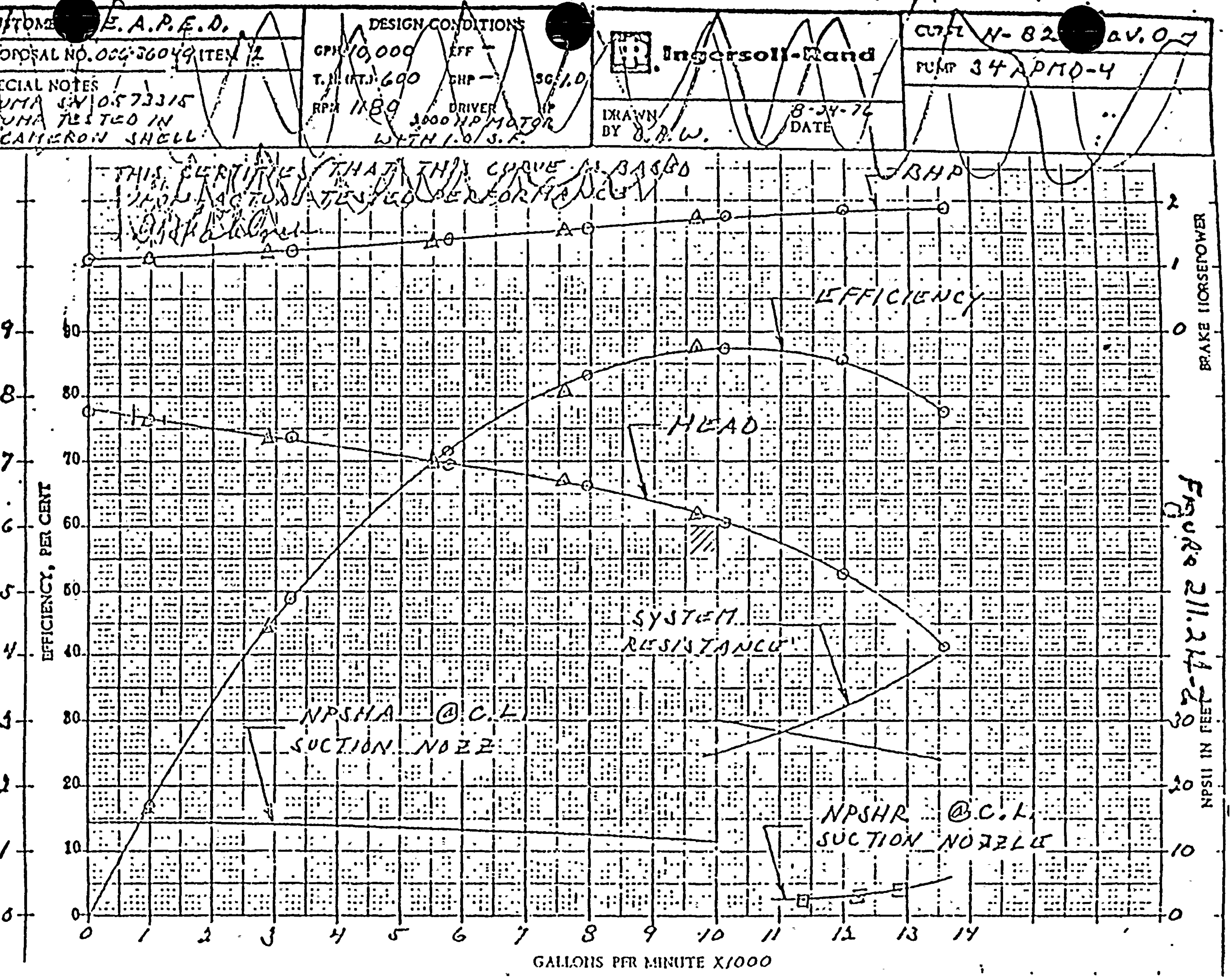
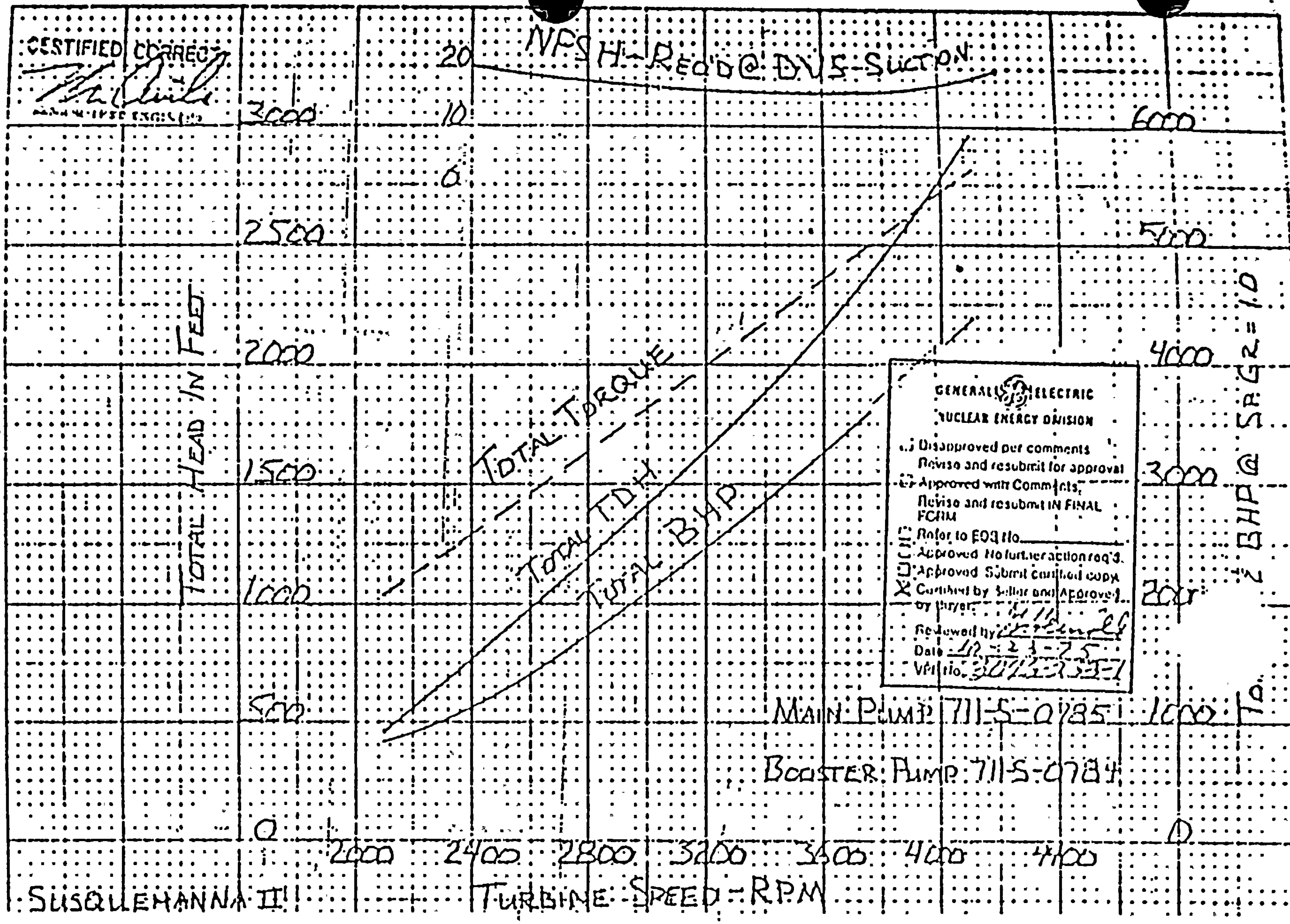

CUSTOMER E.A.P.E.D.
PROPOSAL NO. 004-36049 ITEM 2
SPECIAL NOTES
PUMP S/N 0573315
PUMP TESTED IN
CAMERON SHELL
DESIGN CONDITIONS
GPM 10,000
EFF —
T.H. (FT.) 600
BHP —
SG 1.0
RPM 1180
DRIVER 2000 HP MOTOR WITH 1.0 S.F.
Ingersoll-Rand
DRAWN BY O.R.W.
8-24-76 DATE
CURVE N-82
REV. 0
PUMP 34 APMD-4
THIS CERTIFIES THAT THIS CURVE IS BASED
UPON ACTUAL TESTED PERFORMANCE
BHP
EFFICIENCY
HEAD
SYSTEM
RESISTANCE
NPSHA @ C.L.
SUCTION NOZZ
NPSHR @ C.L.
SUCTION NOZZLE
TOTAL HEAD IN FEET X/100
EFFICIENCY, PER CENT
BRAKE HORSEPOWER
NPSH IN FEET
GALLONS PER MINUTE X/1000
Figure 211.24-2

Figure 6.3-68

Byron Jackson Pump Division



G.E. HPCI PUMPS	CONSTANT 5000 GPM WITH 100 GPM BOOSTER BY-PASS	DATA BY: GG / DRAWN BY: GG	JOB NO: ABOVE / DATE: 9-24-75	T-35420

211.214-4

Figure 211.214-3

Figure 6.3-69

AI

Byron Jackson Pump Division

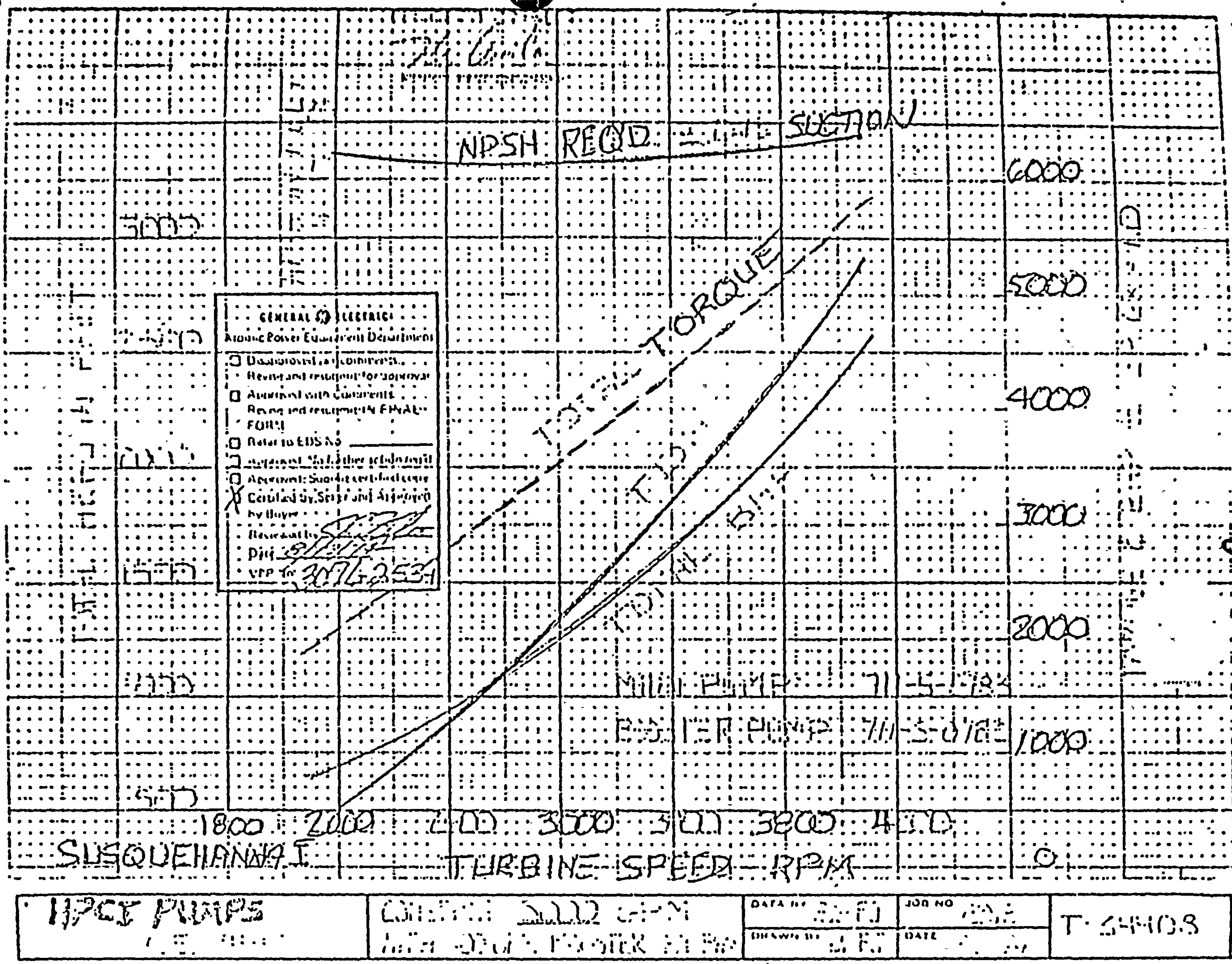
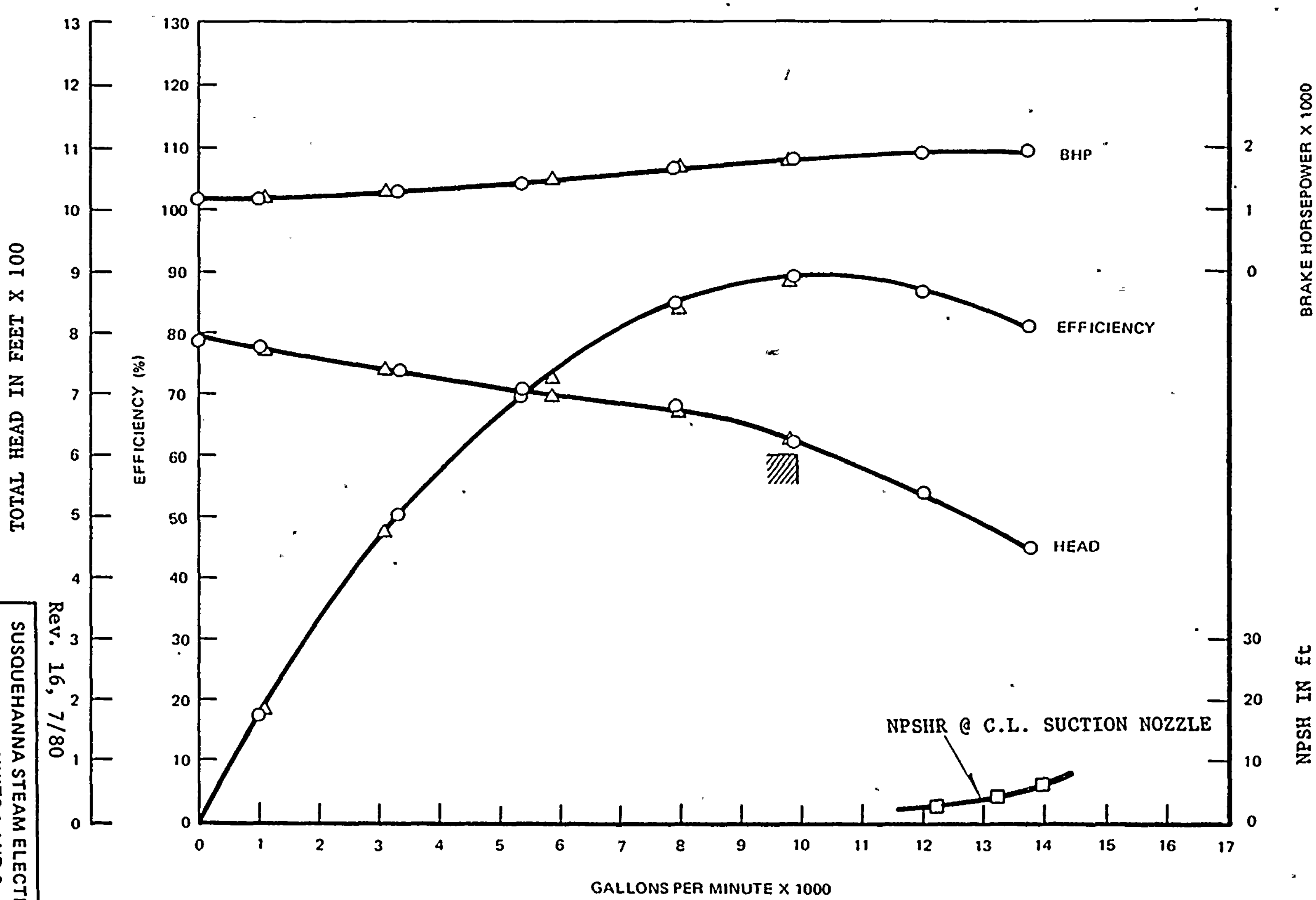


Figure 211.214-4

2/1.214-5

Figure 6.3-70



Rev. 16, 7/80

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

RHR PUMP CHARACTERISTIC CURVE

FIGURE 5.4-15

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 115,810 $ft.^3$

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 200 °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 Presure 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 - Figure 7.3-7.

