GENERAL ELECTRIC

NUCLEAR POWER

SYSTEMS DIVISION

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MFN 061-83
JNF 019-83

March 23, 1983

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

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

Gentlemen:

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

REVISED DRAFT RESPONSES, RESPONSES TO DISCUSSION ITEMS AND TEXT CLARIFICATIONS

Attached please find proposed resolutions to Power, Containment, and Instrumentation and Control Systems Branch discussion items. Also attached is a revised final draft response to a recent Quality Assurance Branch question. The following are provided:

Attachment Number	
1	Proposed Resolution of Power Systems Branch Discussion Items
2	Proposed Resolution of Containment Systems Branch Discussion Items
3	Proposed Resolution to Instrumentation and Control Systems Branch Discussion Items
4	Draft Responses to Quality Assurance Questions

Sincerely,

E003

Glenn G. Sherwood, Manager
Nuclear Safety & Licensing Operation

cc: F.J. Miraglia (w/o attachments)
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ATTACHMENT NO. 1

PROPOSED RESOLUTION OF
POWER SYSTEMS BRANCH
DISCUSSION ITEMS

The following additional information for discussion items is provided:

2. See revised response to Question 430.09 attached.

3. See revised response to Questions 430.01 and 430.22 attached.

7. The voltages given are motor terminal starting voltages. ~~Our~~ The GESSAR II calculations indicate that when power is from an offsite source and the 6900 V bus voltage is 90%, the minimum motor terminal starting voltage will 80% or better. The calculation to verify and determine the actual degraded voltage trip setting is by the applicant. Verification of the 90% condition by the applicant will also verify the 95% condition which is the minimum interface requirement placed on the Applicant.

9. See revised response to Question 430.33, attached,

10. See revised response to Question 430.04, attached

11. See revised response to Question 430.31 attached.

12. See revised response to Question 430.31, attached.

14. See revised response to Question 430.17a, attached.

17 & 18. See attached draft response to discussion items 17 and 18. GESSAR II Subsections 8.2.3 and 8.3.1.5 will be revised in accordance with RG1.70 Rev. 3 as indicated on the response.

Previously submitted responses have resolved discussion items 1, 4, 5, 6, 8, 13, 15 and 16.

Discussion Item #2

430.09 (8.3) A review of malfunction reports of diesel-generators at operating nuclear plants has disclosed that in some cases, the information available to the control room operator to indicate the operational status of the diesel-generator may be imprecise and could lead to misinterpretation. This can be caused by the sharing of a single annunciator station to: (1) alarm conditions that render a diesel-generator unable to respond to an automatic emergency start signal; and (2) alarm abnormal, but not disabling, conditions. Another cause can be the use of wording in an annunciator window which does not specifically indicate that a diesel-generator is inoperable (i.e., unable at the time to respond to an automatic emergency start signal) when in fact, it is inoperable for this purpose.

Accordingly, review and evaluate the alarm and control circuitry for the diesel-generators in your proposed nuclear island to determine how each condition which renders a diesel-generator unable to respond to an automatic emergency start signal, is alarmed in the control room. These conditions include not only the trips that lock out the diesel-generator start and require manual reset but also control switch or mode switch positions which block automatic start. Other conditions in this category are loss of control voltage, insufficient starting air pressure or low battery voltage. Your review should consider all aspects of possible diesel-generator operational conditions (e.g., test conditions and operation from a local control station). One area of particular concern is the unreset condition following a manual stop at the local station which terminates a diesel-generator test and prior to resetting of the diesel-generator controls to permit subsequent automatic operation.

Provide the details of your evaluation, the results and your conclusions, including the following information:

a. All conditions which render the diesel-generator incapable of responding to an automatic emergency start signal for each operating mode as discussed above.

b. The wording on the annunciator window in the control room which is alarmed for each of the conditions identified in your response to Item (a) above.

c. Any other alarm signals which are not included in Item (a) above and which also cause the same annunciator to alarm.

d. Any condition which renders the diesel-generator incapable of responding to an automatic emergency start singal and which is not alarmed in the control room.

e. Any modifications you propose following your evaluation of these matters.

DISCUSSION ITEM #2 (cont)

2.b) Conditions which render the HPCS D-G incapable of responding to an automatic emergency start signal.

	Condition	Actuating device	Alarm in CR	Other Alarms
1.	Auto-Maint SW. in Maint. Pos	Switch MSI	HPCS sys not ready for Autostart	DE in Maint. posi -CR
2.	Loss of 125VDC control power at DGP	BF1,2,3,4,5 via common alarm (-70X11	HPCS sys not ready for Autostart	- Diesel Engine trouble - CR and - count pwr fail - LCL
3.	Brk R1 in closed position	52/a contact from bkr #1 (SWGR Cub[illegible]	~~No alarm but bkr position indication~~ HPCS sys Not ready for Autostart	None
4.	Gen lockout Not reset	K1 lockout relay (H22-P[illegible])	HPCS sys Not ready for Autostart	Gen trip Lockout - CR (Via K3)
5.	Emerg. Shutdown Not reset	SDR	HPCS sys Not ready for Autostart	Gen trip Lockout (Via K3) - CR
6.	Voltage Regulator Mode sw not in Auto pos.	VR mode	HPCS sys Not ready for Autostart	none
7.	Cont pwr flr to SWGR (Cub002, 3&4)	74F1, F2 (Cub002) 74F1, (Cub003) 74F1, (Cub004)	HPCS sys Not ready for Autostart	none

c) No other signals annunciate the "HPCS system not ready for autostart" alarm.

d) Since "Low Starting air pressure" and "Fuel system fault" are annunciated in the control room as a "Diesel Engine Trouble" alarm, no other unalarmed conditions render the diesel generator incapable of responding to an automatic emergency start signal.

e) No modifications are proposed.

DISCUSSION ITEM # 3

430.01 (8.3.1) Describe in Section 8.3.1.1.2 of your FSAR, the interlocking scheme provided on the crosstie circuit breakers between Division 1, bus F1 and Division 2, bus E1. State whether these circuit breakers are interlocked with the bus supply breakers. It is our position that bus ties compromise the independence and redundancy of the onsite electrical power supplies required by General Design Criterion 17 of Appendix A to 10 CFR Part 50. Accordingly, justify why Divisions 1 and 2 ac power supplies cannot be made completely independent by eliminating this crosstie.

Response

The bus ties will be eliminated and the GESSAR II text and drawings revised accordingly.

DISCUSSION ITEM #3
(cont)

~~AUG 2 5 1982~~

430.22
(8.3.2.2) Both the conclusion contained in NUREG-0666, "A Probabilistic Safety Analysis of DC Power Supply Requirements for Nuclear Power Plant" and operating experience indicate that bus ties between redundant dc divisions are a prime contributor to dc system unreliability. As a result, we recommend in NUREG-0666 eliminating the use of a bus tie breaker between redundant buses. Based on the findings in NUREG-0666 and the fact that bus ties compromise the independence and redundancy of the onsite electric power supplies required by Criterion 17 of the GDC it is our position to prohibit the use of bus ties between redundant dc divisions in new plant designs. Accordingly, justify in Section 8.3.2.2 of your FSAR why dc Divisions 1 and 2 cannot be made completely independent by eliminating the interconnecting bus tie shown in your proposed design.

Response

The bus ties will be eliminated and the GESSAR II text and drawings revised accordingly.

DISCUSSION ITEM #9

430.23 (8.3.2.1) The specific requirements for monitoring the dc power system derive from the generi requirements embodied in Section 5.3.2(4), 5.3.4(5) and 5.3.3(5) of IEEE Std. 308-1974 and the guidance we provide in Regulatory Guide 1.47. In summary, these general requirements state that the dc system composed of batteries, distribution systems and chargers shall be monitored to the extent that it can be shown to be ready to perform its intended function. Accordingly, the guidelines used in our review of the dc power system designs are that the following indications and alarms of the Class 1E dc power system should be provided in the control room:

- Battery current (ammeter-charge/discharge)
- Battery charger output current (ammeter)
- DC bus voltage (voltmeter)
- Battery charger output voltage (voltmeter)
- Battery discharge
- DC bus undervoltage and overvoltage alarm
- DC bus ground alarm (for ungrounded systems)
- Battery breaker(s) or fuse(s) open alarm
- Battery charger output breaker(s) or fuse(s) open alarm
- Battery charger trouble alarm (one alarm for a number of abnormal conditions which are usually indicated locally)

We conclude that the monitoring cited above, augmented by the periodic test and surveillance requirements included in the Technical Specifications, provide reasonable assurance that the Class 1E dc power system is ready to perform its intended safety function. Indicate your compliance with these provisions for monitoring the Class 1E prower system. Alternatively, justify any deviation.

