May 26, 1994

Docket No. 52-001

MEMORANDUM FOR: Robert A. Gramm, Leader
Independent GE ABWR ITAAC Review Group (IIRG)

FROM: Kristine M. Shembarger, Project Manager
Standardization Project Directorate
Associate Directorate for Advanced Reactors
and License Renewal, NRR

SUBJECT: FINAL REPORT TO DOCUMENT THE DISPOSITION OF THE IIRG COMMENTS ON THE GE NUCLEAR ENERGY (GE) ADVANCED BOILING WATER REACTOR (ABWR) INSPECTIONS, TESTS, ANALYSES, AND ACCEPTANCE CRITERIA (ITAAC)

Over the past few months, the staff has (1) reviewed the comments on the ABWR ITAAC and SSAR that resulted from the IIRG effort, (2) forwarded comments to GE where review and disposition by GE was warranted, (3) met with GE to resolve the comments, and (4) prepared a report for the IIRG documenting the staff's and GE's resolution of the comments.

Enclosure 1 contains the report that documents closure of all IIRG comments. Enclosure 2 contains the comments forwarded to GE and GE's disposition, which is referenced in Enclosure 1.

If you have any questions on the report, please contact me at 504-1114.

Original Signed By

Kristine M. Shembarger, Project Manager
Standardization Project Directorate
Associate Directorate for Advanced Reactors
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INDEPENDENT REVIEW GROUP COMMENTS REQUIRING DISPOSITION BY GE

Section 2.1.1 Comment No. 1

Comment:

Table 2.1.1a specifies tolerances for RPV dimensions. Has GE evaluated the impact of adverse accumulation of these tolerances on SSAR Chapter 6.0 and 15.0 analyses?

Resolution:

The tolerances are based on GE's experience in RPV design changes that have been made to previous RPV models. This statement has been included in the SSAR in Amendment 34 (Ch. 6 & 15), indicating that tolerances do not affect the safety analyses.

Section 2.1.1 Comment No. 2

Comment:

Add in the paragraph (page 2.1.1-3) that discusses fracture toughness, the requirement that the minimum USE value shall be 6.9 kg-m throughout the life of the RPV. (Ref. 10CFR50, App. G)

Resolution:

Disagree. GE has already calculated the USE at EOL with adequate margins. 10 CFR 50 App. G is still applicable to ABWR throughout its RPV life.

Section 2.1.1 Comment No. 3

Comment:

Is the RPV design life parameter not Tier 1 info?

Resolution:

Yes. The 60-year design life for the RPV is not Tier 1 info.

Section 2.1.1 Comment No. 4

Comment:

Correct typographical error on attached page 5.3-7 of SSAR.

Resolution:

GE agreed to make the changes.

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- Second Capsule: After 20 effective full-power years.
- Third Capsule: With an exposure not to exceed the peak EOL fluence.
- Fourth Capsule: Schedule determined based on results of first two capsules per ASTM E-185, Paragraph 7.6.2 (see Section 5.3.4.2 for additional capsule requirements). Fracture toughness testing of irradiated capsule specimens will be in accordance with requirements of ASTM E-185 as called out for by 10CFR50 Appendix H.

5.3.1.6.2 Neutron Flux and Fluence Calculations

A description of the methods of analysis is contained in Subsections 4.1.4.5 and 4.3.2.2.

5.3.1.6.3 Predicted Irradiation Effects on Beltline Materials

Transition temperature changes and changes in upper-shelf energy shall be calculated in accordance with the rules of Regulatory Guide 1.99. Reference temperatures shall be established in accordance with 10CFR50 Appendix G and NB-2330 of the ASME Code.

Since weld material chemistry and fracture toughness data are not available at this time, the limits in the purchase specification were used to estimate worst-case irradiation effects.

These estimates show that the adjusted reference temperature at end-of-life is less than 34°C, and the end-of-life USE exceeds 69 kg-m (see response to Question 251.5 for the calculation and analysis associated with this estimate). 6.9?

5.3.1.6.4 Positioning of Surveillance Capsules and Methods of Attachment Appendix H.II B (2)

The surveillance specimen holders, described in Subsections 5.3.1.6.1 and 3.9.5.1.2.10, are located at different azimuths at common elevation in the core beltline region. The locations are selected to produce lead factor of approximately 1.2 to 1.5 for the inserted specimen capsules. A positive spring-loaded locking device is provided to retain the capsules in position throughout any anticipated event during the lifetime of the vessel. The capsules can be removed form and reinserted into the surveillance specimen holders. See Subsection 5.3.4.2 for COL license information requirements pertaining to the surveillance material, lead factors, withdrawal schedule and neutron fluence levels.

In areas where brackets (such as the surveillance specimen holder brackets) are located, additional nondestructive examinations are performed on the vessel base metal and stainless steel weld-deposited cladding or weld-buildup pads during vessel manufacture. The base metal is ultrasonically examined by straight-beam techniques to a depth at least equal to the thickness of the bracket being joined. The area examined is the area

Section 2.1.2 Comment No. 1

Comment:

Fig 2.1.2b: The piping symbol for the drain line piping (shown horizontally inside the outside the containment) is NNS though this piping is Class 1. This should be corrected.

Resolution:

GE agreed to make the changes.

Section 2.1.2 Comment No. 2

Comment:

The design description for the ADS states that the high drywell pressure bypass timer is less than or equal to 8 minutes which is in conflict with SSAR Table 6.3-1 which shows this value to be $\geq$ 8 mins.

Resolution:

GE agreed to make the changes to the SSAR as described in the enclosure.

Section 2.1.2 Comment No. 3

Comment:

In the Section "Other Provisions", the first sentence indicates that ASME Class 3 equipment shown in Fig. 2.1.2c is non Seismic Category I. Why? What are the differences between Seismic classes A_s, A, and B shown SSAR Fig. 1.7-1, Sheet 2 ?

Resolution.

It is permissible for equipment to be Class 4D (NNS) and non Seismic Category 1 while also being ASME Code Class 3. The seismic classes are primarily for consistency with Japanese design criteria. From NRC's standpoint, they are all Seismic Class I and acceptable.

Section 2.1.2 Comment No. 4

Comment:

In Fig. 2.1.2b and 2.1.2e, the temperature element should be shown as T, not TE, or the symbol for temperature in App. A should be changed to TE.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.1.2 **Comment No.** 5

Comment:

All figure numbers in Table 2.1.2 and some figure numbers in the description are incorrect.

Resolution:

GE agreed to make the changes.

Section 2.1.2 **Comment No.** 6

Comment:

In the ITA column for entry #6, the word "conducted" should be added after "...MSIV will be ..."

Resolution:

GE agreed to make the changes.

Section 2.1.2 **Comment No.** 7

Comment:

The design description (page 2.1.2-4) should include the requirement that the maximum elapsed time between receiving the overpressure signal at the valve actuator and actual start of SRV motion will not exceed 0.1 sec (SSAR 5.2.2.4.1) and be verified by an ITAAC entry.

Resolution:

GE agreed to make the changes.

Section 2.1.2 **Comment No.** 8

Comment:

Are the tests for MSIVs, MOVs, and CVs described in ITAAC entries 6, 21, and 22 performed essentially at ambient temperature, no pressure and no flow conditions during preop testing?

Resolution:

No - tests are performed at conditions that can be reached during preop testing.

Section 2.1.2 Comment No. 9

Comment:

The SRV discharge line vacuum breakers listed as active valves in SSAR Table 3.9-8 are not shown in Fig. 2.1.2b.

Resolution:

The SRXB and SCSB reviewers made the judgement that the vacuum breakers are not very significant and therefore do not warrant inclusion in the Tier 1 document.

Section 2.1.3 Comment No. 1

Comment:

The minimum dry rotating inertia (17.5 Kg-m2) of the RIP stated in the design description conflicts with the value of 19.5 kg-m2 stated in SSAR Table 5.4-1. The description and ITAAC entry #4 should be revised.

Resolution:

GE agreed to make the changes to the SSAR.

Section 2.2.1 Comment No. 1

Comment:

Figure 2.2.1 "PCS" not defined in design description. Three "PCS" acronyms exist.

Resolution:

No action needed. 2.2.11 defines PCS.

Section 2.2.1 Comment No. 2

Comment:

Figure 2.2.1 "APR" not defined in design description.

Resolution:

No action needed. 2.2.9 defines APR.

Section 2.2.1 Comment No. 3

Comment:

ITAAC design commitment #4 references "automatic thermal power monitor". Design description (2) describes a "automatic thermal limit monitor" and SSAR 7.7.1.2.1 references an "automatic thermal limit monitor, page 7.7-15. The terms need to be made consistent. ITAAC #4 should read "automatic thermal power limit".

Resolution:

GE agreed to make the changes.

Section 2.2.1 Comment No. 4

Comment:

Software development/control is not addressed in the ITAAC.

Resolution:

No action needed. It is addressed in 3.4

Section 2.2.1 Comment No. 5

Comment:

"rod action and position information system- RAPI" is referenced in TS Page 3.1-7, 17 Action statements and 7.7.1.2.1. as used to enforce rod blocks from the ATLM. Not referenced in ITAAC or design description.

Resolution:

No action needed. This remains in Tier 2, since it is not a safety significant detail. The rod withdrawal function is in Tier 1.

Section 2.2.1 Comment No. 6

Comment:

RCIS is stated to be single failure proof with regards to ARI. Does this include common mode failure of software or microprocessor? The design description states that RCIS processors are redundant with single controllers for each FMCRD. SAR 7.4-18

Resolution:

No action needed (See comment #7). There is no statement as "single-failure proof". Redundant microprocessors provided. See ITAAC #2.

Section 2.2.1 Comment No. 7

Comment:

The wording for SAR section 7.4.2.1.2 (1) is not clear. Is the intent to state that any single failure will cause at most only one operable control rod insertion failure (page 7.4-18)? The sentence requires clarification.

Resolution:

GE agreed to make the appropriate changes as described in the enclosure.

Section 2.2.2 Comment No. 1

Comment:

The design description for the switches that detect separation of the FMCRD piston and ball nut need to be identified as Class 1E (see attached mark-up). Reference SSAR section 4.6.2.2.6 page 4.6-9.

Resolution:

NRC agreed with GE disposition.

Section 2.2.2 Comment No. 2

Comment:

The control room alarm for the level switch in the accumulator should be mentioned in the design description (see SSAR 4.6.1.2.3 (3) page 4.6-12). This alarm should be listed in CDM Table 2.7.1a.

Resolution:

This alarm is not safety significant enough for inclusion in the Tier 1 document. There are only sixty alarms included in Tier 1.

Section 2.2.2 Comment No. 3

Comment:

The design description should be corrected as shown in the attached mark-up.

Resolution:

GE agreed to make the changes.

Section 2.2.2 Comment No. 4

Comment:

The electrical separation between Class 1E and non-1E is not addressed in ITAAC Item 9 for the power to the FMCRDs. Suggest that appropriate portions of ITAAC item 8 that deal with electrical separation be copied into DD, ITA, and AC for Item 9.

Resolution:

NRC agreed with GE disposition.

2.2.2 Control Rod Drive System

Design Description

The Control Rod Drive (CRD) System controls changes in core reactivity during power operation by movement and positioning of the neutron absorbing control rods within the core in fine increments in response to control signals from the Rod Control and Information System (RCIS). The CRD System provides rapid control rod insertion (scram) in response to manual or automatic signals from the Reactor Protection System (RPS). Figure 2.2.2a shows the basic system configuration and scope. X

delete to read: 2.2.2

The CRD System consists of three major elements: (1) the electro-hydraulic fine motion control rod drive (FMCRD) mechanisms, (2) the hydraulic control unit (HCU) assemblies, and (3) the control rod drive hydraulic system (CRDHS). The FMCRDs provide electric-motor-driven positioning for normal insertion and withdrawal of the control rods and hydraulic-powered rapid control rod insertion (scram) for abnormal operating conditions. Simultaneous with scram, the FMCRDs also provide electric-motor driven run-in of control rods as a path to rod insertion that is diverse from the hydraulic-powered scram. The hydraulic power required for scram is provided by high pressure water stored in the individual HCUs. An HCU can scram two FMCRDs. It also provides the flow path for purge water to the associated drives during normal operation. The CRDHS supplies pressurized water for charging the HCU scram accumulators and purging to the FMCRDs.

There are 205 FMCRDs mounted in housings welded into the reactor vessel bottom head. The FMCRD has a movable hollow piston tube that is coupled at its upper end, inside the reactor vessel, to the bottom of a control rod. The FMCRD can move the control rod up or down over its entire range, by a ball nut and ball screw driven at a speed of 30 mm/sec ±10% by the electric stepper motor. In response to a scram signal, the piston inserts the control rod into the core hydraulically using stored energy in the HCU scram accumulator. The scram water is introduced into the drive through a scram inlet connection on the FMCRD housing, and is then discharged directly into the reactor vessel via clearances between FMCRD parts. The average scram times of all FMCRDs with the reactor pressure as measured at the vessel bottom below 76.3 kg/cm^2g are:

Percent Insertion	Time (sec)
10	≤ 0.42
40	≤ 1.00

Percent Insertion	Time (sec)
60	≤ 1.44
100	≤ 2.80

These times are measured starting from loss of signal to the scram solenoid pilot valves in the HCUs.

The FMCRD has an electro-mechanical brake with a minimum holding torque of 5 kg-m on the motor drive shaft and a ball check valve at the point of connection with the scram inlet line. ~~The FMCRD switches are powered from~~

Two, Class 1E, redundant and separate switches in the FMCRD detect separation of the hollow piston from the ball nut. Independence is provided between the Class 1E divisions for these switches.

There are 103 HCUs, each of which provides water stored in a pre-charged accumulator for scramming two FMCRDs. Figure 2.2.2 shows the major HCU components. The accumulator is connected to its associated FMCRDs by a hydraulic line that includes a scram valve held closed by pressurized control air. To cause a scram, the RPS provides a signal to de-energize the scram solenoid pilot valve (SSPV) that vents the control air from the scram valve, which then opens by spring action. Loss of either electrical power to the SSPV or loss of control air pressure causes scram. A pressure switch detects low accumulator gas pressure and actuates an alarm in the main control room.

The CRD System also provides alternate rod insertion (ARI) as a means of actuating hydraulic scram when an anticipated transient without scram (ATWS) condition exists. Following receipt of an ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open. The control rod drives then insert the control rods hydraulically.

The CRDHS has pumps, valves, filters, instrumentation, and piping to supply pressurized water for charging the HCUs and purging the FMCRDs.

The CRD System components classified as safety-related are: the HCU components required for scram; the FMCRD components required for scram; the scram inlet piping; the FMCRD reactor coolant primary pressure boundary components; the FMCRD brake and ball check valve; the internal drive housing support; the FMCRD separation switches; and the HCU charging water header pressure instrumentation.

The CRD System components classified as Seismic Category I are: the HCU components required for scram; the FMCRD components required for scram; the scram inlet piping; the FMCRD reactor coolant primary pressure boundary components; the FMCRD brake

and ball check valve; the internal drive housing support; the FMCRD separation switches; and the HCU charging water header pressure instrumentation.

Figure 2.2.2 shows the ASME Code class for the CRD System piping and components.

The CRD System is located in the Reactor Building. The FMCRDs are mounted to the reactor vessel bottom head inside primary containment. The HCUs and CRDHS equipment are located in the Reactor Building at the basemat elevation.

Each of the four divisional HCU charging header pressure sensors are powered from their respective divisional Class 1E power supply. Independence is provided between the Class 1E divisions for these sensors and also between the Class 1E divisions and non-Class 1E equipment.

For their preferred source of power, the FMCRDs are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E Plant Investment Protection (PIP) bus.

The hydraulic portion of the CRD System which performs the scram function is physically separated from and independent of the Standby Liquid Control System.

The CRD System has the following alarms, displays, and controls in the main control room:

(1) Alarms for separation of the hollow piston from the ball-nut and low HCU accumulator gas pressure.

(2) Parameter displays for the instruments shown in Figure 2.2.2.

(3) Controls and status indication for the CRD pumps and flow control valves shown on Figure 2.1.2. X
2

(4) Status indication for the scram valve position.

The following CRD System safety-related electrical equipment are located in either the Reactor Building or primary containment and are qualified for a harsh environment: the HCU charging header pressure instrumentation, the scram solenoid pilot valves, and FMCRD separation switches.

The check valves (CVs) shown inside the HCU boundary on Figure 2.2.2 and the FMCRD ball check valves have active safety-related functions to close under system pressure, fluid flow, and temperature conditions.

The piping and components of the CRD pump suction supply, which extends from the CRD System interfaces with the Condensate Feedwater and Air Extraction (CFCAE)

Table 2.2.2 Control Rod Drive System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. Two redundant and separate switches in the FMCRD detect separation of the hollow piston from the ball nut.	6. Tests of each as-built FMCRD will be conducted.	6. Both switches in each FMCRD detect separation of the hollow piston from the ball nut.
7. Following receipt of an ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open.	7. Tests will be conducted on the as-built ARI valves using a simulated actuation signal.	7. Following receipt of a simulated ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open.
8. Each of the four divisional HCU charging header pressure sensors are powered from their respective divisional Class 1E power supply. For the four HCU charging ~~water header pressure sensors,~~ independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	8. a. Tests will be conducted on the as-built ~~charging water header sensors~~ switches by providing a test signal in only one Class 1E division at a time. b. Inspections of the as-installed ~~charging water header sensor~~ switch Class 1E divisions will be conducted.	8. a. The test signal exists only in the Class 1E Division under test. b. Physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class 1E equipment.
9. For their preferred source of power, the FMCRDs are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E PIP bus.	9. Inspections of the as-built CRD System will be conducted.	9. For their preferred source of power, the FMCRD motors are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E PIP bus.
10. Main control room alarms, displays and controls provided for the CRD System are defined in Section 2.2.2.	10. Inspections will be performed on the main control room alarms, displays and controls for the CRD System.	10. Alarms, displays and controls exist or can be retrieved in the main control room as defined in Section 2.2.2.

Section 2.2.3 **Comment No.** 1

Comment:

ITAAC verification is needed for three element control mode discussed in the design description. Proposed insertion for Table 2.2.3 is the following:

Design Commitment: At high FW flow, the FDWC system controls FW flow in automatic/manual three-element modes, using RPV water level, steam flow, and FW flow.

Inspections, Test and Analysis: Tests will be performed by simulating an increase/decrease in RPV water level or steam flow.

Acceptance Criteria: A signal to increase/decrease FW flow (corresponding to the input signal) will occur to maintain RPV water level.

Resolution:

GE did not agree. (See GE's response to comment in enclosure.)

NRC agreed with GE's disposition.

Section 2.2.4 Comment No. 1

Comment:

SSAR Table 14.3-6 ATWS Analysis, has a non-defined term for ATWS on SSAR page 14.3-38: Manual ARI/FMCRD Run-in Signals. A review of SSAR Chapter 7 did not provide clarification. Is this signal fully tested in ITAAC? Where is the associated logic described?

Resolution:

See SSAR App. 15E.

Section 2.2.5 Comment No. 1

Comment:

Design description 2.2.5 states that the SRNM monitors neutron flux up to 15% of rated power. The SSAR 7.2.1.1.4.2 states that the SRNM monitor flux to 10% of rated power. SSAR section 7.7 has 15% as the range. Revise 7.2.1.1.4.2.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.2.5 Comment No. 2

Comment:

The SSAR 7.2.1.1.4.2 does not list OPRM Oscillation Power range monitor reactor trip signal. Listed in design description 2.2.5, ITAAC and TS. Modify the SSAR to add the OPRM function in SSAR section 7.2.

Resolution:

GE agreed to make the changes.

Section 2.2.5 Comment No. 3

Comment:

SSAR 7.2.1.1.4.2 lists trips for the SRNM as upscale, short period, and SRNM inoperative. The design description ITAAC and TS list trips as high neutron flux and short period with the TS listing SRNM inop as well.

Resolution:

No action needed. SRNM upscale is for high neutron flux.

Section 2.2.5 Comment No. 4

Comment:

SSAR 7.2.1.1.4.2 lists the APRM range as "a few percent to greater than reactor rated power." Design description 2.2.5 states that range is power range up to 125% of rated power. ITAAC does not list the stated range of this instrumentation.

Resolution:

No action needed. Only the trip setpoints are tested by ITAAC. The range remains in Tier 2 because it is not safety significant.

Section 2.2.5 **Comment No.** 5

Comment:

The design description 2.2.5 and ITAAC lists the APRM trips as high neutron flux trip, simulated thermal power trip, rapid core flow decrease trip signal, and a core power oscillation trip signal. SSAR lists the trips as high neutron flux, high simulated thermal power, APRM inoperative and reactor internal pump trip. TS adds oscillation power range monitor to SSAR listing.

Resolution:

(Task Group:) Request GE to add the OPRM trip function in SSAR Section 7.2. (Comment 2 above).

GE agreed to make the changes.

Section 2.2.5 **Comment No.** 6

Comment:

The SRNM includes as interlock signal (ATWS permissive) to the safety system logic and control (SSLC) that indicates whether the SRNM power level is above a specific setpoint and provides a permissive signal to the SSLC for ATWS mitigation (auto SLC actuation). Discuss whether the source range permissive is intended only for SLC or also includes end-of-cycle recirc pump trip. Discuss the impact of a common mode failure of the SSLC upon the automatic functional requirements of SLC and EOC recirc pump trip (see 50.62 (4) and (5). Although 50.62 does not require diversity with regard to EOC and SLC the ABWR arrangement seems to consolidate these functions to a greater extent than previous plants. Based on the above is the intent of 50.62 still met with the proposed ABWR system arrangement?

Resolution:

No action needed. "SRNM not downscale" interlock in the ATWS logic in SSLC is for SLC and FW runback-no interlock to EOC-RPT. (See Figure 15E-1 and Figure 15E-2 in the SSAR) ATWS logic cards in SSLC are functionally independent and diverse from the circuitry in RPS (see CDM item 3.4). EOC-RPT inputs to the RFCS while SLC initiation is from ATWS logic cards in the SSLC. The design meets the requirements of 50.62.

Section 2.2.6 Comment No. 1

Comment:

The ITAAC does not verify the prime function of the RSS of being able to control plant equipment from outside the MCR. Pre-op test 14.2.12.1.8 will verify RSS control of pumps and valves to establish flow path. Equivalent testing needs to be incorporated in ITAAC Table 2.2.6.

Resolution:

Not necessary - see ITAAC 2. ITA for continuity check is sufficient, since the functional test of all components in the system are performed using the controls in the MCR. This functional test in combination with the continuity check, will verify the primary function of the RSS.

Section 2.2.7 **Comment No**. 1

Comment:

Reactor Protection System design description 2.2.7 does not list a reactor trip for high main steamline radiation. ITAAC states that a simulated process variable input will be used (as listed in 2.2.7 and figure 2.2.7a) to test the RPS channel inputs.

Resolution:

GE did not agree. (See GE's response to comment in enclosure.)

NRC agreed with GE's disposition.

Section 2.2.7 **Comment No**. 2

Comment:

The SSAR 7.2.1.1.4.2 does not list OPRM as an initiating condition. (This comment was previously provided to GE for inclusion in Amendment 33.)

Resolution:

GE agreed to make the changes.

Section 2.2.7 **Comment No**. 3

Comment:

Item 7 of ITAAC 2.2.7 provides for inspection of main control room displays and controls as defined in section 2.2.7 of the design description. A reference to required controls or displays is lacking in the design description.

Resolution:

No action needed. Displays and controls are defined in Figure 2.2.7a and in the last paragraph of 2.2.7 design description.

Section 2.2.7 **Comment No.** 4

Comment:

For ATWS mitigation systems included with SSL, confirm that logic and actuation device power for these systems is independent from the reactor trip system supplies and that the possibility of common mode failure of shared instrument and sensor channel supplies is addressed.

Resolution:

No action needed. These statements are provided in CDM 3.4.

Section 2.2.7 **Comment No.** 5

Comment:

For manual actuation of ATWS function confirm that manual actuation is not interfaced with the SSLC source range ATWS (or APRM) permissive. It appears that the permissive is active for both automatic and manual actuation.

Resolution:

No action needed. NMS provides direct imput is ATWS logic in the SSLC. This information is provided in SSAR Chapter 15 and CDM 2.2.5.

Section 2.2.7 **Comment No.** 6

Comment:

Figures 2.2.7a and 2.2.7b use solid and dotted lines for signal flow. No description or legend is provided.

Resolution:

GE reviewed the figures and proposed changes as indicated in the enclosure.

NRC agreed with GE's disposition.

Section 2.2.8 Comment No. 1

Comment:

The design description (2nd para) states 2 MG sets, each of which supplies 3 of 10 ASDs power 10 RIPs. Clarify how the other 4 ASDs (and 4 associated RIPs) are powered, the description should be consistent with SSAR figure 8.3-1.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.2.8 Comment No. 2

Comment:

The design description states RFC operates in either manual or auto control mode. An ITAAC verification is warranted for this aspect.

Resolution:

No action needed. Configuration check only in Tier 1. Operation in manual is Tier 2, because it is not a safety significant detail to be functionally checked.

Section 2.2.9 Comment No. 1

Comment:

Figure 2.2.9 lists TCS, RCIC, and RFC systems but design description does not define these abbreviations.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.2.9 Comment No. 2

Comment:

Chapter 7 Appendix 7B "Implementation Requirements for Hardware/Software development", first paragraph, last sentence appears incomplete. See attached. (This comment was previously provided to GE for inclusion in Amendment 33.)

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.2.9 Comment No. 3

Comment:

Section 7.7.1.5.2, Power Generation Control Subsystem, states that the PGCS issues reactor command signals to the "APR". APR is not defined.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.2.9 Comment No. 4

Comment:

7.7.1.5.3 Safety Evaluation, references 7.7.1.5.1 as providing the explanation of PGCS signals to the APR system. The correct reference might be 7.7.1.5.2.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.2.9 Comment No. 5

Comment:

In 7.7, Control Systems not Required for Safety, the system list is inconsistent with the system included in Chapter 7.7. See attached.

Resolution:

GE agreed to make the changes as described in the enclosure.

2.2.9 (2)

7B Implementation Requirements for Hardware/Software Development

This section defines the requirements to be met by the hardware and software development implementation activities that are to be made available for review by the NRC. Software Development ~~3.4.8 com~~

Software Management Plan

(1) The Software Management Plan shall define:

(a) the organization and responsibilities for development of the software design; the procedures to be used in the software development; the interrelationships between software design activities; and the methods for conducting software safety analyses.

Within the defined scope and content of the Software Management Plan, accepted methods and procedures for the above activities are presented in the following documents:

(i) IEEE 730, Standard for Software Quality Assurance Plans, Section 3.4;

(ii) ASME NQA2a, Part 2.7, Quality Assurance Requirements of Computer Software for Nuclear Facility Application;

(iii) ANSI/IEEE-ANS-7-4.3.2, Application Criteria for Digital Computers in Safety Systems for Nuclear Facilities (to be replaced by the issued version of P 7-4.3.2, "Standard Criteria for Digital Computers Used in Safety Systems of Nuclear Power Generation Stations");

(iv) IEC 880, Software for computers in the safety systems of nuclear power stations, Section 3.1;

(v) IEEE *(draft H)*, Standard for Software Safety Plans;

(vi) IEEE 1012, Standard for Software Verification and Validation Plans, Section 3.5;

(vii) IEEE 830, Guide to Software Requirements Specifications, Section 5;

(viii) IEEE 1042, Guide to Software Configuration Management.

Note that within the set of documents listed above, differences may exist regarding specific methods and criteria applicable to the Software Management Plan. In situations where such differences exist, all of the methods and criteria presented within those documents are considered

7.7 Control Systems Not Required for Safety

7.7.1 Description

This subsection provides discussion (or provides references to other chapter discussions) for instrumentation and controls of systems which are not essential for the safety of the plant, and permits an understanding of the way the reactor and important subsystems are controlled, and why failure of these systems does not impair safety functions. The systems include the following:

- Nuclear Boiler System—Reactor Vessel Instrumentation
- Rod Control and Information System
- Recirculation Flow Control System
- Feedwater Control System
- Process Computer System
- Neutron Monitoring System—ATIP Subsystem
  AND SYSTEMS
- Fire Protection System (Chapter 9)
- Drywell Cooling System (Chapter 9)
- Instrument Air Systems (Chapter 9)
- Makeup Water System (Chapter 9)
- Atmospheric Control System (Chapter 9)
- Fuel Pool Cooling and Cleanup System (Chapter 9)

7.7.1.1 Nuclear Boiler System—Reactor Vessel Instrumentation

Figure 5.1-3 (Nuclear Boiler System P&ID) shows the instrument numbers, arrangements of the sensors, and sensing equipment used to monitor the reactor vessel conditions. The NBS interlock block diagram (IBD) is found in Figure 7.3-2. Because the NBS sensors used for safety-related systems, engineered safeguards, and control systems are described and evaluated in other portions of this document, only the non-safety-related sensors for those systems are described in this subsection.

(1) System Identification

The purpose of the NBS instrumentation is to monitor and provide control input for operation variables during plant operation.

7.7.1.1 Nuclear Boiler System
7.7.1.2 Rod Control
7.7.1.3 Recirculation Flow Control
7.7.1.4 Feedwater Control
7.7.1.5 Process Compute:
7.7.1.6 Neutron Monitoring
7.7.1.7 APR
7.7.1.8 Steam Bypass & Pressure Control
7.7.1.9 Non-Essential multiplexing System
7.7.1.9 Fuel Pool Cooling and Cleanup System
7.7.1.11 Other non-safety Related Control Systems

Section 2.2.10 **Comment No.** 1

Comment:

Figure 2.2.10 labelling of interfacing systems are listed as Turbine Control System, Turbine Bypass System and RFC system. The labelling is inconsistent.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.2.10 **Comment No.** 2

Comment:

Figure 15E-1 ATWS mitigation logic indicates that the SB&PC system provides the steam dome pressure input to the RFC system. Per the system descriptions, the APR system is the RFC interface for the SB&PC system. See CDM 2.2.9 and 2.2.10 attached.

Resolution:

NRC agreed with GE disposition as described in the enclosure.

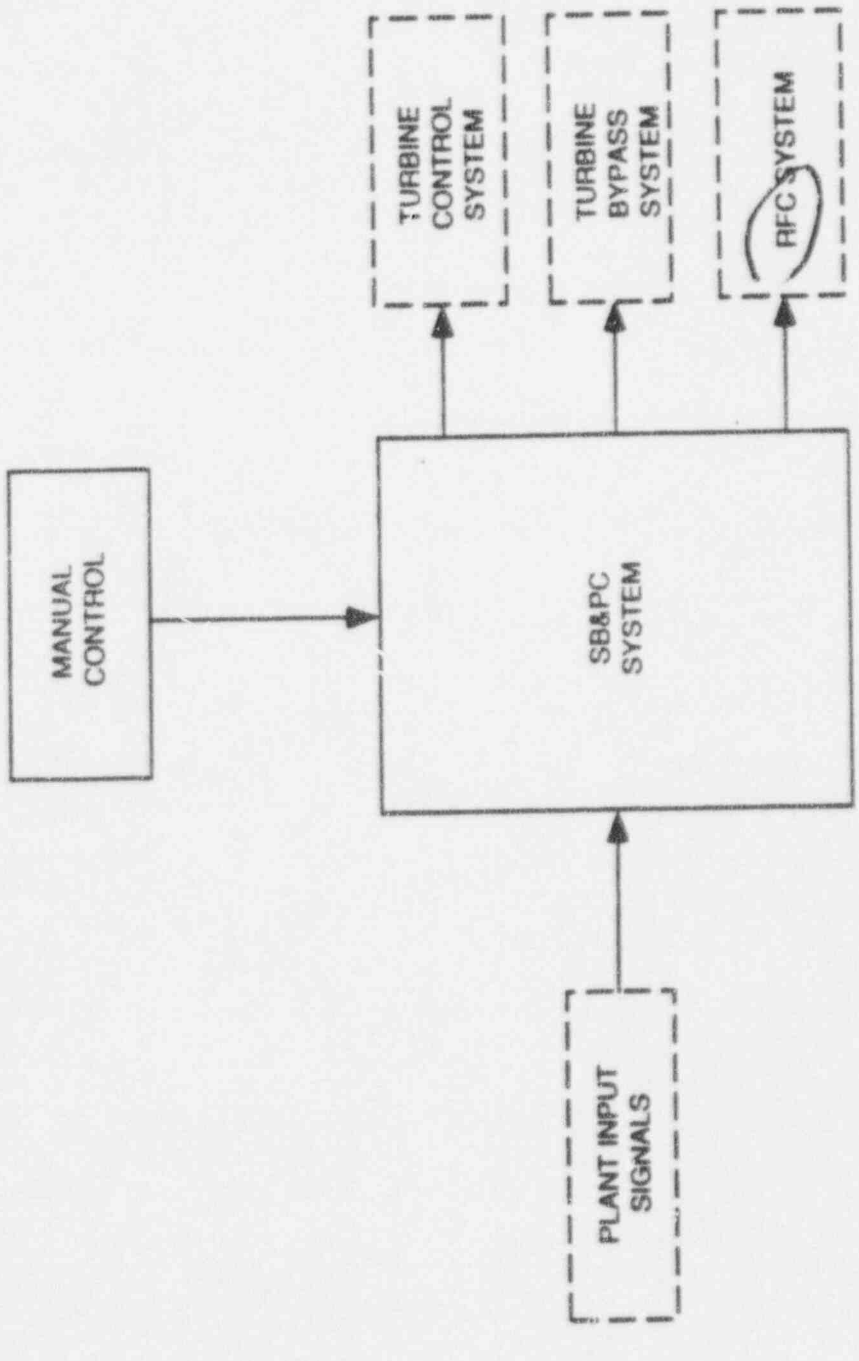
Section 2.2.10 **Comment No.** 3

Comment:

The title of figure 15E-2 is not consistent with the title of figure 15E-1. See SSAR, page 15E-18.

Resolution:

GE agreed to make the changes as described in the enclosure.



NOTE:
1. INTERCONNECTIONS MAY BE FIBER-OPTIC OR METALLIC.

Figure 2.2.10 Steam Bypass and Pressure Control System Control Interface Diagram

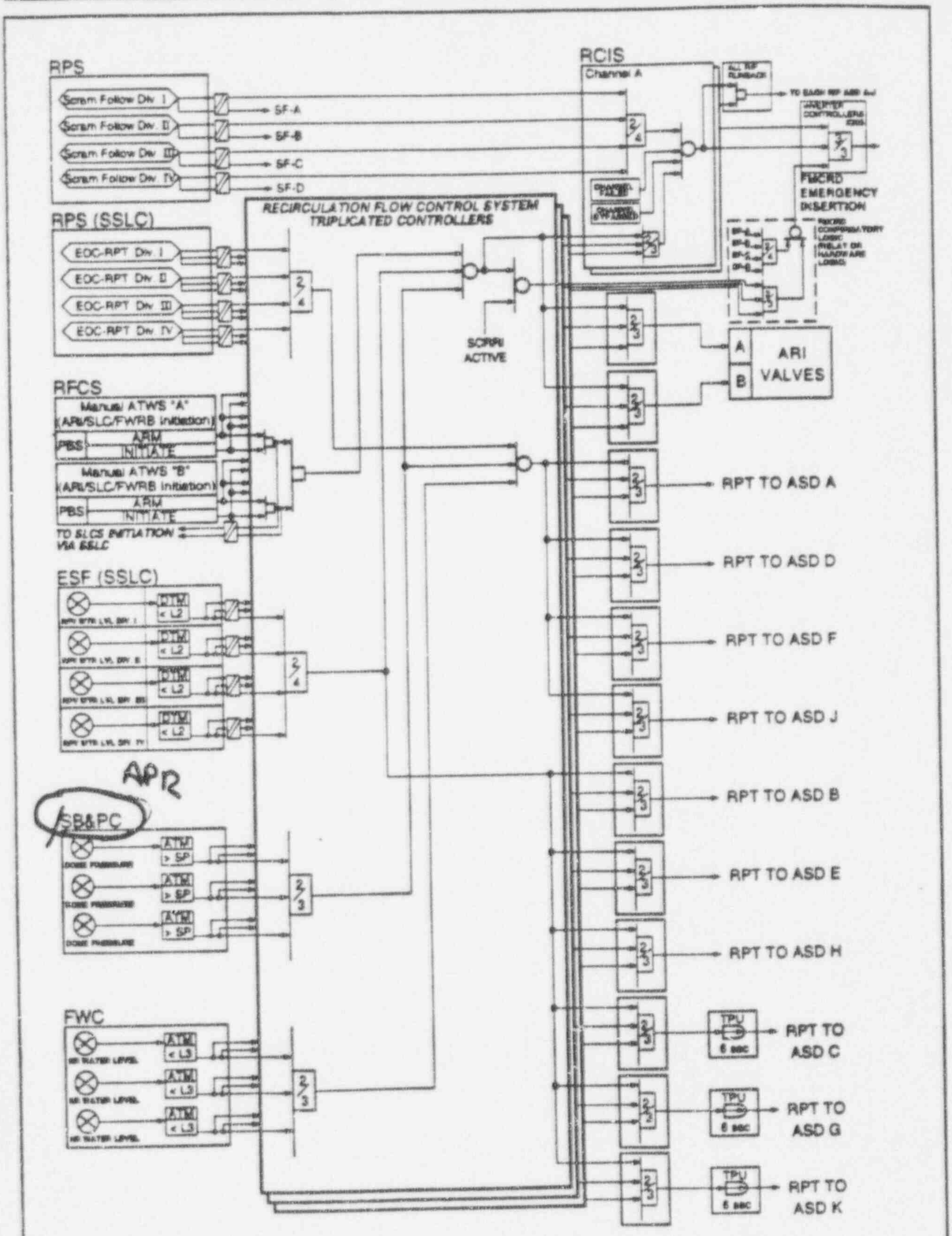


FIGURE 15E-1 ATWS MITIGATION LOGIC (ARI, FMCRD RUN-IN, RPT, RECIRCULATION RUNBACK)

Figure 15E-1 ATWS Mitigation Logic

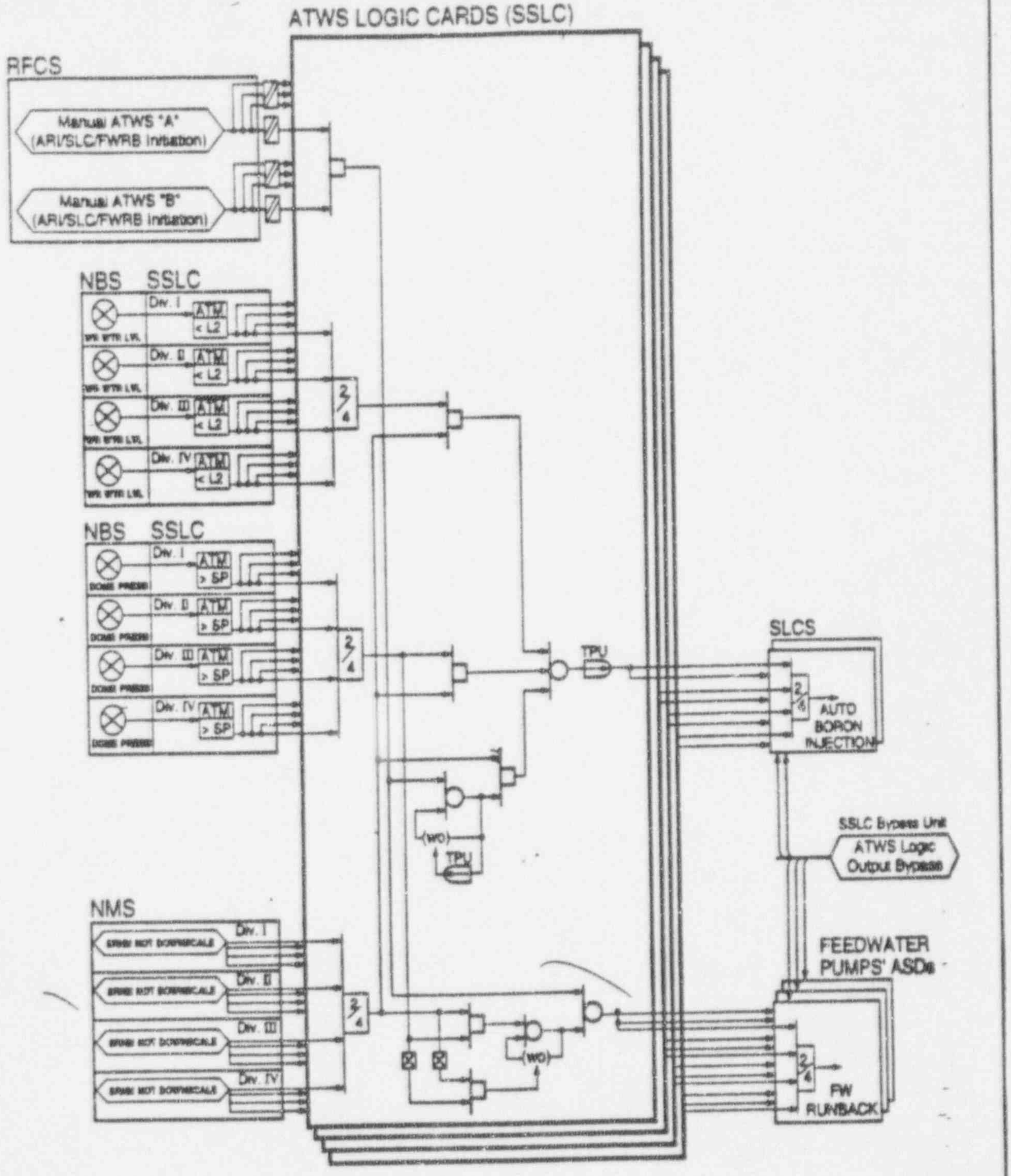


Figure FIGURE 15E-2 ATWS MITIGATION LOGIC (S: ^S INITIATION, FEEDWATER RUNBACK)

15E-2 ATWS Mitigation Logic ~~(SLCS Initiation, Feedwater Runback)~~

Section 2.2.11 Comment No. 1

Comment:

CDM material 2.2.11 references the ATLM, "Automated thermal limit monitor". Acronym is not consistent with other references. See ITAAC review 2.2.1 Rod Control and Information System, Comment No. 3.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.3.1 Comment No. 1

Comment:

Items 8, 9, 10, & 11 do not call for testing of all trip channels, only the high trips. Low and not operative trips should be verified by ITAAC.

Resolution:

Disagree - it was determined that high trips were sufficient for ITAAC.

Section 2.3.1 Comment No. 2

Comment:

The ITAAC/CDM describe the monitors as having only a high level trip. SSAR 11.5.2 states several monitors also have low or not operative trips.

Resolution:

Disagree - it was determined that high trips were sufficient for ITAAC.

Section 2.3.1 Comment No. 3

Comment:

The CDM/ITAAC only lists 5 out of 11 non-safety related monitors (see SSAR section 11.5.1.1.2). Why are other 6 PRM monitors not included?

Resolution:

It was determined during the staff's review that the 5 listed were the most significant.

Section 2.3.1 Comment No. 4

Comment:

Recommend that the attached test statement from 2.4.1 (3 a/b) be used in-lieu of current ITAAC language to assure appropriate trip conditions are verified.

Resolution:

Disagree - see # 1 & 2 above.

2.3.1 (4)

Table 2.4.1 Residual Heat Removal System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the RHR System is shown in Figures 2.4.1a, 2.4.1b, 2.4.1c, and 2.4.1d.	1. Inspections of the as-built system will be conducted.	1. The as-built RHR System conforms with the basic configuration shown in Figures 2.4.1a, 2.4.1b, 2.4.1c, and 2.4.1d.
2. The ASME Code components of the RHR System retain their pressure boundary integrity under internal pressures that will be experienced during service.	2. A hydrostatic test will be conducted on those Code components of the RHR System that are required to be hydrostatically tested by the ASME Code.	2. The results of the hydrostatic test of the ASME Code components of the RHR System conform with the requirements in the ASME Code, Section III.
3.	3.	3.
a. The RHR System is automatically initiated in the LPFL mode when either a high drywell pressure or a low reactor water level condition exists.	a. Tests will be conducted using simulated input signals for each process variable to cause trip conditions in two, three, and four instrument channels of the same process variable.	a. Each division of the RHR System receives an initiation signal.
b. Each RHR division can be initiated manually (LPFL mode).	b. Tests will be conducted by initiating each division manually.	b. Each division of the RHR System receives an initiation signal.

why not use this

Section 2.3.1 Comment No. 5

Comment:

The SSAR states the RW/B exhaust vent monitor reads out in both cpm and mR/hr (eg. 11.5.5.2(6) - cpm, Table 11.5-1(B) - mR/hr, Table 11.5-2 - cpm). The SSAR should be corrected to state cpm, not mR/hr.

Resolution:

GE agreed to make the changes.

Section 2.3.2 **Comment No.** 1

Comment:

Recommend that the attached test statement from 2.4.1 (3 a/b) be used in-lieu of current ITAAC language to assure appropriate trip conditions are verified.

Resolution:

Disagree. Proposed test words are not applicable to ARMS. ARMS not set-up as 1/2 twice logic.

Section 2.3.3 **Comment No.** 1

Comment:

SSAR Table 18F-1 identifies the CAMS operating modes with and sample select switch controls based on EPG/PRA importance. Those switches should be described in the design description.

Resolution:

Disagree. Based on review guidance, if in list, doesn't have to be in DD.

Section 2.3.3 **Comment No.** 2

Comment:

SSAR Table 18F-2 identifies the CAMs room cooler operation status alarms based on EPG/PRA importance. Those alarms should be described in the design description. (ITAAC 2.15.5 does not appear to cover this aspect.)

Resolution:

Disagree. Based on review guidance, if in list, doesn't have to be in DD.

Section 2.3.3 **Comment No.** 3

Comment:

SSAR Table 3.9-8 identifies active containment isolation valves for this system. Those valves need to be discussed in the design description or depicted on a Tier 1 figure to assure the ITAAC configuration verification.

Resolution:

Disagree. CVs on instrument lines are below the level of detail for DD & ITAAC. During the NRC meeting with GE in California on ITAAC, an agreement was reached not to include CVs on instrument lines in the DD and ITAAC. First, CAMS is a closed system outside of containment. Second, the line penetrating containment is very small; if the CV failed or leaked, leakage fromthis line would not create a large dose problem. Consequently, it was decided that the CVs for this system did not rise to a level of importance which would warrant description or depiction of the CVs in the DD and ITAAC for this system.

Section 2.3.3 Comment No. 4

Comment:

SSAR Table 3.2-1 describes the system as ASME class. The design description should discuss this aspect (either in text or on a figure) and the boilerplate ASME pressure boundary integrity ITAAC should be added to CDM Table 2.3.3.

Resolution:

Disagree. Table 3.2-1 identified portions of this system as SC3, but no QG Class. For the ABWR, this class relates to Class 1E electrical equipment, not ASME Class 3.

Section 2.4.1 **Comment No.** 1

Comment:

On page 2.4.1-2, the reactor pressure at minimum RHR rated flow is stated as 2.8 kg/cm2. In SSAR Table 6.3-1, this pressure is listed incorrectly as 28 kg/cm2.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.4.1 **Comment No.** 2

Comment:

In the discussion on suppression pool cooling mode, why the auto initiation of this mode on a signal from suppression pool temperature monitoring system (SSAR 7.3.1.1.4) is not mentioned?

Resolution:

It is discussed in Section 5.4.7.1.1.5.

Section 2.4.1 **Comment No.** 3

Comment:

Page 2.4.1-4: What is the basis of the minimum tube side flow of 350 m^3/hr in RHR hx during the augmented fuel pool cooling mode?

Resolution:

See SSAR Sections 5.4.7 (RHR) 9.1.3 (Fuel Pool Cooling & Cleanup and PFD (Figure 5.4-11, sheet 2 OF 2).

Section 2.4.1 **Comment No.** 4

Comment:

The SSAR does not list the acronyms "SW" and "CS" used in the SSAR Table 18F-1.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.4.1 Comment No. 5

Comment:

Figures 2.4.1a & b should show that the RHR pump discharge pressures are displayed on the RSS panels, i.e., add symbol "R" to the pressure instruments.

Resolution:

GE agreed to make the changes.

Section 2.4.1 Comment No. 6

Comment:

The 2nd note at the bottom of SSAR Table 6.3-2 needs revision.

Resolution:

GE proposed to delete footnote (See GE's response to comment in enclosure.)

NRC agreed with GE's disposition.

Section 2.4.1 Comment No. 7

Comment:

Why are the isolation valves between FPC and RHR in Figures 2.4.1b and 2.4.1c of different type?

Resolution:

GE concurred that the valves should be of the same type and agreed to make the changes as described in the enclosure.

Section 2.4.1 Comment No. 8

Comment:

Why the MUWC interface with RHR is not shown in the figures?

Resolution:

Jockey pump is shown. The MUWC system is used in RHR only for filling and flushing the system. There is no safety significance, hence it need not be included in Tier 1.

Section 2.4.1 Comment No. 9

Comment:

Correct the attached CDM typos.

Resolution:

GE agreed to make the changes.

2.4.1 (97)

Outside the primary containment, each mechanical division of the RHR System (Divisions A, B, and C) is physically separated from the other divisions.

The RHR System has the following displays and controls in the main control room:

(1) Parameter displays for the instruments shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c.

(2) Controls and status indication for the active safety-related components shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c.

(3) Manual system level initiation capability for the following modes:

(a) LPFL initiation

(b) Standby

(c) Shutdown cooling

(d) Suppression pool cooling

(e) Drywell spray

RHR System components with displays and control interfaces with the Remote Shutdown System (RSS) are shown on Figures 2.4.1a and 2.4.1b.

The safety-related electrical equipment shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c located inside the primary containment and the Reactor Building is qualified for a harsh environment.

The motor-operated valves shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c have active safety-related functions and perform these functions to open, close, or both open and close, under differential pressure, fluid flow, and temperature conditions.

valves

The check calves (CVs) shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c have safety-related functions to open, close, or both open and close under system pressure, fluid flow, and temperature conditions.

The RHR System main pumps are interlocked to prevent starting with a closed suction path.

Each RHR loop has a continuously running jockey pump to maintain the system piping continuously filled with water. The jocky pump is stopped by a RHR initiation signal or may be stopped or started manually.

The piping and components outside the shutdown cooling suction line containment isolation valves and outside the suppression pool containment isolation valves, and upstream of the suction side of the pump with all its branches have a design pressure of

Appendix A Legend for Figures

For a number of the systems presented in Section 2, figures depicting the Basic Configuration of the systems have been provided to help facilitate the Design Description. For I&C systems, the figures represent a diagram of significant aspects of the logic of the system. For other systems and buildings, these figures represent a functional diagram, representation, or illustration of design-related information. Unless otherwise specified explicitly, these figures are not necessarily indicative of the scale, location, dimensions, shape, or spatial relationships of as-built structures, systems, and components. In particular, the as-built attributes of structures, systems and components may vary from the attributes depicted on these figures, provided that those safety functions discussed in the Design Description are not adversely affected.

The figures contain information that uses the following conventions:

Mechanical Equipment

Line classification:

		Figure Designation
ASME Code Class 1		1
ASME Code Class 2		2
ASME Code Class 3		3
Non-ASME Code/ Non-Nuclear Safety		NNS
Other Line Type:		This legend can be used for pneumetric lines when needed for clarity. ASME Code class for such lines is defined on the system figure.

Typo

of the FMCRD piston and ball nut need to be identified as class 1E. Reference SSAR section 4.6.2.3.3.2. Also add "Independence is provided between class 1E and non class 1E equipment."

(3) Page 2.2.2-3, Item # 3, Correct Figure "2.1.2" to "2.2.2".

STANDBY LIQUID CONTROL SYSTEM (2.2.4)

No comments

RESIDUAL HEAT REMOVAL SYSTEM (2.4.1)

(1) Figure 2.4.1a & b should show that the RHR pump discharge pressures are displayed on the RSS panels, i.e., add symbol "R" to the discharge pressure instruments.

(2) Why the isolation valves between FPC and RHR in Figures 2.4.1b & c are of different type? Either type would be acceptable, but the valve type should be consistent.

(3) Page 2.4.1-5, 9 th para, correct "check calves" to "check valves".

(4) Page 2.4.1-5, Item # 3- Add wet well spray, Augmented Fuel Pool Cooling and Fuel Pool Makeup and AC Independent Water Addition Mode to the list.

(4) ITAAC Table 2.4.1, Item # 4a-Add "during Suppression Pool Cooling mode" to the first column for design commitment.

HIGH PRESSURE CORE FLOODER SYSTEM(2.4.2)

ITAAC Table Item # 3e -Change "pimp suction" to "pump suction" in the first column.

REACTOR CORE ISOLATION COOLING(2.4.4)

(1) Figure 2.4.4a: Main Steam line is "out of function" in this Figure. But the lines are misleading since the ASME class 2 designation symbol is used. Use different symbols to indicate "out of function" systems.

(2) Figure 2.4.4a: Add "B" to "Main steam line"

(3) Figure 2.4.4a RCIC steam supply line bypass valve line from the outlet to the main line is shown incorrectly. This should be shown as ASME class 1.

(4) Table 2.4.4 Item 1, 3 rd column: Change the end of the statement to read "--- Figures 2.4.2a and 2.4.2b".

(5) Table 2.4.4 Item 3i: Add the following condition to the first and 3rd column " within 29 seconds after the signal to start". In third column change the numeral 2 to three to indicate cubic meters.

(6) Table 2.4.4 Item 3k: Add "test and analysis" to the middle column. Support systems such as HVAC can be tested before fuel loading. Analyses will be required to show the 8 hour capability in the SSAR.

NUCLEAR FUEL (2.8.1)

Design Description-Delete the first sentence starting: "The fuel assembly------100", since this refer to 10 CFR 20,50 and 100.

FUEL CHANNEL (2.8.2)

No comments

CONTROL ROD (2.8.3)

No comments

LOOSE PARTS MONITORING SYSTEM (2.8.4)

No comments

Section 2.4.2 Comment No. 1

Comment:

The actual opening/closing of the minimum flow valves should be verified in addition to the verification of the receipt of actuating signals in ITAAC entry # 3o or in a separate entry.

Resolution:

Disagree - entry 3.p. provides sufficient check.

Section 2.4.2 Comment No. 2

Comment:

Active valves F008 (Test Return Line Inboard Valve) and F020 (Suppression Pool Suction Relief Valve) listed in SSAR Table 3.9-8 are not shown on Fig. 2.4.2a.

Resolution:

There are two valves in the test return line. By having only one valve listed in Tier 1, it provides the COL applicant flexibility in the future design.

In the ITAAC figures, only major valves are shown. The thermal relief valve in the suppression pool suction line is not considered as safety significant for inclusion in Tier 1.

Section 2.4.2 Comment No. 3

Comment:

Correct the attached typos.

Resolution:

GE agreed to make the changes.

Table 2.4.2 High Pressure Core Flooder System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
d. The HPCF System flow in each division is not less than a value corresponding to a straight line between a flow of 182 m^3/hr at a differential pressure of 82.8 kg/cm^3 and a flow of 727 m^3/hr at a differential pressure of 7 kg/cm^2.	d. Tests will be conducted on each division of the as-built HPCF System in the HPCF high pressure flooder mode. Analyses will be performed to convert the test results to the conditions of the Design Commitment.	d. The converted HPCF flow satisfies the following: The HPCF System flow in each division is not less than a value corresponding to a straight line between a flow of 182 m^3/hr at a differential pressure of 82.8 kg/cm^3 and a flow of 727 m^3/hr at a differential pressure of 7 kg/cm^2.
e. The HPCF System has the capability to deliver at least 50% of the flow rates in item 3d with 171°C water at the pimp suction.	e. Analyses will be performed of the as-built HPCF System to assess the system flow capability with 171°C water at the pump suction.	e. The HPCF System has the capability to deliver at least 50% of the flow rates in item 3d with 171°C water at the pump suction.
f. System flow into the reactor vessel is achieved within 16 seconds of receipt of an initiation signal and power available at the emergency busses.	f. Tests will be conducted on each HPCF division using simulated initiation signals.	f. The HPCF System flow is achieved within 16 seconds of receipt of a simulated initiation signal.
g. The HPCF pumps have sufficient NPSH available at the pumps.	g. Inspections, tests and analyses will be performed upon the as-built system. NPSH tests of the pumps will be performed in a test facility. The analyses will consider the effects of: – Pressure losses for pump inlet piping and components. – Suction from the suppression pool with water level at the minimum value. – 50% minimum blockage of the pump suction strainers.	g. The available NPSH exceeds the NPSH required by the pumps.

Section 2.4.3 Comment No. 1

Comment:

The Design Description should include discussion of the main steam line radiation level trip of the MSIVs which is an input from PRMS. This is discussed in SSAR 7.3.1.1.2 as part of LDS.

Resolution:

GE did not agreed. (See GE's response to comment in enclosure.)

NRC agreed with GE's disposition.

Section 2.4.4 Comment No. 1

Comment:

Certified Design Material page 2.4.4-1 first paragraph:
Expand the last sentence to read as follows: "---makeup water to the RPV in order to assure that sufficient water inventory is maintained in the reactor

Resolution:

The system function is adequately described in the Design Description. The staff judged that no changes are required.

Section 2.4.4 Comment No. 2

Comment:

Page 2.4.4-2 second paragraph stated that "This flow rate is achieved within 29 seconds of receipt of the system initiation signal."
SSAR Section 5.4.6.1.1.1 gave a parameter of "---within 30 seconds---."
Please clarify this discrepancy.

Resolution:

One second difference is signal delay.

Section 2.4.4 Comment No. 3

Comment:

Page 2.4.4-3 first paragraph:
Expand the sentence to read as follows:
"Outside the primary containment, except for the piping from the CST, which branches off of one of the two High Pressure Core Flooder (HPCF) Divisions (Division C), the RCIC System shown on Figure 2.4.4a is physically separated from the two divisions of the HPCF System."

Resolution:

The staff judged that the information in the comment is too detailed for Tier 1.

Section 2.4.4 Comment No. 4

Comment:

See comments on attached copy of Figure 2.4.4a.

Resolution:

GE proposed disposition of comment: as described in enclosure.

NRC agreed with GE's disposition.

Section 2.4.4 Comment No. 5

Comment:

In Table 2.4.4, Item 1, 3rd column: change the end of the statement to read " --- Figures 2.4.2a and 2.4.2b."

Resolution:

GE agreed to make the changes.

Section 2.4.4 Comment No. 6

Comment:

Table 2.4.4, Item 3i, add the following condition to the 1st and 3rd column "within 29 seconds after the signal to start." In the 3rd column, change the numeral 2 to an exponent.

Resolution:

GE's proposed disposition of comment is discussed in the enclosure.

NRC agreed with GE's disposition.

Section 2.4.4 Comment No. 7

Comment:

Table 2.4.4 Item 7, 1st and 3rd columns:
Revise the statement to read as follows "---piping from the CST which branches off of one of the two HPCF Divisions,---."

Resolution:

The CST is not safety significant enough to show in the figure. The suggested write-up can be incorporated only with the CST in the figure. For simplicity, the staff decided not to include the CST and not to make any changes.

Section 2.4.4 Comment No. 8

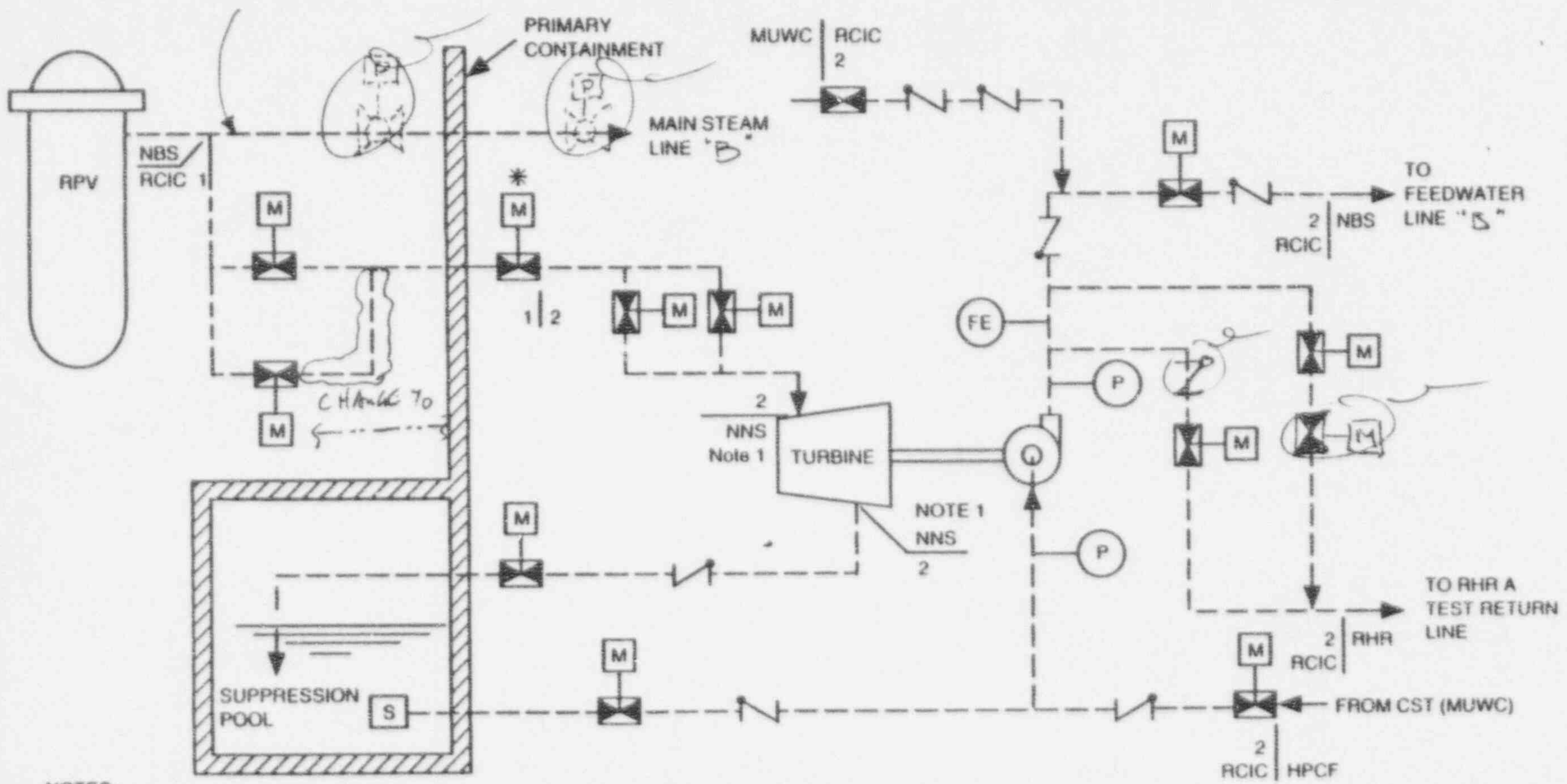
Comment:

Table 2.4.4 Item 9:
The active safety-related MOVs of the RCIC System must operate under extremely severe differential pressure and closure time as delineated in SSAR Table 5.4-2. ITAAC must provide the analysis to demonstrate that these severe operating conditions can be met when the MOVs are tested under the pre-operational conditions.

Resolution:

Disagree - type testing of valves is covered as part of configuration ITAAC. See general provisions.

LINE NBS FROM RPV TO OUTBOARD MSIV IS ASME CODE CLASS 1



NOTES:

1. RCIC TURBINE IS NOT COVERED BY ASME CODE SECTION III BUT IS DESIGNED, FABRICATED, AND INSTALLED TO SAFETY-RELATED STANDARDS AND IS CONSISTENT WITH THE ASME CODE SECTION III REQUIREMENTS. THE TURBINE INCLUDES THE TURBINE TRIP AND THROTTLE VALVE.
2. ALL RCIC SYSTEM COMPONENTS SHOWN ON THIS FIGURE ARE POWERED FROM CLASS 1E DIVISION I EXCEPT FOR THE OUTBOARD CONTAINMENT ISOLATION VALVE (*) WHICH IS CLASS 1E DIVISION II.
3. ALL RCIC SYSTEM COMPONENTS SHOWN ON THIS FIGURE EXCEPT THE INBOARD CONTAINMENT ISOLATION VALVES, ARE POWERED FROM DC SOURCES.

COMMENTS:

1. CHANGE PIPING CODE CLASS IN 2 PLACES.
2. ~~ADD PHANTOM MSIVS.~~
3. STATE SPECIFICALLY LINE "B" FOR MAIN STEAM & FEEDWATER
4. ~~SHOW CHECK VALVE AND SECOND MOV IN ACCORDANCE SSAR TABLE 3.9.8.~~

Figure 2.4.4a Reactor Core Isolation Cooling System

ITAAC COMMENTS PAGE 3 OF 3

GEORGE T. CAR

Section 2.6.1 Comment No. 1

Comment:

Page 2.6.1-1 9th Paragraph, revise as follows: "---this function under design basis and required operating conditions for differential pressure, fluid flow, and temperature. In addition, the containment isolation MOVs are to close in <30 seconds."

Resolution:

Disagree. The <30-second closure time is an acceptable criterion for the MOVs. Not a design commitment.

Section 2.6.1 Comment No. 2

Comment:

Need to develop acronyms for: main condenser, check valve, and containment isolation valve. (Example of problem: "CV" is used for "check valve", but the App. B shows "CV" as "control valve)

Resolution:

GE's proposed disposition in described in the enclosure.

NRC agreed with GE's disposition.

Section 2.6.1 Comment No. 3

Comment:

In the Certified Design Material, SSAR and P&ID, use one consistent parameter for the centerline of the tee connection; select either "at least 460 mm above the centerline of the variable leg nozzle" or "at least 389 mm above the top of active fuel".

Resolution:

NRC agreed with GE's disposition as described in the enclosure.

Section 2.6.1 Comment No. 4

Comment:

Reference attached markup of Figures 2.6.1, 5.1-3, and 5.4-12 for comments.

Resolution:

GE agreed to make the appropriate changes.

Section 2.6.1 Comment No. 5

Comment:

Certified Design Material Table 2.6.1 in ITAAC:

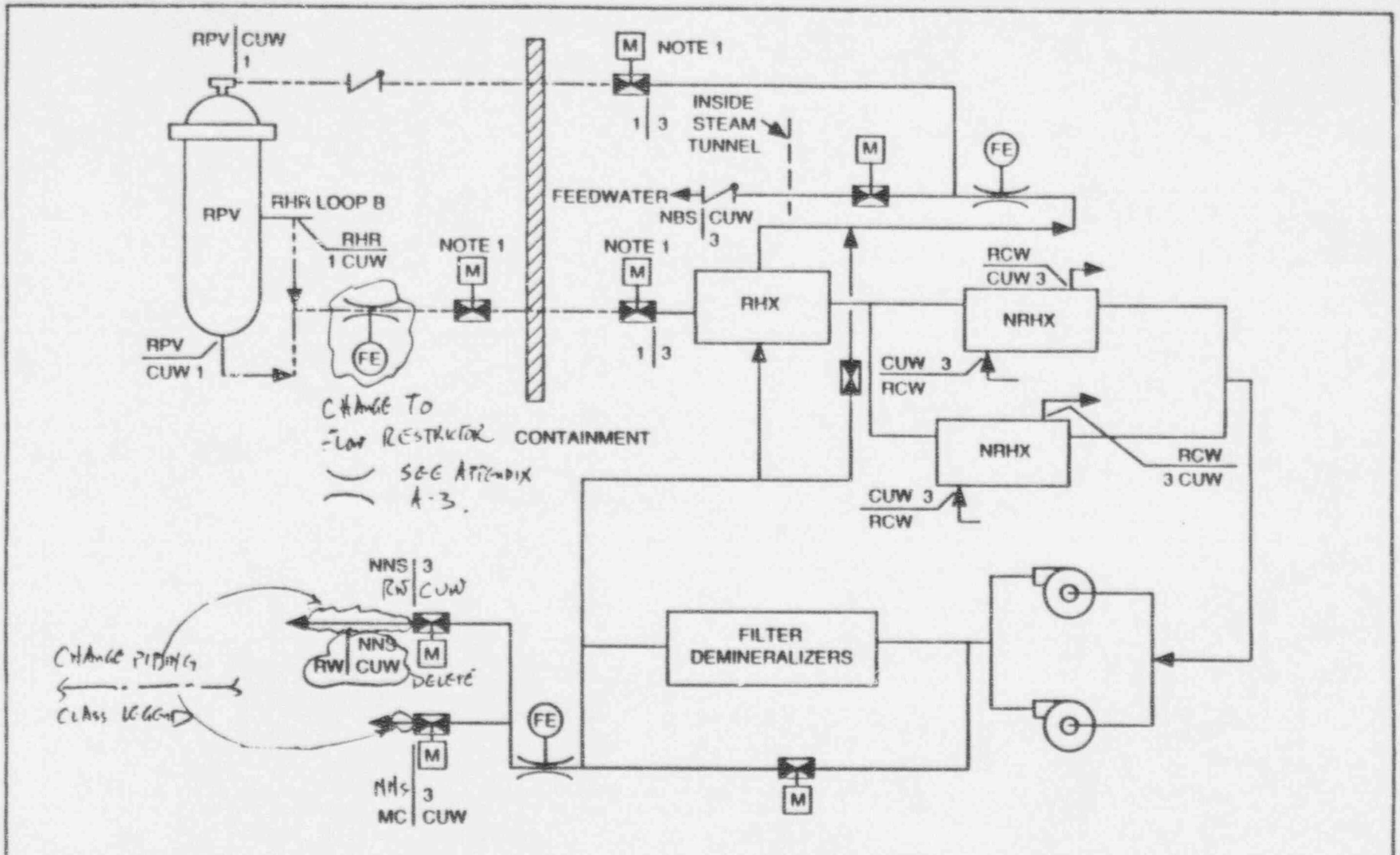
Item 3. - change "non-1E" to "non- Class 1E"

Item 5a provided the closure time of <= 30 sec for two of the three containment isolation MOVs, whereas SSAR Table 5.4-6 requires all three MOVs to close within a time constraint of <30 sec. Should be revised to reflect a closure time of <30 seconds.

(Task Group:) Partially agree. ≤ sec vs. <30 sec needs to be resolved (should be <30). The Tier 1 commitment only specifies those top level MOVs needed for safety. SSAR could commit more valves than CDM. Disagree with need for ITAAC analysis for MOVs to close because MOV qualification is covered under basis configuration ITAAC (General Provision #4)

Resolution:

NRC agreed with GE's disposition as described in the enclosure.

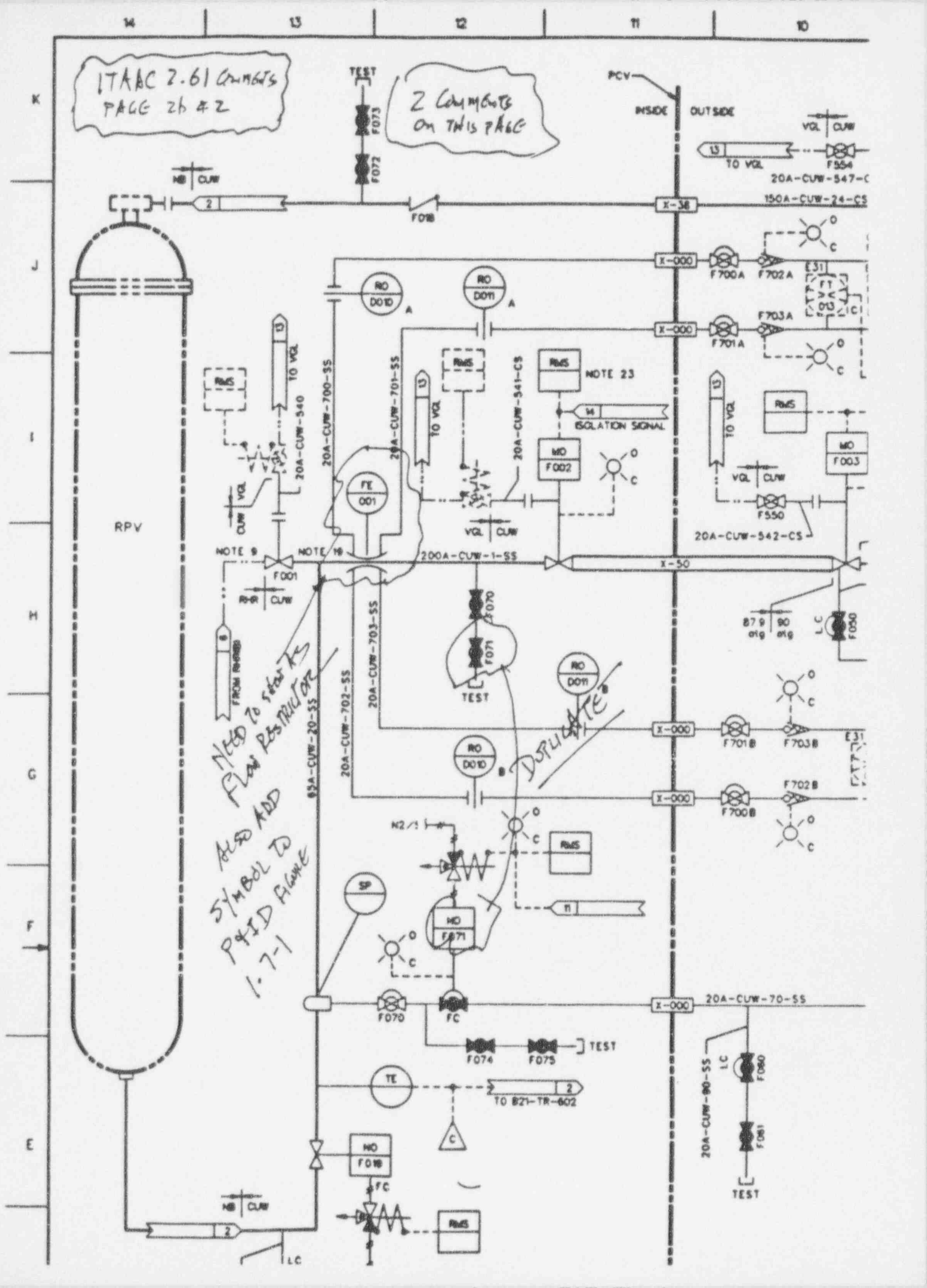


NOTES:
1. THE INBOARD CONTAINMENT ISOLATIONVALVE IS POWERED FROM CLASS 1E DIVISION II AND THE OUTBOARD ISOLATION VALVES ARE POWERED FROM CLASS 1E DIVISION I.