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 - Figure 7.3-9.

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 - Figure 7.3-10.

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.

7.6.1a.3.3 Equipment Design

The following high pressure/low pressure interlock equipment is provided:

Process Line Instrumentation	Type	Valve	Parameter Sensed	Purpose
RHRS Shutdown Supply	MO MO	E11-F009 E11-F008	Reactor pressure	Closes on high pressure and prevents opening until reactor pressure is low
RHRS Shutdown Return & LPCI INJECTION	Check MO MO	E11-F050 E11-F015 E11-F017	NA Reactor pressure Reactor pressure	NA maintains valve closed and/or prevents opening until reactor pressure is low
RHRS Head Spray	Check MO MO	E11-F019 E11-F023 E11-F022	NA Reactor pressure Reactor pressure	NA Closes on high pressure and prevents opening until reactor pressure is lo
CS System Injection	Check MO MO	E21-F006 E21-F004 E21-F005	NA Reactor Press Reactor Press	NA Prevents valve opening until reactor pressure is low

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 vavles, 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 easilystarted again without delay. See Figure 7.3-7 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 Figures 7.3-9 and 7.3-10 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 August 1, 1980.

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		SK-M-5423
DLA-104-1		SK-M-5424

DLA-104-2
DLA-104-3
DLA-104-4
EBB-102-1
EBB-102-2
HBB-107-1
HBB-109-1
HCB-1-2
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.

Section 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 and one actuation against 45 psig in ADS. The response to Question 211.67 further describes these relief valves.

The pilot valve referred to in the 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.

system. The relief by normal mechanical action is intended to prevent overpressurization of the reactor vessel. The depressurization by automatic action of the control system is intended to reduce reactor vessel pressure during a LOCA in which the HPCI system is not available so that the CS system or LPCI system can inject water into the reactor vessel. The instrumentation and controls for one of these safety/relief valves are discussed. Other safety/relief valves equipped for automatic depressurization are identical.

7.3.1.1a.1.4.2 Equipment Design

The control system consists of pressure and water level sensors arranged in trip systems that control a dual solenoid-operated pilot air valve. The dual solenoid-operated pilot valve controls the pneumatic pressure applied to a piston type pneumatic assembly which controls the safety/relief valve directly. An accumulator is included with the control equipment to store pneumatic energy for safety/relief valve operation. The accumulator is sized to provide air for five actuations of the ADS piston type pneumatic actuator via the solenoid valves following failure of the pneumatic supply to the accumulator. Cables from the sensors lead to the control structure where the logic arrangements are formed in cabinets. The electrical control circuitry is powered by dc from the plant batteries. The power supplies for the redundant control circuits are selected and arranged to maintain tripping ability in the event of an electrical power circuit failure. Electrical elements in the control system energize to cause opening of the safety/relief valve.

7.3.1.1a.1.4.3 Initiating Circuits

The pressure and level switches used to initiate one ADS logic are separated from those used to initiate the other logic on the same ADS valve. Reactor vessel low water level is detected by six switches that measure differential pressure. Primary containment high pressure is detected by four pressure switches, which are located outside the primary containment and inside the reactor building. The level instruments are piped individually so that an instrument pipeline break will not inadvertently initiate auto blowdown. The primary containment high pressure signals are arranged to seal into the control circuitry; they must be manually reset to clear.

A timer is used in each ADS logic. The time delay setting before actuation of the ADS is long enough that the HPCI system has time to operate, yet not so long that the LPCI and CS systems are unable to adequately cool the fuel if the HPCI system fails to

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 elctro-pneumatic actuator assembly used on the safety relief valve had been subjected to the following environmental tests.

o 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.

o 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 detrmine 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 subjectd 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	Outlet	TEST UNIT TEMPER.	INLET PRESS. (psig)	OPERABILITY CONDITION
REFERENCE FRAME TESTS						
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
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

Table [illegible].211-1 (page 2)

TEST	ORIENTATION	NOZZLE LOADS (in-lbs) Inlet	Outlet	TEST UNIT TEMPER.	INLET PRESS. (psig)	OPERABILITY CONDITION
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

SSES

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."

during the lower plenum flashing period. Heat transfer then slowly decreases until the high power axial plane uncovers. At that time, convective heat transfer is assumed to cease.

4 Water level inside the shroud (Figure 6.3-15) remains high during the early stages of the blowdown because of flashing of the water in the core. After a short time, the level inside the shroud has decreased to uncover the core. Several seconds later the ECCS is actuated. As a result the vessel water level begins to increase. Some time later, the lower plenum is filled, and the core is subsequently rapidly recovered.

4 The cladding temperature at the high power plane (Figure 6.3-18) decreases initially because nucleate boiling is maintained, the heat input decreases and the sink temperature decreases. A rapid, short duration cladding heatup follows the time of boiling transition when film boiling occurs and the cladding temperature approaches that of the fuel. The subsequent heatup is slower, being governed by decay heat and core spray heat transfer. Finally the heatup is terminated when the core is recovered by the accumulation of ECCS water.

6.3.3.7.3 Break Spectrum Calculations

4

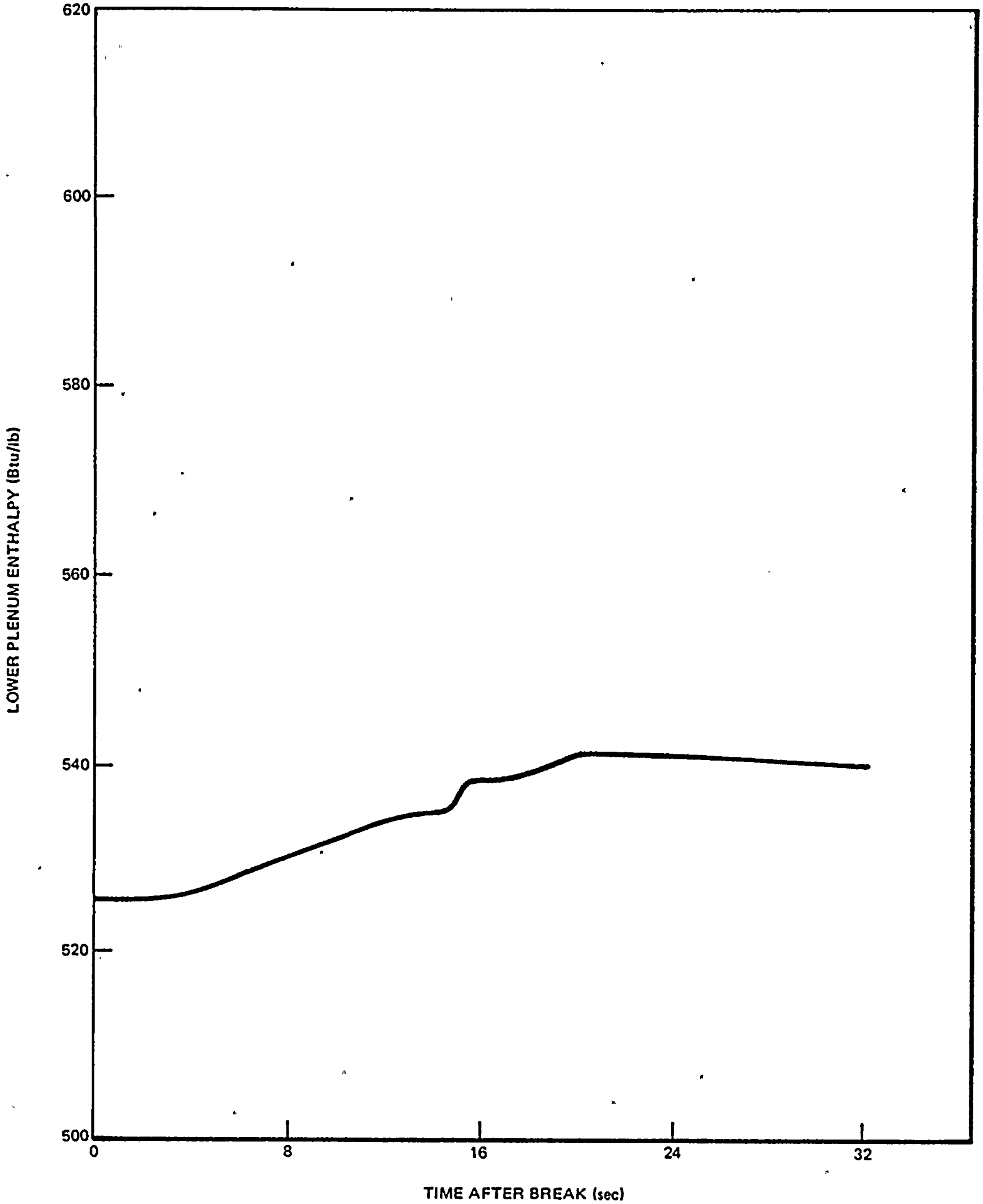
A complete spectrum of postulated break sizes and locations is considered in the evaluation of ECCS performance. The general analytical procedures for conducting break spectrum calculations are discussed in Section III.B of Reference 6.3-2. For ease of reference, a summary of all figures and tables presented in Subsection 6.3.3 is shown in Table 6.3-4.

A summary of the results of the break spectrum calculations is
shown in tabular form in Table 6.3-3 and graphically in Figure
16 4 6.3-10. Conformance to the acceptance criteria (PCT ≤ 2200°F,
local oxidation ≤17% and core wide metal-water reaction ≤1%) is
demonstrated. Details of calculations for specific breaks are
included in subsequent paragraphs.

For convenience in describing the LOCA phenomena, the break spectrum has been separated into three regions: small breaks, intermediate breaks, and large breaks. The selection of the break sizes to be included in each region is dependent on the most limiting single failure and the ECCS evaluation method used.

4 The small break region is defined as that portion of the break spectrum where the high pressure coolant injection (HPCI) is the most limiting single failure. In this region, the small break methods (SBM) are used.

The intermediate break region is defined as that portion of the break spectrum up to the transition break where the LPCI



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LOWER PLENUM ENTHALPY VERSUS TIME AFTER BREAK 68% DESIGN BASIS ACCIDENT RECIRCULATION DISCHARGE BREAK, LPCI INJECTION VALVE FAILURE

FIGURE 6.3-13

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 will be addressed as a TMI concern.

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 in the relief mode the solenoid energization 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 ≤ 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 ≤ 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.

TABLE 6.3-2 (Page 3)

o	Pressure at which injection valve may open	psig (vessel pressure)	500	
o	Injection valve fully open	sec after DBA	27	

High Pressure Coolant Injection

o	Vessel pressure at which flow may commence	psia	1160	4
o	Minimum rated flow available at vessel pressure	GPM psia (vessel to pump suction)	5000 1160 to 165	4
o	Initiating Signals			
	low water level	ft above top of active fuel	≤ 10.27	4 16
	or			
	high Drywell Pressure	psig	≥ 2.0	
o	Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	sec	30	

Automatic Depressurization System

o	Total number of valves installed		6	
o	Number of valves used in analysis		5	
o	Minimum Flow Capacity of any 5 valves at vessel pressure	lb/hr psid (vessel to suppression pool)	4.0×10^6 1125	
o	Initiating Signals			
	low water level (continued)	ft above top of active fuel	≤ 1.0	4

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 DBA, 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 fabricatd 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 500 hours.