Response

We provide a local and/or remote indication for all of the items listed. For further information see the revised version of FSAR Section 8.3.2.2.1, paragraph 1 (see copies attached).

SEE SUPPLEMENT TO TABLE 8.3-12 FOR DIV-3 (HPCS)

8.3.2.2 Analysis

8.3.2.2.1 General DC Power Systems

The 480 VAC power supplies for the divisional battery chargers are from the individual Class 1E MCC to which the particular 125 VDC system belongs (Figure 8.3-1). In this way, separation between the independent systems is maintained and the AC power provided to the chargers can be from either preferred or standby AC power sources. The DC system is so arranged that the probability of an internal system failure resulting in loss of that DC power system is extremely low. Important system components are either self-alarming on failure or capable of clearing faults or being tested during service to detect faults. Each battery set is located on its own ventilated battery room as shown in Figures 8.3-8, 8.3-9, and 8.3-13. All abnormal conditions of important system parameters such as charger failure or low bus voltage are annunciated in the Main Control Room and/or locally (See Table 8.3-12).

Cross connection between the independent 125 VDC systems is limited to manual breakers between Division 1 and Division 2 distribution panels. Key interlocks are used to enforce operating procedures. One breaker is furnished at each end of the cross tie to meet single-failure requirements. A control room indication is provided for each Tie breaker in the "close" position.

AC and DC switchgear power circuit breakers in each division receive control power from the batteries in the respective load groups ensuring the following:

(1) The unlikely loss of one 125 VDC system does not jeopardize the supply of preferred and standby AC power to the Class 1E buses of the other load groups.

(2) The differential relays in one division and all the interlocks associated with these relays are from one

INDIC ... [illegible]

DC SYSTEM INDICATION AND ALARMS

BUS	CONDITION	INDICATION	LOCATION
DC-E	UNDERVOLTAGE, OVERVOLTAGE, GROUND FAULT OPEN BATTERY MAIN BREAKER OPEN BATTERY DISCONNECT SWITCH LOW BATTERY CHARGER DC VOLT & AMPS LOW BATTERY CHARGER AC INPUT VOLTS	D1 125VDC BUS DC-E TROUBLE	CONTROL RM ANNUNCIATOR PNL
		D1 125VDC BUS DC-E & MCC DC-E1 & DC-E2 TROUBLE	CONTROL RM STATUS LIGHT PNL
	BUS VOLTAGE	VOLTMETER	LOCAL & CONTROL RM
	BUS AMMETER BATTERY AMP & VOLTS	VOLT AND AMMETER	LOCAL
DC-F	UNDERVOLTAGE, OVERVOLTAGE, GROUND FAULT OPEN BATTERY MAIN BREAKER OPEN BATTERY DISCONNECT SWITCH LOW BATTERY CHARGER DC VOLT & AMPS LOW BATTERY CHARGER AC INPUT VOLTS	D2 125VDC BUS DC-F TROUBLE	CONTROL RM ANNUNCIATOR PNL
		D2 125VDC BUS DC-F & MCC DC-F1 TROUBLE	CONTROL RM STATUS LIGHT PNL
	BUS VOLTAGE	VOLTMETER	LOCAL & CONTROL RM
	BUS AMMETER BATTERY AMP & VOLTS	VOLT AND AMMETER	LOCAL
DC-H	UNDERVOLTAGE, OVERVOLTAGE, GROUND FAULT OPEN BATTERY MAIN BREAKER OPEN BATTERY DISCONNECT SWITCH LOW BATTERY CHARGER DC VOLT & AMPS LOW BATTERY CHARGER AC INPUT VOLTS	D4 125VDC BUS DC-H TROUBLE	CONTROL RM ANNUNCIATOR PNL
			CONTROL RM STATUS LIGHT PNL
	BUS VOLTAGE	VOLTMETER	LOCAL & CONTROL RM
	BUS AMMETER BATTERY AMP & VOLTS	VOLT AND AMMETER	LOCAL
DC-J	UNDERVOLTAGE, OVERVOLTAGE, GROUND FAULT OPEN BATTERY MAIN BREAKER OPEN BATTERY DISCONNECT SWITCH LOW BATTERY CHARGER DC VOLT & AMPS LOW BATTERY CHARGER AC INPUT VOLTS	ND 125VDC BUS TROUBLE	CONTROL ROOM ANNUNCIATOR PANEL
	BUS VOLTAGE	VOLTMETER	LOCAL & CONTROL RM
	BUS AMMETER BATTERY AMP & VOLTS	VOLT AND AMMETER	LOCAL
DC-E1	UNDERVOLTAGE GROUND FAULT	D1 125VDC MCC DC-E1 TROUBLE	CONTROL RM ANNUNCIATOR
		D1 125VDC BUS DC-E & MCC DC-E1 & MCC DC-E2 TROUBLE	CONTROL RM STATUS LIGHTS
	BUS VOLTAGE & CURRENT	VOLTMETER & AMMETER	LOCAL & CONTROL RM
DC-F1	UNDERVOLTAGE GROUND FAULT	D2 125VDC MCC DC-F1 TROUBLE	CONTROL RM ANNUNCIATOR
		D2 125VDC BUS DC-F & MCC DC-F1 TROUBLE	CONTROL RM STATUS LIGHTS
	BUS VOLTAGE & CURRENT	VOLTMETER & AMMETER	LOCAL & CONTROL RM
DC-E2	UNDERVOLTAGE GROUND FAULT	D1 125VDC MCC DC-E2 TROUBLE	CONTROL RM ANNUNCIATOR
		D1 125VDC DC-E & MCC DC-E1 & MCC DC-E2 TROUBLE	CONTROL RM STATUS LIGHTS
	BUS VOLTAGE & CURRENT	VOLTMETER & AMMETER	LOCAL & CONTROL RM

SUPPLEMENT TO TABLE 8.3-12

BUS	CONDITION	INDICATION	LOCATION
Div. 3 (HPCS) 125VDC BUS "G"	(1) continuous bus voltage	Voltmer	Local and Control room
	(2) Battery output current	Ammeter	Local
	(3) Bus "G" load (Amps)	Ammeter	Local
	(4) Battery Breaker Open Bus "G" ground fault (5) Bus "G" undervoltage	125VDC system trouble alarm	control room
	(6) Control power failure to DG cont. pnl.	Control power failure alarm	control room as "DG Trouble" and Local
	(7) Low Battery Charger Amps Battery charger input breaker tripped/open (8) Battery charger failure (including high voltage and ground fault)	Battery charger trouble alarm	Control room
	(9) Charger output voltage	Voltmeter	Local
	(10) Charger output current	Ammeter	Local
	(11) Charger ground fault	Ground indication Light	Local

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DISCUSSION ITEM #10

430.04 (8.3.1) The undervoltage relaying described in Section 8.3.1.1.7 of your FSAR, by itself, will not protect the Class 1E equipment against a degraded voltage condition. Branch Technical Position PSB-1 contained in Chapter 8 of the Standard Review Plan (SRP) requires that a second level of undervoltage protection be provided to protect Class 1E equipment against degraded voltage conditions. Describe your compliance with this position for Class 1E, Divisions 1, 2 and 3.

Response

The [redacted] GESSAR II design is based on a stable grid voltage conditions with maximum fluctuation of ±5% at the interface points (Refer to Note 4 of fig. 8.3-2 "6900 V S/L Buses E & F".

