GENERAL ELECTRIC

NUCLEAR POWER

SYSTEMS DIVISION

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MFN 200-82
JNF 57-82

December 27, 1982

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555

Attention: Mr. D.G. Eisenhut, Director
Division of Licensing

Gentlemen:

SUBJECT: IN THE MATTER OF 238 NUCLEAR ISLAND
GENERAL ELECTRIC STANDARD SAFETY ANALYSIS REPORT
DOCKET NO. STN 50-447

FINAL DRAFT RESPONSES TO COMMISSION'S NOVEMBER 15, 1982
INFORMATION REQUEST

Attached please find final draft responses to the Reactor Systems Branch questions of the Commission's November 15, 1982 information request on GESSAR II. Final draft responses to the Core Performance Branch Questions will be provided within two weeks following the second GE/NRC-CPB meeting to be held in mid-January 1983.

An amendment is scheduled for February 1983 to formalize the responses.

Sincerely,

Willa for

Glenn G. Sherwood, Manager
Nuclear Safety & Licensing Operation

GGS:td

Attachments

cc: F.J. Miraglia (w/o attachments)
D.C. Scaletti
C.O. Thomas (w/o attachments)
L.S. Gifford (w/o attachments)

E003

DRAFT RESPONSES TO
REACTOR SYSTEMS BRANCH QUESTIONS

440.01 Indicate whether the design of your proposed 238 nuclear island conforms to the LRG-II positions. If there are any known exceptions at this time, so indicate.

Response

As described in Appendix 1E (Sections 1E.1 through 1E.13), the GESSAR II positions conform to all of the Reactor Systems Branch LRG-II positions with one minor exception; 5-RSB. The GESSAR II position is provided in the response to NRC question 480.27.

440.02 **In Section 5.4.6.1.2.1 of your FSAR, you discuss the capability of**
(5.4.6) **performing functional testing of RCIC systems during normal plant operation. In this discussion, you state that system control provides automatic return from the test mode to the operating mode if system initiation is required. (This information is repeated in Section 5.4.6.2.4). In these sections, three exceptions are cited for which some operator action is needed. Accordingly, provide a discussion of these exceptions, including a brief description of the required operator actions, the time needed for these operator actions and whether all these actions can be performed from the control room. Additionally, address the apparent inconsistency between the sections cited above, and Section 5.4.6.2.5 in which there is no mention of any need for operator action.**

Response

A design flow functional test of the RCIC system may be performed during normal plant operation. The control system is designed so that the RCIC systems will return to automatic vessel injection mode if a system initiation signal occurs during a functional test. There are no exceptions to this design feature.

The three exceptions described in FSAR sections 5.4.6.1.2.1 and 5.4.6.2.4 are exceptions to an "automatic return from test to operating mode if system initiation is required." Note that these exceptions are not applicable to a functional test, but rather other system testing, such as component testing. Therefore, there is no inconsistency between sections cited above and sections 5.4.6.2.5 because operator actions are not required to align the system to object to the vessel during a functional test.

The three exceptions are discribed below. These exceptions describe different component tests, that if being performed when an initiation signal is present will require some operator action to enable the system to operate at rated condition.

Exception 1) If the operator is testing the manual station on the flow controller, he may need to turn the switch back to "automatic" if a systems initiation signal occurs so that rated flow will be discharged to the vessel. The system still operates but it will provide the slow that is the current setting on the flow controller.

Exception 2) If the operator is testing the steam isolation valves and a system initiation signal occurs, he must manually reopen the valves so that the system can operate.

Exception 3) If other system testing is being performed, the operator has indication of this in the control room and can take the necessary actions to align the system so that the automatic initiation function can occur.

All of these operator actions can be performed in the control room.

440.03 (5.4.6) In Table 1.8-1 and in Section 6.3.2.2 of your FSAR, you indicate that the design of the emergency core cooling systems (ECCS) provides adequate net positive section head (NPSH) for the pumps in this system in compliance with Regulatory Guide 1.1. However, no other reactor systems are mentioned. Accordingly, indicate whether the reactor core isolation cooling (RCIC) system also complies with this regulatory guide. Additionally, provide a description of your calculations for NPSH for the RCIC system for the most limiting operating conditions. Include appropriate isometric drawings, piping sizes, elevations and flow rates.

Response

The RCIC does comply to Regulatory Guide 1.1. The NPSH calculations are attached.

These calculations show that: NPSH available = 43.1 Feet

NPSH Required = 21 Feet

For the condition to take suction from the suppression pool,

FLOW = 716 GPM

TEMP = 140° F

Δ_p Suction Piping = 3.1 Feet

Min Static Head = 18.5 Feet

C F BRAUN & CO

FINAL (REVISED 1-26-76) E-51 **CALCULATIONS**

CUSTOMER	GENERAL ELECTRIC COMPANY, SAN JOSE	INDEX 115-4	PAGE 3
PROJECT	4840-P, TVA REACTOR ISLAND DESIGN	BY HEH	
SUBJECT	RCIC SYSTEM — PRESSURE DROP	DATE 10-30-75	
		CHK 7925	DATE 2/18/76

MODE A SUCTION FROM CONDENSATE STORAGE

FLOW = 716 GPM; TEMP = 100F DENSITY = 62.00 VISC = 0.66

8-INCH SUCTION; PIPE ID = 7.98"; X-SECT 0.3474 SQ FT

VOL FLOW = $\frac{716}{448.86}$ = 1.595 $\frac{CU FT}{SEC}$; V = 4.59 $\frac{FT}{SEC}$ V^2 = 21.07

$Re = \frac{(124)(7.98)(4.59)(62.0)}{0.66} = 4.27 \times 10^5$ f = 0.0039

STRAIGHT LINE = 62' $\Delta p = \frac{(0.00044)(0.0039)(62)(21.07)(62.0)}{0.665} = 0.208$ psi