QUESTION 211.227:

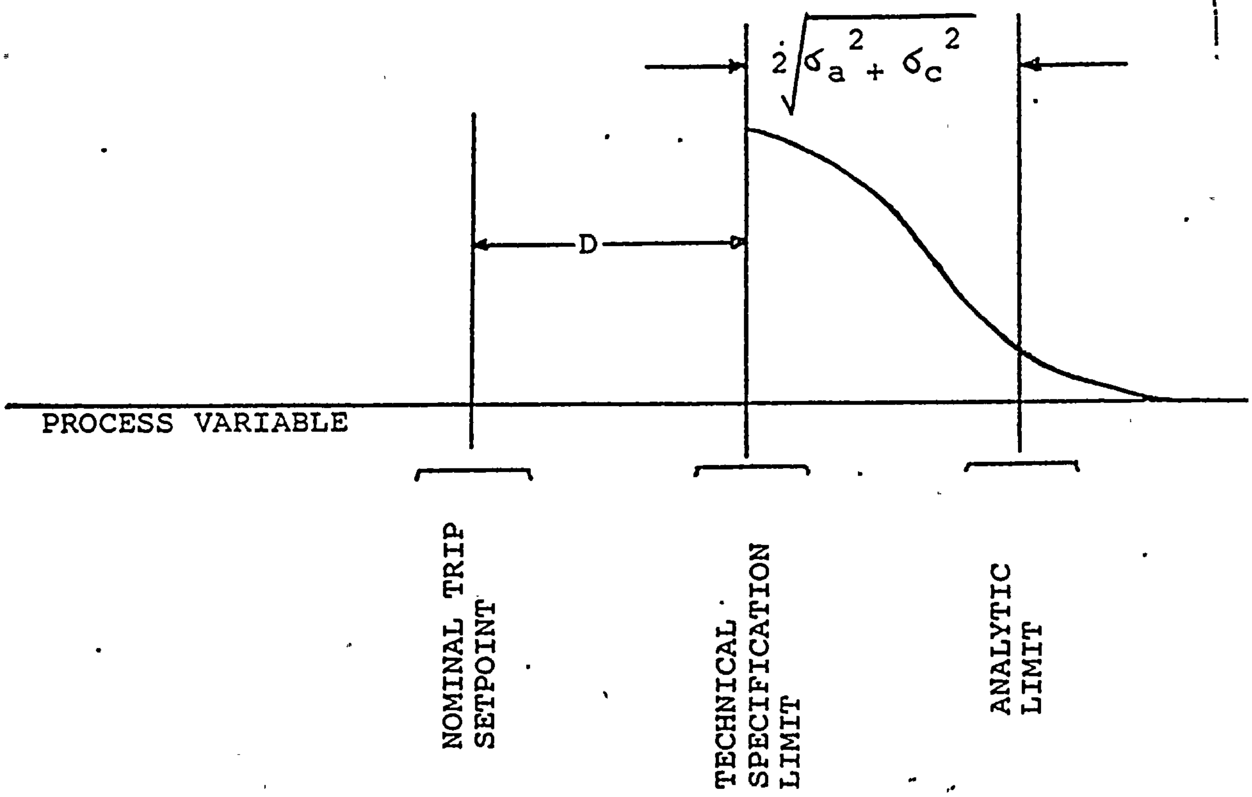
Provide the trip settings and setpoint ranges for the RCIC system isolation instrumentation. Indicate the method of specification of these settings and the provisions for minimizing the potential for inadvertent isolation of RCIC.

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 inadvertat 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 valve of steam flow (indicated by p) and the trip setpoint.



SUSQUEHANNA STEAM ELECTRIC STATION
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TRIP SETPOINT CALCULATION

FIGURE 211.227-1

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 (F017) 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" currently being written by General Electric for the utilities. 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.

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 funtion 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."

Subsection6.3.2.2.4has been revised to include the following statement; "The LPCI pump characteristics are shown in Figure 5.4-15."

subsection 6.3.2.2.4

Using the suppression pool as the source of water for the LPCI establishes a closed loop for recirculation of LPCI water escaping from the break.

The design pressures and temperatures, at various points in the system, during each of the several modes of operation of the RHR subsystems, can be obtained from the miscellaneous information blocks on the LPCI process diagram, Figures 6.3-8a, -8b, and -8c.

LPCI pumps and equipment are described in detail in subsection 5.4.7, which also describes the other functions served by the same pumps if not needed for the LPCI function. The RHR heat exchangers are not associated with the emergency core cooling function. The heat exchangers are discussed in subsection 6.2.2. The portions of the RHR required for accident protection including support structures are designed in accordance with Seismic Category I criteria (see Chapter 3). The LPCI pump characteristics are shown in Figure 5.4-15.

The LPCI system incorporates a relief valve on each pump suction line and the LPCI discharge header which protects the components and piping from inadvertent overpressure conditions. These valves are set to relieve pressure at 500 psig.

Provisions are included in the LPCI system to permit testing of the system. These provisions are:

1) All active LPCI components are designed to be testable during normal plant operation.

2) A discharge test line is provided for the four pumps to route suppression pool water back to the suppression pool without entering the reactor pressure vessel.

3) Instrumentation is provided to indicate system performance during normal and test operations.

4) All motor-operated valves, air-operated valves and check valves are capable of manual operation for test purposes.

5) Shutdown lines taking suction from the recirculation system are provided to permit testing of the pump discharge into the reactor pressure vessel after normal plant shutdown and to provide for shutdown cooling.

6) All relief valves are removable for bench testing during plant shutdown.

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 temperture 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 Figure 6.3-5 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.

ENGINEERED SAFETY SYSTEMS INFORMATION FOR CONTAINMENT RESPONSE ANALYSES

	Full Capacity	Containment Analysis Value Case A*	Case B	Case C	Case D
D. ECCS SYSTEM:					
1. High Pressure Coolant Injection (HPCI)					
a. No. of Pumps	1	0	0	0	0
b. No. of Lines	1	0	0	0	0
c. Flowrate, gpm	5,000	0	0	0	0
2. Core Spray (CS)					
a. No. of Pumps	2	2	1	1	1
b. No. of Lines	2	2	1	1	1
c. Flowrate (rated), gpm/line***	6,250	6,250	6,250	6,250	6,250
d. No. of Headers	2	2	2	2	2
3. Low Pressure Coolant Injection (LPCI) (Injection only)					
a. No. of Pumps	4	4	2	1	1
b. No. of Lines	2	2	1	1	1
c. Flowrate, gpm/line	15,000	15,000	15,000	10,000	10,000

ENGINEERED SAFETY SYSTEMS INFORMATION
FOR CONTAINMENT RESPONSE ANALYSES

	Full Capacity	Containment Analysis Value Case A*	Case B	Case C	Case D
4. Residual Heat Removal (RHR) (containment cooling only)					
a. Pump Flowrate:					
Shell Side	9,000	9,000	9,000	9,000	9,000
Tube Side	9,000	9,000	9,000	9,000	9,000
b. Source of cooling water		RHR Service Water			
c. Flow begins, seconds		Manual, Approximately 600**			
E. AUTOMATIC DEPRESSURIZATION SYSTEM:					
1. Total Number of Safety/ Relief Valves	16				
2. No. Actuated on ADS	6				

* Cases A, B, C, D defined in Table 6.2-6

** LPCI/RHR pumps are initiated on low water level. On signal or on manual, the changeover from LPCI to RHR containment cooling is by manual operation of the associated valves.

*** Accounts for 100 gpm leakage in the piping connection between the vessel nozzel and the shroud.

TABLE 6.3-2 (Page 2)

EMERGENCY CORE COOLING SYSTEM PARAMETERS

Low pressure coolant injection system			
o Vessel Pressure at which flow may commence	psid (vessel to drywell)	280	
o Minimum Rated Flow at Vessel Pressure	GPM psid (vessel to drywell)	Fig. 6.3-7 20	4
o Initiating signals low water level or high drywell pressure	ft. above top of active fuel psig	≤ 1.0 ≥ 2.0	4
o Maximum allowable time delay from initiating signal to pumps at rated speed	sec	40.0	
o Pressure at which injection valve may open	psig (vessel pressure)	500	
o Injection valve fully open	sec after DBA	40.0	
Core Spray System			
o Vessel pressure at which flow may commence	psid (vessel to drywell)	289	
o Minimum rated flow at Vessel Pressure	GPM/Pump psid (vessel to drywell)	6250** 105	4 16
o Initiating signals			
low water level or high Drywell Pressure	ft. above top of active fuel psig	≤ 1.0 ≥ 2.0	4
o Maximum allowed (runout) flow	GPM/Pump	7900	4
o Maximum allowed delay time from initiating signal to pump at rated speed	sec	27.0	

** Accounts for 100 gpm leakage in the piping connection between the vessel nozzel and the shroud. 16

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, even assuming an operator response time of 30 minutes, adequate NPSH is calculated to be available to the unaffected ECCS pumps and the water will be confined to the affected pump room. Preoperational testing to verify pump NPSH adequacy and absence of suppression pool vortex formation will be 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 pump shaft seal is designed such that much lower leakage rates would be expected.

6.3.5 INSTRUMENTATION REQUIREMENTS

Design details including redundancy and logic of the ECCS instrumentation are discussed in Section 7.3.

All instrumentation required for automatic and manual initiation of the HPCI, CS, LPCI and ADS is discussed in Subsection 7.3.2 and is designed to meet the requirements of IEEE 279 and other applicable regulatory requirements. The HPCI, CS, LPCI and ADS can be manually initiated from the control room.

The HPCI, CS, and LPCI are automatically initiated on low reactor water level or high drywell pressure. (See Table 6.3-2 for specific initiation levels for each system.) The ADS is automatically actuated by sensed variables for reactor vessel low water level and drywell high pressure plus the indication that at least one LPCI pump or both CS pumps in the same loop are operating. The HPCI, CS and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The CS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure.

HPCI injection begins as soon as the HPCI turbine pump is up to speed and the injection valve is opened since the HPCI is capable of injecting water into the RPV over a pressure range from 150 psig to 1145 psig.

6.3.6 NPSH MARGIN AND VORTEX FORMATION AFTER A PASSIVE FAILURE IN A WATER TIGHT ECCS PUMP ROOM

NPSH calculations for ECCS pumps have shown adequate margin to assure capability of proper pump operation after a pool level drop due to a worst case passive failure in an ECCS water tight pump room. This capability will be verified during preoperational testing assuming a passive failure in the ECCS pump room resulting in the lowest pool level with subsequent operation of the ECCS pump with the smallest NPSH margin above NPSH required. ECCS pump data is presented in Figures 6.3-67 thru 6.3-70.

The pool level drop has been determined assuming a passive failure in a ECCS water tight pump room with operator action 10 minutes after an alarm in the room indicating high water level. This lowest suppression pool water level will also be used during preoperational testing to verify the absence of vortex formation in the flow approaching the suction strainers in the pool during ECCS pump operation. Pump performance and pump noise will be monitored during these tests to determine if pumps are sensitive to suction flow conditions in the suppression pool.

QUESTION 211.10

Review procedure III.20 of SRP 6.3 requires that 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 to 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 (Figure 1.2-17). 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 Figures 5.4-13, 7.4-1, and 6.3-1. 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 a passive failure in the largest of the ECCS rooms (RHR pumproom A). Approximately 5000 gallons would be lost before the operator would be alerted by the room flooding monitors. The operator would secure the affected RHR train and start the physically separated redundant train within 10 minutes of receipt of the room flooding alarm. 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. The normally closed valve in the area drain line could be opened to drain the room to the sump prior to processing. Appropriate actions could then be undertaken to allow repair or replacement of 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.

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 (4/79) revised the response to Question 211.10, and fully explain the leakage detection system's conformance to IEEE 279. | Δ

See revised Subsections 3.6.1.1 (Flooding) and 6.3.6. | Δ

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.

detected by changes in reactor water level and changes in flow rates in process lines.

The 5 gpm leakage rate is a technical specification limit on unidentified leakage. The leak detection system is fully capable of monitoring flowrates with an accuracy of one gpm and is, thus, in compliance with Paragraph C.2 of Regulatory Guide 1.45.

5.2.5.1.1 Detection of Abnormal Leakage Within the Primary Containment (NSS-Systems)

Normal leakage will result in a decrease of reactor water level and a pressure differential between the core spray line and the vessel shroud. A low reactor water level will cause isolation of the main steam lines.

5.2.5.1.2 Detection of Abnormal Leakage Within the Primary Containment (Non-NSSS)

Leakage through the reactor coolant pressure boundary within the primary containment is detected by monitoring temperatures, pressures, airborne particulate radioactivity, and changes of levels in drain sumps. These monitors and their respective locations are listed in Table 5.2-14. Δ

The following systems are used to monitor these variables:

a) Primary containment and suppression pool temperature monitoring system.

b) Primary containment and suppression chamber pressure monitoring system

c) Primary containment atmosphere monitoring system (containment radiation detection)

d) Drywell floor drain sump monitoring and drywell equipment drain tank level monitoring system.

The above mentioned leak detection systems are designed in accordance with recommendations of Regulatory Guide 1.45.

The drywell leak detection system is not intended to be qualified as a post LOCA system; it is designed for use during power operation as implied by the Technical Specifications. There would be no practical way of recalibrating the system after the LOCA transient. Δ

5.2.5.1.2.1 Primary Containment Temperature Monitoring System

Temperatures within the drywell are monitored at various elevations. A drywell ambient temperature rise will indicate the pressure of reactor coolant or steam leakage. Temperature monitoring of the containment provides an indirect indication of leakage as defined in the regulatory position (3) of Regulatory Guide 1.45.

Δ A detailed description of the system, sensitivity and response time, and the system reliability is discussed in Subsection 7.6.1b.1.2.

Limiting leakage conditions are included in the technical specification of Chapter 16.

Δ Provisions for testing and calibration are described in Section 7.6.2b.

5.2.5.1.2.2 Primary Containment Pressure Monitoring System

Pressure monitoring within the containment provides an indirect method of detecting leakage.

The drywell pressure fluctuates slightly during reactor operation as a result of pressure changes in the reactor building and out-leakage. A pressure increase above normal values indicates a leak in the primary containment.

The primary containment monitoring system and instrumentation is described in Section 7.6.1b.

Δ Section 7.5.1b identifies safety related display instrumentation.

5.2.5.1.2.3 Primary Containment Atmosphere Monitoring - Airborne Particulate Radioactivity Monitoring

The primary containment is continuously monitored for airborne radioactivity. A sample is drawn from the primary containment and a sudden increase of activity indicates a steam or reactor water leakage.

5.2.5.1.2.3.1 Sensitivity and Response Time | A

The objective of the drywell leak detection monitors as indicated in R.G. 1.45 is to detect 1 gpm of unidentified primary coolant pressure boundary leakage in 1 hour. Several detection systems supplied to accomplish this are the drywell sump level monitor (see Subsection 5.2.5.1.2.4), a noble gas radiation monitor, a radioiodine monitor, and a particulates radiation monitor. The three radiation monitors sample drywell for the activity levels on the assumption that flashing coolant leakage will result in radioactivity in the atmosphere. | A

The reliability, sensitivity and response times of radiation monitors to detect 1 gpm in 1 hour of Reactor Coolant Pressure Boundary leakage will depend on many complex factors. The major factors are discussed below: | A

A. Source of Leakage

1) Location of Leakage

The amount of activity which would become airborne following a 1 gpm leak from the RCPB will vary depending upon the leak location and the coolant temperature and pressure. For example, a feedwater pipe leak will have concentration factors of 100 to 1000 lower than a recirculation line leak. A steam line leak will be a factor of 50 to 100 lower in iodine and particulate concentrations than the recirculation line leak, but the noble gas concentrations may be comparable. A RWCU leak upstream of the demineralizers and heat exchangers will be a factor of 10 to 100 higher than downstream, except for noble gases. Differing coolant temperatures and pressures will affect the flashing fraction and partition factor for iodines and particulates. Thus, an airborne concentration cannot be correlated to a quantity of leakage without knowing the source of the leakage.