The Applicant is requested to perform a voltage analysis of his system and guarantee that he can meet the above requirement:

With reference to the Branch Technical Position, PSB-1, [redacted] the following comments apply:

Paragraph B.1

The [redacted] GESSAR II design provides Bus Undervoltage relaying set at 70% for divisions 1 & 2 and 73% for division 3 (HPCS), to detect a loss of the offsite power at the class IE buses and isolate these buses from the BOP. The feeder undervoltage relaying provide a second level of undervoltage protection which satisfy the following requirements as stated in PSB-1

B.1.a) The selection of undervoltage and time delay set points will be determined from an analysis of the voltage requirements of the class IE loads at all onsite system distribution levels;

B.1.b.1) The [redacted] GESSAR II design provides a time delay setting for the feeder undervoltage relaying to insure the existance of a sustained degraded voltage condition. Division 1 and 2 Following this delay, an alarm in the control room will alert the operator to the degraded condition.

If end of first have LOCA trip immediately.

The operator would have the option, if necessary, to separate the class IE distribution system from the degraded offsite power system and perform a manual bus transfer to the other offsite power source or the Diesel Generator. A second time delay is initiated by the first alarm so that ~~the~~ if the operator does not take action the Class IE distribution system will be automatically separated from the offsite power system. Receipt of a LOCA signal at any ~~Division 3~~ If

Following this delay, if the degraded voltage condition still persists, loss of offsite power operational sequence is started. This sequence includes automatic tripping of the offsite power feeder breaker, starting of the HPCS D/G and transfer of the Division 3 bus from offsite,

time during the second timing period will result in an immediate trip of the supply breaker from the offsite power source.

~~to the D/G. Offsite breaker open indication, D/G running indication and the D/G breaker closed indications provide the control room operator the necessary information.~~

B.1.b.2) The ~~[illegible]~~ GESSAR II design ~~does not~~ provides a second time delay. ~~as~~ to ~~suggested in the PSB-1E~~

<u>Division 1 and 2</u> It is left up to operator discretion to isolate the class IE buses required, as stated in B.1.b.1 above.

<u>Division 3</u>

The HPCS (Division 3) bus is automatically separated from the offsite power system upon a sustained degraded voltage condition as described in B.1.b.1 above for Division 3.

B.1.C.1&2) GESSAR II complies. ~~[illegible]~~. Refer to Fig. 8.3-2 "6900 Volt Single Line Buses E & F", and Fig. 8.3-2 "HPCS Power System - Simplified - One Line Diag."

B.1.C.3

Division 1 and 2

GESSAR II complies. ~~Refer Subsection 8.3.1.1.7(2) for Divisions 1&2.~~ Load shedding is block

~~Division 3~~

The HPCS is an independent bus and has no common trippings with Division 1 or 2. No load shedding is required for the HPCS bus loads.

B.1.C.4

~~Division 1 and 2~~

The voltage sensors (feeder undervoltage relaying) ~~do not~~ automatically initiate the disconnection of the offsite power sources whenever the voltage set point and time delay limits have been exceeded. ~~Instead, an alarm is initiated in the Control Room, and the isolation can be done manually by the operator.~~

~~Division 3~~

The voltage sensors (feeder undervoltage relaying) automatically initiate the disconnection of the offsite power sources whenever the voltage set point and time delay limits have been exceeded.

B.1.C.5) The [redacted] GESSAR II design provides means for device testing and calibrating during plant operation.

B.1.C.6) <u>GESSAR II complies.</u>

B.1.d) The Technical Specifications will include limiting conditions for operations, surveillance requirements and will be provided by the Applicants.

The trip set points and the allowable values for the second-level voltage protection sensors and associated time delay devices are plant unique items which will be provided by the Applicant.

<u>Paragraph B.2</u>

~~The GESSAR-II design~~ meets ~~does not provide automatic load shedding for Division 1 or 2 in case of sustained degraded voltage above 70% of rated. The Division 3 bus loads require no load shedding.~~

Paragraph B.3

A voltage drop calculation was performed which shows that, all safety related buses down to the 480 volt level, provide full load operation voltages for safe continuous operation of all energized loads, based on a BOP supply voltage of 6.9 KV ± 5%.

Paragraph B.4

This recommended testing procedure will be addressed in the pre-operational test procedures.

DISCUSSION ITEM #12

4~~3~~0.31 (1.8) Provide the following additional information regarding the protection ~~regarding the protection~~ of containment electrical penetrations:

a. You indicate in Part I.2.13 of Section 1.8 of your FSAR that an analysis is required for circuits normally protected by small fuses or breakers such as control circuits, alarms and solenoids. Provide this analysis.

Response

The requested analysis will be provided as Subsection I.2.13.1 in GESSAR II. Ref: the attached copy.

430.31

b. In this same portion of the FSAR, you also indicate that where very low currents are involved such as in instrumentation circuits, thermocouples and annunciators, no action is required and that conformance with the provisions of Regulatory Guide 1.63 is accomplished by inspection. Explain what is meant by the phrases "no action required" and "conformance by inspection." It is our position that if the fault current available from these circuits is greater than the continuous current rating of the penetrators, the penetrations must be protected by at least two fault current interrupting devices.

Response

The summary table will be clarified as shown in attached copy. This is supported by section D of the analysis in I.2.13.1.

430.31

I.2.13 **Regulatory Guide 1.63, Revision 1, Dated May 1977 (Continued)**

of the redundant protective elements so that no event causing a need for the protection can disable the protective function.

I.2.13.1 Analysis of circuits penetrating primary containment.

A. 6.9 kV cricuits for recirculation pump motors are protected by two circuit breakers in series. in the 6.9KV supply circuit

The recirculation pump motors are also fed from the low frequency motor generator sets. This feed is directly protected by one 6.9KV rated breaker. If this single breaker should fail to trip on a fault within containment, the penetration is capable of withstanding the maximum theoretical generator fault current for 250 seconds without damage. The fault current which could be as high as 13.5 times rated current would be terminated in less than 250 seconds by one or more of the following:

1. Overtemperature failure of the generator output winding.
2. Overcurrent in the field circuit.
3. Tripping of the mg set drive motor breaker on overload.

B. Power circuits for motor control center loads are protected by a circuit breaker and a fuse per phase in series. The application of penetration wire protecting devices is shown on the MCC single line diagrams.

C - MCC control circuits have ~~a single~~ two fuses per control circuit, ~~which we consider adequate to maintain the electrical penetration integrity.~~

Our conclusion is based on the following study.

We used a NEMA size 4 starter in this study as the limiting case, since larger size starters have auxiliary contactors and smaller Control Power Transformers (CPTs). For a NEMA size 4 starter, the standard CPT size is 250 VA which means that the rated secondary current is 2.08 Amps (250 ÷ 120).

The field cable used between the CPT secondary and the containment penetration is size 14 AWG, which is rated for 22.75 Amp continuous at 40° C (104° F) ambient.

maximum short circuit current that the CPT can let through, assuming 5% impedance, to be conservative, is -

$$\frac{250\ VA}{.05 \times 120} = 41.6\ Amps$$

By ignoring the field cable impedance, (conservative), the maximum short circuit current at the containment penetration is 41.6 Amp.

The $I^2 t$ curves of the Westinghouse penetration indicates that the penetration seal can carry 60 Amps for 1000 sec (16.7 minutes) and maintain its mechanical and electrical integrity. *The penetration* ~~#14 AWG pigtail wire~~ can *also* carry 110 Amps for 10 seconds without insulation damage.

From the above, *it is concluded that* the CPT will fail much faster than the field cable, ~~the penetration pigtail~~ or the penetration seal, should the CPT secondary fuse fail to open the circuit under an overload or a short circuit condition.

The CPT may fail and act either as an open circuit or a closed circuit. If it acts as an open circuit, the penetration will be isolated. On the other hand, if it acts as a closed circuit, the MCC feeder breaker/or fuse combination will trip and open the circuit, isolating the penetration, *thus providing the second level of fault current protection.*

Based on the above, the present design is considered to be adequate to maintain the electrical penetration integrity.

- 125V d-c instrument and control circuits will be protected by a 2-pole circuit breaker and a fuse in series where needed.
- 120V a-c instrument circuits and space heater circuits will have one single pole breaker and one fuse in series.

D. Specific circuits, having a limited power source, that cannot produce any short circuit current, damaging to the conductor insulation, do not require a protective device.