FITTINGS	
ENTR (1)	1.5
TEE SIDE (1)	1.4
ELLS (5) =	1.0
TEES (STR) 4 =	0.4
GA VA (2)	0.3
CHK VA (1)	2.0
TOTAL	6.6

$\Delta p = (0.00011)(6.6)(21.07)(62.0) = .950$ psi

TOTAL FOR 8-INCH SECTION = 1.16 psi
+ 15% = 1.34 psi

12-INCH LINE (COND TANK TO 36-INCH HEADER)

(USE LENGTH & CONFIG USED FOR HPCS) PIPE ID = 12.0"; X SECT = 0.785

VOL FLOW = 1.595 $\frac{CU FT}{SEC}$; V = 2.03 FT/SEC; V^2 = 4.13

$Re = \frac{(124)(12)(2.03)(62)}{0.66} = 2.84 \times 10^5$; f = 0.0040

STRAIGHT PIPE TO COND TANK = 500 FT

$\Delta p = \frac{(0.00044)(0.004)(500)(4.13)(62)}{1.00} = 0.225$ psi

FITTINGS K = 4.8 $\Delta p = (0.00011)(4.8)(4.12)(62) = 0.135$ psi

TOTAL FOR 12-INCH LENGTH = 0.36 psi

36-INCH Δp: NEGL. ALLOW 1.0 psi FOR STRAINER

TOTAL = 2.47 psi ADD 15% = 2.84 psi

ELEVATION DIFF (ALLOW FOR 3'-0" LEVEL IN TANK) =

= (46'-2") - (-29-11¼) = 13'-9¼" | NPSH REQ'D = 21 FT

V.P. HEAD = $\frac{14.7 - 0.95}{0.43}$ = 32.0' | NPSH AVAIL = ~~24~~ 13.8' + 32' - 6.6 = ~~49.4~~ 39.2 FT

~~~ 41 FT
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FINAL (REVISED 1-26-76) E-51

CUSTOMER	GENERAL ELECTRIC COMPANY, SAN JOSE
INDEX	115-4
PAGE	7
PROJECT	4840-P, TVA REACTOR ISLAND DESIGN
BY	HEH
SUBJECT	RCIC SYSTEM · PRESSURE DROPS
DATE	10-31-75
CHK	HRS
DATE	2/18/76

MODE C SUCTION FROM SUPPRESSION POOL 8" AAB

FLOW RATE = 716 GPM; TEMP = 140F; DENSITY = 61.39 $\frac{LB}{CU\,FT}$; VISC = 0.455

$V = 4.59 \quad V^2 = 21.07$

STRAIGHT PIPE = 62.5'

$RE = \frac{(124)(7.98)(4.59)(61.27)}{0.455} = 6.37 \times 10^5$; $f = 0.0037$

$\Delta p = \frac{(0.00044)(0.0037)(21.07)(61.39)(62.5)}{0.665} = 0.198$ psi

TEES	(4) =	0.4
ELLS	(5)	1.0
TEES	(1)	1.4
GA VA	(2)	0.3
CH VA	(1)	2.0
ENTR		1.5
SUM		6.6

$\Delta p = (0.00011)(6.6)(21.07)(61.39) = 0.936$ psi

ADD 0.04 FOR SCREEN (SEE BELOW)

TOTAL FOR SUCTION LINE = 1.17 psi

ADD 15% = 1.35

SUCTION SCREENS SEE "CHEMICAL ENG. HANDBOOK 5th Ed"

$$\Delta h = \left(\frac{n}{C^2}\right)\left(\frac{1-\alpha^2}{\alpha^2}\right)\left(\frac{V^2}{2g_c}\right)$$ EQUATION 5-100, P. 5-37

ASSUME

1. TEE WITH SCREEN ON EACH OF TWO LEGS.
2. SQUARE WEAVE (APERTURE WIDTH = WIRE DIA. = 3/32" = 0.0078 FT)
3. EFFECTIVE SCREEN AREA IS FIVE TIMES PIPE X-SECT. FOR EACH SCREEN.
4. SCREENS ARE 50% PLUGGED.

THUS $\alpha = 0.25 \quad \alpha^2 = 0.0625$

$V = \frac{V_P}{5} = \frac{4.59}{5} = 0.918$ FT/SEC

$D_S = 0.0078$ FT ; $RE = \frac{(0.0078)(0.918)(61.39)}{(0.25)(0.455)(0.000672)} = 5750.$

$C = 1.4 \quad \Delta h = \left(\frac{1}{1.96}\right)\left(\frac{1-0.0625}{0.0625}\right)\left(\frac{0.843}{64.34}\right) = 0.100$ FT

$= 0.04$ psi

1 ATM. STATIC?

Δp SUCTION LINE = 1.35 psi = 3.1 FT P(H?)

140°F → 170°F = 7.4' NB

NPSH AVAILABLE = 34.5 + 18.5 − (3.1 + 6.8) = 43.1 FEET

or 35.7'

NPSH REQUIRED = 21 FEET

440.04 (5.4.6) **Discuss the overpressure protection design features of the low pressure portions of the RCIC system. Make reference to appropriate P&IDs to identify the low pressure piping and pressure relief devices.**

Response

The low pressure piping in the RCIC system is the pump suction piping from the suppression pool and the condensate storage tank and the turbine exhaust piping to the suppression pool.

The pump suction piping is protected from high pressure by the pump discharge check valve (E51-F065) and the normally closed motor operated isolation valve (E51-F013). The pump suction piping is also protected from overpressure by a relief valve (E51-F017).

The maximum expected turbine exhaust pressure is 10 PSIG. If a failure occurs in that line, the piping is protected from overpressure by two sets of redundant instrumentation. Two pressure transmitters are provided which trip the turbine on an exhaust pressure of 25 PSIG. The second set of instrumentation trips the system when turbine exhaust diaphrams rupture at approximately 150 PSIG. The logic for the first set is one-out-of-two; for the second set is two-out-of-two-twice.

440.05 (5.4.7) **In Section 5.4.7.1.5 of your FSAR, you provide a discussion of the reactor heat removal (RHR) system alternate shutdown cooling mode in which water is discharged through the automatic depressurization system (ADS) valves. Provide, or make reference to, test data confirming that the ADS valves used in your design can pass sufficient water in this mode for the most limiting conditions. Include a discussion of the applicability of the particular tests which you reference.**

Response

The description of the alternate shutdown cooling flow path presented in Section 5.4.7.1.5 has been superceeded by the EPG.

The EPG require the RHR/LPC loops with heat exchangers to be placed in suppression pool cooling.

The other low pressure injection pumps LPCS & LPCI "c" are used to force water through the S/RV.

Utilization of water directly from the suppression pool which has not been passed through the heat exchangers is also desireable from the consideration of avoiding RPV N T or head tension limit.

440.06 Provide a brief description in Section 5.4.7.2.3 of your FSAR, of the function and location of relief valve E12-F030 which is discussed on page 5.4-55.

Response

Relief valve E12-F030 is located in the RHR and ECCS flushing water discharge piping.

This relief valve prevents overpressurization of the flushing line due to thermal expansion or irregular leakage of water from high pressure sources.

440.07 (5.4.7) On page 5.4-5/ of your FSAR, you discuss the potential for water hammer caused by the sudden closure of the condensate discharge pressure control valve when the plant is in the steam condensing mode. Describe how the water level in the RHR heat exchangers is measured during this mode of operation including the type of sensor and its readout and the location of the readout. Briefly describe the procedure which will be used by the operator to control the water level to ensure that adequate protection against water hammer is provided.

Response