2) Coolant Concentrations

Variations in coolant concentrations during operation can be as much as several orders of magnitude within a time frame of several hours. These effects are mainly due to spiking during power transients or changes in the use of the RWCU system. Examples of these transients for I-131 can be found in NEDO-10585 (8/72), Behavior of Iodine in Reactor Water During Plant Shutdown and Startup. Thus, an increase in the coolant concentrations could give increased containment concentrations when no increase in unidentified leakage occurs.

3) Other Sources of Leakage

Since the unidentified leakage is not the sole source of activity in the containment, changes in other sources will result in changes in the containment airborne concentrations. For example, identified leakage is piped to the equipment drain tank in the drywell, but the tank is vented to the drywell atmosphere allowing the release of noble gases and some small quantities of iodines and particulates from the drain tank.

B. Drywell Conditions Affecting Monitor Performance

1) Equilibrium Activity Levels

During normal operation the activity release from acceptable quantities of identified and unidentified leakage will build up to significant amounts in the drywell air. Conversations with several operating plants indicate that levels as high as .1 to 10 times MPC are not uncommon for noble gases and iodines. (MPC refers to "maximum permissible concentration" as defined by 10CFR20, MPC is used here only as a convenient reference). Due to these high equilibrium activity levels the small increases due to a 1 gpm increase in leakage may be difficult to see within an hour. Typical MPC ranges are:

	.1 MPC to 10 MPC
Noble Gases	$1x10^{-6}$ - $1x10^{-4}$ μCi/cc
Particulates	$1x10^{-6}$ - $1x10^{-4}$ μCi/cc
Iodines	$5x10^{-7}$ - $5x10^{-5}$ μCi/cc

Fresh fuel backgrounds were not considered because no fission products are available at that point in time. The numbers given above include amounts of failed and/or irradiated fuel. These numbers also include normal expected leakage rates.

2) Purge and Pressure Release Effects

Changes in the detected activity levels have occurred during periodic drywell purges to lower the drywell pressure. These changes are of the same order of magnitude as approximately a 1 gpm leak, and are sufficient to invalidate the results from iodine and particulate monitors.

3) Plateout, Mixing, Fan Cooler Depletion

Plateout effects on iodines and particulates will vary with the distance from the coolant release point to the detector. Larger travel distances would result in more plateout. In addition the pathway of the leakage will influence the plateout effects. For example, a leak from a pipe with insulation will have greater plateout than a leak from an uninsulated pipe. Although the drywell air will be mixed by the fan coolers, it may be possible for a leak to develop in the vicinity of the radiation detector sample lines. In addition, condensation in the coolers will remove iodines and particulates from the air. Variations in the flow, temperature and number of coolers will affect the plateout fractions. Plateout within the detector sample tube will also add to the reduction of the iodine and particulate activity levels. The uncertainties in any estimate of plateout effects could be as much as one or two orders of magnitude.

C. Physical Properties and Capabilities of the Detectors

1) Detector Ranges

The detectors were chosen to ensure tha tthe operating ranges covered the concentrations expected in the drywell. The operating ranges are:

Noble Gases	1×10^{-6} to 1×10^{-2}	Ci/cc
Particulates	1×10^{-9} to 1×10^{-4}	Ci/cc
Iodines	1×10^{-9} to 1×10^{-4}	Ci/cc

2) Sensitivity

In the absence of background radiation and equilibrium drywell activity levels, the detectors have the following minimum sensitivity.

A

Noble Gas	1×10^{-6} μCi/cc
Particulates	1×10^{-9} μCi/cc
Iodine	1×10^{-9} μCi/cc

3) Counting Statistics and Monitor Uncertainties

In theory these radioactivity monitors are statistically able to detect increases in concentration as small as 2 or 3 times the square root of the count rate, i.e., at 10^6 cpm an increase of 2×10^3, or 0.2%, is detectable; at 10^2 cpm an increase of 240, or 20% is detectable. In addition at high count rates the monitors have dead-time uncertainties and the potential for saturating the monitor or the electronics. Uncertainties in calibration (±5%) sample flow (±10%) and other instrument design parameters tend to make the uncertainty in a count rate closer to 20% to 40% of the equilibrium drywell activity.

4) Monitor Setpoints

Due to the uncertainty and extreme variability of the concentrations to be measured in the containment the use of alarm setpoints on the radioactivity monitors would not be practical or useful. As indicated in the following section the setpoints which would be required to alarm at 1 gpm would be well within the bounds of uncertainty of the measurements. The use of such setpoints would result in many unnecessary alarms and the frequent resetting of setpoints. A setpoint alarm on the sump level monitor alone is used; the radioactivity monitors are for supporting information to confirm that the leak is radioactive. The alarm setpoints for the radiation monitors will be set significantly above background to prevent nuisance alarms. The actual setpoint will be changed as background increases. At these levels, the radiation monitors will provide no warning of a 1 gpm leak in one hour.

5) Estimated Monitor Responses

Table 5.2-13 estimates the expected monitor responses for several types of leaks and several types of monitors. As indicated in column 3, the added activity in containment from a 1 gpm leak for 1 hour is less than the nominal 20% increase which could be meaningfully detected. The final columns estimate the detectable leakage in 1 hour.

6) Operator Action

There is no direct correlation or known relationship between the detector count rate and the leakage rate, because the coolant activity levels , source of leakage, and background radiation levels (from leakage alone) are not known and cannot be cost-effectively determined in existing reactors. There are also several other sources of containment airborne activity (e.g. safety relief valve leakage) which further complicate the correlation.

Thus, the recommended procedure for the control room operator is to set an alarm setpoint at 1 gpm in 1 hour on the sump level monitor (measuring water collected in the sump which may not exactly correspond to water leaking from an unidentified source). When the alarm is actuated, the operator will review all other monitors (e.g., noble gas, particulates, temperature, pressure, fan cooler drains, etc.) to determine if the leakage is from the primary coolant pressure boundary and not from an SRV or cooling water system, etc. Appropriate actions will then be taken in accordance with Technical Specification 3/4.4.3. The review of other monitors will consist of comparisons of the increases and rates of increase in the values previously recorded on the strip chart recorders. Increases in all parameters except sump level will not be correlated to a RCPB leakage rate. Instead, the increases will be compared to normal operating limits and limitations (e.g., 2 psi maximum pressure for ECCS initiation) and abnormal increases will be investigated.

Since the 5 gpm Technical Specification limit is allowed to be averaged over 24 hours, quick and accurate responses are not necessary unless the leakage is very large and indicative of a pipe break. In this case, the containment pressure and reactor vessel water level monitors will alarm within seconds, and the sump level monitor would alarm within minutes or tens of minutes.

The radiation monitor alarms will not be set to levels that correspond to RCPB leakage levels since the correlations can't be made. Also, since the containment airborne activity levels vary by orders of magnitude during operation due to power transients, spiking, steam leaks, and outgassing from sumps, etc., an appropraite alarm setpoint, if one is used, should be determined by the operator based on experience with the specific plant. A setpoint level of 2 to 3 times the background level during full power steady state operation may be useful for alarming large leaks and pipe breaks, but it would not always alarm for 1 gpm in 1 hour.

7) Conclusion

Due to the sum total of the uncertainties identified in the previous paragraphs the iodine and particulate monitors will not be relied upon for leak detection purposes but only as supporting instrumentation. The noble gas monitor is used to give supporting information to that supplied by the sump level monitor and it would be able to give an early warning of a major leak especially if equilibrium containment activity levels are low. However, the uncertainties and variations in noble gas leaks and concentrations would preclude the setting of a meaningful set point on the monitors.

5.2.5.1.2.4 Drywell Floor Drain Sump Monitoring System

The drywell floor drain sump monitoring system is designed to permit leak detection in accordance with Regulatory Guide 1.45.

5.2.5.1.2.4.1 System Description

Two drywell floor drain sumps are located in the primary containment for collection of leakage from vent coolers, control rod drive flange leakage, chilled water drains, cooling water drains, and overflow from the equipment drain sump.

The drywell floor drain sump is located at the drywell diaphragm slab low point. Unidentified leakages will, by gravity, flow down the slab surface into the floor drain sump. No floor drain piping system is employed. Piped inputs to the drywell floor drain sump are from clean system drains. No surveillance program is planned to detect piped equipment drain system blockage.

Small, unidentified leakages of concern flowing into the drywell floor drain sump will not be masked by larger, acceptable, identified leakages overflowing from the drywell equipment drain tank. The drywell equipment drain tank drains by gravity. During conditions of acceptable identified leakage rates, the gravity flow from the drywell equipment drain tank will be capable of preventing the drywell equipment drain tank from overflowing to the drywell floor drain sump. The operation and control of the drywell equipment drain tank drain is the same as discussed in Subsection 5.2.5.1.2.4.1 for the drywell floor drain sumps.

Water flow rate better than 0.5 gpm can be obtained by monitoring changes of level over a time period. The following method of flow rate measurement was selected to comply with the requirements of Regulatory Guide 1.45. The necessary sensitivity is obtained by measuring the changes of level during a fixed time interval. For this purpose a continuous level measurement system is installed in each of the sumps. An electronic signal directly proportional to the actual sump level is applied to one pen of a two-pen recorder, to an electronic sample and hold device, and to an electronic differential switch. The sample and hold device, upon command from a timer, applies its output signal to the second pen of the two-pen recorder and to the second input of the electronic differential switch. The sample and hold unit's output signal level is regularly updated to the reference sump level signal.

The actual level signal of the sump and the reference level signal are continuously displayed on the two-pen recorder. The same signals are being monitored by the electronic differential switch. When the level signals differ by ± 50 gallons or more during a 50 minute period (equal to 1 gpm) an alarm is actuated on the local panel and on the control board in the main control room. The change in sump level per unit of time determines the leak rate and is available from the recorder slope for confirmation.

There is no reliable quantitative relationship between the sump level and the leakage rate from any source. The quantity is dependent upon the temperature and pressure of the containment and the leak and the location of the leak. Part of the leak will flash to steam; it may be partially trapped between insulation layers. Presumably the leakage will get to an equalibrium level where most of it ends up in the sump, unless the drywell is vented to relieve the pressure buildup. Since the Technical Specification allows 24-hour averaged leak limits, short term variations in the ability to relate the sump quantity to the leaked quantity are ignored, and its is assumed that all leakage reaches the sump. The errors introduced will not impair the ability to detect larger leaks which could rapidly result in severe accidents. Some leakage will no doubt be trapped in insulation etc., but no large reservoirs for leakage have been found.

Each sump is equipped with two submerged pumps which operate in an alternating mode. High sump level starts the pump automatically. Remote manual control of the pump is provided in the control room. Both pumps will be operating as soon as an

abnormal, high level is detected. The capability of each pump is such that normal expected flow rates can be easily accomplished.

5.2.5.1.2.4.2 Instrumentation

Magnetic float type continuous level probes are used to measure the fluid level and provide the signal for the recording of the actual sump level and the rate of level change in the control room. Excessive leak rate is alarmed on the local system panel and with a group trouble alarm in the control room. The leak rate can be observed by the control room operator.

5.2.5.1.2.4.3 Drywell Equipment Drain Tank Level Monitoring System

The drywell equipment drain tank collects identified leakage within the primary containment from reactor head seal leak off, bulkhead drain, refueling bellows drain, refueling RPV head vent, recirculation pump seals, reactor recirculation pump cooler drains, and RPV bottom drain.

All identified leakages which may have temperatures of 212° F or above are hard-piped directly to the drywell equipment drain tank. These leakages will tend to partially flash into steam and then condense in the drain pipe. This approach minimizes the possibility that leakage will escape as steam into the containment atmosphere prior to measurement in the equipment drain tank.

The drywell equipment drain tank drains by gravity. The drain tank's discharge valves automatically open when a predetermined high level in the tank is reached. The discharge valves close at a predetermined low level.

5.2.5.1.2.4.4 Sensitivity and Response Time of Measurement

The method for liquid leak detection in the primary containment is designed to meet the recommended water flow rate changes of 0.5 to 1.0 gpm as defined in Regulatory Guide 1.45.

The following assumptions and design considerations were incorporated:

a) Leak rate is directly proportional to the associated change in sump level.

b) Measurement of the drywell floor drain sump is discontinued during the pump operation and starts immediately after the pump stops. Measurement of the drywell equipment drain tank is discontinued when the tank's discharge valves are opened and starts immediately after the discharge valves close. 4

c) The selected measurement period T for the average change in level is 50 minutes

d) The drywell drain sumps have a capacity of 300 gal with a depth of 5 in.

   The drywell equipment drain tank capacity is 1000 gal with a depth of 42 in.

e) The level instrumentation accuracy is ± 5 percent of full range

f) Recorder response is better than 1 second for full range

g) Recorder chart size/drive speed: 4 in./3/4 in./hr.

h) The electronic differential switch setpoint will alarm rates less than or equal to one gpm.

These design factors allow a detection of 1 gpm flow rate within a 50 minute time period.

The operator can verify this leak rate on the recorder in the control room by observation of the average change of level.

5.2.5.1.2.4.5 Signal Correlation and Calibration

Drywell Drain Sump

The sump depth of 0-5 in. is displayed on a 0-100 percent recorder chart, which relates to the total sump capacity of 0-300 gal.

The average flow rate (changes of level) during the measurement period T is calibrated to read 0-4 gpm over the full chart range.

Drywell Equipment Drain Tank

The tank depth of 42 in. is displayed on a 0-100 percent recorder chart. This relates directly to the tank capacity of 1000 gal.

The average flow rate is calibrated to record 0-4 gpm over the full chart range.

5.2.5.1.2.4.6 Seismic Qualifications

The drywell floor drain sump, all drywell drain piping, and all instrumentation used to monitor drywell floor drain sump and equipment drain tank level will be qualified to operate following an OBE. The drywell equipment drain tank, drywell equipment drain tank cooling coil, and drywell floor drain sump pumps are not qualified to operate following an OBE.

Credit will be taken for monitoring unidentified leakage following an OBE thru the use of the drywell floor drain sump level monitoring system. The proper funtioning of at least one leakage detection system following an SSE is provided by the design of the air borne radioactivity monitoring system. Refer to Section 7.6.1b for description.

5.2.5.1.2.4.7 Testing and Calibration

Calibration of level sensors is possible by observing the change in level during the periodic pump down operations of the drywell floor drain sump, and periodic draining of the drywell equipment drain tank.

For the drywell floor drain sump, the pumps are automatically started and stopped by mechanical level sensing switches (high and low level set points), but can also be operated manually, at any time, to check the calibration of the level sensors. In the event that the high-high level is reached, two pumps will operate. The drain tank discharge valves are opened automatically on high level and can be operated manually at any time, to check the calibration of the level sensors.

5.2.5.1.3 Detection of Abnormal Leakage Outside the Primary Containment

Outside the drywell, the piping within each system monitored for leakage is in compartments or rooms, separate from other systems where feasible, so that leakage may be detected by area temperature indications. Each leakage detection system discussed below is designed to detect leak rates that are less than the technical specification leakage limits. The method used to monitor for leakage for each RCPB component may be seen in Table 5.2-8.