Included in these special circuits are:

- Thermocouple circuits
- Shielded cables for low level signals (4 to 20 mA - LPRM, IRM, SRM, RPIS instru mentation circuits)
- Annunciator circuits

1.13 Regulatory Guide 1.63, Revision 1, Dated May 1977 (Continued)

Summary Table of Conformance with Regulatory Guide 1.63 for Circuits Penetrating Primary Containment

	Use of Two Interrupting Devices in Series	Analysis Required	Very Low Currents Involved ~~No Action Required Conformance by Inspection~~
Recirculation pumps	X		No interrupting device required. circuit is self protecting.
Power Circuits on motor control centers	X		
Control circuits, alarm, solenoids, etc. - circuits, normally protected by small fuses or breakers		X	
Instrumentation circuits, thermocouples, annunciator - all low-current-level applications			X

c. Provide the fault current clearing-time curves of the primary and secondary current interrupting devices for the penetrations plotted against the thermal capability (I^2t) curve of the penetration. Our concern in this matter is the maintenance of mechanical integrity. Provide a simplified one-line diagram showing the location of the protective devices in the penetration circuit and indicate the maximum available fault current of the circuit. If the overcurrent protection is not fault current actuated, identify the power source to the trip circuits. It is our position that the power source for the primary protection device should be from a division different from that supplying the secondary protection device.

Response

The fault current clearing-time curves of the primary and secondary current interrupting devices is by the applicant.

The thermal capability (I^2t) curves of the penetrations must be in accordance with standard IPCEEA P-32-382.

All overcurrent protection is fault current actuated.

DISCUSSION # 19

430.17 (1.8) Provide the following additional information regarding the exceptions you take in Section 1.8 of your FSAR, to Regulatory Guide 1.75:

a. You state with respect to Position C.1 in this regulatory guide that interrupting devices actuated only by a fault current are not considered to be isolation devices unless acceptable coordination can be verified by tests. However, you should first provide justification why the non-Class 1E load must be connected to the Class 1E system and cannot be tripped on an accident signal. If suitably justified, such a design must provide two isolation devices in series, each coordinated with the upstream bus feeder circuit breaker, and periodic testing of the coordination of these devices must be performed. Provide a complete list of the non-Class 1E loads connected to Class 1E systems and identify those loads which are not tripped on a signal indicating a loss-of-coolant accident (LOCA).

b. You state with respect to Position C.4 of this regulatory guide that associated circuits will be subject to the same requirements as Class 1E circuits unless it can be demonstrated that the Class 1E curcuits are not degraded below an acceptable level by the absence of such requirements. Identify each area where this exception is taken and provide an analysis showing that the absence of Class 1E requirements will not significantly reduce the availability of the Class 1E circuits.

c. The exception you take to Position C.6 of this regulatory guide is unacceptable. Specifically, identify all areas where independence or separation is less than that required by IEEE Std. 384-1974. Provide an analysis based on tests.

d. Justify the exception you take to Position C.7 of this regulatory guide by an analysis demonstrating that Class 1E circuits are not degraded below an acceptable level. Provide this analysis.

e. Explain the exceptions taken to Positions C.8 and C.11 of this regulatory guide since they appear to be only a slightly reworded statement of the criteria in the guide.

Response

With one exception to Position C.1, the GESSAR II design now meets the requirements of Regulatory Guide 1.75, Revision 2 with the interpretion and clarification provided in new Subsection 1.8.75 (attached). (It should be noted that Section 1.8 has been completely revised to respond to all regulatory guides effective Feb. 22, 1982).

1.8.75 Regulatory Guide 1.75, Revision 2, Dated September 1978

Title: Physical Independence of Electric Systems

This guide describes a method acceptable to the NRC staff of complying with IEEE 279-1971 and Criteria 3, 17, and 21 of Appendix A to 10CFR50 with respect to the physical independence of the circuits and electric equipment comprising or associated with the Class 1E power system, the protection system, systems actuated or controlled by the protection system, and auxiliary or supporting systems that must be operable for the protection system and the systems it actuates to perform their safety-related functions. This guide applies to all types of nuclear power plants.

This guide addresses only some aspects of defense against the effects of fires. Additional criteria for protection against the effects of fires are provided in Regulatory Guide 1.120.

The guide also states that the guidance of IEEE 384-1974 is acceptable to the NRC staff when supplemented by additional requirements included in the guide.

Evaluation

As discussed in subsections 7.1.1.8 and 7.1.2.10, the GESSAR II design meets the requirements of the regulatory position with interpretation and clarification as enumerated below for specific paragraphs of Regulatory Guide 1.75. ~~The~~

(1) Position C.1 (basis) - GE ~~endorses~~ follows the position stated in Regulatory Guide 1.120 paragraph C.1.d(1) which clearly excludes the combination of a LOCA, LOOP (Loss of Off-site Power), and a fire which has been postulated in the basis of Position C.1.

There is one exception to Position C.1 dealing with the emergency lighting which is a

non-Class IE load fed from safety buses. Since the availability of emergency lighting is important to the orderly shutdown and surveilance of the plant, the lighting is not disconnected upon a LOCA signal. Two isolation devices in series are provided. Each is coordinated with the upstream bus feeder circuit breaker. Periodic testing of the coordination of these devices will be performed by the Applicant.

2.) The regulatory guide endorses, with exceptions, IEEE 384-1974. There are now 1977 and 1981 issues of IEEE 384. GE favors implementation of the 1981 version on the basis that it has addressed all of the NRC exceptions to IEEE 384-1974. ~~Also see Subsections 7.1.2~~.8 ~~and 7.1.2.10~~.

DISCUSSION ITEMS 17 & 18

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e. Allowable harmonic content,

f. Allowable frequency fluctuation,

g. Grounding requirements, and

h. Power supply assignment.

3. Provisions included for the sensors and their instrument lines associated with the SSWS (and additional cooling capacity, if any required) that provide inputs to satisfy station safety functions:

a. Range (including accident conditions),

b. Measurement accuracy,

c. Repeatable accuracy,

d. Maximum expected transient,

e. Response time (maximum allowable time to achieve sensor output after reaching trip level for measured variable),

f. Trip setpoint,

g. Snubbers,

h. Orifice, and

i. Arrangement for instrument lines.

add Reg 1.17; GDC to sec. 8.2.3.1 ~~8.2~~ Gen Des. Cr4

8. ELECTRIC POWER

8.2 Offsite Power System

8.2.3 BOP Interface

1. A listing of all the design criteria including codes, standards, General Design Criteria, and regulatory guides applied to the portion of the design of the offsite power system included within the BOP.

2. For each BOP system, requirements for offsite a.c. power system:

a. Steady-state load, SEE TABLE 8.2-1

b. Inrush kVA for motor loads,

c. Nominal voltage,

d. Allowable voltage regulation, SINGLE LINE FIG. 8.3-2 ±5%

e. Nominal frequency, 60~

f. Allowable frequency fluctuation, ± 2%

g. Maximum frequency decay rate and limiting underfrequency value for reactor coolant pump coastdown, and (APPLIES ONLY TO PWR TYPE PLANT)

h. Minimum number of ESF trains to be energized simultaneously (if more than two trains provided). TWO MINIMUM

NOTE: For complete offsite a.c. power requirements, the BOP designer should also include the NSSS requirements.

8.3 Onsite Power System

8.3.1 A.C. Power Systems

SEE TABLE 8.1-1

8.3.1.5 BOP Interface

1. A listing of all the design criteria including codes, standards, General Design Criteria, and regulatory guides applied to the portion of the design of the onsite a.c. power systems included within the BOP.

2. For each BOP system, requirements for onsite a.c. power:

   a. Steady-state load, SEE TABLE 8.3-10

   b. Inrush kVA for motor loads, "

   c. Nominal voltage, SEE SINGLE LINE FIG. 8.3-2

   d. Allowable voltage drop (to achieve full functional capability within required time period), SEE TABLE 8.3-10

   e. Load sequence, NOT APPLICABLE

   f. Nominal frequency, and 60~

   g. Allowable frequency fluctuation. ± 2%

NOTE A: For complete onsite a.c. power requirements, the BOP designer should also include the NSSS requirements. N/A

NOTE B: This interface assumes that the onsite a.c. diesel generator system is utility-specific. N/A

3. Coordination of the design of the diesel generator room with the utility-applicant. N/A

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8.3.2 D.C. Power Systems

8.3.2.3 BOP Interface

1. A listing of all the design criteria including codes, standards, General Design Criteria, and regulatory guides applied to the portion of the design of the d.c. power systems included within the BOP. SEE TABLE 8.1-1

2. Provisions included to accommodate the needs of the SSWS (and additional cooling capacity, if required) by the d.c. power systems:

a. Steady-state load, SEE TABLE 8.3-10

b. Surge loads, - N/A

c. Load sequence, - N/A

d. Nominal voltage, and - " "

e. Allowable voltage drop (to achieve full functional capability within required time period). SEE TABLE 8.3-10

9. AUXILIARY SYSTEMS

9.2 Water Systems

9.2.7 BOP Interface

1. A listing of all the design criteria including codes, standards, General Design Criteria, and regulatory guides applied to the portion of the design of the SSWS included within the BOP.

