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NUCLEAR POWER

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MFN 178-82

November 19, 1982

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

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

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

Attached please find draft responses to the Commission's October 5, 1982 request for additional information on Chapter 7 of GESSAR II. These responses reflect the NRC/GE information exchange meetings held in Bethesda October 14 & 15, 1982.

Most questions are addressed in this transmittal. Draft responses will be provided for all remaining questions in early January 1983. An amendment is scheduled for mid-January 1983 to formalize the responses.

Sincerely,

Glenn G. Sherwood
Glenn G. Sherwood, Manager
Nuclear Safety & Licensing Operation

E003

Limited Dist.

Attachments.

cc: M. J. Virgilio, NRC
M. D. Lynch, NRC (Without Attachments)
L. S. Gifford, GE-Bethesda (Without Attachments)
F. J. Miraglia (Without Attachments)
C. O. Thomas (Without Attachments)

421.01 QUESTION

You indicate in Section 7.1.2.2, 7.1.2.3 and 7.1.2.4 of your FSAR that your statements regarding the applicability of the conformance of each of your proposed systems with the General Design Criteria (GDC), regulatory guides and the appropriate industry standards are included in Table 7.1-3 through 7.1-6. However, Tables 7.1-3 through 7.1-6 are inconsistent with Table 7-1 of Section 7.1 of the Standard Review Plan (SRP). Identify and deviations between Tables 7.1-3 through 7.1-6 of your FSAR an Table 7-1 of the SRP.

421.01 RESPONSE

The existing tables (7.1-3 through 7.1-6) were arranged consistent with the previous SRP = NUREG 75/087, Table 7-1. However, these tables are in process of being revised with headings consistent with NUREG 0800, Table 7-1. Since there is actually less information required (ie, applicability of regulatory criteria is more specifically refined to appropriate systems), no deviations are anticipated. BTP applicability will not be indicated directly in the GESSAR II Tables. However a note will be provided to reference the response to question 421.02. Assessments for all BTP's in Table 7-1 will be provided in that response.

421.02 QUESTION

In Section 7.1 of your FSAR, you do not address the Branch Technical Positions (BTP) relating to the instrumentation and control systems listed in Table 7-1 of the SRP and provided in Appendix A to Chapter 7 of the SRP. Provide a detailed discussion using drawings, schematics and P&ID's to demonstrate that your proposed design conforms to the guidance provided in the applicable BTP's, including Branch Technical Position ICSB 18 (PSB) contained in Appendix 8-A of the SRP.

421.02 RESPONSE

The following Table provides GE's assessments for all BTP's shown in Table 7-1 of the SRP and BTP ICSB 18 (PSB):

(Next 5 Pages)

SRP ASSESSMENT

SRP NO. ________ REV ________ RESPONSE TO QUESTION 421.02

TITLE ________

SRP ACCEPTANCE CRITERIA	DEVIATION	JUSTIFICATION
(a) BTP ICSB 3: Isolation of low pressure systems from the High Pressure Reactor Coolant System.	See justification "B.2 and B.3" Otherwise, no deviation.	BTP ICSB 3: See Section 7.6.1.5; also Figures 6.3-6 (HPCS P&ID), 6.3-7 (LPCS P&ID) B.1: Two valves are provided. B.2 & B.3: Pressure interlocks are provided in accordance with this requirement. However, E12-F042 (LPCI) and E21-F005 (LPCS) do not automatically close on high pressure (see 7.6.1.5.D). B.4: Control Room valve position indicators are provided. B.5: HPCS utilizes 2 valves between the vessel and the HPCS, though return lines from HPCS to suppression pool have one valve in each line.
(b) BTP ICSB 4: Requirements of MOVs in the ECCS accumulator lines (PWR plants).	Not applicable to BWR plants.	BTP ICSB 4: BWRs do not employ safety injection tanks with MOIVs.
(c) BTP ICSB 12: Protection System trip point changes for operation with reactor coolant pumps out of service.	Not applicable to BWR plants.	BTP ICSB 12: BWRs do not employ reactor coolant pumps and safety setpoints are fixed.
(d) BTP ICSB 13: Design criteria for auxiliary feedwater systems.	Not applicable to BWR plants.	BTP ICSB 13: BWRs do not employ steam generators nor auxiliary feedwater systems.
(e) BTP ICSB 14: Spurious withdrawals of single control rods in PWRs.	Not applicable to BWR plants.	BTP ICSB 14: SRP identified single-failure rod withdrawal problem unique to PWRs only.

*Unless otherwise indicated, all references are in GESSAR II.

SRP ASS. SMENT

SRP NO. ______ REV ______ RESPONSE TO QUESTION 421.02 (continued)

TITLE ______

SRP ACCEPTANCE CRITERIA	DEVIATION	JUSTIFICATION
(f) BTP ICSB 16: Control Element Assembly (CEA) interlocks in Combustion Engineering reactors.	Not applicable to GE BWRs.	BTP ICSB 16: SRP identifies requirement unique to Combustion Engineering vendor.
(fg) BTP ICSB 18 (PSB): Application of the single-failure criterion to manually-controlled electrically-operated valves.	No Deviation.	BTP ICSB 18: Valve operations have been evaluated in the design. If inadvertent operation has adverse safety consequences, two valves are placed in series on the pipe with logic separation such that no single electrical short can open both valves (e.g. see valves F007 and F008 on Figure 6.7-1a). The power disconnect option is therefore unnecessary and is not used.
(g) BTP ICSB 20: Design of instrumentation and controls provided to accomplish changeover from injection to recirculation mode.	No Deviation	BTP ICSB 20: It is not within the BWR operating design base, to transfer from injection to recirculation mode. The BTP is primarily a PWR concern. However, HPCS suction automatically transfers from its preferred source (condensate storage tank) to the suppression pool on receipt of low condensate water level or high suppression pool water level signals. See 7.3.1.1.1.1.C.1 and 6.3.2.2.1. Likewise, RCIC has similar transfer (automatically), as described in 7.4.1.1.D.6 and 5.4.6.1.
(h) BTP ICSB 21: Guideline for application of Regulatory Guide 1.47.	No Deviation	BTP ICSB 21: See analysis sections for each system for application of Regulatory Guide 1-47. For example, 7.3.2.1.2.A.7 for ECCS. B.1 & B.2 Individual system components meeting guidelines B.1, 2 & 3 of Regulatory Guide 1.47 are annunciated at a single "system out of

*Unless otherwise indicated, all references are in GESSAR II.

SRP ACCEPTANCE CRITERIA	DEVIATION	JUSTIFICATION
(h) BTP ICSB 21: (Continued)	No Deviation	BTP ICSB 21: (Continued) service" window for each division. In addition, status lights identify which component causes the out-of-service condition. Manual switches are provided to compliment administrative procedures which cover functions not automatically annunciated. Both annunciators and status lights are located in the Control Room immediately accessible to the operator. B.3 The operator cannot cancel erroneous indications. He can silence the horn, but cannot clear the window or status lights until the problem is cleared. B.4 The annunciators and status lights are not safety related. However, no safety action is required by the operator based solely on annunciator indication. B.5 Interfaces between annunciators and safety-related logic are optically isolated such that no annunciator failures could cause failures of essential safety functions. Status lights are retained in the divisional circuits and are qualified with the panels housing them. Compliance with Regulatory Guide 1.75 assures redundant safety system independence is not compromised.

*Unless otherwise indicated, all references are in GESSAR II.

SRP ASSESSMENT

SRP NO. ______ REV ______

TITLE ______ RESPONSE TO QUESTION 421.02 (continued)

SRP ACCEPTANCE CRITERIA	DEVIATION	JUSTIFICATION
(h) BTP ICSB 21: (Continued)	No Deviation	BTP ICSB 21: (Continued) B.6 All indicating and annunciating functions can be tested during normal plant operation. (This should be confirmed by applicant.)
(i) BTP ICSB 22: Guidance for application of Regulatory Guide 1.22.	No Deviation	BTP ICSB 22: RPS conformance to Regulartory Guide 1.22 is addressed in Subsection 7.2.2.2.A.1. RPS conformance to IEEE-279 is addressed in Subsection 7.2.2.2.C.1. Corresponding conformance sections for ECCS are 7.3.2.1.2.A.3 and 7.3.2.1.2.C.1 respectively.
(j) BTP ICSB 26: Requirements for Reactor Protection System anticipatory trips.	Some RPS inputs come from devices mounted on non-seismically qualified equipment and/or located in non-seismically qualified enclosures.	See Subsection 7.2.3; the analysis on the use of RPS inputs from devices mounted on nonseismically qualified equipment and/or located in nonseismically qualified enclosures has been accepted per three safety evaluation reports: (1) NUREG-0124 (supplement to NUREG 75/110) "Safety Evaluation Report, GESSAR 238 Nuclear Island Standard Design Supplement 1", September 1976, pp. 7-78, 15-3,4. (2) NUREG-0151, "SER, GESSAR 251, Nuclear Steam Supply System Standard Design", March 1977. (3) NUREG-0124 Supplement 2, January 1977, pp. 15-1,2.

*Unless otherwise indicated, all references are in GESSAR II.

SRP ASS. SMENT

SRP NO. ______ REV ______

TITLE ______ RESPONSE TO QUESTION 421.02 (continued)

SRP ACCEPTANCE CRITERIA	DEVIATION	JUSTIFICATION
(j) BTP ICSB 26: (Continued)		The above reports include data for generic 238 and 251 BWR/6 designs. This analysis considers turbine trip, generator load rejection trip and recirculation pump trip (RPT). Generally, GE requires all hardware contributing to scram be qualified per IEEE-279 (7.2.2.2.C.1). Where exceptions are taken by customer/AE (i.e., TVA's turbine control valve fast closure and turbine stop valve closure and turbine stop valve closure sensors), isolation is provided to protect the integrity of the RPS.

*Unless otherwise indicated, all references are in GESSAR II.

421.03 QUESTION

In Section 7.1.2.10.18 of your FSAR, you provide information regarding the conformance of your proposed design with the guidance provided in Regulatory Guide 1.75. Discuss the details of your separation criteria for protection channel circuits, protection logic circuits and nonsafety-related circuits using one-line drawings, schematics or other drawings as appropriate, in light of the guidance provided in this regulatory guide.

421.03 RESPONSE

Details of the separation methods and techniques are provided in GESSAR II, Chapter 8, as required by Regulatory Guide 1.70, revision 3 (See Subsections 8.3.1.1.5.1, 8.3.1.3 and 8.3.1.4). Also, in conjunction with PGCC separation, see the NRC approved topical report = NEDO-10466-A, as referenced in GESSAR II, subsections 7.1.2.10.18.E, 7.7.1.9.A, 7.7.2.9.B, 8.3.1.4.1.2(6), and 8.3.1.4.2.3.2(8).

421.06 QUESTION

We have recently issued Revision 2 to Regulatory Guide 1.97 reflecting a number of major changes in our position on post-accident instrumentation. Discuss your conformance with this revised regulatory guide.

421.06 RESPONSE

A GE Assessment of Regulatory Guide 1.97 is provided in Appendix 1D as indicated in Subsection 1.1 of GESSAR II.

421.07 QUESTION

In footnote 2 to Appendix A of 10 CFR Part 50, we require the assumpution that: "single failures of passive components in electric systems should be assumed in designing against a single failure." Accordingly, discuss how you consider passive failures in all safety-related instrumentation and control systems in your proposed facility. Provide assurance that passive failures were included in a failure mode and effects analysis (FMEA) performed in response to the concerns identified in Question 421.08.

421.07 RESPONSE

Single failures of passive components in electric systems are assumed in the design of safety systems. Passive components used in safety systems are not requried to undergo mechanical motion or a change of state, however they are required to maintain the structural integrity. These components are qualified for safety application. Independent and redundant component, loop or subsystem has been provided for active as well as passive components used for all safety-related instrumentation and control systems. This redundance provided in the design of the safety systems is based on the consideration of the single failures. For detail discussions see Section 7.1.2.11.8 of GESSAR II.

Passive electrical failures have been included in the GESSAR II FMEAs, in Appendix 15c. Passive mechanical failures (pipe break, vessel rupture, valve body failure, pump casing rupture) have not been included. The latter have not been included principally because of their low probability of occurance. In addition, if passive mechanical failures had been included in the FMEAs they would only have been included on a long term basis where their failure could affect safe shutdown. Once the reactor has reached cold shutdown, a passive mechanical failure can be compensated for in so many ways that analysis of such failures in the FMEAs was not felt to be very useful.

421.08 QUESTION

We state our position in Section 7.3.2 of Regulatory Guide 1.70 that a FMEA should be a detailed analysis demonstrating that the appropriate regulatory requirements have been met. However, it is not clear in your FSAR if a FMEA addressing all credible failures has been performed. Verify that the appropriate FMEA's have been performed and address the following:

a. The FMEA is applicable to all ESF equipment.

421.08 a RESPONSE

In accordance with Regulatory Guide 1.70, Appendix 15C provides for FMEAs on selected systems of Chapters 6,7 and 9. There are a total of 32 FMEAs; either completed in detail in Appendix 15C or identified as requiring the Applicant to provide. In addition, several interfacing systems are identified as requiring FMEAs to be provided by the applicant. The combination of the FMEAs detailed in Appendix 15C and those identified to be provided by the applicant is applicable to all ESF equipment.

421.08 b QUESTION

b. The FMEA is applicable to all design changes and modifications to date.

421.08 b RESPONSE

As presented in Subsection 15C.0.6 the FMEA system-defining documents (electrical, instrumentation, and control drawings, and piping and instrumentation diagrams) utilized in conducting the FMEAs are annotated versions of the corresponding documents listed in Table 1.7-1. However, some of the Table 1.7-1 documents were revised (updated) after the FMEAs were completed. In each case the impact of the document update(s) was assessed and it was determined that the FMEA results were still valid.

421.08 c QUESTION

c. Provisions exist to assure that future design changes or modifications are included in the FMEA.

421.08 c RESPONSE

To assure that future design changes or modifications are included in the FMEAs, a statement will be added to Subsection 15C.0.6 that commits the Applicant to assess the impact of future design changes or modifications, on the validity of the FMEA results. This will also be added to section 1.9 as an interface requirement.

421.09 QUESTION

Identify any nonsafety-related electrical equipment which is assumed in Chapter 15 of your FSAR to successfully operate to mitigate the consequences of anticipated operational occurrences and accidents. For each piece of equipment identified, provide the corresponding anticipated operational occurrence(s) and accidents for which that equipment is expected to function.

421.09 RESPONSE

Analyses in FSAR Chapter 15 make no assumptions concerning successful operations of any nonsafety-related equipment to mitigate the consequences of anticipated operational occurences and accidents.

421.10 QUESTION

In Section 7.1 of your FSAR, you identify systems designed and built by you and systems designed by you and built by others. For the latter, discuss the design interface documents.

421.10 RESPONSE

This issue was closed at the GE/NRC meeting October 14, 1982 in Bethesda, Maryland. It was agreed that GE will revise Table 7.1-1 to show GE involvement in both "Designer" and "Supplier" columns for all systems listed except the "Pressure Regulator and Turbine Generator System, which is both designed and supplied by the utility applicant. Interfaces are documented in the systems elementary diagrams: Appendix 7A.

Table 7.1-1

DESIGN AND SUPPLY RESPONSIBILITY

Systems	Designer	Supplier
Reactor Protection System		
Reactor Protection System (RPS)	GE	GE
Engineered Safety Featured Systems		
Emergency Core Cooling Spray (ECCS)	GE	GE
High-Pressure Core Spray (HPCS)	GE	GE
Automatic Depressurization System (ADS)	GE	GE
Low-Pressure Core Spray (LPCS)	GE	GE
Low-Pressure Coolant Injection (LPCI)	GE	GE
Containment and Reactor Vessel Isolation Control System (CRVICS)	GE	GE/U
Main Steamline Positive Leakage Control System (MSPLCS)	GE	GE/U
Containment Spray Cooling (CS-RHR)	GE	GE
Suppression Pool Cooling (SPC-RHR)	GE	GE
Suppression Pool Makeup System (SPMU)	GE	GE/U
Containment Combustible Gas Control System (CCGCS)	GE	GE/U
Standby Gas Treatment System (SGTS)	GE	GE/U
Shield Building Annulus Mixing	GE	GE/U
Secondary Containment Isolation Control System	GE	GE/U
Containment Isolation Valve Leakage Control Systems		
Air Positive Seal (APS)	GE	GE/U
Water Positive Seal (WPS)	GE	GE/U

Table 7.1-1

DESIGN AND SUPPLY RESPONSIBILITY (Continued)

Systems	Designer	Supplier
Standby Power System		
HPCS Diesel Generator System	GE	GE/U
Emergency Diesel Generator System	GE	GE/U
Diesel Generator Auxiliaries	GE	GE/U
Essential Service Water System (ESWS)	GE	GE/U
ESF Area Cooling System	GE	GE/U
Pneumatic Supply System	GE	GE/U
Main Control Room Heating, Ventilating, and Air Conditioning System	GE	GE/U
Systems Required for Safe Shutdown		
Reactor Core Isolation Cooling (RCIC) System[1]	GE	U/GE
Standby Liquid Control System (SLCS)	GE	U/GE
RHRS/Reactor Shutdown Cooling System	GE	GE/U
Remote Shutdown System (RSS)	GE	U/GE
Other Safety Systems		
Neutron Monitoring System (NMS)		
Source Range Monitor (SRM)[2]	GE	GE
Intermediate Range Monitor (IRM)	GE	GE
Local Power Range Monitor (LPRM)	GE	GE

Table 7.1-1

DESIGN AND SUPPLY RESPONSIBILITY (Continued)

Systems	Designer	Supplier
Average Power Range Monitor (APRM)	GE	GE
Traversing Incore Probe (TIP)[2]	GE	GE
Process Radiation Monitoring System (PRMS)	GE	GE/U
Rod Pattern Control System (RPCS)	GE	GE
High-Pressure/Low-Pressure Systems Interlock Function	GE	GE/U
Recirculation Pump Trip (RPT) System	GE	GE/U
Fuel Pool Cooling and Cleanup System	GE	GE/U
Drywell/Containment Vacuum Relief System	GE	GE/U
Containment and Reactor/Auxiliary/Fuel Building Ventilation and Pressure Control System	GE	GE/U
Containment Atmosphere Monitoring System	GE/U	U/GE
Suppression Pool Temperature Monitoring	GE	GE/U
Reactor Vessel Instrumentation (partial)	GE	GE
Control Systems Not Required For Safety		
Reactor Vessel Instrumentation (partial)	GE	GE
Rod Control and Information System		
Rod Movement Control	GE	GE
Recirculation Flow Control System	GE	GE
Feedwater Control System	GE	U/GE

Table 7.1-1

DESIGN AND SUPPLY RESPONSIBILITY (Continued)

Systems	Designer	Supplier
Pressure Regulator and Turbine Generator System	U	U
Performance Monitoring System	GE	GE
Reactor Water Cleanup (RWCU) System	GE	GE
Radwaste System		
Gaseous Radwaste System	GE	GE/U
Liquid Radwaste System	GE	GE/U
Solid Radwaste System	GE	GE/U
Area Radiation Monitoring System (ARMS)	GE	GE/U
Leak Detection System	GE	GE/U
Containment Exhaust	GE	GE/U
Drywell Purge	GE	GE/U
Suppression Pool Cleanup (SPCU)	GE	GE/U
Fire Protection System	GE/U	GE/U
~~Breathing Air System~~	~~GE~~	~~U~~
Drywell Chiller	GE	GE/U
Instrument Air	GE	GE/U
Display Control System	GE	GE
Refueling Interlock Function	GE	GE

NOTES

1. For mitigation of the rod drop accident only
2. The source range monitor and traversing incore probe are included in Neutron Monitoring System discussion for completeness only; they are not safety subsystems.

421.11 QUESTION

Several recent issues related to the instrumentation and control systems have been addressed and resolved by the BWR Owners Group and/or the BWR Licensing Review Group II (LRG II). Revise Chapter 7 and the drawings in Section 1.7 of your FSAR to incorporate the resolution of these issues.

421.11 RESPONSE

LRG II issues are addressed in Appendix 1E of GESSAR II. Chapter 7 will be revised as necessary to incorporate relevant issues associated with Instrumentation and control.