(1) Ambient and Differential Room Ventilation Temperature

A differential temperature sensing system is installed in each room containing equipment that interfaces with

the reactor coolant pressure boundary. These are the HPCI, RCIC, RHR, and reactor water cleanup systems equipment rooms, and main steam line tunnel. Temperature sensors are placed in the inlet and outlet ventilation ducts. Other sensors are installed in the equipment areas to monitor ambient temperature. A differential temperature switch between each set of sensors and/or ambient temperature switch initiates an alarm and isolation when the temperature reaches a preset value. The HPCI, RCIC and RHR leak detection area ambient temperature switch set points are designed to initiate isolation signals at 167°F. This set point includes sufficient margin above the post LOCA maximum area temperature to preclude inadvertent isolation signals. Consideration has been given to keeping this set point low enough to allow a timely detection of a 5 GPM leak, with the room starting at the design minimum temperature. A

The HPCI, RCIC and RHR ventilation inlet and exhaust differential temperature switch set points are designed to initiate isolation signals at a differential temperature of 89°F. This set point includes sufficient margin to prevent inadvertent isolation signals when the area ventilation exhaust is at the maximum post LOCA temperature, and the ventilation inlet corresponds to the minimum reactor building recirculating ventilation design temperature. This set point will allow wide fluctuations in outside air temperature without causing inadvertent isolation signals. This setting will also permit timely detection of a 5 GPM leak, with the area starting at minimum design temperatures.

Annunciator Accessible areas are inspected periodically and the temperature and flow indicators discussed above are monitored regularly as required by Chapter 16. Any instrument indication of abnormal leakage will be investigated.

(2) Visual and Audible Inspection

Accessible areas are inspected periodically and the temperature and flow indicators discussed above are monitored regularly as required by Chapter 16. Any instrument indication of abnormal leakage will be investigated.

(3) Differential Flow Measurement (Reactor Water Cleanup System Only)

Because of the arrangement of the reactor water cleanup system, differential flow measurement provides an accurate leakage detection method.. The flow from the reactor vessel is compared with the flow back to the vessel. An alarm in the control room and an isolation signal are initiated when higher flow out of the reactor vessel indicates that a leak may exist. Major leakage is also detected by excess flow monitoring in the cleanup system suction lines.

5.2.5.2 Leak Detection Devices for NSS-System

(1) Reactor Vessel Head Closure

The reactor vessel head closure is provided with double seals with a leak off connection between seals that is piped through the normally closed manual valves to the equipment drain tank. Leakage through the first seal is indicated locally in the reactor building. The second seal then operates to contain the vessel pressure.

(2) Reactor Water Recirculation Pump Seal

As discussed in Subsection 5.4.1.3, the reactor recirculation pump shaft is provided with two seals. Leakage past each seal is piped to the Drywell Equipment Drain Tank. Leakage past the first stage seal is designed to flow at approximately 0.75 gpm normally. The first stage seal leakoff line is provided with a high/low flow alarm which actuates at 0.9 gpm increasing or 0.5 gpm decreasing. The second stage pump seal is designed for zero leakage normally. The second stage seal leakoff line is provided with a high flow alarm which actuates at 0.1 gpm.

(3) Safety/Relief Valves

Temperature sensors connected to a multipoint recorder are provided to detect safety/relief valve leakage during reactor operation. Safety/relief valve temperature elements are mounted, using a thermowell, in the safety/relief valve discharge piping several feet from the valve body. Temperature rise above ambient is annunciated in the main control room. See the nuclear boiler system P&ID, Figure 5.1-3.

(4) Valve Packing Leakage

Power-operated valves in the nuclear boiler system and recirculation system are provided with valve stem packing leakoff connections. The packing leakoff connection is provided with normally closed isolation valves, and is capped. These valve stem packing leakoff isolation valves will be opened only during shutdown or hydrostatic test conditions to verify the inner valve packing leak tightness. Keeping these leakoff connections isolated provides two sets of packings for limiting stem leakage.

5.2.5.3 Limits for Reactor Coolant Leakage

5.2.5.3.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The criterion for establishing the total leakage rate limit is based on the makeup capability of the RCIC system. The total leakage rate limit is established at 30 gpm, 25 identified and 5 unidentified. The total leakage rate limit is also set low enough to prevent overflow of the drywell sumps.

5.2.5.3.2 Normally Expected Leakage Rate

The pump packing glands, valve stems, and other seals in systems that are part of the reactor coolant pressure boundary and from which normal design leakage is expected are provided with drains or auxiliary sealing systems. Nuclear system valves and pumps inside the drywell are equipped with double seals. Leakage from the primary recirculation pump seals is piped to the drywell equipment drain tank as described in Subsections 5.2.5.2(2) and 5.4.1.3. Leakage from the safety/relief valves is identified by temperature sensors in the discharge line that transmit to the control room. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage. Δ

Except for the leakoffs from the reactor recirculation pumps, all drains routed to the Drywell Equipment Drain Tank are normally isolated by closed values. Therefore, any leakage measured during normal plant operation in the Equipment Drain Tank is attributable to the recirculation pumps. Δ

The leakage rates from the recirculation pumps, plus any other leakage rates measured while the drywell is open, are defined as identified leakage rates. Table 5.2-11 lists normal and maximum identified leakage rates directed into the Drywell Equipment Drain Tank, and the associated activity concentrations.

5.2.5.4 Unidentified Leakage Inside the Drywell

5.2.5.4.1 Unidentified Leakage Rate

The unidentified leakage rate is the portion of the total leakage rate received in the drywell sumps that is not identified as previously described. A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a

crack that is large enough to propagate rapidly (critical crack length). The unidentified leakage rate limit must be low because of the possibility that most of the unidentified leakage rate might be emitted from a single crack in the nuclear system process barrier.

An allowance for leakage that does not compromise barrier integrity and is not identifiable is made for normal plant operation.

The unidentified leakage rate limit is established at 5 gpm rate to allow time for corrective action before the process barrier could be significantly compromised. This 5 gpm unidentified leakage rate is a small fraction of the calculated flow from a critical crack in a primary system pipe (Figure 5.2-10). Safety limits and safety limit settings are discussed in Chapter 16. Table 5.2-12 lists unidentified leakage rates directed into the Drywell Floor Drain Sump, and the associated Activity Concentrations.

5.2.5.4.2 Sensitivity and Response Times

Sensitivity, including sensitivity tests and response time of the leak detection system are covered in Subsection 7.6.1.

TABLE 5.2-13

ESTIMATED MONITOR RESPONSES

Source of Leak	Detector Type	Concentration Increase after 1 hr. @ 1 GPM(1)	Equilibrium Concentration in Containment @ 1 MPC	Equilibrium Concentration in Containment @ 10 MPC	Increase in Conc. Due to 1 GPM in 1 hr As % of Equilibrium @ 1 MPC	Increase in Conc. Due to 1 GPM in 1 hr As % of Equilibrium @ 10 MPC	Nominal Minimum Detectable Increase(4)	Detection Capability
		μCi/cc	μCi/cc	μCi/cc	%	%	%	GPM in 1 hr.
Main Steam Line	N. G.	6.0-7	8.0-6	8.0-5	7.5	.75	10.	1.3
	Part.	4.3-8	1.4-5	1.4-4	.326	.0326	20.	7.7+3
	Iodines	1.4-8	4.8-6	4.8-5	.29	.029	20.	8.0+2
Recirc. Line(3)	N. G.	<6.0-8	8.0-6	8.0-5	<.75	<.075	10.	>13
	Part.	1.7-6	1.4-5	1.4-4	<13.1	<1.31	20.	>11.5
	Iodines	9.4-7	4.8-6	4.8-5	19.	1.9	20.	12.0
Feed-water Line	N. G.	6.0-8	8.0-6	8.0-5	.75	.075	10.	13
	Part.	4.3-9	1.4-5	1.4-4	.0326	.00326	20.	7.7+4
	Iodines	1.4-9	4.8-6	4.8-5	.029	.0029	20.	8.0+3

(1) Plateout effects could further decrease the Particulate and Iodine concentrations.

(2) Calculated numbers assume a stable equilibrium concentration @ 1 MPC in containment and stable NUREG 16 coolant concentrations during the leak. Variations due to spiking and venting, etc. would invalidate the results.

(3) The recirc. line noble gas concentration is unknown but estimated to be less than feedwater since most noble gases will leave the reactor vessel with the steam without mixing with the recirc. water.

(4) Particulate and Iodine monitors accumulate activity on filters, thus the minimum detectable is estimated to be 20% of the accumulated activity, not 20% of the equilibrium conc. in containment.

TABLE 5.2-14

RCPB LEAK DETECTION MONITORS INSIDE
PRIMARY CONTAINMENT DRYWELL

Monitor		Elevation[1]	Azimuth[2]
A. Temperature Monitoring			
TE-15790A		754'	270°
TE-15790B		754'	70°
TE-15791A	(Top Hat)	797'8"	300°
TE-15791B	(Top Hat)	797'8"	110°
TE-15798A	(Outside ped.)	725'0"	255°
TE-15798B	(Outside ped.)	711'0"	60°
TE-15799A	(Under RPV)	711'0"	270°
TE-15799B	(Under RPV)	720'0"	85°
B. Radiation Detection[3]			
Channel A	- RPV head	790'0"	305°
	- Lower drywell	718'0"	280°
Channel B	- Upper drywell	750'0"	150°
	- Under RPV	725'0"	100°
C. Drywell Floor Drain Sump Level			
LE-16102A		704'	200°
LE-16102B		704'	25°
LE-16105A		704'	160°
LE-16105B		704'	340°
D. Drywell Equipment Drain Tank Level			
LE-16112		704'	220°
LE-16113		704'	225°

NOTES

(1) Approximate elevation above MSL.
(2) Approximate azimuth from center-line of reactor where 0° is due West.
(3) Radiation monitors are actually located outside containment; locations given are the sample extraction points.

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 211.242:

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 Q211.28, 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 Question 211.242 and refer to Subsection 5.2.5.1.2.3.1C(6).

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 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.

one is used, should be determined by the operator based on experience with the specific plant. A setpoint level of 2 to 3 times the background level during full power steady state operation may be useful for alarming large leaks and pipe breaks, but it would not always alarm for 1 gpm in 1 hour.

7) Conclusion

Due to the sum total of the uncertainties identified in the previous paragraphs the iodine and particulate monitors will not be relied upon for leak detection purposes but only as supporting instrumentation. The noble gas monitor is used to give supporting information to that supplied by the sump level monitor and it would be able to give an early warning of a major leak especially if equilibrium containment activity levels are low. However, the uncertainties and variations in noble gas leaks and concentrations would preclude the setting of a meaningful set point on the monitors.

5.2.5.1.2.4 Drywell Floor Drain Sump Monitoring System

The drywell floor drain sump monitoring system is designed to permit leak detection in accordance with Regulatory Guide 1.45.

5.2.5.1.2.4.1 System Description

Two drywell floor drain sumps are located in the primary containment for collection of leakage from vent coolers, control rod drive flange leakage, chilled water drains, cooling water drains, and overflow from the equipment drain sump.

The drywell floor drain sump is located at the drywell diaphragm slab low point. Unidentified leakages will, by gravity, flow down the slab surface into the floor drain sump. No floor drain piping system is employed. Piped inputs to the drywell floor drain sump are from clean system drains. No surveillance program is planned to detect piped equipment drain system blockage.

Small, unidentified leakages of concern flowing into the drywell floor drain sump will not be masked by larger, acceptable, identified leakages overflowing from the drywell equipment drain tank. The drywell equipment drain tank drains by gravity. During conditions of acceptable identified leakage rates, the gravity flow from the drywell equipment drain tank will be capable of preventing the drywell equipment drain tank from overflowing

to the drywell floor drain sump. The operation and control of the drywell equipment drain tank drain is the same as discussed in Subsection 5.2.5.1.2.4.1 for the drywell floor drain sumps.

Water flow rate better than 0.5 gpm can be obtained by monitoring changes of level over a time period. The following method of flow rate measurement was selected to comply with the requirements of Regulatory Guide 1.45. The necessary sensitivity is obtained by measuring the changes of level during a fixed time interval. For this purpose a continuous level measurement system is installed in each of the sumps. An electronic signal directly proportional to the actual sump level is applied to one pen of a two-pen recorder, to an electronic sample and hold device, and to an electronic differential switch. The sample and hold device, upon command from a timer, applies its output signal to the second pen of the two-pen recorder and to the second input of the electronic differential switch. The sample and hold unit's output signal level is regularly updated to the reference sump level signal.

The actual level signal of the sump and the reference level signal are continuously displayed on the two-pen recorder. The same signals are being monitored by the electronic differential switch. When the level signals differ by ± 50 gallons or more during a 50 minute period (equal to 1 gpm) an alarm is actuated on the local panel and on the control board in the main control room. The change in sump level per unit of time determines the leak rate and is available from the recorder slope for confirmation.

There is no reliable quantitative relationship between the sump level and the leakage rate from any source. The quantity is dependent upon the temperature and pressure of the containment and the leak and the location of the leak. Part of the leak will flash to steam; it may be partially trapped between insulation layers. Presumably the leakage will get to an equalibrium level where most of it ends up in the sump, unless the drywell is vented to relieve the pressure buildup. Since the Technical Specification allows 24-hour averaged leak limits, short term variations in the ability to relate the sump quantity to the leaked quantity are ignored, and its is assumed that all leakage reaches the sump. The errors introduced will not impair the ability to detect larger leaks which could rapidly result in severe accidents. Some leakage will no doubt be trapped in insulation etc., but no large reservoirs for leakage have been found.

Each sump is equipped with two submerged pumps which operate in an alternating mode. High sump level starts the pump automatically. Remote manual control of the pump is provided in the control room. Both pumps will be operating as soon as an

abnormal, high level is detected. The capability of each pump is such that normal expected flow rates can be easily accomplished.

5.2.5.1.2.4.2 Instrumentation

Magnetic float type continuous level probes are used to measure the fluid level and provide the signal for the recording of the actual sump level and the rate of level change in the control room. Excessive leak rate is alarmed on the local system panel and with a group trouble alarm in the control room. The leak rate can be observed by the control room operator.

5.2.5.1.2.4.3 Drywell Equipment Drain Tank Level Monitoring System

The drywell equipment drain tank collects identified leakage within the primary containment from reactor head seal leak off, bulkhead drain, refueling bellows drain, refueling RPV head vent, recirculation pump seals, reactor recirculation pump cooler drains, and RPV bottom drain.

All identified leakages which may have temperatures of 212° F or above are hard-piped directly to the drywell equipment drain tank. These leakages will tend to partially flash into steam and then condense in the drain pipe. This approach minimizes the possibility that leakage will escape as steam into the containment atmosphere prior to measurement in the equipment drain tank.