2. Integrated heat load (decay heat and station heat load for all NSSS and BOP systems, as a function of time for the various modes of plant operation and limiting accident conditions) that must be transferred to the ultimate heat sink, maximum and minimum temperature limits, pressure, flow rate, plant SSWS pressure drop, etc.

3. Coolant flow, pressure, temperature, and integrated condensate storage capacity to satisfy total plant needs during normal operation, shutdown, and accident conditions. Cooling water requirements for the diesel generator system should be coordinated with the utility-applicant.

4. Limits on quality of makeup water to the station, including conductivity, pH, oxygen, chlorides, fluorides, solids, carbon dioxide, particulates, and silica; and limits on makeup waterflow, temperature, and pressure.

5. Requirements for location and arrangement of potable and sanitary water systems to preclude adverse effects on safety systems and components in the event of failure.

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Table 8.2-1

NUCLEAR ISLAND AC POWER SYSTEM/BOP INTERFACES

Interface Number*	Interface Description	Steady state load	INRUSH KVA
E-1 (A-C)	Normal Feeder from BOP to AB 6900-480V XFMR	2550 KVA	3400
E-2 (A-F)	Normal Feeder from BOP to Bus C	7735 HP	51,578 HP
E-3 (A-C)	Normal Feeder from BOP to AB 6900-480V XFMR	2550 KVA	3400
E-4 (A-F)	Normal Feeder from BOP to Bus D	7735 HP	51,578 HP
E-5 (A-C)	Normal Preferred or Alternate Preferred Feeder from BOP to HPCS Bus G SWGR	(GE)	(GE)
E-13 (A-F)	Normal Preferred Feeder from BOP to Bus E SWGR	3327 KVA	10,423
E-14 (A-F)	Alternate Preferred Feeder from BOP to Bus E SWGR	3327 KVA	10,423
E-15 (A-F)	Normal Preferred Feeder from BOP to Bus F SWGR	3327 KVA	10,423
E-16 (A-F)	Alternate Preferred Feeder from BOP to Bus F SWGR	3327 KVA	10,423
E-41 (A-C)	Normal Feeder from BOP to RW 6900-480V XFMR	1275 KVA	1700
E-43 (A-C)	Normal Feeder from BOP to RW 6900-480V XFMR	1275 KVA	1700
E-58 (A-B)	250 VDC FDR TO INVERTER 2 S.S "K"	50 KVA	—

*See Figure 8.3-1 for interfaces identified in accordance with these numbers. These interfaces are nondivisional.

8.2-4

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Table 8.3-10

NUCLEAR ISLAND ONSITE AC POWER SYSTEM/BOP INTERFACES

Interface Number	Interface Description	Reference Figure or Drawing No.	S.S HP/KVA	INRUSH KVA	NOM. VOLT.	FREQ. HZ	MAX ALLOWABLE BOP VD *
E-8 (A-C)	6900V Feeder from Bus E, SWGR to BOP Div 1 ESWS SWGR	Figure 8.3-2	1202*	7590	6900	60±2%	8%
E-11 (A-C)	6900V Feeder from Bus F, SWGR to BOP Div 2 ESWS SWGR	Figure 8.3-2	1202*	7590	6900		8%
E-12 (A-C)	480V Feeder from Bus G1-2 to BOP Div 3 (HPCS) ESWS Pump	Figure 8.3-16S ~~E251/B028~~	60	296	480		3.75%
E-17	480V Feeder from Bus E1-2, MCC to BOP Div 1 DG Fuel Oil Transfer Pump	Figure 8.3-16P ~~B025/E641-09~~	3	25.5	480		3.5%
E-18	480V Feeder from Bus E1-2, MCC to BOP Div 1 Back up DG Fuel Oil Transfer Pump	Figure 8.3-16P ~~E641-09/B025~~	3	25.5	480		3.5%
E-20	480V Feeder from Bus F1-2, MCC to BOP Div 2 DG Fuel Oil Transfer Pump	Figure 8.3-16P ~~E641-10/B025~~	3	25.5	480		3.5%
E-21	480V Feeder from Bus F1-2, MCC to BOP Div 2 Back up DG Fuel Oil Transfer Pump	Figure 8.3-16P ~~E641-10/B025~~	3	25.5	480		3.5%
E-23	480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) DG Fuel Oil Transfer Pump	Figure 8.3-16S ~~E251-?/B027 or B028~~	3	25.5	480		3.75%
E-24	480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) Back up DG Fuel Oil Transfer Pump	~~E251-14/B023~~	3	25.5	480		3.75%
E-25	480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) ESWS Strainer Motor	~~[illegible]~~	1	8	480		3.75%

*Allowable voltage drop for the BOP portion of the interface cable.

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			S.S HP/KVA	Inrush KVA	Nom. Volt.	FREQ HZ	MAX Allowable DROP V.D
E-44	480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) ESWS Backwash Strainer Valve	~~E028/I251~~ Figure 8.3-16S	3	25.5	480	60±1%	3.75%
E-49	480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) ESWS Return Header Isolation Valve	Figure 8.3-16S ~~E028/I251~~	1	8			3.75%
E-59	480V Feeder from Bus E1-2, MCC to BOP Div 1 Fuel Oil Storage Tank Receptacle	Figure 8.3-16P ~~E025/I641~~	15	–			3.5%
E-60	480V Feeder from Bus F1-2, MCC to BOP Div 2 Fuel Oil Storage Tank Receptacle	Figure 8.3-16P ~~E025/I641~~	15	–			3.5%
E-61	480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) DG Fuel Oil Storage Tank Receptacle	Figure 8.3-16S ~~E028-I251~~	15	–			3.5%
E-50 - E-55	480V Feeder from MCC B1-1 to Steam-line Drain Valves	Figure 8.3-16C/D ~~I219-9~~	7.5	48			3.5%
E-62	Deleted ~~480V Feeder from Bus E1-2, MCC to BOP Div 1 DG Fuel Oil Transfer Pump Room Vent Fan B~~	~~E025/I641~~					
E-63	~~480V Feeder from Bus E1-2 MCC to BOP Div 2 DG Fuel Oil Transfer Pump Room Vent Fan B~~	~~E025/I641~~					
E-64	~~480V Feeder from Bus F1-2, MCC to BOP Div 2 DG Fuel Oil Transfer Pump Room Vent Fan A~~	~~E025/I641~~					
E-65	~~480V Feeder from Bus F1-2, MCC to BOP Div 2 DG Fuel Oil Transfer Pump Room Vent Fan B~~	~~E025/I641~~					
E-66	~~480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) Fuel Oil Transfer Pump Room Vent Fan A~~	~~E028/I251~~					