Water level in the RHR heat exchanger (HX) is measured by a differential pressure transducer E12-N008 that measures the difference in pressure between a constant head fluid column called a reference leg that is exposed to pressure in the steam region of the HX and a fluid column called the variable leg that is connected to the HX below the water level in the HX. The pressure sensed by the variable leg is directly proportional to the elevator of water above the variable leg top on the HX. The differential pressure is thus a direct indication of water level in the HX. The sensed water level is displayed on a water level indicating control E12-R604 in the main control on the RHR main control panel 601.

The potential for minor water hammer exist during refilling of the RHR HX when steam condensing is being terminated. The HX is refilled by closing the condensate discharge valve and allowing steam condensation to fill the HX until water level is increased to near the top of the HX tubes. Valve E12-F003 is then partially opened and the HX refilling completed by discharge from the discharge line fill pumps (EG:E12-C003). A minor overpressure (water hammer) may occur when the HX becomes completely full due to a sudden change in velocity (stopping) of water in the fill system.

Water hammer resulting from closure of the condensate discharge valves is not significant due to the relatively slow closure rate of these valves (30 seconds for E12-F026 and greater than 9 seconds for valve E12-F065).

440.08 (5.4.7) **State whether there is a potential for water hammer due to leaking valves in the steam line connecting the RCIC system with the RHR heat exchangers thereby causing steam pockets in the RHR lines in the steam condensing mode. If so, indicate what design features you have incorporated into your design and what operational procedures are available to prevent or mitigate such occurrences.**

Response

Heat transfer analyses of the piping configuration have shown that the expected steam leakage will be completely condensed and no steam pockets can form in the RHR system.

Two modes of operation were investigated.

CASE 1) The Standby Mode requires valves F051, F052, and F087 to be closed, with valves F047 and F003 to be open and the RHR piping filled with water. Assuming allowable leakage (as specified by the valve procurement specification) through valve F052, the steam will easily be condensed before reaching valves F051 and F087.

CASE 2) The Steam Condensing Mode requires valve F052 to be open, valves F087 and F047 to be closed and valve F051 to be controlling steam to the RHR heat exchanger where it condenses. The dead leg to valve F047 is of sufficient length to condense the steam immediately avove the valve and therefore any leakage through the valve would be condensate.

To produce any steam in the RHR water system, the valve leakage in each case would have to be in the order of ten times the specified allowable.

440.09 (5.4.7) **Discuss your system design provisions to prevent damage to the RHR pumps while operating in the LPCI mode under pump runout conditions during actuation of the ECCS and when operating in test modes.**

Response

The LPCI and suppression pool return liner are provided with restricting orifices E12-D004 and E12-D003 respectively. These orifices are sized during pre-operational test to limit discharge flow to acceptable valves with the discharge valve (s) fully open. Flow is limited to assure adequate post LOCA NPSH and to assure that other pump flow limits are not exceeded (eg: maximum allowable pumps flow specified by the pump supplier.

440.10 (6.3) **We indicate in the Standard Review Plan (SRP) that we do not allow credit for operator action for 20 minutes following a loss-of-coolant accident (LOCA). However, you describe certain operator actions to initiate containment cooling which are needed within 10 minutes following a postulated LOCA. Accordingly, provide an estimate of the time required by an operator to complete the necessary actions to initiate containment cooling assuming that a limiting single failure has occurred requiring the operator to utilize the backup system. Describe the indications available to the operator in the control room to aid him in taking the proper actions to confirm correct valve alignment and the alarms in the control room to make the operator aware of system failures and/or unavailabilities. Provide an estimate of the maximum time available for an operator to complete the planned or corrective actions, if this is necessary, before plant safety criteria are exceeded, assuming the most limiting conditions.**

Response

A maximum of 1.5 minutes is required for an operator to initiate one loop of the RHR in the suppression pool cooling mode assuming the loop to be placed in pool cooling is initially either in the LPCI or standby mode. This time includes valve stroke time.

The operator can verify proper operations of the RHR containment cooling function by monitoring heat exchanger tube (service water) and shell (suppression pool water) side flow rates. Since the heat exchanger heat removal characteristics are known, verification of flow rates assures heat removal. Other indications are available to aid the operator. These indications include: primary flow path valve position indicating lights, heat exchanger inlet and outlet temperature, RHR and service water pump running indications. Pump trips alarms would alert the operator to loss of flow if RHR pump trips.

Both loops of the RHR system would be placed in the containment cooling operating mode after initial core cooling/reflooding had been accomplished with LPCI "C", HPCS or the LPCS systems providing long term core cooling for most accident/LOCA scenarios.

Thus a single failure in the RHR "A" or "B" containment cooling loops would not reduce containment cooling to less than the rated post accident cooling capability for these accidents.