The drywell equipment drain tank drains by gravity. The drain tank's discharge valves automatically open when a predetermined high level in the tank is reached. The discharge valves close at a predetermined low level.

5.2.5.1.2.4.4 Sensitivity and Response Time of Measurement

The method for liquid leak detection in the primary containment is designed to meet the recommended water flow rate changes of 0.5 to 1.0 gpm as defined in Regulatory Guide 1.45.

The following assumptions and design considerations were incorporated:

a) Leak rate is directly proportional to the associated change in sump level.

b) Measurement of the drywell floor drain sump is discontinued during the pump operation and starts immediately after the pump stops. Measurement of the drywell equipment drain tank is discontinued when the tank's discharge valves are opened and starts immediately after the discharge valves close.

c) The selected measurement period T for the average change in level is 50 minutes

d) The drywell drain sumps have a capacity of 300 gal with a depth of 5 in.

   The drywell equipment drain tank capacity is 1000 gal with a depth of 42 in.

e) The level instrumentation accuracy is ± 5 percent of full range

f) Recorder response is better than 1 second for full range

g) Recorder chart size/drive speed: 4 in./3/4 in./hr.

h) The electronic differential switch setpoint will alarm rates less than or equal to one gpm.

These design factors allow a detection of 1 gpm flow rate within a 50 minute time period.

The operator can verify this leak rate on the recorder in the control room by observation of the average change of level.

5.2.5.1.2.4.5 Signal Correlation and Calibration

Drywell Drain Sump

The sump depth of 0-5 in. is displayed on a 0-100 percent recorder chart, which relates to the total sump capacity of 0-300 gal.

The average flow rate (changes of level) during the measurement period T is calibrated to read 0-4 gpm over the full chart range.

Drywell Equipment Drain Tank

The tank depth of 42 in. is displayed on a 0-100 percent recorder chart. This relates directly to the tank capacity of 1000 gal.

The average flow rate is calibrated to record 0-4 gpm over the full chart range.

5.2.5.1.2.4.6 Seismic Qualifications

The drywell floor drain sump, all drywell drain piping, and all instrumentation used to monitor drywell floor drain sump and equipment drain tank level will be qualified to operate following an OBE. The drywell equipment drain tank, drywell equipment drain tank cooling coil, and drywell floor drain sump pumps are not qualified to operate following an OBE.

Credit will be taken for monitoring unidentified leakage following an OBE thru the use of the drywell floor drain sump level monitoring system. The proper funtioning of at least one leakage detection system following an SSE is provided by the design of the air borne radioactivity monitoring system. Refer to Section 7.6.1b for description.

5.2.5.1.2.4.7 Testing and Calibration

Calibration of level sensors is possible by observing the change in level during the periodic pump down operations of the drywell
4 floor drain sump, and periodic draining of the drywell equipment drain tank.

For the drywell floor drain sump, the pumps are automatically started and stopped by mechanical level sensing switches (high and low level set points), but can also be operated manually, at any time, to check the calibration of the level sensors. In the event that the high-high level is reached, two pumps will operate. The drain tank discharge valves are opened
4 automatically on high level and can be operated manually at any time, to check the calibration of the level sensors.

5.2.5.1.3 Detection of Abnormal Leakage Outside the Primary Containment

Outside the drywell, the piping within each system monitored for leakage is in compartments or rooms, separate from other systems where feasible, so that leakage may be detected by area temperature indications. Each leakage detection system discussed below is designed to detect leak rates that are less than the technical specification leakage limits. The method used to monitor for leakage for each RCPB component may be seen in Table 5.2-8.

(1) Ambient and Differential Room Ventilation Temperature

A differential temperature sensing system is installed in each room containing equipment that interfaces with

9.3.3 EQUIPMENT AND FLOOR DRAINAGE SYSTEM

The Equipment and Floor Drainage System (EFDS) is provided throughout the plant to collect liquid wastes from their points of origin and transfer them to the Liquid Waste Management System, the plant discharge water treatment facilities, or the Storm Drainage System.

9.3.3.1 Design Bases

The EFDS is capable of handling the maximum expected influent. The turbine, reactor, circulating water pump, and diesel generator buildings influent is based upon 5 min of Fire Protection System operation. For the drywell and radwaste building the maximum expected leakage from equipment provides the design base.

The EFDS in the chlorine evaporator and sulfuric acid storage building is designed to drain rainwater from the acid unloading pad and from the open sides of the building.

The transformer gravel pits are sized to retain the oil contained in the transformers, in addition to the water volume from 15 min operation of the Deluge Fire Protection System.

The water treatment building acid unloading pad drainage system is designed to catch all acid leakage from the delivery trucks.

To prevent back flow into the Engineered Safety Features (ESF) equipment rooms, normally closed manual valves are provided in each drain line from those rooms.

Seismic Category I level switches, which are designed per IEEE 279 and 308 standards, alarm in the control room on ESF room high water level.

The EFDS is designed and arranged so that no inadvertent introduction of radioactive or potentially radioactive fluid to the segregated Sanitary and Storm Drainage Systems will occur.

Sump and drain tank pumps are designed to discharge at a flow rate adequate to keep the sumps and drain tanks from overflowing because of the expected influents outlined above. A backup pump is provided for each sump and drain tank, except for the condenser area transfer sump and the pipe tunnel sump. Backup pumps are started if the water level rises above the first pump start level.

The drywell equipment drain tank drains by gravity. The drain tank's discharge valves automatically open when a predetermined high level in the tank is reached. The discharge valves close at a predetermined low level.

Normally closed equipment and piping drains and vents discharging occasionally into the EFDS do not control the sizing of the system.

The sump and drain tank live capacities (water volume between pump start and stop levels) are based on not less than 5 min pump-out time with one pump.

The inlet pipes to the sumps are a minimum of 1 ft submerged at all times to prevent back gassing.

Vent lines from sumps containing potentially radioactive wastes are connected to the building ventilation systems.

Static oil interceptors with oil sumps precede the low conductivity sumps in the turbine and reactor buildings. Drainage lines from areas that are required to maintain an air pressure differential but drain to the same header are provided with water seals. Sequenced makeup water is provided to the water seals to maintain the air pressure differential. Where they penetrate the containment, the drywell floor drain sump pump and equipment drain tank discharge lines, including the containment isolation valves, are safety related. Δ

9.3.3.1.1 Codes and Standards

The Equipment and Floor Drainage Systems are designed, fabricated, and installed in accordance with the requirements of the applicable codes and standards shown in Section 3.2, Table 3.2-1.

9.3.3.2 System Description

9.3.3.2.1 General Description

The combined Equipment and Floor Drainage Systems provided for collection of various liquid wastes are shown on Figures 9.3-10, 9.3-11, and 9.3-12. The chemical waste sump of the water treatment building is shown on Figure 9.2-8.

a) For potentially radioactive liquid wastes:

1) The Liquid Radwaste (LRW) Collection System collects potentially radioactive liquid wastes at atmospheric pressure from equipment and floor drainage of the drywells, containments, reactor buildings, turbine building and radwaste building.

pumps to a pair of neutralization basins. Floor drains from the acid storage and chlorine evaporator building containing acid contamination are collected in a sump and automatically pumped to the neutralization basins, or if it is determined that the sump contains only rainwater, to the storm sewer.

The Sanitary Drainage System collects liquid wastes and some entrained solids discharged by all plumbing fixtures located in areas with no sources of potentially radioactive wastes, oily wastes, or acid wastes and conveys them to a sewage treatment facility described in Subsection 9.2.4.

The drain lines were designed to accommodate fire protection system design flow when actuated.

9.3.3.3 Safety Evaluation

With the exception of the drywell equipment drain and drywell floor drain sump discharge pipe penetrations through the primary containment and the associated isolation valves, the failure of the EFDS cannot affect plant safety. The drywell floor drain sumps and the associated leak detection instrumentation are designed to Seismic Category I. Pump operability is not required for the functioning of the differential level Drywell Floor Drain Leak Detection System.

Each of the six pump rooms (ECCS and RCIC) is provided with a separate drain line to the reactor building sump inlet header. A normally closed manual valve is provided in each drain line outside the pump room to prevent backflow. Seismic Category I level instrumentation provides for main control room alarms if the water level in the pump rooms rises above a preset value.

9.3.3.4 Tests and Inspections

All waste collection piping was hydrostatically tested prior to its embedment in concrete. Potentially radioactive drainage piping was tested to 75 psig, in accordance with ANSI B31.1.0. Nonradioactive oily, acid, sanitary, and storm drainage piping was tested to the equivalent of a 10 ft head of water for at least 15 min. The operability of Equipment and Floor Drainage Systems can be checked by normal use and through the instrumentation provided in the sumps and the main control room.

9.3.3.5 Instrumentation Application

High and low level switches are provided in each sump to start and stop the sump pump automatically. For sumps having two pumps, a separate level switch set at a higher level will start the second pump and simultaneously actuate an alarm in the main control room. The first pump to start is alternated on each pumping cycle to equalize run times. Table 9.3-10 shows the usage factors resulting from this provision.

The drywell equipment drain tank drains by gravity. The drain tank's discharge valves automatically open when a predetermined high level in the bank is reached. The discharge valves close at a predetermined low level. A

Oil sumps are equipped with level switches and high level alarms in the main control room.

To detect leaks, a level alarm will be provided in the main control room for each ESF equipment room.

The drywell floor drain sump and the drywell equipment drain tank temperatures are indicated, and a high alarm is annunciated on a local panel in the reactor building of each unit.

The levels in the drywell floor drain sumps and drywell equipment drain tanks are recorded, and a high level alarm is annunciated in the main control room. Refer to Subsection 5.2.5 and Section 7.6 for further details of the Leak Detection System.

9.3.4 CHEMICAL AND VOLUME CONTROL SYSTEM

Not applicable to BWR's.

9.3.5 STANDBY LIQUID CONTROL SYSTEM

9.3.5.1 Design Bases

The standby liquid control system is a special safety system and is designed in accordance with Seismic Category I requirements. It shall meet the following safety design bases:

(a) Backup capability for reactivity control shall be provided, independent of normal reactivity control provisions in the nuclear reactor, to be able to shut down the reactor if the normal control ever becomes inoperative.

TABLE 9.3-10

EQUIPMENT AND FLOOR DRAINAGE SYSTEM COMPONENT DESCRIPTION

	Equipment Nos.	Type	Quantity	Material Casing/imp.	Capacity, Each, gpm	TDH, ft	Usage Factor, Normal (1)	Driver hp	Design Pressure/Temp. psig/°F
PUMPS									
Drywell Floor Drains	1P-402A,B/1P-403A,B	Vert. Centr. Sump	4	SS	30	16	0.013	1	150/180
Drywell Floor Drains	2P-402A,B/2P-403A,B	Vert. Centr. Sump	4	SS	30	16	0.013	1	150/180
Reactor Building Drains	1P-225A,B	Vert. Centr. Sump	2	CI/Ni Hard	250	50	0.009	10	150/150
Reactor Building Drains	2P-225A,B	Vert. Centr. Sump	2	CI/Ni Hard	250	50	0.009	10	150/150
Turbine Bldg. Outer Area Drains	1P-127A,B	Vert. Centr. Sump	2	CI/Ni Hard	250	50	0.005	10	150/150
Turbine Bldg. Outer Area Drains	2P-127A,B	Vert. Centr. Sump	2	CI/Ni Hard	250	50	0.005	10	150/150
Turbine Bldg. Central Area Drains	1P-129A,B	Vert. Centr. Sump	2	CI/Ni Hard	250	50	0.005	10	150/150
Turbine Bldg. Central Area Drains	2P-129A,B	Vert. Centr. Sump	2	CI/Ni Hard	250	50	0.005	10	150/150
Turbine Bldg. Cond. Area Drains	1P-128	Vert. Centr. Sump	1	CI/Ni Hard	1000	55	0.005	25	150/150
Turbine Bldg. Cond. Area Drains	2P-128	Vert. Centr. Sump	1	CI/Ni Hard	1000	55	0.005	25	150/150
Turbine Bldg. Chemical Drains	1P-126A,B	Vert. Centr. Sump	2	SS	50	32	-	2	150/150
Turbine Bldg. Chemical Drains	2P-126A,B	Vert. Centr. Sump	2	SS	50	32	-	2	150/150
Chem. Radwaste Drain Tank	OP-132A,B	Horiz. Centr.	2	SS	50	31	-	2	150/155
Laundry Radwaste Drain Tank	OP-131A,B	Horiz. Centr.	2	CI/CI	50	31	-	2	150/155
Radwaste Building Drains	OP-338A,B	Vert. Centr. Sump	2	CI/Ni Hard	100	39	0.007	3	150/150
Radwaste Building Chem. Drains	OP-337A,B	Vert. Centr. Sump	2	SS	50	31	-	2	150/150
Pipe Tunnel Drains	1P-120	Vert. Subm. Centr.	1	CI	35	15	-	1	125/150
Circ. Water Pump House Drains	OP-549A,B	Vert. Centr. Sump	2	CI/Ni Hard	100	38	-	3	150/150
Diesel Generator Bldg. Drains	OP-553A,B	Vert. Centr. Sump	2	CI/Ni Hard	100	38	-	2	150/150
Cl and Acid Storage Bldg. Drains	OP-534A,B	Vert. Centr. Sump	2	SS	50	20	-	2	150/150
Water Treatment Bldg. Chem. Drains	OP-522A,B	Vert. Centr. Sump	2	SS	50	30	-	2	150/150

(1) Usage factors represent the fraction of time an individual pump is operating at the expected average waste input shown in Table 11.2-1.

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.