421.13 QUESTION

In Table 7-2 of Section 7.1 of the SRP, we provide an applicability matrix for various sections of Chapter 7, including references to the appropriate NUREG documents. We note that you provide general information on this matter in Appendix A of your FSAR. You should be prepared to provide at a forthcoming meeting, more detailed information, using drawings as appropriate, indicating how your proposed design satisfies the following TMI action items:

a. II.D.3, Relief and safety valve position indication.

b. II.E.4.2, Containment isolation dependability, Positions (4), (6) and (7).

c. II.F.1, Accident monitoring instrumentation, Positions (4), (5) and (6).

d. II.F.3, Instrumentation for monitoring accident conditions (Regulatory Guide 1.97, Revision 2).

e. II.K.1.23, Reactor vessel level indication.

f. II.K.3.13, HPCS and RCIC initiation levels.

g. II.K.3.15, Isolation of HPCS and RCIC.

h. II.K.3.18, ADS actuation.

i. II.K.3.21, Restart of LPCS and LPCI.

j. II.K.3.22, RCIC automatic switchover.

Discuss the applicability of the resolution achieved by the BWR Owners Group for the items listed above, to your proposed design.

421.13 RESPONSE

TMI action items are discussed, along with their applicability to GESSAR II, in Appendix 1A. Each of the issues are discussed in specific detail with reference to NUREG 0737, including mark-up prints as necessary. For example, see Figure 1A.24-1 in connection with Subsection 1A-24 (Item II.D.3). Please indicate specifically where more information is required above that which is already given by the Appendix 1A response for each item.

421.15 (7.1) (7.7) Provide an overview of the plant electrical distribution system with emphasis on vital buses and divisional separation which will be used when addressing chapter 7 concerns in a forthcoming meeting. Use one-line diagrams or other drawings as appropriate.

Response

With reference to question 421.15 we direct your attention to GESSAR II, 238 Nuclear Island, volume 18, section 8.1.2

421.16 QUESTION

Identify any "first-of-a-kind" instruments used in, or providing inputs to, safety-related systems. Include any microprocessors, multiplexers or computer systems which are used in, or interface with, safety-related systems.

421.16 RESPONSE

The GESSAR II design incorporates the Solid State Safety System which fundamentally replaces relays with solid-state devices. All hardware components for GESSAR II are identical with those used in the Clinton plant, and also with those planned for TVA, Skagit, Black Fox and Allen's Creek. Therefore GESSAR II, of itself, does not have any first-of-a-kind equipment.

However, these solid-state plant designs employ three basic types of devices which are new compared with Grand Gulf, Perry, Riverbend and previous BWR's. Thses are listed and discussed as follows:

1. The logic itself is solid-state as mentioned above. Functionally, this logic performs the same (i.e, has the same Boolean expressions) as other BWR 6 relay plants for all safety-related systems except the RPS. Solid-state RPS utilizes "2-out-of-4" channels to scram as compared with "1-out-of-2 twice" for relay plants.

2. The self-test feature is unique with the solid-state logic. This feature is described in conjunction with protection system in-service testability in subsections 7.1.2.1.6 of GESSAR II.

3. Analog trip modules (ATM's) replace the more conventional Analog Comparitor Units (ACU's) for solid-state plants. Functionally, both types of trip units serve the same purpose, but ATM's are designed to interface with the self-test feature.

421.17 (7.1) (7.6) In Table 3.2-1 of your FSAR, your provided a "Q-List" of structures, systems and components whose safety functions require conformance to the applicable quality assurance requirements of Appendix B to 10 CFR Part 50. Verify that all safety-related instrumentation and controls (I&C) described in Section 7.1 thru 7.6 and other safety-related I&C equipment used in safety-related systems are subject to your QA program implementing the requirements of Appendix B. Indicate how we may determine which specific components shown in the electrical drawings referenced in Chapter 1.7 are classified as safety-related.

RESPONSE

All safety-related instrumentation and control (I&C) equipment described in Chapter 7 Sections 1 through 6 and other safety-related I&C equipment used in safety-related systems are subject to quality assurance programs which implement the requirements of 10CFR50 AppendixB, per Table 3-2-1, and Chapter 17.

Electrical drawings identified in Chapter 1, Section 7 that contain safety-related components are so indicated on the drawing. Specific safety-related components are identified by safety division classifications or special symbols as shown in Chapter 1, Figures 1-7-1a and 1.7-4.

421.18
(7.1)
(7.3)

Provide a detailed discussion of your methodology to establish the trip setpoint and allowable value for each RPS and ESF channel, including the following additional information:

a. The trip value assumed in your analyses in Chapter 15 of your FSAR.

b. The margin between the combined channel error allowance and the total channel error allowance assumed in the accident analyses.

c. The values assigned to each component of the combined channel error allowance (e.g., process measurement accuracy, sensor calibration accuracy, sensor drift, sensor environmental allowances and instrument rack drift), the basis for these values and your methodology to sum these errors.

d. The degree of your conformance with the guidance provided in Positions C.1 through C.6 of Regulatory Guide 1.105.

Response

See "attachment 1" on following pages.

ATTACHMENT 1

Instrument Setpoint Methodology

The method employed to establish adequate margins for instrument setpoint drift, inaccuracy and calibration uncertainty as discussed in NRC Regulatory Guide 1.105 is explained by reference to Figure 1. Because of the generic nature of this figure it is not drawn to any scale and is used solely to illustrate the qualitative relationships of the various margins. Starting with a Safety Limit as indicated at the extreme right hand of the figure, the first margin extends to the point marked Analytic Limit. This margin is there to account for uncertainties in the calculational model used but excludes allowances for instrumentation. Thus the calculational model can assume ideal or perfect instruments. The next margin is between the Analytical Limit and the Allowable Value of the parametric setpoint, and accounts for instrument errors and calibration capability for the specific instrumentation. The remaining margin which is of interest from a safety standpoint is that shown between the Allowable Value and the Instrument Setpoint. This margin is that which is deemed adequate to cover instrument drift which might occur during the established surveillance period. It follows that if during the surveillance period an instrument has drifted from its setpoint in a non-conservative direction but not beyond the allowable value, then the instrument performance is still within the requirements of the plant safety analysis. In this case, a Licensing Event Report (LER) would not be required.

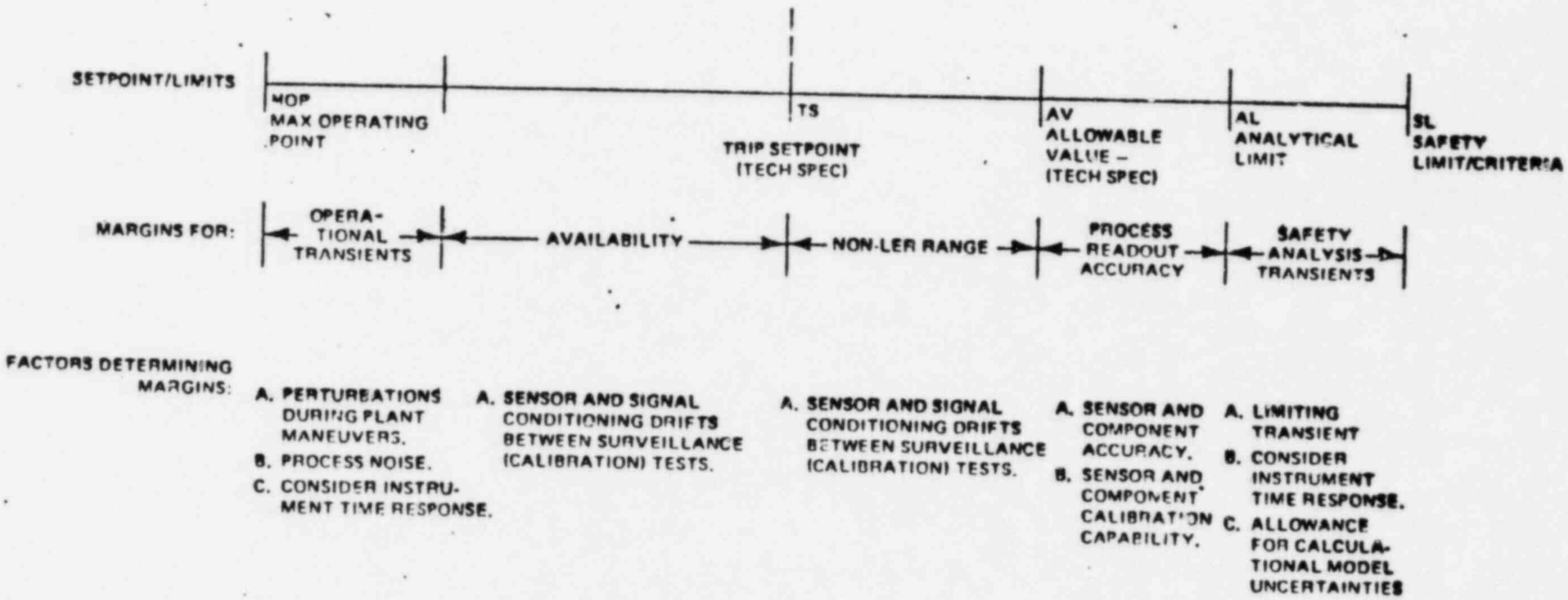
For completeness Figure 1 shows further margin between the Instrument Setpoint and the Maximum (Licensed) Operating Point for the plant. During plant operation transient overshoots may occur for certain parameters and instrument"noise" may be present. The instrument setpoint may also drift in a conservative manner. There must be sufficient margin between the instrument setpoint and the maximum operating point to avoid spurious reactor scrams or unwarranted system initiations.

Not all parameters (functional units) have an associated analytical limit, and a Design Basis (DB) limit is indicated. In general, the analytic limit is employed in those cases where a functional unit setpoint is directly associated with an analyzed abnormal plant transient or accident as described in the FSAR, Section 15. Where a design basis limit is used it is not always possible to provide simple quantification of the limit, e.g., IRMs are only required to overlap in range with portions of the SRM and APRM ranges. A similiar situation occurs with the main steam line radiation sensors which have a setpoint based essentially on previous operating experience.

For further explanation of the methodology details used in establishing the instrument setpoints ~~given in 22A4622AU~~, refer to Paragraph 3.1.9 and the notes accompanying Table 1 of attached.

Figure 1

INSTRUMENT SETPOINT SPECIFICATION BASIS



3.1.9 Instrumentation

3.1.9.1 Table 1 gives system instrumentation requirements for technical specification and non-technical specification instruments.

3.1.9.2 For response time requirements on Nuclear Boiler System instruments that provide signals to the Reactor Protection System (RPS) refer to the RPS Design Specification Data Sheet referenced in Paragraph 2.1.2.a.

3.1.9.3 The values presented are considered to bound the instruments performance with equal to or greater than 95 percent probability assuming a normal distribution. Technical specification instrument setpoints are calculated as follows:

$$\text{Technical Specification Limit} = \text{Analytical Limit} \pm \sqrt{\text{Accuracy}^2 + \text{calibration}^2}$$

$$\text{Nominal Trip Setpoint} = \text{Technical Specification Limit} \pm \text{Drift}$$

TABLE I INSTRUMENT SPECIFICATION REQUIREMENT

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-N004	TEMP ELEMENT THERMOWELL SUPP ELEM	S/R VALVE LEAKAGE DETECTION IN DISCHARGE PIPING	REFER TO B21-N614	N/A	+/- 6 DEG F	N/A	135 DEG F	0-600 DEG F
B21-N061	TEMP ELEMENT THERMOWELL SUPP W/ELEM	RPV HEAD VENT LEAKAGE DETECTION	REFER TO B21-N614	N/A	+/- 6 DEG F	N/A	135 DEG F	0-600 DEG F
B21-R614	TEMP RECORDER AND ALARM SWITCH	REFER TO B21-N004 AND B21-N061	220 DEG F	N/A	1 % FS (RECORD) 2 % FS (ALARM)	N/A	135 DEG F	0-600 DEG F
B21-N029	TEMP ELEMENT	RPV CLOSURE HEAD FLANGE STUD TEMP	REFER TO B21-N648 ETC	N/A	+/- 6 DEG F	N/A	550 DEG F	0-600 DEG F
B21-N030	THERMOCOUPLE	RPV SKIN TEMP AT BOTTOM HEAD REGION	REFER TO B21-N648 ETC	N/A	+/- 6 DEG F	N/A	528 DEG F	0-600 DEG F
B21-N050	THERMOCOUPLE	RPV HEAD SHELL FLANGE TEMP (TOP)	REFER TO B21-N648 ETC	N/A	+/- 6 DEG F	N/A	550 DEG F	0-600 DEG F

TABLE 1 (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-N648 B21-N649 B21-N650 B21-N652	TEMP SWITCH W/ALARM AND TEMP RECORDER B21-R643 (LOW TEMP ALARM)	RPV TEMP (REFER TO B21-N029 B21-N030 B21-N050)	75 DEG F	N/A	+/- 6 DEG F	N/A	REFER TO B21-N029 B21-N030 B21-N050	0-600 DEG F
B21-R643	TEMP RECORDER	RPV TEMP REFER TO B21-N029 B21-N030 B21-N050	REFER TO B21-N648 ETC	N/A	+/- 6 DEG F	N/A	REFER TO B21-N029 B21-N030 B21-N050	0-600 DEG F
B21-N040	TEMP ELEMENT THERMOWELL SUPP ELEM	MONITOR STEAM LINE TEMPERATURE W/B21-N601 A&B	N/A	N/A	+/- 1.5* DEG F	N/A	544 DEG F	400-550 DEG F
B21-N601 A&B	TEMP XMTR W/B21-N040	MAIN STEAM LINE TEMP DETECTION (TEST JACK)	N/A	N/A	+/- 1.5* DEG F	N/A	544 DEG F	400-550 DEG F
B21-N060 B21-N059 B21-N057 A B C&D	TEMP ELEMENT THERMOWELL SUPP/ELEMENT	STEAM LINE DRAIN TEMP W/SEL SWITCH B21-N064 AND INDIC B21-R008	N/A	N/A	+/- 6 DEG F	N/A	544 DEG F	0-600 DEG F
B21-N064	TEMP SELECTOR SWITCH W B21-R008	REFER TO B21-N060 ETC	N/A	N/A	N/A	N/A	544 DEG F	0-600 DEG F

* Combined accuracy of temperature element and temperature transmitter.

TABLE 1 (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-R008 (TI)	TEMP IND W/TEMP SEL SWITCH B21-N064	MONITOR STEAM LINE DRAIN TEMP	N/A	N/A	+/- 6 DEG F	N/A	544 DEG F	0-600 DEG F
B21-N041 A B C&D	TEMP ELEMENT THERMOWELL SUPP W/ELEMENT	MONITOR FEEDWATER TEMPERATURE	REFER TO B21-N602 A B C&D	N/A	+/- 1.5* DEG F	N/A	420 DEG F	300-450 DEG F
B21-N602 A B C&D	TEMP XMTR	MONITOR FEEDWATER TEMPERATURE IN CONTROL ROOM	N/A	N/A	+/- 1.5* DEG F	N/A	420 DEG F	300-450 DEG F
21-N651 A B C&D	TEMPERATURE XMTR	MONITOR FEEDWATER TEMPERATURE IN CONTROL ROOM (NECLENET READ OUT)	N/A	N/A	+/- 1.5* DEG F	N/A	420 DEG F	300-450 DEG F
B21-N027	LEVEL XMTR SHUTDOWN LEVEL	PROVIDE SIGNAL TO B21-R605	N/A	N/A	+/- 6 IN	N/A	34.9 IN (NORMAL WATER LEVEL)	0-400 IN
B21-R605	LEVEL IND SHUTDOWN LEVEL	PROVIDE REACT WATER LEV AND PRES INDICATION IN MAIN CONT RM	N/A	N/A	+/- 6 IN	N/A	34.9 IN (NORMAL WATER LEVEL)	0-400 IN

*Combined accuracy of temperature element and temperature transmitter.

TABLE 1 (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH. SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX. DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-N044 C&D	LEVEL XMTR	PROVIDES SIGNAL TO B21-R615 & B21-R610 (FUEL ZONE)	N/A	N/A	+/-6 IN	N/A	OFF SCALE	-150 TO 50 IN WTR
B21-R610	LEVEL INDICATOR	PROVIDES LEVEL IND (W/B21-N044D) FUEL ZONE	N/A	N/A	+/-2 IN	N/A	OFF SCALE	-150 TO 50 IN WTR
B21-R615	LEVEL METER	PROVIDES LEVEL IND (W/B21-N044C) FUEL ZONE	N/A	N/A	+/-2 IN	N/A	OFF SCALE	-150 TO 50 IN WTR
B21-N091 A B E&F	LEVEL XMTR	PROVIDE SIGNAL TO B21-N691 A B E&F	REFER TO B21-N691 B21-N692 A B E&F B21-N693 A B	NOTE 1			34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N691 A B E&F	LEVEL INDICATOR SWITCH	LEV 1 INIT ADS RHR LPCS PROVIDES SIG TO B21-N692 A B E&F	-149.8 IN	-152.0 -154.2 IN	2.2 IN	.44 2.2 IN	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N692 A B E&F	LEVEL SWITCH	LEV 2 INIT RCIC PROVIDES SIG TO B21-N693 A&B	-36.5 IN	-38.7 -40.9 IN	2.2 IN	.44 2.2 IN	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER

TABLE 1 (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-N693 A&B	LEVEL SWITCH	LEV 8 TRIP RCIC	53.2 IN	55.4 57.6 IN	2.2 IN	.44 .2.2 IN	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N073 C G D&H	LEVEL XMTR	PROVIDE SIGNAL TO B21-N673 C G D&H	REFER TO B21-N673 C G D&H B21-N674 C&H	NOTE 1			34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N673 C G D&H	LEVEL INDICATOR SWITCH	LEV 2 INIT HPCS	-36.5 IN	-38.7 -40.9 IN	2.2 IN	.44 2.2 IN	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N674 C&G	LEVEL SWITCH	LEV 8 INIT HPCS	53.2 IN	55.4 57.6 IN	2.2 IN	.44 2.2 IN	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N099 A E B&F	LEVEL XMTR	PROVIDE SIGNAL TO B21-N699 A B E&F	REFER TO B21-N699 A B E&F	NOTE 1			34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N699 A B E&F	LEVEL INDICATOR SWITCH	LEV 2 TRIP RECIRC	-36.5 IN	N/A	4.4 IN	N/A	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER

TABLE I (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH. SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX. DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-N095 A&B	LEVEL XMTR	PROVIDE LEV IND TO B21-N695 A&B	REFER TO B21-N695 A&B	NOTE 1			34.9 IN (NORMAL WATER LEVEL)	0 TO 60 IN WATER
B21-N695 A&B	LEVEL INDICATOR SWITCH	LEV 3 INIT ADS	11.4 IN	10.8 10.2 IN	.60 IN	.12 .6 IN	34.9 IN (NORMAL WATER LEVEL)	0 TO 60 IN WATER
B21-N081 A B C&D	LEVEL XMTR	PROVIDES LEV IND TO B21-N681 A B C&D	REFER TO B21-N681 B21-N682 A B C&D	NOTE 1			34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N681 A B C&D	LEVEL INDICATOR SWITCH	LEV 1 INIT NS4(MSIV)	-149.8 IN	-152.0 -154.2 IN	2.2 IN	.44 2.2 IN	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N682 A B C&D	LEVEL SWITCH	LEV 2 INIT NS4	-36.5 IN	-38.7 -40.9 IN	2.2 IN	.44 2.2 IN	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-R604	LEVEL INDICATOR (W/B21-N681 C)	MONITORS REACT WATER LEV IN MAIN CONT RM	N/A	N/A	+/- 2.2 IN	N/A	34.9 IN (NORMAL WATER LEVEL)	-160 TO 60 IN WATER