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			S.S HP/KW	Inrush KVA	NOM. VOLT.	FREQ (Hz)	Max Allowable BOP V.D.
E-67 Deleted	~~480V Feeder from Bus G1-2, MCC to BOP Div 3 (HPCS) DG Fuel Oil Transfer Pump Room Vent Fan A~~	~~E028/I252~~					
E-68 (A-C)	~~480V Feeder from MCC Bus E2-1 to BOP 120 VAC Normal Power (UPS)~~	~~Figure 8.3-1~~					
E-74	From Recirc Pump "A" Current Transformer to BOP Switchgear Device	Figure 8.3-3a ~~I110-26~~	5A	–	–	60 ± 2%	–
E-76	From Recirc Pump "~~A~~ B" Current Transformer to BOP Switchgear Device	Figure 8.3-3a ~~I110-27~~	5A	–	–		–
E-82	ESW Pump Station Div 3 Area Supply from GE Div 3 MCC-G1-2	Figure 8.3-16E ~~I110-27~~	2	20	480		3.75%
E-84 (85)	Power Feed for Excess Water Pump A, (B) (Radwaste) G17 FROM MCC A3-1	Figure 8.3-16F ~~I280~~	25	140	480		5%
E-86 (87)	Power Feed for MOV "A" ("B") G17 FROM MCC A3-1	Figure 8.3-16F	0.5	5	480		3.75%
~~E-89~~ Deleted	~~Heat Tracing Feeder for the ESW System~~						
E-93 - E-111	120 Vent Feeder from Bus J1 to Audio Alarms	I211	signal	–	120	–	–
E-34 (A-D)	125VDC BATTERY TEST FEEDER FROM DIV. 1 BATTERY (E) TO BOP	Figure 8.3-18	350A	–	125VDC	–	4%
E-35 (A-B)	125VDC BATTERY TEST FEEDER FROM DIV 4 BATTERY (H) TO BOP	Figure 8.3-18	150A	–		–	
E-36 (A-D)	125VDC BATTERY TEST FEEDER FROM DIV 2 BATTERY (F) TO BOP	Figure 8.3-18	250A	–		–	
E-38 (A-D)	125VDC BATTERY TEST FEEDER FROM DIV 3 BATTERY (G) TO BOP	Figure 8.3-18	100A	–		–	

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C F BRAUN & CO

CALCULATIONS

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			HP/KVA		Volt	Frq	VD
E-79	ESW PUMP STATION DIV 3 AREA SUPPLY FAN "D" From GE DIV3 MCCG1-2	FIG 8.3-16S	2	20	480	60~3Ø	3.75%.
E-80	FDR TO ESW PMP STATION DIV3 CPT FDR	FIG 8.3-16S	6	—	480	60~	3.75%.
E-6(A-B)	125VDC CONTROL FDR FROM BUS DC-E SWGR TO ESWS SWGR	FIG 8.3-18	6	31	125	—	8%
E-9 (A-B)	125VDC CONTROL FDR FROM BUS DC-F SWGR TO ESWS SWGR	FIG 8.3-18	6	31	125	—	8%

ATTACHMENT NO. 2

PROPOSED RESOLUTION OF
CONTAINMENT SYSTEMS BRANCH
DISCUSSION ITEMS

Change to Att. 2

3/18/83

Item 3b

GESSAR Sections 6.2.1.6.1.4 and 6.2.1.6.2, Page 6.2-72 and 6.2.1.7, Page 6.2-74 will be changed to include the requirements for visual inspection of vacuum breakers, etc. The changes are as follows:

ITEM 36 See also next page

The acceptance criteria for the bypass $A/\sqrt{K}$ for the drywell at 3 psig is less than 10% of the $A/\sqrt{K}$ value of 1.45 ft^2, as calculated in Subsection 6.2.1.1.5.5. Figure 6.2-39 shows the expected pressure decay for the drywell, assuming several leak rates and rates-of-temperature changes. The figure demonstrates that the low pressure leak rate test can be completed within the 30-min period and the gross effects of temperature change can be accounted for.

6.2.1.6.2 Post-Operational Leakage Rate Tests

The containment vacuum relief valves will be tested once a year. The leaktightness of the valves will not be tested separately but will be tested along with the entire containment, during the containment leak rate tests. Operability of the vacuum relief valves will be verified by position-limit switches on the valves, after the valve has been activated locally or remotely. ACCESSIBLE PORTIONS OF the drywell VACUUM RELIEF SYSTEM, HYDROGEN MIXING SYSTEM, DRYWELL PURGE SYSTEM AND DRYWELL BLEED SYSTEM WILL be VISUALLY INSPECTED TO DETERMINE THAT THEY ARE FREE OF FOREIGN DEBRIS. AT EACH REFUELING OUTAGE. For descriptions of the containment integrated leak rate test (ILRT) and other post-operational leakage rate tests (10CFR50 Appendix J tests Type A and B) see Subsection 6.2.6.

6.2.1.6.3 Design Provisions for Periodic Pressurization

In order to assure the capability of the containment to withstand the application of peak accident pressure at any time during plant life, for the purpose of performing integrated leakage rate tests, close attention has been given to certain design and maintenance provisions. Specifically, the effects of corrosion on the structural integrity of the containment have been minimized by the use of stainless steel cladding in the suppression pool area. Other design features which have the potential to deteriorate with age, such as flexible seals, will be carefully inspected and tested as outlined above. In this manner, the structural and leak integrity of the containment will remain essentially the same as originally accepted.

ITEM 36

The acceptance criteria for the bypass $A/\sqrt{K}$ for the drywell at 3 psig is less than 10% of the $A/\sqrt{K}$ value of 1.45 ft^2, as calculated in Subsection 6.2.1.1.5.5. Figure 6.2-39 shows the expected pressure decay for the drywell, assuming several leak rates and rates-of-temperature changes. The figure demonstrates that the low pressure leak rate test can be completed within the 30-min period and the gross effects of temperature change can be accounted for.
VISUALLY INSPECT HYDROGEN MIXING, DRYWELL PURGE & DRYWELL VACUUM BREAKERS & DRYWELL [illegible] SYSTEMS FOR LEAKAGE (~~[illegible]~~ SEE FIG 9.V-8).

6.2.1.6.2 Post-Operational Leakage Rate Tests INSPECT ~~[illegible]~~ DRYWELL VACUUM BREAKER SEAL OPENINGS FOR CLEARANCE FROM FOREIGN MATERIAL.

The containment vacuum relief valves will be tested once a year. The leaktightness of the valves will not be tested separately but will be tested along with the entire containment, during the containment leak rate tests. Operability of the vacuum relief valves will be verified by position-limit switches on the valves, after the valve has been activated locally or remotely.

For descriptions of the containment integrated leak rate test (ILRT) and other post-operational leakage rate tests (10CFR50 Appendix J tests Type A and B) see Subsection 6.2.6.

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ITEM 3b

containment. Similar transmitters, which sense containment-to-shield-annulus differential pressure, are initiating inputs to the Containment Vacuum Relief System. VACUUM RELIEF VALVES ARE CHECKED FOR OPERABILITY AT LEAST ONCE A MONTH. ACCESSIBLE PORTIONS OF THE VACUUM RELIEF VALVE SYSTEMS SHALL BE VISUALLY INSPECTED TO DETERMINE THAT THEY ARE CLEAR OF FOREIGN DEBRIS, AT EACH REFUELING OUTAGE. 480.01 Item 3b

[illegible] space and containment RWCU room temperatures are inputs to the Leak Detection System. Four thermocouples are mounted at appropriate elevations of the drywell space, and 12 thermocouples monitor drywell HVAC differential temperatures. Sixteen thermocouples are mounted in the containment RWCU rooms.

Four suppression pool-level sensors are immersed in the suppression pool water, and the assocaited level transducers are mounted above the water level. The level signals are transmitted to SPMU System logic in the control room. Eighteen thermocouples are immersed in the suppression pool water. Suppression pool temperature readouts and alarms are located in the control room.

Two hydrogen analyzers are mounted in the drywell, and two are mounted in the containment. Each analyzer draws a sample from an appropriate area of the drywell or containment.

Hydrogen concentration alarms and recorders are located in the control room.

Radiation detectors are mounted in the containment ventilation exhaust ducts. Radiation monitors and containment isolation trip circuitry is located in the control room.

Refer to Section 7.2 for a description of drywell pressure as an input to the Reactor Protection System, and Section 7.3 for a description of containment and drywell pressure, containment-to-

Change to Att. 2

3/18/83

Item 9c) It was agreed that we would add the following words to GESSAR Section ~~6.2.6.3.2~~ 6.2.6.5, "Leakage testing of the closed ESF systems outside containment is performed in accordance with Section XI of the ASME B&PV code, but will comply with the testing frequencies and leakage reporting requirements of Appendix J of 10CFR50.

Item 9c

6.2.6.4 Scheduling and Reporting of Periodic Tests (Continued)

results shall be submitted to the NRC in a summary report approximately three months after each test.

6.2.6.5 Special Testing Requirements

The maximum allowable leakage rate into the secondary containment and the means to verify that the inleakage rate has not been exceeded, as well as the bypass leakage rate, are discussed in Subsections 6.2.3 and 6.5.1.3.