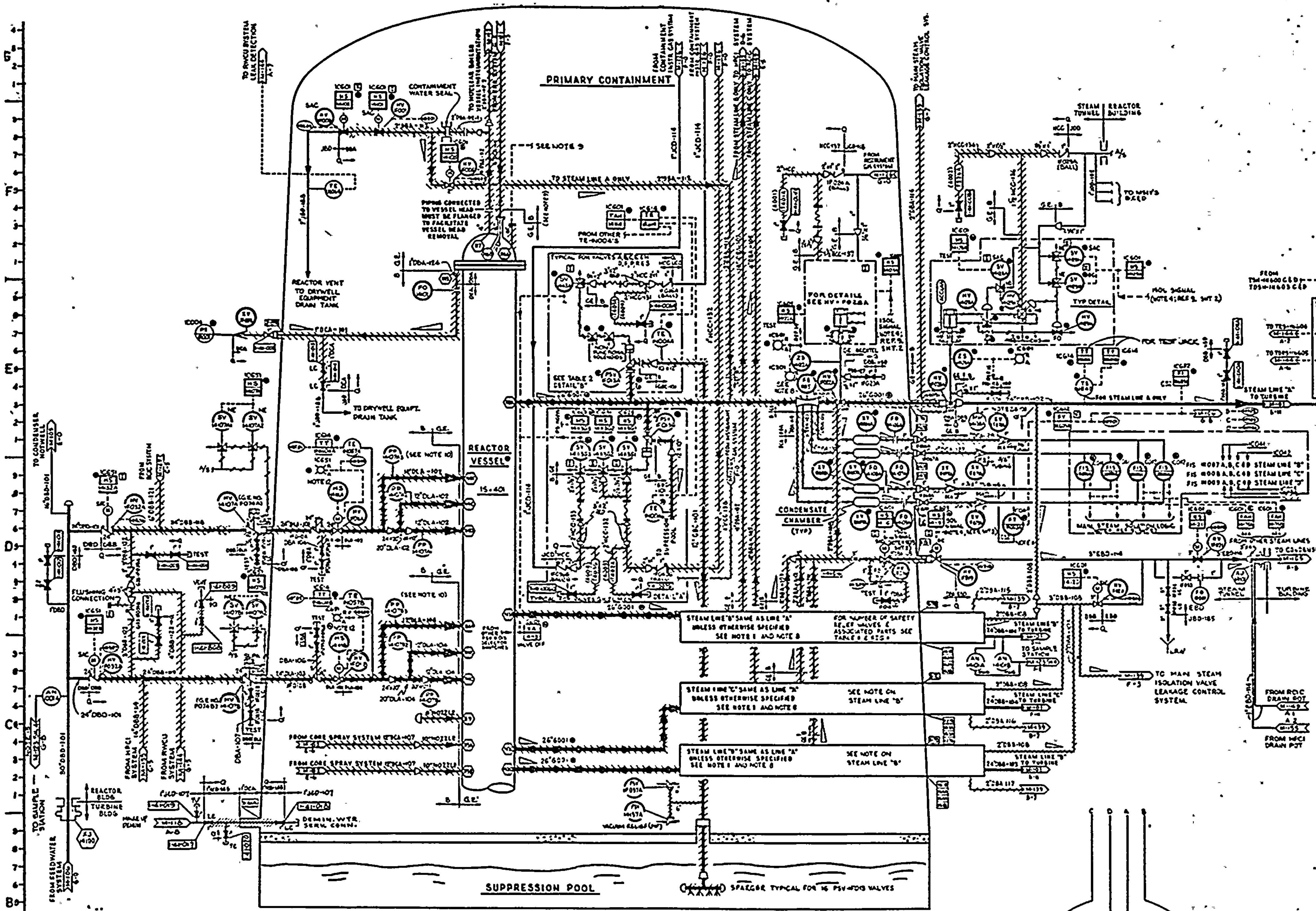
(b) "The main steam isolation valve packing leakoff piping is provided with a normally closed isolation valve, and is capped." "Keeping these leakoff connections isolated provides two sets of packings for limiting steam leakage." Estimate the increase in unidentified leakage as a result of the above feature.

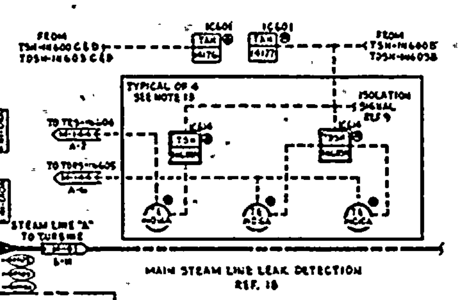
RESPONSE:

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 P&ID M-143, (FSAR Figure 5.4-2d). Also, revised P&ID M-161, Sht. 1 (FSAR Figure 9.3-11), 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. P&ID M-141 (FSAR Figure 5.1-3a), 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.





MAIN STEAM LINE LEAK DETECTION
REF. 18

NOTES:

1. STEAM LINES & ASSOCIATED EQUIPMENT ENCLOSED IN BOXES SHALL HAVE PART NRS. CORRESPONDING TO THEIR RESPECTIVE LINE LETTER UNLESS OTHERWISE NOTED.
   EXAMPLE: XXXXXB IS ON LINE B, YYYYYC IS ON LINE C.
2. THE G.E. MPL NUMBER FOR THIS SYSTEM IS B21.
3. LOCATE PRESSURE TEST POINTS PTM-30 A,B,C,D AS CLOSE AS POSSIBLE TO VALVES F020 A,B,C,D.
4. MAIN STEAM LINE ISOLATION IS INITIATED BY ONE OF THE FOLLOWING CONDITIONS:
   A. REACTOR LOW WATER LEVEL.
   B. MAIN STEAM LINE HIGH RADIATION.
   C. MAIN STEAM LINE HIGH FLOW.
   D. LOW TURBINE INLET PRESSURE.
   E. HIGH STEAM LINE TUNNEL TEMPERATURE.
   F. REACTOR HIGH WATER LEVEL.
5. AUTO DEPRESSURIZATION FUNCTION (ADF) IS INITIATED BY THE FOLLOWING SIMULTANEOUS SIGNALS:
   A. DRYWELL HIGH PRESSURE.
   B. REACTOR WATER LOW LEVEL.
   C. RHR OR CORE SPRAY PUMP MOTOR RUNNING.
6. MISCELLANEOUS VALVE NUMBERS USED ARE 1-41-001 THRU 1-41-020.
7. DELETED
8. FLOW ELEMENT FOR MAIN STEAM LINES B,C,D ARE N052, N053, AND N054 RESPECTIVELY.
9. GE SUPPLIES MATING FLANGE, EITHER NOZZLE 6A OR 6B MAY BE CONNECTED TO THE HEAD SPRAY LINE
10. PRESSURE TAPS TO CONFORM TO ASME PTC 6, 1964, PARA 4 34
11. FT C32-N003 A & B ARE ON 1C004, AND FT C32-N003 C & D ARE ON 1C005.
12. THE VALVE CONTROL SWITCH IS LOCATED ON THE VALVE OPERATOR
13. THE SECOND ELEMENT IS ONLY USED ON STEAM LINE "A" AND IS A SPARE ON LINE B, C & D.
14. SEE DESIGN SPEC. FOR NUCLEAR PIPING 8856-M-175 SECTION 4.3, FOR ADDITIONAL DYNAMIC SEISMIC SYSTEM ANALYSIS REQUIREMENTS ON LINES DBD-101, 102, 103, 104 & 105.
15. INSTALL ROOT VALVES (TWO 1" CCD-GB PER ANALYSIS NOZZLE) ON AN-B21-1D014 TO COMPLY WITH GE-NED SPEC. # 22A2708.

TABLE 2 CONTROL SWITCH ARRANGEMENT FOR DETAIL "B"

1C601 HS 141F13A1 — 1C201 HS 141F13A2 — 1C201 HSS 15113 — SV 141F13A — TYPICAL FOR 1F013 A, B & C

PSV-1F013	1C601 CONTROL SWITCH	1C201 TRANSFER SWITCH	1C201 CONTROL SWITCH	SOLENOID VALVE
A	HS-141F13A2	HSS-141F13A	HS-141F13A1	SV-141F13A
B	HS-141F13B2	HSS-141F13B	HS-141F13B1	SV-141F13B
C	HS-141F13C2	HSS-141F14A	HS-141F13C1	SV-141F13C

1C601 HS 141F13D — SV — TYPICAL FOR 1F013 D, E, F, H, P, R & S

PSV-1F013	1C601 CONTROL SWITCH			SOLENOID VALVE
D	HS-141F13D			SV-141F13D
E	HS-141F13E			SV-141F13E
F	HS-141F13F			SV-141F13F
H	HS-141F13H			SV-141F13H
P	HS-141F13P			SV-141F13P
R	HS-141F13R			SV-141F13R
S	HS-141F13S			SV-141F13S

TABLE 1. SAFETY / RELIEF VALVE LOCATION, SUFFIX ASSIGNMENT & ASSOCIATED EQUIPMENT

		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
SAFETY / RELIEF VALVES 1F013		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
RELIEF VALVE SPRING SET PRESSURE (PSIG)		1175	1146	1175	1175	1146	1185	1205	1175	1195	1205	1195	1205	1195	1185	1185	1185
ACCUMULATORS	(ADS) 1T402(X) 150 PSIG							A		B	C	D	E	F			
	1T403(X) 90 PSIG	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
TEMPERATURE ELEMENT N004		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
CHECK VALVES	1F036(X)	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
	1F040(X) (ADS)							G		J	K	L	M	N			
VACUUM BREAKER 1F037(X) & 1A 37(X)		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
PRESSURE SWITCH 1N022 (REF. B F-2)		A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S
PRESSURE SET POINT OF 1N022 (PSIG)		1086	1076	1086	1086	1076	1096	1116	1086	1106	1116	1106	1116	1106	1096	1096	1096
SOLENOID VALVES 4113 ASSIGN. FUNCTION	ADS (A)							A		A	A	A	A	A			
	ADS (A)							A		A	A	A	A	A			
	141F13X3 PRESS RELIEF (Y)	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

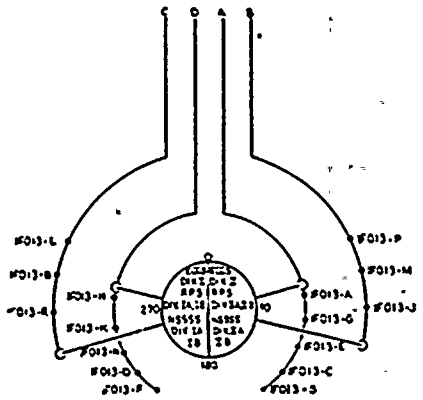


FIG. 1
SAFETY/RELIEF VALVE LOCATION AND SEPARATION ASSIGNMENT OF VESSEL INSTRUMENTATION

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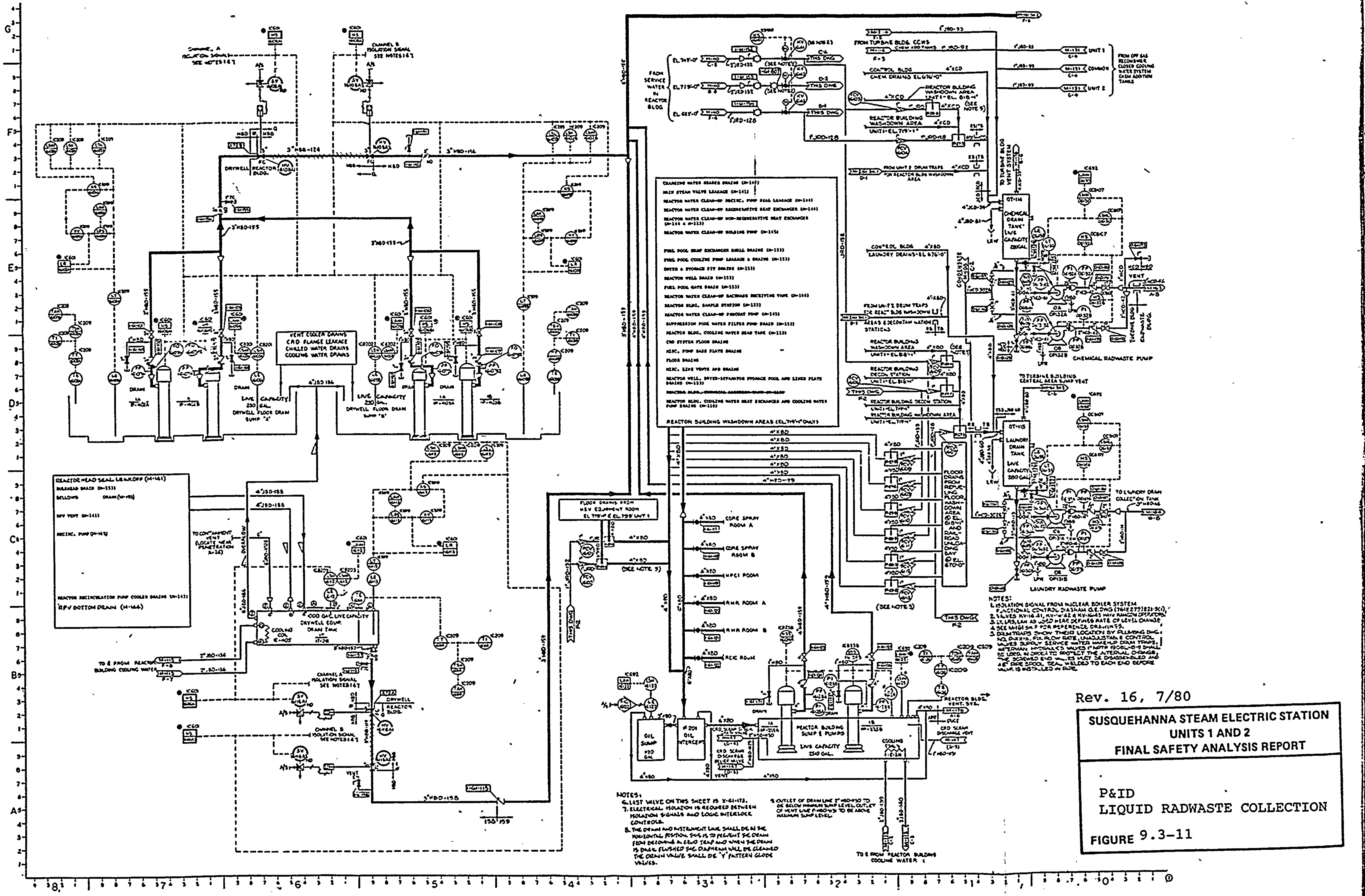
P & ID
NUCLEAR BOILER