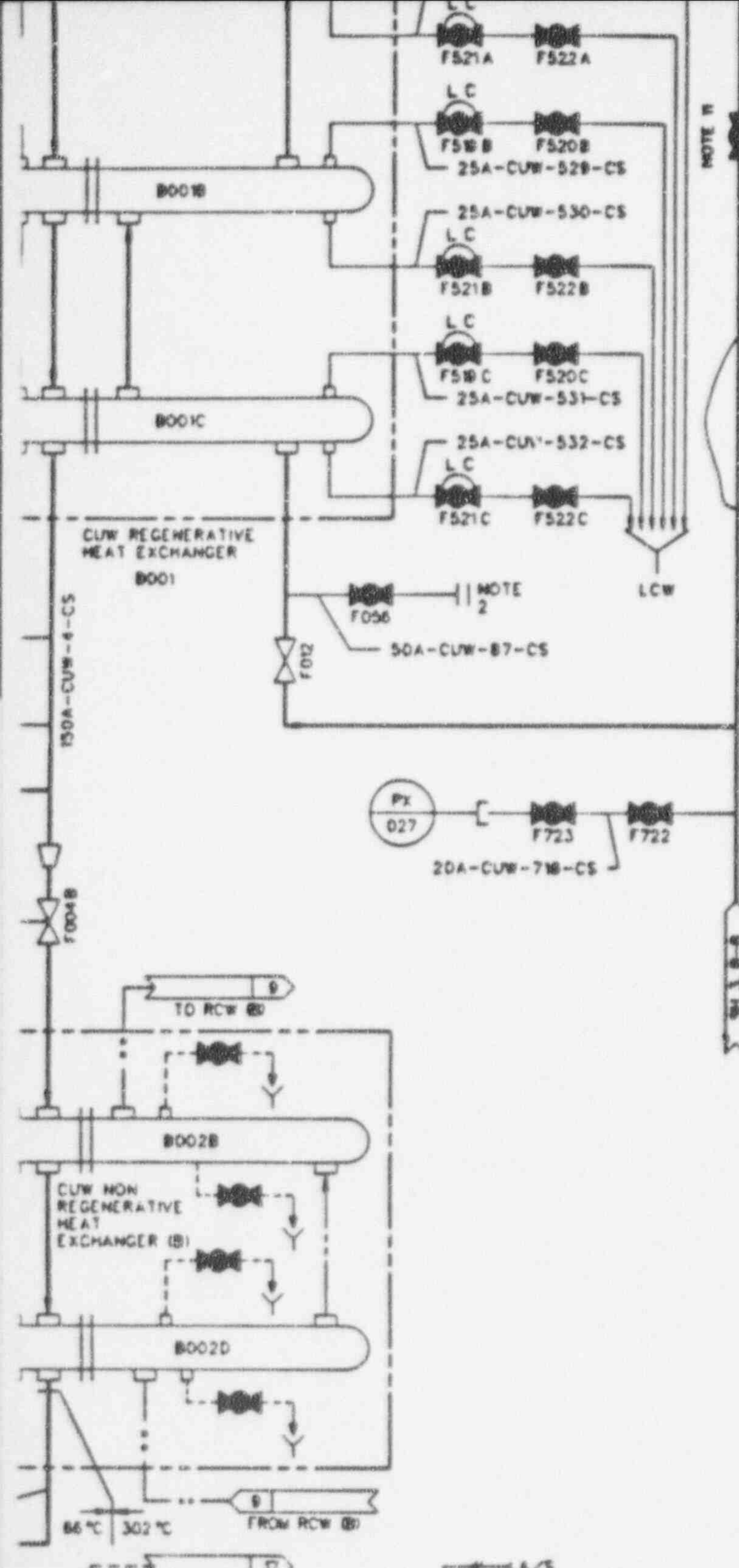
Figure 2.6.1 Reactor Water Cleanup System

ADD ACRONYM MC
TO APPENDIX B.

ITAAC COMMENTS P. 2a OF 2



ITAAC 2.61 Comments
PAGE 2b #2
2 Comments
On this page
TEST
F073
F072
NB
CUW
F018
PCV
INSIDE
OUTSIDE
VQL
CUW
TO VQL
F554
20A-CUW-547-C
150A-CUW-24-CS
X-38
X-000
F700A
F702A
E31
FT
D13
F701A
F703A
RO
D010
A
RO
D011
A
RMS
TO VQL
20A-CUW-540
20A-CUW-700-SS
20A-CUW-701-SS
20A-CUW-541-CS
RMS
NOTE 23
ISOLATION SIGNAL
MO
F002
RMS
MO
F003
VQL
CUW
F550
20A-CUW-542-CS
RPV
FE
001
VQL
CUW
NOTE 9
NOTE 19
200A-CUW-1-SS
X-50
F001
RHR
CUW
FROM RHR
F070
F071
TEST
879
90
LC
F050
20A-CUW-703-SS
20A-CUW-702-SS
80A-CUW-20-SS
RO
D011
RO
D010
B
X-000
F701B
F703B
F702B
F700B
Need to show as
Flow Restrictor
Also add
symbol to
P&ID figure
1.7-1
Duplicate
N2
RMS
SP
MO
F071
FC
F070
X-000
20A-CUW-70-SS
F074
F075
TEST
TE
TO B21-TR-602
C
MO
F019
FC
RMS
NB
CUW
LC
20A-CUW-80-SS
F080
F081
TEST



VALVE POSITION INDICATION LIGHTS LOCATED IN VICINITY OF VALVE CONTROL SWITCH.

13. TE006 INCLUDES TT FUNCTION.

14. MO VALVES AND INSTRUMENTS TO BE LOCATED IN THE SHIELDED COMPARTMENT CONTAINING THE FILTER DEMINERALIZER.

15. DESIGN CONDITIONS ARE FOLLOWING

(A)	FLUID	WATER
(B)	RADIOACTIVE CONCENTRATION	≥ 1μCi/CC
(C)	SCHEDULE	INTERFACE

16. FILTER DEMINERALIZER VALVE CONTROL SWITCHES, VALVE POSITION INDICATION LIGHTS AND ALARMS SHOULD BE INSTALLED IN LOCAL CONTROL PANEL.

Consistency
389 mm
or
460 mm

17. A COMMON TROUBLE ALARM FROM LOCAL ANNUNCIATOR SHALL ALARM IN THE MAIN CONTROL ROOM.

18. MO INDICATES AIR OPERATED VALVES FAIL AS IS ON LOSS OF AIR AND FAIL CLOSED ON LOSS OF ELECTRIC POWER.

19. VESSEL HEAD DRAINLINE TEE CONNECTION TO THE CUW SUCTION LINE SHALL BE INSTALLED AT AN ELEVATION OF AT LEAST 389 mm ABOVE THE TOP OF ACTIVE FUEL.

20. MAXIMUM THROAT DIAMETER OF FLOW RESTRICTOR FE-F001 SHALL BE 70% OF THE INTERNAL PIPE DIAMETER.

CHANGE TO
135 mm

21. PIPE WITH A DESIGN PRESSURE OF 28.8 KG/SQ CM OR GREATER SHALL HAVE ITS MINIMUM WALL THICKNESS NO LESS THAN THAT OF A STANDARD WEIGHT PIPE. THICKER THAN THE STANDARD WEIGHT PIPE SHALL BE USED IF REQUIRED BY THE DESIGN PRESSURE OR OTHER REQUIREMENTS.

22. VALVES WITH A DESIGN PRESSURE OF 28.8 KG/SQ CM OR GREATER SHALL HAVE A MINIMUM OF CLASS 300, OR OF A HIGHER CLASS IF REQUIRED BY THE DESIGN PRESSURE.

23. THE INBOARD CONTAINMENT ISOLATION VALVE F002 MANUAL CONTROL AND VALVE POSITION STATUS INDICATION SHALL BE HARDWIRED (NOT MULTIPLEXED) TO THE MAIN CONTROL ROOM.

REFERENCE DOCUMENTS	MPL NO.
1. REACTOR WATER CLEANUP SYS PFD	G31-1020
2. NUCLEAR BOILER SYSTEM P&ID	B21-1010
3. RADIOACTIVE WASTE (LIQUID, SOLID), RADWASTE SYS P&ID	K17-1010
4. LCW, RADWASTE SYSTEM P&ID	K17-1010
5. REACTOR WATER CLEANUP SYS IBD	G31-1030
6. RESIDUAL HEAT REMOVAL SYS P&ID	E11-1010
7. SERVICE AIR SYS P&ID (REAC BLDG)	P51-1010
8. PIPING & INSTRUMENT SYMBOLS DIAGRAM	A10-3030
9. REAC BLDG CLNG WATER SYS P&ID	P21-1010
10. MUWC SYS P&ID (REAC BLDG)	P13-1010
11. SAMPLING SYSTEM P&ID	P91-1010
12. CONTROL ROD DRIVE SYS P&ID	C12-1010
13. VALVE GLAND LEAKAGE TREATMENT, RADWASTE SYS P&ID	K17-1010
14. LEAK DETECTION AND ISOLATION SYS IED	E31-1010
15. FUEL POOL CLNG & CLEANUP SYS P&ID	G41-1010
16. FEEDWATER CONTROL SYS IBD	C31-1030
17. SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM P&ID	T53-1010
18. MAIN CONDENSER SYSTEM P&ID	N61-1010

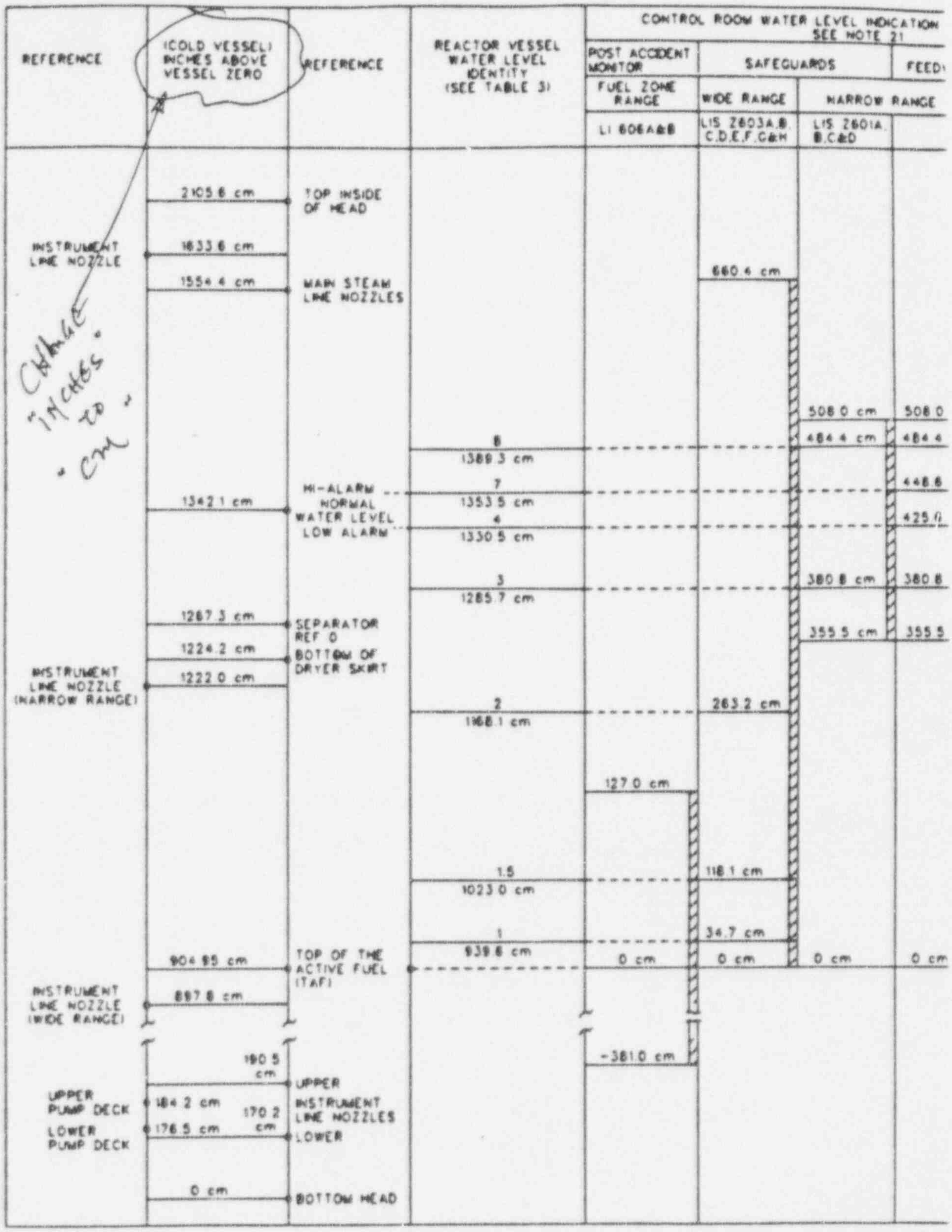
MPL NO. G31-1010

3 Comments on THIS PAGE

ITAAC 2.6.1 Comments PAGE 2 OF 2

FIGURE 5.4-12 REACTOR WATER CLEANUP SYSTEM P&ID (Sheet 1 of 4)

TABLE 2 ELEVATION CORRELATION CHART



ITAAC 2.6.1 COMMENTS
PAGE 2d of 2

PTID FIGURE 5.1-3
SHEET 9 OF 11

Section 2.6.2 **Comment No.** 1

Comment:

Section 2.6.2 second sentence:
Change to read as follows: "---maintains the water quality, monitors and maintains the water level above the spent fuel in the spent fuel storage pool, and removes radioactive materials from the pool to minimize the release of radioactivity to the environs."

Resolution:

Disagree - this detail not required in CDM. The key information for the ITAAC is there. Specifically:

(1) Removes decay heat generated by the spent fuel pool assemblies.
(2) Maintains water quality
(3) Monitors and maintains water level above the spent fuel in the pool.

The removal of radioactive materials from the pool is accomplished by maintaining the water quality, so to add this phrase would be redundant. In addition, the ITAAC team determined that explanatory information (e.g. "to minimize the release of radioactivity to the environs") should be minimized in the ITAAC. Instead, emphasis should be placed on providing the information that requires verification.

Section 2.6.2 **Comment No.** 2

Comment:

Figure 2.6.2:
At the heat exchanger interface with the RCW System, specify RCW-A and RCW-B since the FPC System interfaces only with two of the three RCW Systems.

Resolution:

Disagree - this detail not required in CDM. To identify the RCW divisions which remove heat from the FPC heat exchangers in Tier 1 would unnecessarily restrict design and operational flexibility. Should a COL applicant decide to use a different system lineup for the FPC cooling, it creates an unnecessary burden to require rulemaking to make such a change. Therefore, the staff concluded that identification of the cooling system without regard to division was appropriate.

Section 2.6.2 Comment No. 3

Comment:

P&ID Figure 9.1-1 (Sh 1 of 3) and PFD Figure 9.1-1 (Sh 1 of 3) and PFD Figure 9.1-2 (Sh 1 of 2) showed two additional components to the FPC System: the Reactor Well Pool, and the Dryer Separator Storage pool. These components need to be added to this Certified Design Material section.

Resolution:

Disagree - staff originally asked for this, but later determined these components were not necessary. These component storage areas are not important enough to bring into Tier 1. The apsect of the system which requires Tier 1 treatment relates to the storage and cooling of the fuel, not other components. Based on this, the staff concluded that the reactor cavity and the D/S pool need not be identified in Tier 1.

Section 2.6.2 Comment No. 4

Comment:

SSAR Table 3.9-8 classified the following valves "ACTIVE", they should be included in Figure 2.6.2: F018, F020 (parallel check valves, currently only one is shown), F023.

Resolution:

Disagree - this detail not required in CDM. The CDM figures are functional system representatives. As such, their primary purpose is to show general system layouts, not specific system details. There are 4 safety-related check valves shown on the figure:

F094 on the RHR discharge line
F091 on the SPCU discharge line
F016 on the FPC return line
F018 on the spent fuel pool return line

Valves F020 A and B are check valves on the branch lines downstream of F018. These valves are not shown because the CDM drawing need not be shown to this level of detail at that point. Should the specific design at the COL stage be changed to accomodate a single branch line to the spent fuel pool rather than two branch lines, as currently shown in SSAR Fig. 9.1-1 (sh 1 of 3), rulemaking would have to be instituted to change the CDM, which would be counterproductive.

Section 2.6.2 Comment No. 5

Comment:

Figure 2.6.2 phantom valves: either show phantom valves at all system interfaces, or delete those that are shown.

Resolution:

Disagree - not all components are shown at system boundary. GE and the staff agreed that at boundaries where both the system and safety class change, components should be shown. If, on the other hand, there was no change in safety class between systems, the boundary component would not be shown (if the boundary component is part of the system in question, the component would be displayed as a solid. If the boundary component is part of the system not in question, the component would be displayed in phantom). Therefore, it is expected that some system boundaries will show a component at the boundary while other boundaries will not show a component. In the case of the FPC boundary with SPCU, there is a change in safety class (both systems are non-safety at this boundary). Therefore, the components at the boundary between FPC and RHR involves a change in safety class and therefore the valves should be shown in phantom, however, they were not. GE will show the two MOVs at the boundary on the supply from RHR to FPC and will show the two manual valves at the boundary on the discharge from FPC to RHR in the next ITAAC revision. These will be shown in phantom.

In addition, there are system boundaries which occur at places other that at a component (e.g. a tee-connection). In these instances, a component would not be shown at the boundary.

Section 2.6.2 **Comment No.** 6

Comment:

Add the following statement:

Piping penetrations and arrangements of piping connected to the pool are configured to ensure that the pool is not drained below a minimum level of water above the stored spent fuel in the event of a pipe break, or inadvertent operator action, or siphonic action.

Resolution:

GE agreed to make the changes.

26.2(5).

WARKED UP FIGURE TO SUPPORT COMMENTS 2, 3, 4 AND 5

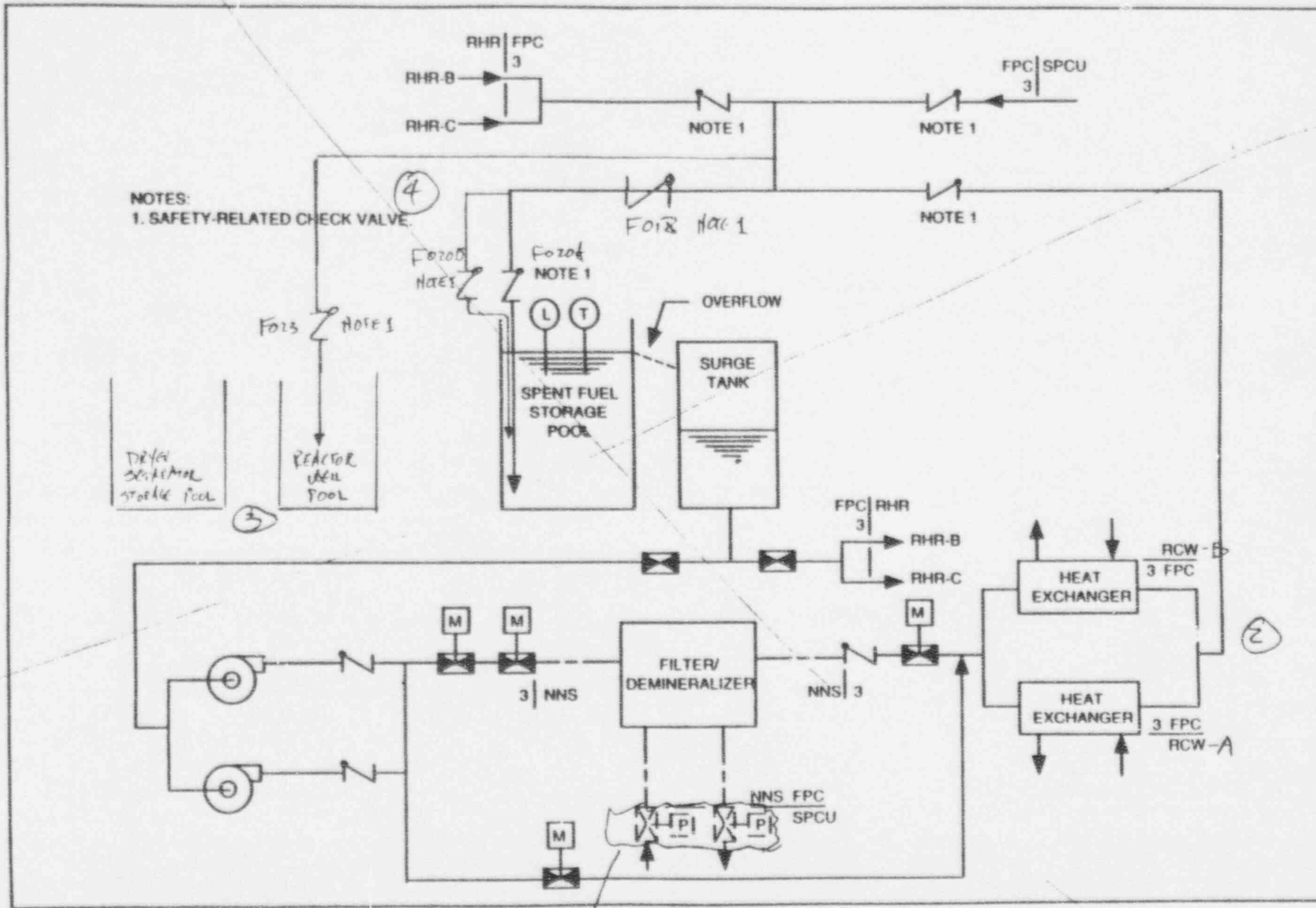


Figure 2.6.2 Fuel Pool Cooling and Cleanup System

5 EITHER SHOW PHANTOM VALVES AT ALL SYSTEM INTERFACES, OR DELETE THESE.

PAGE 3 OF 3

Section 2.6.3 Comment No. 1

Comment:

Page 2.6.3-1 first paragraph: add acronym (CST) after condensate storage tank.

Resolution:

GE agreed to make the changes.

Section 2.6.3 Comment No. 2

Comment:

Page 2.6.3-1 8th paragraph:
Need to state that all three containment isolation MOVs to have active safety-related function.

Resolution:

Disagree - it already says this.

Section 2.6.3 Comment No. 3

Comment:

Figure 2.6.3: Change "SURGE TANK" to "SURGE TANKS".

Resolution:

GE agreed to make the change.

Section 2.6.3 Comment No. 4

Comment:

Figure 2.6.3:
Add the parallel flow path with the pneumatic operator from the filter-demineralizer to the SPCU.

Resolution:

Disagree - not Tier 1.

Section 2.6.3 **Comment No.** 5

Comment:

SSAR Section 9.5.9, page 9.5-57, add acronym (D/S) after dryer/separator.

Resolution:

GE agreed to make the changes.

Section 2.7.1 **Comment No.** 1

Comment:

The ability to control various plant equipment (start/stop pumps, open/close valves) from the MCR was not included as part of the ITAAC. Similarly the operation of instruments and alarms need to be included in the ITAAC.

Resolution:

Disagree - These functions checked as part of individual system ITAAC.

Section 2.7.1 **Comment No.** 2

Comment:

The ITAAC for individual systems indicate controls, instruments, and alarms that are in the MCR. A large number of these important features are not included in the minimum inventory listing of I&C in Table 2.7.1a. The rationale for not including other important instruments and controls is not evident.

Resolution:

Disagree - Minimum inventory issue was reviewed based on EOP Task Analysis and PRA risk significant operator actions.

Section 2.7.1 **Comment No.** 3

Comment:

The system description states that those parts of the MCRP that contain Class 1E equipment are classified as Seismic Category 1. Why isn't the standard boiler plate for the configuration verification used in Table 2.7.1b to verify both seismic and EQ aspects?

Resolution:

The configuration ITAAC used is the standard boilerplate for I&C systems.

Section 2.8.1 **Comment No.** N/A

Comment:

In the Design Description, delete the first sentence starting: "The fuel assembly --- 100", since this refers to 10 CFR 20, 50 and 100.

Resolution:

GE's proposed disposition is described in the enclosure.

NRC agreed with GE's disposition.

Section 2.8.3 Comment No. 1

Comment:

The 4 principal design criteria for the control rods, that are contained in the design description, could not be located in the SSAR. Provide associated SSAR location or transpose information from DD into SSAR as necessary.

Resolution:

In SSAR App 4.C.

Section 2.9.1 Comment No. 1

Comment:

The valves listed in SSAR Table 6.2-7, Containment Isolation Valve Information Radwaste System, are shown on Figures 11.2-2, sheets 29 and 31 of 36. GE deleted these figures in Amendment 33. However, the staff understands the figures will be readded. GE should correct SSAR Table 6.2-7, page 6.2-165 to refer to these figures. F-103 and F-104 are HCW H20, not LCW H20. Also, page 6.2-122 entry page should be 6.2-165.

(Task Group:) These are shown on Figures 11.2.2 sheets 29 and 31 of 36. GE has deleted these 36 figures in Amendment 33. I understand <u>that these will be put back</u>. GE should also correct SSAR Table 6 2-7, Page 6 2-165. Refer to these figures. Also F-103 and F-104 are HCW H_2O not LCW H_2O. Also Page 6.2-122 kitentry page should be 6.0-165 with the figures backs the comment 1 is revised.

Resolution:

GE agreed to make the changes.

Section 2.9.1 Comment No. 2

Comment:

Design Description states that the system collects, treats, monitors, and either recycles or discharges radioactive liquid wastes to the environs. Figures 2.9.1a&b show only the collection portion schematically. Why the other important processes which are part of the system scope not shown in the figures?

Resolution:

Collection, treatment, recycling, monitoring, discharging, etc. are shown in 11.2-2, 36 sheets. These are expected to be put back in the SSAR. There is no need to show them in ITAAC figures. The system is non-safety-related except for containment isolation valves.

Section 2.9.1 **Comment No.** 3

Comment:

Figure 2.9.1.b should show ASME Code components, CIVs, active valves, and instrumentation.

Resolution:

Though the above are not explicitly shown in ITAAC Figure, they are addressed in ITAAC 2.4.3, "Leak Detection and Isolation System". See Item No. 11, Page 2.4.3-2, ITAAC Figure 2.4.3 and ITAAC Table 2.4.3. This is sufficient. The Tier 1 verification for this system is the isolation function on a LOCA signal. This isolation function is part of the Leak Detection and Isolation System function and so is verified there. The code class for these valves is provided in the 2.9.1 DD. Other aspects of the system are not Tier 1. The details of the drain system are to be provided by the COL applicant and therefore cannot be shown in any detail in Tier 1.

Section 2.9.1 **Comment No.** 4

Comment:

Features of the radioactive drain transfer system should be discussed in 2.9.1. See attached.

Resolution:

GE agreed to make the changes.

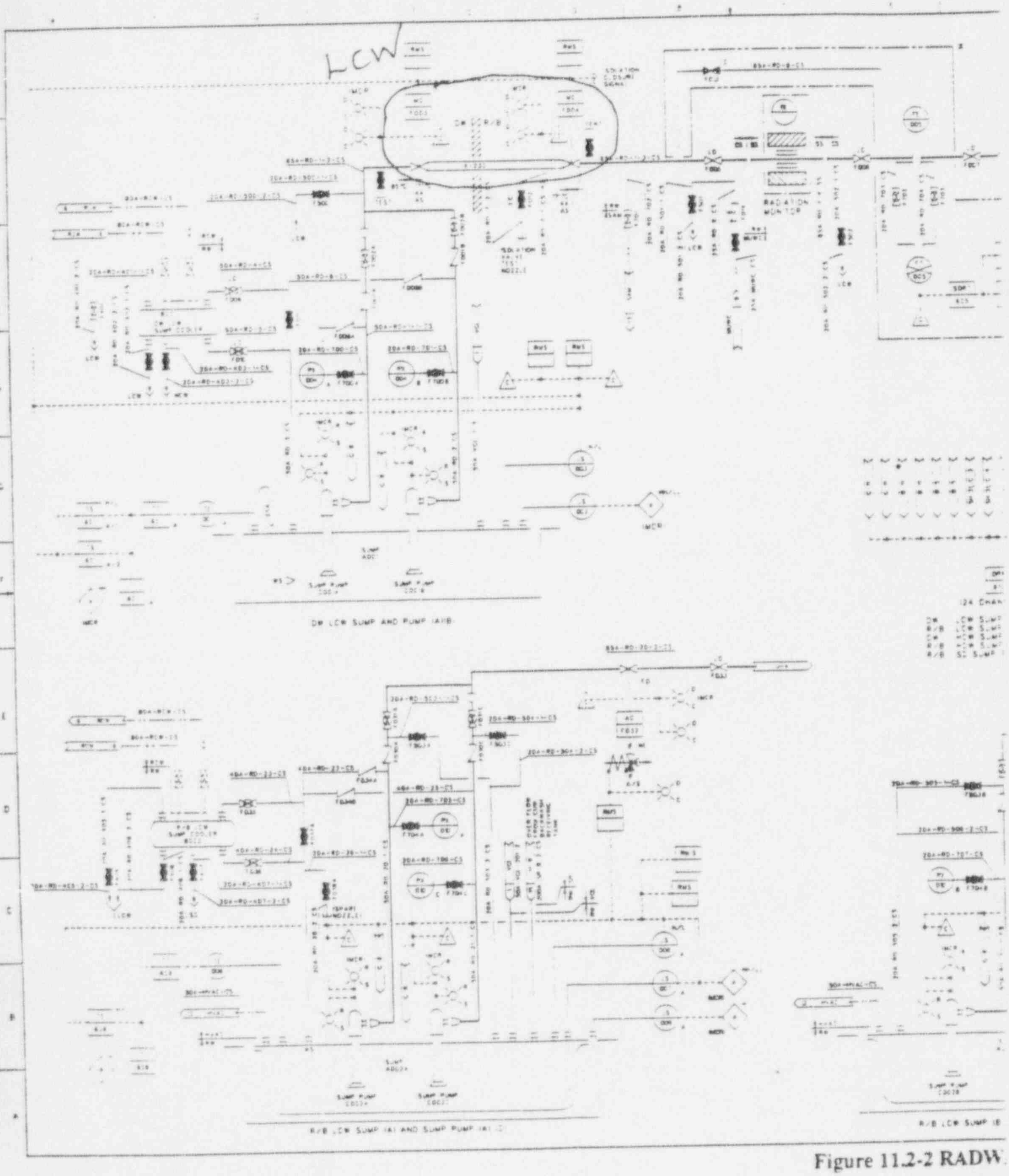


Figure 11.2-2 RADW

proprietary

HCW

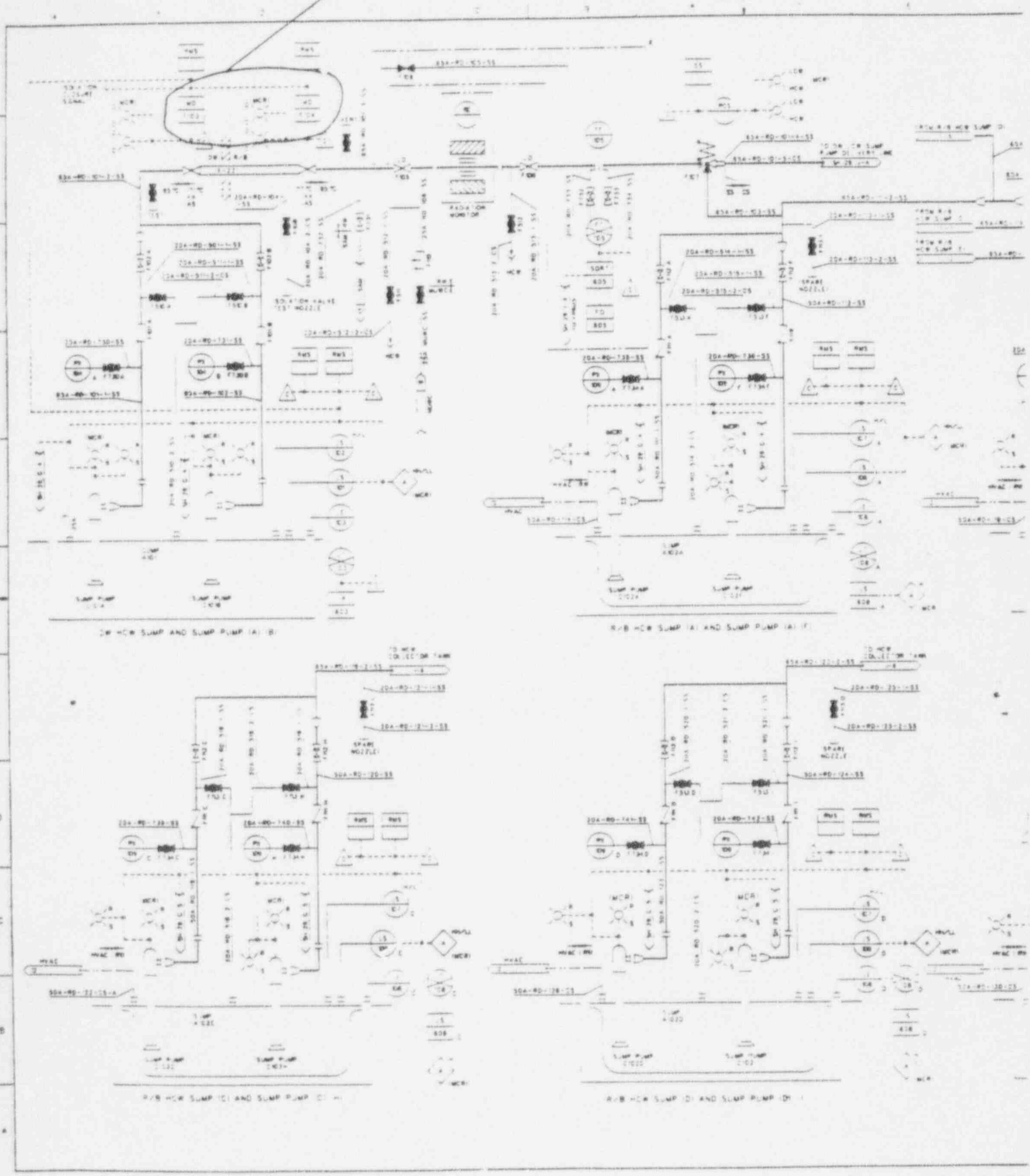


Figure 11.2-2 RADV

Proprietary

Section 2.10.1 **Comment No.** 1

Comment:

Figure 2.10.1:
Present piping line designation is for NNS. Revise this designation for ASME Code Class 2 piping or revise "2" to "NNS" in the figure.

Resolution:

Disagree. This portion of the MS line has a unique classification. It is NNS but is treated as ASME Code Class 2 piping as stated in the DD.

Section 2.10.1 **Comment No.** 2

Comment:

Reference attached SSAR tables for comments:

a) Table 3.2-1 pages 3.2-19 & 3.2-55.
b) Table 10.3-1

(Task Group:) Agree. Revise Item B26 in Table 3.2-1 to reflect proper QA Requirement (E?).

Resolution:

GE agreed to make the changes.

8

Table 3.2-1 Classification Summary (Continued)

Principal Component[a]		Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
6.	Piping including supports—MSL (including branch lines to first valve) from the seismic interface restraint up to but not including the turbine stop valve and turbine bypass valve	N	SC,T	B	F Should be a 'B' or 'E' No 'F' in the note e.	—	(r)
7.	Piping from FW shutoff valve to seismic interface restraint	N	SC	D	E	I	(ee)
8.	Deleted						
9.	Deleted						
10.	Pipe whip restraint—MSL/FW	3	SC,C	—	B	—	
11.	Piping including supports—other within outermost isolation valves						
	a. RPV head vent	1	C	A	B	I	(g)
	b. Main steam drains	1	C,SC	A	B	I	(g)
12.	Piping including supports—other beyond outermost isolation or shutoff valves						
	a. RPV head vent beyond shutoff valves	N	C	C	E	—	
	b. Main steam drains to first valve	2/N	SC,T	B	B	I/—	(r)
	c. Main steam drains beyond first valve	N	SC, T	D	E	—	(r)

Notes and footnotes are listed on pages 3.2-53 through 3.2-60

W	=	Radwaste Building
X	=	Control Building
F	=	Firewater Pump House*
U	=	Ultimate Heat Sink Pump House*
P	=	Power Cycle Heat Sink Pump House*

d. A,B,C,D= Quality groups defined in Regulatory Guide 1.26 and Subsection 3.2.2. The structures, systems and components are designed and constructed in accordance with the requirements identified in Tables 3.2-2 and 3.2-3.

— = Quality Group Classification not applicable to this equipment.

e. B = The quality assurance requirements of 10CFR50, Appendix B are applied in accordance with the quality assurance program described in Chapter 17.

E = Elements of 10CFR50, Appendix B are generally applied, commensurate with the importance of the equipment's function.

f. I = The design requirements of Seismic Category I structures and equipment are applied as described in Section 3.7, Seismic Design.

— = The seismic design requirements for the safe shutdown earthquake (SSE) are not applicable to the equipment. However, the equipment that is not safety-related but which could damage Seismic Category I equipment if its structural integrity failed is checked analytically and designed to assure its integrity under seismic loading resulting from the SSE.

g. 1. Lines one inch and smaller which are part of the reactor coolant pressure boundary and are ASME Code Section III, Class 2 and Seismic Category I.

2. All instrument lines which are connected to the reactor coolant pressure boundary and are utilized to actuate and monitor safety systems shall be Safety Class 2 from the outer isolation valve or the process shutoff valve (root valve) to the sensing instrumentation.

3. All instrument lines which are connected to the reactor coolant pressure boundary and are not utilized to actuate and monitor safety systems shall

---

* Pump House structures are out of the ABWR Standard Plant scope.

Table 10.3-1 Main Steam Supply System Design Data

Main Steam Piping	
Design flow rate at 69.25 kg/cm^2a and 0.40% moisture, lb/hr	~17,000,000
Number of lines	4
Nominal diameter	700A
Minimum wall thickness, mm	38.1
Design pressure, kg/cm^2a	87.89
Design temperature, °C	315.56
Design code	ASME III, Class 2
Seismic design	Analyzed for SSE design loads

Comments:

1. DESIGN PRESSURE IS gauge "g" ON PAGE 10.3-2.
2. DESIGN TEMPERATURE IS 315.55 °C ON PAGE 10.3-2

Section 2.10.2 **Comment No.** 1

Comment:

Page 2.10.2-1:
Acronyms (CPS) and (OGS) are used in the figures, they should be included in the text.

(Task Group:) Add acronyms "CPS" and "OGS" in CDM 2.10.2 design description for condensate purification system and off-gas system, respectively.

Resolution:

GE agreed to make the changes.

Section 2.10.2 **Comment No.** 2

Comment:

Page 2.10.2-3 Figure 2.10.2a:
Line symbol of the CFCAE portion for NNS to CRD is incorrect.

Revise line symbol of the piping class for "CFCAE" portion of "NNS" to "CRD" as "____ _____ __ - __________ _-_____ __".

Resolution:

GE agreed to make the changes.

Section 2.10.2 Comment No. 3

Comment:

Page 2.10.2-4, Figure 2.10.2b:

Valve operators shown are pneumatic, whereas on SSAR figure 10.4-1, they are motor operators. Reconcile the type of valve operators used for the valves on piping from SJAEs to inlet of vacuum pump as shown in ITAAC figure 2.10.2b.

(Task Group:)

(a) reconcile type of valve operators used for the valves on piping from SJAEs to inlet of vacuum pump as shown in ITAAC Figure 2.10.2b and SSAR Figure 10.4-1 and revise accordingly.

Resolution:

(a) GE will make consistent as described in the enclosure.

(b) No change needed since ITAAC Figure 2.10.2b does not have to show stage of SJAEs.

Section 2.10.2 Comment No. 4

Comment:

Page 2.10.2-6, table 2.10.2b, item 2: The acceptance criteria requires the SJAE discharge valves to close. These valves are not shown on figure 2.10.2b.

(Task Group:) Show SJAEs discharge valves on ITAAC figure 2.10.2b as shown in SSAR figure 10.4-1. Also, explain why one of the SJAE discharge goes to "offgas-A" but not diverted to "turbine compartment exhaust system" in certain condition in SSAR figure 10.4-1 (see ITAAC figure 2.10.2b).

Resolution:

NRC agreed with GE's disposition.

2.10.2 Condensate Feedwater and Condensate Air Extraction System

The Condensate Feedwater and Condensate Air Extraction (CFCAE) System consists of two subsystems: the Condensate and Feedwater System (CFS) and the Main Condenser Evacuation System (MCES).

Design Description

(CFS)

Condensate and Feedwater System

The function of the CFS is to receive condensate from the condenser hotwells, supply condensate to the Condensate Purification System, and deliver feedwater to the reactor. Condensate is pumped from the main condenser hotwell by the condensate pumps, passes through the low pressure feedwater heaters to the feedwater pumps, and then is pumped through the high pressure heaters to the reactor. Figure 2.10.2a shows the basic system configuration. The CFS boundaries extend from the main condenser outlet to (but not including) the seismic interface restraint outside the containment.

The CFS is classified as non-safety-related.

The CFS is controlled by signals from the Feedwater Control System.

The CFS is located in the steam tunnel and Turbine Building.

The CFS has parameter displays for the instruments shown on Figure 2.10.2a in the main control room.

(OGS)

Main Condenser Evacuation System

The MCES removes the hydrogen and oxygen produced by the radiolysis of water in the reactor, and other power cycle noncondensable gases. The system exhausts the gases to the Off-Gas System during plant operation, and to the Turbine Building compartment exhaust system at the beginning of each startup. The MCES consists of redundant steam jet air ejector (SJAE) units for power plant operation, and a mechanical vacuum pump for use during startup. Figure 2.10.2b shows the basic system configuration.

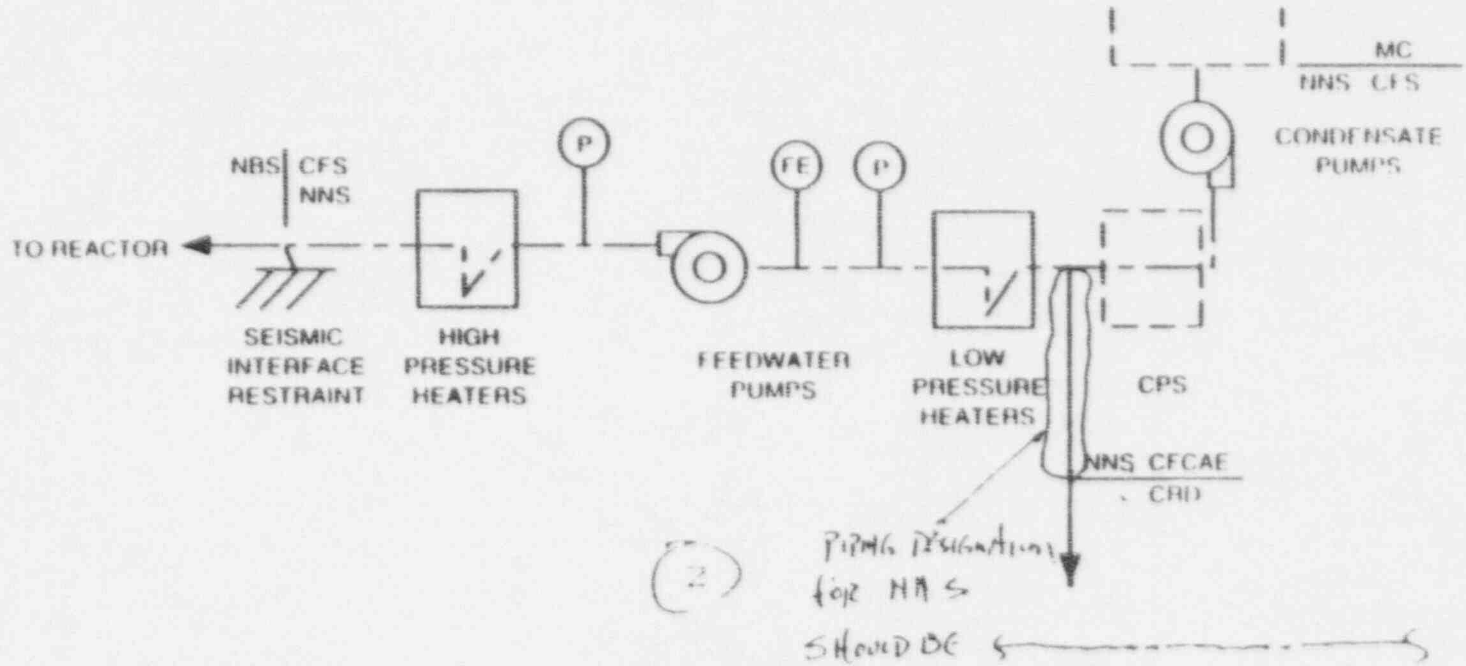
The MCES is classified as non-safety-related.

The MCES is located in the Turbine Building.

Steam supply to the SJAE provides dilution of the hydrogen and prevents the offgas from reaching the flammable limit of hydrogen. When the steam flow drops below the setpoint for stream dilution, the Off-Gas System is isolated.

The vacuum pump is tripped and its discharge valve is closed upon receiving a main steamline high radiation signal.

PAGE 3 OF 5



NOTES
1. RELIEF VALVE DISCHARGE AND VENTS ARE CHANNELED THROUGH CLOSED SYSTEMS
2. FEEDWATER AND CONDENSATE PUMP REDUNDANCY IS PROVIDED

Figure 2.10.2a Condensate and Feedwater System

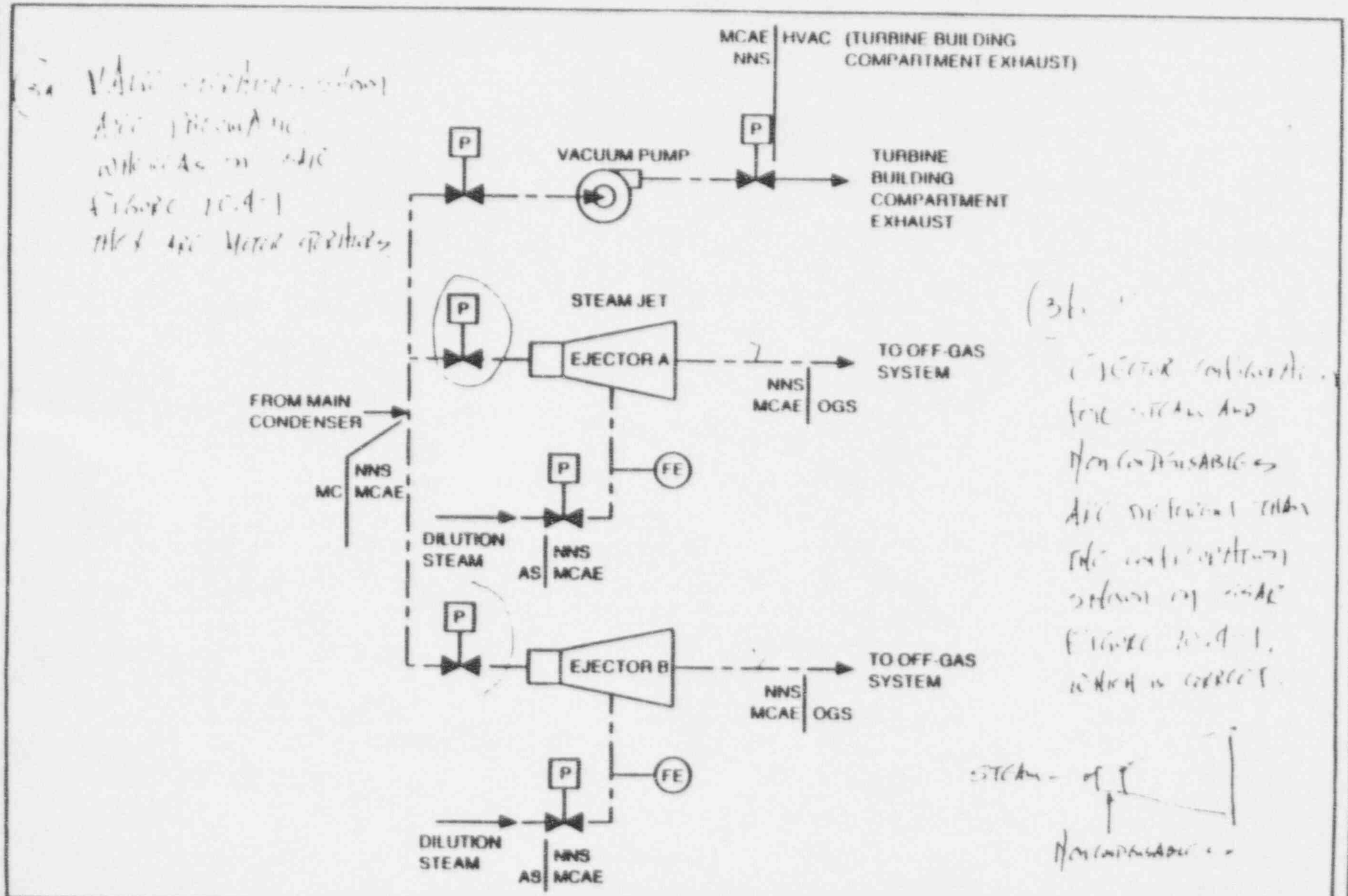


Figure 2.10.2b Main Condenser Evacuation System

Page 2 of 5

Table 2.10.2b Main Condenser Evacuation System

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The basic configuration of the MCES is as shown on Figure 2.10.2b.	1. Inspections of the as built MCES will be conducted.	1. The as built MCES conforms with the basic configuration shown in Figure 2.10.2b.
2. When the steam flow drops below the setpoint for steam dilution, the Off Gas System is isolated.	2. Tests will be conducted on the as built MCES using simulated signals for steam flow.	2. The SJAE discharge valves close on receipt of a simulated low flow signal.
3. The vacuum pump is tripped and its discharge valve is closed upon receiving a main steamline high radiation signal.	3. Tests will be conducted on the as built MCES using simulated signals for radiation in the main steamlines.	3. The vacuum pump trips and the discharge valve closes upon receipt of a simulated high radiation signal.
4. Main control room displays provided for the MCES are as defined in Section 2.10.2.	4. Inspections will be performed on the main control room displays for the MCES.	4. Displays exist or can be retrieved in the main control room as defined in Section 2.10.2.

(7) THESE VALVES ARE NOT SHOWN ON FIGURE 2.10.2b.

Page 5 of 5

Section 2.10.7 **Comment No.** 1

Comment:

See attached pages for comments.

(Task Group:)

(a) Add acronyms for "high pressure" and "low pressure" as "MP" and "LP" respectively in CDM 2.10.7 design description. Also, add acronyms "HP, "LP", "ISVs" and "IVs" in CDM Appendix B.
(b) CDM Table 2.10.7 should show acronym "MTSVs" not "MSVs" in Item 2.b and 2.c as listed in CDM Appendix B.
(c) Delete a word "other" in 2nd sentence of CDM 2.10.7 design description.

Resolution:

GE agreed to make changes as described in the enclosure.

2.10.7 Main Turbine

Design Description

The Main Turbine (MT) uses the energy in steam from the reactor to drive the plant generator. — DELETE

The other major turbine components are: DELETE ACRONYMS FOR APPENDIX B

(1) A high pressure (HP) section

(2) An intermediate section (between HP and LP sections)

(3) Low pressure (LP) sections

The major fluid system boundaries are:

(1) Turbine Main Steam 2.10.1

(2) Main Condenser 2.10.21

(3) Turbine Gland Seal 2.10.9

(4) Extraction System 2.10.12

The MT is classified as non-safety-related.

The MT has the following features that prevent overspeed:

(1) Main turbine stop valves (MTSV)/Control valves (CV) [MTSVs trip/CVs trip and modulate]

— DELETE ACRONYMS FOR APPENDIX B

(2) Combined intermediate valves (CIVs) consist of intercept valves (IVs) and intercept stop valves (ISVs) [IVs trip and modulate/ISVs trip]

(3) Extraction line non-return valves (trip)

(4) Redundant valve closure mechanisms (i.e., fast acting solenoid valves and emergency trip fluid system)

(5) Redundant normal speed control

Three levels of signals to MT valves (i.e., normal speed control/overspeed trip/backup overspeed trip)

Table 2.10.7 Main Turbine System

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The basic configuration of the MT System is as described in Section 2.10.7.	1. Inspection of the as built MT will be conducted.	1. The as built MT conforms with the basic configuration described in Section 2.10.7.
2. MT System overspeed protective actions are as defined in Section 2.10.7.	2. Tests will be conducted on the as-built MT System using simulated overspeed signals.	2. The following protective actions occur: (see below)
3. The turbine MTSV closes in 0.10 seconds or greater.	3. Tests will be conducted on the as-built turbine MTSV.	3. The turbine MTSV closes in 0.10 seconds or greater.
4. The turbine CV trip closure is 0.08 seconds or greater.	4. Tests will be conducted on the as-built turbine CV.	4. The turbine CV trip closure is 0.08 seconds or greater.

Overspeed Condition	Protective Action
a. Exceeds normal speed control setpoint.	Normal speed control signals the CVs and IVs to close.
b. Exceeds overspeed trip setpoint.	Overspeed trip signals MSVs, CVs, ISVs, IVs, and extraction line non-return valves to close.
c. Exceeds backup overspeed trip setpoint.	Backup overspeed trip signals MSVs, CVs, ISVs, IVs, and extraction line non-return valves to close.

MTSVs

Page 3 of 3

Section 2.10.9 Comment No. 1

Comment:

Page 2.10.9-1, see comments as noted.

(Task Group:) Correct typos on page 2.10.9-1 as follows:

- "two exhaust blowers" need not be listed as "two full capacity exhaust blowers" in 2nd paragraph of CDM 2.10.9.
- "main turbine system" should be "main turbine", and "turbine main steam supply systems" should be "turbine main steam supply system" in 3rd paragraph.

Resolution:

GE agreed to make the appropriate changes.

Section 2.10.9 Comment No. 2

Comment:

Figure 2.10.9: (see attached copy for reference).

a. The sealing steam pressure regulator is shown as a gate valve. Is this the correct valve type for this application?

b. A drain connection to the gland steam condenser is required.

c. Delete the piping for main steam and the cross around steam to the main turbine. They are not relevant to this diagram. Retain note 1 if "CROSS AROUND" appears elsewhere on diagram, delete is otherwise.

d. Steam leaving the main turbine stop and control valves and the bypass valves are shown being directed to the feedwater heater. On SSAR Figure 10.4-2, they are directed to the cross around piping. Resolve this discrepancy. Delete note 2 is "FW HEATER" is deleted.

e. Add radiation monitor at the exhaust blower discharge. This item is discussed in Section 2.3.1.

Resolution:

a. ITAAC figure symbol is meant for any type of valve, and therefore no change is needed in ITAAC Figure 2.10.9.

b. No such details are needed in Tier 1 material for non-safety system such as this TGS.

c. TGS is a non-safety system. However, GE shows additional interfaces to understand the TGS which encompasses the several aspects of steam and power conversion system components and/or function(s). Therefore, no change is needed.

d. GE agreed to make changes as described in the enclosure.

e. All radiation monitoring is part of "PRM System" and it does not have to be shown figuratively in ITAAC figure.

2.10.9 Turbine Gland Seal System

Design Description

The Turbine Gland Seal (TGS) System prevents the escape of radioactive steam from the turbine shaft casing penetrations and valve stems and prevents air inleakage through subatmospheric turbine glands. Figure 2.10.9 shows the basic system configuration.

The TGS System consists of a sealing steam pressure regulator, steam seal header and a gland seal condenser (GSC) with two exhaust blowers and associated piping, valves and instrumentation.

The TGS System is bounded by the Main Turbine System and the Turbine Bypass System. The TGS System receives steam from either the Turbine Main Steam System, the feedwater heater drain tank vent header or auxiliary steam sources. The exhaust blowers discharge to the Turbine Building compartment exhaust system.

The TGS System is classified as non-safety-related.

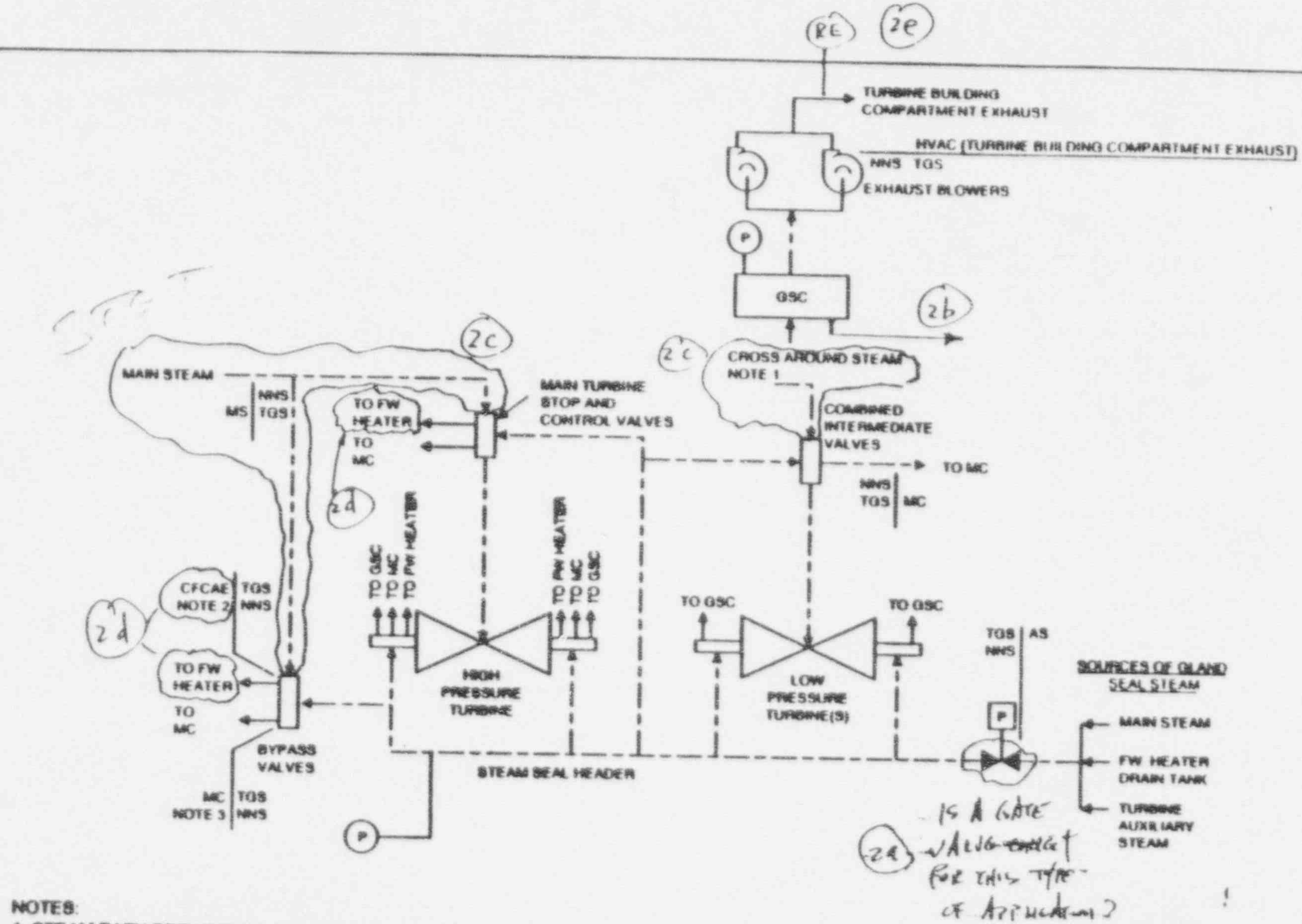
The TGS System is located in the Turbine Building.

The TGS System has displays for gland seal condenser and steam seal header pressure in the main control room.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.9 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the TGS System.

2.10.9(2)



NOTES:
1. STEAM PATH BETWEEN HIGH AND LOW PRESSURE TURBINES.
2. TYPICAL FOR INTERFACES WITH FW HEATER.
3. TYPICAL FOR INTERFACES WITH MC.

Figure 2.10.9 Turbine Gland Seal System

PAGE 3 of 3

Section 2.10.21 **Comment No.** 1

Comment:

Revise CDM Appendix B to add acronym "MC" for "Main Condenser".

Resolution:

GE agreed to make the changes.

Section 2.10.21 **Comment No.** 2

Comment:

First paragraph: Change "TBP" to "TB".

(Task Group:) Revise CDM 2.10.21 Design Description, 1st paragraph, to state "TB", not "TBP".

Resolution:

GE agreed to make the changes.

Section 2.10.21 **Comment No.** 3

Comment:

SSAR Section 10.4.1.2.1:

a. The "intermediate pressure shell" is not shown on Figure 10.4-3; on the figure are two LP and one HP sections.

b. 3rd paragraph: There is no Figure 10.4-6b.

Clarification is required on these items.

(Task Group:) Revise SSAR section 10.4.1.2.1, 2nd paragraph, to state "Figure 10.4-5b", not "Figure 10.4-6b".

Resolution:

a. Revision of SSAR Figure 10.4-3 is not needed since it shows center shell as "I.P.".

b. GE agreed to make the changes.

Section 2.10.22 **Comment No.** 1

Comment:

Is ITAAC #2 a generic ITAAC for hydrostatic testing of non-ASME piping/components? Since similar ITAAC entries are not included for other non-ASME systems, why is this a unique requirement for the off gas system?

Resolution:

There is a special design requirement in terms of seismic criteria for off gas system and the housing for it is spelled out in RG 1.143. ITAAC #2 is recognition of this special requirement.

Section 2.10.22 **Comment No.** 2

Comment:

SSAR Chapter 11.3.6 should be supplemented with information pertaining to the automatic isolation of the OGS, as verified in ITAAC #3.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.10.22 **Comment No.** 3

Comment:

SSAR Chapter 11.3 should be supplemented with information pertaining to the OGS capability to withstand a hydrogen explosion, as verified in ITAAC #6.

Resolution:

NRC agreed with GE's disposition.

Section 2.10.23 Comment No. 1

Comment:

Revise ITAAC figure 2.10.23 to conform with CDM "Appendix A" for "NNS" piping class.

Resolution:

GE agreed to make the changes.

Section 2.11.1 **Comment No.** 1

Comment:

Section 2.11.1 requires a figure/diagram to supplement the text. This is necessary because of the primary containment isolation function which is safety-related.

Resolution:

GE did not agree. (See GE's response to comment in enclosure.)

NRC agreed with GE's disposition.

Section 2.11.1 **Comment No.** 2

Comment:

Section 2.11.1, 4th paragraph, states that the outboard containment isolation valve is locked closed during normal operation. SSAR Section 9.2.10.2 item 7 states " --- locked closed during standby, not standby and power operation." This requires clarification.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.11.1 **Comment No.** 3

Comment:

Section 2.11.1 second paragraph referenced the Makeup Water Preparation System of which there is a description in the SSAR but not in the Certified Design Material. The CDM should acknowledge this system and under the title state the following "No entry for this system".

Resolution:

Comment retracted by IIRG. Necessary information is in CDM Section 4.3.

Section 2.11.1 **Comment No.** 4

Comment:

SSAR Table 9.2-3: combine the two sections on pages 9.2-50 and 9.2-51 into a single unit.

Resolution:

GE agreed to make the changes.

Section 2.11.2 Comment No. 1

Comment:

Add the following statement to the CDM: "The Condensate Storage Tank (CST) capacity includes sufficient water for operation of the RCIC System during station blackout." Also, it should be verified in an ITAAC.

Resolution:

GE did not agree. (See GE's response to comment in enclosure.)

NRC agreed with GE's disposition.

Section 2.11.2 Comment No. 2

Comment:

Revise figure 2.11.2 to incorporate the following:

- 3 pumps should be shown, or indicate that this is 1 of 3 pumps.
- A note should be added to figure 2.11.2 to indicate that RCIC, HPCF, and SPCU take suction from the CST.
- The extraneous piping shown on figure 2.11.2 should be deleted.

Resolution:

NRC agreed with GE's disposition.

Section 2.11.2 Comment No. 3

Comment:

Revise Table 2.11.2 to add the boilerplate ITAAC on hydrostatic testing.

Resolution:

GE agreed to make the changes.

Section 2.11.2 Comment No. 4

Comment:

SSAR Section 9.2.9.2, Item (9):

- Add to the first sentence, "radwaste building control room, and Remote Shutdown System."
- Add to the second sentence, "and low water level shall be alarmed in the main control room."

Resolution:

GE agreed to make the changes.

Section 2.11.3 Comment No. 1

Comment:

Figure 2.11.3b - relocate piping class break immediately after the MOV before the Fuel Pool Cooling HX.

Resolution:

GE agreed to make the changes.

Section 2.11.3 Comment No. 2

Comment:

Verification of valves that have active safety functions as described in SSAR Table 3.9-8:

a. F025, 5 valves (1-2-2) for the three systems, cooling water supply line to HECW refrigerator PCV. These valves are not shown on Figures 2.11.3a, b, and c of the CDM. Please revise the CDM figures to include these valves.

b. F055, 6 valves (2-2-2) for the three systems. Cooling water return line from Emergency Diesel Generator. These valves are shown as parallel pairs on the P&IDs. On CDM Figures 2.11.3a, b, and c, they appear as single valves. Please revise the CDM figures.

c. F072, 6 valves (2-2-2) for the three systems. Cooling water supply line to nonessential coolers. These are AOVs and are arranged as parallel pairs on the P&IDs. On CDM Figures 2.11.3a, b, and c, they appear as single valves. Please revise the CDM figures.

d. F175, 3 valves, one for each system. In accordance with the P&IDs and the CDM figures, these are MOVs supplying cooling water to the fuel pool cooling HX room coolers. Table 3.9-8 of the SSAR describes these valves as "cooling water supply to RHR system HX pressure relief valve". Resolve this discrepancy. Also, both P&IDs and CDM figures showed a total of 2 valves, one for RCW-A and the second for RCW-B. Resolve this discrepancy.

Resolution:

a. Disagree. The CDM figures are functional representations of systems. As such, some system components may not be displayed. The decision whether to display a component is dependent on factors such as its importance to safety and the likelihood that the component function may change in the future. The earlier resolution is not correct. The valve is not shown on the CDM figure nor should it be. The valve isolates the HECW cooler. GE chose not to identify this valve in the CDM because the valve has no automatic isolation function. Therefore, operational verification as part of the normal system functional tests in Tier 2 is sufficient.

b. Disagree. The CDM figures are functional representation of systems. As such, some system components may be displayed. In particular, redundant components within the same division are normally not shown. In addition, the normal practice is to show only one of several redundant divisions unless there are variations between equivalent divisions which may warrant showing more than one division. An example is the RCW system; although the divisions are redundant, there is sufficient variation between divisions to warrant identifying each of them separately in Tier 1. For instance, although RCW has three divisions, it serves several two-division systems, such as FPC, CAMS, and HPCF. One division also serves the single division of RCIC. Because of these variations, the staff felt that each division needed to be shown in Tier 1. However, this is an exception to the rule. Most systems are sufficiently similar to allow only one division to be shown in Tier 1. In these instances, the CDM clarifies that the division shown is representative of the other redundant divisions.

c. Disagree. The CDM figures are functional representation of systems. As such, some system components may be displayed. In particular, redundant components within the same division are normally not shown. In addition, the normal practice is to show only one of several redundant divisions unless there are variations between equivalent divisions which may warrant showing more than one division. An example is the RCW system; although the divisions are redundant, there is sufficient variation between divisions to warrant identifying each of them separately in Tier 1. For instance, although RCW has three divisions, it serves several two-division systems, such as FPC, CAMS, and HPCF. One division also serves the single division of RCIC. Because of these variations, the staff felt that each division needed to be shown in Tier 1. However, this is an exception to the rule. Most systems are sufficiently similar to allow only one division to be shown in Tier 1. In these instances, the CDM clarifies that the division shown is representative of the other redundant divisions.

d. GE's proposed disposition is described in the enclosure.

NRC agreed with GE's disposition.

Section 2.11.4 Comment No. 1

Comment:

Figure 2.11.4 shows the surge tank is shared with the HVAC Normal Cooling Water System (HNCW). Whereas on SSAR figure 9.2-6a, the surge tank is shared with the HNCW and the Hot Water Heating (HWH) Systems. Resolve this discrepancy.

(Task Group:) Also, the HWH discussion in section 9.2 was deleted and should be reinserted.

Resolution:

NRC agreed with GE's disposition.

Section 2.11.6 **Comment No.** 1

Comment:

On figures 2.11.6a and 2.11.6b, DP should be dP.

Resolution:

GE agreed to make the changes.

Section 2.11.6 **Comment No.** 2

Comment:

ITAAC 9, the Design Commitment figures 2.11.3a and 2.11.3b should be 2.11.6a and 2.11.6b.

Resolution:

GE agreed to make the changes.

Section 2.11.9 **Comment No.** 1

Comment:

Page 2.11.9-1, second paragraph, and page 2.11.9-2, item (3): change " --- loss-of-coolant accident (LOCA) signal, ---." to " --- loss-of-coolant accident and/or loss of preferred power (LOCA and/or LOPP) signal, ---."

Resolution:

GE agreed to make the changes.

Section 2.11.9 **Comment No.** 2

Comment:

The CDM describes valves F003 and F005 to have active safety-related functions. In Table 3.9-8 of SSAR, they are classified as "PASSIVE". Resolve this discrepancy.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.11.9 **Comment No.** 3

Comment:

Table 2.11.9, change "LOCA" to "LOCA and/or LOPP" for all three parts across the page.

Resolution:

GE agreed to make the changes.

Section 2.11.9 **Comment No.** 4

Comment:

SSAR Section 9.2.15.1.2, change paragraph to read as follows: " --- shutdown; (d) testing; and (e) loss of preferred power."

Resolution:

GE agreed to make the changes.

Section 2.11.11 Comment No. 1

Comment:

The SSAR does not reference the Fig. 9.3.7, sheets 1&2, Service Air System, in SSAR chapter 9.3.7.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.11.13 Comment No. 1

Comment:

ITAAC item #6 requires each of two HPIN divisions to be powered from the respective Class 1E divisions. This requirement should be included in the HPIN description in SSAR Chapter 6.7.2 or appropriate section in SSAR Chapter 8.

Resolution:

GE agreed to make the changes.

Section 2.11.17 **Comment No.** 1

Comment:

SSAR section 9.3.9 states that portions of the system are designed to Reg Guide 1.29 position C.2. SSAR Table 3.2-1 (system P17) should have a note that some of the HWCS piping is Category 1.

Resolution:

Position C.2 in RG 1.29 does not contain a requirement for the system to be Seismic Category 1. The statement in 9.3.9 refers to BTP 9.5-1, which only requires that hydrogen lines in safety-related areas be Category 1. The turbine building is not safety-related. Therefore, this system does not have to be Category 1.

Section 2.11.17 **Comment No.** 2

Comment:

The design description should include discussion of the system piping that is seismic Category 1 and have an associated ITAAC verification.

Resolution:

Position C.2 in RG 1.29 does not contain a requirement for the system to be Seismic Category 1. The statement in 9.3.9 refers to BTP 9.5-1, which only requires that hydrogen lines in safety-related areas be Category 1. The turbine building is not safety-related. Therefore, this system does not have to be Category 1.

Section 2.11.20 Comment No. 1

Comment:

ITAAC #2 details of the post-accident sampling system measurements for boron and radionuclides is not addressed in the SSAR. This information should be added in the appropriate SSAR section.

Resolution:

Disagree. SSAR addresses the post-accident sampling for boron and radionuclides in Section 1A.2.7 of Appendix 1A.