Accidents that involve failures in the ECCS and/or containment cooling systems are the only accident scenarios that may be expected to result in a single RHR system loop being placed in containment cooling (eg: a LOCA caused by a break in the HPCS Systems discharge line followed by a failure of Division I power would likely result in RHR loop "B" being placed in containment cooling and LPCI "C" used to maintain water level in the reactor). For these highly unlikely scenarios and the most limiting conditions (ie: containment cooling provided by a single RHR loop and assuring containment cooling is lost when the peak suppression pool temperature is reached) the operator would have a minimum of 30 minutes to restore containment cooling following failure of the RHR loop providing containment cooling before any plant safety criteria are exceeded. (ie: peak design suppression pool temperature).

440.11 (6.3) **Our position regarding passive failure during the long-term cooling phase of a LOCA requires, as a minimum, the assumption of the loss of a pump shaft seal or valve packing with its concomitant loss of fluid from the system in question. Show that the worst passive failure has been identified and that it can be isolated during the long-term cooling phase in the spectrum of postulated LOCA's. Valves in operating parts of the ECCS should be considered as well as in other systems serving as a boundary to prevent fluid from entering or leaving the ECCS.**

Response

Compared to all the leakage through the passive failures which includes the leakages from pump shaft seal, valve packing and postulated pipe crack in the ECCS' rooms, the leakage from the postulated pipe crack on the ECCS pump discharge is identified as the worst passive failure during the long-term cooling phase of a LOCA. The leakage rate from each ECCS pump room are listed below:

LPCS Rm - Maximum leakage rate 642 GPM

HPCS Rm - Maximum leakage rate 1,475 GPM

RHR "C" Rm - Maximum leakage rate 753 GPM

RCIC Rm - Maximum leakage rate 397 GPM

RHR "A" or "B" Rm - Maximum leakage rate 755 GPM

The flood can be detected by the safety grade flood level instrumentation located in the floor drain sump in each ECCS room and alarmed in the main control room. The procedures and timing to isolate the affected room are described in Sections 3.4.1.1.2.4.

Valves are designed to prevent leakage out of the ECCS systems due to following design features.

1. All Valves (globe valves and gate valves) are provided with a back seat to prevent leakage into the gland chamber, when valve is on the fully open position. This design feature will minimize the fluid leakage out of the system.

2. The process flow are designed to flow underneath the valve seat, when valve is in it's fully open position. This design feature will minimize the fluid leakage through the valve packing.

   With above valve design feature, valves in operating parts of the ECCS can be considered as a boundary to prevent fluid from entering and/or leaving the ECCS.

440.12 (6.3) **Indicate what provisions you have made to protect from the effects of cold weather, the level instrumentation for che condensate storage tank and the lines from this tank leading to the RCIC and HPCS systems.**

Response

Condensate lines leading to RCIC and HPCS systems with reactor island are located within the Auxiliary Building-thus are protected from cold weather.

440.13 (6.3) **Identify the relief valve discharge lines in the ECCS which penetrate primary containment and have outlets below the surface of the suppression pool. Since these lines form part of the primary containment, our concern is that excessive dynamic loads resulting from waterhammer during relief valve actuation may cause cracking or rupture of these lines. Provide additional information concerning measures you have taken to prevent this type of damage to these lines.**

Response

All ECCS relief valves, except RHR relief valve number E12-F055, that discharge to the suppression pool, discharge subcooled water. Actuation of these relief valves are caused by small quantities of water that either leak back from the reactor and/or result from thermal expansion of water in the ECCS lines. Since these actuation conditions are characterized by pressure slowly approaching the relief valve set point and discharge of small quantities of water, significant water hammer and dynamic loads do not occur.

RHR relief valve number E12-F055 is provided to prevent overpressurization of the RHR heat exchanger during the steam condensing mode (SCM). Actuation of this relief valve would occur if the steam pressure reducing valve number E12-F051 failed open during the SCM and steam would be discharged to the suppression pool. The dynamic loading associated with actuation of E12-F055 during the SCM will be submitted March 31, 1983 when the response to similar containment questions are submitted.

440.14 (6.3) **Discuss your design provisions which permit manual override on the ECCS subsystems once they have received an ECCS initiation signal. Provide a discussion of any lockout devices or timers which 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 then secure several of the ECCS pumps to permit the manual starting of the RHR service water pumps without overloading the diesel-generators. Discuss your design provisions which permit the operator to shutdown these ECCS pumps after they have been automatically started.**

Response