TABLE I (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-R623 A&B	LEVEL &PRESSURE RECORDER	MONITORS REACT WATER LEV&PRES	N/A	N/A	1 % FS	N/A	1025 PSIG 34.9 IN	0-1500 PSIG -160 TO 60 IN WATER
B21-N080 A B C&D	LEVEL XMTR	PROVIDE SIGNAL TO B21-N680 A B C&D	REFER TO B21-N680 A B C&D B21-N683 A B C&D	NOTE #1			34.9 IN (NORMAL WATER LEVEL)	0-60 IN WATER
B21-N680 A B C&D	LEVEL INDICATOR SWITCH (W/B21-N080 A B C&D)	LEV 3 INIT RPS RHR(ISO)	11.4 IN	10.8 10.2 IN	.6 IN	.12 .6 IN	34.9 IN (NORMAL WATER LEVEL)	0-60 IN WATER
B21-N683 A B C&D	LEVEL SWITCH	LEV 8 INIT RPS	53.2 IN	53.8 54.4 IN	.6 IN	.12 .6 IN	34.9 IN (NORMAL WATER LEVEL)	0 TO 60 IN WATER
B21-R009 A&B	DIFFERENTIAL PRESSURE INDICATOR	RPV DIFFERENTIAL PRESSURE	N/A	N/A	+/- 6 IN	N/A	34.9 (NORMAL WATER LEVEL)	-160 TO 60 IN WATER
B21-N068 A B E&F	PRESSURE XMTR	REACT PRES S/RV SET PT SIGNAL TO B21-N668 A B E&F ETC	REFER TO B21-N668 A B E&F ETC	NOTE# 1			1025 PSIG	0-1200 PSIG

TABLE I (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-N668 A B E&F	PRESSURE INDICATOR SWITCH	TRIPS S/RV FOR PRESSURE RELIEF (NOTE 3)	1103 PSIG	1118 1133 PSIG	15.0 PSIG	3.0 15 PSI	1025 PSIG	0-1200 PSIG
B21-N669 A B E&F	PRESSURE SWITCH	TRIPS S/RV FOR PRESSURE RELIEF (NOTE 3)	1113 PSIG	1128 1143 PSIG	15.0 PSIG	3.0 15.0 PSIG	1025 PSIG	0-1200 PSIG
B21-N670 A B E&F	PRESSURE SWITCH	TRIPS S/RV FOR PRESSURE RELIEF (NOTE 3)	1123 PSIG	1138 1153 PSIG	15.0 PSIG	3.0 15.0 PSIG	1025 PSIG	0-1200 PSIG
B21-N616 E&F	PRESSURE SWITCH	TRIPS S/RV FOR LOW LOW SET (REOPEN/RECLOSE) (LOW)	1033 926 PSIG	1048/941 1063/956 PSIG	15.0 PSIG	3.0 15.0 PSIG	1025 PSIG	0-1200 PSIG
B21-N618 A B E&F	PRESSURE SWITCH	TRIPS S/RV FOR LOW LOW SET (REOPEN/RECLOSE) (HIGH)	1113 946 PSIG	1128/961 1143/976 PSIG	15.0 PSIG	3.0 15.0 PSIG	1025 PSIG	0-1200 PSIG
B21-N617 B&F	PRESSURE SWITCH	TRIPS S/RV FOR LOW LOW SET (REOPEN/RECLOSE) (MID)	1073 936 PSIG	1088/951 1103/966 PSIG	15.0 PSIG	3.0 15.0 PSIG	1025 PSIG	0-1200 PSIG

TABLE (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY	CALIBRATION, MAX. DESIGN DRIFT ALLOW	OPERATING POINT	SCALE RANGE
B21-N078 A B C&D	PRESSURE XMTR	MONITOR STEAM DOME PRESSURE & PROVIDE SIGNAL TO B21-N678 A B C&D	REFER TO B21-N678 B21-N679 A B C&D (ETC)	NOTE #1			1025 PSIG	0-1500 PSIG
B21-N678 A B C&D	PRESSURE INDICATOR SWITCH	MONITOR STEAM DOME PRESSURE & TRIP RPS	1064.7 PSIG	1079.7 1095 PSIG	15.0 PSIG	3.0 15 PSI	1025 PSIG	0-1500 PSIG
B21-N679 A B C&D	PRESSURE SWITCH	MONITOR STEAM DOME PRESSURE & TRIP NS4 (RHR ISO)	135 PSIG	150 165 PSIG	15.0 PSI	3.0 15 PSI	1025 PSIG	0-1500 PSIG
B21-N697 E&F	PRESSURE SWITCH	MONITOR STEAM DOME PRESSURE & TRIP LPCS RHR	533 PSIG	542 <550 PSIG	16.8 PSI	.098 8.4 PSIG	1025 PSIG	0-1500 PSIG
B21-N698 E&F	PRESSURE SWITCH	MONITOR STEAM DOME PRESSURE & TRIP LPCS RHR	533 PSIG	542 <550 PSIG	16.8 PSI	.098 8.4 PSI	1025 PSIG	0-1500 PSIG
B21-N058 A B E&F	PRESSURE XMTR	MONITOR STEAM DOME PRESSURE7& PROVIDE SIGNAL TO B21-N658 A B E&F	REFER TO B21-N658 A B E&F	NOTE #1			1025 PSIG	0-1200 PSIG

TABLE 1 (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH. SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY	CALIBRATION, MAX. DESIGN DRIFT ALLOW	OPERATING POINT	SCALE RANGE
B21-N658 A B E&F	PRESSURE INDICATOR SWITCH	MONITOR STEAM DOME PRESSURE & TRIP RECIRC PUMP	1125 PSIG	N/A	+/- 15 PSI	N/A	1025 PSIG	0-1200 PSIG
B21-N067 C G D&H	PRESSURE XMTR	MONITOR DRYWELL PRESSURE & PROVIDE SIGNAL TO B21-N667 C G D&H	REFER TO B21-N667 C G D&H	NOTE #1			0-1 PSIG	0-5 PSIG
B21-N667 C G D&H	PRESSURE INDICATOR SWITCH	MONITOR DRYWELL PRESSURE AND TRIP HPCS	1.88 PSIG	1.93 2.00 PSIG	.06 PSI	.02 .05 PSI	0-1 PSIG	0-5 PSIG
B21-N094 A B E&F	PRESSURE XMTR	MONITOR DRYWELL PRESSURE & PROVIDE SIGNAL TO B21-N694 A B E&F	REFER TO B21-N694 A B E&F	NOTE #1			0-1 PSIG	0-5 PSIG
B21-N694 A B E&F	PRESSURE INDICATOR SWITCH	MONITOR DRYWELL PRESSURE AND PROVIDE SIGNAL TO RHR LPCS ADS RCIC	1.88 PSIG	1.93 2.00 PSIG	.06 PSI	.02 .05 PSI	0-1 PSIG	0-5 PSIG
B21-N076 A B C&D	PRESSURE XMTR	MONITOR MAIN STEAM LINE PRES & PROVIDE SIGNAL TO B21-N676 A B C&D	REFER TO B21-N676 A B C&D	NOTE #1			997 PSIG	0-1200 PSIG

TABLE I (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-N676 A B C&D	PRESSURE INDICATOR SWITCH	MONITOR MAIN STEAM LINE PRES & TRIP NS4	849 PSIG	837 825 PSIG	12.0 PSIG	2.4 12 PSI	997 PSIG	0-1200 PSIG
B21-N075 A B C&D	PRESSURE XMTR	MON CONDENSOR PRES (VACUUM) & PROVIDES SIG TO B21-N675 A B C&D	REFER TO B21-N675 A B C&D	NOTE #1			>27 IN HG	0-30 IN HG
B21-N675 A B C&D	PRESSURE INDICATOR SWITCH	MON CONDENSOR PRES (VACUUM) & TRIPS NS4	9 IN HG	8.7/9.3 8.1/10.0 IN HG	.6 IN HG	.2 .3 IN HG	>27 IN HG	0-30 IN HG
B21-N097 A&B	PRESSURE XMTR	MONITORS STEAM DOME PRESSURE & PROVIDES SIGNAL TO B21-N697 A&B	REFER TO B21-N697 B21-N698 A&B	NOTE #1			OFF SCALE	0-600 PSIG
B21-N697 A&B	PRESSURE INDICATOR SWITCH	MONITORS STEAM DOME PRESSURE & TRIPS RHR	533 PSIG	542 <550 PSIG	16.8 PSIG	.098 8.4 PSIG	OFF SCALE	0-600 PSIG
B21-N698 A&B	PRESSURE SWITCH	MONITORS STEAM DOME PRESSURE & TRIPS RHR	533 PSIG	542 <550 PSIG	16.8 PSIG	.098 8.4 PSIG	OFF SCALE	0-600 PSIG

TABLE 1 (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-R004 A&B	PRESSURE INDICATOR	MONITORS RES ACT STEAM DOME PRES	N/A	N/A	0.5 % FS	N/A	1025 PSIG	0-1500 PSIG
B21-N032	DIFFERENTIAL PRESSURE INDICATOR	MONITOR CORE PLATE DEVELOPED HEAD	N/A	N/A	0.5 % FS	N/A	22 PSID	0-30 PSID
B21-R005	DIFF PRES INDICATOR	MON JET PUMP DEVELOPED HEAD	N/A	N/A	+/-2% FS	N/A	26 PSID	0-30 PSID
B21-N606	TURBIDITY SWITCH W/ALARM	FEEDWATER SAMPLE -CORROSION PRODUCT MONITORING	20% INC 5% DEC	N/A	+/-2% FS	N/A	<18%	0-100%
B21-R622	TURBIDITY RECORDER	FEEDWATER SAMPLE -CORROSION PRODUCT MONITORING	N/A	N/A	+/-2% FS	N/A	<18%	0-100%
B21-R659 B21-R660 B21-R661 B21-R662 A B C&D	AC METER	MSIV CONTROL	N/A	N/A	+/-2% FS	N/A	130 MA	0-250 MA

TABLE 1 (Continued)

MPL NO	TYPE	FUNCTION	NOMINAL SET POINT	TECH.SPEC LIMIT, ANALYTICAL DESIGN LIMIT	ACCURACY (NOTE 10)	CALIBRATION, MAX.DESIGN DRIFT ALLOW (NOTE 10)	OPERATING POINT	SCALE RANGE
B21-R663 (A/B) B21-R664 (A/B)	AC METER	FEEDWATER INLET CHECK SOV	BY OTHERS	BY OTHERS	BY OTHERS	BY OTHERS	BY OTHERS	BY OTHERS
B21-N005	FLOW ELEMENT	STEAM LINE FLOW RESTRICTOR (REFER TO PARA 3.1.5)	N/A	N/A	N/A	N/A	N/A	N/A
B21-Z001	FEEDWATER MONITOR	FEEDWATER CORROSION MONITOR	N/A	N/A	N/A	N/A	N/A	N/A
B21-F022 B21-F028 A B C&D	POSITION SWITCH	MSIV CLOSURE SCRAM	94 % OPEN	93 % 90 % OPEN	+/- 2%	+/- 2 % +/- 1%	OPEN	0-100 %
ADS TIMER	TIMER	ADS INITIATION DELAY	116 SEC	117 120.0 SEC	+/- 2 SEC	+/- 1 +/- 2 SEC	N/A	0-150 SEC

NOTES:

1. Refer to master trip unit for overall accuracy, drift and calibration etc requirements including transmitter.

2. Water level instrumentations are referenced to instrument zero which is 529.75 inches above vessel zero. Fuel Zone Instrumentation are referenced at 363.5 inches (B21-N044, B21-R610, B21-R615), which is at the top of the active fuel.

3. Refer to Paragraph 3.1.3.6 for reclosure pressure.

4. Instrument Accuracy. The quality of freedom from error of the complete instrument channel from the sensor input through the trip device output including the combined conformity, hysteresis and repeatability errors.

5. Calibration Accuracy. The quality of freedom from error to which the trip setpoint is calibrated with respect to the desired setting, including both calibration instrumentation accuracies and calibration procedure allowances. When associated with the calibration instruments, this term is sometimes referred to as "Resolution".

6. Instrument Drift. The change in the value of the process variable, at which the trip action will actually accur, between the time the nominal trip setpoint is calibrated and a subsequent surveillance test, due to all causes, as measured in terms of the instrumentation indicator scale. The value of the process variable at which the trip action will actually accur at the calibration is taken to be the intended nominal trip setpoint value.

7. Analytical Limit. The value of the sensed process variable establisned as part of the safety analysis, prior to which a desired action is to be initiated to prevent the process variable from reaching the associated design safety limit.

8. Technical Specification Limit. The limit prescribed as a license condition on an important process variable.

9. Nominal Trip Setpoint. The intended calibration point at which a trip action is set to operate, commonly the center of an acceptable range of trip operation.

10. Instrument accuracy, calibration and drift specifications are plus and minus ($\pm$) the value specified.

421.19 (7.6) Discuss your methodology and rationale for determining the setpoint values associated with the various leak detection systems (LDS) discussed in Section 7.6 of your FSAR. Discuss details of the manual bypass switch which will be used during testing of the leak detection system for the RCIC, including its conformance with the guidance provided in Regulatory Guide 1.47. Discuss the applicability of your response on this specific leak detection system to other such systems described in Section 7.6 of your FSAR.

Response

Setpoint methodology and rationale for Nuclear Boiler equipment is shown in the response to question 421.18. Differences from this approach, if any, for the LDS will be discussed at the meeting.

The manual bypass switch (Keylocked) is placed in the bypass position when testing the leak detection logic used for RCIC system isolation. Control room annunciation of the bypass condition is provided as "Logic A in Bypass" and "Logic B in Bypass." This bypass and annunciation applies to the leak detection portion of the RCIC isolation logic and does not affect RCIC system initiation or operation. This arrangement meets the intent of Regulatory Guide 1.47.

421.20 Discuss in Chapter 7 of your FSAR, the design criteria you have established to prevent trapping of air or noncondensable gases in the reactor pressure vessel instrument sensing lines. Discuss the applicability of these criteria to safety-related instrument sensing lines.

RESPONSE

The criteria to prevent trapping of non-condensible gases in the RPV sensing lines are as follows:

1) the instrument lines are required to be sloped downward from the vessel to the sensors whereever local instrument racks can be located such as to accommodate the slope. A slope of approximately 1" per foot is specified to assure that gas bubbles will migrate back into the RPV. Lesser slopes required engineering approval. The instrument line slope is required to be maintained through the drywell penetrations area except where structural interferences make it impractical to maintain the 1" per foot slope. In such cases a ½" per foot slope is allowed in this area.
2) Instrument lines for liquid service are required to be installed for self venting back into the process or be provided with high point vents to release trapped non condensibles after initial filling and thereafter if necessary.

   Globe valves are required to be mounted with their stems horizontal to reduce the amount of gas that can be trapped in the valve body to a practical minimum.

   Orifices in impulse lines are concentric to obtain optimum accommodation of venting and avoidance of plugging by foreign particles. The slight heel of non condensibles resulting from this practice does not introduce any instrument error.

21.20 (cont'd)

3) Condensing chambers are connected to the RPV by 1" IPS minimum nozzles which are insulated to within 18 inches of the condensing chamber, thus making the condensing area and the amount of condensate draining back to the RPV more uniform and predictable. The evaluation of the condensing chamber above the vessel instrument tap is limited to provide favorable conditions for the non condensibles to diffuse back into the steam volume so that the accumulation of non condensibles will not become high enough to impair the condensing chambers function of maintaining the reference column level. Conservative analysis has determined that with a condensing chamber located 4 feet above the vessel nozzle the maximum non condensibles partial pressure is less than 300 psi which would not reduce the condensing rate unacceptable since it would not prevent sufficient steam from condensing to maintain the reference level.

The foregoing measures are consistent with the safety functions performed by the vessel sensing lines.

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421.21 Provide impulse line routing criteria for safety-related pressure and flow instrumentation.

RESPONSE:

Safety related pressure and flow instruments sensing lines are required to be routed such that the single failure criterion is complied with and also such as to avoid unacceptable errors from trapped non condensibles. Instrument lines are assigned to mechanical separation divisions and the instruments served by them are assigned to electrical divisions of the same number. In some cases it is necessary to serve more than one division of instruments from a single flow element. These special cases are analyzed on a case by case basis for compliance with safety criteria and shown to be acceptable.

Redundant sets of instrument lines for flow sensing (e.g., Leak Detection sensors) are required to be separated so that an event for which these lines provide sensory information necessary to initiate the mitigating action cannot cause disabling of the sensing lines unless there is provided additional backup by means of diverse sensing or additional redundancy not affected by the same event. (An example of diverse backup is ambient temperature backup for excess flow sensors).

Redundant sensing lines are required to be physically separated except where convergence is unavoidable such as at the flow element itself as in the case of the main steam flow sensors and the recirculation flow sensors. Each of these cases has been analysed to show that localized failure of redundant sensing lines does not impair the safety function as explained on the next page:

421.21
(cont'd)

1. Main Steam Flow Sensing for Main Steam Isolation Valve Closure: A main steam line break within the drywell does not have to be sensed by the steam line flow sensors because the MSIV closure cannot isolate such a break. The high flow sensing is to protect against a break outside the drywell/containment. The sensing lines are widely separated outside the containment, they are outside the steam tunnel and on opposite sides of it so they are not vulnerable to damage from the event they protect against.
2. Recirculation Flow Sensors for Flow Reference Scram: The instrument lines for Recirculation flow converge at a single sensing ~~event~~ element causing pipe whip or jets that could break or crimp an instrument line. It has been determined that a break of sufficient magnitude to be considered damaging to these lines would be sufficient to increase the drywell pressure to the scram point very quickly and thus obviate any need for the flow reference scram to be operative.

Pressure sensing lines for the reactor vessel are also designed and routed to serve as reference pressure lines for the reactor pressure vessel level measurements. Therefore, they follow the same venting, draining, and azimuthal dispersion and limited vertical drip in the drywell as specified for the level reference lines. The routing criteria for these lines are as follows:

1. Redundant sets of instrument nozzles for reactor vessel level (pressure) are required to be widely dispersed around the periphery of the vessel. (Azimuths are 15°, 165°, 195° and 345°).
2. Instrument lines are required to maintain divisional separation as they run radially from the vessel nozzles through the drywell and thence to local instrument racks located in the corresponding four quadrants of the containment.

421.21 (cont'd)

3. Vertical elevation changes for the pairs of level sensing lines are required to be equal within + or - 1 foot inside the drywell where ambient temperatures can vary over a wide range. (from normal to LOCA environment) This practice results in automatic correction for drywell temperature effects and thus keeps errors resulting from varying water density predictably low.
4. Slopes of the instrument lines are required to be adequate for effective venting of non condensibles and to permit effective flushing. This is obtained by a slope of approximately 1" per foot.
5. The vertical elevation difference from the condensing chambers to the drywell penetration is required to be not more than four feet to limit the potential error which might result from instrument line boiloff under condition in which the RPV is cooler than the drywell (in the event that the drywell is maintained above 212°F for a time sufficient to permit gross boiloff of the reference column.)

QUESTION

421.22 (7.2.1) In Section 7.2.1.1.F.2 of our FSAR, you indicate that the reactor system mode switch is used for protective functions, restrictive interlocks and refueling equipment movement. Discuss how this mode switch is incorporated into the overall design so that the single failure criterion and separation requirements are satisfied. Use detailed drawings and schematics as appropriate.

RESPONSE

421.22 The Reactor Protection System (RPS) mode switch provides bypasses and interlocks associated with various plant operation modes; RUN, START/HOT STANDBY, REFUEL, & SHUTDOWN.

The mode switch has four contact blocks, each physically separated within compartmental barriers. These contacts (A, B, C & D BLOCKS) perform interlocking functions within their associated channels (RPS A1, B1, A2 & B2 respectively).

The mode switch, as incorporated in the Reactor Protection System, meets system design requirements of separation and redundancy. The Reactor Protection System is a dual trip system with two channels per trip system. Trip of a single channel trips one trip system. Both trip systems must be tripped to initiate scram.

Failure of any one contact block will not prevent normal protective action of the safety system (scram), nor will it cause a scram.

421.23 Question

Discuss the susceptability of safety-related equipment to electromagnetic interference (EMI).

Response

Refer to attachment on following pages.

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421.23 Response:

The basic elements of the decision making logic of the NSPS are standard MIL grade CMOS logic elements, in dual in-line epoxy packages, mounted on multilayer printed circuit cards.