Section 2.11.21 **Comment No.** 1

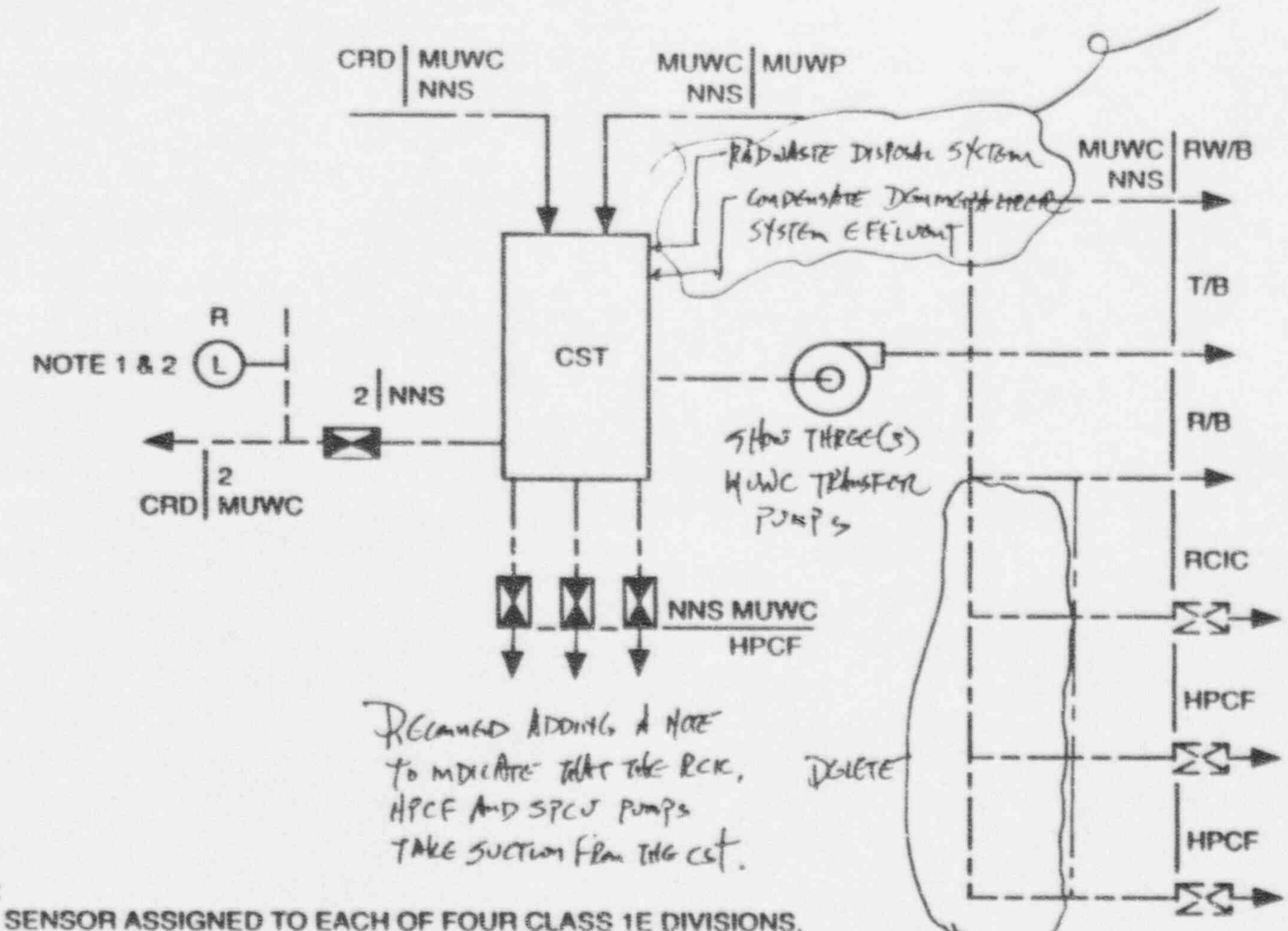
Comment:

See attached markup for SSAR editorial comment.

Resolution:

GE agreed to make the changes.

PAGE 2 of 3



NOTES:
1. ONE SENSOR ASSIGNED TO EACH OF FOUR CLASS 1E DIVISIONS.
2. RSS INTERFACE IS WITH DIVISION II LEVEL SENSOR ONLY.

Figure 2.11.2 Makeup Water (Condensate) System

Table 2.11.2 Makeup Water (Condensate) (MUWC) System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the MUWC System is as shown on Figure 2.11.2.	1. Inspections of the as-built system will be conducted.	1. The as-built MUWC System conforms with the basic configuration on Figure 2.11.2.
2. Each of the four MUWC System water level sensors is powered from the respective divisional Class 1E power supply. In the MUWC System, independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	2. a. Tests will be performed on the MUWC System by providing a test signal in only one Class 1E division at a time.	2. a. The test signal exists only in the Class 1E division under test in the MUWC System.
	b. Inspections of the as-built Class 1E divisions in the MUWC System will be performed.	b. In the MUWC System, physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class 1E equipment.
3. Main control room displays provided for the MUWC System are as defined in Section 2.11.2	3. Inspections will be performed on the main control room displays for the MUWC System.	3. Displays exist or can be retrieved in the main control room as defined in Section 2.11.2.
4. RSS displays provided for the MUWC System are as defined in Section 2.11.2.	4. Inspections will be performed on the RSS displays for the MUWC System.	4. Displays exist on the RSS as defined in Section 2.11.2.

5, ASME CODE CLASS 2 PORTION OF THE MUWC SYSTEM TO BE HYDROSTATICALLY TESTED.
(USE SAME WORDING AS THE OTHER APPLICABLE ITAACS).

PAGE 3 OF 3

located

(7) Any purified water storage tank shall be provided outdoors with adequate freeze protection and adequate diking and other means to control spill and leakage.

9.2.8.3 System Description (Conceptual Design)

The MWP System consists of both mobile and permanently installed water treatment systems.

The permanently installed system consists of a well, filters, reverse osmosis modules and demineralizers which prepare demineralized water from well water. The demineralized water is sent to storage tanks until it is needed. Pumps are provided to keep the Makeup Water Preparation (MWP) System pressurized at all times. The components of the MWP System are listed in Table 9.2-15 and the system block flow diagram is in Figure 9.2-10.

While it is planned to install both permanent divisions, only one division may be installed if plant water requirements and economic conditions indicate that the second division will not be needed.

Mobile water treatment systems will be used before the permanent system is installed and later if water requirements exceed the capacity of the permanent system or if economic condition make use of mobile equipment attractive compared to operating and maintaining the permanent system.

9.2.8.3.1 Well System

A well, well water storage tank and two well water forwarding pumps are provided which can produce sufficient water to meet the concurrent needs of the MWP System and the PSW System.

9.2.8.3.2 Pretreatment System

Two dual media filters are provided in parallel which are backwashed when needed using one of two backwash pumps and water from a filtered water storage tank. This tank is provided with a heater to maintain a water temperature of at least 10°C at all times. Water may be sent from the filtered water storage tank to the PSW System or to the next components of the MWP System.

9.2.8.3.3 Reverse Osmosis Modules

Chemical addition tanks, pumps and controls are provided to add sodium hexametaphosphate and sodium hydroxide to the filtered water.

Four high pressure, horizontal multistage reverse osmosis (RO) feed pumps provide a feed pressure of approximately 32 kg/cm^{2}g. Reverse osmosis membranes are arranged in two parallel divisions of two passes each with the permeate of the first passes going to

Section 2.12.1 **Comment No.** 1

Comment:

Figure 2.12.1 shows "DG II" feeders for all divisions. It should be changed to "DG I, DG II, and DG III" as shown in attached markup.

(Task Group:) This may conflict with SSAR. See SSAR section 8.3.1.1.8.3 and Item 4 of SSAR section 8.3.3.6.2.3.2.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.12.1 **Comment No.** 2

Comment:

Incorrect page numbers are referenced on SSAR pages 8.0.iii/iv and v/vi.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.12.1 **Comment No.** 3

Comment:

SSAR descriptions use "mVA and mW" as abbreviations for showing the units of power for equipment such as transformers, DG, CTG and buses. This is inconsistent with drawing 8.3.1. Drawing used "MVA and MW" as abbreviations. SSAR descriptions need to be updated to be consistent with drawing.

Resolution:

GE agreed to make the changes.

Section 2.12.1 **Comment No.** 4

Comment:

Values referenced in acceptance criteria for ITAAC #s 3, 5, 6, 7, 8.b, and 21 are not described in the design description. These should be described.

(Task Group:) With respect to separation distances in #s 3, 5, 6, and 7, GE should consider removing the actual distances from the acceptance criteria column. Distances are in the SSAR.

Resolution:

NRC agreed with GE's disposition.

Section 2.12.1 **Comment No.** 5

Comment:

The design description states that there are no automatic connections between Class 1E divisions. No ITAAC entry is provided for this item. Need further clarification for this design requirement.

Resolution:

Disagree. Design requirement comes from IEEE 308. Configuration would cover it.

Section 2.12.1 **Comment No.** 6

Comment:

Certified Design Material (CDM) does not describe load shedding and sequencing requirements during LOCA (which offsite power available). This should be included in CDM and appropriate ITAAC entry provided to verify the design requirement.

Resolution:

Disagree. No load shed with offsite available. Load sequencing with offsite available is not Tier 1. Sequencing on EDG is Tier 1.

Section 2.12.1 **Comment No.** 7

Comment:

No ITAAC entry provided to verify under voltage/loss of voltage protection for Class 1E buses.

Resolution:

See 2.12.1 #10, Degraded Voltage and 2.12.13 #4, Loss of Voltage.

Section 2.12.1 **Comment No.** 8

Comment:

SSAR TS Section should be clarified as noted in the attached markup.

Resolution:

GE agreed to make the changes.

Section 2.12.1 Comment No. 9

Comment:

ITAAC #23 and CDM design description should be revised as shown in the attached markup.

Resolution:

GE agreed to make the changes.

Section 2.12.1 Comment No. 10

Comment:

In response to comment no. 17 made during the pilot review, GE stated the proposed changes would be made post-amendment 33. This comment is being made to encourage follow-up on that specific item which is the legend in the SSAR for electrical symbols.

Resolution:

GE agreed to make the changes.

2.12.1 (1)

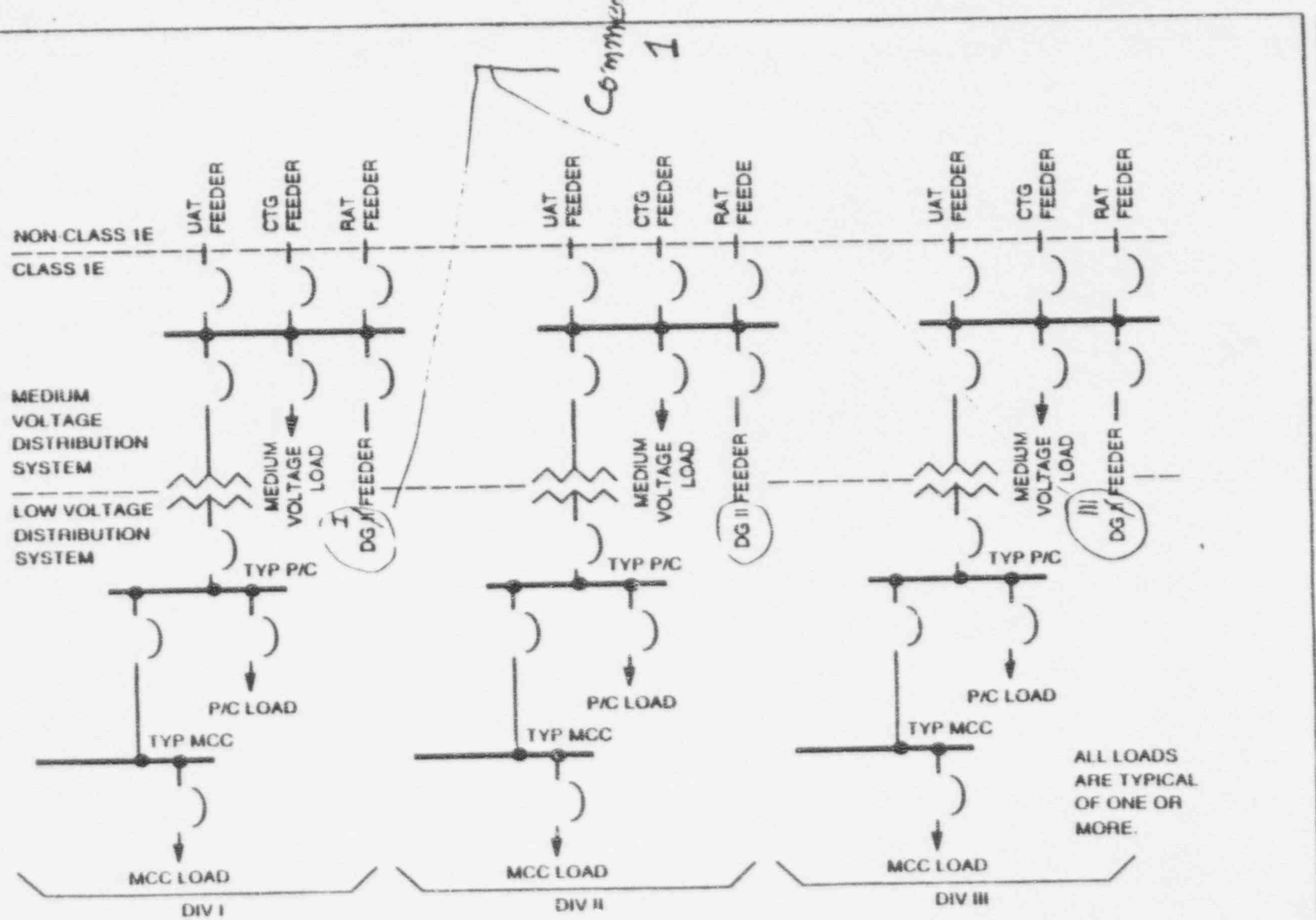


Figure 2.12.1 Class 1E Electrical Power Distribution System

2.2.1(2)

Chapter 8
List of Tables

Comment 2

Chapter 8
List of Figures

2.121(8)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (normal preferred and alternate preferred) and the onsite standby power sources (Division I diesel generator (DG), Division II DG, and Division III DG). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 6.9 kV ESF bus (refer to LCO 3.8.9, "Distribution Systems—Operating"). Each ESF bus has two separate and independent preferred (offsite) sources of power and a dedicated onsite DG. Each ESF bus is also connectable to a combustion turbine generator (CTG). The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Comment #8

CTG may be substituted for the second (delayed access) offsite source

Offsite power is supplied to each of the 6.9 kV ESF buses from the transmission network via two electrically and physically separated circuits. In addition, ~~offsite power may be supplied~~ to any one ESF bus ~~from the CTG~~ (for a limited duration) when the ESF bus is being fed from the reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service, or when the ESF bus is being fed from the unit auxiliary transformer while the reserve auxiliary transformer associated with the ESF bus is out of service. These offsite AC electrical power circuits are designed and located so as to minimize to the extent practicable the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power system and circuits to the onsite Class 1E ESF buses is found in SSAR, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, controls, and

(continued)

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Table 2.12.1 Electric Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
22. The EPD System supplies an operating voltage at the terminals of the Class 1E utilization equipment that is within the utilization equipment's voltage tolerance limits. Comment #19	22. Analyses for the as-built EPD System to determine voltage drops will be performed.	22. Analyses for the as-built EPD System exist and conclude that the analyzed operating voltage supplied at the terminals of the Class 1E utilization equipment is within the utilization equipment's voltage tolerance limits, as determined by their nameplate ratings.
23. An electrical grounding system is provided for (1) instrumentation, control, and computer systems, (2) electrical equipment (switchgear, distribution panels, and motors) and (3) mechanical equipment (fuel and chemical tanks). Lightning protection systems are provided for buildings and for structures and transformers located outside of the buildings. Each grounding system and lightning protection system is seperately grounded to the plant ground grid.	23. Inspections of the as-built EPD System plant Grounding and Lightning Protection Systems will be conducted.	23. The as-built EDP System instrumentation, control, and computer grounding system, electrical equipment and mechanical equipment grounding system, and lightning protection systems provided for buildings and for structures and transformers located outside of the buildings are separately grounded to the plant ground grid.
24. MCR alarms, displays and controls provided for the EPD System are as defined in Section 2.12.1.	24. Inspections will be conducted on the MCR alarms, displays and controls for the EPD System.	24. Displays and controls exist or can be retrieved in the MCR as defined in Section 2.12.1.
25. RSS displays and controls provided for the EPD System are as defined in Section 2.12.1.	25. Inspections will be conducted on the as-built RSS displays and controls for the EPD System.	25. Displays and controls exist or can be retrieved on the RSS as defined in Section 2.12.1.

17 Class 1E medium voltage M/C switchgear and low voltage P/C switchgear and MCCs are identified according to their Class 1E division. Class 1E M/C and P/C switchgear and MCCs are located in Seismic Category I structures, and in their respective divisional areas.

19 Class 1E EPD System cables and raceways are identified according to their Class 1E division. Class 1E divisional cables are routed in Seismic Category I structures and in their respective divisional raceways.

20

21 Harmonic Distortion waveforms do not prevent Class 1E equipment from performing their safety functions.

22 The EPD System supplies an operating voltage at the terminals of the Class 1E utilization equipment that is within the utilization equipment's voltage tolerance limits.

Comp 19 transformers

23 An electrical grounding system is provided for (1) instrumentation, control, and computer systems, (2) electrical equipement (switchgear, distribution panels, and motors) and (3) mechanical equipment (fuel and chemical tanks). Lightning protection systems are provided for buildings and for structures and transformers located outside of the buildings. Each grounding system and lightning protection system is separately grounded to the plant ground grid.

The EPD System has the following alarms, displays and controls in the MCR:

24

(1) Alarms for degraded voltage on Class 1E medium voltage M/C switchgear.

(2) Parameter displays for PMG output voltage, amperes, watts, vars, and frequency.

(3) Parameter displays for EPD System medium voltage M/C switchgear bus voltages and feeder and load amperes.

(4) Controls for the PMG output circuit breaker, medium voltage M/C switchgear feeder circuit breakers, load circuit breakers from the medium voltage M/C switchgear to their respective low voltage P/C switchgear, and low voltage feeder circuit breakers to the low voltage P/C switchgear.

(5) Status indication for the PMG output circuit breaker and the medium voltage M/C switchgear circuit breakers.

The EDP System has the following displays and controls at the Remote Shutdown System (RSS):

25 (1) Parameter displays for the bus voltages on the Class 1E Divisions I and II medium voltage M/C switchgear.

Section 2.12.10 **Comment No.** 1

Comment:

CDM does not fully address the full extend of items covered in acceptance criteria no.2. Clarification is also needed for environmental qualifications. Design Description should be revised as shown in the attached mark-up.

(Task Group:) This should be sent to GE to include the new wording attached.

Resolution:

GE agreed to make the changes.

Section 2.12.10 **Comment No.** 2

Comment:

ITAAC entry #2 should be revised as shown in the attached mark-up.

(Task Group:) This should be sent to GE to include the new wording attached.

Resolution:

GE agreed to make the changes.

Section 2.12.10 **Comment No.** 3

Comment:

IEEE 317 "IEEE Standard for Electrical Penetration Assembly in Containment Structure for Nuclear Power Plant" should be referenced in SSAR for meeting design, construction, qualification, test and installation of electrical penetration assemblies.

Resolution:

GE agreed to make the appropriate changes.

Section 2.12.10 **Comment No.** 4

Comment:

CDM and SSAR should provide information to verify the pressure boundary of containment penetrations. ITAAC entry should be provided to verify this.

Resolution:

Covered by containment structure.

Section 2.12.10 **Comment No.** 5

Comment:

ITAAC entry #4 should be revised as shown in the attached mark-up.

Resolution:

Disagree. Tier 1 independence for penetrations only involves an inspection.

Section 2.12.10 **Comment No.** 6

Comment:

SSAR should provide information regarding penetration withstand capabilities for electromagnetic and thermal forces and penetration nozzle-concrete interface limits.

Resolution:

Not specifically needed in the SSAR. The type of information cited involves detailed design information which is part of the design and specification of particular penetrations. This type of information is expected to be part of the final design, qualification, and procurement of the penetrations and is done in accordance with industry standards and practices. The SSAR (19.F.3.2.2) does specify electrical penetration design requirements including temperature and pressure ratings to account for loadings due to severe accidents.

Section 2.12.10 **Comment No.** 7

Comment:

SSAR should be revised as shown in the attached mark-up.

Resolution:

See comment 1 above.

Section 2.12.10 **Comment No.** 8

Comment:

SSAR Section 8.3.3.1 states that "no penetration carries cables of more than one division." SSAR does not discuss how non-safety related cables are connected to the penetration assemblies. Is there a separate penetration assembly to carry non-safety related circuits? Provide clarification.

Resolution:

Yes. Separate penetrations, as stated in SSAR.

2.12.10 Electrical Wiring Penetration

Design Description

Electrical penetrations are provided for electrical cables passing through the primary containment.

Electrical penetrations are classified as safety-related.

Comment (1)

Electrical penetrations are protected against ~~overcurrent~~ e

Electrical penetrations are classified as Seismic Category I.

Divisional electrical penetrations only contain cables of one Class 1E division. Independence is provided between divisional electrical penetrations and also between divisional electrical penetrations and penetrations containing non-Class 1E cables.

Electrical penetrations and cables are qualified for a harsh environment.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.10 provides a definition of the inspections, tests, and/or analyses, together with the associated acceptance criteria, which will be undertaken for the Electrical Wiring Penetrations.

~~rated continuous currents, rated short-time overload currents and rated short circuit currents. Either the continuous current rating of the penetration is above maximum fault current level or redundant interrupting protective devices (connected in series) are provided for all electric circuits going through containment penetrations, if the maximum available fault current (assuming failure of an upstream device) is greater than the continuous current rating of the penetration.~~

currents that are greater than its continuous current rating.

Table 2.12.10 Electrical Wiring Penetration

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the Electrical Wiring Penetration is described in Section 2.12.10.	1. Inspections of the as-built Electrical Wiring Penetration will be conducted.	1. The as-built Electrical Wiring Penetration conforms with the basic configuration described in Section 2.12.10.
2. Electrical penetrations are protected against overcurrents that are greater than its continuous current rating	2. Analyses for the as-built electrical penetrations and protective features will be performed to assure the penetrations are protected against overcurrent. available fault rated capabilities	2. Analyses for the as-built electrical penetrations and protective features exist and conclude either 1) that the maximum overcurrent of the circuits does not exceed the continuous current rating of the penetration, or 2) that the circuits have redundant overcurrent protective devices in series and that the redundant overcurrent protection devices are coordinated with the penetration's rated short circuit thermal capacity data and prevent overcurrent from exceeding the continuous current rating of the electrical penetrations.
3. Divisional electrical penetrations only contain cables of one Class 1E division.	3. Inspections of the as-built divisional electrical penetrations will be conducted.	3. As-built divisional electrical penetrations only contain cables of one Class 1E division.
4. Independence is provided between divisional electrical penetrations and between divisional electrical penetrations and penetrations containing non-Class 1E cables.	4. Inspections of the as-built electrical penetrations will be conducted.	4. Physical separation exists between as-built divisional electrical penetrations. Physical separation exists between these divisional electrical penetrations and penetrations containing non-Class 1E cables.

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described in Subsection 8.3.3.6.1.1(4). Circuits within penetration assemblies follow the same installation method as described in 8.3.3.6.1.2 for divisional assignment.

For the other ends of the penetrations, which are outside the containment in the non-inerted areas, separation by distance alone is not allowed. These are separated by separate rooms, or barriers, or different floor levels. Such walls, barriers or floors are 3-hour fire-rated.

Such separation criteria applies to the following:

(1) Between redundant (divisional) penetrations

(2) Between penetrations containing non-Class 1E and penetrations containing Class 1E or associated Class 1E circuits

(3) Between penetrations containing Class 1E circuits and other divisional or non-divisional cables.

Redundant ~~over-current~~ protective interrupting devices are provided for all electrical circuits (including all instrumentation and control devices, as well as power circuits) going through containment penetrations, if the maximum available fault current (assuming failure of an upstream device) is greater than the continuous current rating of the penetration. This avoids penetration damage in the event of failure of any single over-current device to clear a fault within the penetration or beyond it. See Subsection 8.3.4.4 for COL license information.

8.3.3.6.1.3 Compliance with Separation During Design and Installation

Compliance with the criteria which insures independence of redundant systems is a supervisory responsibility during both the design and installation phases. The responsibility is discharged by:

(1) Identifying applicable criteria;

(2) Issuing working procedure to implement these criteria;

(3) Modifying procedures to keep them current and workable;

(4) Checking the manufacturer's drawings and specifications to ensure compliance with procedures; and

(5) Controlling installation and procurement to assure compliance with approved and issued drawings and specifications.

rated short circuit thermal capacity (I^2t)

below the maximum continuous current capacity of the penetration. Such devices must be located in separate panels or be separated by barriers and must be independent such that failure of one will not adversely affect the other. Furthermore, they must not be dependent on the same power supply.

(5) A demonstration of leak tightness under the severe accident containment pressure and temperature loadings described in Subsection 19F.3.2.2.

Protective devices designed to protect the penetrations are capable of being tested, calibrated and inspected (see Subsection 8.3.4.4).

8.3.3.8 Fire Protection of Cable Systems

The basic concept of fire protection for the cable system in the ABWR design is that it is incorporated into the design and installation rather than added onto the systems. By use of fire resistant and non-propagating cables, conservative application in regard to ampacity ratings and raceway fill, and by separation, fire protection is built into the system. Cables are rated to withstand fault currents until the fault is cleared. Short circuit analysis will be performed in accordance with IEEE 141 and/or other acceptable industry standards or practices to determine fault currents. Fire suppression systems (e.g., automatic sprinkler systems) are provided as listed in Table 9.5.1-1.

8.3.3.8.1 Resistance of Cables to Combustion

The electrical cable insulation is designed to resist the onset of combustion by limiting cable ampacity to levels which prevent overheating and insulation failures (and resultant possibility of fire) and by choice of insulation and jacket materials which have flame-resistive and self-extinguishing characteristics. Polyvinyl chloride or neoprene cable insulation is not used in the ABWR. All cable trays are fabricated from noncombustible material. Base ampacity rating of the cables was established as published in IPCEA-46-426/IEEE-S-135 and IPCEA-54-440/ NEMA WC-51. Each coaxial cable, each single conductor cable and each conductor in multiconductor cable is specified to pass the vertical flame test in accordance with UL-44.

In addition, each power, control and instrumentation cable is specified to pass the vertical tray flame test in accordance with IEEE-383.

Power and control cables are specified to continue to operate at a conductor temperature not exceeding 90°C and to withstand an emergency overload temperature of up to 130°C in accordance with IPCEA S-66-524/NEMA WC-7 Appendix D. Each power cable has stranded conductor and flame-resistive and radiation-resistant covering. Conductors are specified to continue to operate at 100% relative humidity with a service life expectancy of 60 years (See 8.3.4.3). Also, Class 1E cables are designed and qualified to survive the LOCA ambient condition at the end of the 60-yr. life span.

Section 2.12.11 Comment No. 1

Comment:

Although the physical independence of the CTG and its feeders is maintained relative to the designated offsite and onsite power sources, its electrical independence should also be established with them in order to avoid a common mode failure when it is required to function during Station Blackout. In the SSAR on page 1C-3, the 4th bulleted-item requires that "The CTG design minimize potential for single point vulnerability with onsite emergency power sources." A similar design commitment is also established in the SSAR on page 1C-1, last paragraph, Item (2) in regard to offsite power sources. An ITAAC should be provided to verify that this independence is established.

Resolution:

These type SSAR commitments are too broad for inclusion in Tier 1. Furthermore, electrical independence under SBO was not considered a Tier 1 requirement because it is assumed that all other ac sources are not available.

Section 2.12.11 Comment No. 2

Comment:

In order to meet the guidance of R.G. 1.155 and the commitment of 10CFR50.63 when no coping analysis is to be required, the AAC power source must be able to be connected to the safe shutdown buses within 10 minutes. ITAAC needs to be provided to verify that by preliminary analysis that the combustion turbine generator can be connected to at least one safety-related bus within this time line based on nominal operator response times, breaker operating times, and the postulated startup time of the CTG even though actually verified during pre-op. testing.

Resolution:

No action needed. Since auto start of the CTG is provided, it was concluded that the relatively simple breaker alignment could be procedurally achieved within 10 minutes and therefore, no specific ITAAC was needed.

Section 2.12.11 **Comment No.** 3

Comment:

Design Commitment No. 3 requires the CTG's capacity to be at least equal to that of an EDG. R.G. 1.9 suggests that the continuous load rating of an EDG during the construction permit stage be at least equal to the sum of the nameplate ratings of its loads plus a margin of 10-15%. It would seem, based on this, that the CTG should also be sized similarly to an EDG per R.G. 1.9. The CTG should only be sized with a capacity equal to that of an EDG if their loads are identical. This is not the case since each EDG does not have to pickup the PIP buses in conjunction with the Class 1E buses. Clarification is required. Suggestion is to make a definitive statement in the SSAR about the actual output capacity of the CTG based on a tabulated list of connected loads for SBO and other similar loading scenarios.

Resolution:

No action needed. The SSAR does specify the CTG capacity to be great enough to supply loads on the PIP buses as well as the Class 1E buses. It was decided that for Tier 1 purposes, only the minimum safety requirement would be verified by the ITAAC and therefore a capacity equal to the capacity of the EDG was acceptable for the ITAAC design commitment.

Section 2.12.11 **Comment No.** 4

Comment:

Page 1C-4 of the SSAR, third paragraph - "CTG automatically starts on an undervoltage at the PIP buses... and if voltage is still deficient then power automatically transfers to the CTG." In order to ensure sufficient capacity of the CTG to respond to the shutdown of the plant during a SBO, would the case ever arise when this feature should be overridden? ITAAC should be provided that verifies the operability of this feature since no load has to be picked up during the test.

Resolution:

No action needed. The detailed operation, including specific features such as "overrides", have not been specified in ITAAC. The SSAR describes the automatic operation of the CTG as it would be expected to occur in response to a loss of offsite power event. The operation of the CTG as an AAC source to a Class 1E bus is done under subsequent manual actions.

Section 2.12.11 Comment No. 5

Comment:

In the SSAR on page 8.3-20, Item (5) - "Each diesel generator...has a continuous load rating of 6.25 MVA @.8 power factor." This interprets into a continuous load rating of 5 MW for each EDG. In the SSAR on page 8.2-6, 5th paragraph - "CTG... is a 9 MW self-contained unit." Design commitment no. 3 requires the CTG to be as least as large as an EDG in regard to capacity. On the basis of the capacities for each EDG and CTG quoted above from the SSAR and also for the reasons stated in comment no. 3, the CTG and each EDG can not have similar rated output capacities. This entire ITAAC entry (all three columns for item 3) needs to be re-written or replaced by one which is more appropriate.

Resolution:

As specified in the SSAR, the EDG and CTG do not have similar ratings. However, as stated above in Comment 3, the minimum safety requirement of a capacity equal to an EDG was incorporated into ITAAC.

Section 2.12.11 Comment No. 6

Comment:

Design Description states that "CTG is located in a non-safety related area of the plant." SSAR Section 9.5.11.3 states that "Adequate protection of the CTG against sabotage is provided by locating the unit inside the security protected area." Design Description should be revised to show that the CTG is located in the protected area of the plant and an ITAAC should be provided to verify this location.

Resolution:

GE agreed to make the appropriate changes.

Section 2.12.11 Comment No. 7

Comment:

The operations and surveillance requirements for the CTG should be added to the TS to confirm the operability and availability of this system.
Note: The staff is currently considering inclusion of SBO equipment in TS for operating plants.

Resolution:

Management decision - No (based on ABWRs additional "coping" capability).

Section 2.12.11 **Comment No.** 8

Comment:

Table 2.12.11, item 1, replace 2.12.1 with 2.12.11.

Resolution:

GE agreed to make the changes.

Section 2.12.11 **Comment No.** 9

Comment:

SSAR page 7.3-3, revise as shown on mark-up.

Resolution:

See appropriate section - miscellaneous comments include this.

Section 2.12.11 **Comment No.** 10

Comment:

SSAR Table 14.3-10, clarify statement at top of page with respect to RCIC and HPCF suction piping as outlined in mark-up.

Resolution:

See appropriate section - miscellaneous comments include this.

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Table 2.12.11 Combustion Turbine Generator

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the CTG is described in Section 2.12.1. 2.12.11	1. Inspections of the as-built CTG will be conducted.	1. The as-built CTG conforms with the basic configuration described in Section 2.12.11.
2. The CTG can supply power to the non-Class 1E busses or to the Class 1E divisional busses.	2. Tests on the as-built CTG will be conducted by connecting the CTG to the non-Class 1E PIP busses and to the Class 1E divisional busses.	2. The as-built CTG can supply power to the non-Class 1E PIP busses or to the Class 1E divisional busses.
3. The CTG capacity to supply power is at least as large as the capacity of a DG.	3. Inspections of the as-built CTG and DGs will be conducted.	3. The as-built CTG capacity to supply power is at least as large as the capacity of a DG, as determined by the CTG and DG nameplate ratings.
4. MCR displays and controls provided for the CTG are as defined in Section 2.12.11.	4. Inspections will be conducted on the MCR displays and controls for the CTG.	4. Displays and controls exist or can be retrieved in the MCR as defined in Section 2.12.11.

Item 1 change as 2.12.11

Section 2.12.12 **Comment No.** 1

Comment:

GE response to comment #9 of pilot review is not fully implemented. Figure 8.3.4 sheet 3 as well as other affected drawings (AC and DC systems) should be revised to show non-drawout type MCCBs.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.12.12 **Comment No.** 2

Comment:

One line diagram symbol legend needs to be added to SSAR section 1.7 as committed by GE in response to pilot review comments 10 & 11.

Resolution:

GE agreed to make the changes.

Section 2.12.13 **Comment No.** 1

Comment:

a. Acceptance value for ITAAC 6 should be referenced in design description.

b. Acceptance values (+/- 10%) voltage and +/- 2% frequency) should be deleted from ITAACs 4, 5, and 7 since the design requirement is to establish rated voltage and frequency. The above tolerance requirements are specified only during loading.

Resolution:

a. No action needed. The acceptance values for the diesel generator are controlled throughout operation by the plant technical specifications. The staff believes that the acceptance values specified in ITAAC in conjunction with the TSs provide control of the safety parameters such that inclusion of this information in the design description would not be needed.

b. GE agreed to make the appropriate changes.

Section 2.12.13 **Comment No.** 2

Comment:

SSAR Section 8.3.1.1.8.2, item no. 14 states that "the maximum loads expected to occur for each division do not exceed 90% of the continuous power output rating of the diesel generator." This information should be incorporated in CDM and ITAAC #2 should be revised accordingly. See attached.

Resolution:

NRC agreed with GE's disposition.

Section 2.12.13 **Comment No.** 3

Comment:

No ITAAC entry is provided to verify that DG combustion air intakes are located above the maximum flood level and the intakes are separated from DG exhaust ducts. Refer CDM page 2.12.3.2 for design requirement.

Resolution:

Configuration covers this.

Section 2.12.13 **Comment No.** 4

Comment:

SSAR should state that a transient analysis (simulating various loading conditions) is performed to verify DGs response.

Resolution:

Covered by SSAR commitments.

Section 2.12.13 **Comment No.** 5

Comment:

SSAR and CDM should address Class 1E DC requirements for DG field flashing, control and protective circuits.

Resolution:

The SSAR does cover these requirements. With regard to the CDM, DD/ITAAC 2.12.12 addresses Class 1E DC requirements and the DG field flashing, control and protective circuits would be verified as part of that ITAAC.

Section 2.12.13 **Comment No.** 6

Comment:

Load shedding requirements specified in SSAR 8.3.1.1.7 should be included in CDM. Design commitments 4 & 6 and ITAACs should be revised to take into consideration the shedding of large motors at a bus voltage equal to 30% of nominal.

Resolution:

GE agreed to make the appropriate changes.

Section 2.12.13 **Comment No.** 7

Comment:

Why are cable losses, Division III RCW pump loads and transformer losses (for EA10 A, B, C) not shown in Table 8-3-1 of SSAR. Provide clarification.

Resolution:

Not typically included as loads.

Section 2.12.13 **Comment No.** 8

Comment:

What is the worst case loading for diesel?
Provide clarification in SSAR.

Resolution:

See table in SSAR.

Section 2.12.13 **Comment No.** 9

Comment:

Why are DG qualification test requirements not included in Certified Design Material? Provide clarification.

Resolution:

In general, qualification tests are not covered by the electrical system ITAAC. DG qualification is described in the SSAR in conformance with applicable Regulatory Guides and industry standards.

Section 2.12.13 **Comment No.** 10

Comment:

Last paragraph of TS bases section B 3.8.1 should be revised to include power factor of DG.

Resolution:

GE agreed to make the changes.

Section 2.12.13 **Comment No.** 11

Comment:

TS surveillance requirement 3.8.1.14 states that testing must be performed using a power factor of <0.9. This value should be changed to" 0.8 or to actual load power factor" to be more conservative.

Resolution:

<0.9 is consistent with other documents.

Section 2.12.13 **Comment No.** 12

Comment:

Why are sequence timers started at 70% bus voltage? Sequence timers are started after DGs attain rated voltage and frequency. SSAR states that minimum voltage at the bus is 75%. SSAR and applicable instrument drawings must be revised to state 75% minimum voltage requirement.

Resolution:

70% is typical loss of voltage setpoint. There is typically no requirement to monitor for minimum voltage except degraded grid.

Section 2.12.13 **Comment No.** 13

Comment:

Revise design commitment #7 as shown in the attached markup.

Resolution:

GE agreed to make the changes.

Section 2.12.13 **Comment No.** 14

Comment:

Page 2.12.13-1, 4th paragraph, states that the EDG is automatically connected to its respective divisional bus upon an undervoltage condition., However, this is not really true because in accordance with page 8.3-16, item 1 of the SSAR, it is necessary for large motors to trip first at a bus voltage equal to 30% before the EDG output breaker is closed.

(Task Group:) See comment 6 above on the same aspect.

Resolution:

GE agreed to make the appropriate changes.

Section 2.12.13 **Comment No.** 15

Comment:

The design description should include the maximum time to load the HPCF and RHR loads (less than or equal to 36 sec) as verified by the ITAAC.

Resolution:

As stated in response to comment 1a, the staff concluded that adequate controls exist such that inclusion in the DD was not necessary.

Section 2.12.13 **Comment No.** 16

Comment:

The voltage drop and frequency variations verified in ITAAC (+/- 10 % and +/- 25% respectively) should be included in the design description. (See also comment 1 on sheet 1, comment 16 may be moot)

Resolution:

See response to comment 1a.

Section 2.12.13 **Comment No.** 17

Comment:

The day tank capacity should be specified in the design description.

Resolution:

See 2.16.2 on Fuel.

Section 2.12.13 **Comment No.** 18

Comment:

Table 2.12.13 item 9, acceptance criteria should be clarified to state that the test signal only exists in the Class 1E DG unit <u>auxiliary systems</u> under test.

Resolution:

Disagree. Although "auxiliary systems" is not stated explicitly in the acceptance criteria, design commitment clearly states that this ITAAC entry is for the DG unit auxiliaries. Therefore, both the ITA and the acceptance criteria apply to the auxiliary systems.

Table 2.12.13 Emergency Diesel Generator System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. When LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. After a DG connects to its respective bus, the LOCA loads are automatically sequenced onto the bus.	6. Tests on the as-built DG Systems will be conducted by providing simulated LOCA and LOPP signals.	6. In the as-built DG Systems, when LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. The automatic load sequence begins at ≤ 20 seconds. Following application of each load, the bus voltage does not drop more than 25% measured at the bus. Frequency is restored to within 2% of nominal, and voltage is restored to within 10% of nominal within 60% of each load sequence time interval. The HPCF and RHR loads are sequenced on to the bus in ≤ 36 seconds for design basis events.
comment (13) 7. A manual start signal from the MCR or from the local control station in the DG area starts a DG. After starting, the DG remains in a standby mode, unless a LOPP signal exists. (ie. running at rated voltage and frequency required)	7. Tests on the as-built DG Systems will be conducted by providing a manual start signal from the MCR and from the local control station, without a LOPP signal.	7. As-built DGs automatically start on receiving a manual start signal from the MCR or from the local control station, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds and remain in the standby mode.
8. When a DG is operating in parallel (test mode) with offsite power, a loss of the offsite power source used for testing or a LOCA signal overrides the test mode by disconnecting the DG from its respective divisional bus.	8. Tests on the as-built DG Systems will be conducted by providing simulated loss of offsite power and LOCA signals while operating the DGs in the test mode.	8. When the as-built DG Systems are operating in the test mode with offsite power and a loss of offsite power or a LOCA signal is received, DGs automatically disconnect from their respective divisional buses.

Table 2.12.13 Emergency Diesel Generator System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the DG System is described in Section 2.12.13.	1. Inspection of the as-built system will be conducted.	1. The as-built DG System conforms with the basic configuration described in Section 2.12.13.
2. The DGs are sized to supply their load demand following a LOCA.	2. Analyses to determine DG load demand, based on the as-built DG load profile, will be performed.	2. Analyses for the as-built DG systems exist and conclude that the DG System capacities exceed, as determined by their nameplate ratings, their load demand following a LOCA. by 10%
3. DG air start receiver tanks have capacity for five DG starts without recharging their tanks.	3. Tests on the as-built DG Systems will be conducted by starting the DGs five times.	3. As-built DGs start five times without recharging their air start receiver tanks.
4. A LOPP signal (bus under-voltage) from an EPD System medium voltage divisional bus automatically starts its respective DG, and initiates automatic connection of the DG to its divisional bus. A DG automatically connects to its respective bus when DG rated voltage and frequency conditions are established. After a DG connects to its respective bus, the non-accident loads are automatically sequenced onto the bus.	4. Tests on the as-built DG Systems will be conducted by providing a simulated LOPP signal.	4. As-built DGs automatically start on receiving a LOPP signal, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds, automatically connect to their respective divisional bus, and sequence their non-accident loads onto the bus.
5. LOCA signals from the RHR (Division I) and HPCF (Divisions II and III) System automatically start their respective divisional DG. After starting, the DGs remain in a standby mode (i.e. running at rated voltage and frequency, but not connected to their busses), unless a LOPP signal exists.	5. Tests on the as-built DG Systems will be conducted by providing a simulated LOCA signal, without a LOPP signal.	5. As-built DGs automatically start on receiving a LOCA signal, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds, and remain in the standby mode.

chg

Section 2.12.14 **Comment No.** 1

Comment:

Why are drawout type molded case circuit breakers shown on SSAR figure 8.3.3?

Resolution:

GE will remove the word "drawout" in the SSAR.

Section 2.12.14 **Comment No.** 2

Comment:

Why are Electrical Protection Assemblies (EPAs) not included in certified design material? These are required to protect safety related components from over/under voltage and frequency transients. EPA design requirement should be included in ITAAC and figure 2.12.14.

Resolution:

Not considered Tier 1, because the monitored power is now Class 1E and, in addition, the ABWR is better protected from ATWS. The over/under voltage and frequency alarms are included.

Section 2.12.14 **Comment No.** 3

Comment:

Why are EPAs not required for Computer and non-safety Vital AC system?

Resolution:

Not needed to protect non-safety equipment.

Section ?.12.14 **Comment No.** 4

Comment:

The design description states that there are no automatic connections between Class 1E divisions. No ITAAC entry is provided for this item. Need further clarification for this design requirement.

Resolution:

From IEEE 308. Part of configuration.

Section 2.12.15 **Comment No.** 1

Comment:

Figure 2.12.15 and SSAR figure 8.3-2 do not agree in regard to the type of breakers utilized. Revise the SSAR figure to show non-drawout breakers.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.12.15 **Comment No.** 2

Comment:

Page 2.12.15-1, last paragraph-Selectively between interrupting devices is required; however this is difficult or almost impossible to achieve between molded-case circuit breakers, since their instantaneous trips are not adjustable. Figure 2.12.15 needs to be revised to employ other types of interrupting devices or this requirement needs to be eliminated or a disclaimer added.

Resolution:

NRC agreed with GE's disposition.

Section 2.12.15 **Comment No.** 3

Comment:

Comment No. 2 also applies to Design Commitment No. 9 and the related tests and acceptance criteria. Unless the appropriate types of interrupting devices (typically fuses) are selected, this design requirement can not be met.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.12.15 **Comment No.** 4

Comment:

Design Commitment No. 12 - Full blown voltage drop analysis is not required since each instrument and control power supply has voltage regulating capability. Need to verify range of input voltage to each one is in accordance with its design specifications. Perform voltage drop analysis only on output circuit of each power supply (including pickup and drop-out of load end devices). Provide appropriate ITAAC.

Resolution:

ITAAC is covering voltage drop.

Section 2.12.15 **Comment No.** 5

Comment:

Page 2.12.15-1, 5th paragraph - Last sentence states "There are no automatic connections between Class 1E divisions." Clarification is necessary since no ITAAC entry presently verifies this requirement.

Resolution:

Part of configuration.

Section 2.12.16 **Comment No.** 1

Comment:

SSAR 9.5.2.2.1 states that the communication system is a three channel system. ITAAC design description describes "consists of at least two channels" 2.12.16 Communication System

Resolution:

No action needed - Tier 1 and Tier 2 okay.

Section 2.12.16 **Comment No.** 2

Comment:

SSAR 9.5.2.2.1 Paging Facilities provides locations for the installation of plant paging equipment. The ITAAC design description 2.12.16 or (ITAAC) does not list minimum locations for the power-actuated paging equipment.

Resolution:

No action needed - Tier 1 and Tier 2 okay.

Section 2.12.16 **Comment No.** 3

Comment:

SSAR 9.5.2.2.1 states that the power-actuated paging system will have a dedicated DC power supply and dedicated battery with a 10 hour capacity following a loss of AC power. ITAAC 2.2.16 Communication System design description does not list this requirement in the design description or ITAAC.

Resolution:

No action needed - Tier 1 and Tier 2 okay.

Section 2.12.16 **Comment No.** 4

Comment:

SSAR 9.5.2.2.2 Sound Powered Telephone System lists installed locations as remote shutdown panel, main control boards and field stations. 2.12.16 Communication System design description and ITAAC lists locations as main control room, remote shutdown, electrical equipment and diesel generator areas.

Resolution:

No action needed - Tier 1 and Tier 2 okay.

Section 2.12.16 **Comment No.** 5

Comment:

The ITAAC testing is inconsistent with the SRP Section 9.5.2 with regard to testing of communication system in that the "design basis, design criteria, system descriptions the effectiveness of the system when maximum plant noise levels are being generated during incident and accident conditions are reviewed to verify that the communication system will function effectively". Based on the above the SSAR and the ITAAC testing should reference a functional test that demonstrates that the communication system operates effectively under conditions of maximum noise levels during various operating conditions, including emergencies.

Resolution:

No action needed - not Tier 1. SSAR 14.2 has the tests. Procedures and tests are also in Section 9.5 of the SSAR and as COL license information.

Section 2.12.16 **Comment No.** 6

Comment:

Paging Facilities SSAR 9.5.2.2.1, figure 9.5-2 lists paging equipment as T/B, R/B, Hx/B, S/B, Switching Station and outdoors. Acronyms are not listed for T/B, Hx/B, S/B and locations are not consistent with the ITAAC or SSAR descriptions. Locations are not shown on SSAR Figure 9.5.2 for the sound powered phone system and system is labelled as the communication facilities board for maintenance.

Resolution:

GE agreed to make the appropriate changes.

Section 2.12.16 **Comment No.** 7

Comment:

Clarify the 480 VAC and the 120 VAC power (from DG/CTG buses etc.) requirements for the power actuated paging system. Not discussed in ITAAC or SSAR.

Resolution:

No action needed. Non-safety (non Class 1E) power supply for battery chargers - independent battery. Not Tier 1. Tier 2 description adequate for this non-safety system.

Section 2.12.17 **Comment No.** 1

Comment:

What is the actual backup for the Class 1E AC Associated lighting system? Is it the standby non-Class 1E lighting system, the emergency DC lighting system, or the guide lamp lighting system? Clarification should be provided.

Resolution:

Lighting is described in terms of various lighting systems provided to areas based on power sources, however certain lighting subsystems do not truly "backup" other subsystems. It was concluded that the SSAR and ITAAC do sufficiently describe the lighting without the need for describing backup capability.

Section 2.12.17 **Comment No.** 2

Comment:

The mechanism for transfer to emergency DC lighting upon failure of the AC lighting should be stated in the CDM and an ITAAC provided to verify its correct operation. This is true for both the SSLS and NSLS since the NSLS or its designated backup is required during Station Blackout.

Resolution:

The ITAAC verify the various lighting systems, but actual transfer mechanisms, where provided, were not considered Tier 1 material because it is a design detail that is rather standard in that it involves loss of power. Specifically with respect to SBO, all ac lighting could be lost, but since the ABWR has an AAC source, some lighting could be re-powered when the CTG is started. However, there is no specific "transfer mechanism" for the lighting.

Section 2.12.17 **Comment No.** 3

Comment:

The intensity of lighting in remote safety shutdown areas needs to be verified to eliminate shadows or improperly lit areas. Lighting in these areas is a regulatory requirement per 10 CFR 50, App. R, Section III.J.

Resolution:

In general, lighting intensity was not considered Tier 1 material, and are only specified in the SSAR. Appendix R, Section III.J. does not explicitly require an intensity, but it does require emergency lighting with an 8 hour power source, and this is verified in ITAAC.

Section 2.12.17 **Comment No.** 4

Comment:

What voltage level is Class 1E lighting? Battery packs typically require 120 VAC input.

Resolution:

480/120.

Section 2.12.17 **Comment No.** 5

Comment:

For any Class 1E area, there will be possibly five independent lighting systems: 50% of the lighting by the SSLS backed by the SELS, the other 50% of the lighting by the NSLS backed by the NELS, and in some areas the guide-lamp system. An ITAAC should be provided to verify the independence of all these.

Resolution:

Although is some aspects these various lighting systems are independent, the Tier 1 "independence" to be verified deals with the requirements for the Class 1E divisional power independence and this is verified in ITAAC.

Section 2.12.17 **Comment No.** 6

Comment:

SSAR and CDM use different terminologies. SSAR refers to "Class 1E Associated lighting" whereas CDM refers to "Associated Class 1E lighting". Clarification should be provided.

(Task Group:) Use of associated is acceptable when discussing circuits, however, GE should be consistent.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.14.1 **Comment No.** 1

Comment:

The design certification material does not address containment isolation systems. The requirements (see attached SSAR section 6.2.4.1.2) should be specified in the CDM and verified by ITAAC. The individual system ITAAC do not appear to provide sufficient coverage of this function.

Resolution:

Disagree. System ITAAC verify containment isolation valves are installed and can close against design pressure. Containment isolation functions verified in ITAAC 2.4.3, Leak Detection & Isolation System.

Section 2.14.1 **Comment No.** 2

Comment:

Why are alarms associated with containment isolation not called out in CDM Table 2.7.1a?

Resolution:

They are. Compare Figure 2.4.3 to alarms listed in Table 2.7.1a. Note that alarms listed on Table 2.7.1a are functional descriptions.

(3) The design of isolation valving for lines penetrating the containment follows the requirements of General Design Criteria 54 through 57 to the greatest extent practicable consistent with safety and reliability.

(4) Isolation valves for instrument lines that penetrate the drywell/containment conform to the requirements of Regulatory Guide 1.11.

(5) Isolation valves, actuators and controls are protected against loss of their safety function from missiles and postulated effects of high- and moderate-energy line ruptures.

(6) Design of the containment isolation valves and associated piping and penetrations meets the requirements for Seismic Category I components.

(7) Containment isolation valves and associated piping and penetration meet the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 1, 2, or MC, in accordance with their quality group classification.

(8) The design of the Control Systems for automatic containment isolation valves ensures that resetting the isolation signal shall not result in the automatic reopening of containment isolation valves.

6.2.4.1.2 Design Requirements

The Containment Isolation System, in general, closes fluid penetrations that support systems not required for emergency operation. Fluid penetrations supporting ESF systems have remote manual isolation valves which can be closed from the control room, if required.

The isolation criteria for the determination of the quantity and respective locations of isolation valves for a particular system conform to General Design Criteria 54, 55, 56, 57, and Regulatory Guide 1.11. Redundancy and physical separation are required in the electrical and mechanical design to ensure that no single failure in the CIS prevents the system from performing its intended functions.

Protection of CIS components from missiles is considered in the design, as well as the integrity of the components to withstand seismic occurrences without loss of operability. For power-operated valves used in series, no single event can interrupt motive power to both closure devices. Air-operated containment isolation valves are designed to fail to the required position for containment isolation upon loss of the instrument air supply or electrical power.

The CIS is designed to Seismic Category I requirements. Classification of equipment and systems is found in Table 3.2-1. Figure 6.2-38 identifies the quality group classifications and containment isolation provisions.

Section 2.14.4 Comment No. 1

Comment:

First paragraph: The sentence "SGTS consists of two redundant divisions." has been repeated; delete one.

Resolution:

GE agreed to make the changes.

Section 2.14.4 Comment No. 2

Comment:

SSAR Section 6.5: see attached pages for comments.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 2.14.4 Comment No. 3

Comment:

Figure 6.5-1 (Sh 2 of 3) and (3 of 3), coordinates 4/F: change the title of "EXHAUST" to "PROCESS".

Resolution:

GE agreed to make the changes.

6.5.1.2 System Design

6.5.1.2.1 General

The SGTS P&ID is provided as Figure 6.5-1.

6.5.1.2.2 Component Description

Table 6.5-1 provides a summary of the major SGTS components. The SGTS consists of two parallel and redundant filter trains. The two SGTS trains are located in two adjacent rooms. Each train is protected for fire, flood, pipe break and missiles. The electrical separation is provided by connecting the two trains to Divisions 2 and 3 electric power. The two trains are mechanically separated also. Suction is taken from the secondary containment, including above the refueling area, or from the primary containment via the Atmospheric Control System (ACS). The treated discharge goes to the main plant stack.

The SGTS consists of the following principal components:

(1) Two filter trains, each consisting of a of a moisture separator, an electric process heater, a prefilter, a high efficiency particulate air (HEPA) filter, a charcoal adsorber, a second HEPA filter, space heaters, and a cooling fan for the removal of decay heat from the charcoal.

(2) ~~Two independent process fans~~ located downstream of each filter train.

"A PROCESS FAN IS"

6.5.1.2.3 SGTS Operation

6.5.1.2.3.1 Automatic

Upon receipt of a high drywell pressure signal or a low reactor water level signal, or when high radioactivity is detected in the secondary containment or refueling floor ventilation exhaust, both SGTS trains are automatically actuated and one train is manually placed in the Standby mode. When the operation of both the trains is assured, one train is placed in the Standby mode. In the event that a malfunction disables an operating train, the standby train is automatically initiated.

6.5.1.2.3.2 Manual

T/PO

The SGTS is on standby during normal plant operation. It may be manually initiated for primary containment de-inerting in accordance with the Technical Specifications when required to limit the discharge of contaminants to the environment within 10CFR20 limits. Normal operation of the SGTS while the plant is in the startup, power, hot standby, and hot shutdown modes of operation is much less than 90 hours per year for both trains combined. However, if 90 hours of operation per year for either train (excluding tests) is to be exceeded, the COL applicant is required to demonstrate that maintenance or operating personnel activity or an incredible malfunction of the space heaters. In this case, a fire in the SGTS charcoal, like in the offgas system, would be a matter of plant availability and not of plant safety. The space heaters, located inside the SGTS filter housing, are powered only during SGTS standby and not during system operation. Therefore, the space heaters are not a potential cause of fire (and SGTS unavailability) when the SGTS is required to meet the licensing-basis release limits (and presumably inaccessible for repair).

Note that the space heaters each have a small fan which better distributes the heat and minimizes local warming by providing a more uniform temperature throughout the filter housing. This uniform heating further reduces the risk of fire by lowering local temperatures around the space heater and by improving the accuracy of the temperature measurements (used to detect high temperature) taken at necessarily discrete points within the filter housing.

(4) Degradation of the charcoal effectiveness between charcoal efficiency surveillance tests is not likely to occur. During normal operation, the filter is isolated, and valves upstream and downstream of the filter train are closed. DAMPERS Therefore, during SGTS standby, the potential for impurities entering the filter train and unacceptably reducing charcoal efficiency is small.

The ABWR SGTS charcoal bed thickness has been increased 5 cm to 15 cm as compared to the GESSAR II design. The additional 5 cm of charcoal provide an effective measure of protection against weathering or aging effects when the SGTS is placed into operation.

In addition to the increased charcoal bed depth, significantly more charcoal is provided than is required to meet the 2.5 mg iodine per gram carbon requirement. This added charcoal is used to meet the requirement specifying a residence time of 0.25 sec per 5 cm of bed depth. Approximately 332 kg of charcoal is required based on iodine loading calculated per Regulatory Guide 1.3 requirements, a 100% efficient charcoal adsorber, and no MSIV leakage. The SGTS charcoal adsorber is required to meet a 732 m/hr face velocity, which results in a normal 794 kg of charcoal assembly using a conservatively high 561kg/m^3 charcoal density with 6800 m^3/hr fan size, meeting the 0.25 sec per 5 cm of bed depth (732 m/hr) requirement of Regulatory Guide 1.52 (Position C.3.i), and using a conservatively high 561kg/m^3 charcoal density. The weight of charcoal will be adjusted to be consistent with the purchased charcoal density (usually less than 481 kg/m^3) and any dead space in the adsorber section itself.

THIS SHOULD BE "NOMINAL 794 kg"

Building ventilation exhaust radiation monitors during de-inerting, SGTS may be placed into service.

If purging (i.e., de-inerting) through the HVAC will [or does] result in a trip from the ventilation exhaust radiation monitors, then de-inerting will be [re-]initiated at a reduced rate through the SGTS. Use of SGTS during de-inerting is expected to be infrequent.

The design basis condition for the relevant dose analyses assumes that the large ventilation valves are closed, because the probability of a LOCA occurring at the same time the ventilation valves are open is very small. The large ventilation valves are, in fact, closed throughout normal plant operation except during inerting and de-inerting. The LOCA dose analyses do not assume any release from open containment isolation valves, either through the SGTS or through the normal ventilation system.

A realistic assessment of plant capability in support of the exclusion indicates that the ventilation valves, if open, would be isolated before significant fission products are transported to the containment atmosphere. "Significant" means fission products above that normally present in the primary system. A period much longer than the closing time of the ventilation valves would be required to generate conditions leading to the release of TID 14844-like source terms. Therefore, should a LOCA occur when the ventilation valves are open (valves expected to be open only during inerting or de-inerting), little fission product release to the environment would actually occur. Therefore, the plant design and analysis in this regard is conservative and bounds releases actually expected in the event of a LOCA.

CHANGE "VALVES" TO "DAMPERS"

6.5.1.4 Tests and Inspection

The SGTS and its components are periodically tested during construction and operation. These tests fall in three categories:

(1) Environmental qualification tests

(2) Acceptance tests as defined in ASME N509 and N510

(3) Periodic surveillance tests

The above tests are performed in accordance with the objectives of Regulatory Guide 1.52 and its references. Acceptance tests (including pre-operational tests) and periodic surveillance tests are defined and extensively described in ASME N509 and ASME N510. Testing requirements in ASME N509 are generally located in Section 5, "Components." ASME N510 provides details of each component functional test. These tests are summarized in Table 9-1 of ASME N509 and Table 1 of ASME N510. Specific surveillance testing requirements for SGTS are provided in Technical Specification 3.6.4.3 (Chapter 16). Environmental qualification testing is discussed in

Section 3.11 and is applicable to SGTS components. Dynamic qualification is addressed in Sections 3.9 and 3.10 for Seismic Category I equipment.

6.5.1.5 Instrumentation

Appendix 6B provides a discussion of the instrumentation for the SGTS. Control and instrumentation for the SGTS is also discussed in Subsections 7.3.1.1.5 and 7.3.2.5.

6.5.1.6 Materials

The construction materials used for the SGTS are compatible with normal and accident environments postulated for the area in which the equipment is located. The construction materials used in the dryer and filter trains are consistent with the recommendations of Regulatory Guide 1.52 and its references.

6.5.1.7 Operability and Effectiveness

Efficiency in the usual sense, can not be measured for adsorption systems. Adsorption is time dependent and therefore instantaneous containment-removal efficiency is meaningless. True efficiency tests are run on small, representative samples (test canisters) of the adsorbent using a radioactivity tagged tracer gas having similar properties and composition of those of the containment of interest (e.g., radioactive elemental iodine or methyl iodine). Because of the difficulty in handling radioactive materials, this type of test is generally not made in the field. The in-place field tests of installed systems are leak tests only. The iodine removal efficiency tests are carried out in a laboratory duplicating the field conditions as closely as possible.

The double filter train design for the SGTS depends on stationary components for normal (Routine) and accident operation. The pre-filter assembly is filled with glass fibers as are the pre and after HEPA filters. The charcoal iodine adsorber bed is located between the HEPA filters. All are located in a welded housing making up the filter train. The redundant active space heaters and fans operate only in the standby mode of the SGTS to dry the charcoal and maintain low relative humidity in the sealed train. Readiness for design operation is assured by effective surveillance tests.

The filter train availability depends on the stationary components replacement. The filter fiber glass sections are modularized for ease in handling. The charcoal is replaced by dumping old charcoal from below the bed and refilling with new charcoal from above. The integrity of the charcoal bed structure is maintained by limiting the moisture content of the charcoal in standby. The charcoal bed is oversized to reduce heating and weathering or aging effects. The bed has 795 kg of charcoal and is 150% thick over the calculated 335 kg required for adequate adsorber saturation and combustion protection.

OK IF P. 6.5-6 IS CHANGED TO NOMINAL 794 kg.

Section 2.14.4 **Comment No.** 1

Comment:

ITAAC item 6 does not clearly differentiate between test criteria and acceptance criteria applicable to: 1) Laboratory testing of charcoal absorbers, 2) Inplace testing of HEPA filter removal efficiency, and 3) inplace testing of charcoal adsorber bypass leakage.

Resolution:

Do not concur. Item 6 clearly states removal efficiency is for iodines (not for HEPA/particulates.) Only a laboratory test can determine this efficiency (i.e., not bypass leak test).

Section 2.14.4 **Comment No.** 2

Comment:

ITAAC item 6 acceptance criteria does not agree with the SSAR table 6.5-1. ITAAC = 99% removal efficiency while SSAR states greater/equal to 99.9% for HEPA and greater/equal to 99.825% for iodine.

Resolution:

10 CFR 100 requirement is 99%. Must have lab test at 99.825 to show 99% in plant. By policy the criteria are consistent with the staff's review acceptance criteria, <u>not</u> the values states in the SSAR.

Section 2.14.6 **Comment No.** 1

Comment:

CDM 2.14.6 last paragraph stated that the COPS pneumatic actuated valves (F007 & F1010 on P&ID 6.2-39 SH 1 of 3) have active safety-related functions. SSAR Table 3.9-8 listed these valve function as "PASSIVE."

Resolution:

Disagree. The valves are listed as passive iin Table 3.9-8 because they don't have automatic isolation signal. The CDM lists the valves as active safety-related because following COPS actuation, the operator could use these valves to stop the venting of containment.

Section 2.14.6 **Comment No.** 2

Comment:

See comments on attached Figure 2.14.6.

Resolution:

Disagree.

Section 2.14.6 **Comment No.** 3

Comment:

Level detectors shown on Figure 2.14.6 transmit suppression pool water level to support the following systems:

a) High Pressure Core Flooder (HPCF)
b) Reactor Core Isolation Cooling (RCIC)
c) Suppression Pool Temperature Monitoring (SPTM).

A statement or note to this effect should be included in this CDM.

Resolution:

Disagree. Not Tier 1 material. GE has avoided including explanatory information in the CDM (other than a description of overall system function). The focus of the CDM is verification, not explanation. Therefore, descriptive information of individual component functions has been excluded from the CDM. Explanation of the function of the pool level detectors is beyond the scope of the CDM. A functional description of the individual components can be found in the SSAR.

Section 2.14.6 **Comment No.** 4

Comment:

SSAR Table 6.2-7 pages 6.2-149 & 150:

a) valves T31-F32A/B and T31-F734A/D are listed as gate valves and are equipped with solenoid/electric operators. P&ID 6.2-39, Sheet 3 of 3 showed these as manually operated globe valves.

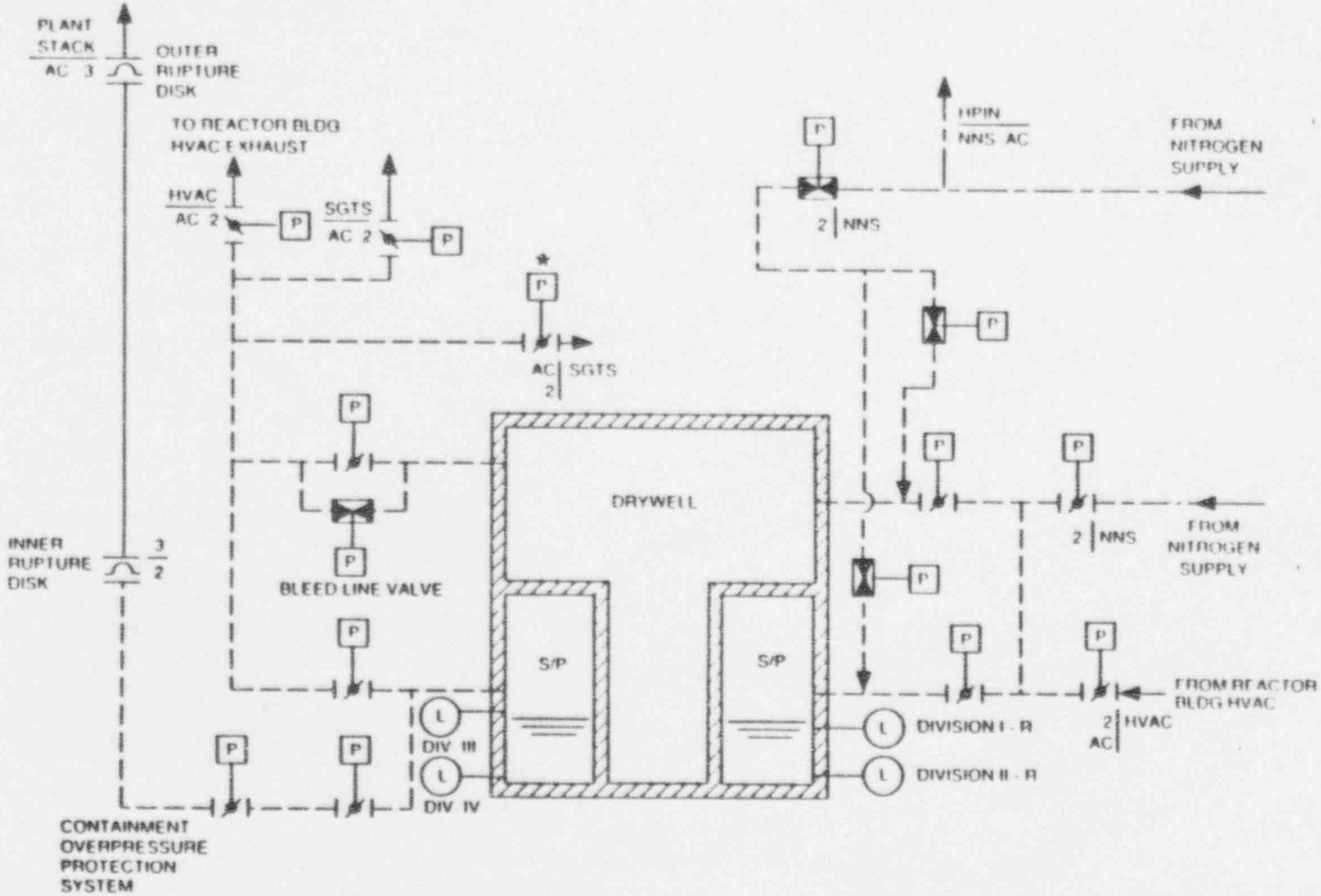
b) valves T31-F737A-D implies 4 valves whereas on P&ID, only valves A & B are shown.

Resolve discrepancies.

Resolution:

GE agreed to provide clarification in the SSAR.

2.14.6(?)



NOTES
1 INBOARD CONTAINMENT ISOLATION VALVES ARE POWERED FROM CLASS 1E DIVISION II OUTBOARD CONTAINMENT ISOLATION VALVES ARE POWERED FROM CLASS 1E DIVISION I EXCEPT AS NOTED WITH "★", WHICH IS POWERED FROM CLASS 1E DIVISION III
2 THE COPS FLOW PATH FROM THE PRIMARY CONTAINMENT TO THE PLANT STACK HAS NO VALVES OTHER THAN THOSE SHOWN ON THE FIGURE
3 THE ACS HAS PROVISIONS FOR SUPPLYING NITROGEN TO THE COPS PIPING BETWEEN THE INNER AND OUTER RUPTURE DISKS

AC SYSTEM

Figure 2.14.6 Atmospheric Control System

Section 2.14.7 Comment No. 1

Comment:

Figure 2.14.7: see comments as noted.

Resolution:

Drywell cooling system is non-safety related system. It provides sufficient diversity and flexibility without tagging the fan coil units and their cooling water sources which are non-safety related. ITAAC Figure 2.14.7 does not warrant any changes.

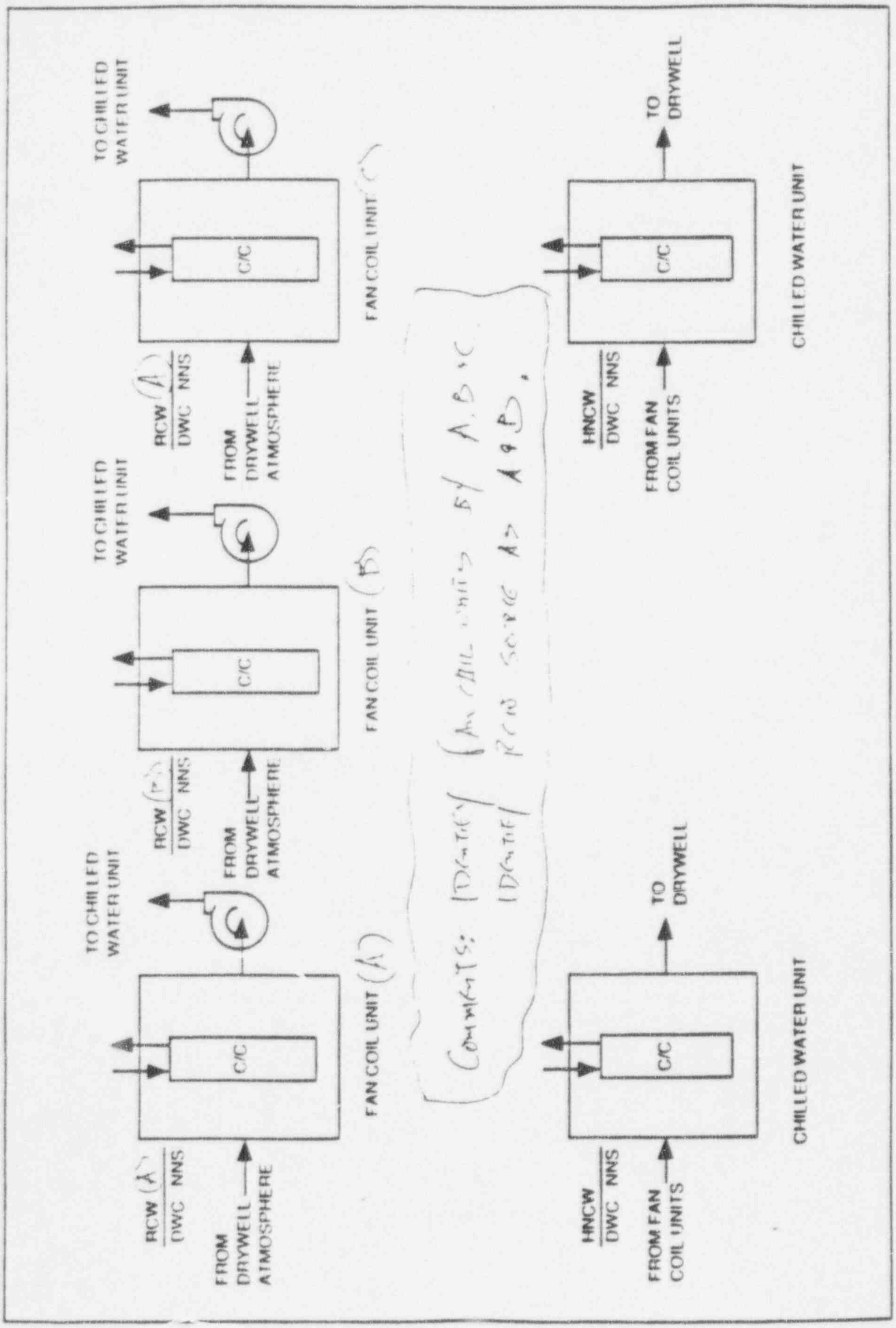


Figure 2.14.7 Drywell Cooling System

Section 2.14.8 **Comment No.** 1

Comment:

ITAAC items # 3 and 5, Class 1E division and main control room displays and controls, respectively, are not addressed in SSAR section 9.5. That information should be incorporated into the appropriate SSAR section.

Resolution:

Disagree. FCS is not discussed in Section 9.5.

Section 2.14.8 **Comment No.** 2

Comment:

The CDD describes how the FCS component interfaces with the Remote Shutdown System. Figure 2.14.8 needs to be revised to reflect the RSS interfaces.

Resolution:

GE agreed to make the changes.