LEAKAGE TESTING OF the closed ESF systems outside CONTAINMENT IS performed in ACCORDANCE with Section XI OF ASME B&PV code, but will comply with the testing frequencies AND reporting requirements of Appendix J of 10CFR50.

6.2.7 Suppression Pool Makeup System

The Suppression Pool Makeup System provides additional water from the upper containment pool to the suppression pool by gravity flow following a LOCA. The quantity of water is sufficient to account for all conceivable post-accident entrapment volumes (i.e., places where water can be stored while maintaining long-term drywell vent water coverage).

6.2.7.1 Design Basis

The following criteria were used in the design of the Suppression Pool Makeup System:

(1) The system is redundant with two 100% capacity lines. The redundant lines are physically separated and electrical controls are separated into two divisions in accordance with IEEE-279.

(2) The system is Safety Class 2, Seismic Category I, and Quality Group B.

(3) Minimum long-term post-accident suppression pool water coverage over the top of the top drywell vent is 2 ft.

9(B&C Testing)d

It was agreed that the following note will be added to Table 6.2-~~27~~ 29, "Test, vent and drain connections used to facilitate local and containment integrated leak rate testing shall be under administrative control and subject to periodic surveillance to assure their integrity".

See response to Item 9a for actual GESSAR changes.

ITEM
11 c

— GE has agreed to install debris screens on the containment purge lines as required by the NRC in BTP CSB 6-4. The Containment Cooling, Pressure Control & Purge System P&ID, Figure 9.4-6 has been changed to reflect this requirement.

Item on Page 19

Response to Staff concern Page 19 Draft SER (on Vacuum Breaker Position)

ADDITION TO 480.01 QUESTION RESPONSE

All lines which communicate with the drywell atmosphere and present a potential steam bypass path have series valves each provided with open/close status indication in the control room. With regard to the sensitivity of the close status indication a conservative value of 10% open is used for the following analysis.

The potential bypass is associated with the Drywell Purge, H_2 mixing, Drywell Vacuum Relief and Drywell Bleed off Systems (Refer to Figure 9.4-8). The following table lists the maximum open Area ~~of the largest valve~~ assuming the worst single failure in each potential path assuming the 10% open limit.

VALVE No	SIZE	PATH	AREA (10% Open) ft^2
T41 FF027	24"	DRYWELL PURGE EXHAUST	3.142×10^{-1}
T41 FF028A	10"	DRYWELL VACUUM RELIEF (DIV 1)	5.454×10^{-2}
T41 FF026	18"	DRYWELL Purge Supply	1.767×10^{-1}
T41 FF028A	10"	DRYWELL VACUUM RELIEF (DIV 2)	5.454×10^{-2}
T41 FF032A	6"	H_2 MIXING (DIV 1)	1.963×10^{-2}
T41 FF032B	6"	H_2 MIXING (DIV 2)	1.963×10^{-2}
T41 FF037A	4"	H_2 MIXING (DIV 1)	8.727×10^{-3}
T41 FF037B	4"	H_2 MIXING (DIV 2)	8.727×10^{-3}
T41 FF035	2"	DRYWELL BLEED OFF	2.182×10^{-3}
T41 FF050	2"	DRYWELL BLEED OFF	2.182×10^{-3}
		TOTAL	6.61×10^{-1}

The total Area 0.061 ft^2 is less than the allowable area of 1.45 ft^2.

Item on Page 36

GESSAR Section 3BA.7.1 will be changed to include the following statement:
"The design dynamic stress on the quencher arm weld, due to a bending moment on the arm, will not be less than 5000 psi, in accordance with NUREG-0802, Appendix B."

3BA.7 QUENCHER ANCHOR LOADS

Figures 3BA-2, 3BA-3, 3BA-5, and 3BA-6 show the general arrangement of the quencher in the pool. The anchor loads for the vertical quencher support method are defined in Tables 3BA-13 and 3BA-14 and Figures 3BA-26 through 3BA-28 for the 238 Standard Plant. Both air-clearing and water-clearing load cases were evaluated, since they do not occur simultaneously.

As shown in Figure 3BA-27, the anchor loads are specified at the base of the quencher and need to be translated to the basemat for embedment design. An additional adapting pedestal is required from the quencher bottom flange to basemat.

The analyses considered line thermal expansion. Thermal calculations for the 238 Standard Plant drywell sleeve show that concrete temperatures for normal operation do not exceed 200°F and 14-inch Schedule 80 sleeve is acceptable.

3BA.7.1 Quencher Arm Loads and Quencher Loading Application

Table 3BA-13 lists maximum forces exerted on the quencher arms. Corresponding points of force application are illustrated in Figure 3BA-26. In design of the quencher, all of these forces shall be considered as acting simultaneously in directions presenting a maximum loading condition. The design dynamic stress on the quencher arm, due to a bending moment on the arm, will not be less than 5000 psi, in accordance with NUREG-0802, Appendix B.
Table 3BA-14 lists typical design loads for the Mark III quencher configuration. These loads consist of allowable inlet line loads, typical operating loads resulting from water clearing, air

Item on Page 47 - GESSAR Section 6.1 will be changed to specify the use of reflective insulation, as shown on the attached sheet.

Item Page 47

6.1 ENGINEERED SAFETY FEATURE MATERIALS

Materials used in the engineered safety feature (ESF) components have been evaluated to ensure that material interactions do not occur that can potentially impair operation of the ESF. Materials have been selected to withstand the environmental conditions encountered during normal operation and any postulated accident. Their compatibility with core and containment spray solutions has been considered, and the effects of radiolytic decomposition products have been evaluated.

Coatings used on exterior surfaces within the primary containment are suitable for the environmental conditions expected. ~~Only metallic insulation is used inside containment, except for duct and antisweat insulation.~~ All nonmetallic thermal insulation employed is required to have the proper ratio of leachable sodium plus silicate ions to leachable chloride plus fluoride ions (Regulatory Guide 1.36), in order to minimize the possible contribution to stress corrosion cracking of austenitic stainless steel.

6.1.1 Metallic Materials

6.1.1.1 Materials Selection and Fabrication

6.1.1.1.1 Material Specifications

Table 5.2-5 lists the principal pressure-retaining materials and the appropriate material specifications for the reactor coolant pressure boundary (RCPB) components. Table 6.1-1 lists the principal pressure-retaining materials and the appropriate material specifications on the plant ESF.

Heat control insulation used inside of containment (including drywell) shall be metallic reflective insulation. Anti-sweat insulation used inside of containment (including drywell) shall be cellular glass type insulation clad with 0.016-inch thick aluminum or 0.010-inch thick series 300 austenitic stainless steel sheet.

Item on Page 53 – GESSAR Section 6.2.4.4, Page 6.2-118, will be changed to include leakage testing requirements for containment isolation valves with resilient seals, as shown on the attached sheet.

6.2.4.4 Tests and Inspections (Continued)

A discussion of testing and inspection of isolation valves is provided in Subsection 6.2.1.6 and Chapter 16. Table 6.2-25 lists all isolation valves. Instruments are periodically tested and inspected. Test and/or calibration points are supplied with each instrument. LEAKAGE INTEGRITY tests shall be performed on the containment ISOLATION VALVES with resilient seals in (a) active purge/vent systems at least once every three months; and (b) passive purge SYSTEMS AT LEAST ONCE EVERY SIX MONTHS.

Item (Page 53)

6.2.5 Combustible Gas Control in Containment

During normal power generation, combustible gas (namely, hydrogen) is not present in the containment. In the case of a LOCA, hydrogen concentration begins to build up in the drywell due to metal-water reaction and radiolytic decomposition of water. Initial control of hydrogen concentration is by diluting the relatively high hydrogen-content gas in the drywell with that of a lower content in the containment area (i.e., the hydrogen mixing system). When the total concentration becomes too great for this method to be effective, hydrogen recombiner equipment is activated. A third mode purge the containment-drywell space to the annulus. The annulus exhaust is then processed by the Standby Gas Treatment System (SGTS).]

Since there is no design requirement for the Combustible Gas Control System in the absence of a LOCA, the following discussion of the requirements for, and the performance of, a Combustible Gas Control System presumes that a LOCA has occurred.