The ECCS design control logic is based on the principal that safety functions required for short term core cooling (ie: less than ten minutes) shall be automatically initiated. Further, that overall plant safety and ECCS reliability is enhanced by permitting operators to stop and secure ECCS at any time during a transient or accident condition. Reliability and safety are enchanced by this design principal due to reduced control logic complexity and the ability of the operator to control unplanned/off-design/degraded plant conditions (eg: the operator could secure an LPCS or LPCI that had a passive failure in the system outside of the containment). The only blockout devices or timers provided are in the RHR/LPCI system. A timer prevents closure of the heat exchanger bypass valve E12-F048 or initiation or containment spray until ten minutes following receipt of a LOCA signal to assure the full capacity of the LPCI system for this time period. These interlocks do not degrade ECCS reliability or significantly hamper freedom of operator action. The standby AC power supply system has sufficient capacity to operate the ECCS and essential support systems such as service water pumps such that shedding of ECCS loads/pumps is not required to permit operation of these support systems.

440.15 **On page 6.3-12 of your FSAR, you indicate that there is an interlock**
(6.3.2) **on high drywell pressure to maintain the HPCS flow although there is a high water level condition in the vessel. We are concerned that maintaining HPCS flow under these conditions could lead to flooding of the steam lines and possibly damage the safety-relief valves. Accordingly, provide justification for not removing the high drywell pressure interlock.**

Response

The NRC required, in approximately 1974, the installation of the high drywell pressure interlock that prevents automatic termination of HPCS injection if the high drywell pressure signal exists. This interlock has recently been discussed with the NRC and the NRC has withdrawn the requirement for this interlock.

The GE standard design has therefore deleted this interlock. Appropriate sections of the GESSAR II will be revised (eg. page 6.3-12, Chapter 7) to reflect deletion of the interlock. *Also, refer to question 421.41 and it's associated response.*

440.16 (6.3.2) The ECCS contains manual as well as motor-operated valves. There is a possibility that manually operated valves might be left in the wrong position and remain undetected prior to the occurrence of an accident. Examples of such valves include those pairs of normally closed valves which are in the test/drain lines between the HPCS, LPCS and LPCI isolation valves. Provide a list of all manually-operated valves in the safety-related reactor systems, including their location and type. Discuss the methods which will be used to minimize such an occurrence. It is our position that you provide indication in the control room for all critical ECCS valves (manually or motor-operated).

RESPONSE

A list of all manually-operated valves in the safety-related reactor systems, including their location and type, which have indication in the control room is provided as follows:

SYSTEM	VALVE MPL NO	LINE LOCATION	VALVE TYPE
RHR	E12-F010	20" RHR 19-EAA	20" Gate - Hand operated
	E12-F029A	18" RHR 7-BAB	18" Gate - Hand operated
	E12-F029B	18" RHR 13-BAB	18" Gate - Hand operated
	E12-F029C	18" RHR 21-BAB	18" Gate - Hand operated
	E12-F039A	12" RHR 10-EAA	12" Gate - Hand operated
	E12-F039B	12" RHR 16-EAA	12" Gate - Hand operated
	E12-F039C	12" RHR 22-EAA	12" Gate - Hand operated
LPCS	E21-F007	12" LPCS 3-EAA	12" Gate - Hand operated
	E21-FF121	4" LPCS 6-BAB	4" Globe - Hand operated
HPCS	E22-F036	12" HPCS 4-EAA	12" Gate - Hand operated
	E22-FF124	4" HPCS 20-EAB	3" Globe - Hand operated
RCIC	E51-FF210	6" RCIC 2-EAB	6" Gate - Hand operated
	E51-FF211	8" RCIC 1-AAB	8" Gate - Hand operated
	E51-FF222	3" RCIC 1 -EAB	1" Globe - Hand operated
HPCS SW (ESW Div 3)	P40-FF001	8" CSSW 1-AKC	8" Butterfly - Hand operated
	P40-FF002	8" CSSW 2-AKC	8" Butterfly - Hand operated
ESW (Div 1 & 2)	P41-FF001A	10" ESW 3-ADC	10" Butterfly - Hand operated
	P41-FF001B	10" ESW 43-ADC	10" Butterfly - Hand operated
	P41-FF002A	10" ESW 4-ADC	10" Butterfly - Hand operated
	P41-FF002B	10" ESW 44-ADC	10" Butterfly - Hand operated
	P41-FF006A	10" ESW 4-ADC	10" Butterfly - Hand operated
	P41-FF06B	10" ESW 44-ADC	10" Butterfly - Hand operated

Each of the above valves is monitored by the Performance Monitoring Systems (PMS) for individual alarming of "not fully open". These valves are then grouped by system and division with a status light in the control room for system level indication of "manual valve misaligned". In addition to the status light, a connection is made to the "system out of service" alarm such that an alarm results whenever the status light is on.

Please note that manually-operated valves list in last pages are for ECCS system main process loops. Other valves such as on the test/drain lines between isolation valves etc, are not included in the above list because it is not a part of an ECCS loop.

440.17 (6.3.2) **In the section of your FSAR describing the HPCS, LPCS and LPCI systems, you state that the motor-operated isolation/safety injection valves are capable of opening against the maximum differential pressure expected for these systems. Briefly describe, or make reference to, the tests which will be performed to verify valve opening capability. State the margin existing between the pressure differential against which the valves are capable of opening and the expected operating pressure differential.**

Response

The maximum operating differential pressure across the LPCS and LPCI motor-operated safety injection valves occurs when the systems are initiated and injection valves opened prior to the systems pumps starting. Under these conditions the valves are signaled to open when reactor pressure decreases to slightly less than the system discharge line design pressure upstreams of the valves and the differential pressure is slightly less than the systems design pressure. The design pressures are 600 PSIG for LPCS and 500 PSIG for LPCI. The LPCI valves are designed to open against a differential pressure of 550 PSI and the LPCS injection valve is designed to open against a differential pressure of 660 PSI and 60 PSI is provided for the LPCI and LPCS injection valves respectively.