Section 2.14.8 **Comment No.** 3

Comment:

The CDD describes the cooling water requirements for operation of the FCS after a LOCA. Figure 2.14.8 needs to be revised to reflect the RHR interface with the FCS.

Resolution:

GE agreed to make the changes.

Section 2.14.9 **Comment No.** 1

Comment:

SSAR figure 7.6-12 (sheet 6) indicates that suppression pool high temperature will initiate RHR S/P cooling or RCW load shedding. This function should be verified in ITAAC and described in the design description.

Resolution:

Disagree. RHR CDM 2.4.1 states that suppression pool cooling is manually initiated. SSAR states the suppression pool cooling auto initiation is not credited in safety analysis.

Section 2.15.5 Comment No. 1

Comment:

Revise CDM 2.15.5, page 2.15.5-12 to include ITAAC "Table 2.15-5b" description.

Resolution:

GE agreed to make the changes.

Section 2.15.5 Comment No. 2

Comment:

DD describes the High Radiation mode with a positive pressure of at least 3.2 mm WG from CRHA to outside and not more than 360 m3/hr flow of outside air. The SSAR has 6.4mm WG and at least 360 m3/hr. Section 9.4.1.1.6 page 9.4-5, 3rd paragraph.

Resolution:

Revise SSAR Section 9.4.1.1.6 on page 9.4-5 to state "3.2 mm" not "6.4 mm" WG positive pressure. The staff has identified this discrepancy in its comments previously, and therefore this was a duplicate comment. GE fixed SSAR value in Amendment 34.

Section 2.15.5 Comment No. 3

Comment:

Figure 2.15.5a has an instrument as DP and should be dP and an additional valve on the MCAE exhaust as shown on attached sheet.

(Task Group:) Revise ITAAC figure 2.15-5b to state "dP" not "DP" for differential instrumentation. SSAR Rigure 9.4-1 shows "M.O. F012" for each division. No change to ITAAC Figure 2.15.5a is needed.

Resolution:

GE agreed to make the changes.

Section 2.15.5 **Comment No.** 4

Comment:

Revise ITAAC Table 2.15.5d, Item 10, to state "Section 2.15.5" not "Section t14".

Resolution:

GE agreed to make the changes.

Section 2.15.5 **Comment No.** 5

Comment:

DD indicates Normal Operating Mode of CBSREA will maintain temperature below 40 C. SSAR indicates temperatures between 40 C and 10 C. Section 9.4.1.2.2 paragraph (4), page 9.4-6.

Resolution:

During ITAAC review, it was determined that minimum temperature didn't need to be in ITAAC. "Below 40 degrees C" limit in CDM bounds the 10 degree C lower limit of the Tier 2 document. Should the temperature fall below 10 degrees C, the applicant will bring in portable heaters to maintain the temperature. The staff found this to be acceptable. Should the applicant want to change the lower limit, the 50.59 process provides more flexibility to implement this change than does the Part 52 process.

Section 2.15.5 **Comment No.** 6

Comment:

DD does not indicate that the CBSREA intake fans are sized to provide positive pressure above outside air. SSAR Section 9.4.1.2.1 paragraph (5). Also, no ITAAC item.

Resolution:

Positive pressure maintenance is meant for clean environment. CBSREA HVACS is not manned continuously during accident conditions and has no ESF filtration requirements to meet GDC 19. Therefore, Tier 2 information is adequate. No Tier 1 changes required.

Section 2.15.5 Comment No. 7

Comment:

DD does not indicate that a positive pressure is maintained above outside air by fan sizing. SSAR 9.4.5.4.1.1 page 9.4-23. Also, no ITAAC.

Resolution:

Positive pressure maintenance is meant for clean environment. R/B SREE HVACS is not manned continuously during accident conditions and has no ESF filtration requirements. Therefore, Tier 2 information is adequate. No Tier 1 changes are required.

Section 2.15.5 Comment No. 8

Comment:

DD does not indicate auto start of standby fan and alarm in the control room. SSAR Section 9.4.5.4.5 page 9.4-25. Also, no ITAAC item for test.

Resolution:

R/B SREE HVACS Tier 2 information is judged adequate to provide a controlled environment to ensure the continued operation of safety-related equipment under accident conditions. R/B SREE HVACS of each division are started manually. No Tier 1 changes required.

Section 2.15.5 Comment No. 9

Comment:

DD does not include prefilters and high efficiency filters. SSAR Section 9.4.6.2.1 and 9.4.6.2.2. page 9.4-32.

Resolution:

RWB HVACS is a non-safety related system. Tier 2 information is judged adequate. No Tier 1 changes are required. The basic configuration ITAAC provides inspections of the as-built design.

Section 2.15.5 Comment No. 10

Comment:

DD does not indicate that the controls and alarms are in the control room. SSAR Section 9.4.5.8.5. page 9.4-31. Also, no ITAAC item.

Resolution:

PIR ASD HVACS is a non-safety related system. Tier 2 information is judged adequate. Basic configuration ITAAC provides inspection of the as-built system. No Tier 1 changes are required.

Section 2.15.5 Comment No. 11

Comment:

DD indicates that the system has two recirculating air conditioning units with cooling coils and four fans. SSAR two units with each having cooling coils and two fans. Section 9.4.5.8.2, page 9.4-30.

Resolution:

SSAR Section 9.4.5.8.2 states that each division has a cooling coil and two fans. Tier 1 design description combines both divisions by stating that the system consists of two ACUs (one per division) and has (two) cooling coils and four fans (each ACU has a cooling coil and two fans). There is no inconsistancy in CDM design description on page 9.4-30.

Section 2.15.5 Comment No. 12

Comment:

Revise CDM design description on page 2.15.5-7 to state "On receipt of a DG start signal, both DG supply fans start. A space thermostat controls allow at least one fan in operation."

Resolution:

GE agreed to make the appropriate changes.

Section 2.15.5 Comment No. 13

Comment:

Revise ITAAC figure 2.15.5j to state "dP", not "DP" for the differential pressure instrument.

Resolution:

GE agreed to make the changes.

Section 2.15.5 Comment No. 14

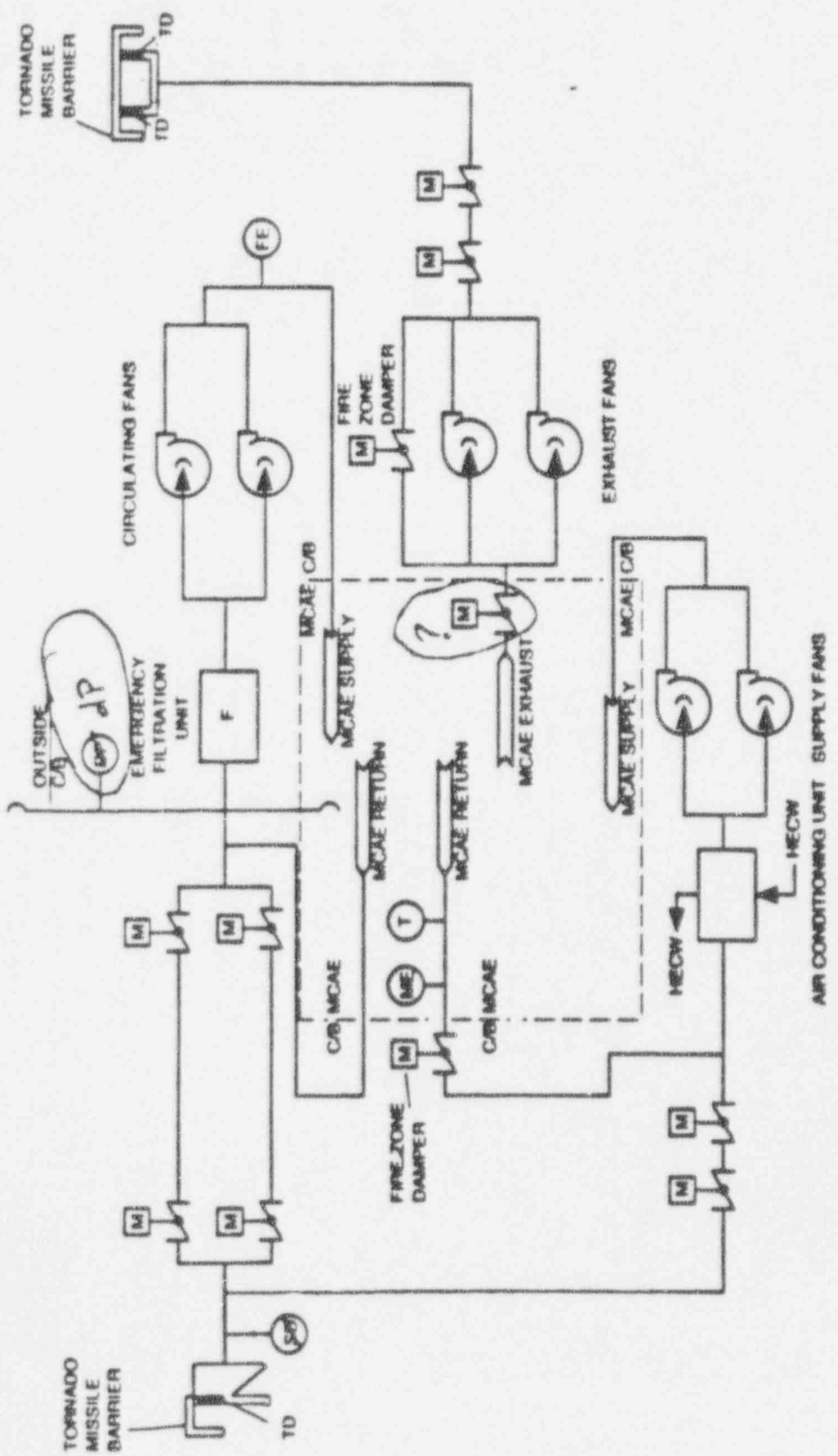
Comment:

Revise SSAR section 9.4.5.1.1.2 to state "A negative pressure of 6.4 mm water gauge is normally maintained in the secondary containment relative to the outdoor atmosphere" as stated in SSAR section 6.5.1.3.1, 1st paragraph.

Resolution:

GE agreed to make the changes.

2.15.5(3)



NOTES:
1. THIS FIGURE SHOWS ONE OF TWO IDENTICAL DIVISIONS. ELECTRICAL POWER LOADS FOR THE COMPONENTS OF DIVISION B ARE POWERED FROM CLASS 1E DIVISION II. ELECTRICAL POWER LOADS FOR THE COMPONENTS OF DIVISION C ARE POWERED FROM CLASS 1E DIVISION III.

Figure 2.15.5a Control Room Habitability Area HVAC System

Section 2.15.5 **Comment No. 1**

Comment:

ITAAC item 2 does not clearly differentiate between criteria applicable to 1) laboratory testing of charcoal adsorbers, 2) inplace testing of HEPA filter removal efficiency and 3) inplace testing of charcoal adsorber bypass leakage.

Resolution:

Same comment as No. 1 of ITAAC 2.14.4.

Section 2.15.5 **Comment No. 2**

Comment:

ITAAC item 2 acceptance criteria does not agree with SSAR table 6.5-1. ITAAC states greater/equal to 99% while the SSAR states greater/equal to 99.9% for HEPA and greater/equal; 99.825 for iodine.

Resolution:

Same comment as No. 2 of ITAAC 2.14.4.

Section 2.15.5 **Comment No. 3**

Comment:

The design description references 95% removal efficiency for iodines. This value appears low.

Resolution:

The system has only 2 inch thich charcoal adsorbers, which is consistent with 95% removal per RG 1.52. Also, 95% removal is consistent with radiological consequence assessment in the FSER.

Section 2.15.6 **Comment No.** 1

Comment:

ITAAC item #3 includes minimum flows for the Reactor and Control Buildings. The SSAR, section 9.5.1.3.2, Fire Suppression System Requirements, specifies the Reactor Building. Resolve discrepancy.

Resolution:

GE agreed to make the changes to the SSAR as described in the enclosure. NRC agreed with GE's disposition.

Section 2.15.16 **Comment No.** 2

Comment:

ITAAC item #5 requires that the sprinkler system and standpipe for the Reactor and Control Building remain operable following an SSE. The SSAR does not mention a sprinkler system for the Control Building.

Resolution:

Disagree. See Section 9.5.1.3.2.

Section 2.15.6 **Comment No.** 3

Comment:

ITAAC item #4 requires that the day tank rooms include automatic foam-water extinguishing systems and SSAR section 9.5.1.3.7 does not specify this.

Resolution:

Disagree. See section 9.5.1, page 9.5-1.

Section 2.15.6 **Comment No.** 4

Comment:

ITAAC item #6 requires non-Class 1E uninterruptible power supply for the fire detection and alarm systems. (1) Section 9.5.1.3.9, Fire Alarm System, does not address electrical power supply requirements for the alarm systems (Fire detection systems are not addressed either). (2) How many hours should the UPS supply power to the fire detection and alarm systems?

Resolution:

Disagree. See section 9.5.1.3.7.

Section 2.15.6 **Comment No.** 5

Comment:

The main control room alarms and displays are not defined in the SSAR, Chapter 9.5, as described in ITAAC #7.

Resolution:

Disagree. See section 9.5.1.3.7.

Section 2.15.7 Comment No. 1

Comment:

There is no Tier 1 material for the Leak Detection Instrumentation and Monitoring system described in SSAR 5.2.5.2. Tier 1 section 2.4.3 should cover this.

Resolution:

Disagree. The staff has reviewed and determined that SSAR 5.2.5.2 needs to be included in Tier 2, not in Tier 1. The key aspects of the ABWR Leakage Detection Systems that deserve Tier 1 verification are the initiation and isolation functions associated with the system. These verifications are performed in Section 2.4.3 of the CDM. Verification of monitoring functions are more appropriate for Tier 2.

Section 2.15.10 **Comment No.** 1

Comment:

The only item in Section 2.15.10 to be alarmed and displayed in the main control room is the water tight doors on the ECCS rooms for open or closing only. Why the alarms different than what was provided for the Control Building?

Resolution:

Disagree. The requirements on the watertight doors in both the reactor and control buildings are consistent. Both have open/close sensors, status indication, and alarms in the main control room.

Section 2.15.14 **Comment No.** 1

Comment:

The Service Building (S/B) is located next to the Control Building (C/B), therefore the failure of the S/B during seismic event should be verified to not damage the functionality of the C/B.

Resolution:

Disagree. Non-seismic-to-seismic (II/I) interaction is not verified by ITAAC at the design certification state. However, II/I will be a COL ITAAC.

Section 2.15.14 **Comment No.** 2

Comment:

A structural analysis should be performed to reconcile the as-built data with the structural design basis and to verify that SSE ground acceleration will not result in impaired safety function. Add ITAAC similar to 2.15.11 #2 to Table 2.15.14.

Resolution:

Disagree. Because the service building is non-safety related, any II/I interaction will be addressed at the COL stage.

Section 2.16.1 **Comment No.** 1

Comment:

The stack is located on top of the reactor building and it reaches a height of 76 meters above grade. Since it is located so close to many safety related systems, structures, and components, has it been seismically analyzed so that its failure during seismic event will not jeopardize the safety function of the others?

Resolution:

No. The stack dimensions will vary according to each site and is considered non-safety related. Therefore, it will be completed by the COL licensee and the seismic design will be considered in the COL II/I program.

Section 2.16.2 **Comment No.** 1

Comment:

The Emergency DG day tank capacities stated in 2.16.2 and in SSAR sections 9.5.4.2 and 8.3.1.1.8.2 (7) are inconsistent.

Resolution:

Disagree. The 4 hour capacity comes from EPRI URD and is the ITAAC value. SSAR value of 8 hours is what the design will be.

Section 2.16.2 **Comment No.** 2

Comment:

The displays and controls of the OST system that are required to be on the main control room panels are not listed in Table 2.7.1a of the certified design material.

Resolution:

Disagree. Minimum inventory of displays and controls comes from EOP Task Analysis & PRA. Items on this list do not need to be shown on CDM figures. It they are not on the list, and it was determined the I & C are needed to be in CDM, then they are shown on the CDM figure as was done here.

Section 3.1 Comment No. 1

Comment:

The design description (p. 3.1-1) defines the HSI scope as applying to the MCR and the RSS. The HSI scope does not include local control panels (LCPs). Failure to include the LCPs is contrary to operating experience, i.e., human error at LCPs has resulted in unnecessary challenges to plant safety systems.

Resolution:

Disagree. This is beyond the scope of Chapter 18 of the SRP. Local control stations are covered under USIs and GSIs and is therefore a COL information requirement item.

Section 3.1 Comment No. 2

Comment:

SSAR 18E.2.7 (p. 18E-4) states that plant and emergency operating procedures will be developed to support and guide human interactions . . . The 3.1 design description does not address procedure development. Procedure development should be addressed in the Section 3.1 design description.

Resolution:

Disagree. Verification and validation (V&V) will be done using completed procedures. V&V is covered under Tier 1 Section 3.1. Procedures are a COL information requirement item.

Section 3.1 Comment No. 3

Comment:

Design acceptance criteria 1.b.(1), (p. 3.1-4) states that the HFE program plan shall establish methods and criteria for HSI design, development, and evaluation. What are the acceptance methods and criteria? Revise 1.b.(1) to include a statement, consistent with SSAR Table 18E-1, Section II(1)(a).

(Task Group:) Send the following to GE: Design acceptance criteria 1.b.(1) on page 3.1-4 should have the following words (from the SSAR) added "... in accordance with accepted human factors practices and principles."

Resolution:

GE agreed to make the changes.

Section 3.1 Comment No. 4

Comment:

SSAR Table 18E-1, Section (II)(2)(e)(ii)(a), (p. 18E-13) states that an operating experience review is not required if a previously implemented ABWR design is utilized. Revise SSAR to require an operating experience review. In the defined case it would be the best source of operating experience input.

Resolution:

Disagree. This is just an SSAR change, however, it cannot be made because Part 52 is limited to a one time review leading to certification. An OER, as discussed in the comment, would lead to a separate review by NRC for each additional ABWR that would be built.

Section 3.1 Comment No. 5

Comment:

Design acceptance criteria 2.a.(1), (p. 3.1-7). Same problem identified in comment 3. Lacks the specificity needed for a judgement of acceptability. Propose same resolution as identified in comment 3.

(Task Group:) Design acceptance criteria 2.a(1) on page 3.1-7 should add the following words (from the SSAR) "... in accordance with accepted human factors practices and principles."

Resolution:

GE agreed to make the changes.

Section 3.1 Comment No. 6

Comment:

Apply Comment No. 5 to 3.a(1)

Resolution:

GE agreed to make the changes.

Section 3.1 Comment No. 7

Comment:

Apply Comment No. 5 to 4.a(1)

Resolution:

GE agreed to make the changes.

Section 3.1 **Comment No.** 8

Comment:

SSAR Table 18E-1, Section V(2)(d), (p.18E-23) states that the Task Analysis Implementation Plan shall establish the methods for identification of critical tasks. Design acceptable methods are established.

Resolution:

Disagree. Acceptance criteria is contained at the Tier 2 level, which is appropriate.

Section 3.1 **Comment No.** 9

Comment:

Apply Comment No. 5 to 5.a(1)

Resolution:

GE agreed to make the changes.

Section 3.1 **Comment No.** 10

Comment:

Design acceptance criteria 5.a(1) should delete the word "equipment" so that HSI is not limited to equipment.

Resolution:

GE agreed to make the changes.

Section 3.1 **Comment No.** 11

Comment:

Design acceptance criteria 5.a.(5), (p.3.1-13) should be revised to include SSAR Table 18E-1, Section VI.1(f)(ii), (p.18E-26). The purpose of the proposed revision is to ensure that critical tasks are evaluated using dynamic simulations and HSI prototypes.

Resolution:

Disagree. Comment referred to HSI, however, dynamic simulations are a requirement under V&V.

Section 3.1 **Comment No.** 12

Comment:

Apply Comment No. 5 to 6.a(1)

Resolution:

GE agreed to make the changes.

Section 3.1 **Comment No.** 13

Comment:

Design acceptance criteria 6.a.(4), page 3.1-15, correct typo to change "ask" to "task".

Resolution:

GE agreed to make the changes.

Section 3.1 **Comment No.** 14

Comment:

Revise design acceptance criteria 6.a., (p.3.1-14) to include SSAR Table 18E-1, Section VII(1)(i), (p. 18E-30) so as to ensure that the human factors verification and validation plan establishes the methods and criteria to be used to evaluate the adequacy of the operating technical procedures.

Resolution:

Disagree. V&V (in Tier 1) will be done using completed procedures. Procedures are a COL information requirement item.

Section 3.1 **Comment No.** 15

Comment:

SSAR page 18C-1, paragraph 1 references section 18.5 (Operator Interface Design Implementation Requirements). This appears to be an incorrect reference. Section 18.5 is Remote Shutdown System.

Resolution:

GE agreed to make the changes.

Section 3.2 Comment No. 1

Comment:

ITAAC item 2 the statement "greater than 0.1 per year" needs to be quantified. This similarly needs to be clarified in the design description.

Resolution:

Disagree. The statement "greater than 0.1 per year" is the quantitative value for the term significant leakage (i.e., leakage probability).

Section 3.2 Comment No. 2

Comment:

ITAAC item 1.b(1) does not state the correct analysis computer code, "QAD" should be "QADF".

Resolution:

Disagree. The ITAAC reflects our acceptance criteria (consistent with the SRP) the ABWR SSAR can specify a value, or in this case a version of the code, that is encompassed by the acceptance criteria. By policy we are not holding the applicant to the SSAR but giving them the flexibility of the design margin where appropriate.

Section 3.2 Comment No. 3

Comment:

ITAAC item 1.b(2) does not state the correct analysis computer code, "DORT or TORT" should be DOT4.4" (per SSAR).

Resolution:

Disagree. See No. 2 above.

Section 3.2 Comment No. 4a

Comment:

Inconsistent use of solid and dotted lines to identify radiation zones.

Resolution:

Disagree. Comment 12.3 is correct, the reactor and control buildings are dotted lines and the radwaste and turbine buildings are solid lines. However, the radiation zones are clearly identified.

Section 3.2 Comment No. 4b

Comment:

SSAR section 12.3.2.3 alludes to an Area Monitor in the spent fuel pool cleanup room. Could not locate one on the P&IDs or on the ARM equipment list.

Resolution:

GE agreed to make the changes to the SSAR.

Section 3.2 Comment No. 4c

Comment:

SSAR section 12.3.2.2.1(10), 1st sentence, "gr/cm3" should read "gm/cm3".

Resolution:

GE agreed to make the change.

Section 3.2 Comment No. 4d

Comment:

See markup to correct typos on attached section 12A.

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 3.2 Comment No. 4e

Comment:

Says that the maximum permissible offgas rate is 400,000 uCi/sec. SSAR Section 16, TS Surveillance 3.76 also established a release rate of 400,000 uCi/sec as a limiting condition of operation for the offgas system. However, SSAR Section 12.3.2.2.2 establishes 100,000 uCi/sec as the release rate used in the design of the plant shielding. This is a serious inconsistency and should be rectified and the proper bases reflected in SSAR Sections 15.7, 11.1.1.2, 12.3.2.2.2; the Tss; and the ITAAC.

Resolution:

Disagree. Comment 15.7: The 400,000 uCi/sec is a maximum instantaneous release rate assumed for evaluating Offgas System failure and is included in the TS, where the 100,000 uCi/sec is an annual-average offgas release rate design basis for radiation protection design features.

Section 3.2 Comment No. 4f

Comment:

SSAR Section 12.3.4.3, 3rd paragraph is confusing - "point" should be changes to "any point".

Resolution:

GE agreed to make the changes as described in the enclosure.

Section 3.2 Comment No. 4g

Comment:

5th sentence is misworded - should state "full flow cleanup".

Resolution:

Comment 12.4: The water chemistry in this sentence refers to the 2% CUW system not the condensate clean-up.

Section 3.2 Comment No. 4h

Comment:

SSAR Table 15.7.1 should be revised to indicate 400,000 uCi/sec Offgas Release Rate, 100,000 uCi/sec Design Basis Rate and 400,000 uCi/sec Maximum TS instead of the current 400,00; 100,00; and 400,00 uCi/sec respectively.

Resolution:

GE agreed to make the changes.

12A Appendix 12A Calculation of Airborne Radionuclides

12A.1 Calculation of Airborne Radionuclides

This appendix presents a simplified methodology to calculate the airborne concentrations of radionuclides in a compartment. This methodology is conservative in nature and assumes that diffusion and mixing in a compartment is basically instantaneous with respect to those mitigating mechanisms such as radioactive decay and other removal mechanisms. The following calculations need to be performed on an isotope-by-isotope basis to verify that airborne concentrations are within the limits of 10CFR20:

(1) For the compartment, all sources of airborne radionuclides need to be identified such as:

(a) Flow of contaminated air from other areas

(b) Gaseous releases from equipment in the compartment

(c) Evolution of airborne sources from sumps or water leaking from equipment

(2) Second, the primary sinks of airborne radionuclides need to be identified. This will primarily be outflow from the compartment but may also take the form of condensation onto room coolers.

(3) Given the above information the following equation will calculate a conservative concentration.

$$C_i = \frac{1}{V}\sum_j \frac{S_{ij}}{\left(\lambda_i + \sum_k R_{ijk}\right)}$$

Where:

C_i = Concentration of the i^{th} radionuclides in the room

V = Volume of room

S_{ij} = The j^{th} source (rate) of the i^{th} radionuclide to the room. These sources are discussed below.

R_{ijk} = The k^{th} removal constant for the j^{th} source and the i^{th} radionuclide as discussed below.

λ_i = Radionuclide decay constant

Evaluation Parameters

The following parameters require evaluation on a case-by-case basis dictated by the physical parameters and processes germane to the modeling process:

(1) S_{ij} is defined as the source rate for radionuclide i into the compartment. Typically, these sources take the form of:

(a) Inflow of contaminated air from an upstream compartment. Given the concentration of radionuclide i, c_i, in this air and a flow rate of "r", the source rate then becomes $S_{ij} = rc_i$.

(b) Production of airborne radionuclides from equipment. This typically takes two forms, gaseous leakage and liquid leakage.

(i) For gaseous leakage sources, the source rate is equal to the concentration of radionuclide i, c_i, and the leakage rate, "r", or $S_{ij} = rc_i$.

(ii) For liquid sources, the source rate is similar but more complex. Given a liquid concentration c_i and a leakage rate, "r", the total release from the leak is rc_i. The fraction of this release which then becomes airborne is typically evaluated by a partition factor, P_f which may be conservatively estimated from:

Noble Gases

$$P_f = 1$$

All others

$$P_f = \frac{h_t - h_f}{h_s - h_f}$$

where:

h_t = Saturated liquid enthalpy

h_f = Saturated liquid enthalpy at one atmosphere = 100.10 kcal/kg

h_s = Saturated vapor enthalpy at one atmosphere = 639.18 kcal/kg

Therefore, the liquid release rate becomes, rc_iP_f.

(2) R_{ijk} is defined as the removal rate constant and typically consists of:

(a) Exhaust rate from the compartment. This term considers not only the exhaust of any initially contaminated air, but also any clean air which may be used to dilute the compartment air.

(b) Compartment filter systems are treated by the equation:

$$R_{ijk} = (1-F_i)^* r_i$$

where

r_i = Filter system flow rate

F_i = Filter efficiency for radionuclide i

(c) Other removal factors on a case-by-case basis which may be deemed reasonable and conservative.

Example Calculation

(Values used below are examples only and should not be used in any actual evaluation.) This example will look at I-131 in a compartment $6.1 \times 6.1 \times 7.6 = 282.80\ m^3 = V$. First, all primary sources of radionuclides need to be identified and categorized.

(1) Flow into the compartment equals 424.8 m^3/hr with the input I-131 concentration equal to $2 \times 10^{-10}\mu Ci/ml$ (from upstream compartments) or $2.4 \times 10^{-11} Ci/sec$. No other sources of air either contaminated or clean air are assumed.

(2) The compartment contains a pump carrying reactor coolant with a maximum specified leakage rate of 0.000034 m^3/hr at 273.6°C.

(a) Conservatively it can be estimated based upon properties from steam tables (Note 1) that under these conditions 44% of the liquid will flash to steam and become airborne. Along with the flashing liquid, it is assumed that a proportional amount of I-131 will become airborne; therefore, $P_f = 0.44$.

(b) Using the design basis iodine concentrations for reactor water from Table 11.1-2 of 0.016μ Ci/gm of I-131, it is calculated that the pump is providing a source of I-131 of $5.0 \times 10^{-11} Ci/sec$ to the air (Note 2).

Second, the sinks for airborne material need to be identified. This example includes only exhaust which is categorized as flow out of the compartment at 150% per hour or 4.2×10^{-4} per second.

Therefore, for an equilibrium situation, the I-131 airborne concentration from this liquid source would be calculated from the following equation:

$$\lambda C = \frac{1}{V} S_1/(\lambda + R_1) + S_2/(\lambda + R_2)$$

where

V = Room volume = 28280 m^3

S_1 = Source rate in Curies per second = 5.0×10^{-11} Ci/sec from liquid

S_2 = Source rate from inflow = 2.4×10^{-11} Ci/sec

λ = Isotope decay constant in units per second = 9.977×10^{-7}/sec

R_1 = R_2 = removal rate constant per second (exfiltration) = 4.2×10^{-4} per second

λC = 6.2×10^{-10} µCi/ml of I-131.

NOTE:

(1) The assumption of 44% flashing at 273.6°C is extremely conservative; see Reference 12A-1 for a discussion of fission product transport.

(2) Water density assumed at 0.743 gm/cm³ based upon standard tables for water at 273.6°C.

12A.2 References

12A-1 Paquette, et al, *Volatility of Fission Products During Reactor Accidents*, Journal of Nuclear Materials, Vol 130 Pg 129–138, 1985.

Section 3.3 **Comment No.** 1

Comment:

Correct attached CDM typo.

Resolution:

GE agreed to make the changes.

3.3(1)

For those piping systems using austenitic stainless steel materials as permitted by the design specification, the stainless steel piping material and fabrication process shall be selected to reduce the possibility of cracking during service. Chemical, fabrication, handling, welding, and examination requirements that reduce cracking shall be met.

Piping system supports shall be designed to meet the requirements of ASME Code Subsection NF.

For piping systems, the pipe applied loads on attached equipment shall be calculated and shown to be less than the equipment allowable loads.

Analytical methods and load combinations used for analysis of piping systems shall be referenced or specified in the ASME Code Certified Stress Report. Piping systems and their supports shall be mathematically modeled to provide results for piping system frequencies up to the analysis cutoff frequency. Computer programs used for piping system dynamic analysis shall be benchmarked.

Systems, structures and components that shall be required to be functional during and following an SSE shall be protected against the dynamic effects associated with postulated high energy pipe breaks in Seismic Cateogry I and NNS piping systems. The Pipe Break Analyses Report shall specify the criteria used to postulate breaks and the analytical methods used to perform the pipe break analysis. For postulated pipe breaks, the Pipe Break Analysis Report shall confirm: (1) piping stresses in the containment penetration area shall be within their allowable stress limits, (2) pipe whip restraints and jet shield designs shall be capable of mitigating pipe break loads, and (3) loads on safety-related systems, structures and components shall be within their design loads limits. Piping systems that shall be qualified for leak-before-break design may exclude design features to mitigate the dynamic effects from postulated high energy pipe breaks.

typo

Structures, systems, and components that shall be required to be functional during and following an SSE shall be protected against the effects of spraying, flooding, pressure and temperature due to pstulated pipe breaks and cracks in Seismic Category I and NNS piping systems.

typo

Piping systems shall be designed to provide clearance from structures, systems, and components where necessary for the accomplishment of the structure, system, or component's safety function as specified in the respective structure or system Design Description.

The as-built piping shall be reconciled with the piping design required by this section.

Section 3.4 Comment No. 1

Comment:

Electromagnetic compatibility CDM 3.4B, Page 3.4-11, does not list "ground" as a possible noise path.

Resolution:

No action needed. Tier 2 information. Details of testing provided in standards reference in the SSAR.

Section 3.4 Comment No. 2

Comment:

CDM 3.4B Instrumentation Setpoint Methodology, page 3.4-9. SSAR 7.1.2.10.9 Regulatory Guide 1.105, Instrumentation setpoints. CDM description is inconsistent with the standard and regulatory guide:

1. The CDM references a "nominal trip setpoint". This term is not defined in RG 1.105 or ISA 67.04-1982. See attached.

2. Time response testing is not discussed. See attached.

3. CDM does not discuss probability or confidence levels of setpoint calculations. Staff recognizes 95/95 and the R.G. endorses 95% probability with no confidence term stated.

4. A definition of allowable value is not given in ISA 76.04-1982. RG 1.105 endorses the figure description as depicted in ISA 67.04-1982. The allowable value description listed in the CDM material is inconsistent with the standard (both 1982 and 1987) and RG 1.105. See attached.

5. The last paragraph on page 3.4-10 appears to be an attempt at "setpoint grading" this methodology has not been endorsed by ISA. The Scope of ISA 67.04 however provides for the minimum requirements for nuclear safety related instrumentation. The graded approach listed here is not endorsed within a standard or R.G. See Attached.

Resolution:

1. NRC agreed with GE's disposition.

2. No action needed. Response time not Tier 1 (not safety significant).

3. No action needed. Not Tier 1. Probability numbers not in Tier 1. Setpoint methodology details in Tier 2.

4. NRC agreed with GE's disposition.

5. No action needed. Tier 1 treatment is appropriate. Based on operating experience.

Section 3.4 Comment No. 3

Comment:

Equipment qualification CDM Page 3.4-11 follows 10 CFR 50.49 except that it does not list a commitment to maintain an EQ file (list and information) for the period that the equipment is installed. Commitment is listed in ITAAC.

Resolution:

No action needed. Tier 1 commitment is to an EQ program and its implementation is based on meeting the acceptance criteria. Details in Tier 2.

Section 3.4 Comment No. 4

Comment:

CDM Page 3.4-13 the word undetected may be more appropriately stated as undetectable. (IEEE-379) See attached.

Resolution:

No change needed.

Section 3.4 Comment No. 5

Comment:

Figure 4.3c, page 3.4-19 "NMS" should be blocked in with input designated to be consistent. See attached.

Resolution:

GE agreed to make the change.

Section 3.4 Comment No. 6

Comment:

ITAAC Table 3.4, Item 5, ATWS, Design commitment. Reference is made to both APRM and SRNM not downscale. This is not consistent with other design material or Figure 15E-2.

Resolution:

GE agreed to make the changes.

Section 3.4 Comment No. 7

Comment:

ITAAC Table 4.3, Item 8, Software Mangement Plan, design commitment, 2nd paragraph is unclear. See attached.

Resolution:

This was discussed with IRG reviewer, and it was agreed that no action was needed.

The plan is structured on the basis that EMC of I&C equipment is verified by factory testing and site testing of both individual components and interconnected systems to meet electromagnetic compatibility requirements for protection against the effects of:

(1) Electromagnetic Interference (EMI)

(2) Radio Frequency Interference (RFI)

(3) Electrostatic Discharge (ESD)

(4) Electrical surge [Surge Withstand Capability (SWC)]

5. Harmonic Distortion

To be able to predict the degree of electromagnetic compatibility of a given equipment design, the following information is developed:

(1) Characteristics of the sources of electrical noise

(2) Means of transmission of electrical noise

(3) Characteristics of the susceptibility of the system

(4) Techniques to attenuate electrical noise

After these characteristics of the equipment are identified, noise susceptibility is tested for four different paths of electrical noise entry:

(1) Power feed lines

(2) Input signal lines

(3) Output signal lines

(4) Radiated electromagnetic energy

5) Ground

Instrument Setpoint Methodology

Setpoints for initiation of safety-related functions are determined, documented, installed and maintained using a process that establishes a general program for:

(1) Specifying requirements for documenting the bases for selection of trip setpoints.

(2) Accounting for instrument inaccuracies, uncertainties, and drift.

(3) Testing of instrumentation setpoint dynamic response. / Time Response Characteristic

(4) Replacement of setpoint-related instrumentation.

The determination of nominal trip setpoints includes consideration of the following factors:

Design Basis Analytical Limit

In the case of setpoints that are directly associated with an abnormal plant transient or accident analyzed in the safety analysis, a design basis analytical limit is established as part of the safety analysis. The design basis analytical limit is the value of the sensed process variable prior to or at the point which a desired action is to be initiated. This limit is set so that associated licensing safety limits are not exceeded, as confirmed by plant design basis performance analysis.

Allowable Value

SEE ENCLOSED STANDARD

An allowable value is determined from the analytical limit by providing allowances for the specified or expected calibration capability, the accuracy of the instrumentation, and the measurement errors. The allowable value is the limiting value of the sensed process variable at which the trip setpoint may be found during instrument surveillance.

Nominal Trip Setpoint

SEE ENCLOSED STANDARD

The nominal trip setpoint value is calculated from the analytical limit by taking into account instrument drift in addition to the instrument accuracy, calibration capability, and the measurement errors. The nominal trip setpoint value is the limiting value of the sensed process variable at which a trip action will be set to operate at the time of calibration.

Signal Processing Devices in the Instrument Channel

Within an instrument channel, there may exist other components or devices that are used to further process the electrical signal provided by the sensor (e.g., analog-to-digital converters, signal conditioners, temperature compensation circuits, and multiplexing and demultiplexing components). The worst-case instrument accuracy, calibration accuracy, and instrument drift contributions of each of these additional signal conversion components are separately or jointly accounted for when determining the characteristics of the entire instrument loop.

5) Not all parameters have an associated design basis analytical limit (e.g., main steamline radiation monitoring). An allowable value may be defined directly based on plant licensing requirements, previous operating experience or other appropriate criteria. The nominal trip setpoint is then calculated from this allowable value, allowing for instrument drift. [Where appropriate, a nominal trip setpoint may be determined directly based on operating experience.]

ISA 67.04 1994 - ONLY INSTALLED HISTORICAL RESULTS MAY BE EVALUATED AND SETPTS REVISED

Procedures will be used that provide a method for establishing instrument nominal trip setpoint and allowable value. Because of the general characteristics of the instrumentation and processes involved, two different methods are applied:

(1) Computational

(2) Historical data

INCONSISTENT WITH PREVIOUS PAGE

The computational method is used when sufficient information is available regarding a dynamic process and the associated instrumentation. The procedure takes into account channel instrument accuracy, calibration accuracy, process measurement accuracy, primary element accuracy, and instrument drift. If the resulting nominal trip setpoint and allowable value are not acceptable when checked to ensure that they will not result in an unacceptable level of trips caused by normal operational transients, then more rigorous statistical evaluation or the use of actual operational data may be considered.

Some setpoint values have been historically established as acceptable, both for regulatory and operational requirements. These setpoints have non-critical functions or are intended to provide trip actions related to gross changes in the process variable. The continued recommendation of these historically accepted setpoint values is another method for establishing nominal trip setpoint and allowable values. This approach is only valid where the governing conditions remain essentially unaltered from those imposed previously and where the historical values have been adequate for their intended functions.

The setpoint methodology plan requires that activities related to instrument setpoints be documented and stored in retrievable, auditable files.

Equipment Qualification (EQ)

Qualification of safety-related instrumentation and control equipment is implemented by a program that assures this equipment is able to complete its safety-related function under the environmental conditions that exist up to and including the time the equipment has finished performing that function. Qualification specifications consider conditions that exist during normal, abnormal, and design basis accident events in terms of their cumulative effect on equipment performance for the time period up to the end of equipment life.

The material discussed herein identifies an EQ program that addresses the spectrum of design basis environmental conditions that may occur in plant areas where I&C equipment is installed. Not all safety-related I&C equipment will experience all of these conditions; the intent is that qualification be performed by selecting the conditions applicable to each particular piece of equipment and performing the necessary qualification.

As-built I&C components are environmentally qualified if they can withstand the environmental conditions associated with design basis events without loss of their safety functions for the time needed to be functional. Safety-related I&C components are designed to continue normal operation after loss of HVAC. The environmental conditions are as follows, as applicable to the bounding design basis events: Expected time-dependent temperature and pressure profiles, humidity, chemical effects, radiation, aging, seismic events, submergence, and synergistic effects which have a significant effect on equipment performance.

I&C equipment environmental qualification is demonstrated through analysis of the environmental conditions that would exist in the location of the equipment during and following a design basis accident and through a determination that the equipment is qualified to withstand those conditions for the time needed is functional. This determination may be demonstrated by:

(1) Type testing of an identical item of equipment under identical or similar conditions with a supporting analysis to show that the equipment to be qualified.

(2) Type testing of a similar item of equipment with a supporting analysis to show that the equipment is qualified.

(3) Experience with identical or similar equipment under similar conditions with a supporting analysis to show that the equipment is qualified.

(4) Analysis in combination with partial type test data that supports the analytical assumptions and conclusions to show that the equipment is qualified.

The installed condition of safety-related I&C equipment is assured by a program whose objective is to verify that the installed configuration is bounded by the test configuration and test conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.4, Items 7 through 15, provides a definition of the inspections, tests and analyses, together with associated acceptance criteria, which will be used to demonstrate compliance with the above commitments for hardware and software development, electromagnetic compatibility, instrument setpoint methodology, and equipment qualification.

C. Diversity and Defense-in-Depth Considerations

Subsection B discusses processes for developing hardware and software qualification programs that will assure a low probability of occurrence of both random and common-mode system failures for the installed ABWR I&C equipment. However, to address the

ISA 67.04

1 PURPOSE

The purpose of the standard is to develop a basis for establishing setpoints for actions determined by the design basis for protection systems and to account for instrument errors and drift in the channel from the sensor through and including the bistable trip device.

2 SCOPE

This standard defines minimum requirements for assuring that setpoints are established and held within specified limits in nuclear safety-related instruments in nuclear power plants.

3 DEFINITIONS

Accuracy - Degree of conformity of an indicated value to a recognized accepted standard value, or ideal value. [1]

Design Basis - The Design Basis for protection systems for nuclear power generating stations is delineated in IEEE Standard 279-1971, "IEEE Standard for Protection Systems for Nuclear Power Generating Stations," Part 3, Design Basis.

Drift - An undesired change in the output-input relationship over a period of time. [1,11]

Dynamic response - The behavior of the output of a device as a function of the input, both with respect to time. [1]

Foldover - A characteristic of the steady-state or dynamic conditions of a device for which, at a point, a further change in the input signal produces an output signal which reverses its direction from the specified input-output relationship.

Hysteresis - That property of an element evidenced by the dependence of the value of the output, for a given excursion of the input, upon the history of prior excursions and the direction of the current traverse. [1]

Instrument channel - An arrangement of components and modules as required to generate a single protective action signal when required by a generating station condition. A channel loses its identity where single protective action signals are combined. [2]

Instrument range - The region between the limits within which a quantity is measured, received, or transmitted, expressed by stating the lower and upper range values. [1]

Limiting Safety System Setting (LSSS) - Limiting Safety System Settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. [3]

Note: For the purposes of this standard, the phrase "nuclear reactors" used in this definition should be understood to mean "nuclear power plants."

Protective action - The initiation of a signal or operation of equipment within the protection system, or protective action system, for the purpose of accomplishing a protective function in response to a generating station condition having reached a limit specified in the design basis. [4]

Protective function - The sensing of one or more variables associated with a particular generating station condition, the signal processing, and the initiation and completion of the protective action within the values of the variables established in the design basis. [2]

Protection system - The electrical and mechanical devices (measured process variables to protective action system input terminals) involved in generating those signals associated with the protective functions. These signals include those that initiate reactor trip, engineered safety features, and auxiliary supporting features. [4]

Repeatability - The closeness of agreement among a number of consecutive measurements of the output for the same value of the input under the same operating conditions, approaching from the same direction, for full range traverses. [1]

Nuclear safety-related instrumentation - That which is essential to:

(1) emergency reactor shutdown;
(2) containment isolation;
(3) reactor core cooling;
(4) containment or reactor heat removal;
(5) prevent or mitigate a significant release of radioactive material to the environment; or is otherwise essential to provide reasonable assurance that a nuclear power plant can be operated without undue risk to the health and safety of the public.

Saturation - A characteristic of the steady state or dynamic conditions of a device under which, at a point, a further change in the input signal, produces no additional change in the output signal.

Sensor - That portion of a channel which responds to changes in a plant variable or condition, and converts the measured process variable into an instrument signal.

Setpoint - A predetermined level at which a bistable device changes state to indicate that the quantity under surveillance has reached the selected value. [5]

Test interval - The elapsed time between the initiation of identical tests on the same sensor, channel, train, load group, or other specified system or device. [5]

4 ESTABLISHMENT OF SETPOINTS

Setpoints in nuclear safety-related instruments shall be selected to provide sufficient margin between the trip setpoint and the safety limits to account for accuracies, drift, uncertainties and dynamic responses. Detailed requirements for safety-related instrument setpoint relationships are given in the sections which follow as illustrated in Figure 1.

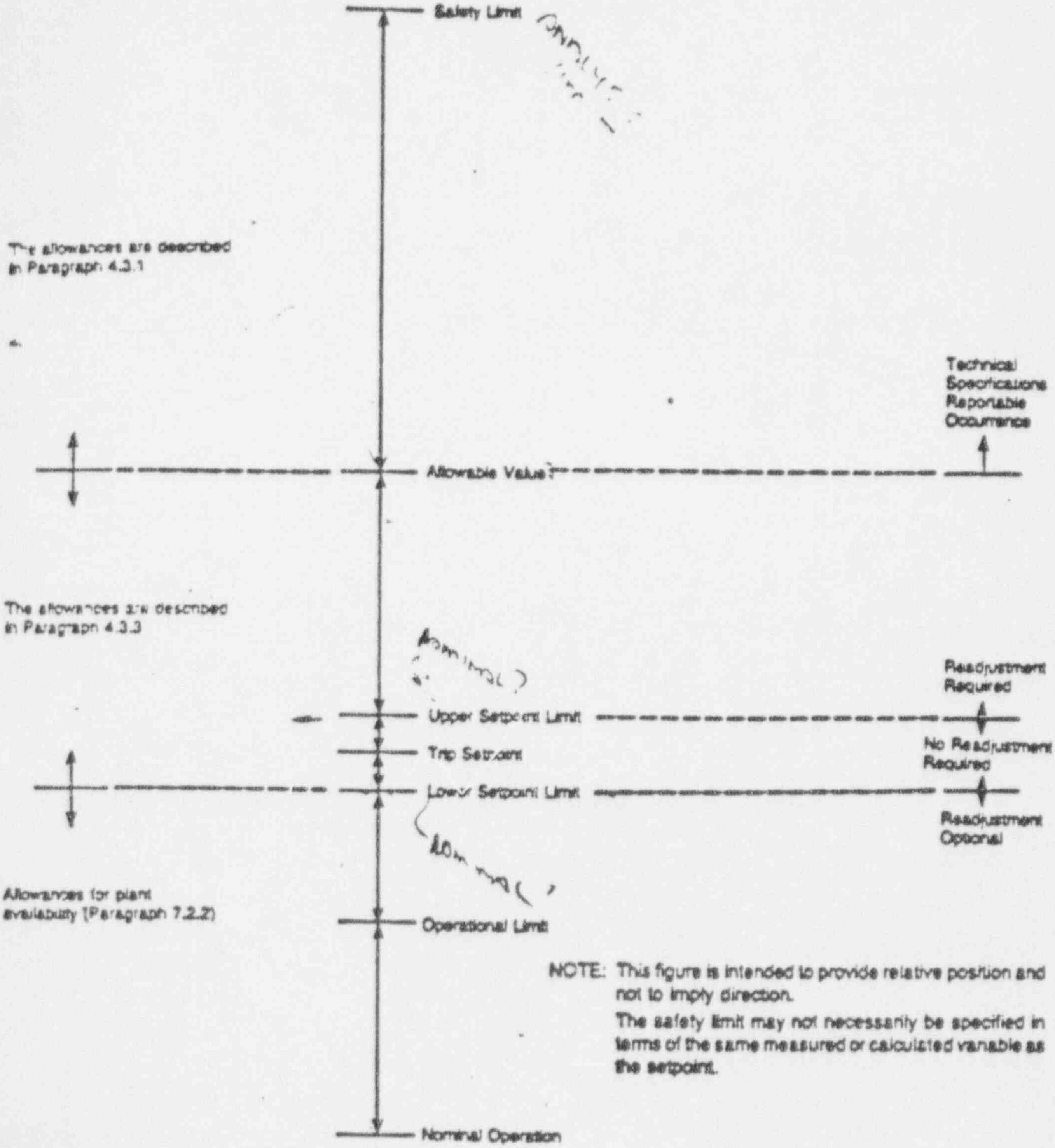


Figure 1. Nuclear Safety-Related Instrument Setpoints Relationships

4.1 Safety Limits

Safety limits for nuclear reactors are limits upon important process variables which are found to be necessary to reasonably protect the integrity of certain of the physical barriers which guard against the uncontrolled release of radioactivity. [3] The safety limit may not necessarily be specified in terms of the same measured or calculated variable as the setpoint. For example, a setpoint using temperature as a measured variable may be related to a safety limit specified in terms of Departure from Nucleate Boiling Ratio (DNBR)

4.2 Safety Analysis

The conclusions of the safety analysis are assured in part by establishing appropriate safety system setpoints to be stated in the technical specifications and maintained through operating procedures. The selection of setpoints for safety-related instruments shall be documented or referenced in the basis for the technical specifications including the parameters and assumptions upon which the setpoint selection was based.

4.3 Limiting Safety System Settings

Limiting Safety System Settings (LSSS) shall be selected such that operation within LSSS provides assurance that the physical barriers will not be damaged beyond acceptable limits during anticipated operational occurrences and accidents. For each LSSS a trip setpoint and its associated allowable value shall be established. (See Figure 1.)

4.3.1 The allowances between the allowable value and the safety limit shall include the following items unless they are included in the determination of the safety limit:

(1) Accuracy (including drift) of components not tested when setpoint is measured. Setpoint measurements shall be made by:
   (a) Perturbing the monitored variable (the same or a substitute process variable), and noting the point at which a channel trip occurs, or:
   (b) Substituting a known signal in the instrument channel as close to the monitored variable as practical and noting the point at which a channel trip occurs. Justification for selecting Item (b) over (a) shall be documented.

(2) Accuracy of test equipment for:
   (a) Measuring setpoints
   (b) Calibrating sensors for the case where sensors are not included in setpoint measurements.

(3) Process measurement accuracy. Examples are the effect of fluid stratification on temperature measurement and the effect of changing fluid density on level measurements.

(4) The effects of potential transient overshoot determined in the design basis events analyses.

(5) The effects of the time reponse characteristics of the total instrument channel, including the sensor.

(6) Environmental effects on equipment accuracy or time response characteristics caused by anticipated operational occurrences or accidents for those systems required to mitigate the consequences of such events.

The above items shall be combined in one of the following five ways:

(1) Algebraically,
(2) Square root of the sum of the squares,
(3) Statistically,
(4) Probabilistically, or
(5) Combinations of 1 thru 4.

Justification shall be provided for the adequacy of the method used.

4.3.2 Where items listed in Paragraph 4.3.1 are accounted for by compensating the signal(s) representing the monitored variable(s) prior to comparison with the trip setpoint, these items need not be considered in the allowance between the safety limit and the allowable value.

4.3.3 The trip setpoint shall be a value which allows margin for drift and adjustment. The trip setpoint shall be chosen so that the corresponding allowable value is not exceeded due to the following:

(1) Drift of that portion of the instrument channel which is tested when the setpoint is determined.

(2) Actual setting of the setpoint within an allowable tolerance of upper and lower setpoint limits. (See Figure 1.)

The band between upper and lower setpoint limits shall account for the ability to adjust the setpoint and minimize the need for frequent adjustments.

5 INSTRUMENT PERFORMANCE AND SETPOINT SETTING

Setpoints shall be specified in units of the monitored value.

Instrument performance requirements shall be specified such that during the interval between setpoint tests the actual setpoint does not exceed the allowable value due to expected drift.

Instrument performance requirements shall be specified for that portion of the instrument channel not tested (Paragraph 4.3.1) such that the parameters remain within the values assumed in the determination of the allowable value.

(1) acc. of comp. not calibrated → — safety limit
— allowable value
(2) test equipment
(3) process measurement accuracy
(4) ...
(5,6) environmental effects

Setpoints shall be located in that portion of the instrument's range which has the required accuracy.

Instrument performance requirements shall be specified such that as long as the process variable exceeds the setpoint, the protective action of that instrument channel is not negated by saturation, foldover, or any other cause for expected values of the process variable.

Instrumentation calibration correction factors shall be identified and documented. Correction factors which have been incorporated in the determination of the setpoint (for example, to compensate for differences in physical location, temperature or pressure between the required point of measurement and actual sensor location) shall be separately identified.

6 QUALIFICATION

The nuclear safety-related instrumentation hardware and software qualification shall be documented and available to verify all parameters used in determining the setpoints, including:

(1) The value of setpoint drift during proposed test intervals due to expected exposure to normal operating temperature, pressure, humidity, power variation, electromagnetic interference, vibration, seismic acceleration and radiation exposure.

(2) The time response characteristics or other response characteristics of the instrument channel.

(3) The instrument channel performance such as accuracy, repeatability and hysteresis at the trip setpoint and at the allowable value under design basis conditions.

These requirements are supplemental to those of IEEE Standard 323-1974. [10]

7 MAINTENANCE OF SETPOINTS

Maintenance of setpoints shall include all actions taken to assure that the instrumentation is installed and continues to operate within the design requirements used to establish the setpoints. The following sections address those aspects of nuclear safety-related instrument setpoint maintenance that are necessary to support the establishment of the allowable values and trip setpoints as described in Section 4. Specific guidance for implementing each of the following maintenance activities can be found in other industry standards (See references 6 through 9, for examples.)

7.1 Installation

Installation requirements shall include:

(1) Receipt, storage and handling provisions to prevent instrumentation degradation.

(2) Provisions for necessary access and other design features to assure setpoint maintenance.

7.2 Operation

7.2.1 Initial Calibration and Operation

Nuclear safety-related instrument channels shall be calibrated, functionally tested and set at their trip setpoint as soon as practicable after installation and again prior to initial criticality, where practical, to determine if the drift rate of the channel meets design requirements. Inability to perform these tests shall be justified and documented.

If within this period the drift rate of the channel fails to meet the design requirements, an evaluation shall be conducted to determine the cause. The evaluation shall include consideration of the installation (including all possible environmental effects), adequacy of the supplied instrumentation, accuracy of calibration, and calibration techniques. This evaluation shall provide the basis for proper and timely resolution and shall be documented.

7.2.2 Periodic Testing

Testing of safety-related instrumentation shall be in accordance with the technical specifications. Written procedures shall be used to verify the proper operation of the instrumentation, including each instrument channel's compliance with design requirements related to setpoints. These procedures shall include, as a minimum, requirements to record sufficient data on each channel to determine the true setpoint in terms of measured or derived process variables, before any adjustments are made.

If the "as found" setpoint indicates the setpoint is within the "no readjustment" band (See Figure 1.) or that calculations based on the analog value would result in setpoints within the "no readjustment" band, documentation of the results is the only required action. If the "as found" setpoint exceeds the upper setpoint limit, readjustment shall be performed to bring this channel back within the "no readjustment" band. The "as found" and "as left" setpoint shall be recorded. If the "as found" setpoint was also beyond the allowable value, a review shall be conducted immediately to determine the availability of the other redundant channels of the same protective function and their setpoints. Based on this review and subsequent evaluation, it may be necessary to decrease the time between tests in order to ensure proper operation. A review of the parameters verified in Paragraph 7.2.1, above shall be required to determine the cause. The action taken when the allowable value has been exceeded shall be based on the measured drift rates determined by previous "as left" and current "as found" data.

This evaluation shall be documented.

If subsequent tests show the allowable value continues to be exceeded the following shall be considered:

(1) Upgrading the instrument system
(2) Revising the required tolerances for the trip setpoint
(3) Revising the upper setpoint limit and lower setpoint limit ("no readjustment" band)
(4) Revising the test interval.

unnessary

This evaluation shall be documented.

If the "as found" setpoint is below the lower setpoint limit, readjustment may be made to avoid necessary trips, but is not mandatory. The "as found" and "as left" setpoint shall be recorded.

Should these data indicate drift rates considerably less than originally expected, testing intervals or tolerances may be revised accordingly, with suitable justification and documented.

7.3 Test Equipment

A system shall be established to ensure the accuracy and adequacy of the test equipment used to verify setpoints and tolerances of safety-related instrumentation. Calibration records shall identify all test equipment by serial number. The test equipment shall be calibrated at specified intervals and shall be traceable to the U.S. National Bureau of Standards or have a known valid relationship to physical constants. If test equipment is found out of tolerance, an evaluation shall be conducted to determine the effect on safety-related instrumentation calibrated with that equipment since its last calibration. The evaluation including corrective action taken shall be documented. The accuracy of the test equipment used shall equal or exceed that required of the instrumentation under test.

7.4 Repair and Replacement

Replacement of material, parts and components shall be "in kind." Substitutions shall be evaluated and documented to assure equal or better performance than that provided in the design basis.

REFERENCES

1. Definition per ISA - S51.1 (1976) "Process Instrumentation Terminology."
2. Definition per IEEE Standard 279-1971 "Criteria for Protection System for Nuclear Power Generating Stations."
3. Definition per "Code of Federal Regulations" Title 10, Part 50, dated January 1, 1978, Paragraph 50.36.
4. Definition per IEEE Trial Use Standard 603-1977 "Criteria for Safety Systems for Nuclear Power Generating Stations."
5. Definition per IEEE Standard 380-1975 "Definition of Terms Used in IEEE Standards on Nuclear Power Generating Stations."
6. IEEE Standard 338-1975, "IEEE Standard Criteria for the Periodic Testing of Nuclear Power Generating Station Class 1E Power and Protection Systems."
7. ANSI N45.2-1971, "Quality Assurance Program Requirements for Nuclear Power Plants."
8. IEEE Standard 352-1975, "IEEE Guide for General Principles of Reliability Analysis of Nuclear Power Generating Station Protection Systems."
9. IEEE Standard 498-1975, "IEEE Standard Supplementary Requirements for the Calibration and Control of Measuring and Test Equipment Used in the Construction and Maintenance of Nuclear Power Generating Stations."
10. IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations."
11. The committee chose this specific definition for drift to explain the output-input relationship of a safety-related instrument channel.

INFORMATIVE REFERENCES

The Instrument Society of America (ISA) has developed standards for the nuclear industry through the SP67 Nuclear Power Plant Standards Committee (NPPSC)

ANSI/ISA-67.01-1981, "Transducer and Transmitter Installation for Nuclear Safety Applications."

ISA-S67.02, "Nuclear-Safety-Related Instrument Sensing Line Piping and Tubing Standards for Use in Nuclear Power Plants."

mode system failures for the installed ABWR I&C equipment. However, to address the concern that software design faults or other initiating events common to redundant, multi-divisional logic channels could disable significant portions of the plant's automatic standby safety functions (the reactor protection system and engineered safety features systems) at the moment when these functions are needed to mitigate an accident, several diverse backup features are provided for the primary automatic logic:

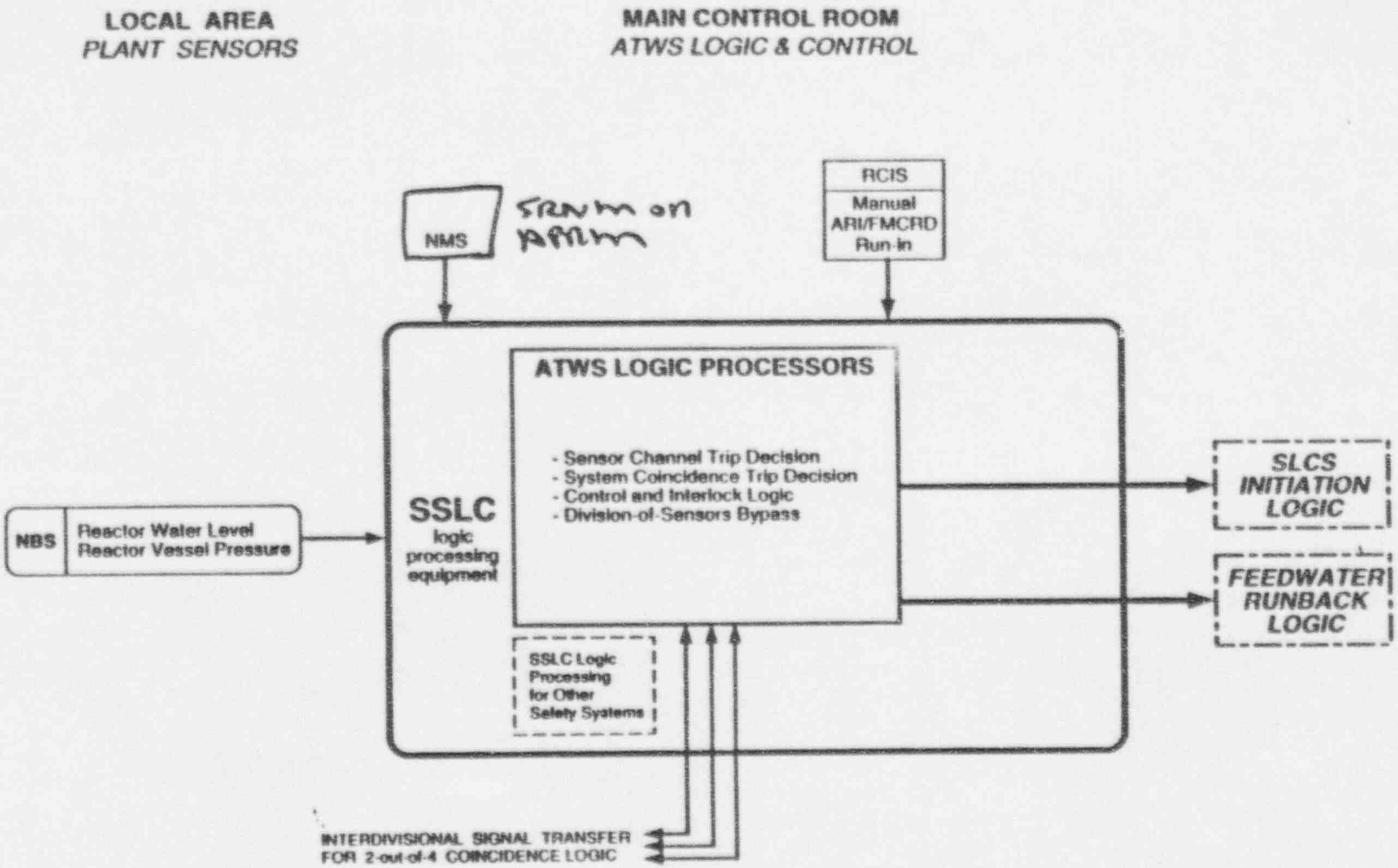
- Manual scram and isolation by the operator in the main control room in response to diverse parameter indications.
- Core makeup water capability from the feedwater system, Control Rod Drive (CRD) System, and condensate system, which are diverse from SSLC and the EMS.
- Availability of manual high pressure injection capability.
- Long term shutdown capability provided in a conventionally hardwired, 2-division, analog Remote Shutdown System (RSS); local displays of process variables in RSS are continuously powered and so are available for monitoring at any time.

UNDETECTABLE

Thus, to maintain protection system defense-in-depth in the presence of a postulated worst-case event (i.e., undetected, 4-division common mode failure of protection system communications or logic processing functions in conjunction with a large break LOCA), diversity is provided in the form of hardwired backup of reactor trip, diverse display of important process parameters, defense-in-depth arrangement of equipment, and other equipment diversity as outlined in the following table:

Diverse Backup Support for SSLC Equipment

Diverse Features of Protection System	Functional Diversity in Protection System	Defense-in-Depth Configuration	Equipment Diversity
(1) 2-button scram	H		
(2) Manual division trip	H		
(3) Reactor mode switch placed in shutdown mode.	H		
(4) Manual MSIV closure	H		
(5) ATWS mitigation	D		



Notes:
1. Diagram represents one of four ATWS divisions.
2. Remaining ATWS functions are processed as part of Recirculation Flow Control System logic and Nuclear Boiler System logic.

Figure 3.4c Anticipated Transient Without Scram (ATWS) Control Interface Diagram

3.4(5)

3.4(7)

Table 3.4 Instrumentation and Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
Hardware/Software Development		
7. A quality assurance program encompassing software is employed as a controlled process for software development hardware integration, and final product and system testing.	7. The program for quality assurance that encompasses software shall be reviewed.	7. A quality assurance program is in place that defines controlled processes for software development, hardware integration, and final product and system testing. As a minimum, the program requires a Software Management Plan, Configuration Management Plan and Verification and Validation Plan as described in the following items.
8. A Software Management Plan (SMP) shall be instituted which establishes that software for embedded control hardware shall be developed, designed, evaluated, and documented per a design development process that addresses, for safety-related software, software safety issues at each defined life-cycle phase of the software development. The SMP shall state that the output of each defined life-cycle phase shall be documents that define the current state of that design phase and the design input for the next design phase.	8. The Software Management Plan shall be reviewed.	8. The Software Management Plan shall define: a. The organization and responsibilities for development of the software design; the procedures to be used in the software development; the interrelationships between software design activities; and the methods for conducting software safety analyses. b. That the software safety analyses to be conducted for safety-related software applications shall: (1) Identify software requirements having safety-related implications. (2) Document the identified safety-critical software requirements in the software requirements specification for the design.

Section 3.5 **Comment No.** 1

Comment:

SSAR 14.2.1 states the ITP covers construction, pre-operational, and start-up tests. Design Description mark-up is attached to reflect that scope more clearly.

Resolution:

No change required. The design description reflects the regulatory position in RG 1.68 that designated construction-related inspections and tests should be completed prior to beginning preoperational testing.

Section 3.5 **Comment No.** 2

Comment:

The ITP design description does not specify the scope of the test program. A test matrix similar to SSAR 14.2-1 could be used.

Resolution:

No change required. The design description currently reflects the scope of the preoperational and startup test programs. The scope of construction testing is specified in SSAR Section 14.2.1.1.

Section 4.1 Comment No. 1

Comment:

Section 4.1 item (3):
Add the following sentence to the statement: "Independence is also provided between the Class 1E Divisions and non-Class 1E equipment."

Resolution:

Disagree. At the COL stage, the system will be reviewed to all applicable NRC requirements regardless of what the "Interface Requirements" state.

Section 4.1 Comment No. 2

Comment:

The following Interface Requirements delineated in SSAR Section 9.2.5.1 shall be included in Section 4.1 of the Certified Design Material:

a. Item 5--withstand the most severe natural phenomenon.
b. Item 6--single active failure in any mechanical or electrical system.
c. Item 11--capability for full operational inspection and testing.

Resolution:

Disagree. SSAR has been modified to identify additional "interface requirements" that were originally included as part of the conceptual design. These "interface requirements" do not have to be brought up to Tier 1. At COL stage, the system will be reviewed to all applicable NRC requirements.

Miscellaneous Comments:

1. SSAR Acronym use: revise SSAR list as marked-up for VAC and VDC. SSAR list needs to reflect PRA as Probabilistic Risk Assessment. SSAR acronym list is incomplete, such as: TN, MPT, PIP, D/G, IED, NBS, UAT, PMG, M/C, RAT, SBO, MVA. Recommend total SSAR search to identify all missing acronyms.

   Resolution:

   GE agreed to make the changes.

2. SSAR Section 14.2.12.1.45 used loss of offsite power (LOP) for loss of preferred power (LOPP). Revise to be consistent with CDM and other SSAR sections.

   Resolution:

   GE agreed to make the changes.

3. SSAR page 9.3-9, revise as marked-up - see attached.

   Resolution:

   GE agreed to make the changes.

4. SSAR pages 9.3-26 and 9.3-27 are not continuous, information is missing in section 9.3.8.2.3 that should be added to SSAR.

   Resolution:

   GE agreed to make the changes.

5. SSAR Table 14.3-10, clarify the statement at top of page with respect to RCIC and HPCF suction piping as outlined in mark-up.

   Resolution:

   GE agreed to make the changes.

6. SSAR page 7.3-3, revise as shown on markup.

   Resolution:

   GE agreed to make the changes.

SSAR Section 8.2 Comment No. 1

Comment:

In responding to comment no. 24 on ITAAC 2.12.1, GE incorrectly interjected the letter "B" between "isolated" and "phase" in the next to the last paragraph on page 8.2-2.

Resolution:

GE agreed to make the change.

SSAR Section 8.2 Comment No. 2

Comment:

In responding to comment no. 20 on ITAAC 2.12.1, GE incorrectly changes SSAR Fig. 8.2.1 (sh 2). "Gas Combustion Turbine Generator" should just be "Combustion Turbine Generator".

Resolution:

GE agreed to make the changes.

for lead unit and standby unit of air compressors and dryers shall be switched periodically. The pressure setpoints for these operational changes are adjustable, depending on air requirements that might exist.

During normal operation, the nonsafety-related nitrogen users within containment are downstream of P52-F277 and P54-F208. (The safety-related nitrogen users are downstream of P54-F008A and B.) Should the AC/HPIN Systems become unable to supply nitrogen to the non-safety-related users downstream of P52-F277, the operator may remote manually open P52-F257 to supply instrument air to these users (Figure 20.3-55).

During refueling, the IAS provides compressed air instead of nitrogen gas to the users located inside containment in Figure 9.3-6.

Acceptance Criterion II.1 of SRP Section 9.3.1 requires that the maximum particle size of 3 microns in the air stream at the instrument. The corresponding maximum particle size for the ABWR design is 5 microns. Experience to date for plants with a maximum filtered particle size of 5 microns in the compressed gases has been very satisfactory.

All equipment using instrument air shall be capable of operating with air of the quality listed above.

9.3.6.3 Safety Evaluation

The operation of the IAS is not required to assure any of the following:

(1) Integrity of the reactor coolant pressure boundary.

(2) Capability to shut down the reactor and maintain it in a safe shutdown condition.

(3) Ability to prevent or mitigate the consequences of accidents which can result in potential offsite exposures comparable to the guideline exposures of 10CFR100.

However, the IAS incorporates features that assure this operation over the full range of normal plant operations. If IAS pressure falls below a desired limit, air from the Service Air System (SAS) is automatically added from a tie-line. An air receiver is provided to maintain air supply pressure if all of the IAS and SAS compressors fail. Pneumatic-operated devices are designed for a failsafe mode and do not require continuous air supply under emergency or abnormal conditions.