CMOS logic was chosen for the NSPS application because of its high noise immunity compared to other types of solid state devices. With the CMOS devices powered by 12 vdc, it takes an input greater than approximately 4 volts to switch the output on a low to high transition, and less than approximately 8 volts to switch on a high to low transition. Thus, noise spikes of considerable magnitude can be tolerated on the input lines without causing erroneous logic states. As a comparison, TTL logic which must be operated at +5V has a low to high minimum threshold of approximately .7 volt.

Numerous design techniques have been utilized to reduce the possibility of any significant electrical noise being coupled into the logic circuitry. All inputs and outputs that leave the NSPS cabinets are buffered and isolated, and internal wiring is routed to prevent "crosstalk" or radiated electromagnetic interference.

Specifically, prevention of electromagnetic conducted interference is accomplished in the following ways.

<u>Power Lines</u>: Conduction of EMI via power lines to the logic elements is prevented by the use of switching power supplies which are specified by the manufacturer to have a maximum noise spike of 62 mv. In addition, each logic card has single pole filters on the power input to remove any remaining high frequency noise.

<u>Input signal lines</u>: Inputs from other separation divisions, and from nondivisional sources are processed through optical isolators which are also filtered on the input side. Inputs from same-division sources such as the control room panels or field sources are processed through Digital Signal Conditioners (DSC's) which are filtered and optically coupled. Inputs to trip units are current loops and therefore not vulnerable to EMI.

Output signal lines: Outputs to actuated devices pass through load drivers which have pulse transformer coupling between input and output stages. Outputs to other logic elements in other divisions pass through optical isolators.

Internal wiring: Interconnections between logic cards is on a backplane of wire wrapped terminals. The connections are made point to point so that groups of wires do not run in parallel for long distances. Power wiring is routed as far from signal wiring as possible. The high current wiring of the drives to the pilot valve solenoids is run in conduit, as is the wiring for utility services (lighting).

Card layout: All signal inputs at the card level are buffered by a 100 K ohm resistor. The use of ground planes over large areas of the boards also insures electrically quiet circuitry.

All standards of good practice were applied during the design and construction of the solid state safety system to prevent any problem with EMI.

421.24 QUESTION

In Sections 7.4.1.1.B and Section 7.4.1.2.B of your FSAR, you provide details of the design criteria and classification of the RCIC and the standby liquid control system (SLCS). However, it is not clear if you have classified the RCIC as safety-related. Additionally, you indicate that you do not consider the SLCS as being required to meet the safety design basis requirements of the plant safety system. In contrast, recent applications for operating licenses (e.g., Shorham, Perry and Clinton) have classified all portions of the SLCS required for the injection of fluid, including the switch used to initiate the system, as safety-related while the heaters, indicator lights and alarms are classified as not safety-related. In these applications, all the equipment required for the RCIC system to perform its safety function of injecting water, is safety-related. Even though the RCIC is not part of the ECCS network, it is our position that the RCIC is a safety-related system similar to that of the auxiliary feedwater system in a PWR. In light of our position on this matter, discuss in detail your proposed design criteria and classification of the RCIC and SLC systems.

421.24 RESPONSE

The C&I components required to perform their safety functions for both RCIC and SLCS are classified as safety-related. The "safety-related" classification as well as the systems themselves are identical for all BWR 6 plants (See GESSAR II, table 7.1-2).

As indicated in the response to question 421.17, safety-related components are so indicated on the electrical drawings. Note the "NUCLEAR SAFETY RELATED" stamp on the front pages of RCIC and SLCS elemantaries (GESSAR II figures 7A.4-1 and 7A.4-2 respectively). Textual statements attesting the safety-related status of RCIC and SLCS are found in Subsections 7.4.2.1.1.B.1.(d) and 7.4.2.2.B.3.(c),(e) respectively. The safety design bases for both systems are found in Subsections 7.1.2.4.1 and 7.1.2.4.2 respectively.

421.25 QUESTION

In Section 7.7 of your FSAR, you indicate that the rod pattern control system (RPCS) is used to restrict rod worths and credit for this is taken in the design basis rod drop accident. You also indicate that the rod block monitor (RBM) is used to prevent erroneous withdrawal of control rods to prevent localized fuel damage. Discuss your rationale and basis for not designating these systems, or portions of these systems, as safety-related. Discuss their interfaces with safety-related portions of your design; e.g., the average power range monitor (APRM) and the refueling interlocks.

421.25 RESPONSE

The Rod Pattern Control System (RPCS) has been classified as safety-related since the PSAR stage of the GESSAR standard. (See Section 7.7 of GESSAR - 238 Safety Evaluation Report: NUREG-0124 Supplement 1 to NUREG-75/110, September 1976; also Section 7.7 of GESSAR - 251 SER: NUREG-0151, March 1977.)

Statements attesting its essentuality are found in GESSAR II, Subsections 7.6.2.4.2.C and 7.7.1.2.B. Since the RPCS is safety-related, its textual discussions are found in Section 7.6, which is disassociated from the non-essential Rod Control and Information System (RC&IS) discussion in Section 7.7.

The Rod Block Monitor (RBM) is not a part of the GESSAR II design and is not mentioned in the text. This function was associated with pre-BWR 6 designs as a subsystem within the Reactor Manual Control System.

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421.26 (7.1) (7.7) In Section 7.2 of your FSAR, you indicate that interconnections between redundant safety divisions are allowable through isolation devices. These isolating devices are used to maintain independence between safety-related circuits and between safety-related and nonsafety circuits. Provide the following additional information:

a. Identify the types of isolation devices used.

b. Provide the details of the testing which has been performed, including the results, to ensure that the isolation devices provide adequate protection against EMI, microphonics, short-circuit failures, voltage faults and voltage surges.

c. Discuss the applicability of the tests performed in Item (b) above.

RESPONSE:

a. Optical isolators are the principal devices used to provide physical and electrical isolation between safety-related circuits and between safety-related and non-safety circuits.

An isolator is an optical coupler with a high degree of electrical and physical separation. The working parts consist of a LED (light Emitting Diode) photo receiver (phototransistor or photo diode) pair separated by an optical barrier that will permit light to travel from the LED to the photo receiver, but will provide the necessary physical separation to satisfy USNRC Regulatory Guide 1.75. The LED's are mounted near the edge of an input circuit card that also contains the appropriate excitation and logic circuitry; the card is slid into one side of a specially designed double-sided printed circuit card file. The output circuit card containing photo receivers and appropriate output circuitry is located on the opposite side. A refractory material between the two sides contains holes filled with clear quartz rods which permit the light to pass while providing the necessary impervious physical barrier. The printed circuit card file is designed to be mounted in a control panel wall or other bulkhead between redundant divisions or between divisional and non-divisional bays or ducts to provide signal continuity while maintaining electrical and physical separation.

Several different input and output circuit boards will handle a variety of input and output signal levels and characteristics. Some can be intermixed for maximum flexibility ~~iwht~~ with a minimum number of different card types.

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b. Optical isolators are tested to conform to the following requirements:

1. Provide electrical isolation between the input and output sides so that any abnormal circuit condition which occurs on one side will not affect the functional capability of circuitry on the other side. Electrical isolation between the input and output is sufficient so that a voltage of 5 kV applied to the input or output will not impair the function of devices on the other side of the barrier. The applicable requirements of USNRC Regulatory Guide 1.75 are also satisfied.

2. Provide physical isolation between the input side and the output side so that any environmental abnormality (such as fire) that occurs on one side and affects circuit operation will be inhibited in affecting the functional capability of circuitry on the other side. The center barrier between the input and output sides of the isolator card file is designed using special materials as are required to allow light to pass with negligible loss while providing a physical barrier capable of preventing fire or other severe environments from having easier access between control panel divisions than if there were no isolators.

3. Provide the means of coupling between the input and output sides to allow electrical stimuli on the input side to produce the desired electrical response at the output.

4. The isolators are capable of operation within specifications when exposed to the following environments:

   a. Temperature, humidity, pressure, and radiation according to the requirements specified in FSAR 3.11.

   b. Seismic vibration according to IEEE 344 and the requirements specified in FSAR 3.10 using standard plant response spectrum multi-frequency excitation while mounted in control panels in which used.

c. The isolators have wide application and therefore meet codes and standards as separate equipment as well as part of system control panels in which they are to be located.

1. Institute of Electrical and Electronics Engineers (IEEE)

   a. IEEE 323- Qualifying Class 1E Equipment for Nuclear Power Generating Stations.

   b. IEEE 344- Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations

   c. IEEE 384- Criteria for Separation of Class 1E Equipment and Circuits.

2. Nuclear Regulatory Commission (NRC)

   a. USNRC Regulatory Guide 1.75 (Physical Independence of Electrical Systems) Rev. 1.

   b. USNRC Regulatory Guide 1.89 (Qualification of Class 1E Equipment for Nuclear Power Plants)

   c. USNRC Regulatory Guide 1.100 (Seismic Qualification of Electrical Equipment for Nuclear Power Plants)

QUESTION 421.27

In our review of the Clinton application for an OL, we were concerned about the seismic and environmental qualification of the analog trip modules (ATM) and the optical isolators (OI). In response to that concern, the applicant stated that a qualification test of these devices is underway. State whether the ATM's and the OI's proposed in your design are identical to those used in the Clinton facility. If not, discuss how they will be qualified.

RESPONSE:
The seismic and environmental qualifactions of the optical isolators are fully discussed in the response to Question 421.26. The ATM's and OI's are identical to those used in the Clinton facility.

421.29 QUESTION

In Table 7.1-2 of your FSAR, you state that your design of the main steam positive leakage control system (MS-PLCS) is identical to the River Bend design. The River Bend application in turn identifies this system as similar in design to the comparable system in the Hartsville facility. Since construction of the Hartsville plant has been delayed, modify Table 7.1-2 to either reference another facility having the same MS-PLCS design as your proposed design or list this system as a new design.

421.29 RESPONSE

Table 7.1-2 (in GESSAR II) correctly identifies Riverbend as having an identical MS-PLCS design. This is in accordance with Subsection 7.1.1 of Regulatory Guide 1.70, Revision 3. However, the Riverbend reference to Hartsville predated that plant's cancellation. Riverbend is now committed to revise its FSAR table in response to a similar NRC question on their docket (See Riverbend question #421.25).

421.30 QUESTION

We discuss our requirements for anticipated transients without scram (ATWS) in Volume 4 of NUREG-0460. However, we note that no description of the instrumentation and controls to implement these requirements for your proposed design has been provided in Chapter 7 of your FSAR. Accordingly, discuss your design and its conformance with our requirements in NUREG-0460 for ATWS. Identify all non-safety related equipment relied upon in your design to satisfy our ATWS requirements.

421.30 RESPONSE

The GESSAR II design incorporates the safety-related Recirculation Pump Trip (RPT) as required by the NRC for the BWR. Its safety design basis is stated in Subsection 7.1.2.6.6 and the system technical descriptions and analysis are found in Subsections 7.6.1.6 and 7.6.2.6 respectively.

Plant requirements for ATWS in addition to the RPT have been proposed and are currently being reviewed by the NRC. It is not clear what, if any, additional ATWS requirements will result from this review. It should be noted that the NRC has determined that the current risk from an ATWS event is acceptably small. Therefore any additional plant modifications would only be required for long-term resolution of the ATWS issue and such modifications need not satisfy the requirements for a design basis event.

Should the NRC mandate additional ATWS modifications, the GESSAR II design will be appropriately modified.

GESSAR

421.31 As a result of an event at the Brown's Ferry facility where a complete insertion of the control rods was not successful until after several attempts were made, we required design modifications related to hydraulic coupling and level monitoring to resolve this problem. You indicate in Paragraph 7.2.1.1.D.2(g) of your FSAR that four nonindicating level sensors provide scram discharge volume high water level inputs to the RPS. We conclude from this that your proposed system for monitoring the level of the scram discharge volume lacks diversity. Discuss what modifications are planned to meet the recommendations of the Office for Analysis and Evaluation of Operational Data (AEOD) presented in NUREG-0785.

RESPONSE

Scram discharge volume (SDV) level instrumentation is being changed to provide diversity in SDV high water level sensing (per PWA 20422Z/ECA 800911-1). Necessary changes to GESSAR subsection 7.2.1.1.D.2(g) are shown on the attached sheets.

7.2.1.1.D.2.f System Description (Continued)

The arrangement of signals within the trip logic requires closing of at least one valve in two or more steamlines to cause a scram. In no case does closure of two valves in one steamline cause a scram due to valve closure. The wiring for position-sensing channels feeding the different trip channels is separated.

Main steamline isolation valve closure trip channel operating bypasses are described in Subsection 7.2.1.1.D.4.(c).

(g) Scram Discharge Volume

INSERT

~~Four nonindicating level sensors provide scram discharge volume high water level inputs to the reactor protection system. Each sensor provides an input to one instrument channel. The sensors are arranged so that no single event will prevent a reactor scram caused by scram discharge volume high water level.~~

With the predetermined scram setting, a scram is initiated when sufficient capacity still remains in the tank to accommodate a scram.

Scram discharge volume water level trip channel operating bypasses are described in Subsection 7.2.1.1.D.4(d).

The environmental conditions for the RPS are described in Section 3.11. The piping arrangement of the scram discharge volume level sensors is shown in Section 4.6.

(h) Drywell Pressure

Drywell pressure is monitored by four nonindicating pressure transmitters mounted on instrument racks

GESSAR

Insert - Page 7.2-12

Four non-indicating float-type level switches (one for each channel) provide scram discharge volume (SDV) high water level inputs to the four RPS channels. In addition, a level transmitter and trip unit for each channel provide redundant SDV high water level inputs. This arrangement provides diversity, as well as redundancy, to assure that no single failure could ~~cause a~~ prevent a scram caused by SDV high water level.

QUESTION

421.32 Based on our review, it appears the the proposed logic for manual initiation for several ESF systems is interlocked with permissive logic from various sensors. In some cases, it appears that the permissive logic is dependent on the same sensors as those used for automatic initiation of the system. Our position on this matter is that the capability to manually initiate each safety system should be independent of the permissive logic, the sensors and the circuitry used for automatic initiation of that system. (Refer to Section 4.17 of IEEE Std. 279). Identify each safety system which is interlocked in a manner similar to that described above. Provide proposed modifications or justification for the present design.

In this regard, manual control of actuated devices at the motor control center (MCC) has been typically provided in previous designs. Our review of drawings I-960 A through M indicates that this feature has not been provided for your proposed design. Provide your rationale for not providing local control at the MCC's.

RESPONSE

421.32 ESF Manual Initiation

I. ECCS

The Emergency Core Cooling System (including the LPCS, LPCI, HPCS and ADS subsystems) as a whole meet IEEE 279 Paragraph 4.17 since each individual system has a provision for its own manual initiation. In addition no single failure in the manual initiation portion of the network of systems will prevent manual or automatic initiation of redundant portions of the network.

Individual Subsystem Level

LPCS, LPCI (RHR), and HPCS

The LPCS, LPCI and HPCS initiating logics can be activated manually by the operator. HPCS, LPCS each have a system manual initiation switch, LPCI is manually initiated by selecting loops B and C or loop A. The system operation after manual initiation is dependent on normal or auxiliary power being available at the pump bus and on normal valve and pump control lineup for "auto" operation. Additionally the LPCS, LPCI and HPCS operation can be initiated manually by the manipulation of the individual subsystem valve, pump and power systems control switches. In this mode the LPCS and LPCI injection valves cannot be opened manually unless a LOCA signal exists or until the reactor pressure is below the setpoint which inhibits manual operations of these valves. The HPCS flow to the vessel is inhibited in manual or automatic mode with a high vessel water level signal present.

<u>ADS</u>

The ADS initiating logic can be activated manually by the operator. There are two manual switches per division logic. The manual initiation action bypasses the ADS timer but is subject to interlock conditions which are the same as the automatic mode. The interlock ensures the LPCS or LPCI pump is running prior to depressurization of the reactor vessel by ADS. Additionally, each ADS valve can be operated manually without restriction from a control switch in the control room.

421.32 (Continued)

II. CRVICS

The CRVICS initiating logic can be activated manually by the operator. Initiation is accomplished by operating the two switches for inboard logic and the two switches for the outboard logic. There are no interlocks for manual operation.

III. MS-PLCS

The MS-PLCS is remote manually actuated in the main control room. Both inboard and outboard divisions are activated to establish the necessary pressure barrier. One switch is provided for each division (inboard and outboard). Both the inboard and outboard division systems are provided with plant air pressure and reactor pressure interlocks to prevent inadvertent system initiation during normal reactor power operation.

IV. Containment Spray Mode (RHR)

The Containment Spray Mode initiating logic can be activated manually by the operator. Separate manual initiation switches are provided for loops A and B. The manual initiation is subject to interlocks which include High Drywell Pressure for both A and B subsystems and a 90 second delay timer for the B subsystem. These interlocks are considered necessary to protect containment integrity.

421.32 (Continued)

V. Suppression Pool Cooling Mode (RHR)

The Suppression Pool Cooling mode of RHR is initiated only by manual action. Initiation is performed by manual switches for each valve and the two main RHR pumps. Manual initiation is governed by a 10 minute post-LOCA timer. The 10 minute timer prevents operator action which could divert LPCI flow away from the reactor core.

Containment Spray Mode also takes precedence over the Suppression Pool Cooling mode. Upon initiation of containment spray the RHR test return valve F024 and heat exchanger bypass valves will close if open or will be interlocked to prevent opening if they are closed.

421.32 ESF Manual Initiation

ESF Systems with Manual Initiation Permissives and/or Interlocks

System	Permissives/Interlocks	Basis
Low Pressure Core Spray (LPCS) Low Pressure Coolant Injection (LPCI)	Manual operation of LPCS and LPCI Injection Valves requires LOCA signal or reactor pressure below setpoint.	Overpressurizing LPCS, LPCI System
High Pressure Core Spray (HPCS)	High reactor water level shutdown	Overfilling reactor vessel
Automatic Depressurization System (ADS)	LPCS or LPCI pump running	Depressurization without core flow
Main Steam Positive Leakage Control System (MS-PLCS)	Reactor pressure, Air system pressure	Inadvertent initiation during reactor power operatior
Containment Spray Mode (RHR)	High drywell pressure 90 second delay, loop B only	Containment integrity
Suppression Pool Cooling Mode (RHR)	10 min post LOCA timer, reactor vessel low level, high drywell pressure	Operator directing LPCI flow away from reactor core

421.33 (7.2.1) In testing the operation of the scram pilot solenoid valve at the Grand Gulf facility, several valves were found stuck in the energized position when the solenoids were de-energized. The licensee has determined that the valves were damaged when operated with insufficient voltage applied to the solenoid coils. The basic cause of this problem was undersized cables leading from the power supply to the solenoid. Discuss what steps are being taken, if any, in your proposed design to prevent such an occurrence.

Response

421.33

The GESSAR II ~~SCRIDS~~ design uses #8 AWG wire in the scram solenoid circuits.

Our analysis indicates that the voltage drop in these circuits is so small, that the voltage applied to the solenoid coils is much higher than the recommended minimum pickup value.

QUESTION:

421.34 In Section 7.2.1.1.D.6 of your FSAR, you indicate that pilot solenoids for the scram valves "are not part of the RPS" and that the RPS interfaces with the pilot solenoids. Discuss this interface using detailed schematics and drawings as appropriate, including a discussion of the backup scram valves, their classification and their interaction or interface with the RPS.

RESPONSE:

421.34 SECTION 7.2.1.1.D.6 DOES INDICATE THAT: "THE INDIVIDUAL CONTROL RODS AND THE SCRAM VALVES, PILOT SOLENOIDS AND THEIR CONTROLS ARE NOT PART OF THE RPS."