For most LOCA scenarios, the LPCI LPCS pumps will be up to speed before reactor pressure decreases to the injection valve reactor pressure opening permissive pressure which is slightly less than the discharge line design pressure. Therefore, for most LOCAs the injection valve will be signaled to open against a differential pressure approximately equal to discharge line design pressure minus system shutoff pressures of 289 PSID*and for LPCS and 225 PSID for LPCI. Hence for most LOCA scenarios the opening margin is 660 - 289 = 371 PSI for LPCS and 550 - 225 = 325 PSI for LPCI.

The maximum HPCS operating differential pressure occurs when the HPCS is initiated at zero reactor pressure. Under these conditions the maximum differential pressure is equal to the HPCS system shutoff pressure of 1495 PSID*. The injection valve is designed to open against a differential pressure of 1575 PSI. Thus a minimum margin of 1575 PSI - 1495 PSI = 80 PSI is provided for the HPCS injection valve. If the HPCS is signaled to initiate with the reactor at the normal 1000 PSI operating pressure a margin of 1575 PSI - 1000 PSI - 575 PSI is provided.

The capability of the injection valves to open against required differential pressure is verified during pre-operational test by increasing the pressure on one side of the injection valve to the design valve and than opening the injection valves.

** As for example, for LPCI, valve E12-F039 in the drywell can be closed and the discharge line pressure between E12-F039 and the injection valve increased by connecting a pressure source to the test connection downstream of the injection valve (eg: the test connection with valves E12-F057 and E12-F056); pressurizing the time to 550 PSI and then opening the injection valve.

*For LPCS/LPCI, PSID = differential pressure between reactor and drywell.
For HPCS, PSID = differential pressure between reactor and suction source.

**Verification that this test is specified in the pre-operational test specifications must be obtained.

440.18 (6.3.3) You have proposed certain changes for your ECCS evaluation model; these changes are currently under review. State which, if any, of the proposed changes were used in the lead plant ECCS performance evaluation described in Section 6.3.3 of your FSAR.

Response

None of the proposed changes were used in the lead plant ECCS performance evaluation described in section 6.3.3 of GESSAR II. Once the NRC approves the new ECCS models they will be optional for use in future GESSAR II plants.

440.19 (15.0) **Provide a listing of the transients and accidents analyzed in Chapter 15 of your FSAR for which operator action is required to mitigate their consequences. Describe in either the NSOA tables or in the sequence of events listed in Chapter 15, the manual actions or automatic system changes required to place the plant in a cold shutdown condition. This desciption should include the estimated times at which these manual actions are required.**

Response

A listing of the transients and accidents analyzed in Chapter 15 for which operator action is required for safety related reasons to mitigate their consequences is as follows:*

EVENT	GESSAR II SECTION
o Recirculation Loop Flow Control Failure with increasing flow	15.4.5
o Inadvertent opening of a Safety/Relief valve	15.1.4
o RHR Loss of Shutdown Cooling	15.2.9
o Pipe break inside and outside containment	15.6.4 & 15.6.5
o Reactor shutdown from anticipated transients without scram	15.8
o Reactor shutdown without control rods	9.3.5

The manual actions or automatic system changes required to place the plant in a cold shutdown condition will vary initially according to the initiating event and resulting consequences. Rapid cool down may not be required for some events while other events may create a situation just in reverse. Manual actions not safety related (i.e., securing the turbine and condenser) are usually always performed to protect systems and hardware from unnecessary wear and tear. On the other hand some safety related manual actions are required to be performed by the operator and there is sufficient time, for the operator to perform such action (e.g.) upon discharge of SRV to suppression pool, the operator may have to put the RHH in the pool cooling mode.

It should be known that each utility writes their own procedure for a normal planned shutdown. For shutdowns other than normal, G.E. has prepared NEDO 24934 which documents the Emergency Procedure Guidelines reviewed and approved by the NRC. These guidelines apply to BWR product lines 1 through 6 there by making them applicable to GESSAR II which is based upon the BWR 6 product line. The EPG addresses all automatic systems and manual operator actions required to achieve coed shutdown of the reactor in response to documented emergencies. G.E. does suggest a method/procedure to effect a cold shutdown (BWR 6 Perry Simulation). G.E. also strongly recommends that the operator follows a documented procedure that limits the maximum temperature reduction of the reactor to 100°F/hr. In addition, some events do not require cold shutdown because they allow the reactor to remain at partial pressure and temperature condition depending upon the degree of severity of the problem (e.g.) simple active component failure. Most automatic actions initiated by an event are monitored and verified by the operator who has a manual alternative action should the automatic action fail to initiate.

*Most of the Safety related actions identified in Chapter 15 are automatic in nature. The key operator role is to confirm automatic actions.

440.20 (15.0) **We state in the SRP (e.g., in Section 15.1) that for anticipated transients, the most limiting plant systems single failure shall be identified and assumed in the analysis. Accordingly, describe the worst single failure for each event analyzed in Chapter 15 of your FSAR. Provide analyses including these postulated failures for the five most limiting events identified in your FSAR.**

Response

This question is currently under evaluation. A final draft response will be provided no later than January 14, 1983.