The instrument air system does p orivide air service to a number of safety-related systems and components. The loss of air to these systems will result in current or new valva positions. These positions have been evaluated. The subject system safety functions have

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Table 14.3-10 TMI Issues (Continued)

SAR Entry	Parameter	SSAR Value
	RCIC and HPCF Do not Share Any Common Suction Piping with RHR	
	RCIC	—
	HPCF	—
	LPFL	—
	?	
	ECCS Have Minimum Flow Protection for All Operating Modes	
	RCIC	—
	HPCF	—
	RHR	—
	Number of RCW Divisions	3
	Individual ECCS Pumps Can be Isolated Without Affecting Other ECCS Pumps	
	RCIC	—
	HPCF	—
	RHR	—
	ABWR has Water Level Measurement Directly on the Vessel	
	Containment Sprays are Manually Initiated	—
	Essential Equipment Inside the Containment is Qualified for Harsh Environment	—
	ADS Automatically Depressurizes the Vessel on Low Water Level	—
	ABWR has Manual Vessel Depressurization Capability	—
1A.2.34	III.D.1.1(1) Review Information Submitted by Licensee Pertaining to Reducing Leakage from Operating Systems	
	Inboard and Outboard Isolation Valves on All Lines Which Penetrate Primary Containment	—
	ABWR has a Leak Detection and Isolation System	—
	MSIV Closure on:	
	High Temperature in Steam Tunnel	—
	High Temperature in Turbine Building	—
	High Radiation in HVAC Air Exhaust Results In:	
	Closure of HVAC Air Ducts to Reactor Building	—
	Closure of Containment Purge and Vent Lines	—

Misc (6)

List of Acronyms (Continued)

TCS	Turbine Control System
TCV	Turbine Control Valve
TCW	Turbine Building Cooling Water (System)
TGSS	Turbine Gland Sealing System
THA	Time-History Accelerographs
TIP	Traversing Incore Probe or Traversing Ion Chamber
TIU	Technician Interface Unit
TLU	Trip Logic Unit
TRS	Test Response Spectra
TSC	Technical Support Center
TSV	Turbine Stop Valve
TSW	Turbine Service Water
U/D	Upper Drywell
UHS	Ulumate Heat Sink
UPS	Uninterruptible Power System
USE	Upper Shelf Energy
USMA	Uniform Support Motion Response Spectrum Analysis
USNRC	United States Nuclear Regulatory Commission
VAC	Volts Direct Current switch
VDC	Volts Alternating Current
VDU	Video Display Unit
VLC	Vent Line Clearing
VWO	Valves-Wide-Open
WDSC	Wetwell and Drywell Spray Cooling (Mode of RHR)
WDVB	Wetwell-to-Drywell Vacuum Breaker
WDVBS	Wetwell-to-Drywell Vacuum Breaker System
ZIS	Zinc Injection System
ZSI	Zone Selective Interlocks

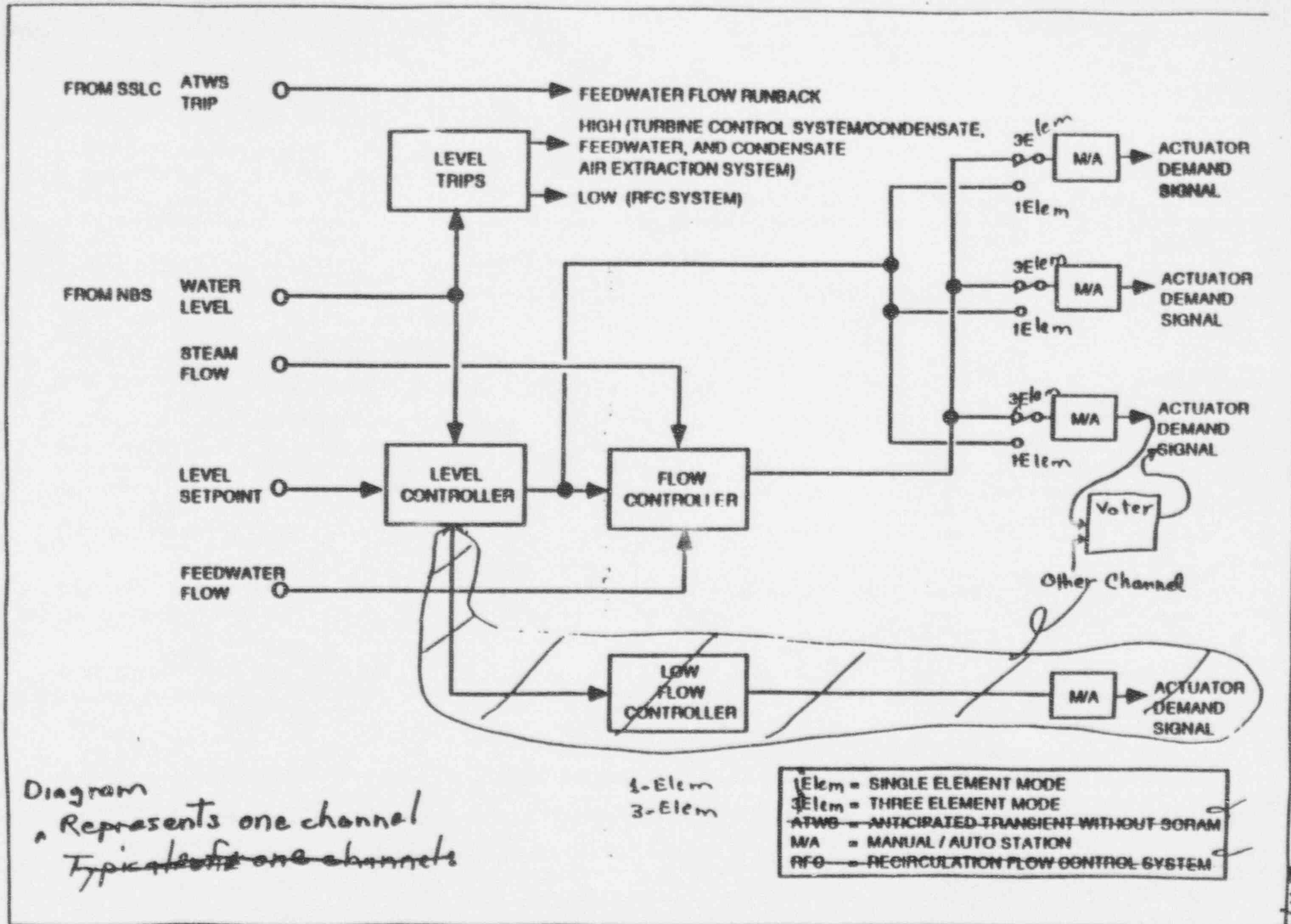

Figure 2.2.3 FDWC Control ~~Algorithm~~ Architecture

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Table 2.2.3 Feedwater Control System

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The FDWC System incorporates redundant ~~FTDCs~~. digital controllers.	1. A test will be each performed by simulating failure of ~~an~~ operating FDWC System ~~FTDC~~. digital controller	1. There is no loss of FDWC System output upon loss of any one ~~FTDC~~. digital controller.
2. The FDWC System FTDCs identify and isolate failure of ~~process~~ level input signals.	2. Tests will be performed by simulating level, std ~~input~~ signal failures to the FDWC System ~~FTDCs~~. digital controllers	2. ~~The FDWC System FTDCs output signal is based upon the remaining valid input signals.~~ There is no loss of FDWC system output upon loss of any one level input signal.
3. The FDWC System is powered by redundant power supplies.	3. A test shall be performed by simulating failure of a power supply to the FDWC System.	3. There is no loss of FDWC System output upon loss of any one power supply.
4. The FDWC System monitors reactor water level signals and, ~~in the event that~~ if a high RPV water level setpoint is reached, issues trip signals to the Turbine Control System and to the Condensate, Feedwater and Condensate Air Extraction System. ~~In the event that~~ If a low RPV water level setpoint is reached, the FDWC System issues trip signals to the RFC System.	4. Using simulated RPV water level signals, testing will be performed on the FDWC System.	4. ~~In the event that~~ When a high RPV water level setpoint is reached, trip signals are issued to Turbine Control System and Condensate, Feedwater and Condensate Air Extraction System. use std. terms throughout In the event that a low RPV water level setpoint is reached, trip signal is issued to the RFC System.
5. Control Room controls and displays provided for the FDWC System are as defined in Section 2.2.3.	5. Inspections will be performed on the Control Room controls and displays for the FDWC System.	5. controls and Displays exist or can be retrieved in the Control Room as defined in Section 2.2.3.
6. In ~~the event that~~ If the FDWC System receives an ATWS trip signal from SSLC, FDWC issues signals to runback feedwater flow.	6. Using simulated trip signals, testing will be performed on the FDWC System	6. FDWC issues ~~signals to runback~~ feedwater ~~flow in response to the ATWS trip signal.~~ runback signals.
7. The FDWC System is powered from non-safety-related uninterruptible power supply (UPS).	7. ~~A test shall be performed by simulating failure of each UPS/preferred power source, one FTDC at a time.~~ Tests will be performed on the FDWC System by providin an electrical power ~~system~~ test signal to only one	7. There is no loss of power to each FTDC. The electrical power or test signal exists only in the digital controller channel under test.
8. (insert ITAAC for functional		

4

2.2.3

(39)

2.2.3 Feedwater Control System

Design Description

The Feedwater Control (FDWC) System controls the flow of feedwater into the ~~reactor pressure vessel (RPV)~~ to maintain the water level in the vessel ~~within setpoint limits~~ during plant operation. The FDWC system consists of redundant, microprocessor based controllers ~~,~~ located in the Control Building, and flow transmitters for main steam lines and feedwater lines ~~flow~~, ~~configured~~ as shown in Figure 2.2.3. The FDWC System operates in either manual, automatic single- or three-element control modes selectable from the MCR. ~~from the main control room~~. At low ~~reactor powers~~ feedwater flow, the FDWC System utilizes ~~only~~ water level measurement in single-element control mode. At higher ~~powers~~ flow rates, the FDWC System in three-element control mode uses water level, steam flow, and feedwater flow measurements for water level control. The FDWC System control ~~structure~~ architecture is shown in Figure 2.2.3.

The FDWC System is ~~a power generation (control) system with operation range between high water level and low water level trip setpoints. It is~~ classified as non-safety-related.

The FDWC ~~fault tolerant~~ reactor digital controllers ~~(FTDCs)~~ determine narrow range level signal using three level measurement inputs from the NBS. ~~Nuclear Boiler System.~~ ~~The validated narrow range water level is displayed on the main control panel.~~

The steam flow in each of four main steamlines is sensed at the RPV nozzle venturis. Transmitter signals are transmitted to the FDWC digital controllers by the NEMS. These measurements are processed in the digital controllers ~~FTDCs~~ to give the total steam flow ~~rate~~ out of the vessel. ~~The total steam flow rate is displayed on the main control panel.~~

Feedwater flow is sensed at a ~~single~~ flow element in each of the two feedwater lines. These measurements are processed in the digital controllers ~~FTDCs~~ to give the total feedwater flow ~~rate~~ into the vessel. The total feedwater flow ~~rate~~ is displayed on the main control panel.

~~The FDWC System provides interlocks and control functions to other systems.~~ If ~~When~~ the reactor water level reaches the high level trip setpoint, the FDWC system sends a trip signal to the Turbine Control System and Condensate, Feedwater and Condensate Air Extraction System. The FDWC System also sends low RPV water level signals to the ~~recirculation flow control (RFC)~~ system.

~~In the event that~~ If the FDWC System receives an ATWS trip signal from the SSLC, FDWC issues signals to runback feedwater flow.

The FDWC System is powered by redundant non-safety-related ~~uninterruptible power supplies (UPS)~~. Controllers used for the FDWC System are redundant, ~~fault tolerant~~ digital

~~digital type~~ with self-test and diagnostic capabilities that identify and isolate failure of ~~process~~ level input signals.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.3 provides definition of the inspection, tests, and/or analysis, together with associated acceptance criteria which will be undertaken for the Feedwater Control System.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.3 FDWC No. 1

NRC COMMENT:

ITAAC verification is needed for three element control mode discussed in the design description. Proposed insertion for Table 2.2.3 is the following:

Design Commitment: At high FW flow, the FDWC system controls FW flow in automatic/manual three-element modes, using RPV water level, steam flow, and FW flow.

Inspections, Test and Analysis: Tests will be performed by simulating an increase/ decrease in RPV water level or steam flow

GE RESPONSE:

GE does not concur that this material should be added to CDM Section 2.2.3. The basis for this position is the GE/NRC agreement on Feedwater Control System (FDWC) functional testing which was reached during March 1993 (GE/NRC/NUMARC) meetings.

The GE/NRC agreement was based on:

1) The FDWC System is not classified as safety-related but is related to safety in that it is associated with water addition to the reactor pressure vessel (RPV). Consequently, the CDM should address FDWC functionality.
(Continued on next page...)

PROPOSED CHANGES

CDM: None

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.3 FDWC No. 1 (Continued)

NRC COMMENT: (Continued)

Acceptance Criteria: A signal to increase/decrease FW flow (corresponding to the input signal) will occur to maintain RPV water level.

GE RESPONSE: (Continued)

2) The FDWC function of most relevance to safety is to add water under conditions of decreasing RPV level. This function is verified by entry #2 in Table 2.2.3 which is (essentially) the same as item 8 in the material referenced below.

3) It is not necessary for the CDM to address other control parameters since these relate to plant operational characteristics.

Consequently, GE does not propose to make any changes in response to this NRC comment.

REFERENCE:

Attached marked-up Control Copy of the FDWC System CDM agreed to by NRC and GE at the March 1993 meetings.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.2 CRDS No. 4

NRC COMMENT:

The electrical separation between Class 1E and non-1E is not addressed in ITAAC Item 9 for the power to the FMCRDs. Suggest that appropriate portions of ITAAC item 8 that deal with electrical separation be copied into DD, ITA, and AC for Item 9.

GE RESPONSE:

~~GE concurs that the issue of electrical independence for the FMCRD separation switches needs to be addressed and has included proposed changes in response to Section 2.2.2, comment No. 1.~~

(Continued on next page...)

PROPOSED CHANGES

CDM: ~~See response to Section 2.2.2, comment No. 1~~

None

SSAR: None

CDM SECTION AND COMMENT No.: 2.2.2 CRDS No. 4 (Continued)

GE RESPONSE: (Continued)

Revised Response

The issue of power supplies to the FMCRDs is addressed in CDM Section 2.12.1 where it is clearly stated that the FMCRD units are connected to the Class 1E EPD System. Entry No. 16 in Table 2.12.1 addresses power supply separation – including the 1E-non-1E interface at the FMCRDs. Consequently GE does not believe any CDM changes are necessary as a result of this NRC comment.

2.2.2 Control Rod Drive System

Design Description

The Control Rod Drive (CRD) System controls changes in core reactivity during power operation by movement and positioning of the neutron absorbing control rods within the core in fine increments in response to control signals from the Rod Control and Information System (RCIS). The CRD System provides rapid control rod insertion (scram) in response to manual or automatic signals from the Reactor Protection System (RPS). Figure 2.2.2a shows the basic system configuration and scope.

delete to read: 2.2.2

The CRD System consists of three major elements: (1) the electro-hydraulic fine motion control rod drive (FMCRD) mechanisms, (2) the hydraulic control unit (HCU) assemblies, and (3) the control rod drive hydraulic system (CRDHS). The FMCRDs provide electric-motor-driven positioning for normal insertion and withdrawal of the control rods and hydraulic-powered rapid control rod insertion (scram) for abnormal operating conditions. Simultaneous with scram, the FMCRDs also provide electric-motor driven run-in of control rods as a path to rod insertion that is diverse from the hydraulic-powered scram. The hydraulic power required for scram is provided by high pressure water stored in the individual HCUs. An HCU can scram two FMCRDs. It also provides the flow path for purge water to the associated drives during normal operation. The CRDHS supplies pressurized water for charging the HCU scram accumulators and purging to the FMCRDs.

There are 205 FMCRDs mounted in housings welded into the reactor vessel bottom head. The FMCRD has a movable hollow piston tube that is coupled at its upper end, inside the reactor vessel, to the bottom of a control rod. The FMCRD can move the control rod up or down over its entire range, by a ball nut and ball screw driven at a speed of 30 mm/sec ±10% by the electric stepper motor. In response to a scram signal, the piston inserts the control rod into the core hydraulically using stored energy in the HCU scram accumulator. The scram water is introduced into the drive through a scram inlet connection on the FMCRD housing, and is then discharged directly into the reactor vessel via clearances between FMCRD parts. The average scram times of all FMCRDs with the reactor pressure as measured at the vessel bottom below 76.5 kg/cm^2g are:

Percent Insertion	Time (sec)
10	≤ 0.42
40	≤ 1.00

and ball check valve; the internal drive housing support; the FMCRD separation switches; and the HCU charging water header pressure instrumentation.

Figure 2.2.2 shows the ASME Code class for the CRD System piping and components.

The CRD System is located in the Reactor Building. The FMCRDs are mounted to the reactor vessel bottom head inside primary containment. The HCUs and CRDHS equipment are located in the Reactor Building at the basemat elevation.

Each of the four divisional HCU charging header pressure sensors are powered from their respective divisional Class 1E power supply. Independence is provided between the Class 1E divisions for these sensors and also between the Class 1E divisions and non-Class 1E equipment.

For their preferred source of power, the FMCRDs are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E Plant Investment Protection (PIP) bus.

The hydraulic portion of the CRD System which performs the scram function is physically separated from and independent of the Standby Liquid Control System.

The CRD System has the following alarms, displays, and controls in the main control room:

(1) Alarms for separation of the hollow piston from the ball-nut and low HCU accumulator gas pressure.

(2) Parameter displays for the instruments shown in Figure 2.2.2.

(3) Controls and status indication for the CRD pumps and flow control valves shown on Figure 2.1.2. X
2

(4) Status indication for the scram valve position.

The following CRD System safety-related electrical equipment are located in either the Reactor Building or primary containment and are qualified for a harsh environment: the HCU charging header pressure instrumentation, the scram solenoid pilot valves, and FMCRD separation switches.

The check valves (CVs) shown inside the HCU boundary on Figure 2.2.2 and the FMCRD ball check valves have active safety-related functions to close under system pressure, fluid flow, and temperature conditions.

The piping and components of the CRD pump suction supply, which extends from the CRD System interfaces with the Condensate Feedwater and Air Extraction (CFCAE)

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Table 2.2.2 Control Rod Drive System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
~~11~~ 12. CVs designated in Section 2.2.2 as having an active safety-related function close under system pressure, fluid flow, and temperature conditions.	~~11~~ 12. Tests of installed valves for closing will be conducted under system preoperational pressure, fluid flow, and temperature conditions.	~~11~~ 12. Each CV closes.

New # 9

9. For the FMCRD separation switches, independence is provided between the Class 1E divisions and also between the Class 1E divisions and non-Class 1E equipment.	9. Inspections of the as-installed Class 1E divisions in the CRD System will be performed.	9. In the CRD System, physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between Class 1E divisions and non-Class 1E equipment.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.2 CRDS No. 3

NRC COMMENT:

The design description should be corrected as shown in the attached mark-up.

GE RESPONSE:

GE concurs and will include in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC markup; see attached pages 2.2.2-1, 2.2.2-3.

SSAR: None

and ball check valve; the internal drive housing support; the FMCRD separation switches; and the HCU charging water header pressure instrumentation.

Figure 2.2.2 shows the ASME Code class for the CRD System piping and components.

The CRD System is located in the Reactor Building. The FMCRDs are mounted to the reactor vessel bottom head inside primary containment. The HCUs and CRDHS equipment are located in the Reactor Building at the basemat elevation.

Each of the four divisional HCU charging header pressure sensors are powered from their respective divisional Class 1E power supply. Independence is provided between the Class 1E divisions for these sensors and also between the Class 1E divisions and non-Class 1E equipment.

For the FMCRD separation switches, independence is provided between the Class 1E divisions and also between the Class 1E divisions and non-Class 1E equipment.

For their preferred source of power, the FMCRDs are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E Plant Investment Protection (PIP) bus.

The hydraulic portion of the CRD System which performs the scram function is physically separated from and independent of the Standby Liquid Control System.

The CRD System has the following alarms, displays, and controls in the main control room:

(1) Alarms for separation of the hollow piston from the ball-nut and low HCU accumulator gas pressure.

(2) Parameter displays for the instruments shown in Figure 2.2.2.

(3) Controls and status indication for the CRD pumps and flow control valves shown on Figure ~~2.1.2.~~ 2.2.2

(4) Status indication for the scram valve position.

The following CRD System safety-related electrical equipment are located in either the Reactor Building or primary containment and are qualified for a harsh environment: the HCU charging header pressure instrumentation, the scram solenoid pilot valves, and FMCRD separation switches.

The check valves (CVs) shown inside the HCU boundary on Figure 2.2.2 and the FMCRD ball check valves have active safety-related functions to close under system pressure, fluid flow, and temperature conditions.

The piping and components of the CRD pump suction supply, which extends from the CRD System interfaces with the Condensate Feedwater and Air Extraction (CFCAE)

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Table 2.2.2 Control Rod Drive System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. Two redundant and separate switches in the FMCRD detect separation of the hollow piston from the ball nut.	6. Tests of each as-built FMCRD will be conducted.	6. Both switches in each FMCRD detect separation of the hollow piston from the ball nut.
7. Following receipt of an ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open.	7. Tests will be conducted on the as-built ARI valves using a simulated actuation signal.	7. Following receipt of a simulated ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open.
8. Each of the four divisional HCU charging header pressure sensors are powered from their respective divisional Class 1E power supply. For the four HCU charging water header pressure sensors, independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	8. a. Tests will be conducted on the as-built charging water header sensors by providing a test signal in only one Class 1E division at a time. b. Inspections of the as-installed charging water header sensor Class 1E divisions will be conducted.	8. a. The test signal exists only in the Class 1E Division under test. b. Physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class 1E equipment.
9.		
~~9.~~ 10 For their preferred source of power, the FMCRDs are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E PIP bus.	~~9.~~ 10 Inspections of the as-built CRD System will be conducted.	~~9.~~ 10 For their preferred source of power, the FMCRD motors are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E PIP bus.
~~10.~~ 11 Main control room alarms, displays and controls provided for the CRD System are defined in Section 2.2.2.	~~10.~~ 11 Inspections will be performed on the main control room alarms, displays and controls for the CRD System.	~~10.~~ 11 Alarms, displays and controls exist or can be retrieved in the main control room as defined in Section 2.2.2.

Add new #9 - see p2.2.2-8

Percent Insertion	Time (sec)
60	≤ 1.44
100	≤ 2.80

These times are measured starting from loss of signal to the scram solenoid pilot valves in the HCUs.

The FMCRD has an electro-mechanical brake with a minimum holding torque of 5 kg-m on the motor drive shaft and a ball check valve at the point of connection with the scram inlet line.

, Class 1E,

Two redundant and separate switches in the FMCRD detect separation of the hollow piston from the ball nut. Independence is provided between the Class 1E divisions for ~~these~~ switches.

There are 103 HCUs, each of which provides water stored in a pre-charged accumulator for scramming two FMCRDs. Figure 2.2.2 shows the major HCU components. The accumulator is connected to its associated FMCRDs by a hydraulic line that includes a scram valve held closed by pressurized control air. To cause a scram, the RPS provides a signal to de-energize the scram solenoid pilot valve (SSPV) that vents the control air from the scram valve, which then opens by spring action. Loss of either electrical power to the SSPV or loss of control air pressure causes scram. A pressure switch detects low accumulator gas pressure and actuates an alarm in the main control room.

The CRD System also provides alternate rod insertion (ARI) as a means of actuating hydraulic scram when an anticipated transient without scram (ATWS) condition exists. Following receipt of an ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open. The control rod drives then insert the control rods hydraulically.

The CRDHS has pumps, valves, filters, instrumentation, and piping to supply pressurized water for charging the HCUs and purging the FMCRDs.

The CRD System components classified as safety-related are: the HCU components required for scram; the FMCRD components required for scram; the scram inlet piping; the FMCRD reactor coolant primary pressure boundary components; the FMCRD brake and ball check valve; the internal drive housing support; the FMCRD separation switches; and the HCU charging water header pressure instrumentation.

The CRD System components classified as Seismic Category I are: the HCU components required for scram; the FMCRD components required for scram; the scram inlet piping; the FMCRD reactor coolant primary pressure boundary components; the FMCRD brake

Table 2.2.2 Control Rod Drive System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. Two redundant and separate switches in the FMCRD detect separation of the hollow piston from the ball nut.	6. Tests of each as-built FMCRD will be conducted.	6. Both switches in each FMCRD detect separation of the hollow piston from the ball nut.
7. Following receipt of an ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open.	7. Tests will be conducted on the as-built ARI valves using a simulated actuation signal.	7. Following receipt of a simulated ARI signal, solenoid valves on the scram air header open to reduce pressure in the header, allowing the HCU scram valves to open.
8. Each of the four divisional HCU charging header pressure sensors are powered from their respective divisional Class 1E power supply. For the four HCU charging ~~water header pressure sensors,~~ independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	8. a. Tests will be conducted on the as-built ~~charging water header sensors~~ switches by providing a test signal in only one Class 1E division at a time. b. Inspections of the as-installed ~~charging water header sensor~~ switch Class 1E divisions will be conducted.	8. a. The test signal exists only in the Class 1E Division under test. b. Physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class 1E equipment.
9. For their preferred source of power, the FMCRDs are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E PIP bus.	9. Inspections of the as-built CRD System will be conducted.	9. For their preferred source of power, the FMCRD motors are collectively powered from one Class 1E division; for their alternate source of power, they are collectively powered from one non-Class 1E PIP bus.
10. Main control room alarms, displays and controls provided for the CRD System are defined in Section 2.2.2.	10. Inspections will be performed on the main control room alarms, displays and controls for the CRD System.	10. Alarms, displays and controls exist or can be retrieved in the main control room as defined in Section 2.2.2.

analyzed along with the Reactor Protection System (trip) discussed in Section 7.2.

With regard to IEEE-279, Section 4.7, signals which interface between ARI and RPS are optically isolated such that postulated failures within the ARI controls cannot affect the safety-related scram function.

The RCIS logic has been designed such that ~~no~~ a single failure ~~results in failure to insert more than one operable control rod~~, only in the inverter controller part of a ~~particular~~ given rod drive logic, may result in insertion failure of that rod when the ARI function is activated. Also, two manual actions are required at the dedicated operator interface panel to manually initiate ARI.

(2) General Design Criteria (GDC)

(a) **Criteria: GDCs 13, 19, and 25.**

(b) **Conformance:** The ARI is in compliance (in part, or as a whole, as applicable) with these GDCs. All GDCs are generically addressed in Subsection 3.1.2.

(3) Regulatory Guides (RGs)

(a) RG 1.75--*Physical Independence of Electric Systems*

The ARI is not required for safety, nor are its components considered Class 1E. The subsystem derives control power from the non-1E UPS buses. However, for ATWS considerations, the reliability of the subsystem is enhanced by using Class 1E power for the drive motors.

There are three separate groups of non-1E drives with each receiving power from Division I Class 1E bus. Class 1E circuit breakers are used as isolation devices in accordance with IEEE-384. The breakers are designed to trip on fault current only and are not tripped for LOCA. However, the breaker coordination is assured through the use of zone selective interlocks (ZSI) (Subsection 8.3.1.1.1).

A LOCA trip of these breakers could preclude the advantages of ARI for postulated ATWS conditions.

The ZSI feature assures that the FMCRDs power breaker time-over-current trip characteristic for all circuit faults shall cause the breaker to interrupt the fault current prior to trip initiation of any upstream breaker. The power source shall supply the necessary fault current for sufficient time to ensure the proper coordination without loss of function of Class 1E loads. The ZSI is a new technology which assures

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.2 CRDS No. 1

NRC COMMENT:

The design description for the switches that detect separation of the FMCRD piston and ball nut need to be identified as Class 1E (see attached mark-up). Reference SSAR section 4.6.2.2.6 page 4.6-9.

GE RESPONSE:

GE and NRC agreed that it was not necessary in the CDM to identify which electrical components are Class 1E provided these components are covered in the CDM entry which identifies which part(s) of the system are safety related.

GE believes the existing CDM adequately addresses the classification of these switches. The last full paragraph on page 2.2.2-2 states the switches are safety-related (which for electrical equipment is the same as Class 1E) and the pen ultimate full paragraph on page 2.2.2-3 addresses qualification. GE agrees to add an entry on independence.

PROPOSED CHANGES

CDM: See attached markup.

SSAR: None

This setup and action by the operator sends rod coordinates and other setup data to the PMCS. The data representing a single rod to be withdrawn is coded and stored in PMCS memory. The PMCS addresses the RCIS and sends the coded messages. The coded messages are received at the RCIS and stored in the Rod Position and Information Subsystem memory. The operator has an option to stop the rod movement by using the light pen. Touching the "SINGLE ROD" poke point a second time causes rod motion stop signals to be sent to the RCIS interface.

The information displayed to the operator at this time is the vertical position of the rod selected and it remains displayed until a new selection is made or the rod is deselected. The display array boxes representing all other rods in the core at this time dim to approximately half brightness.

The CRT display stores information in memory during the initial setup and transmits the information to the PMCS. When the operator initializes the last poke point (ROD SELECTED), the information stored in memory addressing the manual rod movement command signals in the PMCS are downloaded, as two independent signals, into channels A and B of the RCIS Rod Action and Position Information (RAPI) Subsystems.

The RCIS receives the two independent streams of data signals transmitted from the PMCS. The data are received and loaded into memory at the RAPI Subsystems (channel A/B). Both channel A/B are identical and perform the same functions. If there is a disagreement between A and B, the logic issues a rod motion inhibit signal. The operator has the capability to bypass certain functions in the manual mode.

ATLM

The PMCS also sends data to the automated thermal limit monitor (ATLM) of the RCIS on the calculated fuel thermal operating limits and corresponding initial LPRM values when an ATLM setpoint update is requested.

The logic of the Automated Thermal Limit Monitor (ATLM) subsystem issues a rod block signal that is used in the RAPI System logic to enforce a rod block that prevents violation of the fuel thermal operating limits. The ATLM interfaces with and receives signals from the RAPI Subsystem control logic for rod position data, other plant data and control signals.

The ATLM interfaces with Recirculation Flow Control (RFC) System and when it trips, a signal is sent to the RFCS which would cause a flow increase block.

The ATLM also receives input signals, based upon the LPRMs and APRMs of the Neutron Monitoring System (NMS). The RAPI Subsystem logic enforces

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.1 RCIS No. 7

NRC COMMENT:

The wording for SAR section 7.4.2.1.2(1) is not clear. Is the intent to state that any single failure will cause at most only one operable control rod insertion failure (page 7.4-18)? The sentence requires clarification.

GE RESPONSE:

GE concurs that this SSAR entry needs clarification and will make the changes shown on the attached markup in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per the attached.

Verified

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.1 RCIS No. 3

NRC COMMENT:

ITAAC design commitment #4 references "automatic thermal power monitor". Design description (2) describes a "automatic thermal limit monitor" and SSAR 7.7.1.2.1 references an "automatic thermal limit monitor, page 7.7-15. The terms need to be made consistent. ITAAC #4 should read "automatic thermal power limit".

GE RESPONSE:

The subsystem of the RCIS which simulates fuel thermal conditions and can a) initiate a block signal and b) block RFCS flow increases is the Automated Thermal Limit Monitor (ATLM). Consequently GE believes:

- CDM DD Item (2) is correct.
- SSAR page 7.7-15 is correct.
- CDM ITAAC entry #4 should be modified per the attached.

PROPOSED CHANGES

CDM: Per attached markup.

SSAR: None. (See copy of SSAR page 7.7-15 which uses the term Automated Thermal Limit Monitor.)

R- 8/94

Table 2.2.1 Rod Control and Information System

ATLM

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspection, Tests, Analyses**	**Acceptance Criteria**
1. The equipment comprising the RCIS is defined in Section 2.2.1.	1. Inspections of the as-built system will be conducted.	1. The as-built RCIS conforms with the description in Section 2.2.1.
2. The RCIS consists of redundant microprocessor based controllers (except for controllers associated with individual FMCRDs).	2. Tests will be performed by simulating failure of each operating RCIS controller.	2. There is no loss of RCIS output upon loss of any one controller.
3. The RCIS provides a rod worth minimizer which uses control rod position signals to enforce preestablished sequences for control rod movement when the reactor power (neutron flux) is below the low power setpoint by issuing a control rod block signal when an out of sequence control rod movement is attempted.	3. Tests will be conducted on the RCIS using simulated control rod position signals, and simulated neutron flux signals.	3. A control rod block signal occurs when an out-of-sequence control rod movement is simulated and when reactor power is below the low power setpoint.
4. The RCIS provides an ~~automatic thermal power monitor~~ which uses control rod position signals, neutron flux signals, and fuel operating thermal limits to enforce fuel thermal limits when the reactor power is above the low power setpoint and the plant is in automatic operation.	4. Tests will be conducted on the RCIS using simulated control rod position signals, neutron flux signals, and fuel operating thermal limits.	4. A control rod block signal occurs upon simulation of a control rod movement which would cause fuel thermal limits to be approached.
5. The RCIS provides a selected control rod run-in function which uses a signal from the RFC System to insert selected control rods into the core.	5. Tests will be conducted on the RCIS using simulated control rod run-in signal from RFC System.	5. A control rod insertion signal occurs for those positions assigned to this function upon receipt of a simulated signal from the RFC System.
6. The RCIS provides an automatic control rod run-in which uses a scram-follow signal from the RPS to insert all control rods into the core.	6. Tests will be conducted on the RCIS using a simulated scram-follow signal from the RPS.	6. A control rod run-in signal occurs upon receipt of a simulated scram-follow signal.

receipt of signal at the valve actuator to the

For overpressure relief valve operation (power-actuated mode), reactor vessel pressure sensors generate a high pressure trip signal which is used to initiate opening the SRVs. Valve opening is initiated when an electrical signal is received at the solenoid valve associated with power actuated relief (Figure 2.1.2d). The SRV relief mode opening time from the ~~[illegible]~~ full ASME lift position is less than or equal to ~~0.15~~ seconds when the reactor pressure is at or above 70 kg/cm^2 gauge. 0.25

The SRV pneumatic operator is so arranged that, if it malfunctions, it does not prevent the SRV from opening when steam inlet pressure reaches the spring lift setpoint. Each SRV is provided with its own pneumatic accumulator and inlet check valve for power actuated relief as shown in Figure 2.1.2d.

The SRVs are either DC powered, or powered from uninterruptible AC.

(3) Automatic depressurization system (ADS) operation: The ADS valves open automatically or manually in the power actuated mode when required during a loss-of-coolant accident (LOCA). Eight of the eighteen SRVs are designated as ADS valves and are capable of operating from either ADS LOCA logic or overpressure relief logic signals. The above table identifies the ADS SRVs.

The ADS accumulator capacity can open the SRV with the drywell pressure at design pressure following failure of the pneumatic supply to the accumulator.

The SRVs can be operated individually in the power-actuated mode by remote manual switches located in the main control room. They are provided with position sensors which provide positive indication of SRV disk/stem position.

Automatic Depressurization System

As shown in Figure 2.1.2f, the NBS channel measurements are provided for the Safety System Logic and Control (SSLC) for signal processing, setpoint comparisons, and generating trip signals. Except for the pump running permissive, the SSLC uses a two-out-of-four voting logic for ADS initiation. The ADS logic is automatically initiated when a low reactor water level signal is present. If the RPV low water level signal is present concurrently with high drywell pressure signal, both the main ADS timer (less than or equal to 29 seconds) and the high drywell pressure bypass timer (less than or equal to 8 minutes) are initiated. Absent a concurrent high drywell pressure signal, only the ADS high drywell pressure bypass timer is initiated. Upon the time out of the ADS high drywell pressure bypass timer, concurrent with RPV low water level signal, the main ADS timer is initiated, if not already initiated. The main timer continues to completion and times out only in the continued presence of an RPV low water level signal. Upon time out of the main ADS timer, concurrent with positive indication by pump discharge pressure of at least one RHR or one HPCF pump running, the ADS function is initiated.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.3 R RRS No. 1

NRC COMMENT:

The minimum dry rotating inertia (17.5 kg-m^2) of the RIP stated in the design description conflicts with the value of 19.5 kg-m^2 stated in SSAR Table 5.4-1. The description and ITAAC entry [illegible] should be revised.

GE RESPONSE:

The CDM correctly states that the RIP dry rotating inertia is not less than 17.5 kg-m^2. SSAR Amendment 33, Table 5.4-1 incorrectly uses the 19.5 value. This will be corrected in Amendment 34.

PROPOSED CHANGES

CDM: None

SSAR: Table 5.4-1 will be corrected to show RIP dry rotating inertia of 17.55 – 26.5 kg-m^2.

Verified

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.2 NBS No. 7

NRC COMMENT:

The design description (page 2.1.2-4) should include the requirement that the maximum elapsed time between receiving the overpressure signal at the valve actuator and actual start of SRV motion will not exceed 0.1 sec (SSAR 5.2.2.4.1) and be verified by an ITAAC entry.

GE RESPONSE:

GE concurs and will modify the DD text and ITAAC table entry no. 9b. to reflect a 0.25 second opening time between receipt of signal at the valve actuator to the valve full open. This change will be included in the next revision of 25A5447.

PROPOSED CHANGES

CDM: See attached markups.

SSAR: None.

Table 2.1.2 Nuclear Boiler System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
7. When all MSIVs are closed, the combined leakage through the MSIVs for all four MSLs is less than or equal to 66.1 liters per minute at standard temperature (20°C) and pressure (one atmosphere absolute pressure) with the differential pressure across the MSIV equal to, or greater than, 1.76 kg/cm^2 gauge.	7. Test and analysis will be conducted on the as-built MSIVs to determine the leakage.	7. When all MSIVs are closed, the combined leakage through the MSIVs for all four MSLs is less than or equal to 66.1 liters per minute at standard temperature (20°C) and pressure (one atmosphere absolute pressure) with the differential pressure across the MSIV equal to, or greater than, 1.76 kg/cm^2 gauge.
8. Springs close the MSIV if pneumatic pressure to the MSIV actuator is lost.	8. Tests will be conducted on the as-built MSIV.	8. The MSIV closes when pneumatic pressure is removed from the MSIV actuator.
9.	9.	9.
a. The SRV spring set pressure and flow capacities are given in Section 2.1.2. The opening time for the SRVs from the time the pressure exceeds the valve set pressure to the time the valve is fully open, is less than or equal to 0.3 seconds.	a. Analysis and tests (at a test facility) will be conducted in accordance with the ASME Code.	a. The SRVs have the capacities and set pressures shown on Section 2.1.2. The opening time for the SRVs from the time the pressure exceeds the valve set pressure to the time the valve is fully open is less than or equal to 0.3 seconds.
b. The SRV relief mode opening time from the ~~start of steam motion to~~ full ASME lift position is less than or equal to ~~0.15~~ seconds when the reactor vessel pressure is at or above 70 kg/cm^2 gauge.	b. Tests of the SRVs will be conducted at a test facility.	b. The SRV relief mode opening time from the ~~start of steam motion to~~ full ASME lift position is less than or equal to ~~0.15~~ seconds.

0.25

0.25

receipt of signal at the valve actuator to the

2.1.2a, 2.1.2b and 2.1.2d

Safety/Relief Valves

The safety/relief valves (SRVs) are located on the MSLs between the RPV and the inboard MSIV. These valves protect against overpressurization of the RCPB. Figures ~~[illegible]~~ show the general configuration of the SRVs and the SRV discharge lines.

The rated capacity of the SRVs is sufficient to prevent a rise in pressure within the RPV of more than 110% of the design pressure (96.7 kg/cm^{2}gauge) for design basis events.

The SRV discharge lines are sized so that critical flow conditions occur through the valve. Each SRV has its own discharge line. The SRV discharge lines terminate at quenchers located below the surface of the suppression pool.

The SRVs provide three main protection functions:

(1) Overpressure safety operation: The valves function as spring-loaded safety valves and open to prevent RCPB overpressurization. The valves are self-actuated by inlet steam pressure.

The following table identifies the SRV spring set pressures and flow capacities. The opening time for the SRVs, from the time the pressure exceeds the valve set pressure to the time the valve is fully open, is less than or equal to 0.3 seconds.

Set Pressures and Capacities

SRVs	Number* of Valves	Nameplate Spring Set Pressure (kg/cm^{2}g)†	ASME Rated Capacity at 103% Spring Set Pressure (kg/hr each)‡	Used For ADS
J, P	2	80.8	395,000	
B, G, M, S	4	81.5	399,000	
D, E, K, U	4	82.2	402,000	
C, H, N, T	4	82.9	406,000	X
A, F, L, R	4	83.6	409,000	X

* Eight of the SRVs serve in the automatic depressurization system function.

† Spring set pressure tolerances as permitted by the ASME Boiler and Pressure Vessel Code, Section III.

‡ Minimum capacity per the ASME Boiler and Pressure Vessel, Section III.

(2) Overpressure relief operation: The valves are opened using a pneumatic actuator upon receipt of an automatic or manually initiated signal.

Other Provisions

The NBS equipment identified as safety-related is classified as Seismic Category I except for the American Society of Mechanical Engineers (ASME) Class 3 equipment shown on Figure 2.1.2c. The non-safety-related section of the feedwater lines between the 2.1.2c seismic interface restraint and the motor-operated valves shown in Figure [illegible] is classified as Seismic Category I. The MSL drain lines from the MSLs to the Main Condenser are seismically analyzed to withstand the Safe Shutdown Earthquake (SSE).

Figures 2.1.2a, 2.1.2b, and 2.1.2c show the ASME Boiler and Pressure Vessel Code classes.

The divisional equipment in the NBS is powered from its respective Class 1E divisions as shown in Figures 2.1.2b, 2.1.2d, and 2.1.2e. In the NBS, independence is provided between Class 1E divisions, and also between Class 1E divisions and non-Class 1E equipment.

The NBS has the following displays and controls in the main control room:

(1) Parameter displays for the instruments shown on Figures 2.1.2b and 2.1.2e. This includes the reactor vessel pressure, reactor vessel water level, drywell pressure, main condenser vacuum, and turbine inlet pressure.

(2) Controls and status indication for the active safety-related components shown on Figures 2.1.2b, 2.1.2c (excluding the inboard FW line check valves, and the ASME Boiler and Pressure Vessel Code Class 2 check valves), and 2.1.2d.

(3) Manual system level initiation capability for the ADS.

(4) Manual capability to inhibit automatic initiation of the ADS.

NBS components with displays and control interfaces with the Remote Shutdown System (RSS) are shown on Figures 2.1.2a and 2.1.2e.

The safety-related electrical equipment (including instrumentation and controls) shown on Figures 2.1.2b, 2.1.2c, 2.1.2d, and 2.1.2e located in the containment, steam tunnel and Reactor Building, is qualified for a harsh environment.

The MOVs shown on Figure 2.1.2b (except for the ASME Boiler and Pressure Vessel Code Class 2 MOV) have an active safety-related function to close, and perform this function under differential pressure, fluid flow, and temperature conditions.

The check valves (CVs) shown on Figures 2.1.2c and 2.1.2d (ADS pneumatic CVs only) have the safety-related functions to open, close, or both open and close under system pressure, fluid flow, and temperature conditions.

2.1.2 Nuclear Boiler System

Design Description

General System Description

The primary functions of the Nuclear Boiler System (NBS) are:

(1) Deliver steam from the Reactor Pressure Vessel (RPV) to the Main Steam (MS) System.

(2) Provide containment isolation of the main steamlines (MSLs) and the feedwater (FW) lines.

(3) Deliver feedwater from the Condensate, Feedwater, and Condensate Air Extraction (CFCAE) System to the RPV.

(4) Provide overpressure protection of the reactor coolant pressure boundary (RCPB).

(5) Provide automatic depressurization of the RPV in the event of a loss- of-coolant accident (LOCA) where the RPV does not depressurize rapidly and the high pressure makeup systems fail to adequately maintain the water level in the RPV.

(6) Provide instrumentation to monitor the drywell pressure and RPV pressure, metal temperature, and water level.

Figures 2.1.2a, 2.1.2b, 2.1.2c, 2.1.2d, and 2.1.2e show the basic system configuration and scope. Figure ~~2.1.1f~~ shows the NBS control interfaces.

2.1.2f

The NBS equipment shown on Figures 2.1.2a, 2.1.2b, 2.1.2c, 2.1.2d, and 2.1.2e is classified as safety-related except for the non-safety-related part of the MSL drains, equipment associated with the power actuated relief mode of the SRVs, the SRV discharge pipe temperature sensors, and the non-safety-related instruments shown on Figure 2.1.2e.

Main Steam Lines

The MSLs direct steam from the RPV to the MS System. The NBS contains only the portion of the MSLs from their connection to the RPV to the boundary with the MS System, which occurs at the seismic interface located downstream of the outboard main steam isolation valves (MSIVs). Figures 2.1.2a and 2.1.2b show the general configuration of the MSLs and the MSL drain lines. The MSL drain lines provide a flow path for the MSIV leakage during an accident.

The combined volume of the steamlines, from the RPV to the main steam turbine stop valves and turbine bypass valves, is greater than or equal to 113.2 m^3.

Each MSL has a flow limiter. The MSL flow limiter consists of a flow restricting venturi which is located in each RPV MSL outlet nozzle. The restrictor limits the coolant blowdown rate from the RPV, in the event that a MSL break occurs outside the containment, to a flow rate equal to or less than 200% of rated steam flow at 72.1 kg/cm^2 g upstream pressure. The throat diameter of each MSL flow limiter is less than or equal to 355 mm.

2.1.2b

The pneumatic-operated valve in the MSL drain line shown in Figure ~~[illegible]~~b opens, if either electric power to the valves actuating solenoid is lost, or pneumatic pressure to the valve is lost.

The MSLs and the MSL drain lines are located in the drywell and the steam tunnel.

Main Steam Isolation Valves

Two isolation valves are located in a horizontal run of each of the four main steamlines; one valve is inside of the drywell, and the other is near the outside of the primary containment pressure boundary.

The MSIV closing time is equal to or greater than 3 seconds and less than or equal to 4.5 seconds when N_2 or air is admitted to the MSIV actuator. The MSIVs are capable of closing within 3 to 4.5 seconds under differential pressure, fluid flow and temperature conditions. When all the MSIVs are closed, the combined leakage through the MSIVs for all four MSLs is less than or equal to 66.1 liters per minute at standard temperature (20°C) and pressure (one atmosphere absolute pressure) with the differential pressure across the MSIV equal to, or greater than 1.76 kg/cm^2 gauge.

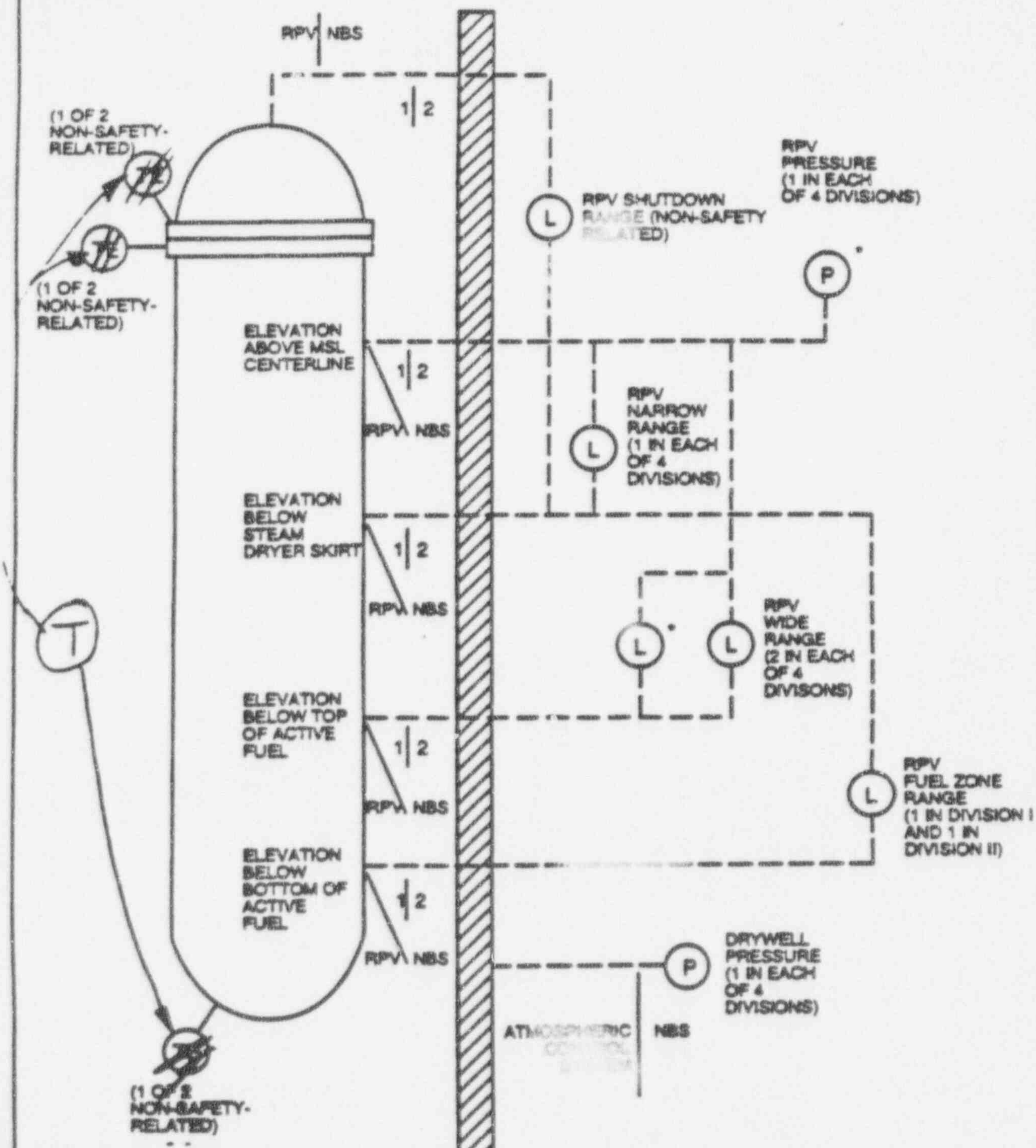
The MSIV's primary actuation mechanism for opening and closing is pneumatic. Springs close the MSIV if pneumatic pressure to the MSIV actuator is lost.

Feedwater Lines

The FW lines direct feedwater from the CFCAE System to the RPV. The NBS contains only the portion of the FW lines from the seismic interface located upstream of the motor-operated valves (MOVs) to their connections to the RPV. Figure ~~[illegible]~~c shows the portion of the FW lines within the NBS.

2.1.2c

Isolation of each FW line is accomplished by two containment isolation valves consisting of one check valve inside the drywell and one positive closing check valve outside the containment. The FW line isolation check valves are qualified to withstand a FW line break outside the primary containment. The FW line upstream of the outboard isolation valve contains an MOV and a seismic interface restraint.



* DISPLAY AND/OR CONTROL INTERFACES WITH RSS (2 OF 4 DIVISIONS)

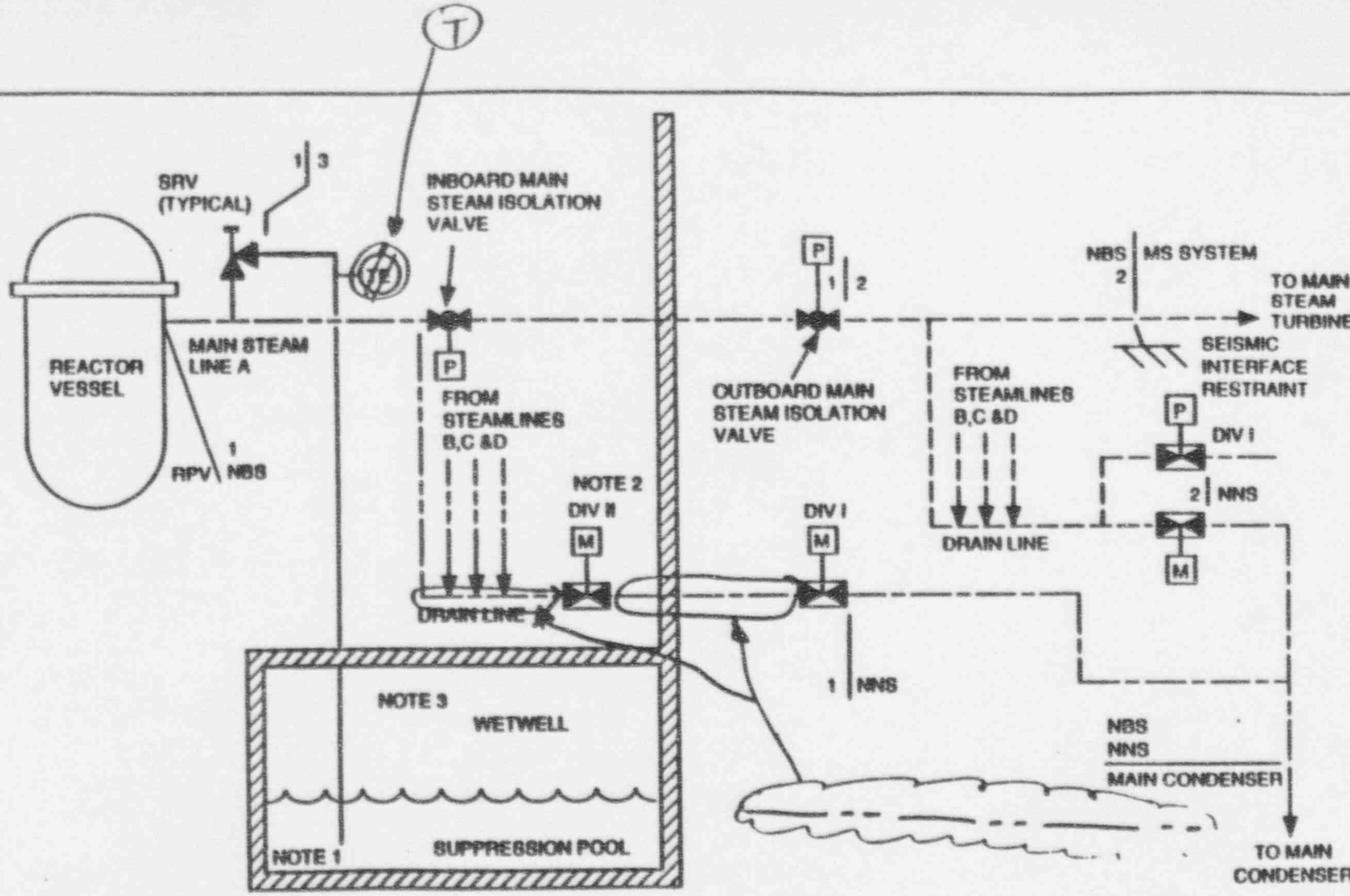
NOTES:
1. EACH OF FOUR DIVISIONS OF NBS INSTRUMENTATION HAS ONE TURBINE INLET PRESSURE SENSOR AND ONE MAIN CONDENSER VACUUM SENSOR.
2. EACH DIVISION IS POWERED BY ITS RESPECTIVE CLASS 1E DIVISION.
3. THE MAIN CONDENSER VACUUM SENSORS ARE LOCATED ABOVE THE TURBINE BUILDING DESIGN BASIS FLOOD LEVEL.

Figure 2.1.2e NBS Drywell Pressure and Reactor Vessel Instrumentation

2.1.2a, 2.1.2b, 2.1.2c, 2.1.2d, 2.1.2e, and 2.1.2f

Table 2.1.2 Nuclear Boiler System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the NBS is shown in Figures ~~2.1.1a, 2.1.1b, 2.1.1c, 2.1.1d, 2.1.1e, and 2.1.1f~~.	1. Inspections will be conducted for the NBS System.	1. The as-built NBS conforms with the basic configuration shown in Figures ~~2.1.1a, 2.1.1b, 2.1.1c, 2.1.1d, 2.1.1e, and 2.1.1f~~.
2. The ASME Code components of the NBS System retain their pressure boundary integrity under internal pressures that will be experienced during service.	2. A hydrostatic test will be conducted on those Code components of the NBS required to be hydrostatically tested by the ASME Code.	2. The results of the hydrostatic test of the ASME Code components of the NBS conform with the requirements in the ASME Code, Section III
3. The combined volume of the four main steamlines (MSLs) and branch lines from the RPV to the main steam turbine stop valves and turbine bypass valves is greater than or equal to 113.2 m^3.	3. Analyses will be performed using as-built dimensions of the steamlines to determine the combined steamline volume.	3. The combined steamline volume is greater than or equal to 113.2 m^3.
4. The throat diameter of each MSL flow limiter is less than or equal to 355 mm.	4. Inspections of the as-built MSL flow limiters will be conducted.	4. The throat diameter of each MSL flow limiter is less than or equal to 355 mm.
5. The pneumatic-operated valve in the MSL drain line shown in Figure ~~2.1.1b~~ opens if either electric power to the valve actuating solenoid is lost, or pneumatic pressure to the valve is lost.	5. Tests will be conducted on the as-built MSL drain valve.	5. The MSL pneumatic drain line valve shown in Figure ~~2.1.1b~~ opens when either electric power to the valve actuating solenoid is lost, or pneumatic pressure to the valve is lost.
6. MSIV closing time is equal to or greater than 3 seconds and less than or equal to 4.5 seconds when N_2 or air is admitted into the MSIV actuator. The MSIVs are capable of closing within 3 to 4.5 seconds under differential pressure, fluid flow and temperature conditions. 2.1.2b	6. conducted a. Tests of the as-built MSIV will be under preoperational differential pressure, fluid flow, and temperature conditions. b. Tests, or type tests, of an MSIV will be conducted under design basis differential pressure, fluid flow and temperature conditions.	6. The MSIV closing time is equal to or greater than 3 and less than or equal to 4.5 seconds. 2.1.2b



NOTES:
1. AT MINIMUM LEVEL
2. MAY BE PNEUMATIC
3. THE PIPING PRESSURE WELDS IN THE WETWELL AIRSPACE SHALL BE EXAMINED USING ASME CODE CLASS 2 REQUIREMENTS.
4. EACH MSIV HAS CLASS 1E POSITION SWITCHES WHICH RECEIVE POWER FROM ITS RESPECTIVE CLASS 1E DIVISION.
5. EACH SRV HAS POSITION SENSORS.
6. THE RCIC SYSTEM STEAM SUPPLY COMES FROM MAIN STEAM LINE B UPSTREAM OF THE INBOARD MSIV.

Figure 2.1.2b NBS Steamline

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.2 NBS No. 6

NRC COMMENT:

In the ITA column for entry #6, the word "conducted" should be added after "...MSIV will be..."

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.2 NBS No. 4

NRC COMMENT:

In Figures 2.1.2b and 2.1.2e, the temperature element should be shown as T, not TE, or the symbol for temperature in App. A should be changed to TE.

GE RESPONSE:

GE concurs and will change the symbol to T in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached markup for comment no. 6

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.2 NBS No. 5

NRC COMMENT:

All figure numbers in Table 2.1.2 and some figure numbers in the description are incorrect.

GE RESPONSE:

GE concurs and will correct these typographical errors in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached markup for comment no. 6

SSAR: None.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.2 NBS No. 1

NRC COMMENT:

Figure 2.1.2b: The piping symbol for the drain line piping (shown horizontally inside and outside the containment) is NNS though this piping is Class 1. This should be corrected.

GE RESPONSE:

GE concurs and will modify Figure 2.1.2b in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached or markup for comment no. 6

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUI COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.2 NBS No. 2

NRC COMMENT:

The design description for the ADS states that the high drywell pressure bypass timer is less than or equal to 8 minutes which is in conflict with SSAR Table 6.3-1 which shows this value to be >= 8 minutes.

GE RESPONSE:

The CDM is correct and the SSAR needs to be connected to state "equal to or less than 8 minutes." This change will be included in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

Verified

- Second Capsule: After 20 effective full-power years.
- Third Capsule: With an exposure not to exceed the peak EOL fluence.
- Fourth Capsule: Schedule determined based on results of first two capsules per ASTM E-185, Paragraph 7.6.2 (see Section 5.3.4.2 for additional capsule requirements). Fracture toughness testing of irradiated capsule specimens will be in accordance with requirements of ASTM E-185 as called out for by 10CFR50 Appendix H.

5.3.1.6.2 Neutron Flux and Fluence Calculations

A description of the methods of analysis is contained in Subsections 4.1.4.5 and 4.3.2.2.

5.3.1.6.3 Predicted Irradiation Effects on Beltline Materials

Transition temperature changes and changes in upper-shelf energy shall be calculated in accordance with the rules of Regulatory Guide 1.99. Reference temperatures shall be established in accordance with 10CFR50 Appendix G and NB-2330 of the ASME Code.

Since weld material chemistry and fracture toughness data are not available at this time, the limits in the purchase specification were used to estimate worst-case irradiation effects.

These estimates show that the adjusted reference temperature at end-of-life is less than 34°C, and the end-of-life USE exceeds 69 kg-m (see response to Question 251.5 for the calculation and analysis associated with this estimate). 6.9 ?

5.3.1.6.4 Positioning of Surveillance Capsules and Methods of Attachment Appendix H.II B (2)

The surveillance specimen holders, described in Subsections 5.3.1.6.1 and 3.9.5.1.2.10, are located at different azimuths at common elevation in the core beltline region. The locations are selected to produce lead factor of approximately 1.2 to 1.5 for the inserted specimen capsules. A positive spring-loaded locking device is provided to retain the capsules in position throughout any anticipated event during the lifetime of the vessel. The capsules can be removed form and reinserted into the surveillance specimen holders. See Subsection 5.3.4.2 for COL license information requirements pertaining to the surveillance material, lead factors, withdrawal schedule and neutron fluence levels.

In areas where brackets (such as the surveillance specimen holder brackets) are located, additional nondestructive examinations are performed on the vessel base metal and stainless steel weld-deposited cladding or weld-buildup pads during vessel manufacture. The base metal is ultrasonically examined by straight-beam techniques to a depth at least equal to the thickness of the bracket being joined. The area examined is the area

Initial Value 75 ft-lb

Final Values

Weld	75 x 0.86 = 65
Base	75 x 0.89 = 67

0.89

Kkl 2/8/94

vel

Question 251.6
Subsection 5.3.2.1 should clarify where "Reference 2" is located. Has the NRC staff reviewed and approved Reference 2? If not the staff needs to review Reference 2 in order to complete the review of this subsection.

Response 251.6
Reference 2, *Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors*, January 1979, (NEDO-21778-A), is an NRC staff approved licensing topical report. This topical report was approved by letter to GE, dated November 13, 1978 according to NUREG-0390 Vol.7, No. 2 (October 15, 1984).

Question 251.7
Subsections 5.3.2.1.1, 5.3.2.1.2, 5.3.2.1.3, and 5.3.2.1.5 need to be rewritten. The level of detail must be comparable to that of Standard Review Plan 5.3.2 and Branch Technical Position MTEB 5-2.

Response 251.7
Response to this question is provided in revised Subsections 5.3.2.1, 5.3.2.1.1, and 5.3.2.1.5.

Question 251.8
Subsection 5.3.3 cited three GE documents:

(1) GE quality assurance program,

(2) Approved" inspection procedures, and

(3) NEDO-10029

Has the NRC staff reviewed and approved the above documents? The staff cannot satisfactorily review this subsection without reviewing the above three documents.

Response 251.8
The GE quality assurance program is contained in topical report NEDO-11029-04A. *GE BWR Quality Assurance Program*, Revision 7, which has been approved by the NRC staff (May 1987).

2.7.1 Main Control Room Panels

Design Description

The Main Control Room Panels (MCRP) consist of the main control console, the large display panel, the supervisor's console, the auxiliary or back panels and their respective internal wiring.

The MCRP locates and configures the alarms displays and controls for plant systems. Those parts of the MCRP that contain Class 1E equipment are classified as Seismic Category I.

Non-Class 1E and divisional Class 1E control and instrument power is provided for the MCRP. Independence is provided between Class 1E divisions and also between the Class 1E divisions and non-Class 1E equipment.

as a minimum

The MCRP has the fixed alarms, displays, and controls shown on Table 2.7.1a.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.7.1a provides a definition of the inspections, tests and/or analyses, together with associated acceptance criteria, which will be undertaken for the MCRP.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.1.1 RPV No. 4

NRC COMMENT:

Correct typographical error on attached page 5.3-7 of SSAR.

GE RESPONSE:

GE concurs that the SSAR value is 6.9 and will correct this typographical error in the next SSAR amendment. The attached markup also identifies a related error that GE will correct.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment; see attached.

verified

COMMENT	STATUS OF RESOLUTION
2.12.13(2)	NRC agrees with GE disposition.
2.12.13(6)	GE agrees.
2.12.13(10)	GE agrees.
2.12.13(13)	GE agrees.
2.12.13(14)	GE agrees.
2.12.14(1)	GE agrees.
2.12.15(1)	GE agrees.
2.12.15(2)	NRC agrees with GE disposition.
2.12.15(3)	GE agrees.
2.12.16(6)	GE agrees.
2.12.17(6)	GE agrees.
2.14.4(1)	GE agrees.
2.14.4(2)	GE agrees.
2.14.4(3)	GE agrees.
2.14.6(4)	GE agrees.
2.14.8(2)	GE agrees.
2.14.8(3)	GE agrees.
2.15.5(1)	GE agrees.
2.15.5(3)	GE agrees.
2.15.5(4)	GE agrees.
2.15.5(12)	NRC agrees with GE disposition.
2.15.5(13)	GE agrees.
2.15.5(14)	GE agrees.
2.15.6(1)	NRC agrees with GE disposition.
3.1(3)	GE agrees.
3.1(5)	GE agrees.
3.1(6)	GE agrees.
3.1(7)	GE agrees.
3.1(9)	GE agrees.
3.1(10)	GE agrees.
3.1(12)	GE agrees.
3.1(13)	GE agrees.
3.1(15)	GE agrees.
3.2(4b)	GE agrees.
3.2(4c)	GE agrees.
3.2(4d)	GE agrees.
3.2(4f)	GE agrees.
3.2(4h)	GE agrees.
3.3(1)	GE agrees.
3.4(2.1&2.4)	NRC agrees with GE disposition.
3.4(5)	GE agrees.
3.4(6)	GE agrees.
Misc(1)	GE agrees.
Misc(2)	GE agrees.
Misc(3)	GE agrees.
Misc(4)	GE agrees.
Misc(5)	GE agrees.
Misc(6)	GE agrees.

REVISION: 0 2/15/94
1 2/21/94 - DELIVERED TO NRC 2/2:
2 2/25/94 - FURTHER MODS

ABWR DESIGN CERTIFICATION

SET B

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP (IQRG) COMMENTS ON SSAR AMENDMENT 33 AND CDM REVISION 2.

Enclosure 2

Table 2.6.1 Reactor Water Cleanup System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitments	**Inspections, Tests, Analyses**	**Acceptance Criteria**
5.	5.	5.
a. MOVs designated in Section 2.6.1 as having an active safety- related function close under differential pressure and fluid flow and temperature conditions.	a. Tests of installed valves for closing will be conducted under preoperational differential pressure, fluid flow, and temperature conditions.	a. Upon receipt of the actuation signal each MOV closes. The following valves close in the following time limits: Valve — Time (sec) Suction line inboard CIV — ≤30 Close Suction line outboard CIV — ≤30 Close
b. CVs designated in Section 2.6.1 as having an active safety-related function close under system pressure, fluid flow, and temperature conditions.	b. Tests of installed valves for closing will be conducted under system pre-operational pressure, fluid flow, and temperature conditions.	b. Each CV closes.
6. Maximum throat diameter of the CUW suction line flow restrictor is 135 mm.	6. Inspections will be performed on the CUW suction line flow restrictor throat diameter.	6. Maximum throat diameter of the CUW suction line flow restrictor is 135 mm.
7. The bottom head drain line is connected to the main CUW suction piping by a tee. The centerline of the tee connection is at an elevation of at least 460 mm above the centerline of the variable leg nozzle of the RPV wide-range water level instrument.	7. Inspections of the as-built CUW and RPV will be performed.	7. The centerline of the vessel bottom head drain line tee connection is at least 460 mm above the centerline of the variable leg nozzle of the RPV wide-range water level instrument.

ILL 2/17

CDM SECTION AND COMMENT No.: 2.6.1 RWCU No. 3 (Continued)

GE RESPONSE: (Continued)

In addition to deleting the tee configuration from the CDM, GE proposes to add the third valve with a note stating that it is not a containment isolation valve and thus not subject to the Class 1E and qualification provisions stated in the design description for the containment isolation valves. See attached CDM markup.

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.1 RWCU No. 3

NRC COMMENT:

In the Certified Design Material, SSAR and P&ID, use one consistent parameter for the centerline of the tee connection; select either "at least 460 mm above the centerline of the variable leg nozzle" or "at least 389 mm above the top of active fuel."

GE RESPONSE:

GE proposes to delete this entry from the CDM. Basis: With the addition of a third isolation valve in the RWCU, the PRA studies no longer identify this tee junction configuration as making a significant contribution to plant risk reduction. Consequently, the feature no longer merits CDM treatment. Note: This configuration requirement is not being deleted from the SSAR.

(Continued on next page...)

PROPOSED CHANGES

CDM: See attached markup for tee configuration and addition of the third valve.

SSAR: None; GE proposes to leave the SSAR as is with respect to tee junction configuration.

(3rd valve and supporting changes are being added to the SSAR)

(5.4.12 Sheet 1 ver)

GL	Grade Level
GSC	Gland Seal Condenser
HAZ	Heat-Affected Zone
HCU	Hydraulic Control Unit
HCW	High Conductivity Waste
HECW	HVAC Emergency Cooling Water
HEPA	High Efficiency Particulate Air
HFE	Human Factors Engineering
HNCW	HVAC Normal Cooling Water
HPCF	High Pressure Core Flooder
HPIN	High Pressure Nitrogen Gas Supply
HSI	Human-System Interfaces
HVAC	Heating, Ventilating, and Air Conditioning
HWH	Hot Water Heating
HX	Heat Exchanger
IA	Instrument Air
ICGT	In-Core Guide Tube
I&C	Instrumentation and Control
INST	Instrumentation
ISLOCA	Intersystem Loss-of-Coolant Accident
ISI	In-Service Inspection
ITAAC	Inspection, Tests, Analyses, and Acceptance Criteria
ITP	Initial Test Program
LCP	Local Control Panels
LCW	Low Conductivity Waste
LD	Load Driver
LDS	Leak Detection and Isolation System
LOCA	Loss-of-Coolant Accident
LOPP	Loss of Preferred Power
LPFL	Low Pressure Core Flooder
LPMS	Loose Parts Monitoring System
LPRM	Local Power Range Monitor
LPZ	Low Population Zone
LSPS	Lighting and Servicing Power Supply
MC	Main Condensal
M/C	Metal-Clad
MCAE	Main Control Area Envelope
MCC	Motor Control Center
MCES	Main Condenser Evacuation System
MCR	Main Control Room
MCRP	Main Control Room Panels
MG	Motor Generator
MOV	Motor-Operated Valve
MPT	Main Power Transformer
MRBM	Multi-Channel Rod Block Monitor
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSL	Main Steamline
MTSV	Main Turbine Stop Valve
MT	Main Turbine
MUWC	Make Up Water (Condensate)
MUWP	Make Up Water (Purified)
MWP	Makeup Water Preparation
NBS	Nuclear Boiler System
NEMS	Non-Essential Multiplexing System
NMS	Neutron Monitoring System
NPSH	Net Positive Suction Head
NRHX	Non-Regenerative HX
NSD	Non-Radioactive Storm Drain
OGS	Off-Gas System
OLU	Output Logic Unit
OPRM	Oscillating Power Range Monitor
OSC	Operational Support Center
OST	Oil Storage and Transfer
P/C	Power Center
PASS	Post-Accident Sampling System
PCHS	Power Cycle Heat Sink
PCS	Primary Containment System
PIP	Plant Investment Protection
PMG	Plant Main Generator
PRM	Process Radiation Monitoring
PROM	Programmable Read-Only Memory
PS	Pipe Space
PSW	Potable and Sanitary Water
R/B	Reactor Building

Add

CV Check Valve

Appendix B Abbreviations and Acronyms Used in the ABWR Certified Design Material

ABS	Absolute
AC	Alternating Current
AC	Atmospheric Control
ADS	Automatic Depressurization System
AFPC	Augmented Fuel Pool Cooling
AMB	Ambient
ATLM	Automated Thermal Limit Monitor
APR	Automatic Power Regulator
APRM	Average Power Range Monitor
ARD	Anti-Rotation Device
ARI	Alternate Rod Insertion
ARM	Area Radiation Monitoring
AS	Turbine Auxiliary Steam System
ASD	Adjustable Speed Drive
ASME Code	American Society of Mechanical Engineers, Boiler and Pressure Vessel Code
ATWS	Anticipated Transient Without Scram
BLDG	Building
C&I	Control and Instrumentation
C/B	Control Building
C/C	Cooling Coil
CAMS	Containment Atmospheric Monitoring System
CFCAE	Condensate Feedwater and Condensate Air Extraction
CFS	Condensate and Feedwater System
CID	Control Interface Diagram
CIV	Combined Intermediate Valve
CMP	Configuration Management Plan
CMU	Control Room Multiplexing Unit
COL	Combined Operating License
CPS	Condensate Purification System
CRD	Control Rod Drive
CRDHS	Control Rod Drive Hydraulic System
CRGT	Control Rod Guide Tube
CS	Containment Spray
CST	Condensate Storage Tank
CTG	Combustion Turbine Generator
CUW	Reactor Water Cleanup
CV	Control Valve
CVCF	Constant Voltage Constant Frequency
CW	Circulating Water
DC	Direct Current
DEPSS	Drywell Equipment and Piping Support Structure
DG	Diesel Generator, Emergency
DIV	Division
D/S	Dryer and Separator
DTM	Digital Trip Modules
DWC	Drywell Cooling
E/B	Electrical Building
EAB	Exclusion Area Boundary
EAROM	Electrically-Alterable Read-Only Memory
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EMC	Electromagnetic Compatibility
EMI	Electromagnetic Interference
EMS	Essential Multiplexing System
EPD	Electrical Power Distribution
ESD	Electrostatic Discharge
ESF	Engineered Safety Feature
FCS	Flammability Control System
FCU	Fan Coil Unit
FDWC	Feedwater Control
FIV	Flow-Induced Vibration
FMCRD	Fine Motion Control Rod Drive
FP	Fire Protection
FPC	Fuel Pool Cooling and Cleanup
FPS	Fire Protection System
FW	Feedwater

CDM SECTION AND COMMENT No.: 2.6.1 RWCU No. 2 (Continued)

GE RESPONSE: (Continued)

2) Add MC to the Appendix B list.

3) No changes with respect to the existing CDM use of the acronym CIV. This has been used for combined intermediate value. In all sections, the phrase containment isolation valve has been spelled out.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.1 RWCU No. 2

NRC COMMENT:

Need to develop acronyms for: main condenser, check valve, and containment isolation valve. (Example of problem: "CV" is used for "check valve," but the App. B shows "CV" as "control valve").

GE RESPONSE:

GE does not believe there is a major CDM acronym problem. To resolve the items raised by this NRC comment, GE proposes:

1) Change Appendix B definition of CV per the attached markup. This dual use of one acronym for two different phrases is acceptable because the acronym is defined at the time of first use in each CDM Section and there are no sections which use the acronym for both types of valves, i.e., there is no ambiguity. This item is following the AC precedent already established in the CDM.
(Continued on next page...)

PROPOSED CHANGES

CDM: See attached markups.

SSAR: None

RL 2/9/96

m^3/hr

Table 2.4.4 Reactor Core Isolation Cooling System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
i. In the RPV water makeup mode, the RCIC pump delivers a flow rate of at least 182 m^3/hr against a maximum differential pressure (between the RPV and the pump suction) of 82.8 kg/cm^2.	i. Tests will be conducted in a test facility on the RCIC System pump and turbine.	i. (1) The RCIC pump delivers a flow rate of at least 182 m2/hr against a maximum differential pressure (between the RPV and the pump suction) of 82.8 kg/cm^2) (2) The RCIC turbine delivers the speed and torque required by the pump at the above conditions.
j. The RCIC System pump has sufficient NPSH.	j. Inspections, tests, and analyses will be performed based upon the as-built system. NPSH tests of the pump will be performed at a test facility. The analyses will consider the effects of: (1) Pressure losses for pump inlet piping and components. (2) Suction from suppression pool with water level at the minimum value. (3) 50% blockage of pump suction strainers. (4) Design basis fluid temperature (77°C). (5) Containment at atmospheric pressure.	j. The available NPSH exceeds the NPSH required by the pump.