THE ACTUATING DEVICES OR LOAD DRIVERS WHICH ARE USED TO PROVIDE OR INTERUPT THE POWER TO THE SOLENOIDS OF THE SCRAM PILOT VALVES ARE PART OF THE RPS. HOWEVER, THE ACTUATED DEVICES OR THE SCRAM PILOT VALVES THEMSELVES, AND THEIR SOLENOIDS, ARE NOT PART OF THE RPS, BUT RATHER ARE COMPONENTS OF THE CONTROL ROD DRIVE (CRD) SYSTEM. EACH HYDRAULIC CONTROL UNIT (HCU) OF THE CRD SYSTEM HAS A SINGLE SCRAM PILOT VALVE WHICH CONTROLS THE AIR SUPPLY TO THE TWO SCRAM VALVES OF THAT HCU. THE SCRAM PILOT VALVE WILL BLOCK SCRAM AIR HEADER AIR AND EXHAUST THE AIR TO THE TWO SCRAM VALVES WHEN BOTH OF THE TWO SOLENOIDS OF THE SCRAM PILOT VALVE ARE DEENERGIZED.

FIGURES 7A-2-1y, 7A-2-1z AND 7A-2-1w SHOW THE INTERFACES BETWEEN THE LOAD DRIVERS OF THE RPS AND THE SOLENOIDS OF THE SCRAM PILOT VALVES OF THE CRD SYSTEM.

THE HCU'S AND CONTROL RODS ARE ARRANGED INTO FOUR SCRAM GROUPS. IN EACH SCRAM GROUP, THE POWER TO ALL "A" SOLENOIDS OF THE SCRAM PILOT VALVES IN THAT SCRAM GROUP ARE CONTROLLED BY THE ACTIONS OF TWO RPS LOAD DRIVERS. SIMILARLY, THE POWER TO ALL "B" SOLENOIDS OF THE SCRAM PILOT VALVES IN THAT SCRAM GROUP ARE CONTROLLED BY TWO DIFFERENT LOAD DRIVERS. A TOTAL OF SIXTEEN LOAD DRIVERS ARE USED TO CONTROL THE POWER TO THE "A" AND

(421.34 RESPONSE CONT.)

"B" SOLENOIDS OF THE SCRAM PILOT VALVES OF THE FOUR SCRAM GROUPS.

EACH OF THE FOUR LOAD DRIVERS ASSOCIATED WITH A SINGLE SCRAM GROUP RECEIVES ITS TRIP SIGNAL FROM A DIFFERENT RPS DIVISION. THE INTERFACE BETWEEN THE RPS LOAD DRIVERS AND THE SOLENOIDS OF THE SCRAM PILOT VALVES ARE SUCH THAT TRIP CONDITIONS IN THE TRIP LOGICS OF EITHER OF TWO RPS DIVISIONS WILL CAUSE THE INTERUPTION OF POWER TO ALL OF THE "A" SOLENOIDS OF A SCRAM GROUP, AND TRIP CONDITIONS IN THE TRIP LOGICS OF EITHER OF THE TWO REMAINING RPS DIVISIONS WILL CAUSE THE INTERUPTION OF POWER TO ALL OF THE "B" SOLENOIDS OF THE SAME SCRAM GROUP. THE INTERFACE BETWEEN THE FOUR RPS DIVISIONS AND THE SCRAM PILOT VALVE SOLENOIDS OF EACH SCRAM GROUP IS THUS OF A ONE-OUT-OF-TWO-TAKEN-TWICE DESIGN CONFIGURATION.

THE ATTACHED SKETCH A SHOWS THE INTERFACES OF THE RPS LOAD DRIVERS WITH THE VALVES OF THE (RD) SYSTEM PRIOR TO IMPLEMENTATION OF ECA'S 810108-1, REV 0 AND 800911-1, REV. 0. ATTACHED SKETCH B SHOWS THE INTERFACES THAT WILL EXIST AFTER THE ECA'S ARE IMPLEMENTED FOR GESSAR II. ALL FURTHER DISCUSSION OF THE INTERFACES WILL ASSUME CONFIGURATION AS PER SKETCH B.

FOUR LOGIC LEVEL SIGNALS USED TO TRIP THE RPS LOAD DRIVERS ORIGINATE FROM EACH OF THE FOUR RPS DIVISIONS. FROM DIVISION 1, THESE FOUR SIGNALS CONTROL FOUR OF THE SIXTEEN LOAD DRIVERS ASSOCIATED WITH THE SCRAM PILOT VALVE SOLENOIDS. THE FOUR SIGNALS ARE IDENTICAL IN SIGNAL CONTENT, AND WHENEVER THE SIGNALS ARE AT LOGIC LEVEL ZERO (0), ONE OF THE SIGNALS WILL INTERUPT POWER TO ALL "A" SOLENOIDS IN SCRAM GROUP 1; THE SECOND WILL INTERUPT POWER TO ALL "B" SOLENOIDS IN SCRAM GROUP 2; THE THIRD WILL INTERUPT POWER TO

(421.34 RESPONSE CONT.)

ALL "B" SOLENOIDS IN SCRAM GROUP 3; AND, THE FOURTH WILL INTERUPT POWER TO ALL "A" SOLENOIDS IN SCRAM GROUP 4. SIMILARLY, THE FOUR LOGIC LEVEL SIGNALS ORIGINATING FROM RPS DIVISION 2, WHEN IN THE LOGIC LEVEL ZERO (0) STATE, WILL INTERUPT THE POWER TO ALL "A" SOLENOIDS IN SCRAM GROUPS 2 AND 1 AND TO ALL "B" SOLENOIDS IN SCRAM GROUPS 3 AND 4. THE FOUR SIGNALS ORIGINATING FROM RPS DIVISION 3, WHEN IN THE LOGIC LEVEL ZERO (0) STATE, WILL INTERUPT THE POWER TO ALL "A" SOLENOIDS IN SCRAM GROUPS 3 AND 2 AND TO ALL "B" SOLENOIDS IN SCRAM GROUPS 4 AND 1. THE REMAINING FOUR SIGNALS ORIGINATING FROM RPS DIVISION 4, WHEN IN THE LOGIC LEVEL ZERO (0) STATE, WILL INTERUPT POWER TO ALL "A" SOLENOIDS IN SCRAM GROUPS 4 AND 3 AND TO ALL "B" SOLENOIDS IN SCRAM GROUPS 1 AND 2.

NOTE THAT THE TRIP SIGNALS TO THE LOAD DRIVERS CONTROLLING THE POWER TO THE SCRAM PILOT VALVE SOLENOIDS DO NOT JUST REPRESENT TRIPS OF INDIVIDUAL RPS DIVISION TRIP LOGICS. THE FOUR SIGNALS ORIGINATING FROM RPS DIVISION 1 WILL CHANGE FROM A LOGIC LEVEL ONE (1), UNTRIPPED STATE TO A LOGIC LEVEL ZERO (0), TRIPPED STATE IF THE DIVISION 1 TRIP LOGIC HAS BEEN TRIPPED, OR IF BOTH THE DIVISION 2 AND DIVISION 3 TRIP LOGICS ARE SIMULTANEOUSLY IN A TRIPPED CONDITION, OR IF BOTH THE DIVISION 2 AND DIVISION 4 TRIP LOGICS ARE SIMULTANEOUSLY IN A TRIPPED CONDITION. THE FINAL TRIP SIGNALS FROM THE THREE OTHER RPS DIVISIONS ARE SIMILARLY CONFIGURED BUT ARE DIFFERENT FOR EACH RPS DIVISION. THE FOUR SIGNALS FROM RPS DIVISION 2 WILL CHANGE TO THE LOGIC LEVEL ZERO (0) STATE IF DIVISION 2 ALONE HAS BEEN TRIPPED, OR IF DIVISIONS 3 AND 4 HAVE BOTH BEEN TRIPPED, OR IF DIVISIONS 3 AND 1 HAVE BOTH BEEN TRIPPED. THE FOUR SIGNALS FROM RPS DIVISION 3 WILL CHANGE TO THE LOGIC LEVEL ZERO (0) STATE IF DIVISION 3 ALONE HAS BEEN TRIPPED, OR IF DIVISIONS 4 AND 1 HAVE BOTH BEEN

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TRIPPED, OR IF DIVISIONS 4 AND 2 HAVE BOTH BEEN TRIPPED. THE FOUR SIGNALS FROM RPS DIVISION 4 WILL CHANGE TO THE LOGIC LEVEL ZERO (0) STATE IF DIVISION 4 ALONE HAS BEEN TRIPPED, OR IF DIVISIONS 1 AND 2 HAVE BOTH BEEN TRIPPED, OR IF DIVISIONS 1 AND 3 HAVE BOTH BEEN TRIPPED.

THE UNIQUE SIGNAL CONTENT OF THE FINAL TRIP LOGIC SIGNALS FROM EACH RPS DIVISION, COMBINED WITH THE FINAL ONE-OUT-OF-TWO-TAKEN-TWICE CONFIGURATION INTERFACE OF THE FOUR DIVISIONS WITH EACH OF THE FOUR SCRAM GROUPS RESULTS IN A DESIGN WHEREBY ALL SCRAM PILOT VALVES OF ALL SCRAM GROUPS WILL BE ACTUATED IF ANY TWO OF THE FOUR RPS DIVISION LOGICS ARE TRIPPED. NO SCRAM RESULTS IF ONLY A SINGLE RPS LOGIC IS TRIPPED. THE RESULTING COMBINATION TRIP LOGIC BETWEEN THE INDIVIDUAL RPS DIVISION TRIPS AND THE ACTUATION OF THE SCRAM PILOT VALVES COULD BEST BE DESCRIBED AS ONE-OUT-OF-TWO TWICE COMBINED WITH PARTIAL TWO-OUT-OF FOUR TWICE COMBINATION LOGIC. THE DESIGN ALLOWS THE FUNCTIONAL TESTING OF THE FINAL ACTUATED ELEMENTS DURING PLANT OPERATION WITHOUT SUBJECTING THE PLANT TO AN UNWANTED SCRAM AND YET HAS A PROBABILITY OF SUCCESSFUL SCRAM THAT IS GREATER THAN EITHER A ONE-OUT-OF-TWO-TWICE DESIGN OR A TWO-OUT-OF-FOUR DESIGN.

THE INTERFACE OF THE RPS WITH THE BACKUP SCRAM VALVES IS ALSO SHOWN ON SKETCH B. TWO DC LOAD DRIVERS OF THE RPS ARE USED TO PROVIDE POWER TO THE SOLENOIDS OF THE TWO BACKUP SCRAM VALVES IN THE EVENT OF A FULL REACTOR SCRAM. THE SOLENOID OF BACKUP SCRAM VALVE C11-F110A WILL BE ENERGIZED IF A DIVISION TRIP EXISTS IN RPS

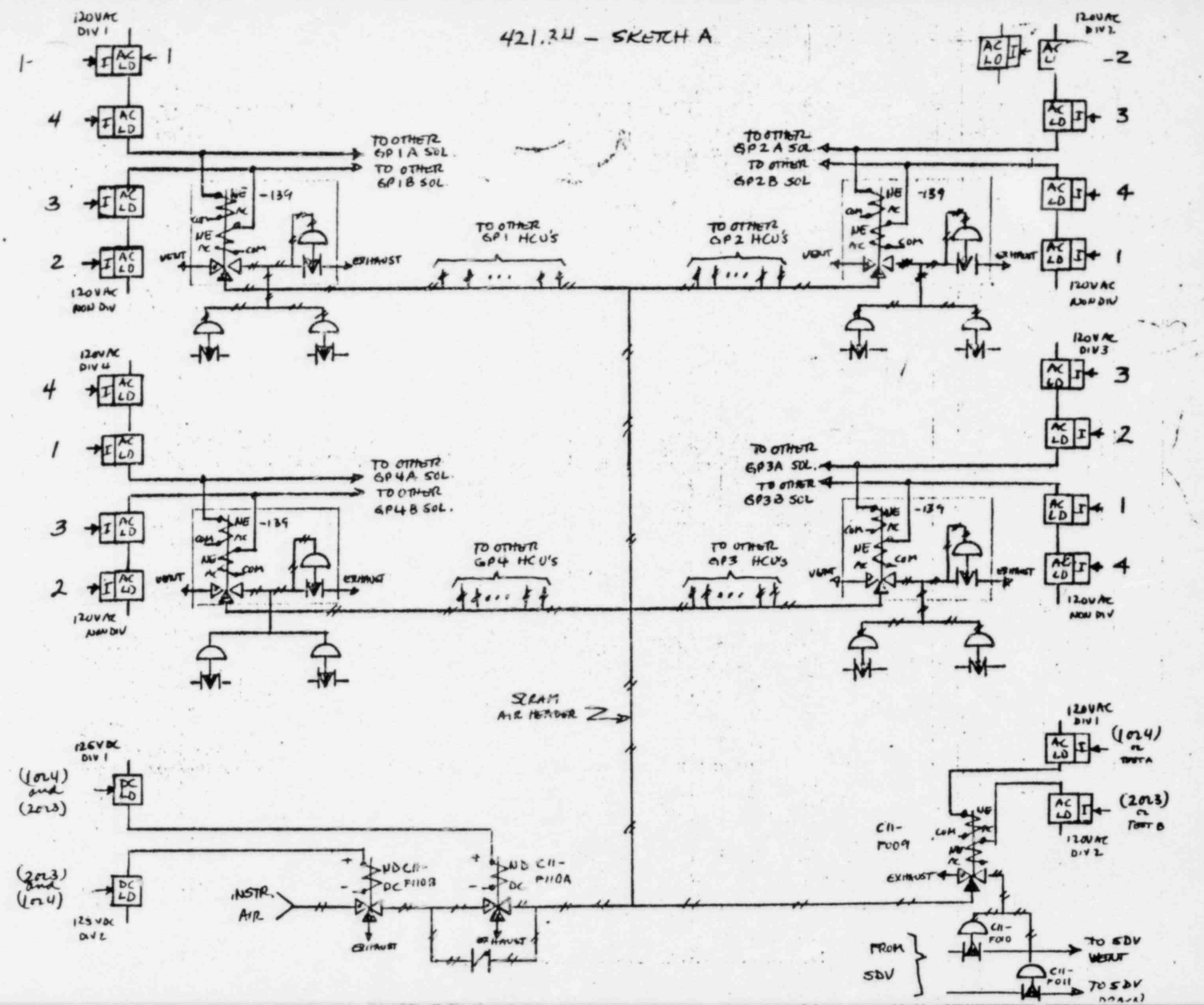
(421.34 RESPONSE CONT.)

DIVISION 1 OR DIVISION 2 AND AT THE SAME TIME A DIVISION TRIP EXISTS IN RPS DIVISION 3 OR DIVISION 4. THE SOLENOID OF BACKUP SCRAM VALVE C11-F110B WILL BE ENERGIZED IF A DIVISION TRIP EXISTS IN RPS DIVISION 2 OR DIVISION 3 AND AT THE SAME TIME A DIVISION TRIP EXISTS IN RPS DIVISION 4 OR DIVISION 1. ENERGIZATION OF THE SOLENOIDS OF EITHER OF THE TWO BACKUP SCRAM VALVES WILL BLOCK THE INSTRUMENT AIR SUPPLY TO THE SCRAM AIR HEADER AND AT THE SAME TIME EXHAUST THE AIR IN THE SCRAM AIR HEADER. THE LOAD DRIVERS ARE PART OF THE RPS WHEREAS THE BACKUP SCRAM VALVES AND THEIR SOLENOIDS ARE COMPONENTS OF THE CRD SYSTEM.

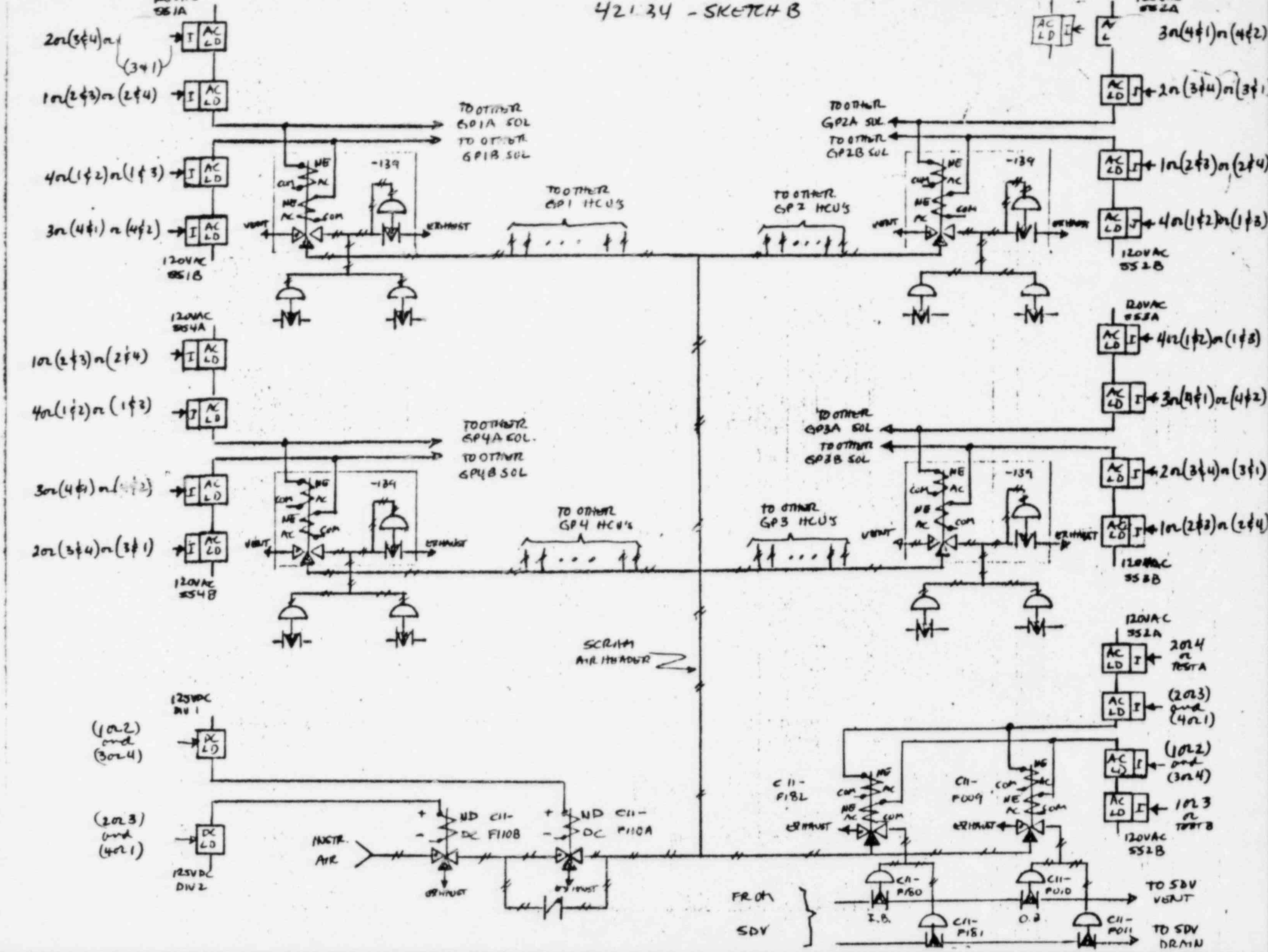
THE BACKUP SCRAM VALVES AND THEIR SOLENOIDS ARE CLASSIFIED AS NOT IMPORTANT TO SAFETY AS NO CREDIT IS TAKEN IN ANY SAFETY ANALYSIS FOR THE OPERATION OF THE BACKUP SCRAM VALVES. THEIR ONLY FUNCTION IS TO EXHAUST THE AIR IN THE SCRAM AIR HEADER AFTER A REACTOR SCRAM SUCH THAT, IF ANY SINGLE SCRAM PILOT VALVE HAS FAILED TO OPERATE AS IT SHOULD UPON THE DEENERGIZATION OF ITS TWO SOLENOIDS, THE AIR SUPPLIED TO THE TWO SCRAM VALVES ASSOCIATED WITH THAT PILOT VALVE WILL STILL EVENTUALLY BE EXHAUSTED AND THE ASSOCIATED CONTROL ROD WILL BE INSERTED INTO THE REACTOR CORE. THERE IS NO SAFETY CONSEQUENCE ASSOCIATED WITH THE FAILURE OF A SINGLE WITHDRAWN CONTROL ROD TO INSERT VIA SCRAM LOGIC. SHOULD THE SCRAM PILOT VALVE FAIL TO OPERATE AND BOTH BACKUP SCRAM VALVES ALSO FAIL TO OPERATE, THE CONTROL ROD CAN STILL BE MANUALLY INSERTED BY THE OPERATOR VIA THE NORMAL CRD SYSTEM CONTROLS.