440.21 (15.0.4) **Provide further justification for your statement in Section 15.0.4.5 that applicants referencing your FSAR will need to supply analysis results only for events identified as limiting in your FSAR since the relative results will not change. Where differences in specific plants exist (e.g., bypass capability), it is our position that other transients and not just limiting transients from your FSAR, should be reanalyzed.**

Response

The GESSAR II design utilizes 35% bypass capability. Should the applicant's design process identify other than 35% bypass capability then this difference or any similar differences to GESSAR II will be addressed by the applicant.

See GESSAR II text page 15.0-13. (as per attached)

15.0.4.5 Evaluation of Results (Continued)

2. Limiting Decrease in Core Coolant Temperature Event: Loss of Feedwater Heating (manual control), and

3. Limiting Temperature Decrease/Pressurization Event Feedwater Controller Failure (Maximum Demand).

hat these two events are infrequent events. And

The Load Rejection and Turbine Trip without Bypass Events are categorized as ~~infrequent~~ MODERATE events BY THE NRC. HOWEVER, IT IS GE's POSITION ~~but~~ are included in this list as they are not limiting events. Results reported in Table 15.0-2 for pressurization events were calculated using ODYN Option A. The resulting initial core MCPR operating limit is 1.18.

Results of the transient analyses for individual plant reference core loading patterns will differ from the standard plant results. However, the relative results between CORE ASSOCIATED events will not change. Therefore, only the results of the identified limiting events need to be provided by the Applicant. ~~These results will be provided in the format given in~~ RESULTS WILL DIFFER FROM STANDARD PLANT FOR EACH IDENTIFIED EVENT GIVEN IN Tables 15.0-4 and 15.0-5, depending upon the applicants core management activities and procedures.

15.0.4.5.1 Effect of Single Failures and Operator Errors

The effect of a single equipment failure or malfunction or operator error is provided in Appendix 15A.

15.0.4.5.2 Analysis Uncertainties

See Appendix A, Subsection A.15.0.4.5.2 of Reference 1.

440.22 (15.0.4) **In Section 15.0.4.5 and in Table 15.0-2 of your FSAR, you classify as "infrequent", the events identified as Load Rejection without bypass and Turbine Trip without bypass. Until approval is granted to reduce their classification, it is our position that these events be classified as "moderate" frequency events.**

Response

Load Rejection without Bypass and Turbine Trip without Bypass are events categorized as "moderate" by the NRC. Also it is the LRG II position (Section N.E-12) that such events be categorized as moderate frequency events. However the G.E. position is that these two events should be categorized as non-limiting infrequent events. See pages GESSAR 15.0-13,15.0-21,15.2-7,15.2-11 15.2-13. (as per attached)

15.0.4.5 Evaluation of Results (Continued)

2. Limiting Decrease in Core Coolant Temperature Event: Loss of Feedwater Heating (manual control), and

3. Limiting Temperature Decrease/Pressurization Event Feedwater Controller Failure (Maximum Demand).

The Load Rejection and Turbine Trip without Bypass Events are categorized as ~~infrequent~~ MODERATE events BY THE NRC. HOWEVER IT'S GE'S POSITION that these two events ARE INFREQUENT EVENTS AND ~~but~~ are included in this list as they are not limiting events. Results reported in Table 15.0-2 for pressurization events were calculated using ODYN Option A. The resulting initial core MCPR operating limit is 1.18.

Results of the transient analyses for individual plant reference core loading patterns will differ from the standard plant results. However, the relative results between CORE ASSOCIATED events will not change. Therefore, only the results of the identified limiting events need to be provided by the Applicant. ~~These results will be provided in the format given~~ THE RESULTS WILL DIFFER FROM STANDARD PLANT FOR EACH IDENTIFIED EVENT GIVEN in Tables 15.0-4 and 15.0-5, depending upon the APPLICANTS CORE MANAGEMENT ACTIVITIES & PROCEDURES.

15.0.4.5.1 Effect of Single Failures and Operator Errors

The effect of a single equipment failure or malfunction or operator error is provided in Appendix 15A.

15.0.4.5.2 Analysis Uncertainties

See Appendix A, Subsection A.15.0.4.5.2 of Reference 1.

Table 15.0-2

RESULTS SUMMARY OF APPLICABLE TRANSIENT EVENTS

Sub-section I.D.	Figure I.D.	Description	Maximum Neutron Flux (% NBR)	Maximum Dome Pressure (psig)	Maximum Vessel Bottom Pressure (psig)	Maximum Steam Line Pressure (psig)	Maximum Core Average Surface Heat Flux (% of Initial)	ΔCPR -	Frequency Category*	Duration of Blowdown: No. of Valves First Blow-down	Duration of Blowdown: Dura-tion of Blow-down (sec)
15.1		DECREASE IN CORE COOLANT TEMPERATURE									
15.1.1	15.1-1	Loss of Feedwater Heater, Auto Flow Control	111.5	1045	1087	1034	105.8	**	a	0	0
15.1.1	15.1-2	Loss of Feedwater Heater, Manual Flow Control	124.2	1060	1102	1047	113.7	0.12	a	0	0
15.1.2	15.1-3	Feedwater Cntl Failure, Max Demand	124.3	1163	1193	1159	105	0.10	a	19	5
15.1.3	1.51-4	Pressure Controller Fail - Open	104.2	1138	1161	1136	100	**	a	10	5
15.1.4		Inadvertent Opening of Safety or Relief Valve			See Text						
15.1.6		RHR Shutdown Cooling Malfunction Decreasing Temp			See Text						
15.2		INCREASE IN REACTOR PRESSURE			See Text						
15.2.1	15.2-1	Pressure Controller Downscale Failure	156.8	1187	1221	1181	102.6	0.09	a	19	7
15.2.2	15.2-2	Generator Load Rejection, Bypass-On,	128.2	1160	1189	1157	100	**	a	19	5
15.2.2	15.2-3	Generator Load Rejection, Bypass-Off,	198.7	1203	1233	1202	102.7	0.08	~~a~~ b	19	7
15.2.3	15.2-4	Turbine Trip, Bypass-On	114.5	1158	1188	1155	100	**	a	19	5
15.2.3	15.2-5	Turbine Trip, Bypass-Off	179.4	1202	1231	1201	101.3	0.05	~~a~~ b	19	7
15.2.4	15.2-6	Inadvertent MSIV Closure	105.3	1177	1207	1174	100	**	a	19	5