CDM SECTION AND COMMENT No.: 2.4.4 RCIC No. 6 (Continued)

GE RESPONSE: (Continued)

1) (Continued)

times, turbine control system delays. None of these system characteristics will be simulated in the simple factory pump/turbine test defined in entry 3i.

2) In-situ testing of the RCIC system to confirm the 29 second start time cannot be conducted prior to fuel load (no high pressure steam available) and thus cannot be addressed by an ITAAC entry. (ITAAC must be completed prior to fuel load per 10 CFR 52).

3) Confirmation of RCIC start times with the reactor at full pressure will be obtained during the plant startup test program committed to in SSAR Chapter 14. The RCIC System testing is described in Section 14.2.12.2.22.

Consequently, GE proposes no changes in response to this NRC comment regarding the 29 second issue.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.4 RCIC No. 6

NRC COMMENT:

Table 2.4.4, Item 3i, add the following condition to the 1st and 3rd column "within 29 seconds after the signal to start." In the 3rd column, change the numeral 2 to an exponent.

GE RESPONSE:

GE agrees to change the exponent in column 3 and will include this correction in the next revision of 25A5447.

GE does not concur with the proposed NRC addition regarding RCIC start times. GE believes that this change is ~~not~~ appropriate. The basis for this position are:

1) The 29 seconds is the system delay time between receipt of an initiation signal and achieving rated flow. The delay time includes valve opening times, turbine spin-up (Continued on next page...)

PROPOSED CHANGES

CDM: Typographical error only per NRC comment. See attached.

SSAR: None

Table 2.4.4 Reactor Core Isolation Cooling System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the RCIC System is as shown on Figures 2.4.2a and 2.4.2b 2.4.4b 2.4.4a	1. Inspections of the as-built system will be conducted.	1. The as-built RCIC System conforms with the basic configuration shown on Figure ~~2.4.2a~~
2. The ASME Code components of the RCIC System retain their pressure boundary integrity under internal pressures that will be experienced during service.	2. A hydrostatic test will be conducted on those Code components of the RCIC System required to be hydrostatically tested by the ASME Code.	2. The results of the hydrostatic test of the ASME Code components of the RCIC System conform with the requirements in the ASME Code Section III.
3.	3.	3.
a. The RCIC System is automatically initiated in the RPV water makeup mode when either a high drywell pressure or a low reactor water level condition exists.	a. Tests will be conducted using simulated input signals for each process variable to cause trip conditions in two, three, and four instrument channels of the same process variable.	a. The RCIC System receives an initiation signal.
b. Manual RCIC System initiation can be performed.	b. Tests will be conducted by manually initiating RCIC System.	b. The RCIC System receives an initiation signal.

Figures 2.4.4a and 2.4.4b

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.4 RCIC No. 5

NRC COMMENT:

In Table 2.2.4, Item 1, 3rd column: change the end of the statement to read "…Figures 2.4.2a and 2.4.2b."

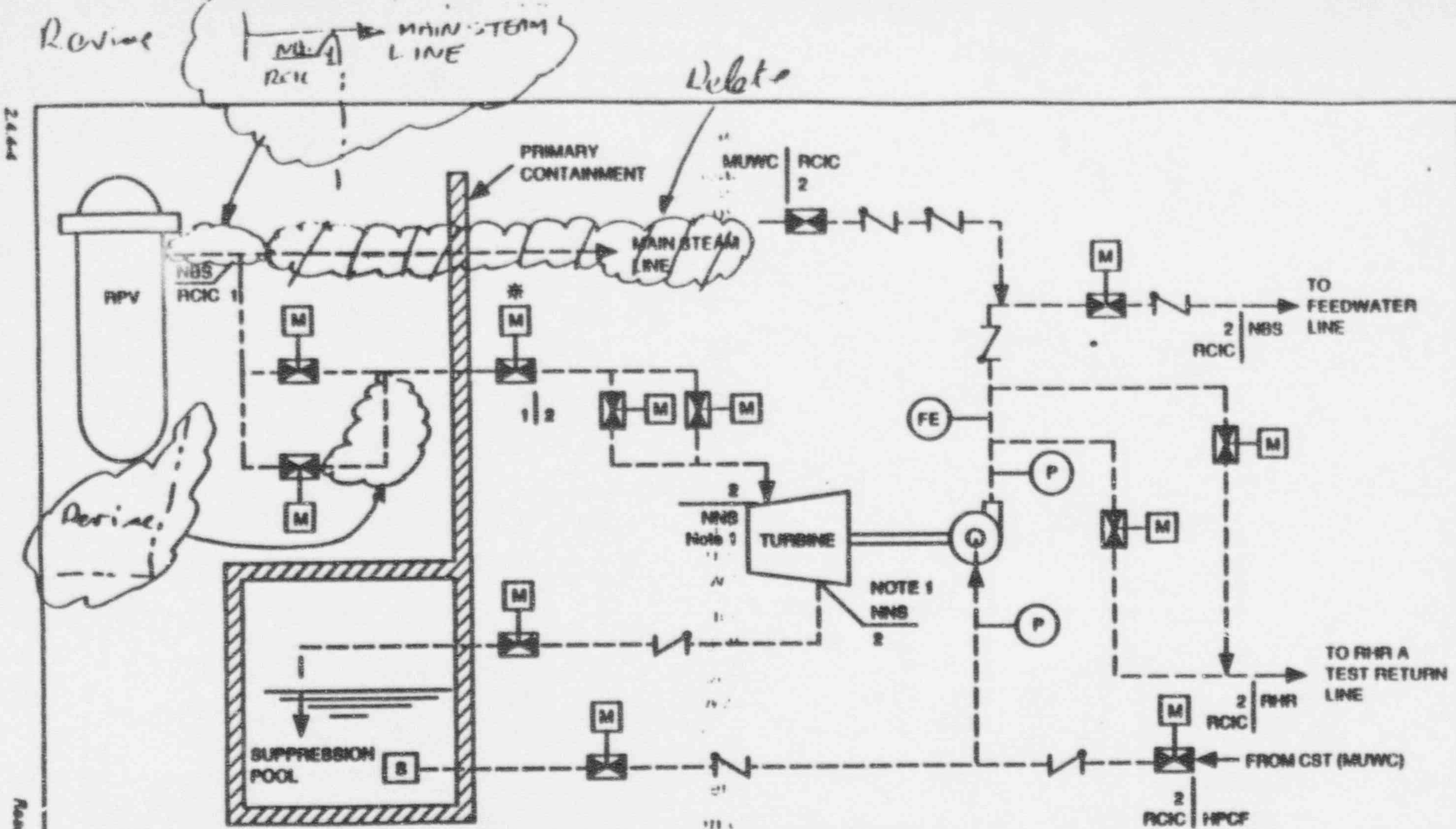
GE RESPONSE:

GE concurs that this item has a typographical error and will correct it in the next revision of 25A5447.

PROPOSED CHANGES

CDM: See attached.

SSAR: None.



NOTES:

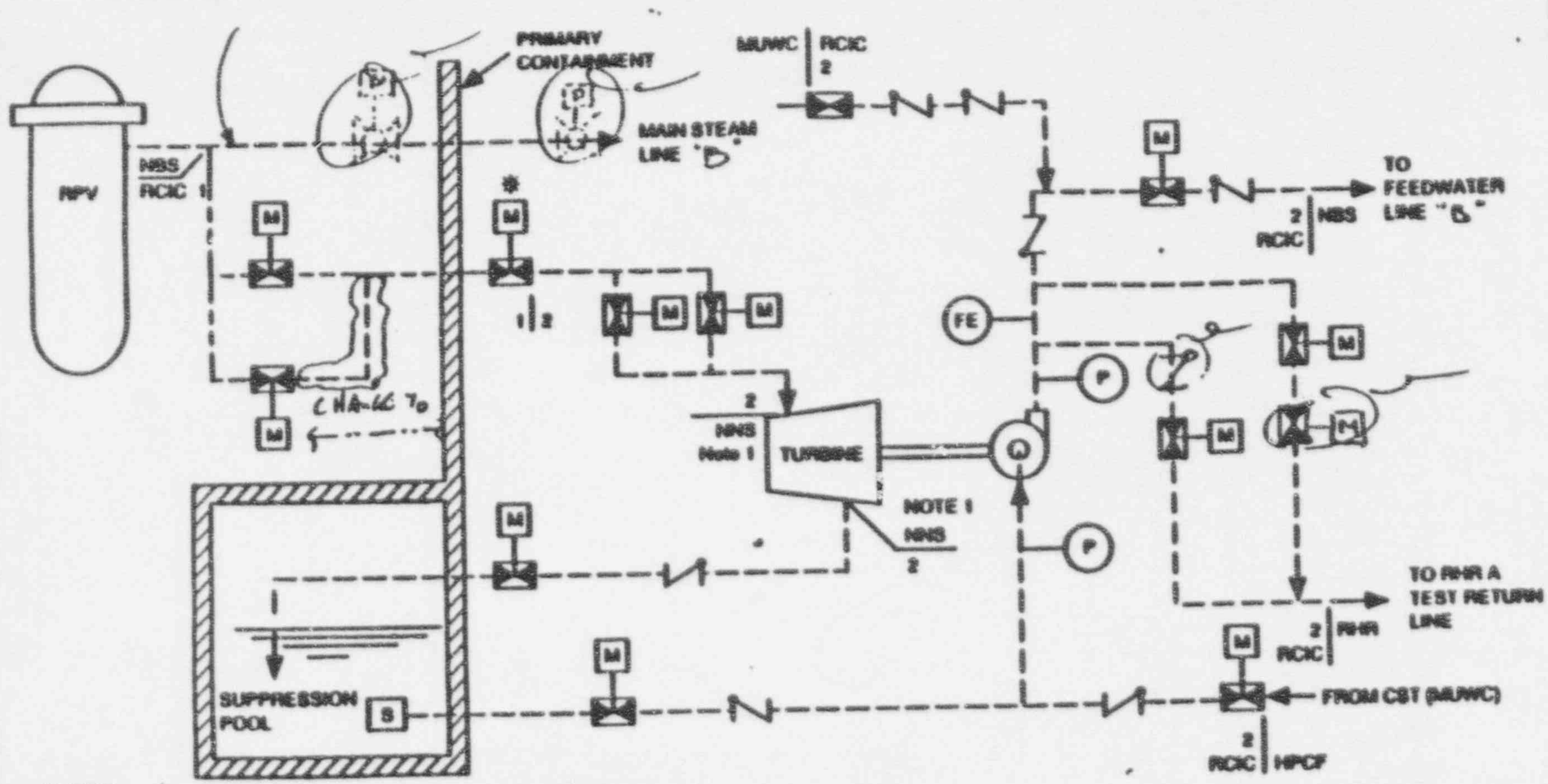
1. RCIC TURBINE IS NOT COVERED BY ASME CODE SECTION III BUT IS DESIGNED, FABRICATED, AND INSTALLED TO SAFETY-RELATED STANDARDS AND IS CONSISTENT WITH THE ASME CODE SECTION III REQUIREMENTS. THE TURBINE INCLUDES THE TURBINE TRIP AND THROTTLE VALVE.

2. ALL RCIC SYSTEM COMPONENTS SHOWN ON THIS FIGURE ARE POWERED FROM CLASS 1E DIVISION I EXCEPT FOR THE OUTBOARD CONTAINMENT ISOLATION VALVE (*) WHICH IS CLASS 1E DIVISION II.

3. ALL RCIC SYSTEM COMPONENTS SHOWN ON THIS FIGURE EXCEPT THE INBOARD CONTAINMENT ISOLATION VALVES, ARE POWERED FROM DC SOURCES.

Figure 2.4.4a Reactor Core Isolation Cooling System

LINE NBS FROM RPV TO OUTBOARD MSIV
IS ASME CODE CLASS 1



NOTES:

1. RCIC TURBINE IS NOT COVERED BY ASME CODE SECTION III BUT IS DESIGNED, FABRICATED, AND INSTALLED TO SAFETY-RELATED STANDARDS AND IS CONSISTENT WITH THE ASME CODE SECTION III REQUIREMENTS. THE TURBINE INCLUDES THE TURBINE TRIP AND THROTTLE VALVE.

2. ALL RCIC SYSTEM COMPONENTS SHOWN ON THIS FIGURE ARE POWERED FROM CLASS 1E DIVISION I EXCEPT FOR THE OUTBOARD CONTAINMENT ISOLATION VALVE (*) WHICH IS CLASS 1E DIVISION II.

3. ALL RCIC SYSTEM COMPONENTS SHOWN ON THIS FIGURE EXCEPT THE INBOARD CONTAINMENT ISOLATION VALVES, ARE POWERED FROM DC SOURCES.

COMMENTS:

1. CHANGE PIPING CODE CLASS IN 2 [illegible]S.

~~2. ADD PRIMARY MSIVS.~~

3. STATE SPECIFICALLY LINE "B" FOR MAIN STEAM & FEEDWATER.

Figure 2.4.4a Reactor Core Isolation Cooling System

~~4. SHOW CHECK VALVE AND SECOND MOV IN ACCORDANCE SSAR TABLE 3.9-8.~~

ITAAC COMMENTS PAGE 3 OF 3

GENPC 1A

CDM SECTION AND COMMENT No.: 2.4.4 RCIC No. 4 (Continued)

GE RESPONSES: (Continued)

3) (Continued)

This selection is made on the basis of arrangement convenience and is not of safety significance. GE proposes no changes to Figure 2.4.4a in response to this NRC comment.

4) Do not add the check valve and additional MOV suggested by NRC.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.4 RCIC No. 4

NRC COMMENT:

See comments on attached copy of Figure 2.4.4a.

GE RESPONSE:

GE proposes the following in response to these items:

1) Clarify piping classification symbols for the main steamline and bypass around the inboard isolation valve. See attached.

2) Do <u>not</u> add the phantom MSIV; this is not CDM practice. (See changes proposed in item 1).

3) Do <u>not</u> identify the RCIC steam supply line as being connected to steamline B. (Continued on next page...)

PROPOSED CHANGES

CDM: See attached markups.

SSAR: None

ABWR TIER 1 – GE RESPONSES TO NRC COMMENTS

I&C TASK GROUP

SYSTEM NUMBER AND NAME:

2.2.7 REACTOR PROTECTION SYSTEM

DD

NRC COMMENT:

1. Add High Main Steam Line Radiation trip signal to list of scram inputs.

GE RESPONSE: GE does not concur. Based on GE/NRC discussions it was mutually agreed that MSL high radiation trip would not be included in Tier 1, in either LDISS or RPS. The basis for this agreement was the recognition that this feature might well be deleted from the design at sometime in the future. CHAP 15 analyses not dependent on MSL radiation trip signal.

PROPOSED CHANGES TO TIER 1:

1. NONE

2.

3.

NOTE!
THIS AGREEMENT
ADDRESSES SCRAM BUT
IS APPLICABLE TO
MSIV CLOSURE
GE
2/10/94

Agreed 7/28/93 [illegible] (GE)
[illegible] (NRC)

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.3 LDIS No. 1

NRC COMMENT:

The Design Description should include discussion of the main steamline radiation level trip of the MSIVs which is an input from PRMS. This is discussed in SSAR 7.3.1.1.2 as part of LDS.

GE RESPONSE:

As discussed in the response to CDM entry 2.2.7, RPS, NRC comment No. 1, GE does not concur. The basis for this position is the earlier GE/NRC agreement that it may well be appropriate and beneficial at some time in the future to delete MSIV closure and reactor scram based on steamline radiation signals. Such deletion would be complicated if the feature is described in the CDM. Consequently GE proposes no changes in response to this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

Table 2.4.2 High Pressure Core Flooder System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
d. The HPCF System flow in each division is not less than a value corresponding to a straight line between a flow of 182 m^3/hr at a differential pressure of 82.8 kg/cm^2 and a flow of 727 m^3/hr at a differential pressure of 7 kg/cm^2.	d. Tests will be conducted on each division of the as-built HPCF System in the HPCF high pressure flooder mode. Analyses will be performed to convert the test results to the conditions of the Design Commitment.	d. The converted HPCF flow satisfies the following: The HPCF System flow in each division is not less than a value corresponding to a straight line between a flow of 182 m^3/hr at a differential pressure of 82.8 kg/cm^2 and a flow of 727 m^3/hr at a differential pressure of 7 kg/cm^2.
e. The HPCF System has the capability to deliver at least 50% of the flow rates in item 3d with 171°C water at the pimp suction.	e. Analyses will be performed of the as-built HPCF System to assess the system flow capability with 171°C water at the pump suction.	e. The HPCF System has the capability to deliver at least 50% of the flow rates in item 3d with 171°C water at the pump suction.
f. System flow into the reactor vessel is achieved within 16 seconds of receipt of an initiation signal and power available at the emergency busses.	f. Tests will be conducted on each HPCF division using simulated initiation signals.	f. The HPCF System flow is achieved within 16 seconds of receipt of a simulated initiation signal.
g. The HPCF pumps have sufficient NPSH available at the pumps.	g. Inspections, tests and analyses will be performed upon the as-built system. NPSH tests of the pumps will be performed in a test facility. The analyses will consider the effects of: – Pressure losses for pump inlet piping and components. – Suction from the suppression pool with water level at the minimum value. – 50% minimum blockage of the pump suction strainers.	g. The available NPSH exceeds the NPSH required by the pumps.

Typo

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.2 HPCF No. 3

NRC COMMENT:

Correct the attached typos.

GE RESPONSE:

GE concurs and will make this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment.

SSAR: None

Appendix A Legend for Figures

For a number of the systems presented in Section 2, figures depicting the Basic Configuration of the systems have been provided to help facilitate the Design Description. For I&C systems, the figures represent a diagram of significant aspects of the logic of the system. For other systems and buildings, these figures represent a functional diagram, representation, or illustration of design-related information. Unless otherwise specified explicitly, these figures are not necessarily indicative of the scale, location, dimensions, shape, or spatial relationships of as-built structures, systems, and components. In particular, the as-built attributes of structures, systems and components may vary from the attributes depicted on these figures, provided that those safety functions discussed in the Design Description are not adversely affected.

The figures contain information that uses the following conventions:

Mechanical Equipment

Line classification:

		Figure Designation
ASME Code Class 1	— — — — — — —	1
ASME Code Class 2	— — — — — — —	2
ASME Code Class 3	————————	3
Non-ASME Code/ Non-Nuclear Safety	— — — — — — —	NNS
Other Line Type:	—//—//—//—//	This legend can be used for pneumetric lines when needed for clarity. ASME Code class for such lines is defined on the system figure.

← Typo

Outside the primary containment, each mechanical division of the RHR System (Divisions A, B, and C) is physically separated from the other divisions.

The RHR System has the following displays and controls in the main control room:

(1) Parameter displays for the instruments shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c.

(2) Controls and status indication for the active safety-related components shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c.

(3) Manual system level initiation capability for the following modes:

(a) LPFL initiation

(b) Standby

(c) Shutdown cooling

(d) Suppression pool cooling

(e) Drywell spray

RHR System components with displays and control interfaces with the Remote Shutdown System (RSS) are shown on Figures 2.4.1a and 2.4.1b.

The safety-related electrical equipment shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c located inside the primary containment and the Reactor Building is qualified for a harsh environment.

The motor-operated valves shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c have active safety-related functions and perform these functions to open, close, or both open and close, under differential pressure, fluid flow, and temperature conditions.

valves

The check calves (CVs) shown on Figures 2.4.1a, 2.4.1b, and 2.4.1c have safety-related functions to open, close, or both open and close under system pressure, fluid flow, and temperature conditions.

The RHR System main pumps are interlocked to prevent starting with a closed suction path.

Each RHR loop has a continuously running jockey pump to maintain the system piping continuously filled with water. The jocky pump is stopped by a RHR initiation signal or may be stopped or started manually.

The piping and components outside the shutdown cooling suction line containment isolation valves and outside the suppression pool containment isolation valves, and upstream of the suction side of the pump with all its branches have a design pressure of

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.1 RHR No. 9

NRC COMMENT:

Correct the attached CDM typos.

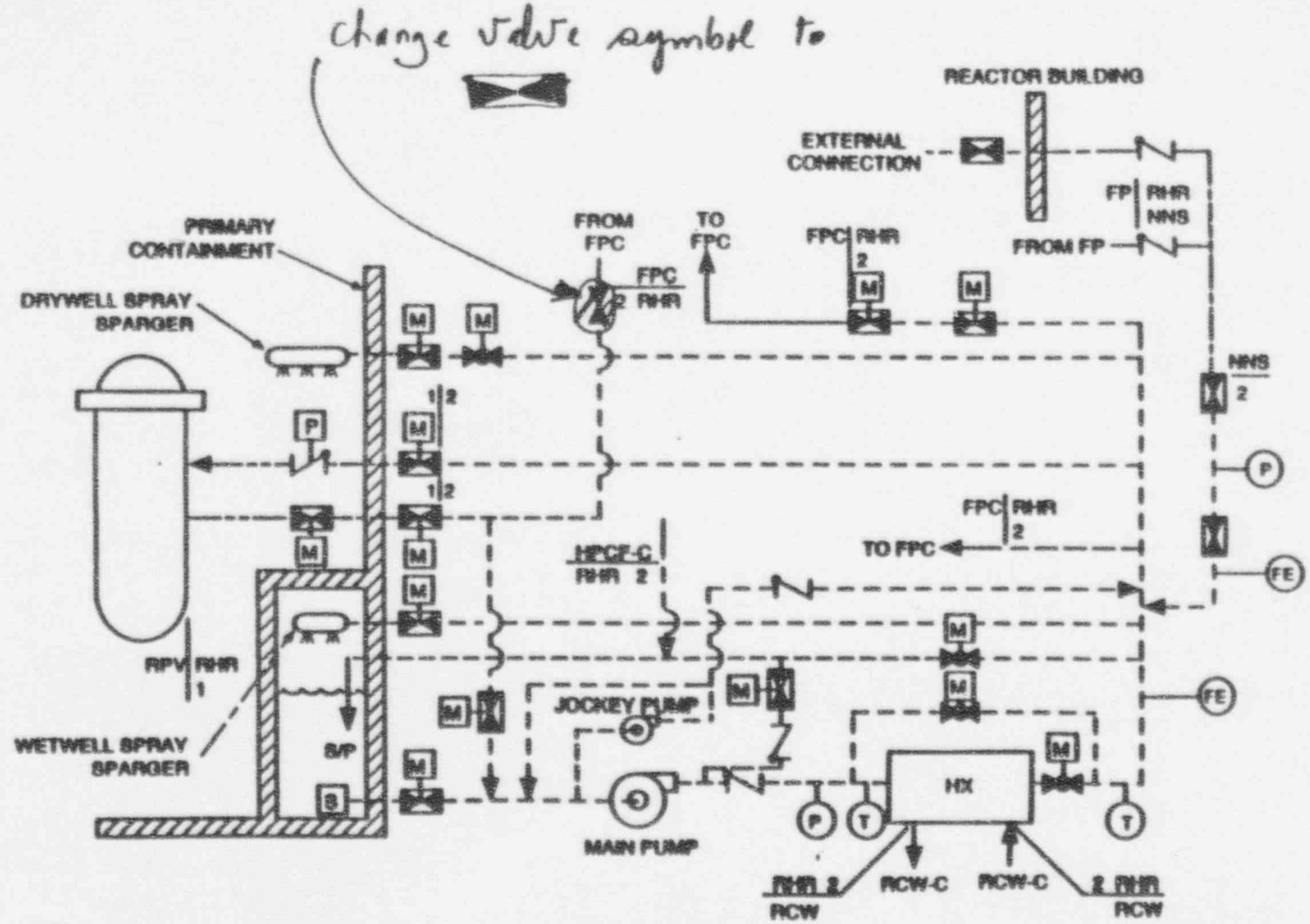
GE RESPONSE:

GE concurs and will make these corrections in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comments.

SSAR: None



NOTES:

1. ALL ELECTRICAL POWER LOADS FOR THE CLASS 1E COMPONENTS SHOWN ON THIS FIGURE ARE POWERED FROM CLASS 1E DIVISION III EXCEPT FOR THE OUTBOARD CONTAINMENT ISOLATION VALVE, WHICH IS DIVISION I.
2. DRYWELL AND WETWELL SPRAY SPRAGERS ARE COMMON TO DIVISIONS B AND C.

Figure 2.4.1c Residual Heat Removal System (RHR-C)

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.1 RHR No. 7

NRC COMMENT:

Why are the isolation valves between FPC and RHR in Figures 2.4.1b and 2.4.1c of different types?

GE RESPONSE:

GE concurs that the valves in the lines from the FPC to the RHR pump suction should be the same and will modify the gate valve shown in Figure 2.4.1c to the unspecified valve symbol used in Figure 2.4.1b.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

Table 6.3-1 Significant Input Variables Used in the Loss-of-Coolant Accident Analysis (Continued)

Variable	Units	Value
Initial Minimum Critical Power Ratio	——	1.13
Design Axial Peaking Factor	——	1.40

* The system response analysis is based upon the core loading in Figure 4.3-1. The sensitivities demonstrated are valid for other core loadings.

Table 6.3-2 Operational Sequence of Emergency Core Cooling System Maximum Core Flooder Line Break

Time (sec)	Events
0	Design basis LOCA assumed to start; normal auxiliary power assumed to be lost.*
~5	Reactor Low Water Level 3 is reached. Reactor scram occurs.†
~10	Drywell high pressure is reached. All diesel-generators, RCIC, HPCF, RHR/LPFL signaled to start. ‡
~18	Reactor Low Water Level 2 is reached. RCIC System receives second signal to start.
~48	RCIC injection valve open and pump at design flow which completes RCIC startup.
~65	Reactor Low Water Level 1.5 is reached. All diesel-generators and HPCF receive second signal to start. Main steam isolation valves signaled to close.
~78	All diesel-generators ready to load; RHR/LPFL and HPCF loading sequence begins.
~102	HPCF injection valves open and pumps at design flow, which completes HPCF startup.
~118	Reactor Low Water Level 1 is reached. RHR/LPFL receives second signal to start. ADS delay timer initiated.
~148	ADS delay timer timed out. ADS valves actuated.
~344	Vessel pressure decreases below shutoff head of RHR/LPFL. RHR/LPFL injection valves open and flow into vessel begins.
See Figure 6.3-46	Core effectively reflooded assuming worst single failure; heatup terminated.

K

* For the purpose of all but the next to last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (Subsection 6.3.3.3).

~~† For the LOCA analysis, the water level is initiated at the scram water level.~~ K

‡ For the LOCA analysis, the ECCS initiation on high drywell pressure is not considered.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.1 RHR No. 6

NRC COMMENT:

The second note at the bottom of SSAR Table 6.3-2 needs revision.

GE RESPONSE:

GE proposes to delete this footnote because it is related to GE analytical procedures* and is not necessary for an understanding of the basic LOCA sequence defined in Table 6.3-2.

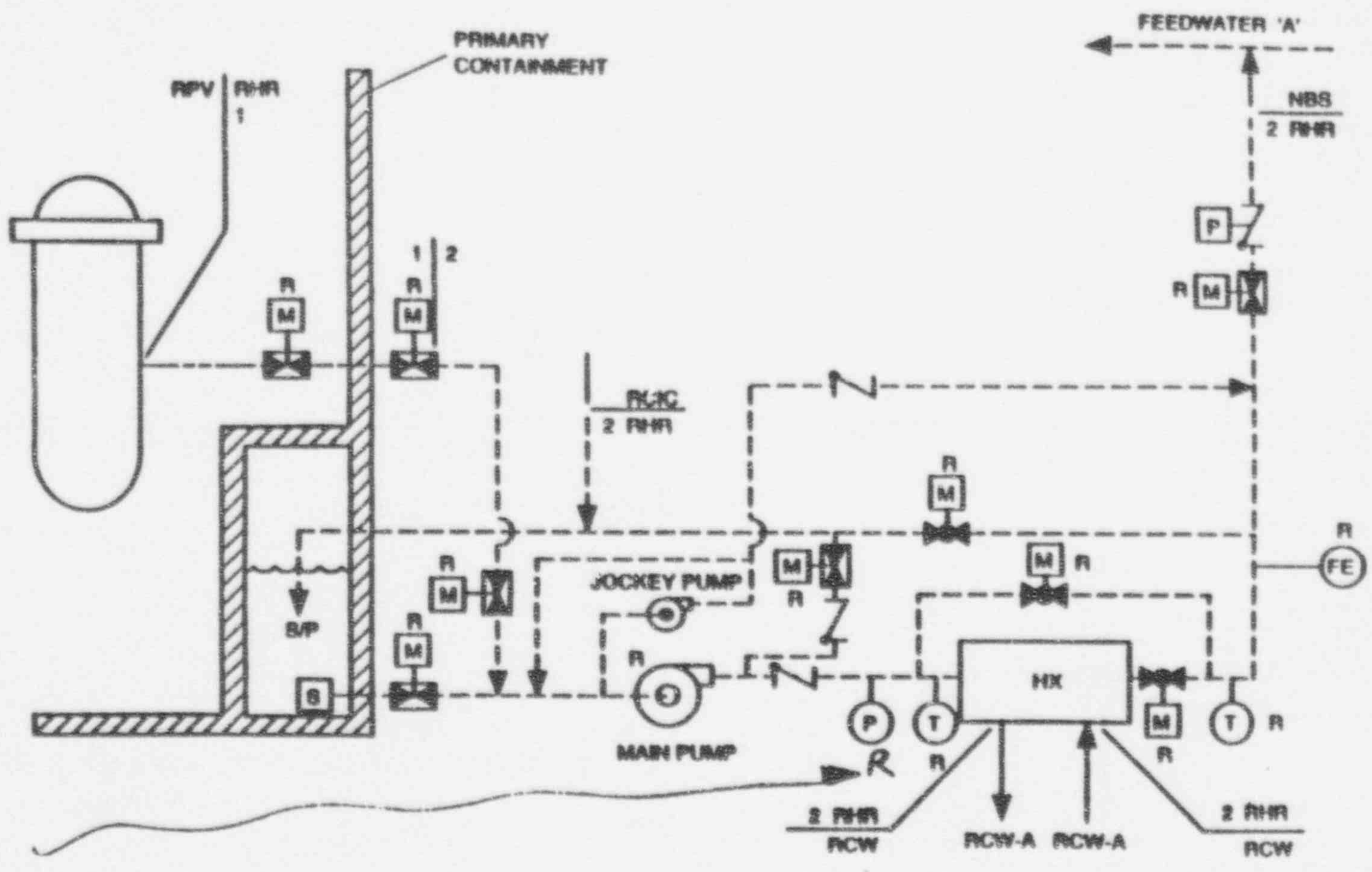
PROPOSED CHANGES

CDM: None

SSAR: Per attached markup.

---

* Time – zero for the GE analysis of this event is assumed to be when the RPV water level is at the Level 3 scram value. This is an analytical convenience that has no influence on the results.



NOTES:
1. ALL ELECTRICAL POWER LOADS FOR THE CLASS 1E COMPONENTS SHOWN ON THIS FIGURE ARE POWERED FROM CLASS 1E DIVISION I EXCEPT FOR THE OUTBOARD CONTAINMENT ISOLATION VALVE, WHICH IS DIVISION II.

Figure 2.4.1a Residual Heat Removal System (RHR-A)

SAME FOR FIG. 2.4.1b

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.1 RHR No. 5

NRC COMMENT:

Figures 2.4.1a and b should show that the RHR pump discharge pressures are displayed on the RSS panels, i.e., add symbol "R" to the pressure instruments.

GE RESPONSE:

GE concurs and will add this information to the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

List of Acronyms (Continued)

SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
SLD	Single Line Diagram
SLMCPR	Safety Limit Minimum Critical Power Ratio
SMS	Seismic Monitoring System
SOE	Single Operator Error
SORV	Stuck Open Relief Valve
SOT	System Operational Transients
SPCU	Suppression Pool Cleanup (System)
SPDS	Safety Parameter Display System
SPTMS	Suppression Pool Temperature Monitoring System
SR	Surveillance Requirements
SRMS	Solid Radwaste Management System
SRNM	Startup Range Neutron Monitor
SRP	Standard Review Plan
SRSS	Square-Root-of-the-Sum-of-the-Squares
SRV	Safety Relief Valves
SSAR	Standard Safety Analysis Report
SSAS	Station Service Air System
SSE	Safe Shutdown Earthquake
SSI	Soil-Structure Interaction
SSLC	Safety System Logic and Control
SSW	Station Service Water (System)
STC	Surveillance Test Controller
STPT	Simulated Thermal Power Trip
STS	Sewage Treatment System
SWSA	Solid Waste Storage Area
TASS	Turbine Auxiliary Steam System
TBCE	Turbine Building Compartment Exhaust (System)
TBCWS	Turbine Building Cooling Water System
TBE	Turbine Building Exhaust (System)
TBLOE	Turbine Building Lube Oil Area Exhaust (System)
TBS	Turbine Building Supply (System)
TBS	Turbine Bypass System
TBVS	Turbine Building Ventilation System
TCF	Total Core Flow

SW switch

List of Acronyms (Continued)

CHRS	Containment Heat Removal System
CIS	Containment Isolation System
CIV	Combined Intermediate Valve
CLOC	Closed Loop Outside Containment
CO	Condensation Oscillation
COL	Combined Operating License
CPDP	Core Plate Differential Pressure
CRD	Control Rod Drive
CRDH	Control Rod Drive Hydraulic (System)
CRGT	Control Rod Guide Tube
CTG	Combustion Turbine Generator
CUW	Reactor Water Cleanup System
CWS	Circulating Water System
D-RAP	Design Reliability Assurance Program
D/F	Diaphragm Floor
DAW	Dry Active Waste
DBA	Design Basis Accident
DBE	Design Basis Event
DC	Design Certification
DCS	Drywell Cooling System
DCV	Drywell Connecting Vent
DEGB	Double-Ended Guillotine Break
DEPSS	Drywell Equipment and Pipe Support Structure
DOF	Degree of Freedom
DOI	Dedicated Operator Interface
DQR	Dynamic Qualification Report
DTM	Digital Trip Module
DTS	Drain Transfer System
DWM	Demineralized Water Makeup (System)
E/C	Erosion/Corrosion
EBVS	Electrical Building Ventilation System
ECCS	Emergency Core Cooling System
ECLL	Electric Room Combustible Loading Limit
ECP	Engineering Computer Program
EDGS	Emergency Diesel Generator System
EDM	Electrodischarge Machining

CS Control Switch

Table 18F-1
Inventory of Controls Based Upon the ABWR EPGs and PRA

No.	Fixed Position Controls
1	Manual Scram Initiation SW(A)
2	Manual Scram Initiation SW(B)
3	Reactor Mode SW
4	Div. I Main steamline Manual Isolation SW
5	Div. II Main steamline Manual Isolation SW
6	Div. III Main steamline Manual Isolation SW
7	Div. IV Main steamline Manual Isolation SW
8	Primary Containment Div. I Manual Isolation SW
9	Primary Containment Div. II Manual Isolation SW
10	Primary Containment Div. III Manual Isolation SW
11	RCIC Initiation SW
12	HPCF (B) Initiation SW
13	HPCF (C) Initiation SW
14	RHR (A) Initiation SW
15	RHR (B) Initiation SW
16	RHR (C) Initiation SW
17	DG(A) Start SW
18	DG(B) Start SW
19	DG(C) Start SW
20	RCIC System Standby Mode Initiation SW
21	Condensate Pump Standby Mode Initiation Switches (3)
22	Reactor Feedpump Standby Mode Initiation Switches (3)
23	Condensate Pump Startup Mode Initiation Switches (3)
24	Reactor Feedpump Startup Mode Initiation Switches (3)
25	SLC (A) Pump CS
26	SLC (B) Pump CS
27	ADS (A) Inhibit SW
28	ADS (B) Inhibit SW
29	RHR(A) Standby Mode SW
30	RHR(B) Standby Mode SW
31	RHR(C) Standby Mode SW

NOTE:
SW: Switch.
CS: Control Switch

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.1 RHR No. 4

NRC COMMENT:

The SSAR does not list the acronyms "SW" and "CS" used in the SSAR Table 18F-1.

GE RESPONSE:

GE concurs and will make the attached SSAR changes as part of the next amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per attached

vay

Table 6.3-1 Significant Input Variables Used in the Loss-of-Coolant Accident Analysis

Variable	Units	Value
A. Plant Parameters		
Core Thermal Power	MWt	4005
Vessel Steam Output	kg/hr	7.82×10^6
Corresponding Percentage of Rated Steam Flow	%	102.4
Vessel Steam Dome Pressure	kg/cm^2a	74.2
B. Emergency Core Cooling Systems Parameters		
B.1 Low Pressure Flooder System		
Vessel Pressure at which Flow may Commence	kg/cm^2d (vessel to drywell)	15.8
Minimum Rated Flow per system at Vessel Pressure	m^3/hr kg/cm^2d (vessel to drywell)	954 ~~2.8~~ 2.8
Initiating signals Low Water Level or High Drywell Pressure	cm above TAF kg/cm^2g	≤15.3 ≥0.14
Maximum Allowable Time Delay from Initiating Signal to Pumps at Rated Speed	sec	29.0
Maximum Allowable Time Delay from Low Pressure Permissive Signal to Injection Valve Fully Open	sec	36.0
B.2 Reactor Core Isolation Cooling System		
Vessel Pressure at which flow may commence	kg/cm^2d (vessel to pump suction)	82.75
Minimum Rated Flow at Vessel Pressure	m^3/hr kg/cm^2d (vessel to the air space of the compartment containing the water source for the pump suction)	182 82.75 to 10.55
Initiating signals Low Water Level or High Drywell Pressure	cm above TAF kg/cm^2g	≤243.4 ≥0.14

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.4.1 RHR No. 1

NRC COMMENT:

On page 2.4.1-2, the reactor pressure at minimum RHR rated flow is stated as 2.8 kg/cm^2. In SSAR Table 6.3-1, this pressure is listed incorrectly as 28 kg/cm^2.

GE RESPONSE:

GE concurs and will modify the SSAR Table 6.3-1 entry in the next amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment; change 28 to 2.8.

Veg

Table 11.5-1 Process and Effluent Radiation Monitoring Systems (Continued)

Monitored Process	No. of Channels	Detector Type	Sample Line or Detector Location	Channel Range*	Setpoint Warning Alarm	Setpoint ACF Trip	Scale
B. Monitors Required for Plant Operation (Continued)							
Charcoal vault vent	1	S/C	On charcoal vault HVAC exhaust line	1 to 10^6 mR/hr	Above background	None	6 dec. log
Plant stack discharge	2 Δ	S/D	Sample line	10 to 10^6 cpm	At quarterly tech spec level	None	5 dec. log
		IC	Sample line	10^{-13} to 10^{-8} Amps (1 to 10^6 mR/hr)	Above background, below trip	None	6 dec. log
Radwaste Building exhaust vent	1	GM-B	Exhaust ducts	1 to 10^6 ~~mR/hr~~ cpm	Above background, below trip	None	6 dec. log
Turbine Building vent exhaust	4	S/C	Exhaust duct	0.01 to 100 mR/hr	Above background	None	4 dec. log
Standby Gas Treatment System offgas	2 Δ	S/D IC	SGTS exhaust air duct downstream of exhaust fans	1 to 10^6 cpm 10^{-13} to 10^{-8} Amps (1 to 10^6 mR/hr)	Above background, below trip above background	None None	6 dec. log 6 dec. log
Turbine gland seal condenser offgas	1	S/D	Sample line	1 to 10^6 cpm	Above background	None	6 dec. log
Incinerator stack discharge	1	GM-B	Sample line	1 to 10^6 cpm	Above background	Technical Specification	6 dec. log

ACF = Automatic Control Function; GM-B = Beta-Sensitive GM Detector; IC = Ion Chamber; S/C = Digital Gamma-Sensitive GM Detector; S/D = Scintillation Detector

* The channel range specified in this table is the equipment measuring or display range of the indicated parameter. Refer to Tables 11.5-2 and 11.5-3 for the dynamic detection range of the monitoring channel expressed as concentration in units of microcuries per cubic centimeter, referenced to a specific nuclide.

† 4 Channels for each air intake

Δ One each S/D and IC is required to cover the channel range.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.3.1 PRMS No. 5

NRC COMMENT:

The SSAR states the RW/B exhaust vent monitor reads out in both cpm and mR/hr (e.g., 11.5.5.2(6) - cpm, Table 11.5-1(B) - mR/hr, Table 11.5-2 – cpm). The SSAR should be corrected to state cpm, not mR/hr.

GE RESPONSE:

GE concurs and will correct the SSAR Table 11.5-1(B) to use cpm.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment; see attached markup.

Verified

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.11 PROCESS COMPUTER, No. 1

NRC COMMENT:

CDM material 2.2.11 references the ATLM, "Automated thermal limit monitor". Acronym is not consistent with other references. See ITAAC review 2.2.1 Rod Control and Information System, Comment No. 3.

GE RESPONSE:

As discussed in the response to 2.2.1, No. 3, the name of the RCIS subsystem which provides this function is the Automated Thermal Limit Monitor (ATLM). No changes are proposed to CDM 2.2.11 in response to this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

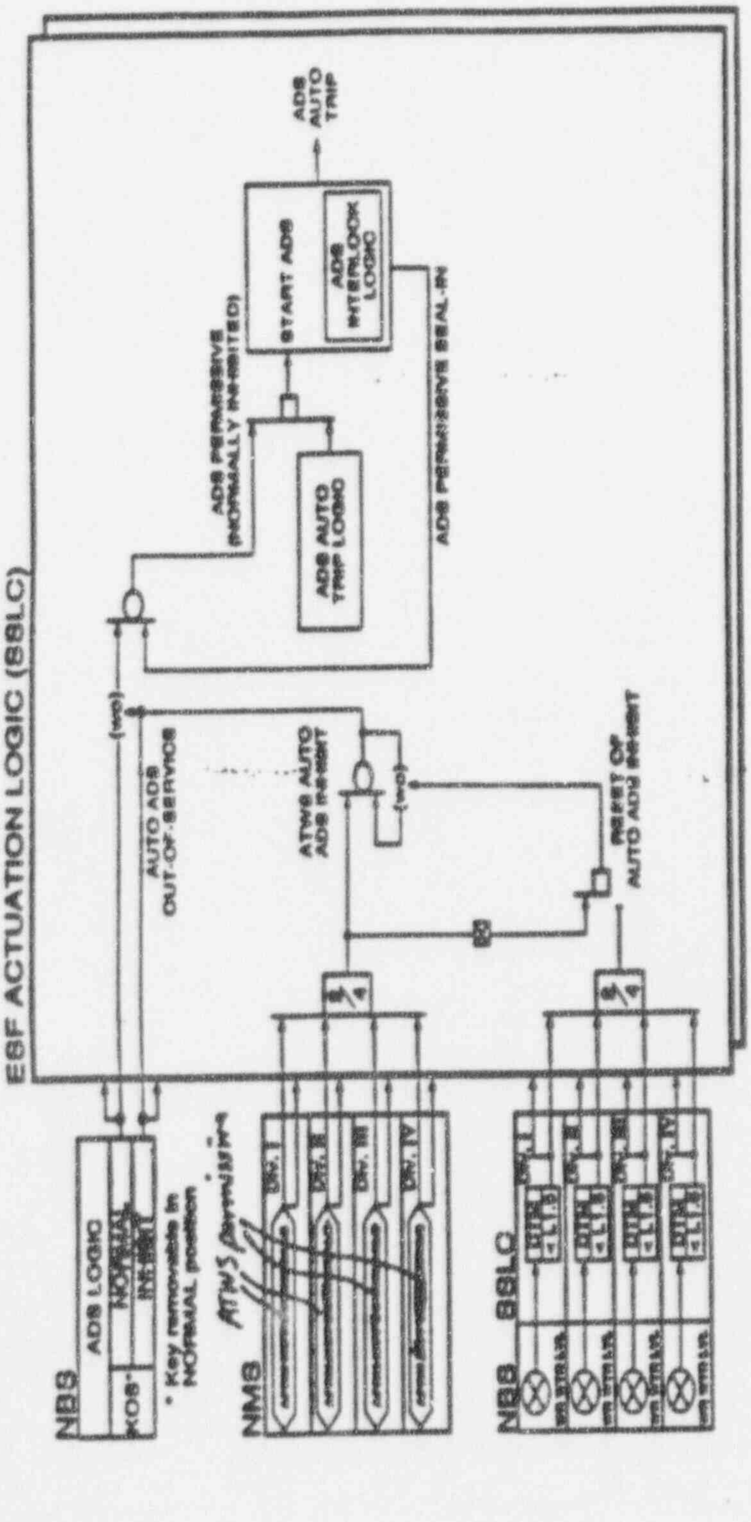


FIGURE 15E-3 ATWS MITIGATION LOGIC (ADS INHIBIT)

15E-~~3~~ 1c ATWS Mitigation Logic (ADS Inhibit)

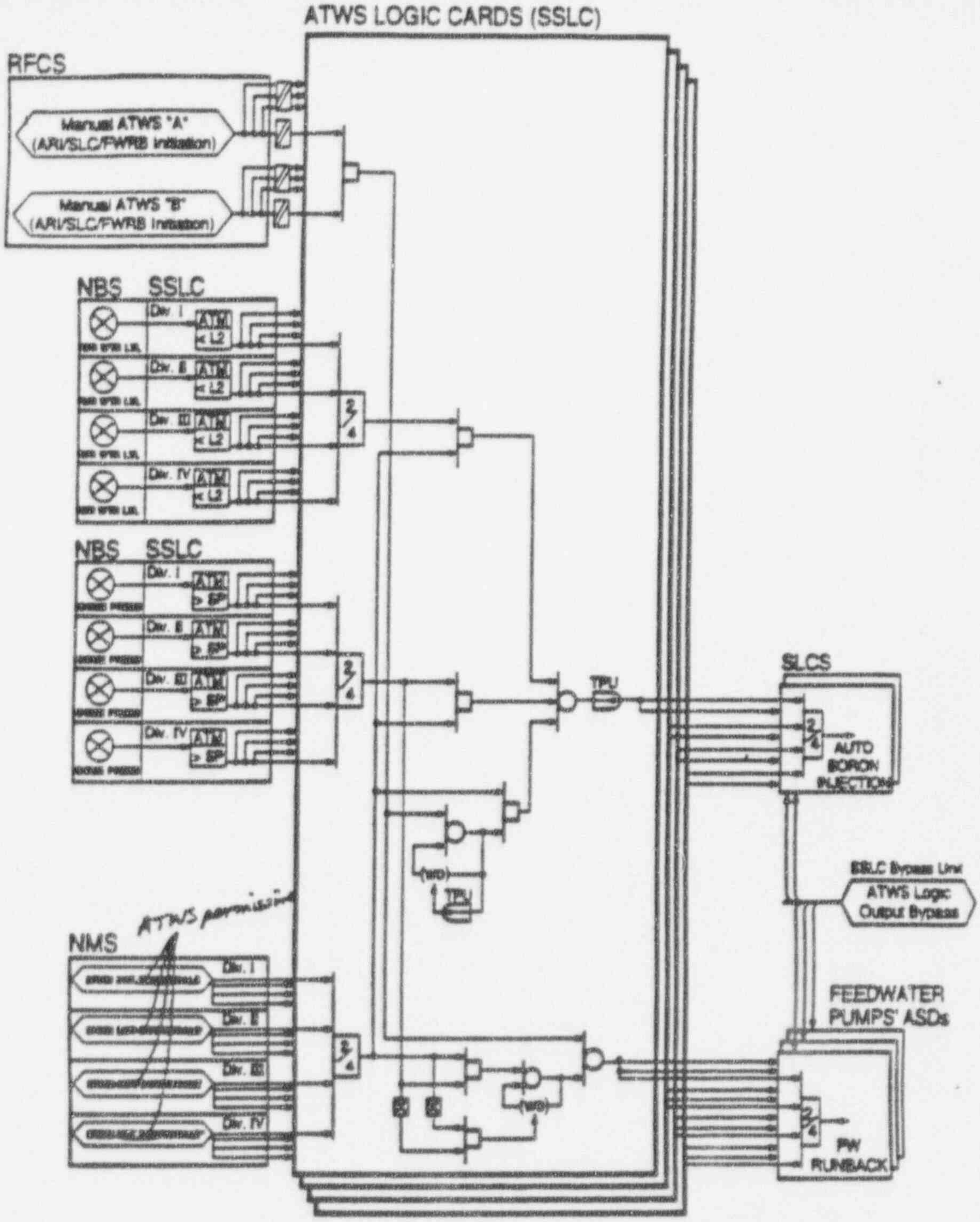


FIGURE 15E-2 ATWS MITIGATION LOGIC (SLCS INITIATION, FEEDWATER RUNBACK)

Figure 15E-16 ATWS Mitigation Logic (SLCS Initiation, Feedwater Runback)

SIMOR

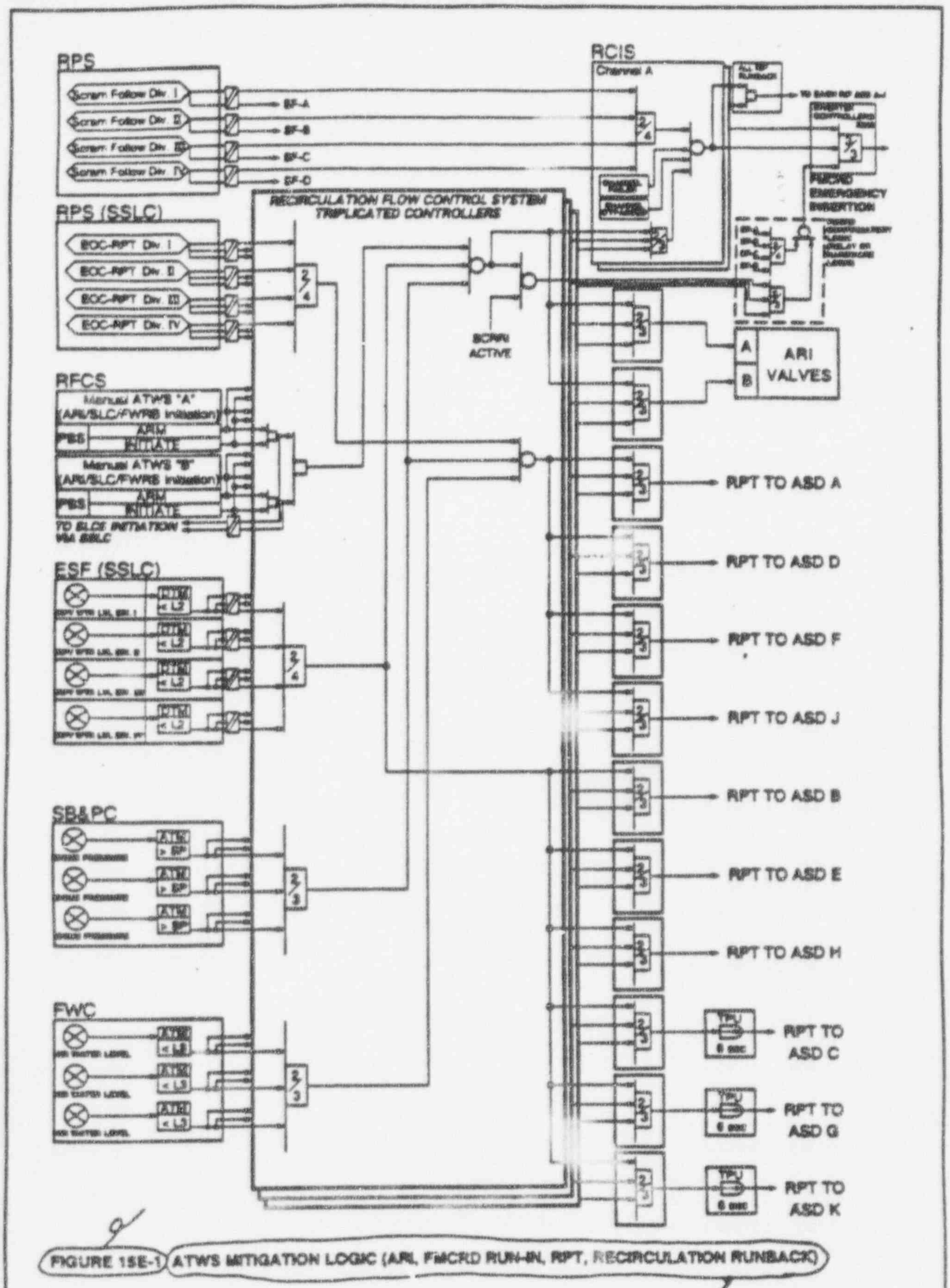
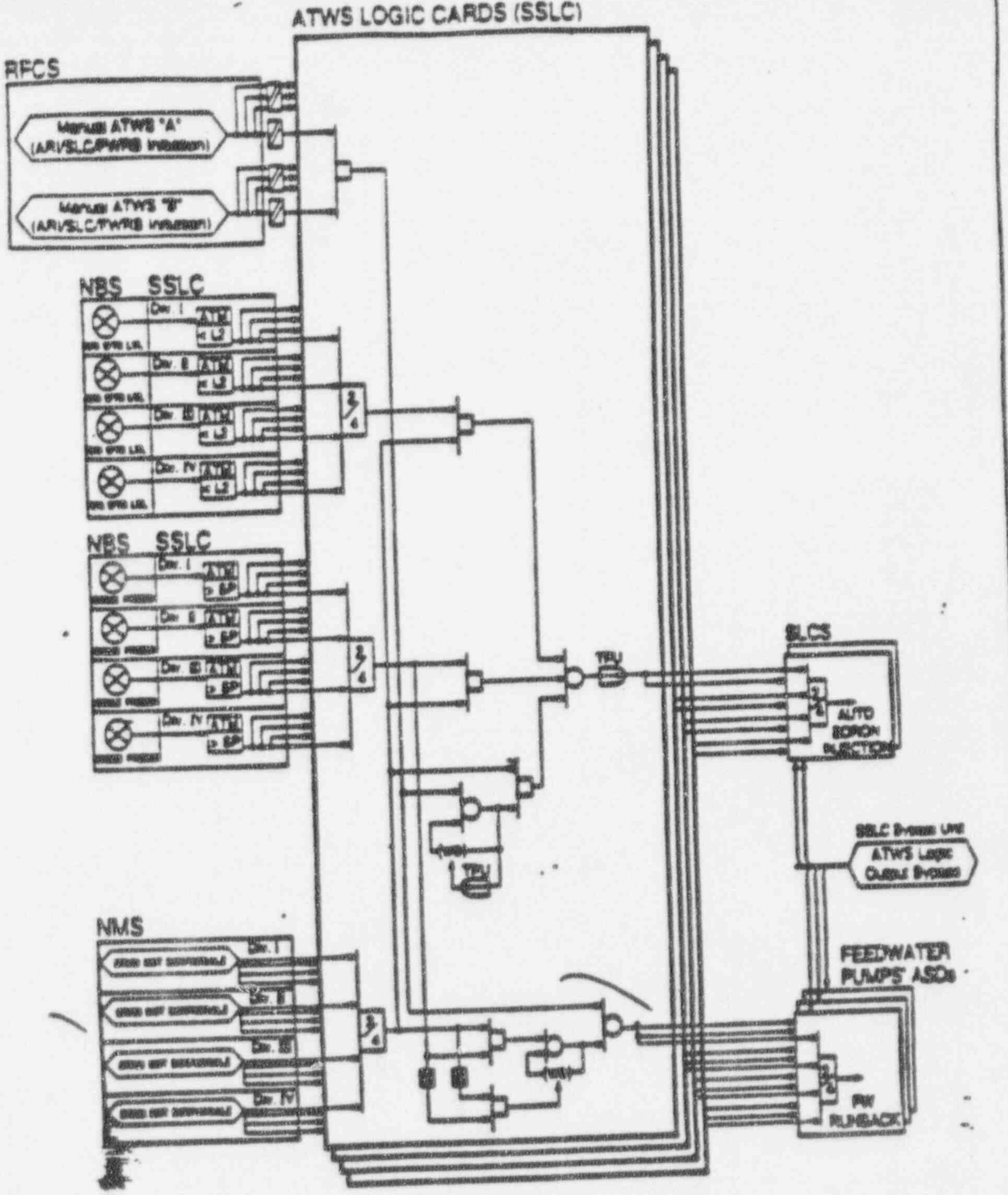


Figure 15E-1 ATWS Mitigation Logic

a

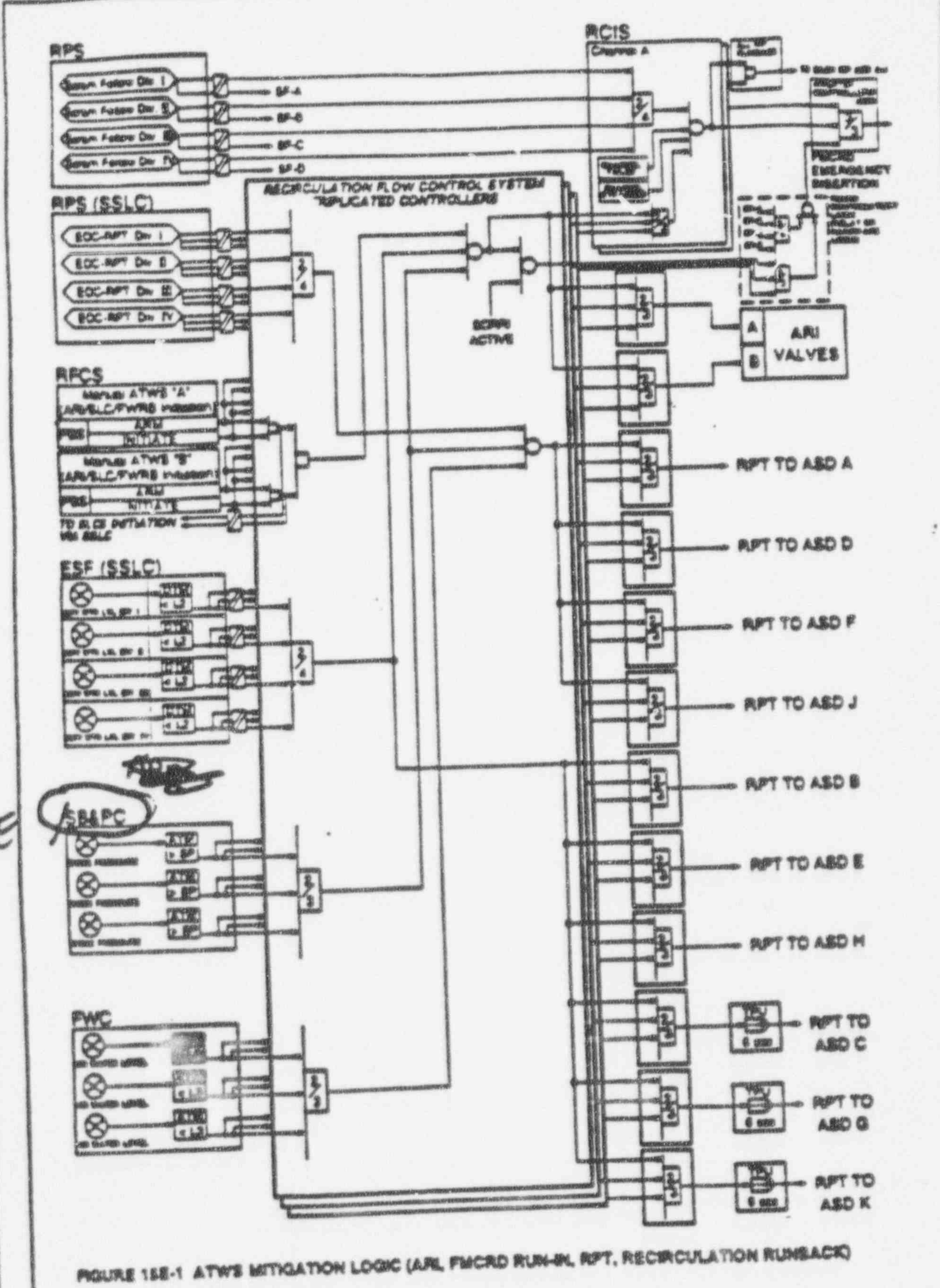


Figure

FIGURE 15E-2 ATWS MITIGATION LOGIC (SLCS INITIATION, FEEDWATER RUNBACK)

15E-2 ATWS Mitigation Logic (SLCS Initiation, Feedwater Runback)

SAF 2/11



10 Ignore

Figure 15E-1 ATWS Mitigation Logic

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.10 SBPC No. 3

NRC COMMENT:

The title of Figure 15E-2 is not consistent with the title of Figure 15E-1. See SSAR, page 15E-18.

GE RESPONSE:

GE concurs and will correct this figure title in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment; see attached.

Figure Renumbered

CDM SECTION AND COMMENT No.: 2.2.10 SBPC No. 2 (Continued)

GE RESPONSE: (Continued)

Additional Response

There is no explicit APR input to RFC shown on Figure 2.2.8 because this power control signal is considered part of the PLANT INPUT SIGNALS interface. This approach is consistent with the overview CDM treatment of non-safety-related plant controls.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.10 SBPC No. 2

NRC COMMENT:

Figure 15E-1 ATWS mitigation logic indicates that the SB&PC system provides the steam dome pressure input to the RFC system. Per the system descriptions, the APR system is the RFC interface for the SB&PC system. See CDM 2.2.9 and 2.2.10 attached.

GE RESPONSE:

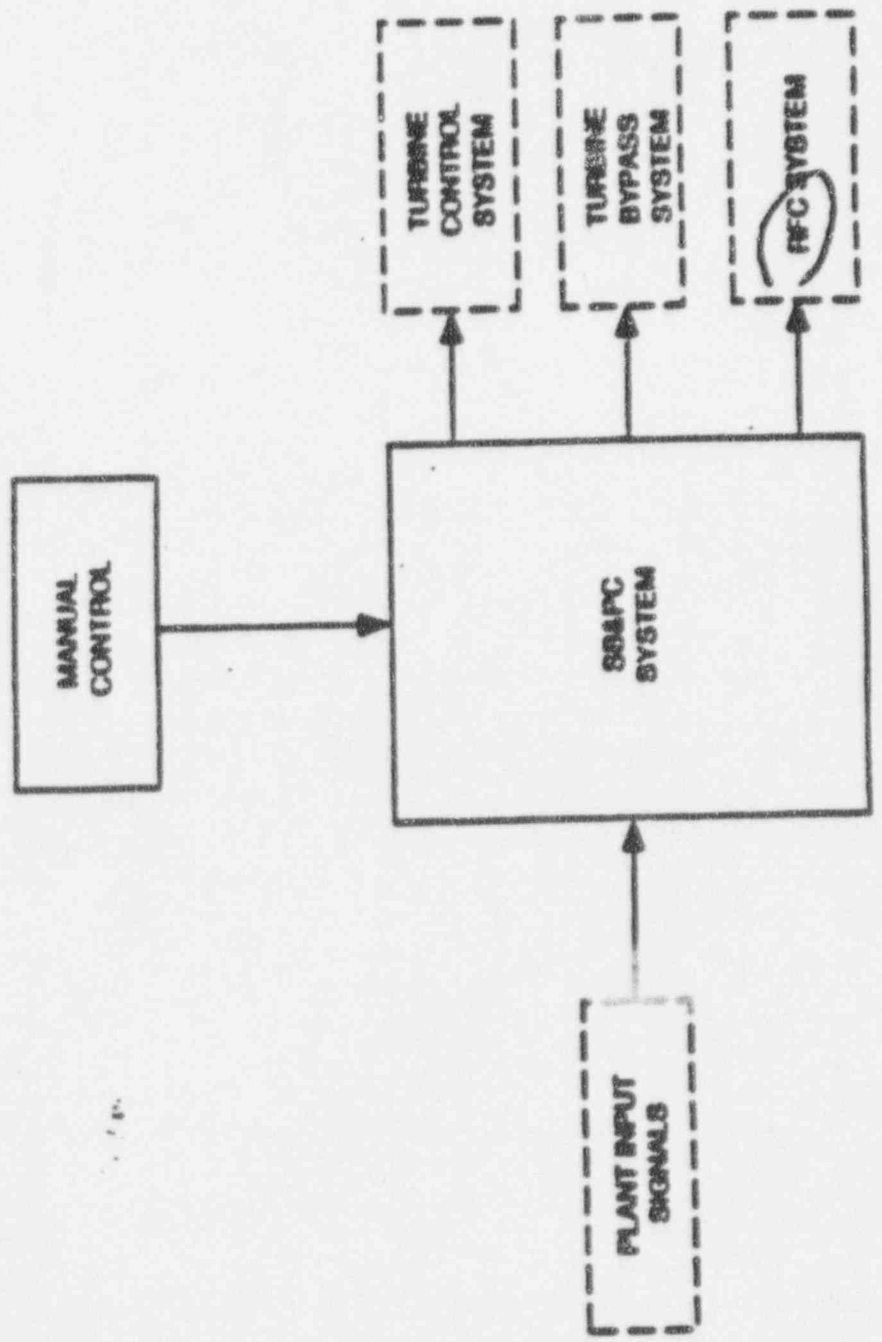
GE does not believe there are any inconsistencies requiring CDM changes. The SB&PC does in fact provide pressure signals to the RFC System for ATWS logic as shown on SSAR Figure 15E-1 and CDM Figures 2.2.8 and 2.2.10. The APR/RFC interface shown on Figure 2.2.9 is associated with the APR control function and is input to RFC for reactor power regulation (via flow control).

Consequently, GE proposes no changes in response to this NRC comment.
(Continued on next page...)

PROPOSED CHANGES

CDM: None

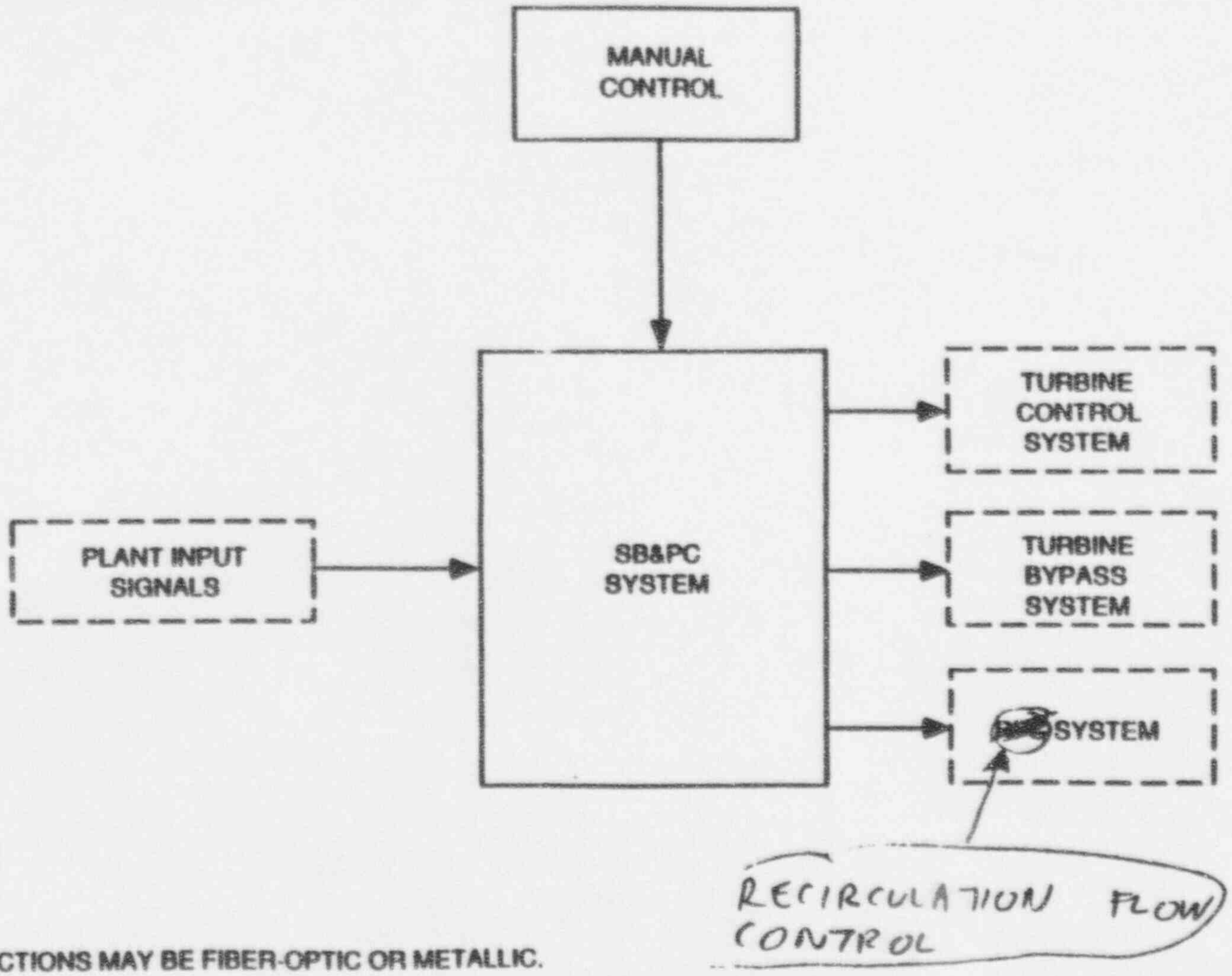
SSAR: None



NOTE:
1. INTERCONNECTIONS MAY BE FIBER-OPTIC OR METALLIC.

Figure 2.2.10 Steam Bypass and Pressure Control System Control Interface Diagram

RL 7|9|96



NOTE:
1. INTERCONNECTIONS MAY BE FIBER-OPTIC OR METALLIC.

Figure 2.2.10 Steam Bypass and Pressure Control System Control Interface Diagram

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.10 SBPC No. 1

NRC COMMENT:

Figure 2.2.10 labeling of interfacing systems are listed as Turbine Control System, Turbine Bypass System and RFC system. The labeling is inconsistent.

GE RESPONSE:

GE concurs that this table involves a mixture of spelled out system names and system acronyms that is inconsistent (stylistically) with 2.2.9. GE proposes to fix per the attached.

PROPOSED CHANGES

CDM: See attached markup.

SSAR: None

7.7.1.1 Nuclear Boiler System
7.7.1.2 Rod Control
7.7.1.3 Recirculation Flow Control
7.7.1.4 Feedwater Control
7.7.1.5 Process Computer
7.7.1.6 Neutron Monitoring ✓
7.7.1.7 APR
7.7.1.8 Steam Bypass & Pressure Control
7.7.1.9 Non-Essential multiplexing System
7.7.1.9 Fuel Pool Cooling and Cleanup System
7.7.1.11 Other non-safety Related Control Systems

?

7.7 Control Systems Not Required for Safety

7.7.1 Description

This subsection provides discussion (or provides references to other chapter discussions) for instrumentation and controls of systems which are not essential for the safety of the plant, and permits an understanding of the way the reactor and important subsystems are controlled, and why failure of these systems does not impair safety functions. The systems include the following:

- Nuclear Boiler System—Reactor Vessel Instrumentation
- Rod Control and Information System
- Recirculation Flow Control System
- Feedwater Control System
- Process Computer System
- Neutron Monitoring System—ATIP Subsystem
- Fire Protection System (Chapter 9)
- Drywell Cooling System (Chapter 9)
- Instrument Air Systems (Chapter 9)
- Makeup Water System (Chapter 9)
- Atmospheric Control System (Chapter 9)
- Fuel Pool Cooling and Cleanup System (Chapter 9)

7.7.1.1 Nuclear Boiler System—Reactor Vessel Instrumentation

Figure 5.1-3 (Nuclear Boiler System P&ID) shows the instrument numbers, arrangements of the sensors, and sensing equipment used to monitor the reactor vessel conditions. The NBS interlock block diagram (IBD) is found in Figure 7.3-2. Because the NBS sensors used for safety-related systems, engineered safeguards, and control systems are described and evaluated in other portions of this document, only the non-safety-related sensors for those systems are described in this subsection.

(1) System Identification

The purpose of the NBS instrumentation is to monitor and provide control input for operation variables during plant operation.

7.7 Control Systems Not Required for Safety

MODIFIED BY FOX

7.7.1 Description

This subsection provides discussion (or provides references to other chapter discussions) for instrumentation and controls of systems which are not essential for the safety of the plant, and permits an understanding of the way the reactor and important subsystems are controlled, and why failure of these systems does not impair safety functions. The systems include the following:

- Nuclear Boiler System—Reactor Vessel Instrumentation
- Rod Control and Information System
- Recirculation Flow Control System
- Feedwater Control System
- Process Computer System
- Neutron Monitoring System—ATIP Subsystem
- ~~Fire Protection System (Chapter 9)~~
- ~~Drywell Cooling System (Chapter 9)~~
- ~~Instrument Air Systems (Chapter 9)~~
- ~~Makeup Water System (Chapter 9)~~
- ~~Atmospheric Control System (Chapter 9)~~
- ~~Fuel Pool Cooling and Cleanup System (Chapter 9)~~

- Automatic Power Regulator System
- Steam Bypass and Pressure Control System
- Non-Essential Multiplexing System
- Fuel Pool Cooling and Cleanup System
- Other Non-Safety-Related Control Systems

7.7.1.1 Nuclear Boiler System—Reactor Vessel Instrumentation

Figure 5.1-3 (Nuclear Boiler System P&ID) shows the instrument numbers, arrangements of the sensors, and sensing equipment used to monitor the reactor vessel conditions. The NBS interlock block diagram (IBD) is found in Figure 7.3-2. Because the NBS sensors used for safety-related systems, engineered safeguards, and control systems are described and evaluated in other portions of this document, only the non-safety-related sensors for those systems are described in this subsection.