ATTACHED: 421.34 SKETCH A
421.34 SKETCH B

421.34 – SKETCH A



421.34 - SKETCH B



421.35 (7.7) In Figure 5.1-3C of your FSAR, you indicate that the RPV pressure and water level instruments use the same instrument lines. Identify all other instances where instrument sensors or transmitters supplying information to more than one protection channel, are located in a common instrument line or connected to a common instrument tap. Verify that a single failure in a common instrument line or tap (such as a break or a blockage) cannot defeat the required protection system redundancy. Identify where instrument sensors or transmitters supplying information to both a protection channel and one or more control channels are located in a common instrument line or connected to a common instrument tap. Verify that a single failure in a common instrument line or tap cannot cause an initiating event and also defeat protection channels or functions. Provide a list of the shared equipment identified in response to these questions. Include the turbine stop valve/control valves as well as the RPV instrumentation in your analysis.

RESPONSE:

The figure cited (5.1-3C) shows a part of the nuclear boiler system and its safety related level and pressure instrumentation and illustrates schematically the grouping of instruments on the four sets of instrument taps at the four different azumuths. The vessel level and pressure instruments of each single division are connected to the same tap. This is consistent with the single failure criterion which assumes failure of an entire division of equipment as a Single Failure.
There are instances where a single instrument line or tap serves instruments in more than one division of the protection system. These cases are:

1. Main Steam Line high flow sensor for isolation of large main steam line breaks outside containment.

2. Reactor Recirculation flow sensors for flow reference scram inputs.
3. RPV level sensors for RPS division 4 and HPCS division 3 level inputs.
4. The Main Turbine First Stage pressure taps providing power level information to the RPS to permit scram on turbine trip above a specific power level.

Each of these four cases has been analyzed for single line break or blockage consequences and found to be acceptable as follows:

1. The main steam flow sensing element has two sets of ΔP taps which run in divergent directions to two local instrument racks located outside the drywell on opposite sides the containment outside the steam tunnel. Each local rack has two steam flow transmitters, which are assigned to different electrical divisions located on different separated sections of the same rack. Postulated instrument line failure could cause two high flow signals to be disabled. Such a failure could not be the result of a main steam line break outside the containment because of the location of the instrument racks. Therefore, the failure can be considered a random failure. The remaining two channels of flow information emanating from the second instrument rack provides the signals to the 2/4 logic which will initiate isolation as required by a large main steam line break. These main steam flow taps serve no control functions.
2. The Reactor Recirculation Line flow element is an elbow tap which has two sets of instrument lines which run in divergent directions to local instrument racks outside the drywell and in different quadrants of the containment. Each set of instrument lines serve two ΔP transmitters which are assigned to different electrical divisions and so are located on separate sections of the sub divided local instrument rack. A postulated instrument line failure could affect two of the four channels of flow information to the flow reference scram circuit but the remaining two operative channels would

provide the necessary 2/4 inputs to obtain a scram on the 2/4 logic IF low recirc flow were to occur. Instrument line damage in the vicinity of the elbow taps as a result of a LOCA induced pipe whip or jet could not result from a leak so small that it could not quickly raise the drywell pressure to the scram set point. Therefore, failure of these lines as consequences of a LOCA is not a safety concern.

These recirculation flow taps serve a rod block function but do not cause any active control action that would initiate a transient.

3. The division 4 RPV level sensors includes level transmitters for the HPCS system which is a Division 3 system. Therefore these transmitters have 24 VDC circuits from division 4 coming into a Division 4 CABINET ~~rack. These~~ THE DIVISION 3 circuits are required to be ~~separated~~ ISOLATED from the Division 4 circuits by ~~separate enclosures~~ CLASS 1E ISOLATORS IN THE DIVISION 4 CABINET and routed in a Division 3 raceway or conduit ~~even though the 4-20 ma signal poses no threat to the Division 4 circuits in the vicinity. Conversely, the Division 4 circuits are in their own raceway so they cannot pose a threat to~~ to the Division 3 ~~circuits~~ CABINET. It is also noted that the HPCS has a separate set of sensors located on the other side of the vessel/ containment. The division 4 RPV level taps do not serve any control function.

4. The main turbine first stage pressure connections are not always separable into four separate taps because of physical constraints. Where only two taps are available each tap serves two sensors one in each of two divisions. The breaking of an instrument line can thus disable two sensors. However in the 2/4 logic the two remaining operable ~~taps~~ SENSORS would give the required two inputs to permit the turbine stop-valve-closure scram on pressure above their set point.

The first stage pressure taps provide input to transmitters used in the rod block circuits. Each tap serves one of the rod block circuits so failure of a tap could disable one of two rod block circuits leaving the other active. This failure would not initiate any transient that could cause a need for the first stage pressure safety signals.

5. The Turbine Control Valve fast closure signals are taken from four separate taps. The only other instrument taps that serve both safety and control functions are the RPV level taps on divisions 1 and 2. The transient analysis covering a failure of one of these taps as an initiating event is covered in detail elsewhere but in summary a single failure that could initiate a RPV level transient that exceeded normal operating limits would cause either a high or low level scram which would not be disabled by an additional single failure.

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421.36 (7.1) (7.7) Provide an evaluation of the effects of high temperatures on the reference legs of the water level measuring instruments resulting from exposure to high-energy line breaks.

RESPONSE:

Exposure of the RPV level reference columns to the high ambient temperature associated with a High Energy line break will heat the column at a rate corresponding to a thermal time constant of approximately 10 minutes. Therefore, the water in the reference column will approach the temperature of the drywell environment in about 30 minutes. This temperature will depend upon the nature of the break. A large break will give a relatively low temperature (approx. 280°F) whereas a Small break will superheat the drywell to approximately 340°F. This is the condition which is of greatest concern because in the small break case, it is expected that the vessel will be depressurized after a short time and vessel water temperature will then be lower than the reference column water so that the reference column will boil. The boiling will be rapid if the vessel depressurization is rapid and it has been determined that approximately 20% of the reference column exposed to the high drywell temperature could flash quickly. This is based on a vertical column and will be less for a sloping reference line such as exists in the drywell because the volume of water per unit of vertical drop will depend on the slope which will typically be ½ inch per foot compared with 12 inches per foot for a vertical pipe. After the initial rapid flashing there would be a gradual boiling over a period of hours if the drywell ambient was maintained above the vessel temperature. Thus the reference column could be gradually depleted. The effect of this depletion will be limited by the vertical height differential between the reference level and the instrument line penetration through the drywell wall. This distance is limited by design recommendation to 4 feet so as to limit the boil off potential error to not more than that equivalent to four feet of reference column. The error would be in the direction to make the indicated level higher than the actual level. This error will not exist prior to the depressurization of the vessel because there will be no boiloff and the reference and variable legs will heat up at very nearly the same rate and thus compensate each other.

It has been determined that an error of the magnitude cited will not result in incorrect operator action or unsafe reactor conditions during recovery from LOCA.

421.37 QUESTION

Verify that there is sufficient redundancy in the water level instrumentation to prevent a sensing line failure (i.e., break, blockage or leak), concurrent with a random single electrical failure, defeating an automatic reactor protection or an ESF actuation.

421.37 RESPONSE

A complete analysis of this event scenerio was performed and submitted to J.E. Knight (NRC-ICSB) for the Grand Gulf docket. This was in response to Grand Gulf Question "J" (LRG II Item 1-ICSB), "Failure in Vessel Level Sensing Lines Common to Control and Protective Systems."

In July, 1982, Rick Kendall and Jerry Mauck (NRC-ICSB) did an independent matrix study of systems/divisional failure combinations and confirmed GE's identification of the worst-case scenerio. Furthermore, they indicated they were satisfied with GE's analysis of BWR 6 plants, and of the results which assured adequate core coverage throughout the postulated event.

GE made a comparison study of the Grand Gulf analysis relative to solid-state (GESSAR II & Clinton) designs, and assured the results were conservative. This is because RPS scram logic is any 2-out-of-4 for solid-state plants compared with 1-out-of-2 twice for Grand Gulf. The results of this comparison study is described as follows:

In BWR/6 solid-state plants, the RPS logic is any 2-out-of-4 channels to scram. Therefore, if one RPS channel reads erroneously high due to the instrument line failure and any additional RPS channel is assumed to fail-short, there are still 2 remaining channels left to accomplish normal scram. Assuring an instrument line break in Division 1 (worst-case in the Grand Gulf analysis), it is possible to fail either RCIC or HPCS by postulating the additional failure in ECCS busses 2 or 3 respectively. However, both systems cannot fail due to a single electrical failure and there will always be a normal Level 3 scram prior to automatic initiation of either (or both) high-pressure system.

The worst-case scenerio is postulated to be the reference line break coupled with HPCS failure. Normally, the operator would switch feedwater control from the bad instrument line to the good one as soon as the level mis-match is detected by the annunciator alarm. This would immediately restore normal water level. Should he neglect to do this, the water level would continue to drop until it reaches Level 2. This level would normally initiate both HPCS and RCIC and trip the recirc pumps. Assuming the additional electric failure of HPCS, only RCIC will start. Since a successful scram occurred at Level 3, RCIC is sufficient to cause water level to turn around between Level 2 and Level 1 and rise; slowly filling the vessel as power decays. If still unattended, the vessel level will gradually increase until it reaches Level 8 which trips the RCIC turbine and assures closure of the main turbine stop valves. Thus, level will drop back toward Level 2 and the cycle will continue to repeat itself even slower due to residual heat decay occuring in the vessel. This will limit vessel level between Level 2 and Level 8 indefinitely until the operator takes the remaining shutdown action. The postulated scenerio therefore has no adverse safety consequences for BWR/6 solid-state plants.

421.39 (7.3.1) In Section 7.3.1.1.2.K of your FSAR, you indicated that the containment and reactor vessel isolatior control system (CRVICS) is capable of operation during any unfavorable ambient conditions anticipated during normal operation. Discuss the capability of the CRVICS to function during abnormal and accident conditions such high-energy line breaks.

RESPONSE:

The CRVICS is made up of two separate divisions of equipment controlling two sets of valves; one set outside the containment and the other set on the inside of the containment with certain lines having their inboard valves within the drywell. All of the CRVICS valves close on low reactor vessel level and all except the MSIVs and those valves associated therewith (MS drain valves and Reactor Water sample) close on Drywell High Pressure. Isolation valves within the drywell are required to withstand the temperature and pressure and radiation conditions of all normal, abnormal and LOCA with a time limit on the duration of the LOCA environment because of their short function time for closure on a LOCA signal. Since all the valves that close on drywell high perssure start to close when the drywell pressure exceeds two psig they do not have time to reach LOCA ambient steady state conditions before they are closed and their isolation mission is completed.

Consideration of localized damage to equipment as a result of a LOCA focuses attention on the inboard isolation valves and their ability to withstand jet forces and missiles associated with a LOCA.

While it is true that an inboard valve may be affected by such forces, it is beyond the design basis to impose a LOCA pipe break and more than one single failure beyond those which can be postulated as consequential. With this groundrule it is evident that the inboard

421.39
(7.3.1)
(cont'd)

isolation valve failure as a result of consequential damages would not open a release path for radioactivity if the line involved were part of a closed system and had another isolation valve on the outside of the containment.

The following considers postulated damage to various inboard isolation valves and cites mechanisms of potential failures together with the isolation condition resulting.

MSIVS Normally Open- Fail Closed

Electrical or air service interruption may be impaired by LOCA. The valves are capable of closure on loss of air or electric power or both. Additionally a third manually operated Motor Operated valve is provided.

MAIN STEAM DRAIN VALVES - Motor Operated Valves.

These valves are normally closed during power operation but open during low power operation. Therefore, failures (electrical cable damage or mechanical damage to the operator) could open a release path to the main condenser if the outboard drain valve failure was the SAF. Because of this possibility, the MS drain valves inside the drywell are located in a protected area within the guard piped area of the main steam lines and considered to be out of the LOCA consequential damage zone. The AE and constructor are responsible for the design and installation adequacy with regard to explicit protection methods. (CF Braun is to verify the foregoing statement).

SHUTDOWN COOLING Suction Valves, Normally Closed MOV's.

Since the inboard valve is normally closed and no electrical failure as a consequence of a LOCA can command the valve to open there is no release path established through this valve.

421.39 (7.3.1) (cont'd) Reactor Water Cleanup Inboard Isolation Valve - Motor Operated. Fail-as-Is.

Damage mechanisms include cable damage or mechanical damage to the operator rendering the valve incapable of closure.

In view of the fact that the portion of the RWCU system outside containment is closed system and also protected by a second isolation valve; no radiation release path will result from inboard valve failure and a single active failure. (or single passive failure provided the outboard valve operates.)

OTHER Inboard Containment Isolation Valves. Motor Operated, Normally Open.

Closed cooling water, chilled water and air systems are examples of systems that could communicate with the drywell atmsophere in the event of a LOCA and consequential breakage of one of these pipes. The damage could also be postulated to damage the inboard valve but in each case the outboard valve and the closed system piping outside the containment would accommodate a single active failure or single passive failure without opening a release path to the environs.

421.40 QUESTION

Provide a discussion on high pressure/low pressure interfaces and the associated interlocks in Section 7.6 of your FSAR. Discuss how each of the high pressure/low pressure interfaces in your design conforms to our positions in Branch Technical Position ICSB 3. Discuss how the associated interlock circuitry conforms to the requirements of IEEE Std. 279. Your discussion should include illustrations from applicable drawings; e.g., the reactor heat removal (RHR) system.

421.40 RESPONSE

The High Pressure/Low Pressure (HP/LP) System Interlocks are described in GESSAR II, Section 7.6.1.5. The table under subsection C lists each of the isolation valves and their interlocked process line, etc. As indicated in Subsection D, all lines have at least two series valves except the steam condensing mode line. These valves can be identified on the Process and Instrumentation Diagrams (P&ID's) for each system. For example, see Figure 6.3-7 for LPCS and Figure 5.4-12 for RHR.

Interlocks prevent each valve from being opened until the primary system pressure is below the subsystem design pressure. In most cases, they also provide signals to automatically reclose the valves when primary pressure exceeds the subsystem design pressure. Exceptions are the emergency injection valves used for ECCS which must open reliably and rapidly upon receipt of an accident signal. HP/LP interlocks are controlled by transmitters which sense vessel pressure directly from the instrument lines. These transmitters are connected to trip units arranged in complimentary logic channels to prevent inadvertant operation of the valves should single failures occur. For example, the 1-out-of-2-twice logic to open LPCS injection valve F005 is shown on the LPCS Functional Control Diagram, Figure 7.3-2 of GESSAR II.

With the allowable exception for ECCS valves (i.e., they do not automatically reclose), the HP/LP interlocks described in GESSAR II meet the positions outlined in BTP ICSB-3. Also, the instrumentation and controls for the HP/LP interlocks are qualified as class 1E equipment. They are designed in accordance with the single failure criterion, redundancy requirements and testability criterion of IEEE 279.

421.41 QUESTION

In your discussion of the high pressure core spray (HPCS) system in Section 7.3.1.1.1.1.C of your FSAR, you state that the HPCS system provides water to the reactor as long as a high drywell pressure signal is present, regardless of the water level in the vessel. The control logic has been modified in the HPCS designs of other BWR's (e.g., Grand Gulf and Clinton) to stop the HPCS when the water level reaches the high level trip. This modification was implemented to prevent possible flooding of the steam lines and subsequent damage to safety/relief valves and the primary system piping. Discuss your proposed HPCS control and its "termination" logic.

421.41 RESPONSE

The GESSAR II design is to be modified just like the other BWR's mentioned. Engineering Change Authorization (ECA) number 801203-1 is already in place to facilitate the change in the GESSAR II documentation. Attached is a mark-up showing how the text will be modified to delete the high drywell signal which inhibits the level 8 trip of HPCS. The HPCS Elementary and FCD will also be revised in accordance with this change.

7.3.1.1.1.1.C High Pressure Core Spray System Instrumentation and Controls (Continued)

transmitter provides an input to an analog trip module (ATM). The output trip signals from the analog trip modules feed into one-out-of-two twice logic. The initiation logic for HPCS sensors is shown in Figure 7.3-1.

Drywell pressure is monitored by four pressure transmitters (two in Division 3 and two in Division 4). Instrument sensing lines that terminate outside the drywell allow the transmitter to communicate with the drywell interior. Each drywell high-pressure trip channel provides an input into the trip logic shown in Figure 7.3-1. The trip logic inputs are electrically connected to a one-out-of-two twice circuit.

The HPCS system is initiated on receipt of a reactor vessel low water level signal or drywell high-pressure signal from the trip logic. The HPCS system reaches its design flow rate within 27 seconds of receipt of initiation signal. Makeup water is discharged to the reactor vessel until the reactor high water level is reached. The HPCS then automatically stops flow by closing the injection valve if the high water level signal is available, ~~and drywell pressure is below the trip setting.~~ The system is arranged to allow automatic or manual operation. The HPCS initiation signal also initiates the HPCS Division 3 diesel generator.

Two ac motor operated valves are provided in the HPCS pump suction. One valve lines up pump suction from the condensate storage tank, the other from the suppression pool. The control arrangement is shown in Figure 7.3-1. Reactor grade water in the condensate storage tank is the preferred source. On receipt of an HPCS initiation signal, the condensate storage tank suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction from the suppression pool

7.3.1.1.1.1.C High Pressure Core Spray System Instrumentation and Controls (Continued)

The valves in the test line to the condensate storage tank are interlocked closed, if the suppression pool suction valve is not fully closed, to maintain the quantity of water in the suppression pool.

4. Redundancy and Diversity

The HPCS is actuated by reactor vessel low water level or drywell high pressure. Both of these conditions may result from a design basis loss-of-coolant accident.

The HPCS system logic requires two independent reactor vessel water level measurements to concurrently indicate the high water level condition. When the high water level condition is reached following HPCS operation, ~~and drywell pressure is below the trip setting,~~ these two signals are used to stop HPCS flow to the reactor vessel by closing the injection valve until such time as the low water level initiation setpoint again is reached. Should this latter condition recur, HPCS will be initiated to restore water level within the reactor.

5. Actuated Devices

All motor-operated valves in the HPCS system are equipped with remote-manual functional test feature. The entire system can be manually operated from the main control room. Motor-operator valves are provided with limit switches to turn off the motor when the full open or closed positions are reached. Torque switches also control valve motor forces while the valves are seating.

The HPCS valves must be opened sufficiently to provide design flow rate within 27 seconds from receipt of the initiation signal.

7.3.1.1.1.1.C High Pressure Core Spray System Instrumentation and Controls (Continued)

The HPCS pump discharge line is provided with an ac motor operated injection valve. The control scheme for this valve is shown in Figure 7.3-1. The valve opens on receipt of the HPCS initiation signal. The pump injection valve closes automatically on receipt of a reactor high water level signal. ~~and when drywell pressure is below the trip setting.~~

6. Separation

Separation within the Emergency Core Cooling System is in accordance with criteria given in Subsection 8.3.1.4.2. It is such that no single design basis event can prevent core cooling when required. Control and electrically driven equipment wiring is segregated into three separate electrical divisions, designated 1, 2, and 3 (Figure 8.3-1).

HPCS is a Division 3 system augmented by redundant Division 4 instrument channels (Figure 8.3-1). In order to maintain the required separation, HPCS control logic, cabling, manual controls and instrumentation are mounted so that divisional separation is maintained. System separation is as shown in Table 8.3-1.

7. Testability

The high pressure core spray instrumentation and control system is capable of being tested during normal unit operation to verify the operability of each system component. Testing of the initiation transmitters which are located outside the drywell is accomplished by valving out each transmitter, one at a time, and applying a test pressure source. This verifies the

QUESTION

421.42 (7.3) In Section 7.3.1.1.1.1 of your FSAR, you indicate that the HPCS system will automatically initiate, if required, during testing with specific exceptions. Parts of the system which are bypassed or rendered inoperable are indicated in the control room at the system level. In your response to Question 421.04, provide details relating to the HPCS system. Specifically, discuss the interlock which prevents HPCS injection into the reactor when test plugs are inserted during logic testing. Resolve the discrepancy between your statements in Sections 7.3.1.1.1.1.C.7 and 7.3.2.1.C.1.j.