6.2.5.1 Design Bases

Following are generalized criteria that serve as the bases for design of the Combustible Gas Control System:

(1) The system is designed to control combustible gas concentration in containment to nonexplosive levels when the generation rate of hydrogen is calculated in

ATTACHMENT NO. 3

PROPOSED RESOLUTION TO
INSTRUMENTATION AND CONTROL SYSTEMS BRANCH
DISUCSSION ITEM

Amended Draft 3/23/83
ICSB

Testing of the Backup Scram Valves

Although not associated with the formal ICSB questions, the staff requested additional justification supporting the testability of the design and the frequency for testing the backup scram valves, and their associated solenoids.

Response

The following applicant interface requirement has been added to Table 1.9-19 in GESSAR II, Section 1.9:

> "Revise technical specifications to include functional testing of back-up scram valves each refueling outage. Also, add method for confirming back-up scram valve operation following each scram occurence."

The Table 1.9-19 entry also references Section 7.2.2.2.c.i.j which addresses conformance of the RPS with Paragraph 4.10 of IEEE 279 (Capability for Test and Calibration). The following information has been added to the end of that section:

> "The applicants Technical Specifications shall require independant functional testing of the back-up scram valves each refueling outage. In addition, operation of at least one back-up scram valve shall be confirmed following each scram occurance.
>
> "Independant testing of each back-up scram valve during refueling outages will be performed using one of the following methods:
>
> "(Prefered Method) The power supply to one of the back-up scram valves shall be interrupted by pulling and tagging out its fuse. Then, with only the other valve functional, the scram buttons shall be depressed and the valve's operation confirmed by observing the subsequent 'Low Scram Air Header Pressure' alarm. In addition, an observer should confirm the pressure drop indication on the local scram valve air header pressure guage. The scram logic can then be reset, the fuse reinstalled, and the tag and annunciator cleared. The procedure should be repeated for the remaining back-up scram valve.
>
> "(Alternate Method) An observer shall stand between the back-up scram valves while the operator depresses the manual scram buttons. The operator then confirms the 'Low Scram Air Header Pressure' alarm while the observer confirms air discharges from the exhaust ports of each valve. In addition, the observer should confirm the pressure drop indication on the local scram valve air

header pressure guage. When air discharges have been confirmed on both valves, the test is complete and the scram logic and annunciator can be reset.

"After each scram occurance, the operator shall acknowledge the 'Low Scram Air Header Pressure' alarm before resetting the scram logic. This confirms at least one back-up scram valve has functioned properly."

ATTACHMENT NO. 4

DRAFT RESPONSES TO
QUALITY ASSURANCE BRANCH
QUESTIONS

260.3 Section 17.1.2.2 of the standard format (Regulatory Guide 1.70) requires the identification of safety-related structures, systems, and components controlled by the QA program. You are requested to supplement and clarify the GESSAR II application for FDA in accordance with the following:

A. The following items do not appear in Table 3.2-1. Add the appropriate items and provide a commitment that the remaining items are subject to the pertinent requirements of GE's QA program and Appendix B to 10 CFR Part 50 or justify not doing so.

(1) Control rod grapple
(2) All containment isolation valves, piping within containment isolation valves, and piping forming isolation barriers (Ref. Table 6.2-25)
(3) Drywell
(4) Drywell head region
(5) Drywell-to-suppression pool vents
(6) Reactor pressure vessel biological shield annulus
(7) Containment steam tunnel
(8) RWCU Rooms:
  a. Filter/Demineralizers Room
  b. Demineralizer Valve NEst and Holding Pump Room
  c. Precoat Room
  d. Demineralizer Drain Valve Room
  e. Backwash Receiving Tank Room
  f. Heat Exchanger Room
(9) Weir wall
(10) RHR containment spray piping
(11) RHR containment spray nozzles
(12) RHR strainers
(13) Drywell vacuum relief
(14) Containment isolation leakage detection system
(15) Personnel air locks
(16) Equipment hatch
(17) 6900 volt switchgear
(18) 480 volt load centers
(19) 480 volt motor control centers
(20) 120 VAC safety-related distribution equipment including inverters and voltage regulators
(21) Control and power cables (including underground cable system, cable splices, connectors and terminal blocks)

(22) Conduit and cable trays and their supports (Raceways containing Class IE cables and those whose failure could damage other safety-related items)
(23) Containment Electrical penetration assemblies
(24) Transformers
(25) Motors
(26) Load sequencers
(27) Protective relays and control panels
(28) 125 volt batteries, battery rocks, battery chargers, and distribution equipment
(29) Roof drainage systems (including drains and parapets) of safety-related buildings
(30) Scram discharge volume header

B. The following items are in Table 3.2-1 with indication that 10 CFR 50 Appendix B does not apply. Provide a commitment that the pertinent requirements of GE's QA program and Appendix B to 10 CFR Part 50 will apply or justify not doing so.

(1) Reactor internal structure - other (I.6)
(2) Pipe restrainings - main steam (II.6)

C. Add the following items under XLVI, "Diesel Generator System" in Table 3.2-1 or justify not doing so.

(1) Lube oil system
(2) Combustion air intake and exhaust systems
(3) Fuel oil system (all components)
(4) Diesel service water system (all components)
(5) Starting air system (all components)

D. Provide a commitment that the safety-related instrumentation and controls (I&C) described in Sections 7.1 through 7.6 of the FDA application plus safety-related I&C for safety-related fluid systems will be subject to the pertinent requirements of General Electric's QA program and Appendix B to 10 CFR Part 50. This can be done by a footnote to Table 3.2-1.

E. Enclosure 2 of NUREG-0737, "Clarification of TMI Action Plan Requirements" (November 1980) identified numerous items that are safety-related and therefore should be in Table 3.2-1. These items are listed below. Add the appropriate items to Table 3.2-1 and provide a commitment that the remaining items are subject to the pertinent requirements of General Electric's QA program and Appendix B to 10 CFR Part 50 or justify not doing so.

		NUREG-0737 (Enclosure 2) Clarification Item
(1)	Plant-safety-parameter display console.	I.D.2
(2)	Reactor coolant system vents.	II.B.1
(3)	Plant shielding.	II.B.2
(4)	Post accident sampling capability.	II.B.3
(5)	Valve position indication.	II.D.3
(6)	Dedicated hydrogen penetrations.	II.E.4.1
(7)	Containment isolation dependability.	II.E.4.2
(8)	Accident monitoring instrumentation.	II.F.1
(9)	Instrumentation for detection of inadequate core-cooling.	II.F.2
(10)	HPCI & RCIC initiation levels.	II.K.3(13)
(11)	Isolation of HPCI & RCIC.	II.K.3(15)
(12)	Challenges to and failure of relief valves.	II.K.3(16)
(13)	ADS actuation.	II.K.3(18)
(14)	Restart of core spray and LPCI.	II.K.3(21)
(15)	RCIC suction.	II.K.3(22)
(16)	Space cooling for HPCI & RCIC.	II.K.3(24)
(17)	Power on pump seals.	II.K.3(25)
(18)	Common reference level.	II.K.3(27)
(19)	ADS valve, accumulators, and associated equipment and instrumentation.	II.K.3(28)
(20)	Equipment and other items associated with the emergency support facilities.	III.A.1.2
(21)	Inplant I_2 radiation monitoring.	III.D.3.3
(22)	Control-room habitability.	III.D.3.4

<u>Response</u>

See revised subsection 17.1.2 (attached).

17.1 QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

17.1.1 Organization

See Section 1 of Reference 1.

17.1.2 Quality Assurance Program

The identification of safety-related structures, systems, and components (Q-list) to be controlled by the quality assurance program is the responsibility of the Applicant. ~~The Applicant's Q-list will be based on the quality assurance requirements given in Table 3.2-1.~~ The Applicant will supplement and clarify its Q-list in accordance with NRC Question 260.3. The appropriate items will be added to Table 3.2-1. The remaining items will be subject to the pertinent requirements of GE's and/or the Applicant's QA programs unless otherwise justified. The remainder of this subsection is covered in Section 2 of Reference 1.

17.1.3 Design Control

See Section 3 of Reference 1.

17.1.4 Procurement Document Control

See Section 4 of Reference 1.

17.1.5 Instructions, Procedures, and Drawings

See Section 5 of Reference 1.

17.1.6 Document Control

See Section 6 of Reference 1.

17.1.7 Control of Purchased Material, Equipment, and Services

See Section 7 of Reference 1.