(1) System Identification

The purpose of the NBS instrumentation is to monitor and provide control input for operation variables during plant operation.

7B Implementation Requirements for Hardware/Software Development

This section defines the requirements to be met by the hardware and software development implementation activities that are to be made available for review by the NRC. Software Development

Software Management Plan

(1) The Software Management Plan shall define:

(a) the organization and responsibilities for development of the software design; the procedures to be used in the software development; the interrelationships between software design activities; and the methods for conducting software safety analyses.

Within the defined scope and content of the Software Management Plan, accepted methods and procedures for the above activities are presented in the following documents:

(i) IEEE 730, Standard for Software Quality Assurance Plans, Section 3.4;

(ii) ASME NQA2a, Part 2.7, Quality Assurance Requirements of Computer Software for Nuclear Facility Application;

(iii) ANSI/IEEE-ANS-7-4.3.2, Application Criteria for Digital Computers in Safety Systems for Nuclear Facilities (to be replaced by the issued version of P 7-4.3.2, "Standard Criteria for Digital Computers Used in Safety Systems of Nuclear Power Generation Stations");

(iv) IEC 880, Software for computers in the safety systems of nuclear power stations, Section 3.1;

(v) IEEE *(draft H)*, Standard for Software Safety Plans;

(vi) IEEE 1012, Standard for Software Verification and Validation Plans, Section 3.5;

(vii) IEEE 830, Guide to Software Requirements Specifications, Section 5;

(viii) IEEE 1042, Guide to Software Configuration Management.

Note that within the set of documents listed above, differences may exist regarding specific methods and criteria applicable to the Software Management Plan. In situations where such differences exist, all of the methods and criteria presented within those documents are considered

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.9 APR No. 5

NRC COMMENT:

In 7.7, Control Systems not Required for Safety, the system list is inconsistent with the system included in Chapter 7.7. See attached.

GE RESPONSE:

GE concurs that the system listing or SSAR page 7.7-1 is incomplete and will make the necessary changes in the next SSAR amendment per the attached markup.

PROPOSED CHANGES

CDM: None

SSAR: Per attached markup.

NRC QUESTION - SHOULD THIS BE 7.7.1.5.2 YES

as explained in Subsection 7.7.1.5.1. However, this is a power generation function. Neither the Process Computer System nor its PGCS function initiate or control any engineered safeguard or safety-related system.

7.7.1.5.4 Testing and Inspection Requirements

The Process Computer System has self-checking provisions. It performs diagnostic checks to determine the operability of certain portions of the system hardware and performs internal programming checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.

7.7.1.5.5 Instrumentation Requirements

There is no instrumentation in the Process Computer System other than the video display units (VDUs). Control of the Process Computer System is accomplished with on-screen methods and a few hard switches. System auxiliaries such as printers, plotters, and tape handlers have their own local controls.

7.7.1.6 Neutron Monitoring System—Non-Safety-Related Subsystems

7.7.1.6.1 Automatic Traversing Incore Probe (ATIP)

This subsection describes the non-safety-related Automatic Traversing Incore Probe (ATIP) Subsystem of the Neutron Monitoring System (NMS). Safety-related NMS subsystems are discussed in Subsection 7.6.1.1.

(1) Description

The ATIP is comprised of three TIP machines, each with a neutron-sensitive sensor attached to the machine's flexible cable. Other than the sensor itself, each machine has a drive mechanism, a 20-position index mechanism, associated guide tube, and other parts. While not in use, the sensor is normally stored and shielded in a storage area inside the TIP room in the reactor building. During operation, the ATIP sensors are inserted, either manually or automatically, via guide tubing and through desired index positions to the designated LPRM assembly calibration tube. Each ATIP machine has designated number and locations of LPRM assemblies to cover, such that the ATIP sensor can travel to all LPRM locations assigned to this machine via the index mechanism of this machine. The LPRM assignments to the three machines are shown in Figure 7.7-10.

Flux readings along the axial length of the core are obtained by first inserting the sensor fully to the top of the calibration tube and then taking data as the sensor is withdrawn continuously from the top. Sensor flux reading, sensor axial positions data in the core, and LPRM location data are all sent to an ATIP control unit located in the control room, where the data can be stored. The

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.9 APR No. 4

NRC COMMENT:

7.7.1.5.3 Safety Evaluation, references 7.7.1.5.1 as providing the explanation of PGCS signals to the APR system. The correct reference might be 7.7.1.5.2.

GE RESPONSE:

~~Later~~ GE concurs that the reference is 7.7.1.5.2 and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

Automatic Power Regulator

7.7.1.5.2 Power Generation Control Subsystem

The Power Generation Control Subsystem (PGCS) is a top level controller that monitors the overall plant conditions, issues control commands to non-safety-related systems, and adjusts setpoints of lower level controllers to support automation of the normal plant startup, shutdown, and power range operations. The PGCS is a separate function of the Process Computer System. The PGCS contains the algorithms for the automated control sequences associated with plant startup, shutdown and normal power range operation. The PGCS issues reactor command signals to the APR. The reactor power change algorithms are implemented in the APR.

In the automatic mode, the PGCS issues command signals to the turbine master controller which contains appropriate algorithms for automated sequences of turbine, feedwater, and related auxiliary systems. Command signals for setpoint adjustment of lower level controllers and for startup/shutdown of other systems required for plant operation are executed by the PGCS. The operator interfaces with the PGCS through a series of breakpoint controls to initiate automated sequences from the operator control console. For selected operations that are not automated, the PGCS prompts the operator to perform such operations. In the semi automatic mode, the PGCS provides guidance messages to the operator to carry out the startup, shutdown, and power range operations.

The PGCS is classified as a power generation system and is not required for safety. Safety-related events requiring control rod scram are sensed and controlled by the safety-related Reactor Protection System which is completely independent of the PGCS.

The PGCS interfaces with the operator's console to perform its designated functions. The operator's control console for PGCS consists of a series of breakpoint controls for a prescribed pla[illegible]eration sequence. When all the prerequisites are satisfied for a prescribed breakpoint in a control sequence, a permissive is given and, upon verification by the operator, the operator initiates the prescribed sequence. The PGCS then initiates demand signals to the various system controllers to carry out the predefined control functions. (NOTE: For non-automated operations that are required during normal startup or shutdown (e.g., change of reactor mode switch status), automatic prompts are provided to the operator. Automated operations continue after the operator completes the prompted action manually.)

7.7.1.5.3 Safety Evaluation

The Process Computer System is designed to provide the operator with certain categories of information and to supplement procedure requirements for control rod manipulation during reactor startup and shutdown. The system augments existing information from other systems such that the operator can start up, operate at power and shut down in an efficient manner. The PGCS function provides signals to the APR

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.9 APR No. 3

NRC COMMENT:

Section 7.7.1.5.2, Power Generation Control Subsystem, states that the PGCS issues reactor command signals to the "APR". APR is not defined.

GE RESPONSE:

GE concurs and will make the attached change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: See attached.

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7B Implementation Requirements for Hardware/Software Development

This section defines the requirements to be met by the hardware and software development implementation activities that are to be made available for review by the NRC. Software Development

Software Management Plan

(1) The Software Management Plan shall define:

(a) the organization and responsibilities for development of the software design; the procedures to be used in the software development; the interrelationships between software design activities; and the methods for conducting software safety analyses.

Within the defined scope and content of the Software Management Plan, accepted methods and procedures for the above activities are presented in the following documents:

(i) IEEE 730, Standard for Software Quality Assurance Plans, Section 3.4;

(ii) ASME NQA2a, Part 2.7, Quality Assurance Requirements of Computer Software for Nuclear Facility Application;

(iii) ANSI/IEEE-ANS-7-4.3.2, Application Criteria for Digital Computers in Safety Systems for Nuclear Facilities (to be replaced by the issued version of P 7-4.3.2, "Standard Criteria for Digital Computers Used in Safety Systems of Nuclear Power Generation Stations");

(iv) IEC 880, Software for computers in the safety systems of nuclear power stations, Section 3.1;

(v) IEEE *(draft H)*, Standard for Software Safety Plans;

(vi) IEEE 1012, Standard for Software Verification and Validation Plans, Section 3.5;

(vii) IEEE 830, Guide to Software Requirements Specifications, Section 5;

(viii) IEEE 1042, Guide to Software Configuration Management.

Note that within the set of documents listed above, differences may exist regarding specific methods and criteria applicable to the Software Management Plan. In situations where such differences exist, all of the methods and criteria presented within those documents are considered

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.9 APR No. 2

NRC COMMENT:

Chapter 7 Appendix 7B "Implementation Requirements for Hardware/Software development", first paragraph, last sentence appears incomplete. See attached. (This comment was previously provided to GE for inclusion in Amendment 33.)

GE RESPONSE:

~~Later~~ GE will delete the words Software Development from this section in the next SSAR amendment

PROPOSED CHANGES

CDM: None

SSAR: Per above response; see attached

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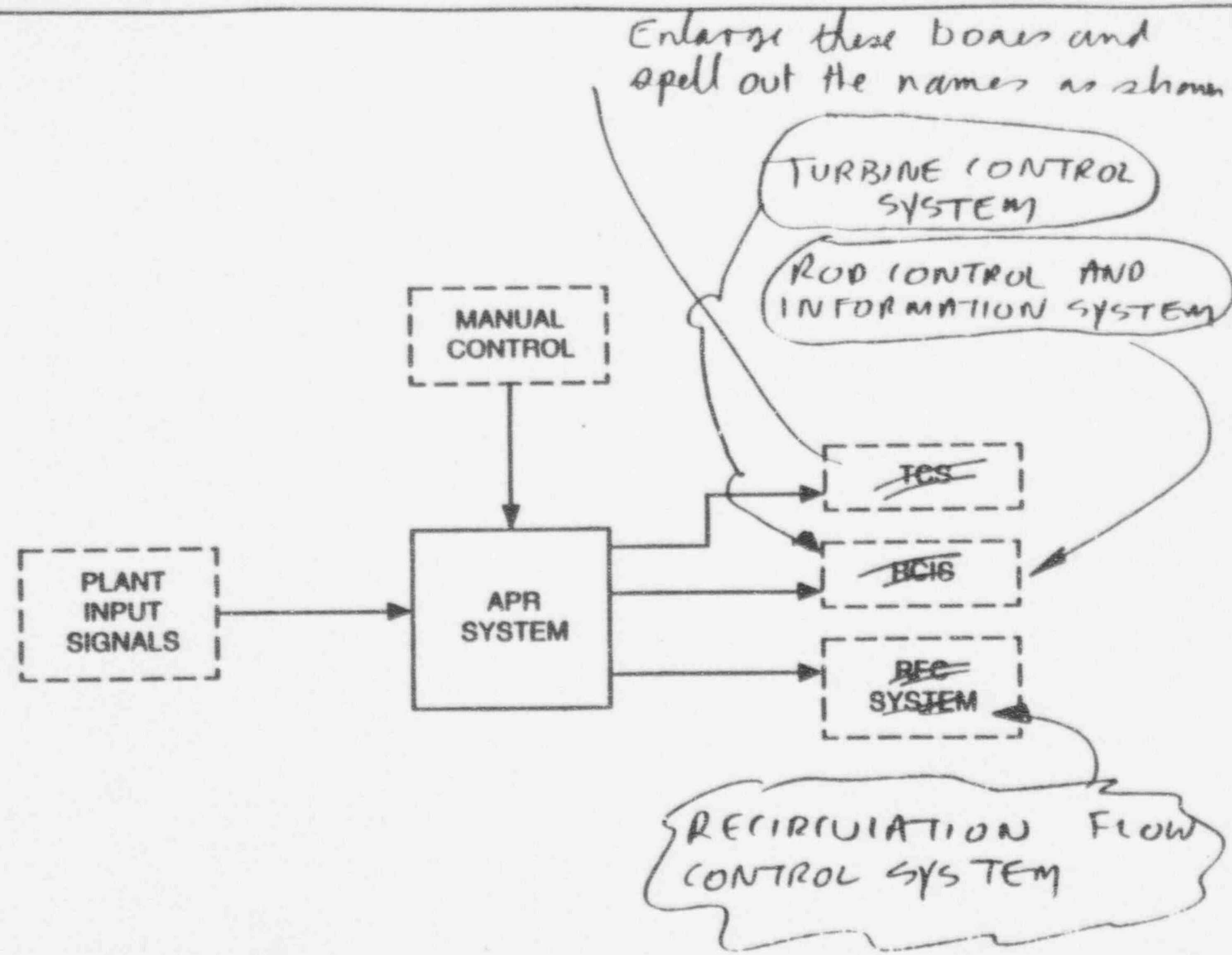

NOTE:
1. INTERCONNECTIONS MAY BE FIBER-OPTIC OR METALLIC.

Figure 2.2.9 Automatic Power Regulator System Control Interface Diagram

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.9 APR No. 1

NRC COMMENT:

Figure 2.2.9 lists TCS, RCIC, and RFC systems but design description does not define these abbreviations.

GE RESPONSE:

GE concurs that these acronyms are undefined and will correct per the attached markup.

PROPOSED CHANGES

CDM: See attached markup.

SSAR: None.

RL 2/15

2.2.8 Recirculation Flow Control System

Design Description

The Recirculation Flow Control (RFC) System controls reactor power by controlling the recirculation flow rate through the reactor core. This is achieved by modulating the recirculation internal pump (RIP) speeds using voltage and frequency modulation of adjustable speed drive (ASD) outputs.

The RFC System consists of redundant microprocessor-based controllers, adjustable speed drives, and motor generator (MG) sets. There are two MG sets, each of which supplies three of the ten ASDs which power the ten RIPs. No more than three RIPs are connected to any one power supply bus.

The other four ASDs receive power directly from the power supply bus.

The RFC System operates in either manual or automatic control modes and has the control interfaces shown on Figure 2.2.8.

Except for the core plate differential pressure sensors provided for the Neutron Monitoring System (NMS), the RFC System is classified as non-safety-related. The four core plate differential pressure sensors for the NMS are classified as Class 1E safety-related.

RFC System logic trips four of the ten RIPs when any one of the following conditions occurs:

(1) Turbine trip or generator load rejection when reactor power exceeds a preset level.

(2) Reactor water level drops below a preset level.

The RFC System has the following logic to mitigate an anticipated transient without scram (ATWS) event:

(1) A signal to open the alternate rod insertion (ARI) valves in the Control Rod Drive (CRD) System on either a high reactor vessel pressure signal or a low reactor water level signal.

(2) A signal to the Rod Control and Information System (RCIS) to initiate electrical insertion of all control rods on either high reactor vessel pressure signal or a low reactor water level signal.

(3) A signal to trip four of the ten RIPs on a high reactor vessel pressure signal.

(4) A signal to trip six additional RIPs on a low reactor water level signal. Three of the six RIPs are tripped after a preset time delay.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.8 RFCS No. 1

NRC COMMENT:

The design description (second paragraph) states 2 MG sets, each of which supplies 3 of 10 ASDs power 10 RIPs. Clarify how the other four ASDs (and four associated RIPs) are powered, the description should be consistent with SSAR Figure 8.3-1.

GE RESPONSE:

GE will clarify the CDM in this area by including the attached change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: See attached.

SSAR: None

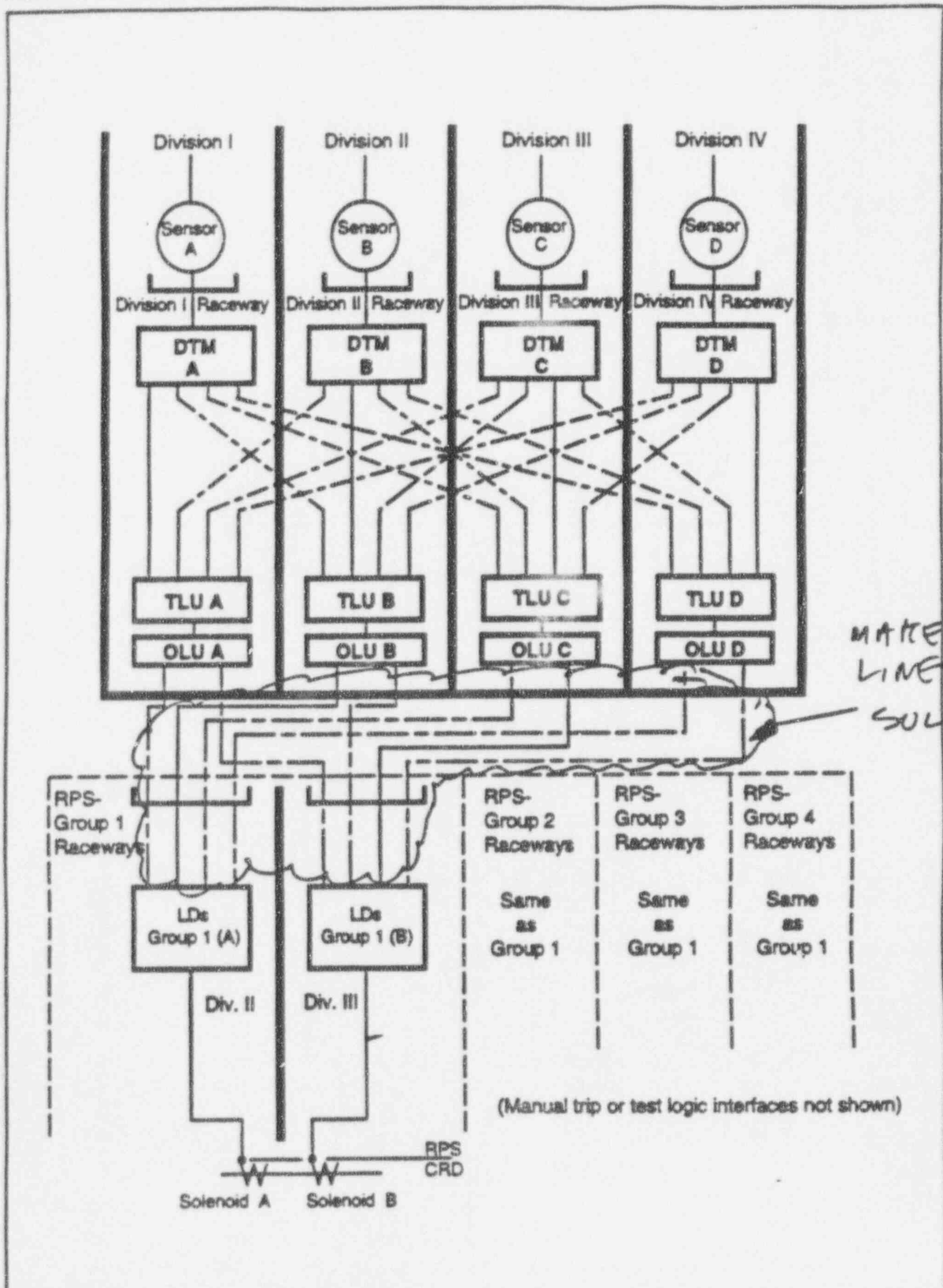
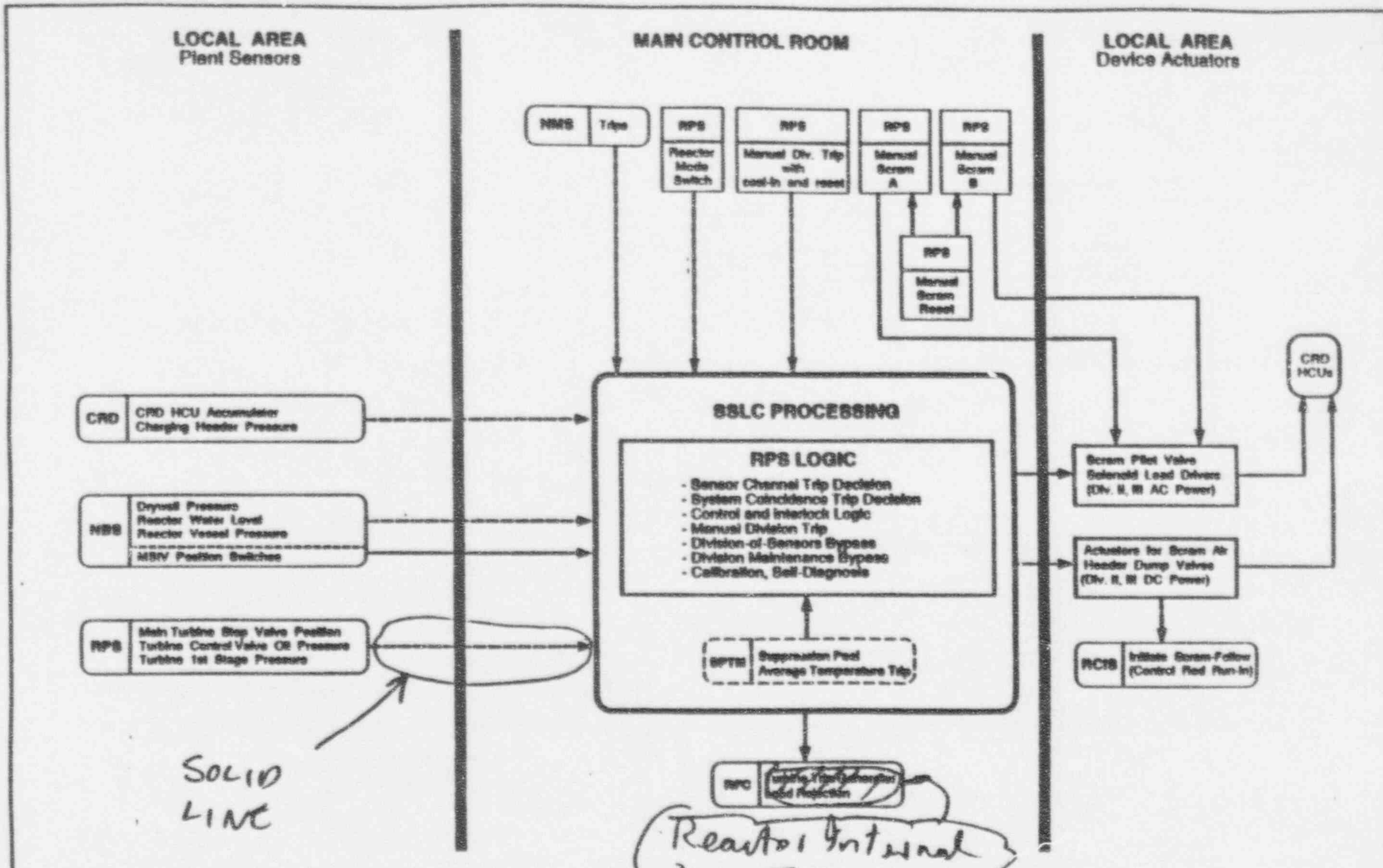


Figure 2.2.7b Reactor Protection System



NOTES:
1. Diagram represents one of four divisions.

Figure 2.2.7a Reactor Protection System Control Interface Diagram

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.7 RPS No. 6

NRC COMMENT:

Figures 2.2.7a and 2.2.7b use solid and dotted lines for signal flow. No description or legend is provided.

GE RESPONSE:

The connections shown in Figures 2.2.7a and 2.2.7b follow the C&I conventions defined on page A-5 of Appendix A to the CDM. GE has reviewed these figures and proposes the changes shown on the attached markups.

PROPOSED CHANGES

CDM: Per attached markups.

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.7 RPS No. 2

NRC COMMENT:

The SSAR 7.2.1.1.4.2 does not list OPRM as an initiating condition. (This comment was previously provided to GE for inclusion in Amendment 33.)

GE RESPONSE:

GE believes the SSAR adequately describes the OPRM function and no changes are necessary. See response to CDM Section 2.2.5 NMS, NRC comment No. 2. However, clarifying SSAR changes will be included in the next amendment.

PROPOSED CHANGES

CDM: None

SSAR: See response to Comment #2, Section 2.2.5.

Vey

ABWR TIER 1 – GE RESPONSES TO NRC COMMENTS

I&C TASK GROUP

SYSTEM NUMBER AND NAME:

2.2.7 REACTOR PROTECTION SYSTEM

DD

NRC COMMENT:

1. Add High Main Steam Line Radiation trip signal to list of scram inputs.

GE RESPONSE: GE does not concur. Based on GE/NRC discussions it was mutually agreed that MSL high radiation trip would not be included in Tier 1; in either LDISS or RPS. The basis for this agreement was the recognition that this feature might well be deleted from the design at sometime in the future. CHAP 15 Analyses not dependent on MSL radiation Trip signal.

PROPOSED CHANGES TO TIER 1:

1. NONE

2.

3.

Agreed 7/28/93 [illegible] (GE)
[illegible] (NRC)

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.7 RPS No. 1

NRC COMMENT:

Reactor Protection Section design description 2.2.7 does not list a reactor trip for high main steamline radiation. ITAAC states that a simulated process variable input will be used (as listed in 2.2.7 and figure 2.2.7a) to test the RPS channel inputs.

GE RESPONSE:

During 1993 GE/NRC discussions of CDM scope and content, it was specifically decided not to include the RPS main steamline high radiation trip in the CDM. This mutual decision was based on the observation that this BWR feature is not working well in the field (spurious trips) and might well be deleted/replaced at some time in the future. This deletion would be severely complicated if the feature is defined in the CDM and is thus a part of the certified design. Consequently, the RPS steamline radiation trip was not included. The attached signed meeting minutes dated 7-27-93 document the earlier GE/NRC agreement on this issue.

GE plans no changes as a result of this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

List of Acronyms (Continued)

LRMS	Liquid Radwaste Management System
LVDT	Linear Variable Differential Transformers
MAPLHGR	Maximum Average Planar Linear Heat Generation Rate
MBA	Misplaced Bundle Accident
MCES	Main Condenser Evacuation System
MCPR	Minimal Critical Power Ratio
MEB	NRC Mechanical Engineering Branch
MOFB	Mis-oriented Fuel Bundle
MPC	Maximum Permissible Concentration
MPL	Master Parts List
MRBM	Multi-Channel Rod Block Monitor (Subsystem)
MS	Multiplexing System
MSF	Main Steam Flow
MSIV	Main Steamline Isolation Valve
MSR	Moisture Separator Reheater
MSV	Mean Square Voltage
MUWC	Makeup Water Condensate (System)
MUWP	Makeup Water-Purified Distribution System
MWP	Makeup Water (Preparation System)
MWS	Makeup Water System
NBR	Nuclear Boiler Rated
NCLL	Normal Combustible Loading Limit
NEMS	Non-Essential Multiplexing System
NG	Nuclear Grade
NPSH	Net Positive Suction Head
NRHX	Non-Regenerative Heat Exchanger
NRR	NRC Office of Nuclear Reactor Regulation
NSOA	Nuclear Safety Operational Analysis
NSS	Nuclear Safety Systems
NSSS	Nuclear Steam Supply System
O-RAP	Operational Reliability Assurance Program
OGS	Off Gas System
OIS	Oxygen Injection System
OLMCPR	Operating Limit Minimum Critical Power Ratio
OLU	Output Logic Unit
OSC	Operational Support Center

OPRM Oscillation Power Range Monitor

JLR

, Oscillation Power Range Monitor (OP. , Trips

Five

rated power. ~~Four~~ conditions monitored as a function of the NMS comprise the APRM trip logic output to the RPS. These conditions are high neutron flux, high simulated thermal power, APRM inoperative, and ~~reactor internal pump~~ trip. The specific condition within the NMS that caused the APRM trip output is not detectable within the RPS.

reactor core flow rapid coastdown

(2) Nuclear Boiler System (NBS) (Figure 7.2-6)

(a) Reactor Pressure

Reactor pressure is measured at four physically separated locations by locally mounted pressure transducers. Each transducer is on a separate instrument line and provides analog equivalent output through the EMS to the DTM in one of four RPS sensor channels. The pressure transducers and instrument lines are components of the NBS.

(b) Reactor Water Level

Reactor water level is measured at four physically separated locations by locally mounted level (differential pressure) transducers. Each transducer is on a separate pair of instrument lines and provides analog equivalent output through the EMS to the DTM in one of the four RPS sensor channels. The level transducers and instrument lines are components of the NBS.

(c) Drywell Pressure

Drywell pressure is measured at four physically separated locations by locally mounted pressure transducers. Each transducer is on a separate instrument line and provides analog equivalent output through the EMS to the DTM in one of the four RPS sensor channels of the NBS.

(d) Main Steamline Isolation (Figure 7.2-4)

Each of the four main steamlines can be isolated by closing either the inboard or the outboard isolation valve. Separate position switches on both of the isolation valves of one of the main steamlines provide bistable output through the EMS to the DTM in one of the four RPS sensor channels. Each main steamline is associated with a different RPS sensor channel. The main steamline isolation valves and position switches are components of the NBS.

(e) High Suppression Pool Temperature

High suppression pool temperature is measured at four physically separated locations by locally mounted sensors. Each sensor is on a

(4) High Drywell Pressure

(5) Main Steamline Isolation

(6) Low Control Rod Drive Charging Header Pressure

(7) High Main Steamline Radiation

(8) Deleted

(9) Turbine Stop Valve Closed

(10) Turbine Control Valve Fast Closure

(11) Operator-initiated Manual Scram

(12) High Suppression Pool Temperature

The systems and equipment that provide trip and scram initiating inputs to the RPS for these conditions are discussed in the following subsections. With the exception of the NMS (1) and PRRM (7), and the TB-trips (5 and 7) all of the building signals (9) and (10), all of the other systems provide sensor outputs through the EMS. Analog-to-digital conversion of these sensor output values is done by EMS equipment. NMS and PRRM trip signals are provided directly to the RPS by NMS and PRRM trip logic units. The turbine building signals 9 and 10 are hardwired to connections in the control building. The TB-trips (5 and 7) are provided through hardwired connections.

(1) Neutron Monitoring System (NMS)

Each of the four divisions of the NMS equipment provides separate, isolated, bistable SRNM trip and APRM trip signals to all four divisions of RPS trip logics (Figure 7.2-5).

(a) SRNM Trip Signals

15%

The SRNMs of the NMS provide trip signals to the RPS to cover the range of plant operation from source range through startup range to about 10% of reactor rated power. Three conditions monitored as a function of the NMS comprise the SRNM trip logic output to the RPS. These conditions are upscale, short period and SRNM inoperative. The specific condition within the NMS that caused the SRNM trip output is not detectable within the RPS.

(b) APRM Trip Signals

The APRMs of the NMS provide trip signals to the RPS to cover the range of plant operation from a few percent to greater than reactor

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.5 NMS No. 2

NRC COMMENT:

The SSAR 7.2.1.1.4.2 does not list OPRM Oscillation Power range monitor reactor trip signal. Listed in design description 2.2.5, ITAAC and TS. Modify the SSAR to add the OPRM function in SSAR section 7.2.

GE RESPONSE:

GE does not believe that the RPS discussion in Section 7.2.1.1.4.2 should contain extensive details of the Neutron Monitoring System logic which produces trip inputs to the RPS. This section does state that the RPS receives input from the NMS but also states "The specific conditions within the NMS that caused the APRM trip output is not detectable within the RPS." The OPRM function of the NMS is discussed in Section 7.6.1.1.2.2 where it clearly states that the NMS creates trip signals which are sent to the RPS.

However, to clarify this issue, GE will make the SSAR page 7.2-6 changes shown on the attached markup.

PROPOSED CHANGES

CDM: None

SSAR: See attached markup.

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~~3/9/93~~
3/11/93

2.2.3 FEEDWATER CONTROL System

	Design Commitment	ITA	AC
B	The FDWC System controls flow of feedwater.	A test will be ~~performed~~ performed by simulating a decreasing reactor level signal and observing a signal to increase feedwater flow.	The signal to increase feedwater flow occurs.

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.2.5 NMS No. 1

NRC COMMENT:

Design description 2.2.5 states that the SRNM monitors neutron flux up to 15% of rated power. The SSAR 7.2.1.1.4.2 states that the SRNM monitor flux to 10% of rated power. SSAR section 7.7 has 15% as the range. Revised 7.2.1.1.4.2.

GE RESPONSE:

The correct number is 15% and GE will update the SSAR as part of the next amendment.

PROPOSED CHANGES

CDM: None

SSAR: Correct section 7.2.1.1.4.2 per attached.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.1 MUWP No. 1

NRC COMMENT:

Section 2.11.1 requires a figure/diagram to supplement the text. This is necessary because of the primary containment isolation function which is safety-related.

GE RESPONSE:

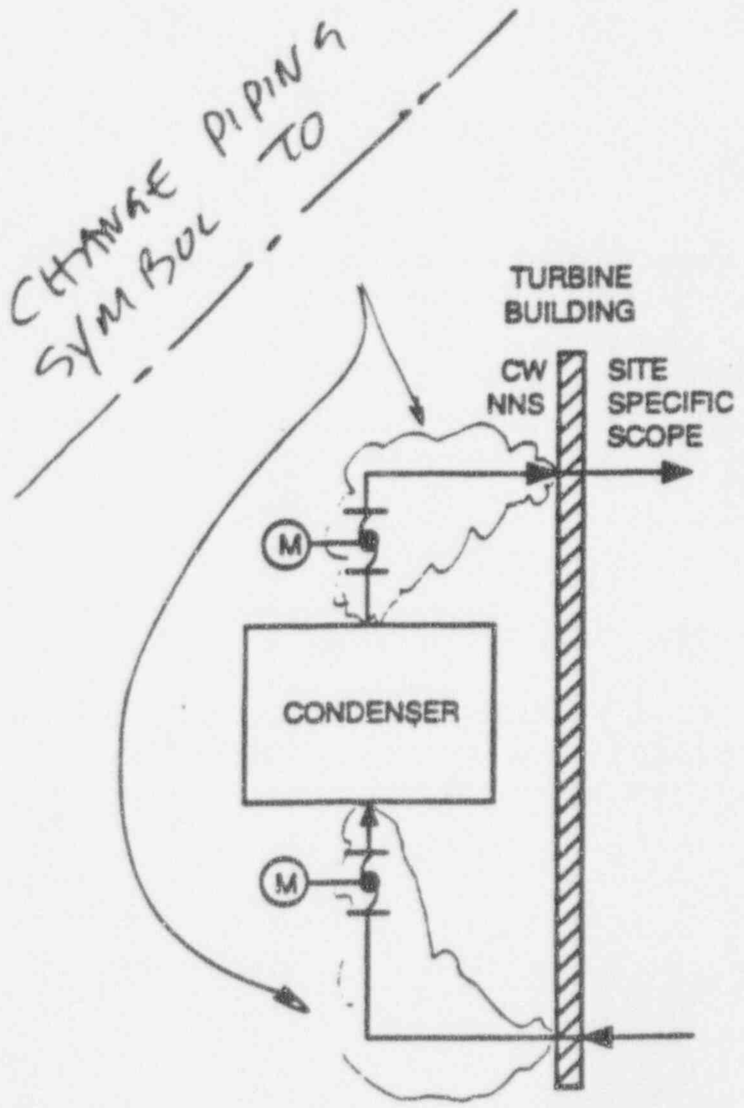
GE does not concur. The text of Section 2.11.1 adequately defines the MUWP isolation provisions. Furthermore, there is no CDM form/content/scope guideline requiring a figure for systems having safety-related containment isolation features.

PROPOSED CHANGES

CDM: None

SSAR: None

R/L 1



NOTES:
1. MULTIPLE LINES MAY BE USED.
2. CONDENSER ISOLATION PROVISIONS ARE REQUIRED FOR EACH LINE.

Figure 2.10.23 Circulating Water System

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.23 CWS No. 1

NRC COMMENT:

Revise ITAAC figure 2.10.23 to conform with CDM "Appendix A" for "NNS" piping class.

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

delivered to the process line or equipment. The air supply is protected from back flow of process gas by two check valves in series or a check valve and a pressure control valve in series.

11.3.4.2.8 Charcoal Vault Temperature

The charcoal adsorber vault air conditioning system is controlled at any selected temperature within a range of 29°C to 41°C. The temperature of the vault is maintained as indicated in Subsection 11.3.4.3.13.

11.3.4.2.9 Rangeability

The process can accommodate reactor operation from 0 to 100% of full power (full power is defined as the Normal Operating Case). In normal operation, radiolytic gas production varies linearly with thermal power. The process can accommodate an air flow at 10 to 425 m^3/hr for the full range of reactor power operation.

In addition, the process can mechanically accommodate a startup high air flow upon initiation of the steam jet air ejectors. This startup air flow results from evacuation of the turbine condensing equipment while the reactor is in the range of about 3 to 7% of rated power.

11.3.4.2.10 Redundancy

All active equipment (e.g., pumps, valves and instrumentation) whose operation is necessary to maintain operability of the Offgas System is redundant. Passive equipment (e.g., charcoal adsorber) is not redundant. Instrumentation that performs an information function and is backed up by design considerations or other instrumentation need not be redundant. Instrumentation used to record hydrogen concentration or activity release (e.g., flow measurement, hydrogen analyzers) is also redundant.

Design provisions are incorporated which preclude the uncontrolled release of radioactivity to the environment as a result of any single equipment failure short of the equipment failure accident described in Chapter 15.

Design precautions taken to prevent uncontrolled releases of activity include the following:

(1) The system design minimizes ignition sources so that a hydrogen detonation is highly unlikely even in the event of a recombiner failure.

(2) The system pressure boundary is detonation-resistant in addition to the measure taken to avoid a possible detonation.

delivered to the process line or equipment. The air supply is protected from back flow of process gas by two check valves in series or a check valve and a pressure control valve in series.

11.3.4.2.8 Charcoal Vault Temperature

The charcoal adsorber vault air conditioning system is controlled at any selected temperature within a range of 29°C to 41°C. The temperature of the vault is maintained as indicated in Subsection 11.3.4.3.13.

11.3.4.2.9 Rangeability

The process can accommodate reactor operation from 0 to 100% of full power (full power is defined as the Normal Operating Case). In normal operation, radiolytic gas production varies linearly with thermal power. The process can accommodate an air flow at 10 to 425 m^3/hr for the full range of reactor power operation.

In addition, the process can mechanically accommodate a startup high air flow upon initiation of the steam jet air ejectors. This startup air flow results from evacuation of the turbine condensing equipment while the reactor is in the range of about 3 to 7% of rated power.

11.3.4.2.10 Redundancy

All active equipment (e.g., pumps, valves and instrumentation) whose operation is necessary to maintain operability of the Offgas System is redundant. Passive equipment (e.g., charcoal adsorber) is not redundant. Instrumentation that performs an information function and is backed up by design considerations or other instrumentation need not be redundant. Instrumentation used to record hydrogen concentration or activity release (e.g., flow measurement, hydrogen analyzers) is also redundant.

Design provisions are incorporated which preclude the uncontrolled release of radioactivity to the environment as a result of any single equipment failure short of the equipment failure accident described in Chapter 15.

Design precautions taken to prevent uncontrolled releases of activity include the following:

(1) The system design minimizes ignition sources so that a hydrogen detonation is highly unlikely even in the event of a recombiner failure.

(2) The system pressure boundary is detonation-resistant in addition to the measure taken to avoid a possible detonation.

Delete [illegible] by applying a design pressure for H recom stream equipment which is approximately seventeen times the design operating pressure of the system.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.22 OGS No. 3

NRC COMMENT:

SSAR Chapter 11.3 should be supplemented with information pertaining to the OGS capability to withstand a hydrogen explosion, as verified in ITAAC #6.

ver

GE RESPONSE:

GE proposes to add text to SSAR Section 11.3.4.2.10 as shown on the attached. For information, the design pressure noted in the revised text is the 24.6 kg/cm² noted in 11.3.9 (see amendment 34) and the design operating pressure of the system is the 0.47 Kg/cm² shown in Table 11.3-4. The factor of seventeen is developed using the absolute values of these gauge pressures

PROPOSED CHANGES

CDM: None

SSAR: Per the attached.

In addition to these changes, the data in SSAR Section 11.3.9 is being changed per the attached markup to be consistent with Fig 11.3-1 (see amendment 3

(3) Identification and Corrective Action for Items of Nonconformance: Measures shall be established to identify items of nonconformance with regard to the requirements of the procurement documents or applicable codes and standards and to identify the action taken to correct such items.

Quality control for the ventilation systems is described in Section 9.4.

11.3.8 Seismic Design

Offgas System equipment and piping are classified non-Seismic Category I. The support elements of the charcoal adsorbers, including legs or skirts, lateral supports (if required) and anchor bolting, are designed such that the fundamental frequency of the vessels including all support elements, is greater than 33 Hz. The charcoal adsorbers, including support elements, are designed to static seismic coefficients of 0.2g horizontal and 0.0g vertical. Stress levels in the charcoal adsorber support elements do not exceed 1.33 times the allowable stress levels permitted by the AISC Manual of Steel Construction, 7th Edition (Section 11.3.2).

Seismic design for the ventilation systems is described in Section 9.4.

11.3.9 Testing

Shop fabricated equipment and the piping system will pass the required tests for integrity as specified in the pressure integrity design specification. In all cases, pressure-containing butt welds exposed to radioactive gas will have 100% radiography and all other pressure-containing welds will have liquid penetrant or magnetic particle surface inspection.

36.9 24.6

Completed process systems are pressure tested to the maximum practicable extent. Piping systems are hydrostatically tested in their entirety, utilizing available valves or temporary plugs at atmospheric tank connections. Hydrostatic testing of piping systems is performed at a pressure of ~~38.7~~ kg/cm^2~~g~~, which is 1.5 times ~~25.8~~ kg/cm^2, the design pressure of the lowest pressure rated part of the system. The test pressure will be held for a minimum of 30 minutes with no leakage indicated. Hydrostatic testing will not be performed with the recombiner catalyst, the activated carbon or the filter element in place in the system. Pneumatic testing may be substituted for hydrostatic testing in accordance with the applicable Code of Construction. However, any pressure testing performed after the activated carbon is in place in the vessels would utilize vaporized liquid nitrogen (not compressed air) to avoid contamination or combustion of the carbon.

The installed Offgas System will be leak tested to verify that the leak criteria of Subsection 11.3.4.3.5 are met. A helium leak test is used. Testing is completed prior to application of thermal insulation or corrosion protective coating. Surfaces of the Offgas

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.22 OGS No. 3

NRC COMMENT:

SSAR Chapter 11.3 should be supplemented with information pertaining to the OGS capability to withstand a hydrogen explosion, as verified in ITAAC #6.

GE RESPONSE:

~~Later~~ GE believes that SSAR Section 11.3.4.2.10. addresses the issue of OGS detonation resistance. ~~No~~ Additional SSAR changes are proposed as a result of this NRC comment. (Copy attached)

SEE SSAR SECTIONS 11.3.4.3 (REFERENCES ANSI STD FOR MECH. TESTING, 11.3.9 FOR ITAAC SUPPORTING TESTING)

PROPOSED CHANGES

CDM: None

SSAR: None

calculation of offgas discharge to the vent in µCi/sec and will permit calculation of the charcoal adsorber system performance.

A ivity release that would exceed the maximum permi: set instantaneous value is alarmed, and causes closure of the final process gas release valve.

Instrumentation and control of the ventilation systems are described in Section 9.4.

11.3.7 Quality Control

The following, exerpted from ANS-55.4 (Section 11.3.2), provides quality control features to be established for the design, construction, and testing of the Offgas System.

System Designer and Procurer

(1) Design and Procurement Document Control: Design and procurement documents shall be independently verified for conformance to the requirements of this standard by individual(s) within the design organization who are not the originators of the document. Changes to these documents shall be verified or controlled to maintain conformance to this standard.

(2) Control of Purchased Material, Equipment and Services: Measures shall be established to ensure that suppliers of material, equipment and construction services are capable of supplying these items to the quality specified in the procurement documents. This may be done by an evaluation or a survey of the suppliers' products and facilities.

(3) Handling, Storage and Shipping: Instructions shall be provided in procurement documents to control the handling, storage, shipping and preservation of material and equipment to prevent damage, deterioration and reduction of cleanness.

System Constructor

(1) Inspection: In addition to required code inspections, a program for inspection of activities affecting quality shall be established and executed by, or for, the organization performing the activity to verify conformance with the documented instructions, procedures, and drawings for accomplishing the activity. This shall include the visual inspection of components prior to installation for conformance with procurement documents and the visual inspection of items and systems following installation, cleaning and passivation (where applied).

(2) Inspection, Test and Operating Status: Measures shall be established to provide for the identification of items which have satisfactorily passed required inspections and tests.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.22 OGS No. 2

NRC COMMENT:

SSAR Chapter 11.3.6 should be supplemented with information pertaining to the automatic isolation of the OGS, as verified in ITAAC #3.

GE RESPONSE:

~~Later~~ GE concurs and will include the SSAR change shown on the attached markup.

PROPOSED CHANGES

CDM: None

SSAR: Per attached markup.

ref.

Power Generation Design Basis Five—The main condenser provides for deaeration of the condensate, such that condensate dissolved oxygen content will not exceed 10 ppb during normal operation above 50% load.

Power Generation Design Basis Six—The condenser is designed in accordance with requirements of the Heat Exchange Institute *Standards for Steam Surface Condensers.*

10.4.1.2 Description

10.4.1.2.1 General Description

The main condenser is a multipressure, three-shell, reheating/deaerating unit. Each shell is located beneath its respective low-pressure turbine.

The three condenser shells are designated as the low-pressure shell, the intermediate-pressure shell, and the high-pressure shell. Each shell has two tube bundles. Circulating water flows in series through the three single-pass shells (Figure 10.4-3).

Each condenser shell hotwell is divided longitudinally by a vertical partition plate. The condensate pumps take suction from these hotwells ~~(Figure 10.4-6b)~~.

Figure 10.4-5b

The condenser shells are located in pits below the Turbine Building operating floor and are supported on the Turbine Building basemat. Failure of or leakage from a condenser hotwell during plant shutdown will only result in a minimum water level in the condenser pit. Expansion joints are provided between each turbine exhaust opening and the steam inlet connections of the condenser shell. Water seals are provided around the entire outside periphery of these expansion joints. Level indication provides detection of leakage through the expansion joint. The hotwells of the three shells are interconnected by steam-equalizing lines. Four low-pressure feedwater heaters are located in the steam dome of each shell. Piping is installed for hotwell level control and condensate sampling.

10.4.1.2.2 Component Description

Table 10.4-1 provides general condenser design data and reference data that is typical of condensers operating with closed loop circulating water systems.

10.4.1.2.3 System Operation

During plant operation, steam expanding through the low-pressure turbine is directed downward into the condenser through the exhaust openings in the bottom of the turbine casings and is condensed. The condenser also serves as a heat sink for several other flows, such as cascading heater drains, and miscellaneous turbine cycle drains and vents.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.21 MAIN CONDENSER No. 3

NRC COMMENT:

Revise SSAR section 10.4.1.2.1, second paragraph, to state "Figure 10.4-5b," not "Figure 10.4-6b."

GE RESPONSE:

GE concurs and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment.

Vey 2

RL 7/17

2.10.21 Main Condenser

TB

Design Description

The Main Condenser (MC) condenses and deaerates the exhaust steam from the main turbine (MT) and provides a heat sink for the Turbine Bypass (TBP) System. The MC is also a collection point for other steam cycle drains and vents.

The MC hotwell provides a holdup volume for main steam isolation valve (MSIV) fission product leakage.

The MC is classified as non-safety-related and non-seismic Category I. The supports and anchors for the MC are designed to withstand a safe shutdown earthquake (SSE).

The MC is located in the Turbine Building (T/B).

The MC tubes are made from corrosion-resistant material. The MC operates at a vacuum; consequently, leakage is into the shell side of the MC. Circulating water leakage from the tubes to the condenser is detected by measuring the conductivity of sample water extracted beneath the tube bundles. In addition, a conductivity monitor is located at the discharge of the condensate pumps, and alarms are provided in the main control room.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.21 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the MC.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.21 MAIN CONDENSER No. 2

NRC COMMENT:

Revise CDM 2.10.21 Design Description, 1st paragraph, to state "TB," not "TBP."

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.21 MAIN CONDENSER No. 1

NRC COMMENT:

Revise CDM Appendix B to add acronym "MC" for "Main Condenser."

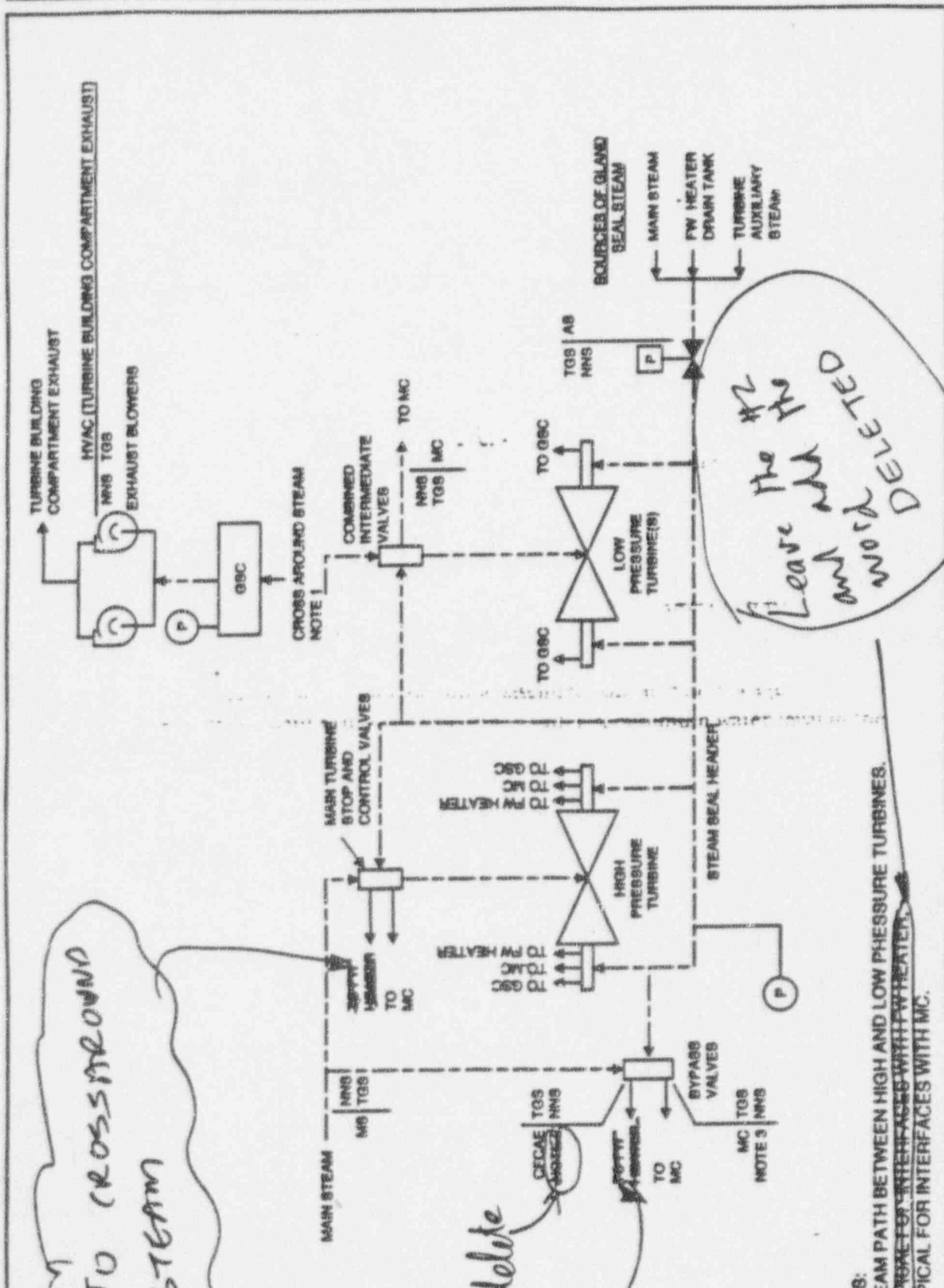
GE RESPONSE:

GE concurs and will make this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment

SSAR: None



NOTES:
1. STEAM PATH BETWEEN HIGH AND LOW PRESSURE TURBINES.
2. ~~SYMBOL FOR INTERFACES WITH FW HEATER.~~
3. TYPICAL FOR INTERFACES WITH MC.

Figure 2.10.9 Turbine Gland Seal System

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.9 TGSS No. 2d.

NRC COMMENT:

On Figure 2.10.9, steam leaving the main turbine stop and control valves and the bypass valves are shown being directed to the feedwater heater. On SSAR Figure 10.4-2, they are directed to the cross around piping. Resolve this discrepancy. Delete note 2 is "FW HEATER" is deleted.

GE RESPONSE:

GE concurs and will modify Figure 2.10.9 to show the leak-off connections going to the crossaround steam piping between the high and low pressure turbine stages. See attached. GE concurs with the suggestion to delete Note 2.

PROPOSED CHANGES

CDM: See attached.

SSAR: None

2.10.9 Turbine Gland Seal System

Design Description

The Turbine Gland Seal (TGS) System prevents the escape of radioactive steam from the turbine shaft casing penetrations and valve stems and prevents air inleakage through subatmospheric turbine glands. Figure 2.10.9 shows the basic system configuration.

The TGS System consists of a sealing steam pressure regulator, steam seal header and a gland seal condenser (GSC) with two exhaust blowers and associated piping, valves and instrumentation.

(full capacity)

The TGS System is bounded by the Main Turbine ~~System~~ and the Turbine Bypass System. The TGS System receives steam from either the Turbine Main Steam System, the feedwater heater drain tank vent header or auxiliary steam sources. The exhaust blowers discharge to the Turbine Building compartment exhaust system.

The TGS System is classified as non-safety-related.

The TGS System is located in the Turbine Building.

The TGS System has displays for gland seal condenser and steam seal header pressure in the main control room.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.9 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the TGS System.

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.9 TGSS No. 1

NRC COMMENT:

Correct typos on page 2.10.9-1 as follows:

- "two exhaust blowers" ~~need not~~ should be listed as "two fully capacity exhaust blowers" in second paragraph of CDM 2.10.9.
- "main turbine system" should be "main turbine," and "turbine main steam supply systems" should be "turbine main steam supply system" in third paragraph.

GE RESPONSE:

In response to this NRC comment, GE proposes:

1) Add "full capacity" to the blower description.

2) Use the official CDM system names in the third paragraph (see attached).

PROPOSED CHANGES

CDM: See attached.

SSAR: None

Table 2.10.7 Main Turbine System

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The basic configuration of the MT System is as described in Section 2.10.7.	1. Inspection of the as built MT will be conducted.	1. The as built MT conforms with the basic configuration described in Section 2.10.7.
2. MT System overspeed protective actions are as defined in Section 2.10.7.	2. Tests will be conducted on the as built MT System using simulated overspeed signals.	2. The following protective actions occur: **Overspeed Condition** / **Protective Action** a. Exceeds normal speed control setpoint. / Normal speed control signals the CVs and IVs to close. b. Exceeds overspeed trip setpoint. / Overspeed trip signals MSVs, CVs, ISVs, IVs, and extraction line non-return valves to close. c. Exceeds backup overspeed trip setpoint. / Backup overspeed trip signals MSVs, CVs, ISVs, IVs, and extraction line non return valves to close. MTSVs
3. The turbine MTSV closes in 0.10 seconds or greater.	3. Tests will be conducted on the as built turbine MTSV.	3. The turbine MTSV closes in 0.10 seconds or greater.
4. The turbine CV trip closure is 0.08 seconds or greater.	4. Tests will be conducted on the as built turbine CV.	4. The turbine CV trip closure is 0.08 seconds or greater.

PAGE 2 OF 3

2.10.7

2.10.7 Main Turbine

Design Description

The Main Turbine (MT) uses the energy in steam from the reactor to drive the plant generator. - DELETE

The other main turbine components are: DELETE ACRONYMS FOR APPENDIX B

(1) A high pressure (HP) ~~section~~

(2) An intermediate section (between HP and LP sections)

(3) Low pressure (LP) ~~sections~~

The major fluid system boundaries are:

(1) Turbine Main Steam 2.10.1

(2) Main Condenser 2.10.21

(3) Turbine Gland Seal 2.10.9

(4) Extraction System 2.10.12

The MT is classified as non-safety-related.

The MT has the following features that prevent overspeed:

(1) Main turbine stop valves (MTSV)/Control valves (CV) [MTSVs trip, CVs trip and modulate] - DELETE ACRONYMS FOR APPENDIX B

(2) Combined intermediate valves (CIVs) consist of intercept valves (IVs) and intercept stop valves (ISVs) [IVs trip and modulate, ISVs trip]

(3) Extraction line non-return valves (trip)

(4) Redundant valve closure mechanisms (i.e., fast acting solenoid valves and emergency trip fluid system)

(5) Redundant normal speed control

Three levels of signals to MT valves (i.e., normal speed control, overspeed trip, backup overspeed trip)

2.10.7 Main Turbine

Design Description

The Main Turbine (MT) uses the energy in steam from the reactor to drive the plant generator. e

The ~~other~~ major turbine components are: high pressure

(1) A high pressure section.

(2) An intermediate section (between ~~HP~~ and ~~LP~~ sections).

(3) Low pressure sections. low pressure

The major fluid system boundaries are:

(1) Turbine Main Steam 2.10.1.

(2) Main Condenser 2.10.21.

(3) Turbine Gland Seal 2.10.9.

(4) Extraction System 2.10.12.

The MT is classified as non-safety-related.

The MT has the following features that prevent overspeed:

(1) Main turbine stop valves (MTSV)/Control valves (CV) [MTSVs trip/CVs trip and modulate].

(2) Combined intermediate valves (CIVs) consist of intercept valves (IVs) and intercept stop valves (ISVs) [IVs trip and modulate/ISVs trip].

(3) Extraction line non-return valves (trip).

(4) Redundant valve closure mechanisms (i.e., fast acting solenoid valves and emergency trip fluid system).

(5) Redundant normal speed control.

Three levels of signals to MT valves (i.e., normal speed control/overspeed trip/backup overspeed trip).

Table 2.10.7 Main Turbine System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the MT System is as described in Section 2.10.7.	1. Inspection of the as-built MT will be conducted.	1. The as-built MT conforms with the basic configuration described in Section 2.10.7.
2. MT System overspeed protective actions are as defined in Section 2.10.7.	2. Tests will be conducted on the as-built MT System using simulated overspeed signals. MTSV	2. The following protective actions occur: **Overspeed Condition** / **Protective Action** a. Exceeds normal speed control setpoint. / Normal speed control signals the CVs and IVs to close. b. Exceeds overspeed trip setpoint. / Overspeed trip signals ~~MSVs~~, CVs, ISVs, IVs, and extraction line non-return valves to close. c. Exceeds backup overspeed trip setpoint. / Backup overspeed trip signals ~~MSVs~~, CVs, ISVs, IVs, and extraction line non-return valves to close.
3. The turbine MTSV closes in 0.10 seconds or greater.	3. Tests will be conducted on the as-built turbine MTSV.	3. The turbine MTSV closes in 0.10 seconds or greater
4. The turbine CV trip closure is 0.08 seconds or greater.	4. Tests will be conducted on the as-built turbine CV.	4. The turbine CV trip closure is 0.08 seconds or greater.

IV Intercept Valve
ISV Intercept Stop Valve

GL	Grade Level
GSC	Gland Seal Condenser
HAZ	Heat-Affected Zone
HCU	Hydraulic Control Unit
HCW	High Conductivity Waste
HECW	HVAC Emergency Cooling Water
HEPA	High Efficiency Particulate Air
HFE	Human Factors Engineering
HNCW	HVAC Normal Cooling Water
HPCF	High Pressure Core Flooder
HPIN	High Pressure Nitrogen Gas Supply
HSI	Human-System Interfaces
HVAC	Heating, Ventilating, and Air Conditioning
HWH	Hot Water Heating
HX	Heat Exchanger
IA	Instrument Air
ICGT	In-Core Guide Tube
I&C	Instrumentation and Control
INST	Instrumentation
ISLOCA	Intersystem Loss-of-Coolant Accident
ISI	In-Service Inspection
ITAAC	Inspection, Tests, Analyses, and Acceptance Criteria
ITP	Initial Test Program
LCP	Local Control Panels
LCW	Low Conductivity Waste
LD	Load Driver
LDS	Leak Detection and Isolation System
LOCA	Loss-of-Coolant Accident
LOPP	Loss of Preferred Power
LPFL	Low Pressure Core Flooder
LPMS	Loose Parts Monitoring System
LPRM	Local Power Range Monitor
LPZ	Low Population Zone
LSPS	Lighting and Servicing Power Supply
MC	Main Condenser
M/C	Metal-Clad
MCAE	Main Control Area Envelope
MCC	Motor Control Center
MCES	Main Condenser Evacuation System
MCR	Main Control Room
MCRP	Main Control Room Panels
MG	Motor Generator
MOV	Motor-Operated Valve
MPT	Main Power Transformer
MRBM	Multi-Channel Rod Block Monitor
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSL	Main Steamline
MTSV	Main Turbine Stop Valve
MT	Main Turbine
MUWC	Make Up Water (Condensate)
MUWP	Make Up Water (Purified)
MWP	Makeup Water Preparation
NBS	Nuclear Boiler System
NEMS	Non-Essential Multiplexing System
NMS	Neutron Monitoring System
NPSH	Net Positive Suction Head
NRHX	Non-Regenerative HX
NSD	Non-Radioactive Storm Drain
OGS	Off-Gas System
OLU	Output Logic Unit
OPRM	Oscillating Power Range Monitor
OSC	Operational Support Center
OST	Oil Storage and Transfer
P/C	Power Center
PASS	Post-Accident Sampling System
PCHS	Power Cycle Heat Sink
PCS	Primary Containment System
PIP	Plant Investment Protection
PMG	Plant Main Generator
PRM	Process Radiation Monitoring
PROM	Programmable Read-Only Memory
PS	Pipe Space
PSW	Potable and Sanitary Water
R/B	Reactor Building

Add

Add

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.7 MAIN TURBINE No. 1

NRC COMMENT:

Add acronyms for "high pressure" and "low pressure" as "HP" and "LP" respectively in CDM 2.10.7 Design Description. Also, add acronyms "HP," "LP," "ISVs" and "IVs" in CDM Appendix B.

CDM Table 2.10.7 should show acronym "MTSVs," not "MSVs" in items 2.b and 2.c as listed in CDM Appendix B.

Delete the word "other" in 2nd sentence of CDM 2.10.7 Design Description. See attached markup.

GE RESPONSE:

GE proposes the following CDM changes in response to these comments:

1. Delete the acronyms HP, LP and spell out the terms at each use.
2. Add the acronyms ISV, IV to Appendix B. ISV, IV
3. Correct Table 2.10.7, items 2b, 2c.
4. Delete the word "other" in 2.10.7, "design description", second sentence.

PROPOSED CHANGES

CDM: See attached

SSAR: None

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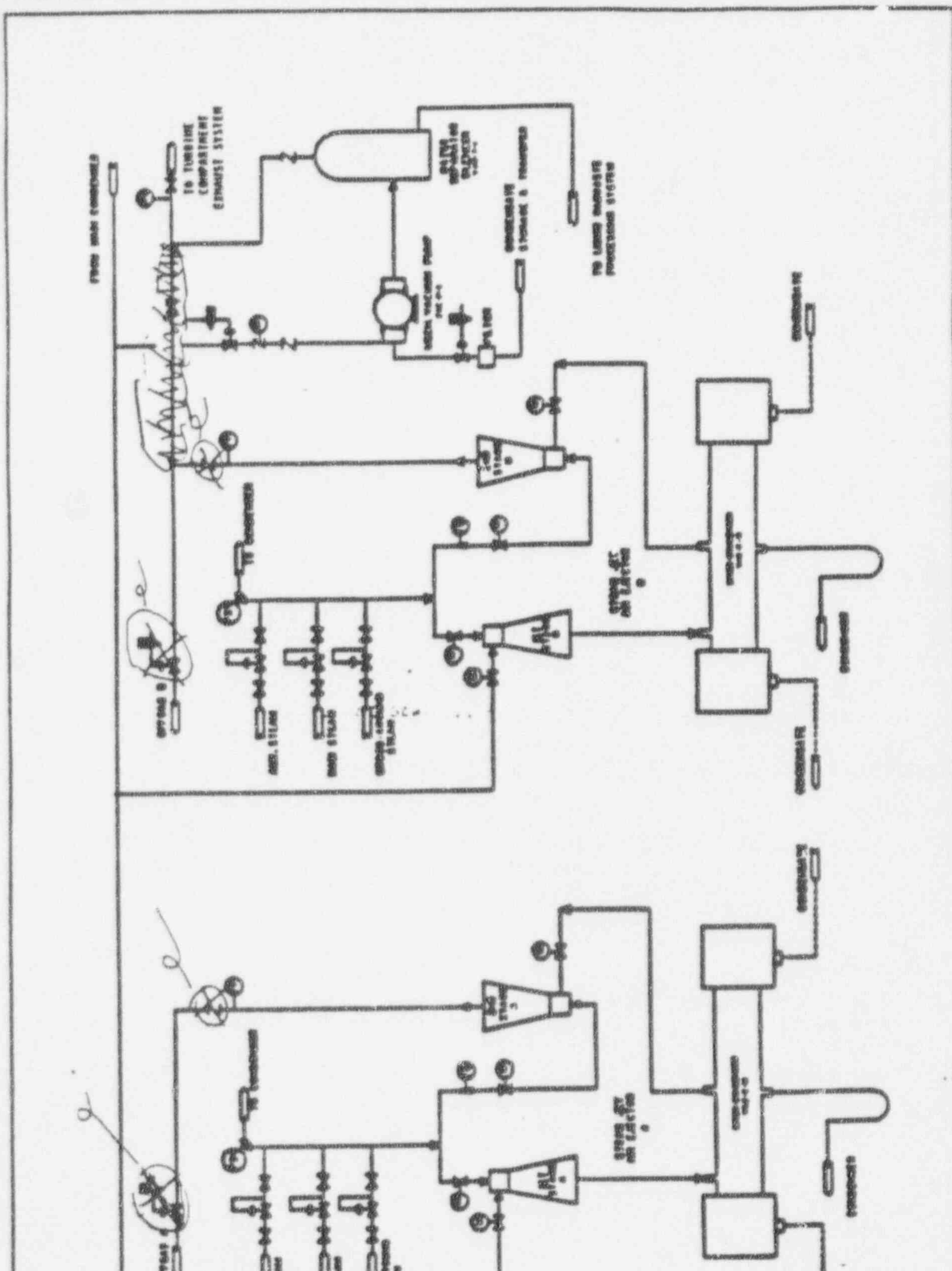

Figure 10.4-1 Main Condenser Evacuation System

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operation of the mechanical vacuum pumps to ensure the flammable limit of hydrogen will not be reached.

The MCES has no safety-related function (Section 3.2) and, thus, failure of the system will not compromise any safety-related system or component and will not prevent safe reactor shutdown.

Should the system fail completely, a gradual reduction in condenser vacuum would result from the buildup of noncondensable gases. This reduction in vacuum would first cause a lowering of turbine cycle efficiency due to the increase in turbine exhaust pressure. If the MCES remained inoperable, condenser pressure would then reach the turbine trip setpoint and a turbine trip would result. The loss of condenser vacuum incident is discussed in Subsection 15.2.5.

10.4.2.4 Tests and Inspections

Testing and inspection of the system is performed prior to plant operation in accordance with applicable codes and standards.

Components of the system are continuously monitored during operation to ensure satisfactory performance. Periodic inservice tests and inspections of the evacuation system are performed in conjunction with the scheduled maintenance outages.

10.4.2.5 Instrumentation Applications

Local and remote indicating devices for such parameters such as pressure, temperature, and flow indicators are provided as required for monitoring the system operation. Dilution steam flow and vacuum pump and SJAE ~~discharge~~ valve status is monitored in the main control room.

~~Suction~~ suction

10.4.2.5.1 Steam Jet Air Ejectors

Steam pressure and flow is continuously monitored and controlled in the ejector steam supply lines. Redundant pressure controllers sense steam pressure at the second-stage inlet and modulate the steam supply control valves upstream of the air ejectors. The steam flow transmitters provide inputs to logic devices. These logic devices provide for isolating the offgas flow from the air ejector unit on a two-out-of-three logic, should the steam flow drop below acceptable limits for offgas steam dilution.

10.4.2.5.2 Mechanical Vacuum Pump

transmitter or

Pressure is measured on the suction line of the mechanical vacuum pump by a pressure switch. Upon reaching a preset vacuum, the pressure switch energizes a solenoid valve, which allows additional seal water to be pumped to the vacuum pump. Seal pump discharge pressure is locally monitored. Seal water cooler discharge temperature is measured by a temperature indicating switch. On high temperature, the switch activates

transmitter or

Table 2.10.2b Main Condenser Evacuation System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the MCES is as shown on Figure 2.10.2b.	1. Inspections of the as-built MCES will be conducted.	1. The as-built MCES conforms with the basic configuration shown in Figure 2.10.2b.
2. When the steam flow drops below the setpoint for steam dilution, the Off-Gas System is isolated.	2. Tests will be conducted on the as-built MCES using simulated signals for steam flow.	2. The SJAE ~~discharge~~ suction valves close on receipt of a simulated low flow signal.
3. The vacuum pump is tripped and its discharge valve is closed upon receiving a main steamline high radiation signal.	3. Tests will be conducted on the as-built MCES using simulated signals for radiation in the main steamlines.	3. The vacuum pump trips and the discharge valve closes upon receipt of a simulated high radiation signal.
4. Main control room displays provided for the MCES are as defined in Section 2.10.2.	4. Inspections will be performed on the main control room displays for the MCES.	4. Displays exist or can be retrieved in the main control room as defined in Section 2.10.2.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.2 CF CAES No. 4 (Continued)

GE RESPONSE: (Continued)

First Part of the Question (Continued)

b) To support this CDM change, SSAR Figure 10.4-1 will be modified to eliminate the SJAE discharge check and isolation valves. (See attached.) In addition SSAR text describing the isolation function will be modified to state that isolation occurs using the SJAE suction valves. (See attached.)

Second Part of the Question

a) The cross connection was intended to give a backup to the mechanical vacuum pump during plant startup by using the B SJAE unit. This is an availability issue unrelated to plant safety. GE proposes to delete this backup junction from the SSAR per the attached markup. This action is being taken because the offgas system is capable of performing this backup function by bypassing the ~~channel.~~ charcoal.

b) No CDM changes are necessary because it was not intended for the CDM to describe the mechanical pump backup function.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.2 CF CAES No. 4

NRC COMMENT:

Page 2.10.2-6, Table 2.10.2b, item 2: The acceptance criteria requires the SJAE discharge valves to close. These valves are not shown on Figure 2.10.2b. Show SJAEs discharge valves on the ITAAC Figure 2.10.2b as shown in SSAR Figure 10.4-1. Also, explain why one of the SJAE discharge goes to "offgas-A" but not diverted to "turbine compartment exhaust system" in certain condition in SSAR Figure 10.4-1 (see ITAAC Figure 2.10.2b).

GE RESPONSE:

First Part of the Question

a) GE concurs that minor MCES changes are required in response to this NRC comment to resolve minor SSAR inconsistencies in the MCES/offgas interface. Specifically, GE proposes the following changes:

   1) Table 2.10.2.b; item 2, right hand column changed per the attached. This makes the CDM compatible with the offgas isolation described in the SSAR.

(Continued on next page…)

PROPOSED CHANGES

CDM: Table 2.10.2b, item 2 per the attached. to verify

verified

SSAR: See attached markups (Figures 10.4-1 and Section 10.4.2.5).