RESPONSE

421.42 The High Pressure Core Spray (HPCS) system is capable of being completely tested during normal plant operation. Motor-operated valves can be exercised by the appropriate control relays and starters. Should HPCS be initiated during testing, valves will re-align, allowing high pressure core spray into reactor vessel. A motor-operated valve (MOV) test switch in control room removes the over-torque interlock bypass associated with MOV's for testing. This is considered less reliable mode of operation, but does not prevent HPCS initiation (<u>HPCS OUT OF SERVICE</u> light illuminates in control room). During plant normal operation HPCS system can be flow tested by discharging into condensate storage tank.

HPCS logic is tested by applying a test signal to each analog trip module (ATM) in turn and observing that channel trip device changes state. To verify that both elements in one out of two twice logic are functional a plug in test box is used to operate the logic as one out of one for verification of single element function. If desired, the variable associated with the ATM can be varied and, in conjunction with the ATM output indicator light and appropriate instruments, both the transmitter and ATM outputs can be verified. In those cases where the sensor is disconnected from the process variable to allow testing, an out-of-service alarm will be indicated in control room by administrative action or automatically when analog comparator trip unit is in calibration. Test specification allows this system (division 3 power augmented by division 4 channels) to be down for testing during plant normal operation. The HPCS OUT OF SERVICE light in control room will indicate HPCS is at degraded performance or inoperable during these conditions.

Though not implemented to meet the requirements of testability, the Automatic Pulse Test (APT) continuously and automatically performs end to end testing of all active circuitry. The APT improves availability of HPCS system by minimizing time to detect and locate failures.

7.3.2.1.2.C.1.i) Specific Regulatory Requirements Conformance (Continued)

The sensors can be calibrated by application of pressure from a low pressure source (instrument air or inert gas bottle) after closing the instrument valve and opening the calibration valve.

However, transmitter output is continually monitorable from the control room by observing meters on master trip units. Accuracy checks can be made by cross comparison of each of the four channels (A, E, B and F). For this reason, transmitters need not be valved out of service more than once per operating fuel cycle.

The trip units mounted in the control room are calibrated separately by introducing a calibration source and verifying the setpoint through the use of a digital readout on the trip calibration module.

j) Capability for Test and Calibration (IEEE-279-1971, Paragraph 4.10)

1) HPCS

HPCS control system is capable of being completely tested during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. Sensors can be exercised by applying test pressures. Logic can be exercised by means of plug-in test switches used alone or in conjunction with single sensor tests. Pumps can be started by the appropriate breakers, to pump against system injection valves and/or return to the suppression pool through test valves while the reactor is at pressure. Motor-operated valves can be exercised by the appropriate control relays and starters, and all indications and annunciations can be observed as the system is tested. Check valves are testable by a remotely operable pneumatic piston. HPCS water will not actually be introduced into the vessel except initially before fuel loading.

CONDENSATE STORAGE TANK

JOB NOTES

CUSTOMER	PAGES 1	PAGE
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DATE	BY	

QUESTION 421.43

Indicate why drawing I-170 A. Rev. 4, lists check valve F 019 as a control valve.

RESPONSE 421.43

Drawing I-170A, Rev. 4, lists valve F019 as a control valve in the E51 (RCIC) System, not as a check valve in the E12 (RHR) System.

421.44 (7.3) In Section 7.4.1.1 of your FSAR, you identify conditions which are monitored and which can trip the RCIC turbine stop valve and isolate the system if their set points are exceeded. Discuss the details of this design.

421.44 RESPONSE:

Table 1 lists the conditions which initiate an RCIC turbine trip by rapidly closing the RCIC turbine steam supply stop valve.

Table 2 lists the conditions which initiate RCIC system isolation and shutdown.

Instrumentation incorporated in both the RCIC and steam leak detection systems are designed to continually monitor the conditions listed in Tables 1 and 2, and initiate an RCIC system turbine trip or turbine trip and isolation, as illustrated in Figure 1&2 logic diagrams.

GESSAR II, sections 7.4.1.1.2,3,6 and 7.6.1.3.2 describe the details of the logic shown in Figures 1&2. While environmental and equipment protection is the primary purpose for isolating and shutting down the RCIC system during abnormal operations, the design incorporates precautions to preclude spurious or premature corrective actions. Table 3 lists some of these precautions.

TABLE 1

RCIC TURBINE TRIP SIGNALS

HIGH TURBINE EXHAUST PRESSURE

LOW RCIC PUMP SUCTION PRESSURE

TURBINE OVERSPEED MECHANICAL

TURBINE OVERSPEED ELECTRICAL

RCIC ISOLATION LOGIC "A"

RCIC ISOLATION LOGIC "B"

TURBINE TRIP MANUAL

TABLE 2

RCIC SYSTEM ISOLATION SIGNALS

HIGH TURBINE EXHAUST DIAPHRAGM PRESSURE

HIGH RHR EQUIPMENT AREA AMBIENT TEMP.

HIGH RCIC EQUIPMENT AREA AMBIENT TEMP.

HIGH RHR EQUIPMENT AREA VENTILATION
INLET AND OUTLET DIFFERENTIAL TEMP.

HIGH RCIC EQUIPMENT AREA VENTILATION
INLET AND OUTLET DIFFERENTIAL TEMP.

HIGH RCIC PIPE IN STEAM TUNNEL AREA TEMPERATURE.

HIGH RCIC STEAM LINE DIFFERENTIAL PRESSURE OR INSTRUMENT
LINE BREAK.

LOW RCIC STEAM SUPPLY PRESSURE

TABLE 3

1. ESTABLISHING TRIP SET-POINT VALVES FAR ENOUGH AWAY FROM NORMAL OPERATING VALVES, YET SUFFICIENTLY CLOSE TO PROTECT THE ENVIRONS AND EQUIPMENT.
2. INCORPORATING TIME-DELAY TRIP LOGIC CIRCUITS
3. REQUIRING COINCIDENT TRIPS TO INITIATE CORRECTIVE ACTION
4. USING TURBINE SPEED RUN-BACK, RATHER THAN COMPLETE SHUTDOWN, TO CORRECT ABNORMALITIES WHERE ENVIRONMENTAL OR EQUIPMENT DAMAGE IS NOT IMMINENT.
5. SELECTING RELIABLE, SAFETY-QUALIFIED INSTRUMENTATION AND CONTROL EQUIPMENT.

FIGURE-1

RCIC TURBINE TRIP LOGIC CIRCUIT

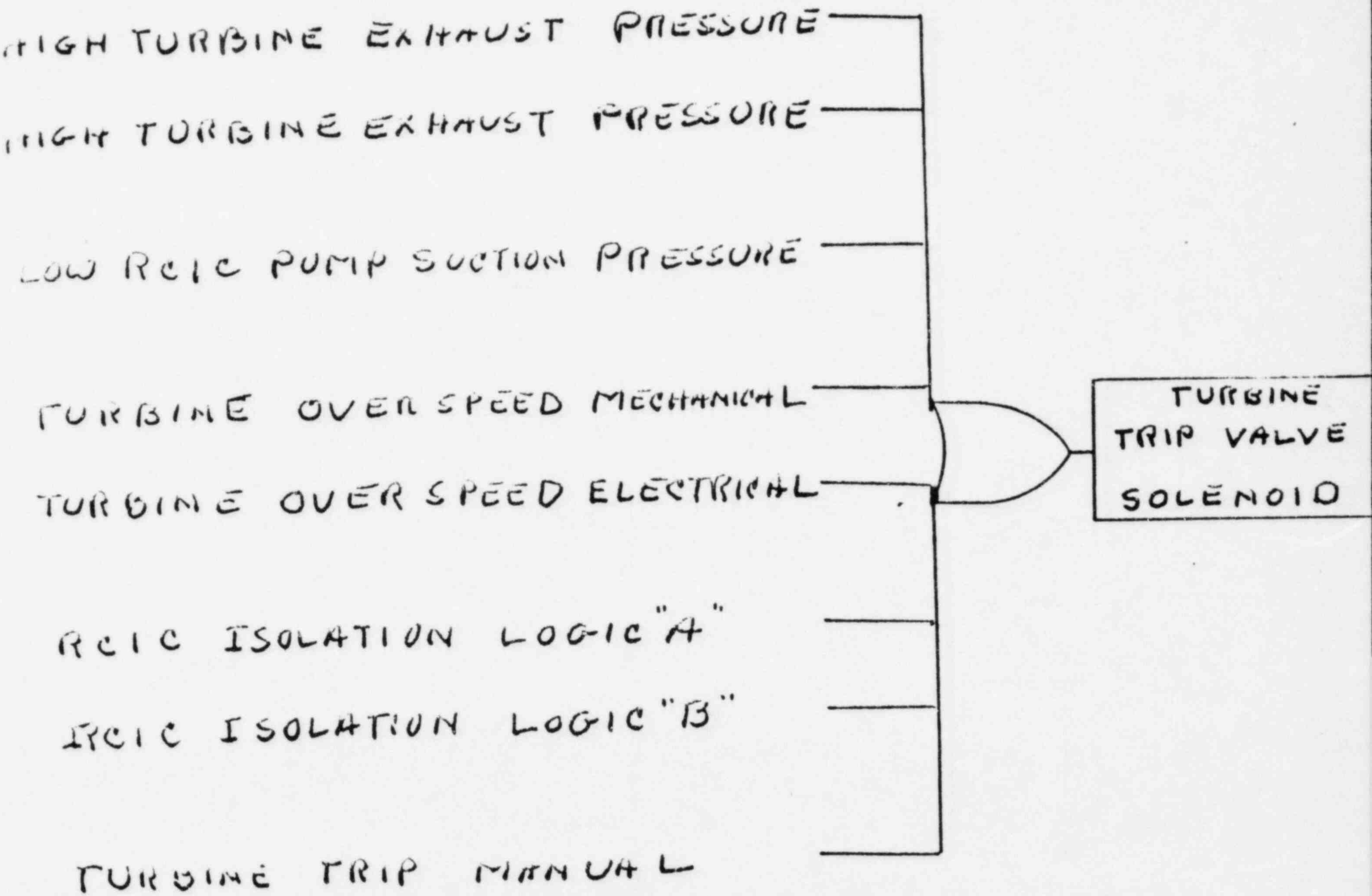
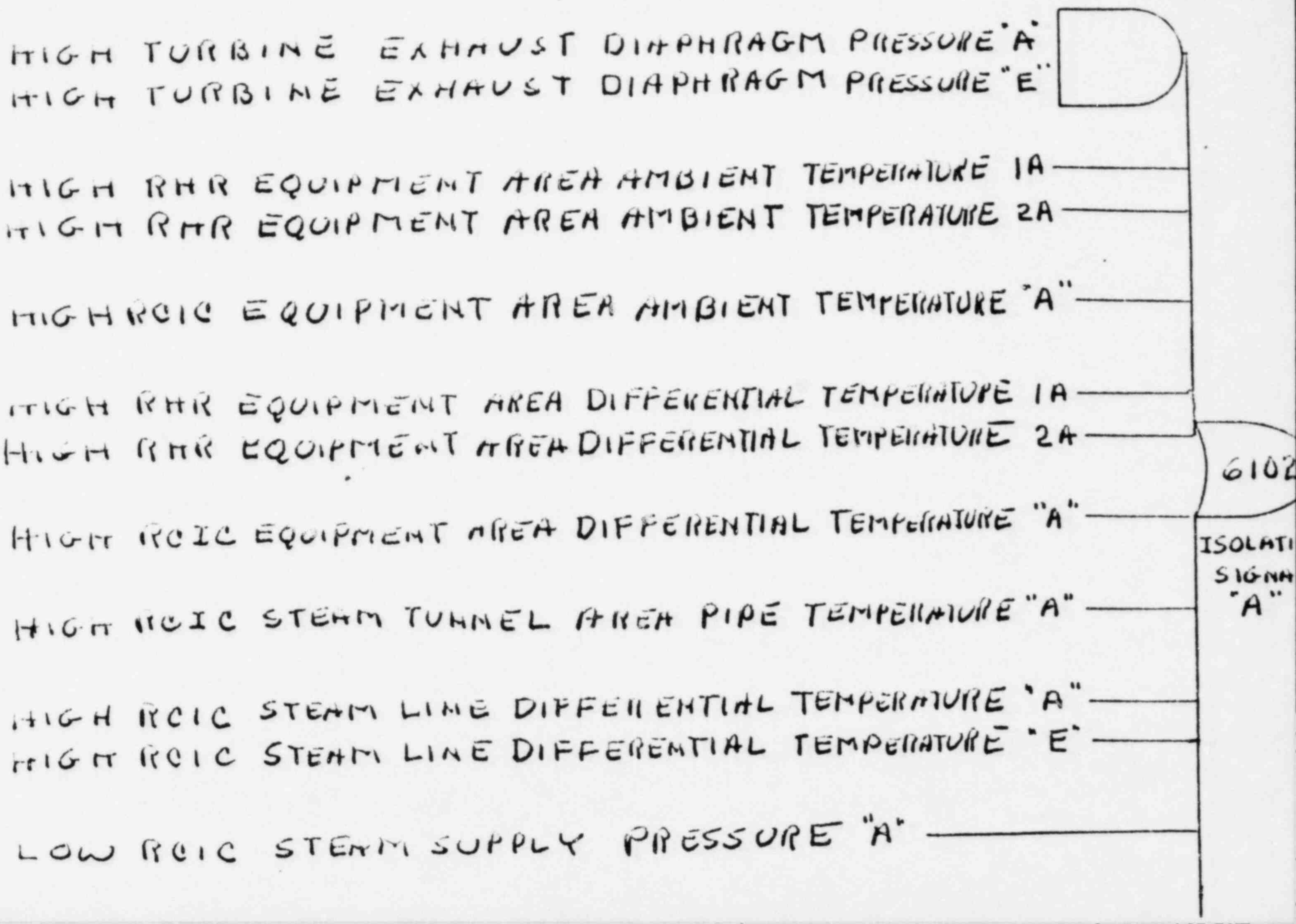


FIGURE-2

RCIC SYSTEM ISOLATION LOGIC CIRCUIT "A"



421.45 (7.2.2) In Section 7.2.2.1.I of your FSAR, you indicated that the condensing chambers and all essential components of the control and electrical equipment are either similar to those which have been qualified by tests for other facilities or additional qualification tests have been conducted. You also indicate special precautions are taken to ensure the operability of the condensing chambers and the inboard main steam isolation valve (MSIV) psotion switches for a reactor coolant pressure boundary (RCPB) break inside the drywell. Confirm that the condensing chambers and MSIV psotion switches are included in the environmental qualification program. Discuss the differences between the qualified control and electrical equipment which are similar to those used in your design and the additional tests which have been conducted. In addition, provide the details for the "precautions" you have taken to ensure the operability of condensing chambers and the MSIV postion switches.

RESPONSE:

The MSIV position switches have been included in the environmental test program applied to other safety related instrumentation and control devices located in the drywell in accordance with IEEE 323 1974 and RG 1.89 as stated in Section 1.8 Condensing chambers are code vessels controlled by ASME code rather than being subjected to qualification tests which are applied to electrical equipment therefore they are not included in the same qualification program, as the position switches.

421.45
(cont'd) However, the ability of the condensing chambers to perform their safety function as components of the instrumentation and control system as predicted by analysis has been confirmed by actual operation in reactor plants under the extreme environmental conditions associated with a LOCA.

All essential equipment used in existing plants has been (or is being) required to be environmentally qualified and from that qualification is developed a list of instrumentation and electrical equipment types and models acceptable for applications in GE standard plants. Such equipment models are considered type qualified for use within their qualified applications and ranges, and environments. In the event that other equipment types or models not previously qualified are considered as alternatives for these qualified devices they shall be subjected to the same qualification as those already typed qualified.

The precautions taken to ensure operability of condensing chambers during a LOCA event are as follows: The condensing chambers on the reactor vessel are physically separated by dispersing them around the periphery of the vessel at four different azimuths at least 30° apart. The routing of the lines from the condensing chambers is such as to avoid convergence where there would be a potential for common damage as a result of a LOCA. The slopes of the instrument lines from the condensing chambers to the drywell penetrations are kept to a minimum consistent with adequate venting of non condensibles and air back into the chamber so that the vertical elevation difference within the drywell is kept to a

421.45 (cont'd) practical minimum with a recommended maximum of four feet. This serves to limit the maximum boil off that might occur during a postulated condition of drywell temperature being maintained in excess of reactor temperature of time sufficient to permit boiloff. In addition, the condensing chambers are connected to the vessel with a pipe sized to allow ample cross section for condensate drainback and free exchange of steam and non condensibles between the vessel and the condensing chamber, to prevent any possibility of condensate binding or excessive non condensibles buildup that could prevent adequate condensing of steam to keep the reference leg filled.

The MSIV position switches are not required to initiate a scram on the RCPB leak within the drywell. Therefore, they are not required to be protected from damages that might result therefrom. Drywell high pressure avoides the scram signal for this condition. obviating the need for MSIV "closure scram" for this condition. Therefore, no special precautions are required to ensure operability of the MSIV position switches during a RCPB inside the drywell. However the following features give a high degree of assurance that they could give a valid signal during a RCPB if desired. 1) distribution of the position switches among the four valves (one on each inboard valve and one on each of the outboard valves), 2) housing each of the switches in a separate cast steel condulet switchbox, 3) qualifying them for the LOCA environment (pressure and temperature and radiation) and 4) use of fail safe logic.

The MSIV closure scram logic is three out of four inboard or three out of four outboard valves closed 10% or more to cause scram. The valve position switch circuit is fail safe in that a broken wire will give a channel trip signal.

421.45 (cont'd) Furthermore, the MSIV closure scram is not a safety function that is required for a RCPB condition within the drywell becasue MISV closure is not initiated by a high drywell pressure condition.

QUESTION 421.46

In Sections 7.6.1.8 and 7.6.2.8 of your FSAR, you describe the containment vacuum relief (CVR) system. Confirm that the CVR is powered from class IE power sources.

RESPONSE 421.46

The Containment Vacuum Relief (CVR) System is powered from Class 1E power sources, 125 VDC Bus DC-E for Division 1 and 125 VDC Bus DC-F for Division 2, as stated in Section 7.6.1.8.2B. These Class 1E power sources are shown in Figure 8.3-1.

421.47 In Section 7.3.1.1.1.2.C of your FSAR, you briefly mention testing of the automatic depressurization system (ADS) solenoid valves. These valves cannot be fully tested with the plant at power. Provide a discussion of your proposed method for integrated testing of these valves and circuits, including the frequency of testing. Identify other ESF systems where either a portion of the actuation circuitry or the actuated device is not routinely tested with the actuation circuits. Discuss your proposed method for integrated testing of the circuits and components, including the test frequency.

RESPONSE

Integrated testing of the ADS solenoid valves and circuitry is not performed with the plant operating at power which is consistent for safety systems where the final actuating device(s) would cause temporary modification of plant processes such as fluid injection or discharges. The BWR-6 standard technical specifications provides for a functional partially integrated test without valve actuation. This is supplemented by a manual one-at-a-time valve test using ~~its~~ a associated actuation circuitry from the transmitter trip units with the reactor shutdown but with steam dome pressure equal or greater than 100 psig. This test interval is 18 months. Additionally, the transmitter/trip units that provide sensory inputs to the ADS are checked by control room personnel and the logic chain up to the solenoid is tested by the automatic pulse test performed by the self test subsystem and described as the sixth test in the discussion in 7.1.2.1.6

Other safety systemssuch as RPS, portions of CRVICS, MS-PLCS, HPCS, LPCS, RHR/LPCI, RHR/containment spray mode, RHR/suspression pool cooling mode, safety relief valves, and water positive seal system likewise have components which are not activated or tested with a complete integrated testing procedure. Each of these systems has a modified test procedure that utilizes a manual test which allows for independently checking of individual components. The frequency of these tests, parameters verified, and procedures are included as part of the technical specification. The automatic pulse test described in 7.1.2.1.6 is utilized for these systems where appropriate, and also is included as part of the technical specifications.