FIGURE 5.1-3a



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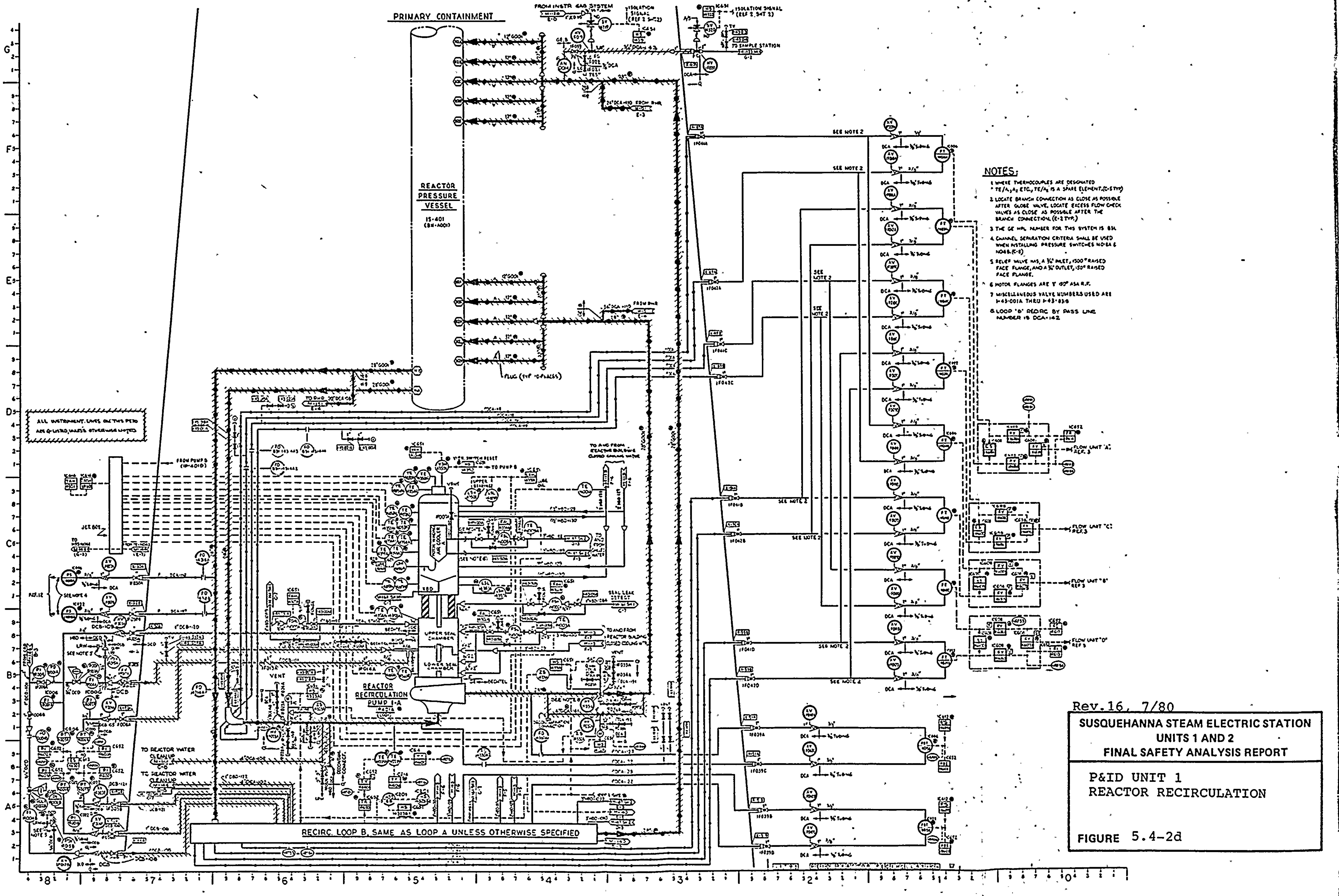
P&ID
LIQUID RADWASTE COLLECTION

FIGURE 9.3-11



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P&ID UNIT 1
REACTOR RECIRCULATION

FIGURE 5.4-2d

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 drywell. According to P&ID Diagrams M-149 and M-141, the RCIC pump discharge line connects to the feedwater line outside the drywell. 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. (Figure 10.4-5)

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 211.249:

Provide results of an analysis to demonstrate that no single failure will result in overpressurization 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 vessle 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. RHR steam supply piping: The steam supply piping for each individual heat exchanger passes through at least two valves in series. E11-F052 is the upstream isolation valve, and

E11-F051 is the downstream isolation valve. If E11-F052 is inadvertently opened, the downstream valve remains closed and no problem results since that portion of the system between these two isolation valves is designed for high pressure. If both valves should fail to close during the steam condensing operation due to controller failure, relief valve E11-F055 will relieve the excessive pressure by blowing down steam until high flow is sensed in the supply system (RCIC steam supply) and the steam supply line is isolated.

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. In addition, valve E11-F055 is normally available to relieve system pressure if required to do so during the standby mode. Valves E11-F126 and E11-F029 relieve shutdown line thermal expansion or leakage pressure; valves E11-F025 and E11-F055 relieve 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:

Figure 5.4-14a 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.

MODE A (SEE NOTE 15)

RX PRESS. 20 PSID ABOVE DRYWELL PRESSURE

POSITION ○	1				2A	3A	4A	5A	6A	7A	8A	9A	10A	11A					12A	13A	14A	15A	16
FLOW-GPM	—				12200								12200						12200			12200	—
PRESS-PSIA	14.7																						34.7
TEMP. °F	—				130/75																	130/75	—
MAX. PRESS. DROP-FEET							TDH=530				ΔP=73										ΔP=44		

MODE B (SEE NOTE 13 & 15)

RX PRESS. 20 PSID ABOVE DRYWELL PRESSURE

POSITION ○	1	2A/C	3A/C	4A/C	5A/C	6A/C	7A	8A	9A	10A	11A		12A	13A	14A	15A	16
FLOW-GPM	—	10650				10650	21300									21300	—
PRESS-PSIA	14.7																34.7
TEMP. °F	—	130/75														130/75	—
MAX. PRESS. DROP-FEET					TDH=530												

MODE C-1

HEAT REMOVAL PER HX 88 x 10⁶ BTU/HR (1 HX OPERATING)

MODE C-2 (SEE NOTE 2)

HEAT REMOVAL PER HX 122 x 10⁶ BTU/HR (1 HX OPERATING)

MODE D-1 (SEE NOTE 9)

RX PRESS. 1000 PSIG

HEAT REMOVAL PER HX 107 x 10⁶ BTU/HR (2 HX'S STEAM CONDENSING)

MODE D-2 (SEE NOTE 9)

RX PRESS. 1000 PSIG

HEAT REMOVAL PER STEAM CONDENSING HX 135 x 10⁶ BTU/HR (1 HX OPERATING) SEE NOTE 10

MODE D2 CONT'D

HEAT REMOVAL PER POOL COOLING HX 38.2 x 10⁶ BTU/HR (1 HX OPERATING)

MODE E

RX PRESS. 75 PSIG (SEE NOTE 8)

HEAT REMOVAL PER HX 215.6 x 10⁶ BTU/HR (2 HX'S OPERATING)

MODE F

RX PRESS. 0 PSIG

HEAT REMOVAL PER HX 44 x 10⁶ BTU/HR (2 HX OPERATING) SEE NOTE 10

MODE G (SEE NOTE 2)

RX PRESS. 0 PSID ABOVE DRYWELL PRESSURE

MODE H

MODE J

RX PRESS. 75 PSIG

SEE NOTE 12

MODE S

DESIGN PRESSURE & TEMPERATURE, GIVEN BELOW, IS FOR INFORMATION ONLY AND IS THE BASIS FOR THE DESIGN OF BWSD SUPPLIED EQUIPMENT

LPCI LINE — HX BYPASS LINE — SHUTDOWN SUCTION

STEAM TO HX — STEAM FROM HX — HEAD SPRAY LINE — STEAM TO POOL

CONTAINMENT SPRAY — SUPPRESSION SPRAY

TABLE 1 VALVE POSITION CHART (SEE NOTE 7)

BLANK SPACE INDICATES VALVE IS CLOSED
O = VALVE OPEN
P = STRAINER PLUGGED
T = VALVE THROTTLED
O-T VALVE OPENED TO THROTTLED
T-C VALVE THROTTLED TO CLOSED

TABLE 2 LIMITING LINE LOSS

LEGEND:
RX PRESS = REACTOR VESSEL PRESSURE
SOH = SHUTOFF HEAD (PUMPS)
TDH = TOTAL DYNAMIC HEAD

REFERENCE DOCUMENTS: — DWG. ITEM NO.
1. RESIDUAL HEAT REMOVAL SYSTEM P&ID — E11-1010
2. RECIRCULATION SYSTEM PROCESS FLOW DATA — B31-1040
3. NUCLEAR BOILER PROCESS DATA — B21-1080

MODES:
A. ACCIDENT W/RECIRC LINE BREAK IN SIDE II WITH ONE PUMP OPERATION AND STRAINER 50% PLUGGED, 20 PSID ABOVE DRYWELL PRESSURE
B. ACCIDENT W/RECIRC LINE BREAK IN SIDE II WITH TWO PUMP OPERATION AND STRAINER 50% PLUGGED, 20 PSID ABOVE DRYWELL PRESSURE
C-1 POST ACCIDENT CONTAINMENT SPRAY W/HEAT REJECTION WITH TWO PUMP OPERATION AND STRAINER 50% PLUGGED. (NORMAL SUPPRESSION POOL TEMPERATURE)
C-2 POST ACCIDENT CONTAINMENT SPRAY W/HEAT REJECTION WITH ONE PUMP OPERATION AND STRAINER 50% PLUGGED. (PEAK SUPPRESSION POOL TEMPERATURE)
D-1 REACTOR ISOLATION - 2HX STEAM CONDENSER.
D-2 REACTOR ISOLATION 1HX STEAM CONDENSER & 1 HX POOL COOLING.
E. NORMAL SHUTDOWN AFTER BLOWDOWN TO MAIN CONDENSER. (SEE NOTE 8.)
F. CONTINUATION OF NORMAL SHUTDOWN FROM PLANT MODE E. (0 PSIG) & FUNCTIONAL TEST FOLLOWING SHUTDOWN.
G. ACCIDENT W/RECIRC LINE BREAK IN SIDE II WITH STRAINER 50% PLUGGED AND ONE PUMP OPERATION, (0 PSIG), MAXIMUM RUNOUT CONDITION.
H. R.H.R. SYSTEM TEST DURING PLANT OPERATION.
J. MINIMUM FLOW BYPASS MODE.
S. SYSTEM ON STANDBY DUTY

NOTES:
1. EMPTY DATA BLANKS ARE TO BE FILLED IN BY AE (BASED ON HIS ARRANGEMENTS) AND SUBMITTED TO BWSD FOR REVIEW. IF SIDE I AND SIDE II ARE NOT SYMMETRICALLY ARRANGED, VALUES FOR BOTH SHALL BE SUBMITTED.
2. [illegible]
3. ELEVATIONS ARE NOT INCLUDED IN ΔP VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.
4. DASHED LINES INDICATES FLOW DOES NOT PASS THROUGH THESE POINTS.
5. SERVICE WATER CROSSTIE SHALL BE SIZED TO FLOW SUFFICIENT WATER TO FLOOD THE CONTAINMENT UP TO THE WATER SEAL, IN ONE WEEK.
6.
7. TABLE 1 INDICATES VALVE POSITIONS DURING VARIOUS MODES OF OPERATION.
8. SHUTDOWN OPERATION WILL BE INITIATED AT A MAXIMUM REACTOR VESSEL PRESSURE OF 100 PSIG.
9. THE MAXIMUM ALLOWABLE CONDENSATE RETURN TEMPERATURE TO RCIC PUMP DURING MODES D1 & D2 SHALL NOT EXCEED 140°F.
10. HEAT EXCHANGER DUTY BASED UPON 105% PLANT THERMAL RATING
11. THE WEIGHT OF WATER IN THE SHUTDOWN COOLING SUB-SYSTEM PIPING, INCLUDING THE HEAT EXCHANGERS AND PUMPS, SHALL NOT EXCEED 300,000 LBS AT 70°F TO PREVENT DILUTION OF STANDBY LIQUID CONTROL NEUTRON ABSORBER BELOW MINIMUM REQUIREMENTS.
12. PUMP S.O.H. 600 FT. MAXIMUM.
13.
14. [illegible]
15. FLOWS SHOWN FOR MODE A AND B ARE THE MINIMUM ALLOWABLE (TRUE) FLOW SHOWN FOR MODE G IS THE MAXIMUM ALLOWABLE MEASURED FLOW.

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RHR PROCESS DIAGRAM

FIGURE 5.4-14a

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 th orifice (D001) installed upstream of the bypass valve.

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:

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 will indicate abnormally high temperatures and will cause an alarm to annunciate in the control room. In addition, high temperature on the RHR side of the heat exchanger will produce a high temperature in the RHR service water. TE N005, located between the heat exchanger and the isolation valves will, 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.

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 by throttling the reactor coolant through the heat exchanger bypass using valve F048 and throttling total flow using valve F017. The operator determines the cooldown rate by monitoring reactor coolant temperature change with time.

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 limitng 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 disturbance 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 Fialure 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 insignficant effect on calculated values of CPR and peak pressure.

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.

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:

The Failure Mode and Effect Analysis and protection from common mode failures are not present in Appendix 15A.

Subsection 4.6.2 will be revised to cover this subject by the fourth Quarter of 1980.

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:

The final resolution of details for the application fo ODYN calculations in the transient licensing process has not yet been achieved. Generic efforts are underway to determine implementation. Reanalysis (utilizing ODYN) for key pressurization events will necessarily follow the generic resolution. No major change in transient margins is anticipated, as indicated by preliminary, generic analyses.

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 faster flow coastdown will result in less severe thermal power transient due to negative void reactivity coefficient. If the loss of offsite power is 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 ocur earlier in the former accident.

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 th 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 ft², 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°F should be 1.3 ft² (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 6.3-73. 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 6.3-73) is determined by

the difference between the recovery and uncovery time of the hot node for each break analyzed. The uncovery time genreally 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 6.3-73 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.

TABLE 6.3-3

SUMMARY OF RESULTS OF LOCA ANALYSIS

Break Size Location Single Failure		PCT (°F)	Peak Local Oxidation
Break Spectrum Analysis			
1.3 ft² Recirc. Discharge Break LPCI IV Failure		1874(1)	< 1.0%
1.0 ft² Recirc. Discharge Break LPCI IV Failure	Large Break Methods	1755(1)	< 1.0%
	Small Break Methods	1447(2)	< 1.0%
0.08 ft² Recirc. Discharge Break HPCI Failure		1531(2)	< 1.0%
1.9 ft² (DBA) Recirc. Discharge LPCI Injection Valve Failure		1818(1)	< 1.0%
4.2 ft² (DBA) Recirc. Suction LPCI Injection Valve Failure		1688(1)	< 1.0%

NOTES:

(1) CHASTE - large break methods
(2) Non-DBA reflood - small break methods

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 CS (core sprays) + HPCI (high pressrue 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

b. Recirculation Suction Breaks

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 ws 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. Small Breaks

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 sumamrized on Table 6.3-3 and in Figure 6.3-10 of the FSAR.

a. Recirculation discharge Breaks

1. HPCI failure (2 LPCI + 2 CS + 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 CS + ADS remaining)

Breaks (ft^2) analyzed:

1.0, .7, .6, .5, .45, .4, .35, .3

3. LPCI injection valve failure (HPCI + 2 CS + ADS remaining)

Breaks (ft²) 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 CS + ADS remaining)

Breaks (ft²) analyzed:

0.1, .08, .06, .04, .02

2. Diesel generator failure (HPCI + 3 LPCI + 1 CS + ADS remaining)

Breaks (ft²) analyzed:

1.0, .9, .8, .7, .6, .5, .4, .3, .25, .2

3. LPCI injection valve failure (HPCI + 2 LPCI + 2 CS + ADS remaining)

Breaks (ft²) 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.