15.2.5	15.2-7	Loss of Condenser Vacuum	113.7	1157	1186	1153	100	**	a	19	5
15.2.6	15.2-8	Loss of Auxiliary Power Transformer	104.2	1100	1112	1098	100	**	a	1	5
15.2.6	15.2-9	Loss of All Grid Connections	105.3	1159	1184	1156	100	**	a	19	7
15.2.7	15.2-10	Loss of All Feedwater Flow	104.2	1045	1086	1034	100	**	a	0	0
15.2.8		Feedwater Piping Break See Table 15.0-2, event 15.6.6									
15.2.9		Failure of RHR Shutdown Cooling				See Text					

*Frequency definition is discussed in Subsection 15.0.4.1.
**See Subsection 15.0.4.5.
[a]Moderate frequency
[b]Infrequent

15.2.2 Generator Load Rejection

15.2.2.1 Identification of Causes and Frequency Classification

15.2.2.1.1 Identification of Causes

Fast closure of the turbine control valves (TCV) is initiated whenever electrical grid disturbances occur which result in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent excessive overspeed of the turbine-generator (T-G) rotor. Closure of the main turbine control valves will cause a sudden reduction in steam flow, which results in an increase in system pressure and reactor shutdown.

15.2.2.1.2 Frequency Classification

15.2.2.1.2.1 Generator Load Rejection

This event is categorized as an incident of moderate frequency.

15.2.2.1.2.2 Generator Load Rejection with Bypass Failure

This event is categorized as an ~~infrequent~~ MODERATE incident BY THE NRC with the following characteristics:

Frequency: 0.0036/plant year
MTBE: 278 years

IT IS THE GE POSITION THIS EVENT IS AN INFREQUENT EVENT.

Frequency Basis: Thorough searches of domestic plant operating records have revealed three instances of bypass failure during 628 bypass system operations. This gives a probability of bypass failure of 0.0048. Combining the actual frequency of a generator load rejection with the failure rate of bypass yields a frequency of a generator load rejection with bypass failure of 0.0036 event/plant year.

15.2.2.3.1 Input Parameters and Initial Conditions (Continued)

effects have occurred, and are expected to be less severe than those already experienced by the system.

15.2.2.3.2 Results

15.2.2.3.2.1 Generator Load Rejection with Bypass

Figure 15.2-2 shows the results of the generator trip from 105% rated steam flow conditions. Peak neutron flow rises 24% above NB rated conditions.

The average surface heat flux shows no increase from its initial value, and MCPR does not significantly decrease below its initial value. Therefore, this event does not have to be reanalyzed for a specific core configuration.

15.2.2.3.2.2 Generator Load Rejection with Failure of Bypass

Figure 15.2-3 shows that, for the case of bypass failure, peak neutron flux reaches about 199% of rated, and average surface heat flux reaches 102.7% of its initial value. Since this event is classified as an MODERATE ~~infrequent~~ incident BY THE NRC, IT SHOULD BE KNOWN THAT GE STILL CONSIDERS TH ~~it~~ is not limited by the GETAB criteria and the MCPR limit is permitted to fall below the safety limit for the incidents of moderate frequency. However, the MCPR for this event, with a value of 1.14, is well above the safety limit. The Applicant will provide reanalysis of this event for the specific core configuration.

15.2.3 Turbine Trip

15.2.3.1 Identification of Causes and Frequency Classification

15.2.3.1.1 Identification of Causes

A variety of turbine or nuclear system malfunctions will initiate a turbine trip. Some examples are moisture separator and heater drain tank high levels, large vibrations, operator lockout, loss of control fluid pressure, low condenser vacuum and reactor high water level.

15.2.3.1.2 Frequency Classification

15.2.3.1.2.1 Turbine Trip

This transient is categorized as an incident of moderate frequency. In defining the frequency of this event, turbine trips which occur as a byproduct of other transients such as loss of condenser vacuum or reactor high level trip events are not included. However, spurious low vacuum or high level trip signals which cause an unnecessary turbine trip are included in defining the frequency. In order to get an accurate event-by-event frequency breakdown, this type of division of initiating causes is required.

15.2.3.1.2.2 Turbine Trip with Failure of the Bypass

This transient disturbance is categorized as an ~~infrequent~~ MODERATE incident. by the NRC. IT IS GE's Position That this event is an infrequent even Frequency ~~is expected to be~~ as follows:

Frequency: 0.0064/plant year
MTBE: 156 years

440.23 **Provide justification for using the value of 0.0 seconds for the Safety Function Delay (Item #26) in Table 15.0-1 of your FSAR.**

Response

Item 26 serves only as a programming convenience. Table 15.0-1 will be marked to reflect this information. (as per attached)

Table 15.0-1 (Continued)

INPUT PARAMETERS AND INITIAL CONDITIONS FOR TRANSIENTS

17. Void Coefficient (-)¢/% Rated Voids	
Analysis Data for Power Increase Events (REDY only)*	14.0
Analysis Data for Power Decrease Events (REDY only)*	4.0
18. Core Average Rated Void Fraction (%) (REDY only)*	42.54
19. Scram Reactivity, Δk Analysis Data (REDY only)*	Subsection S.2.2, Reference 1
20. Control Rod Drive Position versus time	Subsection S.2.2, Reference 1
21. Nuclear characteristics used in ODYN simulations	EOEC**
22. Jet Pump Ratio (M)	2.257
23. Safety/Relief Valve Capacity (% NBR) at 1210 psig	110.8
Manufacturer	***
Quantity Installed	19
24. Relief Function Delay (sec)	0.4
25. Relief Function Response Time Constant (sec)	0.1
26. Safety Function Delay (sec)	0.0 (1)
27. Safety Function Response Time Constant (sec)	0.2
28. Set Points for Safety/Relief Valves	
Safety Function (psig)	1175,1185,1195,1205,1215
Relief Function (psig)	1125,1135,1145,1155
29. Number of Valve Groupings Simulated	
Safety Function (No.)	5
Relief Function (No.)	4

*For transients simulated on the ODYN model, this input is calculated by ODYN.
**EOEC = End of Equilibrium Cycle.
***Applicant to Supply
(1) THIS IS A PROGRAMMING CONVENIENCE NUMBER