421.49 QUESTION

Demonstrate that the safety/relief valve (SRV) low-low set point function is adequate assuming a single failure which could cause an additional SRV to open during the time when only one valve is permitted to be open (i.e., on second and subsequent valve pops).

421.49 RESPONSE

This concern was already analyzed and the Low-Low Setpoint logic was subsequently approved by the NRC. See NUREG-0802 written by T.M. Su, USNRC, Division of Safety Technology. The instrumentation and control logic is specifically addressed in Section 3.4.2 of that report which is titled "Safety/Relief Valve-Quencher Loads Evaluation Reports - BWR Mark II and III Containments."

GESSAR

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421.50 (7.4.1) In Section 7.4.1.4 of your FSAR, you provide information on the remote shutdown system (RSS). Attachment 2 provides the Instrumentation and Control Systems Branch guidance for remote shutdown capability (i.e., guidance for meeting the requirements of GDC 19). Indicate the extent to which your proposed design of the RSS conforms to the guidance provided in Attachment 2. Provide the following additional information in your discussion using drawings as appropriate:

a. Design criteria for the remote control station equipment including the transfer switches and separation requirements for redundant functions.

b. Discuss the separation arrangement between safety-related and non-safety-related instrumentation and controls on the auxiliary shutdown panel.

c. The location of the transfer switches and the remote control stations.

d. A description of your isolation, separation and transfer override provisions. This should include the provisions for preventing electrical interaction between the control room and the remote shutdown equipment.

e. A description of the administrative and procedural control features to restrict and to assure access, when necessary, to the displays and controls located outside the control room.

f. A description of any communication systems required to coordinate operator actions, including redundancy and separation.

g. The means for ensuring that cold shutdown can be accomplished.

h. A description of the control room annunciation of the status of remote control or override status of devices under local control.

i. Discuss your proposed startup test program to demonstrate remote shutdown capability in accordance with the guidance provided in Regulatory Guide 1.68, Revision 2.

j. Discuss the testing to be performed during plant operation to verify the capability of maintaining the plant in a safe shutdown condition from outside the control room. none

ATTACHMENT 1: ASSESSMENT OF ~~SKAGIT~~ ~~RIVER BEND~~ standard plant RSS COMPLIANCE

The NRC's Instrumentation and Control Systems Branch (ICSB) has issued a position on remote shutdown capability. An assessment of the compliance of the ~~River Bend~~ ~~SKAGIT~~ standard plant RSS with the ICSB position is outlined below.

ICSB POSITION	~~SKAGIT~~ standard plant ~~RIVER BEND~~ RSS DESIGN
- 10CFR50 Appendix K, ECCS Requirements	
o Transfer of control to RSS should not disable any automatic actuation of ESF functions.	o Only LPCI in one RHR loop and RCIC are ~~is~~ disabled in transfer to RSS panel. However, these equipments can be manually placed in service from the RSS panel. All other automatic actuations of ESF functions operate normally. Therefore, the ~~River Bend~~ ~~SKAGIT~~ standard plant RSS design satisfies Appendix K.
o Specifically allows bypass of automatic LPCI actuation.	
- 10CFR50 Appendix R, Fire Protection Requirements	
o Provide separation and fire protection in control room design.	o ~~River Bend~~ ~~SKAGIT~~ standard plant control room design includes necessary separation and fire proection.
o Or, provide non-redundant safety grade systems for remote shutdown assuming a fire in any fire area.	o RSS is not a safety system and fire damage is not within the existing RSS design bases. Barriers inside RSS panel will prevent the propagation of fire from one division to another. (A/E responsibility to locate panel & provide fire protection)
- 10CFR50 Appendix A, GDC 19 (As interpreted in Standard Review Plan 7.4)	
o Provide redundant safety grade capability for remote shutdown assuming no fire damage or accident has occurred.	o RSS is not a safety system and therefore ~~redundancy is not required.~~ safety-grade and redundant control and display instrumentation are not required at the RSS panel.
	o Some redundancy is provided through operator actions at local panels.
o RSS equipment should be seismically qualified	o The RSS panel itself and the transfer switches are seismically qualified. The control switches and display instrumentation ~~may~~ can be seismically qualified.

a). The Remote Shutdown System (RSS) provides remote manual control of normal and nuclear safety-related systems necessary for prompt shutdown and subsequent cooldown of the reactor from outside the control room.

The remote shutdown capability in itself does not perform any safety related function. Those RSS components that interface with safety related systems maintain the integrity and channel separation of those systems.

(also see part d)

b) ~~Physical barriers~~ ~~in~~ Inside the ~~R~~ remote shutdown panel ~~prevents~~, physical barriers between redundant divisions, and between safety related and non-safety related equipments prevent the propagation of fire or effects of electrical faults from one division to another.

C. The transfer switches are located at the Remote Shutdown ~~System~~ panel.

The RSP panel shall be located by the customer so that access to and function of the panel will not be affected by the event causing the control room evacuation. It is suggested that the panel be located near a local RHR system control board or where convenient communication can be maintained with the RHR system switch gear and where failure of any other equipment will not damage the equipment on the remote shutdown panel. The panel shall be located in a controlled environment similar to that of the control room.

d, h) The functions needed for the remote shutdown control are provided with manual transfer switches located at the remote shutdown panel, which defeat the controls from the control room and transfer the controls to the remote shutdown control.

Remote shutdown control is not possible without actuation of the transfer switches operation of any of the transfer switches causes an alarm in the control room.

e) Customer/AE to describe administrative and procedural control on access to remote shutdown panel.

f) Customer/AE to describe communication systems.

g) The RSS design includes a panel and associated controls, indicators, and monitors for interfacing with the RHR, RCIC, Main Steam, and Condensate and Feedwater systems. In the event the reactor vessel is isolated, ~~and~~ the feedwater supply is unavailable, the normal heat sinks (turbine and condenser) are lost, and evacuation of the control room is necessary, remote manual control of normal reactor cold shutdown systems is taken as follows:

Reactor pressure will be controlled and core decay and sensible heat will be rejected to the suppression pool by releasing steam through the safety relief valves. Reactor water inventory

g) (cont'd) will be maintained by the RCIC system. The suppression pool will be cooled as required by operating the RHR system in the suppression pool cooling mode. This procedure will cool the reactor and reduce its pressure at a controlled rate. The RHR system will then be operated in the shutdown cooling mode to bring and maintain the reactor to the cold shutdown condition.

i) The startup test program for the RSS shall be performed after the completion of the preoperational testing of the RSS, & the establishment of remote shutdown operating procedures and test procedures, and the communications between the control room and remote shutdown locations.

The reactor shall be scrammed and the MSIV's closed from outside the control room while the reactor is ~~in~~ a normal~~ly~~ steady state condition.

Reactor water level and pressure shall be controlled from outside the main control room.

Data shall be obtained and recorded at locations outside the control room to

i) verify that the plant has achieved
(cont'd) hot shutdown conditions and can be ~~mat~~ maintained at stable hot shutdown for at least 30 minutes.

Manual operation of the safety relief valve(s) and the suppression pool cooling mode of the RHR system from outside the control room shall be demonstrated.

From outside the control room, water level shall be controlled in the normal range and reactor pressure shall be lowered at a rate not to exceed the technical specification limits.

The reactor coolant temperature shall be reduced 50°F by controlling the shutdown cooling mode of the RHR and/or the Reactor Core Isolation Cooling Systems from outside the control room at a rate not to exceed technical specification limits.

(cont'd.) i) A test report shall document the results of all tests performed and a summary of any significant deviations from the required system performance.

j) Customer / AE to discuss testing to be performed during plant operation in accordance with plant technical specifications.

l

QUESTION

421.51 (7.7.1) You describe the performance monitoring system in Section 7.7.1.5 of your FSAR. Provide the following additional information in this section:

a) Identify all safety-related parameters which will be monitored with the performance monitoring system during initial operation.

b) For each safety parameter identified above, provide a concise description of how its associated circuitry connects (either directly or indirectly by means of isolation devices) with the performance monitoring system circuitry. Where appropriate, supplement this description with detailed electrical schematics.

c) Describe your proposed design provisions to prevent failures of the performance monitoring system degrading safety-related systems.

d) Provide the above information for the startup "transient monitoring system," if provided and distinct from the performance monitoring system.

RESPONSE

421.51 a) The following parameters in safety-related systems will be monitored during initial operation:

SYSTEM	PARAMETERS
Nuclear Boiler/Nuclear Steam Supply Shutoff System (NBS)	Vessel Wide Range Level ADS/SRV Position ADS/SRV Initiation Signal MSIV's Position MSIV's Isolation Trip Signal Vessel High/Low Level Alarm RHR/ADS/LPCS/HPCS Low Water Level Initiation Signals RHR/ADS/LPCS/HPCS High Drywell Pressure Initiation Signals
Neutron Monitoring System (NMS)	APRM Output APRM Heat Flux LPRM Output Recirc. System Flow

SYSTEM	PARAMETERS
Reactor Protection System (RPS)	Reactor Manual Scram Reactor Scram Trip System
Residual Heat Removal System (RHR)	RHR System Flow (A,B,C) RHR Heat Exchanger Inlet Temp (A,B) RHR Heat Exchanger Outlet Temp (A,B) RHR System Pressure
Low Pressure Core Spray System (LPCS)	LPCS System Pressure LPCS System Flow
High Pressure Core Spray System (HPCS)	HPCS System Pressure HPCS System Flow

b) Isolation will be accomplished by means of optical isolators. The isolation will be accomplished downstream of signal conditioning and analog-to-digital conversion. Figure 1 demonstrates a typical signal flow from a safety-system parameter to the non-safety PMS. The optical isolators shall be qualified in accordance with Regulatory Guides 1.75 and 1.89. The isolators provide a means for preventing a fault in the non-divisional wiring from affecting the safety-system circuitry. Figure 2 exhibits the power and signal connnections to the isolators.

c) To maintain the PMS as a highly reliable system, i's normal power will be supplied from an uninterruptible power source (UPS). In addition, interfaces to safety system will be by means of isolation devices. Failures in the PMS will not affect safety-system operation other than possible erroneous operator information.

d) Based upon current transient monitoring requirements, the following safety systems will have interface with the safety transient monitoring system:

Neutron Monitoring System
Reactor Protection System
Nuclear Boiler System
Nuclear Steam Supply Shutoff System
Diesel Generator System
4.16 kV Power Distribution System
High-Pressure Core Spray System
Residual Heat Removal System

421.51 (Continued)

A concise description of how the associated circuitry merges or connects with the start-up transient monitoring system is inappropriate at this time because system design is not yet specified. Response at a later date, after system design, will be necessary to properly respond to this question. C. F. Braun and Company will provide the system design.

FIGURE 1

TYPICAL SAFETY PARAMETER ISOLATION PROTECTION

EXAMPLE: HPCS INITIATION

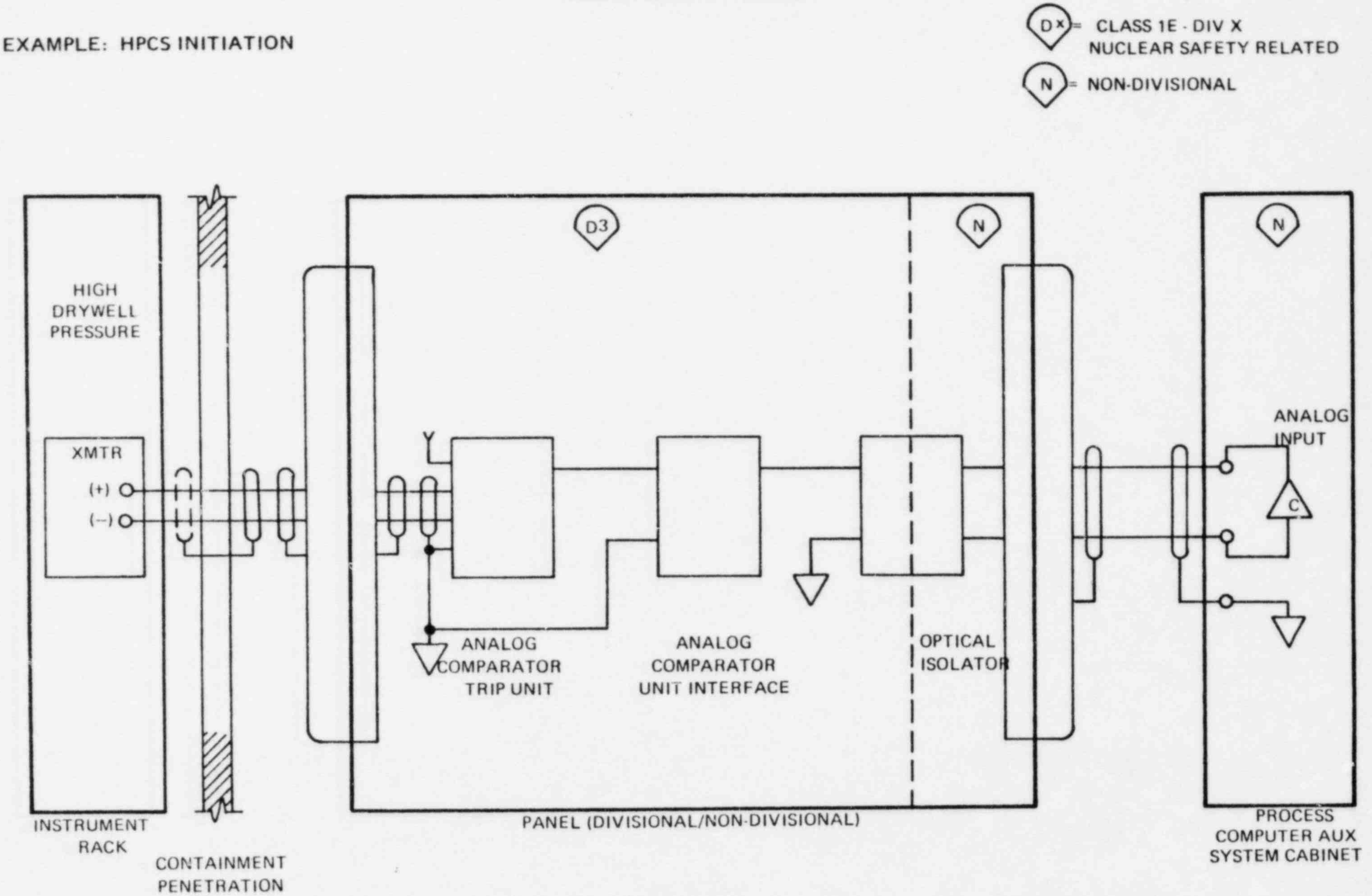
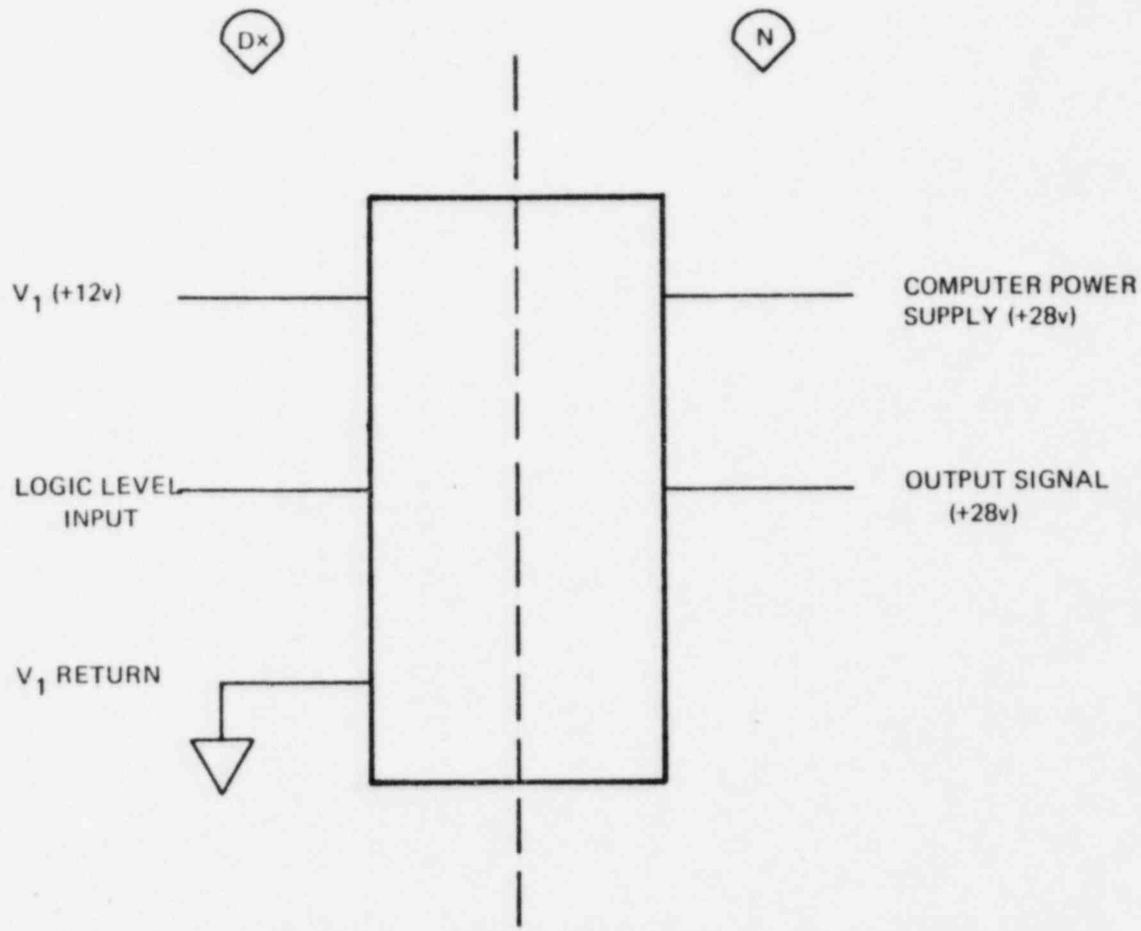


FIGURE 2

COMPUTER OPTICAL ISOLATOR



421.53 In Section 11.5.2.1.2 of your FSAR, you indicate that if one channel in both the A and B trip logic is downscale in the reactor containment heating, ventilation and air-conditioning (HVAC) radiation monitoring system, system isolation is not possible. Your design is such that any one downscale trip sounds an alarm in the control room. Discuss the details of your design which are provided to preclude downscale trips in one channel in each logic from occurring simultaneously. Discuss the required actions, either automatic or by the operator, including the procedures to be followed by the operator if a channel in one or both logics is downscale. Indicate whether the details provided in this discussion are applicable to the other radiation monitoring systems identified in Section 11.5.2.1 of your FSAR.

Response

The logic embodied in the reactor containment heating, ventilation and air conditioning (HVAC) radiation monitoring system (see figure 7A.6-4K) is such that either a downscale trip or an upscale per channel will be sufficient to provide one half of the required signal for the interlock. Figure 7.6-10C Note 7 also indicates that two-out-of-two high high/inop or downscale trips (in either A and D or B and C) will provide an interlock signal.

The procedure to be followed in case of a downscale trip will be provided in the technical specifications chapter of the Safety Analysis Report. Although the exact procedure will need to be reviewed by the applicant, in general, the following is typical: With the requirements for the minimum number of Operable channels not satisfied for one trip system, place the inoperable channel in the tripped condition within one hour or establish Secondary Containment Integrity with the standby gas treatment system operating within one hour. With the requirements for the minimum number of Operable channels not satisfied for both trip systems, establish Secondary Containment Integrity with the standby gas treatment system operating within one hour.

The details provided above are not directly applicable to the other radiation monitirong systems (i.e., containment space - refueling mode, fuel building ventilation exhaust, auxiliary building exhaust, standby gas treatment, shield annulus HVAC, and control building HVAC) in Section 11.5.2.1 because these systems are configured with a one-out-of-two trip logic.

421.54 QUESTION

Provide a discussion of the process computer system in Chapter 7 of your FSAR.

421.54 RESPONSE

The Performance Monitoring System (formally called the Process Computer System) is discussed in Subsection 7.7.1.5 and 7.7.2.5.

As indicated in 7.7.2.5.A, the PMS is not required to initiate or control any engineered safeguard or safety-related system.