~~LATER~~ DONE

ver

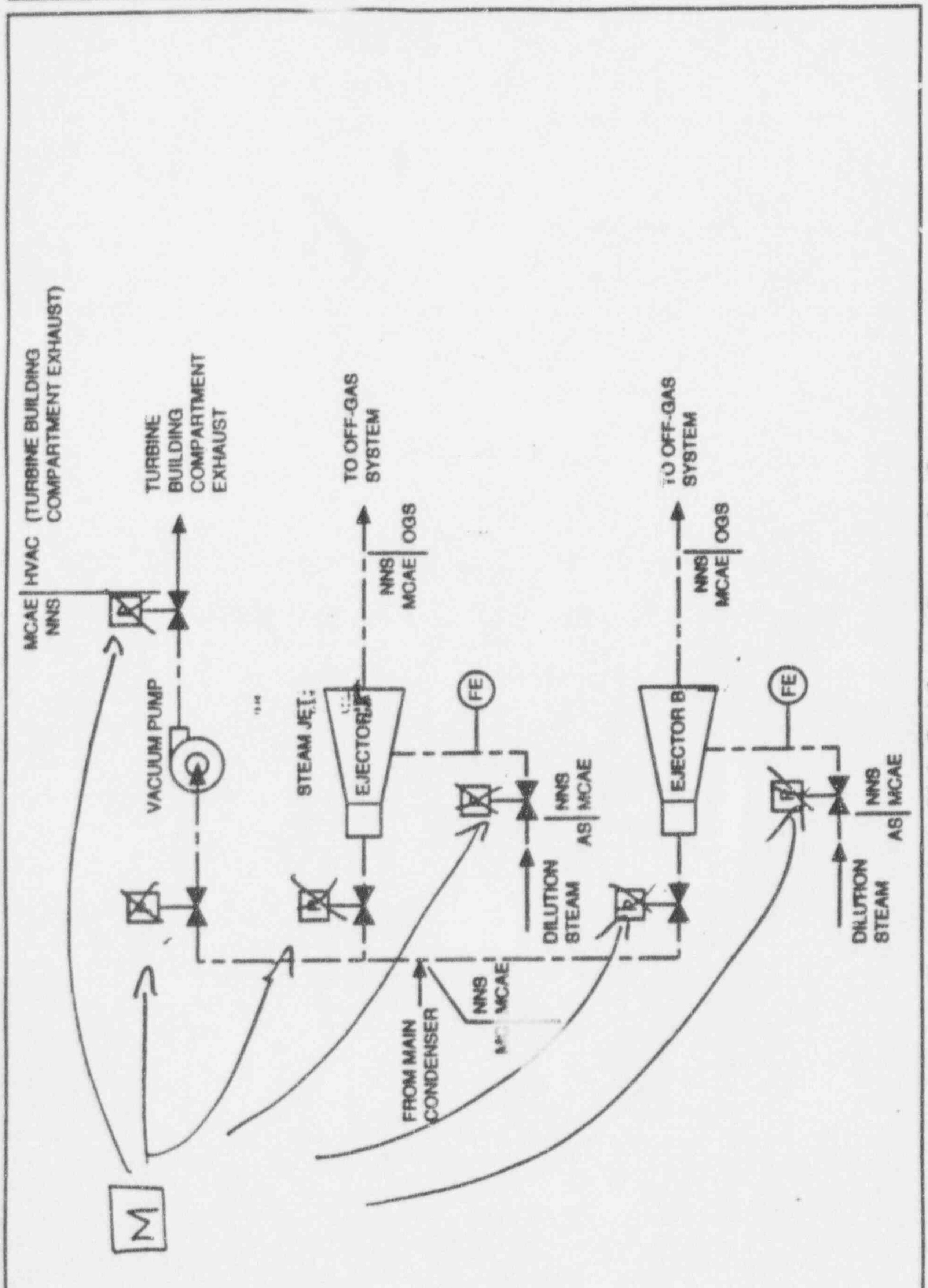


Figure 2.10.2b Main Condenser Evacuation System

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.2 CF CAES No. 3

NRC COMMENT:

Page 2.10.2-4, Figure 2.10.2b:

Valve operators shown are pneumatic, whereas on SSAR Figure 10.4-1, they are motor operators. Reconcile the type of valve operators used for the valves on piping from SJAEs to inlet of vacuum pump as shown in ITAAC Figure 2.10.2b.

GE RESPONSE:

GE concurs that there is an SSAR/CDM inconsistency. The SSAR is correct and the CDM will be corrected in the next revision.

PROPOSED CHANGES

CDM: Per attached markup.

SSAR: None

2.10.1 Turbine Main Steam System

Design Description

The Turbine Main Steam (MS) System, as shown in Figure 2.10.1, supplies steam generated in the reactor to the turbine, steam auxiliaries and turbine bypass valves. The MS boundaries are shown in Figure 2.10.1. The MS System does not include the seismic interface restraint nor main turbine stop or bypass valves.

The MS System:

(1) Accommodates operational stresses such as internal pressure and dynamic loads without failures.

(2) Provides a seismically analyzed fission product leakage path to the main condenser.

(3) Has suitable access to permit in-service testing and inspections.

(4) Closes the steam auxiliary (SA) valve(s) on a main steam isolation valve (MSIV) isolation signal. These valves fail closed on loss of electrical power to the valve actuating solenoid or on loss of pneumatic pressure.

The MS System main steam piping consists of four lines from the seismic interface restraint to the main turbine stop valves. The header arrangement upstream of the turbine stop valves allows the valves to be tested on-line and also supplies steam to the power cycle auxiliaries.

The MS System is classified as non-safety-related. However, the MS System is analyzed, fabricated and examined to ASME Code Class 2 requirements, and classified as non-Seismic Category I ~~and subject to pertinent QA requirements of Appendix B, 10CFR Part 50.~~ Inservice inspection shall be performed in accordance with ASME Section XI requirements for Code Class 2 piping. ASME authorized nuclear inspector and ASME Code stamping is not required.

MS piping, including the steam auxiliary valve(s), from the seismic interface restraint to the main stop and main turbine bypass valves is analyzed to demonstrate structural integrity under safe shutdown earthquake (SSE) loading conditions.

The MS System is located in the steam tunnel and Turbine Building.

Main steam piping from the seismic interface restraint to the main stop, main turbine bypass, including the steam auxiliary valves(s) is analyzed to demonstrate structural integrity under safe shutdown earthquake (SSE) loading conditions. Refer to Subsection 3.2.5.3 for seismic classification for the lines.

10.3.1.2 Power Generation Design Bases

Power Generation Design Basis One—The system is designed to deliver steam from the reactor to the turbine-generator system for a range of flows and pressures varying from warmup to rated conditions. It also provides steam to the reheaters, the steam jet air ejectors, the turbine gland seal system, the offgas system and the deaerating section of the main condenser and the turbine bypass system.

10.3.2 Description

10.3.2.1 General Description

The Main Steam Supply System is illustrated in Figure 10.3-1. The system design data is provided in Table 10.3-1. The main steam piping consists of four 700A nominal pipe size diameter lines from the outboard MSIVs to the main turbine stop valves. The four main steamlines are connected to a header upstream of the turbine stop valves to permit testing of the MSIVs during plant operation with a minimum load reduction. This header arrangement is also provided to ensure that the turbine bypass and other main steam supplies are connected to operating steamlines and not to idle lines. The main steam process downstream of the turbine stop valves is illustrated in Figures 10.3-2a and 10.3-2b.

The design pressure and temperature of the main steam piping is 87.89 kg/cm^{2}g and 302° 315.55°C, respectively, the same values as the design parameters of the reactor. The main steam-lines are classified as discussed in Section 3.2.

A drain line is connected to the low points of each main steamline, both inside and outside the containment. Both sets of drains are headered and connected with isolation valves to allow drainage to the main condenser. To permit intermittent draining of the steamline low points at low loads, orificed lines are provided around the final valve to the main condenser. The steamline drains maintain a continuous downward slope from the steam system low points to the orifice located near the condenser. The drain line from the orifice to the condenser also slopes downward. To permit emptying the drain lines for maintenance, drains are provided from the line low points going to the radwaste system.

The drains from the steamlines inside containment are connected to the steamlines outside the containment to permit equalizing pressure across the MSIVs during startup and following a steamline isolation.

will be fixed as part of SSAR metrication.

Table 10.3-1 Main Steam Supply System Design Data

Main Steam Piping	
Design flow rate at 69.25 kg/cm²a and 0.40% moisture, lb/hr	~17,000,000
Number of lines	4
Nominal diameter	700A
Minimum wall thickness, mm	38.1
Design pressure, kg/cm²a	87.89
Design temperature, °C	~~315.56~~
Design code	ASME III, Class 2
Seismic design	Analyzed for SSE design loads

g

~~315.55~~

302

Table 3.2-1 Classification Summary (Continued)

Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
6. Piping including supports—MSL (including branch lines to first valve) from the seismic interface restraint up to but not including the turbine stop valve and turbine bypass valve	N	SC,T	B	~~B~~ E	—	(r)
7. Piping from FW shutoff valve to seismic interface restraint	N	SC	D	E	I	(ee)
8. Deleted						
9. Deleted						
10. Pipe whip restraint—MSL/FW	3	SC,C	—	B	—	
11. Piping including supports—other within outermost isolation valves						
a. RPV head vent	1	C	A	B	I	(g)
b. Main steam drains	1	C,SC	A	B	I	(g)
12. Piping including supports—other beyond outermost isolation or shutoff valves						
a. RPV head vent beyond shutoff valves	N	C	C	E	—	
b. Main steam drains to first valve	2/N	SC,T	B	B	I/—	(r)
c. Main steam drains beyond first valve	N	SC, T	D	E	—	(r)

Notes and footnotes are listed on pages 3.2-53 through 3.2-60

Staff Markup

Table 10.3-1 Main Steam Supply System Design Data

Main Steam Piping	
Design flow rate at 69.25 kg/cm^2a and 0.40% moisture, lb/hr	~17,000,000
Number of lines	4
Nominal diameter	700A
Minimum wall thickness, mm	38.1
Design pressure, kg/cm^2a	87.89
Design temperature, °C	315.56
Design code	ASME III, Class 2
Seismic design	Analyzed for SSE design loads

Comments:

1. DESIGN PRESSURE IS "g" (gauge) ON PAGE 10.3-2.
2. DESIGN TEMPERATURE IS 315.55 °C ON PAGE 10.3-2

SVOH markup

W = Radwaste Building
X = Control Building
F = Firewater Pump House*
U = Ultimate Heat Sink Pump House*
P = Power Cycle Heat Sink Pump House*

d. A,B,C,D= Quality groups defined in Regulatory Guide 1.26 and Subsection 3.2.2. The structures, systems and components are designed and constructed in accordance with the requirements identified in Tables 3.2-2 and 3.2-3.

— = Quality Group Classification not applicable to this equipment.

e. B = The quality assurance requirements of 10CFR50, Appendix B are applied in accordance with the quality assurance program described in Chapter 17.

E = Elements of 10CFR50, Appendix B are generally applied, commensurate with the importance of the equipment's function.

f. I = The design requirements of Seismic Category I structures and equipment are applied as described in Section 3.7, Seismic Design.

— = The seismic design requirements for the safe shutdown earthquake (SSE) are not applicable to the equipment. However, the equipment that is not safety-related but which could damage Seismic Category I equipment if its structural integrity failed is checked analytically and designed to assure its integrity under seismic loading resulting from the SSE.

g. 1. Lines one inch and smaller which are part of the reactor coolant pressure boundary and are ASME Code Section III, Class 2 and Seismic Category I.

2. All instrument lines which are connected to the reactor coolant pressure boundary and are utilized to actuate and monitor safety systems shall be Safety Class 2 from the outer isolation valve or the process shutoff valve (root valve) to the sensing instrumentation.

3. All instrument lines which are connected to the reactor coolant pressure boundary and are not utilized to actuate and monitor safety systems shall

* Pump House structures are out of the ABWR Standard Plant scope.

CHANGE TO E

Table 3.2-1 Classification Summary (Continued)

	Principal Component[a]	Safety Class[b]	Location[c]	Quality Group Classification[d]	Quality Assurance Requirement[e]	Seismic Category[f]	Notes
1	6. Piping including supports—MSL (including branch lines to first valve) from the seismic interface restraint up to but not including the turbine stop valve and turbine bypass valve	N	SC,T	B	F	—	(r)
	Should be a 'B' or 'E' No 'F' in the note e.						
	7. Piping from FW shutoff valve to seismic interface restraint	N	SC	D	E	I	(ee)
	8. Deleted						
	9. Deleted						
	10. Pipe whip restraint—MSL/FW	3	SC,C	—	B	—	
	11. Piping including supports—other within outermost isolation valves						
	a. RPV head vent	1	C	A	B	I	(g)
	b. Main steam drains	1	C,SC	A	B	I	(g)
	12. Piping including supports—other beyond outermost isolation or shutoff valves						
	a. RPV head vent beyond shutoff valves	N	C	C	E	—	
1	b. Main steam drains to first valve	2/N	SC,T	B	B	I/—	(r)
	c. Main steam drains beyond first valve	N	SC, T	D	E	—	(r)

Notes and footnotes are listed on pages 3.2-53 through 3.2-60

Insert AB

However, GE believes the design temperature identified in Table 10.3-1 should be 302°C. This will make the design temperature for this system the same as the design temperature for the reactor pressure vessel (RPV) and the steamline portion of the Nuclear Boiler System (NBS). (See SSAR Section 5.3.3.1.4 for the RPV design temperature of 302°C and Figure 5.1-3 for the NBS steamline design temperature of 302°C). Consequently GE proposes to make the following changes:

1) Change Table 10.3-1 design temperature to 302°C
2) Revise SSAR Section 10.3.2.1 to 302°C design temperature.

In addition, Table 10.3-1 will change the design flow rate from lb/hr to kg/sec

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.10.1 TURBINE MSS No. 2

NRC COMMENT:

Reference attached SSAR tables for comments:

a) Table 3.2-1 pages 3.2-19 and 3.2-55.

b) Table 10.3-1 verify

GE RESPONSE:

a) GE concurs that page 3.1-19 requires modification and will replace F with E per attached markup.

b) GE concurs that the 87.29 value is gauge and will correct the entry.

c) GE concurs that the design temperature should be 316.55°C ~~and will correct this entry~~.
(for numerical consistency)

Comment (AB) on the next page

PROPOSED CHANGES

CDM: None

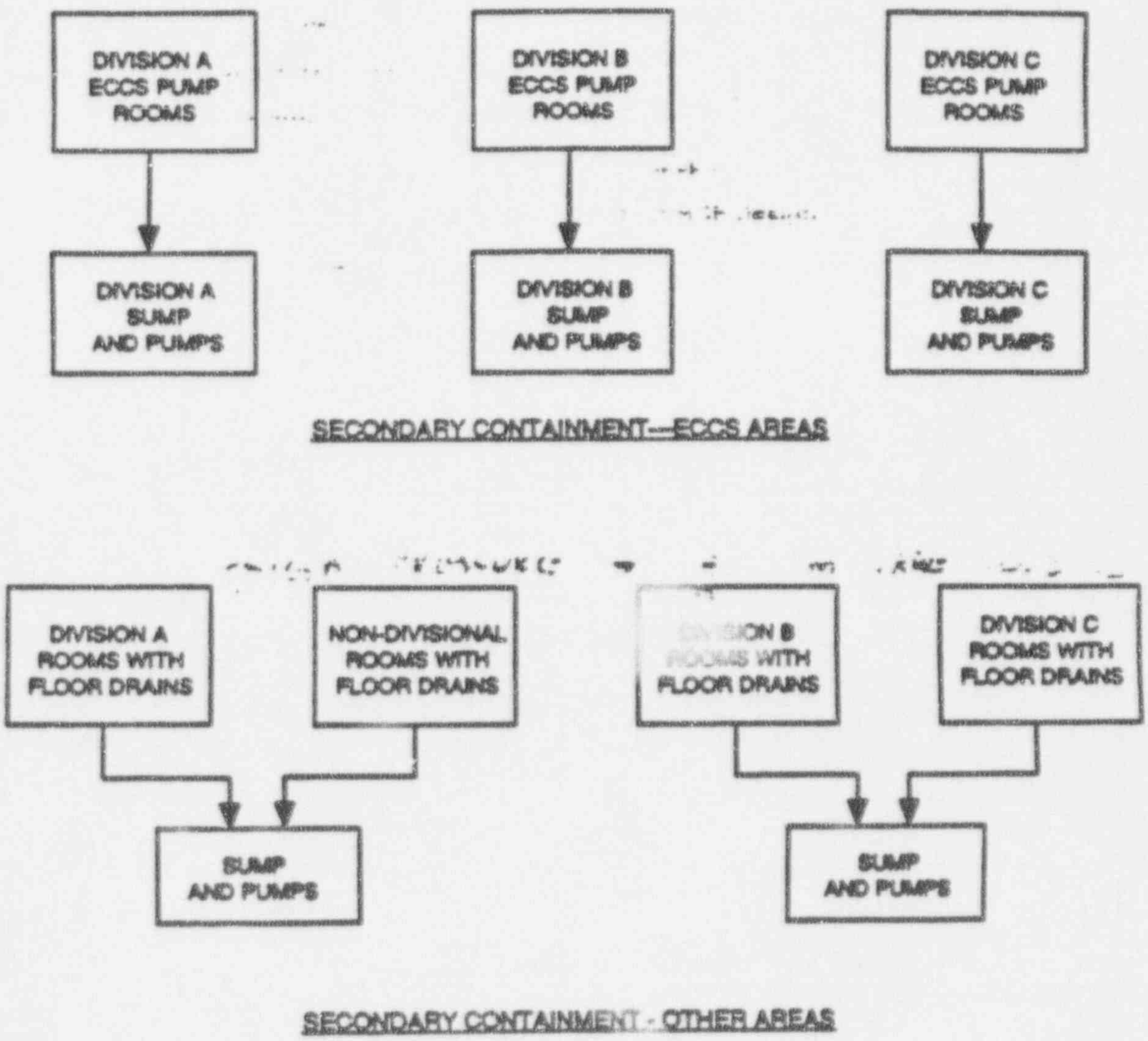
SSAR: Per NRC comments; see attached.

verify
DS IN PROCESS

Table 2.9.1 Radwaste System (Continued)

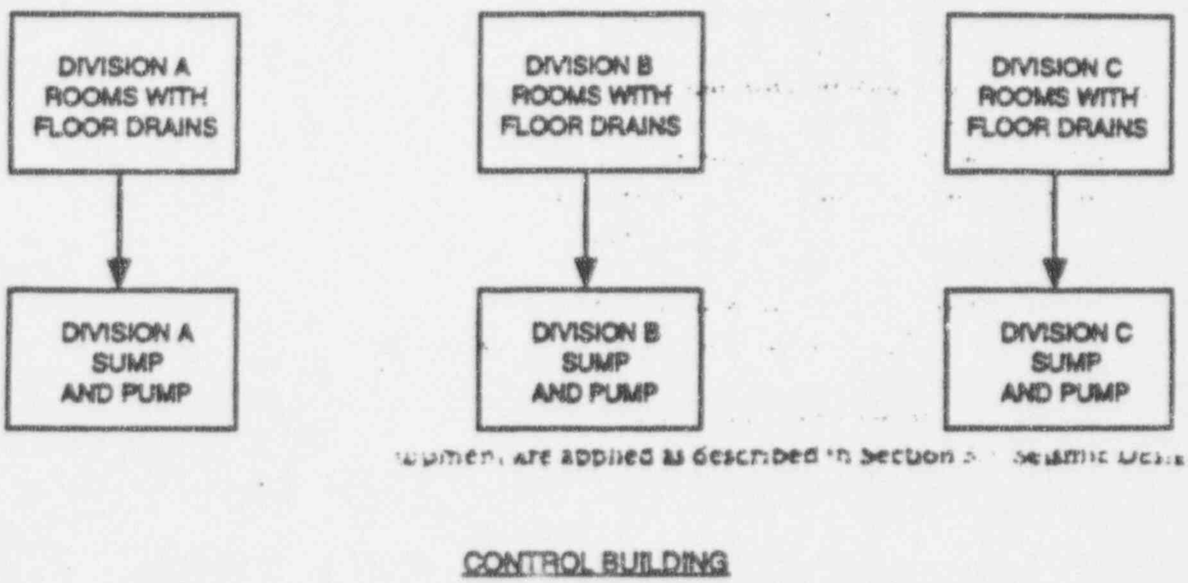
Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
7. The radioactive ~~floor drain collection~~ system in each divisional area of the ECCS pump rooms and the Control Building are physically separated from drains in the other divisions.	7. Tests will be conducted on the as-built system by individually pressuring each divisional area drains with water and observing other divisional area draine for interdivisional leakage.	7. No interconnection exist (i.e. no water leakage in to other divisions not being tested).

drain transfer



NOTES:
1. THE SYSTEM HAS NO VALVES, PUMPS, OR OTHER ACTIVE COMPONENTS IN THE DRAINAGE PATHS.

Figure 2.9.1b Radioactive ~~Floor Drain Collection~~ System
(Drain Transfer)



NOTES:
1. THE SYSTEM HAS NO VALVES, PUMPS, OR OTHER ACTIVE COMPONENTS IN THE DRAINAGE PATHS.

Drain Transfer

Figure 2.9.1a Radioactive ~~Floor Drain Collection~~ System

2.9.1 Radwaste System

X

Design Description

and a radioactive drain transfer system.

The Radwaste (RW) System consists of a liquid waste system ~~and~~ a solid waste system. The liquid waste system includes primary containment penetrations, and inboard and outboard motor-operated isolation valves for the high conductivity and low conductivity waste drains from the lower drywell. The liquid waste system collects, treats, monitors, and either recycles treated radioactive liquid wastes within the plant or discharges them to the environs. The solid waste system sorts, processes, monitors and packages processed solid radwastes for shipment to an offsite disposal facility.

The RW System is classified as non-safety-related with the exception of the primary containment isolation function.

The primary containment penetrations and isolation valves are classified as Seismic Category I and ASME Code Class 2. The back flow check valves in the emergency core cooling system (ECCS) equipment room sumps are classified as Seismic Category I.

The RW System processing equipment is located in the Radwaste Building.

The inboard containment isolation valves are powered from Class 1E Division II, and the outboard isolation valves are powered from Class 1E Division I. In the RW System, independence is provided between Class 1E divisions, and also between the Class 1E divisions and non-Class 1E equipment.

The main control room has control and open/close status indications for the primary containment isolation valves.

The safety-related electrical equipment that provides containment isolation, located in the primary containment and the Reactor Building, is qualified for a harsh environment.

The primary containment isolation motor-operated valves (MOVs) have active safety-related function to close and perform these functions under differential pressure, fluid flow, and temperature conditions.

The liquid waste system has one discharge line which has a radiation monitor. Discharge flow is terminated on receipt of a high radiation signal from this monitor.

X

The radioactive ~~floor~~ drain ~~collection~~ transfer system in each divisional area of the ECCS pump rooms and the Control Building are physically separated from drains in the other divisions. Figures 2.9.1a and 2.9.1b show the basic system configuration and scope.

COMMENTS ON IRG COMMENTS ON ITAAC

2.9.1 - RADWASTE SYSTEM - COMMENT #4:

The aspects of the radioactive drain transfer system which deserve Tier 1 treatment are adequately addressed in ITAAC. Specifically:

1. The purpose of the system is identified (though not explicitly). The system, "The liquid waste system collects, treats, monitors, and either recycles treated radioactive liquid wastes within the plant <u>or discharges them to the environs</u>.

2. The containment isolation valves (CIVs) are safety-related and seismic Category I.

3. The backflow check valves which prevent flooding in more than one division of the ECCS pump rooms are seismic Category I.

4. Each system is divisionally separated.

These are the key aspects of the system that should be identified and verified in Tier I. However, there are some other problems in both the SSAR and Tier I which should be addressed. They're discussed below.

SSAR AND TIER 1 MODIFICATIONS

THIS IS CORRECT

1. The SSAR calls the system the "Radioactive Drain Transfer System" (SSAR Section 9.3.8) while the design description (DD) calls it the "radioactive floor drain collection system." This discrepancy should be corrected in the DD.

2. The DD should clearly state that the radioactive drain transfer system is part of the liquid waste management system. NRC AGREES NO CHANGE REQUIRED.

3. There are several discrepancies between the Tier I figures and the P&ID for the sump arrangements in the control and reactor buildings:

   a. Only 2 LCW sumps are shown in Fig. 11.2-2, sheet 29 when there should be 3. NRC AGREES NO CHANGE REQUIRED.

   b. Fig. 11.2-2, sheet 3 doesn't identify the drywell HCW dump to the common header. NRC AGREES NO CHANGE REQD.

   c. Fig. 11.2-2, sheet 7 doesn't identify the HCW dumps from sumps C,D, and E. ALL LABELLED HCW DUMPS ON FIG. 11.2-2 (PROPRIETARY) GE AGREES

   SSAR CHANGE

   d. Fig. 11.2-2, sheet 36 shows only 2 control building sumps instead of 3 and Fig. 11.2-2, sheet 14 should clarify that there are control building <u>sumps</u> not just one sump. NRC AGREES NO CHANGE REQD

   E. The Tier I DD or figures should clarify between LCW and HCW sumps (how many of each and where they're located). NRC AGREES NO CHANGE REQD

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.9.1 RWS No. 4

NRC COMMENT:

Additional comments shown on next sheet

GE RESPONSE: GE responses to the comments are:

1. GE concurs that the SSAR and CDM use inconsistent terminology and proposes to change the CDM to use the SSAR terminology. See attached markup of CDM pages 2.9.1-1, -3, -4, -6
2. GE concurs. See attached markup
3. GE believes these NRC comments have been resolved by GE/NR verbal interactions with ~~no~~ CDM/SSAR changes necessary.

PROPOSED CHANGES

CDM: See attached markup

SSAR: FIGURE 11.2-2, Sheet 7 modified IAW comment 3.c (attached)

Verified

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.9.1 RWS No. 4

NRC COMMENT:

HCW & LCW Features of the radioactive drain transfer system should be discussed in 2.9.1. ~~See attached~~

GE RESPONSE:

GE believes that important characteristics of the LCW and HCW containment penetration/isolation are already discussed in Section 2.9.1 and no further material is needed. The existing material identifies valve types, seismic classifications, ASME code class, Class 1E configuration/separation, MOV testing and MOV qualification.

Note: This response is based on ~~the attached two pages of~~ GE's understanding of NRC comments. It is GE's understanding that additional comments will be issued shortly.

PROPOSED CHANGES

CDM: None

SSAR: None

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.9.1 RWS No. 1

NRC COMMENT:

The valves listed in SSAR Table 6.2-7, Containment Isolation Valve Information Radwaste System, are shown on Figures 11.2-2, sheets 29 and 31 of 36. GE deleted these figures in Amendment 33. However, the staff understands the figures will be readded. GE should correct SSAR Table 6.2-7, page 6.2-165 to refer to these figures. F-103 and F-104 are HCW H20, not LCW H20. Also, page 6.2-122 entry page should be 6.2-165.

GE RESPONSE:

GE concurs that SSAR changes regarding HCW/LCW valve assignments are necessary and will include them in the next SSAR amendment. In addition, Amendment 34 will include the full complement of RWS documents.

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

WKL
3/1/94

Based on verbal input
from NRC Staff 1/13/94

2.8.1 Nuclear Fuel

Design Description

The fuel assembly is designed to ensure that possible fuel damage would not result in the release of radioactive materials in excess of limits prescribed ~~[illegible]~~. The fuel assembly is comprised of the fuel bundle, channel and channel fastener. The fuel bundle is comprised of fuel rods, water rods, fuel rods containing burnable neutron absorber, spacers, springs and assembly end fittings.

The following is a summary of the principal design requirements which must be met by the fuel and is evaluated using methods and criteria to assure that:

(1) Fuel rod failure is predicted not occur as a result of normal operation and anticipated operational occurrences.

(2) Control rod insertion will not be prevented as a result of normal operation, anticipated operational occurrences or postulated accident.

(3) The number of fuel rod failures will not be underestimated for postulated accidents.

(4) Coolability will be maintained for all design basis events, including seismic and LOCA events.

(5) Specified acceptable fuel design limits (thermal and mechanical design limits) will not be exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

(6) In the power operating ranges, the prompt inherent nuclear feedback characteristics will tend to compensate for a rapid increase in reactivity.

(7) The reactor core and associated coolant, control and protection systems will be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC COMMENTS ON SSAR AMENDMENT 33 AND CDM REVISION 2

CDM SECTION: 2.8.1 NUCLEAR FUEL

NRC COMMENT:

Design Description – Delete the first sentence starting: "The fuel assembly... 100", since this refers to 10 CFR 20, 50 and 100.

COMMENT TYPE: 3

GE RESPONSE:

GE believes the deletion suggestion in this comment has been superceded by more recent NRC staff input to GE regarding this sentence in Section 2.8.1. This later input is shown on the attached markup and will be implemented by GE in the next revision of 25A5447.

PROPOSED CHANGES

CDM: See attached.

SSAR: ~~Change package to be included in Amendment 34. (Copies not attached)~~

None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.8.1 NUCLEAR FUEL NO. N/A

NRC COMMENT:

In the Design Description, delete the first sentence starting: "The fuel assembly ... 100," since this refers to 10 CFR 20, 50 and 100.

GE RESPONSE:

GE concurs that references to 10CFR requirements should be deleted from 2.8.1. See earlier response for revised wording suggested by NRC staff (attached).

PROPOSED CHANGES

CDM: Per attached response.

SSAR: None

silencer condition inspection are included in the diesel-generator inspection procedure.

9.5.9 Suppression Pool Cleanup System

9.5.9.1 Power Generation Design Bases

The primary function of the Suppression Pool Cleanup (SPCU) System is to provide a continuous purifying water treatment of the suppression pool. During normal plant operation, the SPCU is designed to recirculate approximately 250 m^3/hr of suppression pool water through a Fuel Pool Cooling and Cleanup System filter-demineralizer.

The SPCU System also fills the upper pools from the suppression pool during a refueling outage.

9.5.9.2 System Description

Except for the primary containment penetrations, the SPCU is a non-safety-related system designed to provide a continuous purifying water treatment of the suppression pool. The system removes various impurities by filtration, adsorption, and ion exchange processes. The system maintains the water quality in the suppression pool at a quality equal to that of the fuel and equipment pools. Water quality limits for these upper pools are specified in Subsection 9.1.3.2.

The SPCU System can provide makeup to the fuel pool and the surge tanks of the RCW System as a backup to normal makeup supplied by the condensate system.

The SPCU System also provides water from the suppression pool to the upper pools before a refueling outage.

The system draws water from the suppression pool through a single 250 m^3/hr pump, and directs flow to either the fuel pool seismic makeup line or to a connection to the filter demineralizer that is part of the fuel Pool Cooling and Cleanup (FPCU) System. Water is returned from the filter-demineralizer and directed to the suppression pool or the upper pools via the dryer/separator pit.

(D/S)

In the event of a LOCA, the SPCU System function is automatically terminated to accomplish containment isolation. Containment isolation valves are provided with Class 1E power.

The SPCU System, consisting of piping, valves, and instrumentation, is shown in Figure 9.5-1. The system has no unique major components.

List of Acronyms (Continued)

CHRS	Containment Heat Removal System
CIS	Containment Isolation System
CIV	Combined Intermediate Valve
CLOC	Closed Loop Outside Containment
CO	Condensation Oscillation
COL	Combined Operating License
CPDP	Core Plate Differential Pressure
CRD	Control Rod Drive
CRDH	Control Rod Drive Hydraulic (System)
CRGT	Control Rod Guide Tube
CS	Control Switch
CTG	Combustion Turbine Generator
CUW	Reactor Water Cleanup System
CWS	Circulating Water System
D-RAP	Design Reliability Assurance Program
D/F	Diaphragm Floor
DAW	Dry Active Waste
DBA	Design Basis Accident
DBE	Design Basis Event
DC	Design Certification
DCS	Drywell Cooling System
DCV	Drywell Connecting Vent
DEGB	Double-Ended Guillotine Break
DEPSS	Drywell Equipment and Pipe Support Structure
DOF	Degree of Freedom
DOI	Dedicated Operator Interface
DQR	Dynamic Qualification Report
DTM	Digital Trip Module
D/S	Dryer/Separator
DTS	Drain Transfer System
DWM	Demineralized Water Makeup (System)
E/C	Erosion/Corrosion
EBVS	Electrical Building Ventilation System
ECCS	Emergency Core Cooling System
ECLL	Electric Room Combustible Loading Limit
ECP	Engineering Computer Program
EDGS	Emergency Diesel Generator System
EDM	Electrodischarge Machining

FEBRUARY 1994

BWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.3 SPCU No. 5

NRC COMMENT:

SSAR Section 9.5.9, page 9.5-57, add acronym (D/S) after dryer/separator.

GE RESPONSE:

~~Later~~

GE concurs and will include this change in the next SSAR amendment.

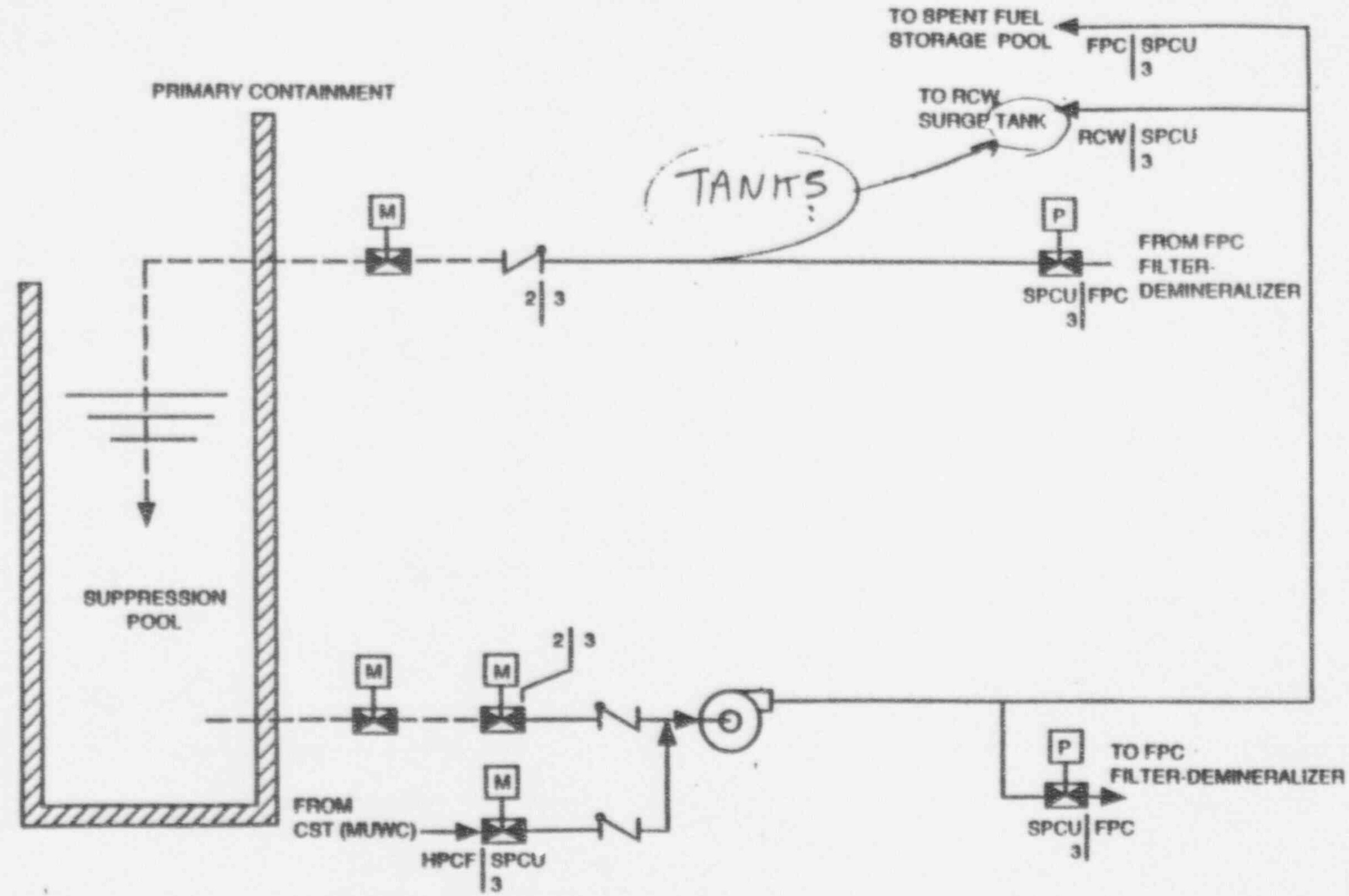
will be maintained for all design basis events, including seismic and

PROPOSED CHANGES

CDM: None

SSAR: See attached.

Verified



NOTES:
1. THE INBOARD CONTAINMENT ISOLATION VALVES ARE POWERED FROM CLASS 1E DIVISION II AND THE OUTBOARD CONTAINMENT ISOLATION VALVE IS POWERED FROM CLASS 1E DIVISION I.

Figure 2.6.3 Suppression Pool Cleanup System

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.3 SPCU No. 3

NRC COMMENT:

Figure 2.6.3: Change "SURGE TANK" to "SURGE TANKS."

GE RESPONSE:

GE concurs and will include this change in the next version of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

2.6.3 Suppression Pool Cleanup System

Design Description

The Suppression Pool Cleanup (SPCU) System removes particulates and dissolved impurities from the suppression pool by circulating suppression pool water through the Fuel Pool Cooling (FPC) System water treatment equipment. The SPCU System also provides a source of makeup water to the spent fuel storage pool and the Reactor Building Cooling Water (RCW) System surge tanks using either the suppression pool or condensate storage tank (CST) water via the High Pressure Core Flooder (HPCF) System supply piping. Figure 2.6.3 shows the basic system configuration and scope.

Except for the primary containment penetration and isolation valves, the SPCU System is classified as non-safety-related.

The SPCU System piping and components, as shown on Figure 2.6.3, are classified as Seismic Category I. Figure 2.6.3 shows ASME Code class for the SPCU System piping and components.

The SPCU System is located outside the primary containment in the Reactor Building.

The inboard containment isolation valves are powered from Class 1E Division II, and the outboard containment isolation valve is powered from Class 1E Division I. In the SPCU System, independence is provided between the Class 1E divisions, and also between Class 1E divisions and non-Class 1E equipment.

The main control room has control and open/close status indication for the containment isolation valves.

The safety-related electrical equipment located outside the primary containment in the Reactor Building is qualified for a harsh environment.

The motor-operated valves (MOVs) for containment isolation, shown on Figure 2.6.3 have active safety-related function to close and perform this function under differential pressure, fluid flow, and temperature conditions.

The check valve (CV) for containment isolation shown on Figure 2.6.3, has active safety-related function to close under system pressure, fluid flow, and temperature conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.6.3 provides definition of inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the SPCU System.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.3 SPCU No. 1

NRC COMMENT:

Page 2.6.3-1 first paragraph: add acronym (CST) after condensate storage tank.

GE RESPONSE:

GE concurs and will include this change in the next version of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

of a core. The temperature of the fuel pool water may be permitted to rise to approximately 60°C under these conditions. During cold shutdown conditions, if it appears that the fuel pool temperature will exceed 52°C, the operator can connect the FPC System to the RHR System. Combining the capacities enables the two systems to keep the water temperature below 52°C. The RHR System will be used only to supplement the fuel pool cooling when the reactor is shut down. The reactor will not be started up whenever portions of the RHR System are needed to cool the fuel pool.

These connections may also be utilized during emergency conditions to assure cooling of the spent fuel regardless of the availability of the FPC System. The volume of water in the storage pool is such that there is enough heat absorption capability to allow sufficient time for switching over to the RHR System for emergency cooling.

During the initial stages of refueling, the reactor cavity communicates with the fuel pool, since the reactor well is flooded and the fuel pool gates are open. Decay heat removal is provided jointly by the RHR and FPC Systems and the pool temperature kept below 60°C. Evaluation studies concluded that after 150 hours decay following shutdown (fuel pool gates open), the combined decay heat removal capacity of the 1-RHR and 1-FPC heat exchangers (single active failure postulated) can keep the pool temperature well below 60°C. The RHR-FPC joint decay heat removal performance evaluation is shown in Table 9.1-12.

The 60°C temperature limit is set to assure that the fuel building environment does not exceed equipment environmental limits.

The spent-fuel storage pool is designed so that no single failure of structures or equipment will cause inability to:

(1) Maintain irradiated fuel submerged in water

(2) Re-establish normal fuel pool water level

(3) Remove decay heat from the pool

In order to limit the possibility of pool leakage around pool penetrations, the pool is lined with stainless steel. In addition to providing a high degree of integrity, the lining is designed to withstand possible abuse when equipment is moved. No inlets, outlets or drains are provided that might permit the pool to be drained below a safe shielding ~~level.~~ Lines extending below this level are equipped with siphon breakers, check valves, or other suitable devices to prevent inadvertent pool drainage. Interconnected drainage paths are provided behind the liner welds. These paths are designed to:

i.e. below a point 3m above the top of active fuel located in the spent fuel storage racks

(1) Prevent pressure buildup behind the liner plate

DC	17A	AC
a. The spent fuel storage pool has no piping connections (inlet, outlet, drains or other piping) located below a point 3m. above the top of active fuel located in the spent fuel storage racks.	a. Inspections of the as-built spent fuel storage pool will be conducted.	a. use the same words as the right hand column.

2/17

n(71/)

Table 2.6.2 Fuel Pool Cooling and Cleanup System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the FPC System is as shown on Figure 2.6.2.	1. Inspection of the as-built system will be conducted.	1. The as-built FPC System conforms with the basic configuration shown on Figure 2.6.2.
2. The ASME Code components of the FPC System retain their pressure boundary integrity under internal pressures that will be experienced during service.	2. A hydrostatic test will be conducted on those Code components of the FPC System required to be hydrostatically tested by the ASME Code.	2. The results of the hydrostatic test of the ASME Code components of the FPC System conform with requirements in the ASME Code, Section III.
3. The safety-related makeup water source for the spent fuel storage pool is provided by the RHR System, which pumps suppression pool water to the FPC System.	3. Tests will conducted on the as-built FPC and RHR Systems by aligning the systems so that the RHR System draws water from the suppression pool and discharges into the spent fuel storage pool.	3. The combined RHR System and FPC System operation transfers water from suppression pool to the spent fuel storage pool.
~~4.~~ 5 Main control room displays provided for the FPC System are as defined in Section 2.6.2.	~~4.~~ 5 Inspections will be performed on the main control room displays for the FPC System.	5 ~~4.~~ Displays exist or can be retrieved in the main control room as defined in Section 2.6.2.
~~5.~~ 6 CVs designated in Section 2.6.2 as having an active safety-related function open, close, or open and close, under system pressure, fluid flow, and temperature conditions.	~~5.~~ 6 Tests of installed valves for opening, closing, or both opening and closing, will be conducted under system preoperational pressure, fluid flow, and temperature conditions.	6 ~~5.~~ Based on the direction of the differential pressure across the valve, each CV opens, close, or both opens and closes depending upon the valve's safety functions.

New # 4

4 4 4

ADD THE NEW # 4
FROM THE NEXT
SHEET.

2.6.2 Fuel Pool Cooling and Cleanup System

Design Description

The Fuel Pool Cooling and Cleanup (FPC) System (Figure 2.6.2) removes decay heat generated by the spent fuel assemblies in the spent fuel storage pool. The system also maintains the water quality and monitors and maintains the water level above the spent fuel in the spent fuel storage pool. Figure 2.6.2 shows the basic FPC System configuration and scope.

The FPC System is classified non-safety-related, except for piping connections and valves for safety-related fuel pool makeup and supplemental cooling by the Residual Heat Removal (RHR) System.

The safety-related makeup water source for the spent fuel storage pool is provided by the RHR System, which pumps suppression pool water to the FPC System.

The FPC System components, with the exception of the filter/demineralizer unit, are classified as Seismic Category I. Figure 2.6.2 shows the ASME Code class for the FPC System piping and components.

The FPC System is located in the Reactor Building.

The FPC System has parameter displays in the main control room for instruments shown on Figure 2.6.2.

The check valves (CVs) shown on Figure 2.6.2 have active safety-related functions to open, close, or both open and close under system pressure, fluid flow, and temperature conditions.

The piping and components of the FPC System at the suction side of the RHR System from the upstream isolation valve have a design pressure of 28.8 kg/cm^2g for intersystem LOCA (ISLOCA) conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.6.2 provides a definition of the inspections, tests and/or analyses, together with associated acceptance criteria, which will be undertaken for the FPC System.

The spent fuel storage pool has no piping connections (inlet, outlet, drains or other piping) located below a point ~~[illegible]~~ 3 m. above the top of active fuel located in the spent fuel storage racks.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.2 FPCU No. 6

NRC COMMENT:

Piping penetrations and arrangements of piping connected to the pool are configured to ensure that the pool is not drained below a minimum level of water above the stored spent fuel in the event of a pipe break, or inadvertent operator action, or siphonic action.

GE RESPONSE:

GE concurs that this issue needs to be addressed and proposes the following changes:

1. Add an entry to the 2.6.2 design ~~destination~~ description per the attached markup. This entry addresses the piping ~~correction~~ connection elevation aspects of this ~~comment~~ comment. GE believes this addition coupled with the check valve and configuration information already on Figure 2.6.2 represents appropriate CDM treatment of the fuel pool drainage issue.

2. Modify SSAR Section 9.1.3.3 per the attached markups. These SSAR changes are necessary to support the proposed additions to the CDM.

PROPOSED CHANGES

CDM: See attached markups.

SSAR: See attached markups.

Verified

Table 2.6.1 Reactor Water Cleanup System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitments	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration for the CUW System is as shown in Figure 2.6.1.	1. Inspection of the as-built system will be conducted.	1. The as-built CUW System conforms with the basic configuration shown in Figure 2.6.1.
2. The ASME Code components of the CUW System retain their pressure boundary integrity under internal pressures that will be experienced during service.	2. A hydrostatic test will be conducted on those Code components of the CUW System required to be hydrostatically tested by the ASME Code.	2. The results of the hydrostatic test of the ASME Code components of the CUW System conform with the requirements in the ASME Code, Section III.
3. The inboard containment isolation valve is powered from Class 1E Division II, and the outboard containment isolation valves are powered from Class 1E Division I. In the CUW System, independence is provided between Class 1E divisions, and between Class 1E divisions and ~~non-1E~~ non-Class 1E equipment.	3. a. Tests will be performed on the CUW System by providing a test signal in only one Class 1E division at a time. b. Inspections of the as-installed Class 1E divisions in the CUW System will be performed.	3. a. The test signal exists only in the Class 1E division under test in the CUW System. b. In the CUW System, physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between Class 1E divisions and non-Class 1E equipment.
4. Main control room displays and controls provided for CUW System are as defined in Section 2.6.1.	4. Inspections will be performed on the main control room displays and controls for the CUW System.	4. Displays and controls exist or can be retrieved in main control room as defined in Section 2.6.1.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.1 RWCU No. 5

NRC COMMENT:

Certified Design Material Table 2.6.1 in ITAAC:

Item 3. – change "non-IE" to "non-Class 1E".

Item 5a provided the closure time of <=30 sec for two of the three containment isolation MOVs, whereas SSAR Table 5.4-6 requires all three MOVs to close within a time constraint of <30 sec. Should be revised to reflect a closure time of <30 seconds.

GE RESPONSE:

1. GE agrees to the Class 1E change.

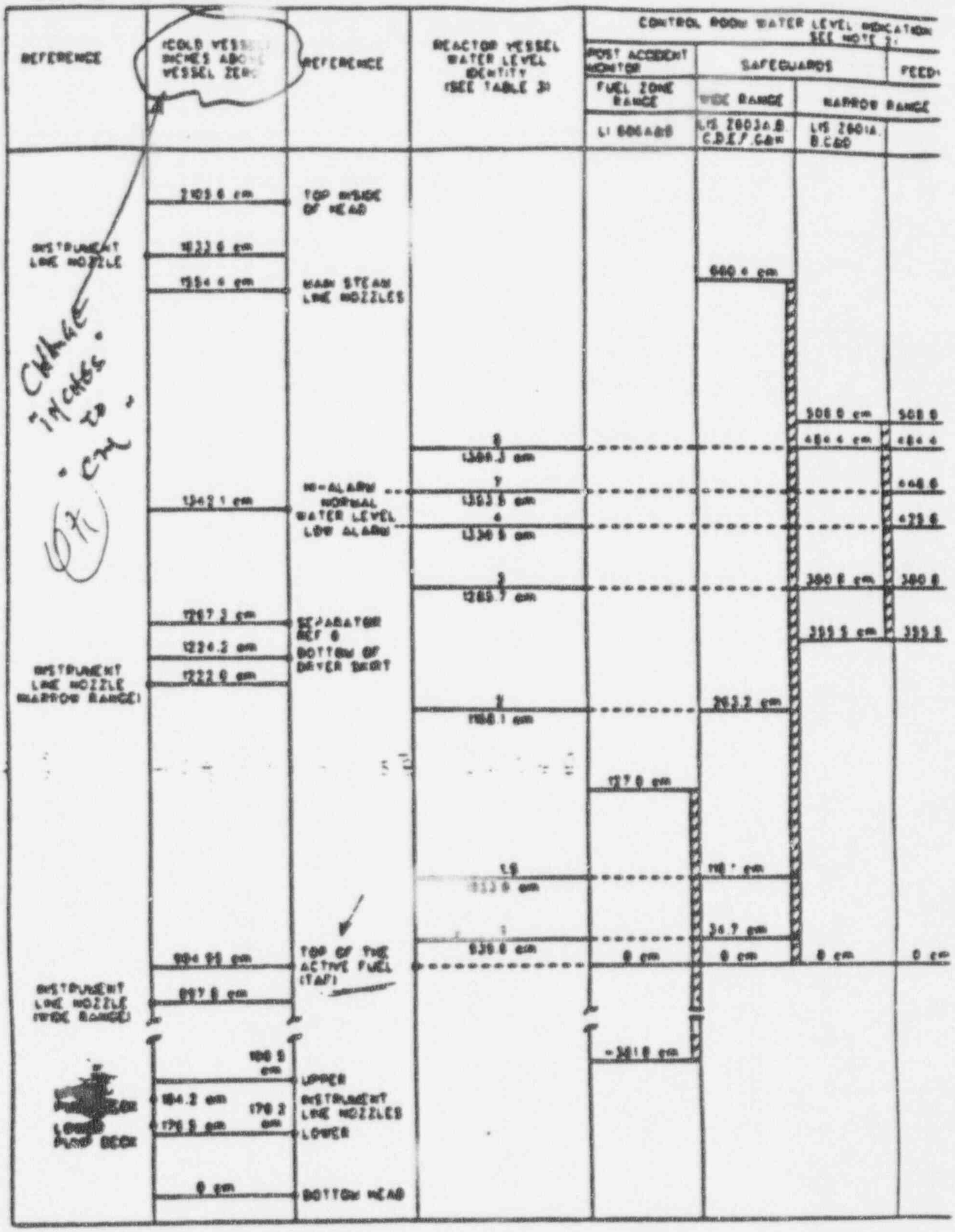
2. Ge does not agree to the time-related change. The CDM has consistently used the "equal to or greater/less than" symbol for valve operating times. This is not technically incompatible with the SSAR use of the "greater or less than" symbol without the equal term. Consequently, GE proposes no symbol-related changes in response to this NRC comment. INTENT OF SSAR STATEMENT IS ≤. CDM IS MORE PRECISE, BUT BOTH SSAR + CDM ARE CORRECT.

PROPOSED CHANGES

CDM: See attached.

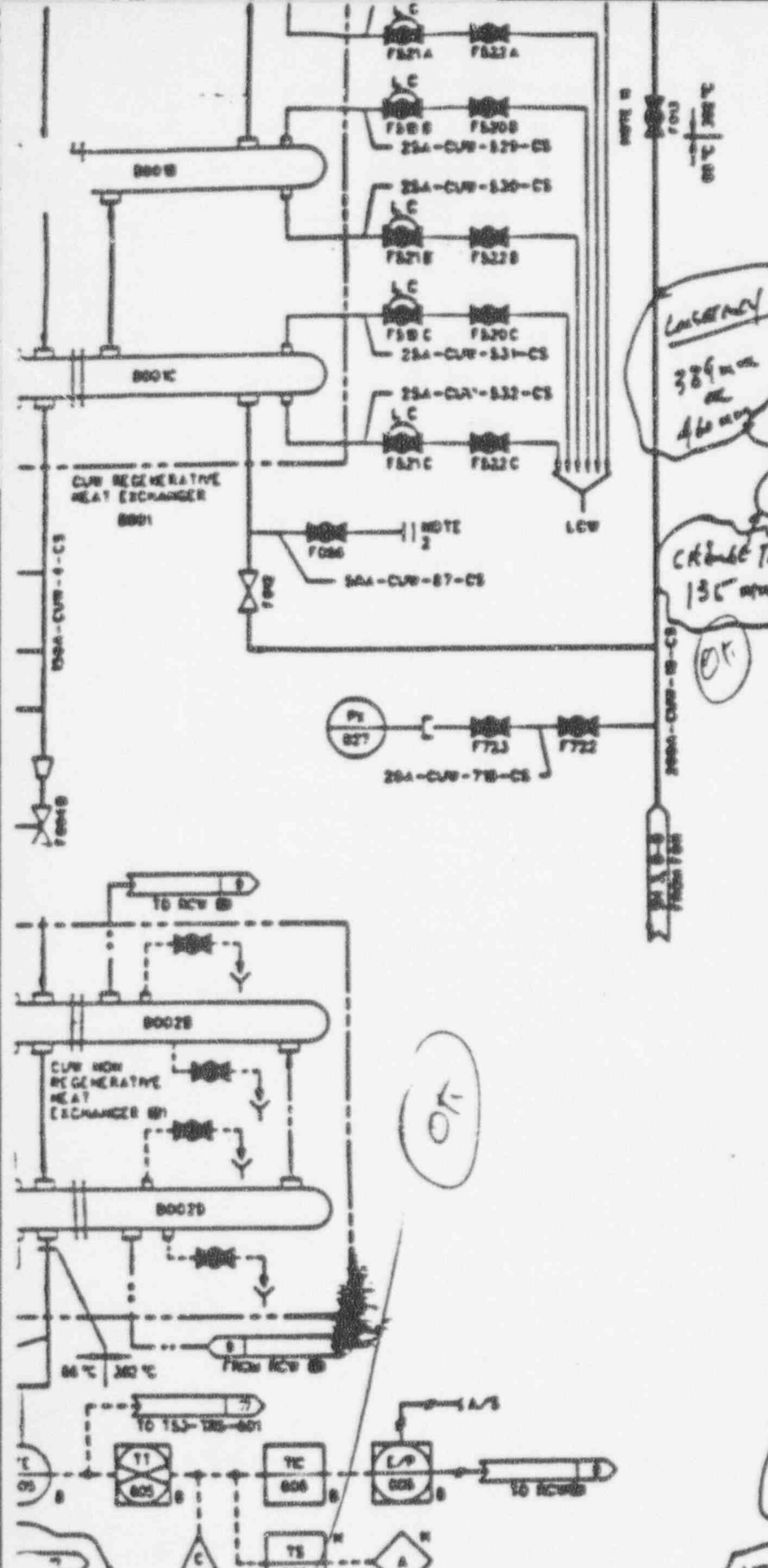
SSAR: None

TABLE 2 ELEVATION CORRELATION CHART



ITAAC 2.6.1 COMMENTS
PAGE 2d of 2

PDSD FIGURE 5.1-3
SHEET 9 OF 11



VALVE POSITION INDICATION LIGHTS LOCATED IN VICINITY OF VALVE CONTROL SWITCH.

13 TE000 INCLUDES TT FUNCTION.

14 NO VALVES AND INSTRUMENTS TO BE LOCATED IN THE SHIELDED COMPARTMENT CONTAINING THE FILTER DEMINERALIZER.

15 DESIGN CONDITIONS ARE FOLLOWING

(A) FLUID	WATER
(B) RADIOACTIVE CONCENTRATION	2 uCi/CC
(C) SCHEDULE	INTERFACE

16 FILTER DEMINERALIZER VALVE CONTROL SWITCHES, VALVE POSITION INDICATION LIGHTS AND ALARMS SHOULD BE INSTALLED IN LOCAL CONTROL PANEL.

17 A COMMON TROUBLE ALARM FROM LOCAL ANNUNCIATOR SHALL ALARM IN THE MAIN CONTROL ROOM.

18 WO INDICATES AIR OPERATED VALVES FAIL AS IS ON LOSS OF AIR AND FAIL CLOSED ON LOSS OF ELECTRIC POWER.

19 VESSEL HEAD DRAINLINE TEE CONNECTION TO THE CUW SUCTION LINE SHALL BE INSTALLED AT AN ELEVATION OF AT LEAST 389 mm ABOVE THE TOP OF ACTIVE FUEL.

20 MAXIMUM THROAT DIAMETER OF FLOW RESTRICTOR FE-F001 SHALL BE 70% OF THE INTERNAL PIPE DIAMETER.

21 PIPE WITH A DESIGN PRESSURE OF 28.8 KG/SQ CM OR GREATER SHALL HAVE ITS MINIMUM WALL THICKNESS NO LESS THAN THAT OF A STANDARD WEIGHT PIPE. THICKER THAN THE STANDARD WEIGHT PIPE SHALL BE USED IF REQUIRED BY THE DESIGN PRESSURE OR OTHER REQUIREMENTS.

22 VALVES WITH A DESIGN PRESSURE OF 28.8 KG/SQ CM OR GREATER SHALL HAVE A MINIMUM OF CLASS 300, OR OF A HIGHER CLASS IF REQUIRED BY THE DESIGN PRESSURE.

23 THE INBOARD CONTAINMENT ISOLATION VALVE F002 MANUAL CONTROL AND VALVE POSITION STATUS INDICATION SHALL BE HARDWIRED (NOT MULTIPLEXED) TO THE MAIN CONTROL ROOM.

REFERENCE DOCUMENTS	MPL NO.
1. REACTOR WATER CLEANUP SYS PFD	G31-1020
2. NUCLEAR BOILER SYSTEM P&ID	B21-1010
3. RADIOACTIVE WASTE (LIQUID, SOLID), RADWASTE SYS P&ID	K17-1010
4. LCW, RADWASTE SYSTEM P&ID	K17-1010
5. REACTOR WATER CLEANUP SYS IBD	G31-1030
6. RESIDUAL HEAT REMOVAL SYS P&ID	E11-1010
7. SERVICE AIR SYS P&ID (REAC BLDG)	P51-1010
8. PIPING & INSTRUMENT SYMBOLS DIAGRAM	A10-3030
9. REAC BLDG CLNG WATER SYS P&ID	P21-1010
10. HVAC SYS P&ID (REAC BLDG)	P13-1010
11. SAMPLING SYSTEM P&ID	P91-1010
12. CONTROL ROD DRIVE SYS P&ID	C12-1010
13. VALVE GLAND LEAKAGE TREATMENT, RADWASTE SYS P&ID	K17-1010
14. LEAK DETECTION AND ISOLATION SYS IED	E31-1010
15. FUEL POOL CLNG & CLEANUP SYS P&ID	G41-1010
16. FEEDWATER CONTROL SYS IBD	C31-1030
17. SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM P&ID	T53-1010
18. MAIN CONDENSER SYSTEM P&ID	N61-1010

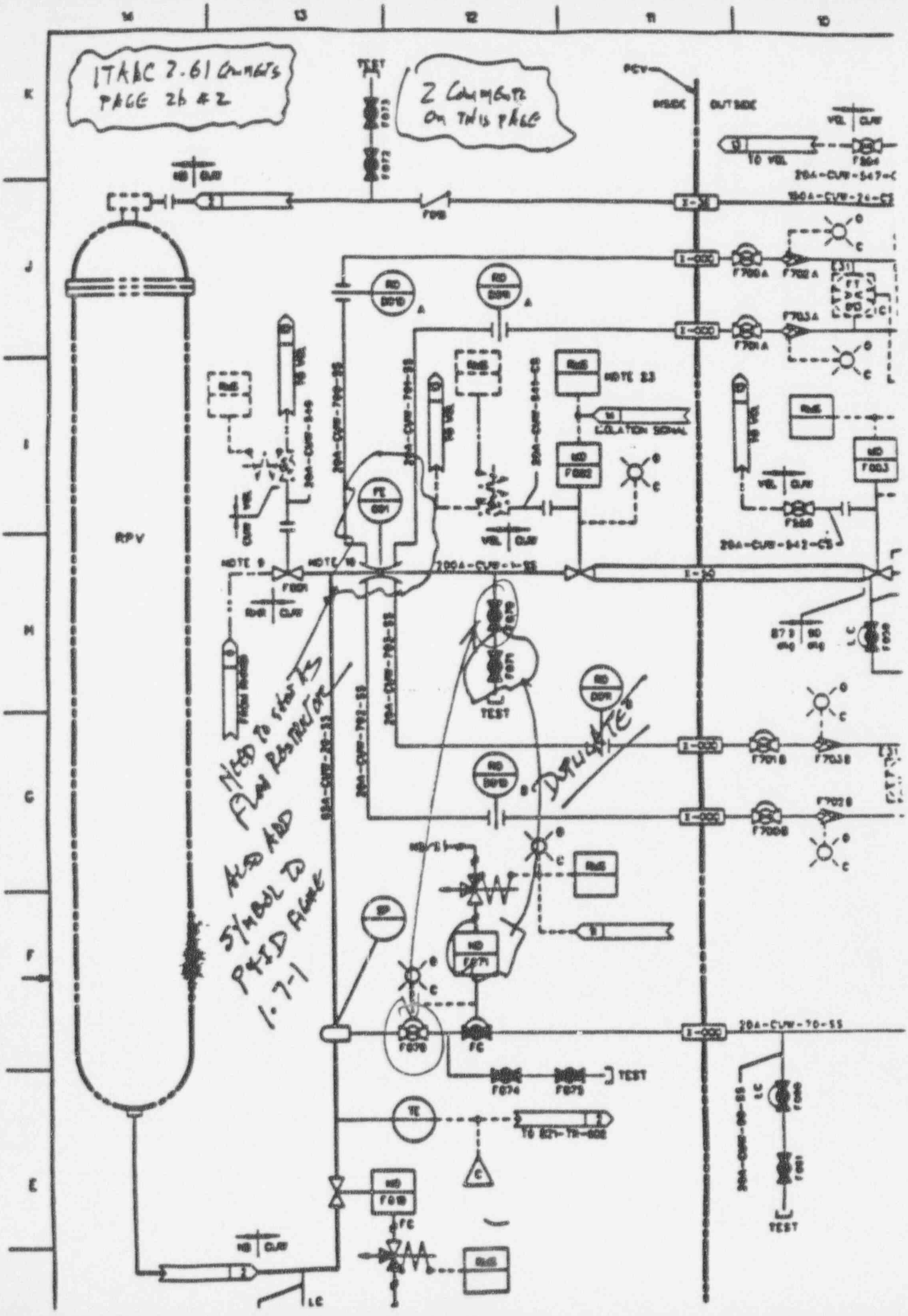
MPL NO. G31-1010

3 Comments on this PAGE

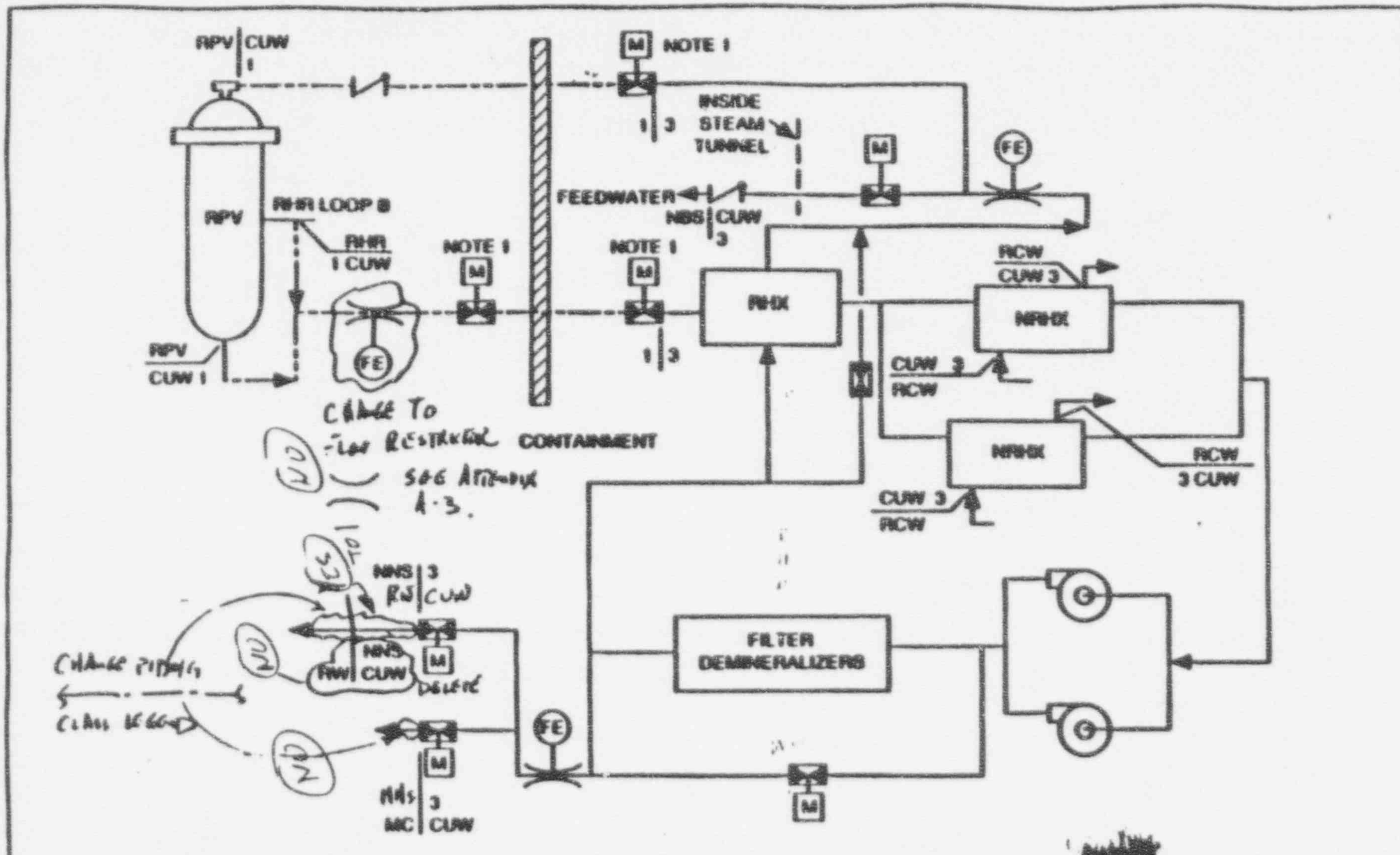
ITAAC 2.6.1 Comments PAGE 2 of 2

SR 2.6-13

FIGURE 5.4-12 REACTOR WATER CLEANUP SYSTEM P&ID (Sheet 1 of 4)



ITAAC 2.61 Comments
PAGE 2b #2
2 Comments On this page
PCV
INSIDE
OUTSIDE
TO VSL
RPV
NOTE 9
NOTE 16
NOTE 23
ISOLATION SIGNAL
TEST
NEED TO SHOW FLOW RESTRICTOR
ALSO ADD SYMBOL TO P&ID FIGURE 1.7-1
DUPLICATE
20A-CUW-70-SS
TEST



NOTES:
1. THE INBOARD CONTAINMENT ISOLATIONVALVE IS POWERED FROM CLASS 1E DIVISION II AND THE OUTBOARD ISOLATION VALVES ARE POWERED FROM CLASS 1E DIVISION I.

Figure 2.6.1 Reactor Water Cleanup System

ADD ACRONYM MC
TO APPENDIX B.

ITAAC COMMENTS P. 2a OF 2

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.1 RWCU No. 4 (Continued)

GE RESPONSE: (Continued)

GE AGREES. correct

b) ~~Connect~~ the pipe classification in the line to the RW ~~per~~ for the pipe length between the last valve and the system boundary (CUW-RW). The lines ~~required~~ beyond the boundary are not meant to ~~present~~ represent piping but are just interface arrows; this interface arrow connection has been used throughout the CDM and GE plans no changes.

GE DOES NOT AGREE.

c) Do not delete the RW-CUW interface as suggested by NRC. It is correct as-is. (A section of this piping is in the CUW system.)

GE AGREES.

d) Add an MC acronym in Appendix B.

B. SSAR Figure 5.1-3

GE DOES NOT AGREE.

a) Do not change the FE Venturi. See above item A(a).

b) GE concurs that valve numbers F071, F070 are duplicated. This will be corrected in the next SSAR amendment.

c) GE agrees that the column heading should be changed to cm from inches.

C. SSAR Figure 5.4-12

a) GE agrees to both NRC suggested changes (i.e., use 135mm and correct the interface tag).

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.6.1 RWCU No. 4

NRC COMMENT:

Reference attached markup of Figures 2.6.1, 5.1-3, and 5.4-12 for comments.

GE RESPONSE:

GE proposes the following in response to these comments.

A. Figure 2.6.1 CDM

a) Leave the FE Venturi as-is. This is common use throughout the BWR and represents a dual-function flow measuring device based on a Venturi and a flow restriction device. SYMBOL IDENTIFIED IN LEGEND FOR CDM AS A FLOW RESTRICT. ALSO STATED IN DD.

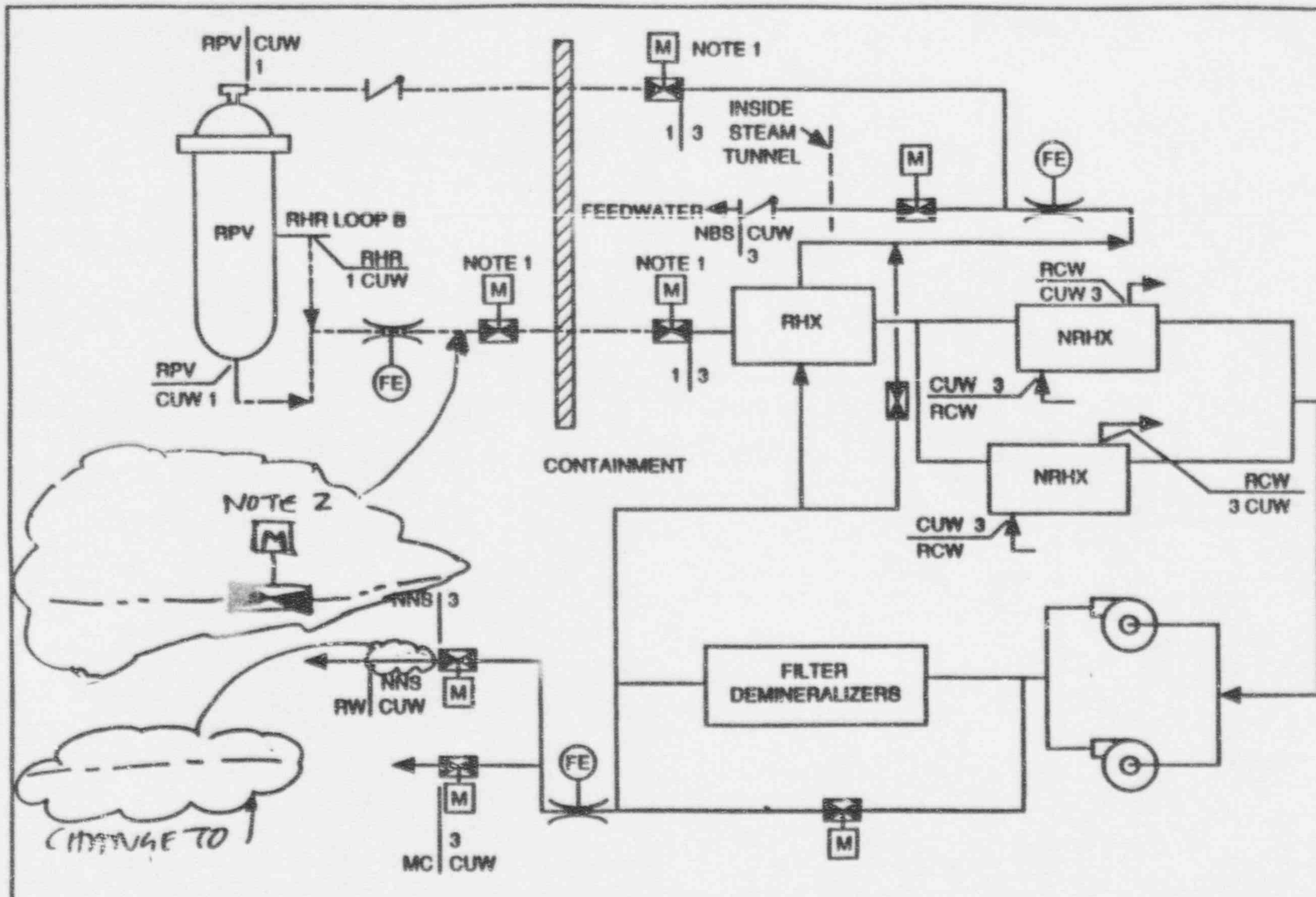
SSAR SYMBOL FOR VENTURI ALSO REPRESENTS FLOW RESTRICT.

(Continued on next page...)

PROPOSED CHANGES

CDM: Per above response. (See markup of Figure 2.6.1 attached to NRC comment 2.6.1 No. 3.)

SSAR: Per above response.



NOTES:
1. THE INBOARD CONTAINMENT ISOLATIONVALVE IS POWERED FROM CLASS 1E DIVISION II AND THE OUTBOARD ISOLATION VALVES ARE POWERED FROM CLASS 1E DIVISION I.

Figure 2.6.1 Reactor Water Cleanup System

2. NOT CONSIDERED A CONTAINMENT ISOLATION VALVE; CLASSIFIED AS NON-SAFETY-RELATED.

The CUW suction line is provided with a flow restrictor which provides flow restricting and flow monitoring functions. Maximum throat diameter is 135 mm.

The reactor vessel bottom head drain line is connected to the main CUW suction piping by a tee. The centerline of the tee connection is at an elevation of at least 460 mm above the centerline of the variable leg nozzle of the RPV wide range water level instrument.

The CUW piping and components downstream of the blowdown valve leading towards the Radwaste System shown on Figure 2.6.1 have a design pressure of 28.8 kg/cm^2g for intersystem loss-of-coolant accident (ISLOCA) conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.6.1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the CUW System.

Figure 1.7-3 Graphical Symbols for Use in Electrical SLDs (Sheet 3 of 4)

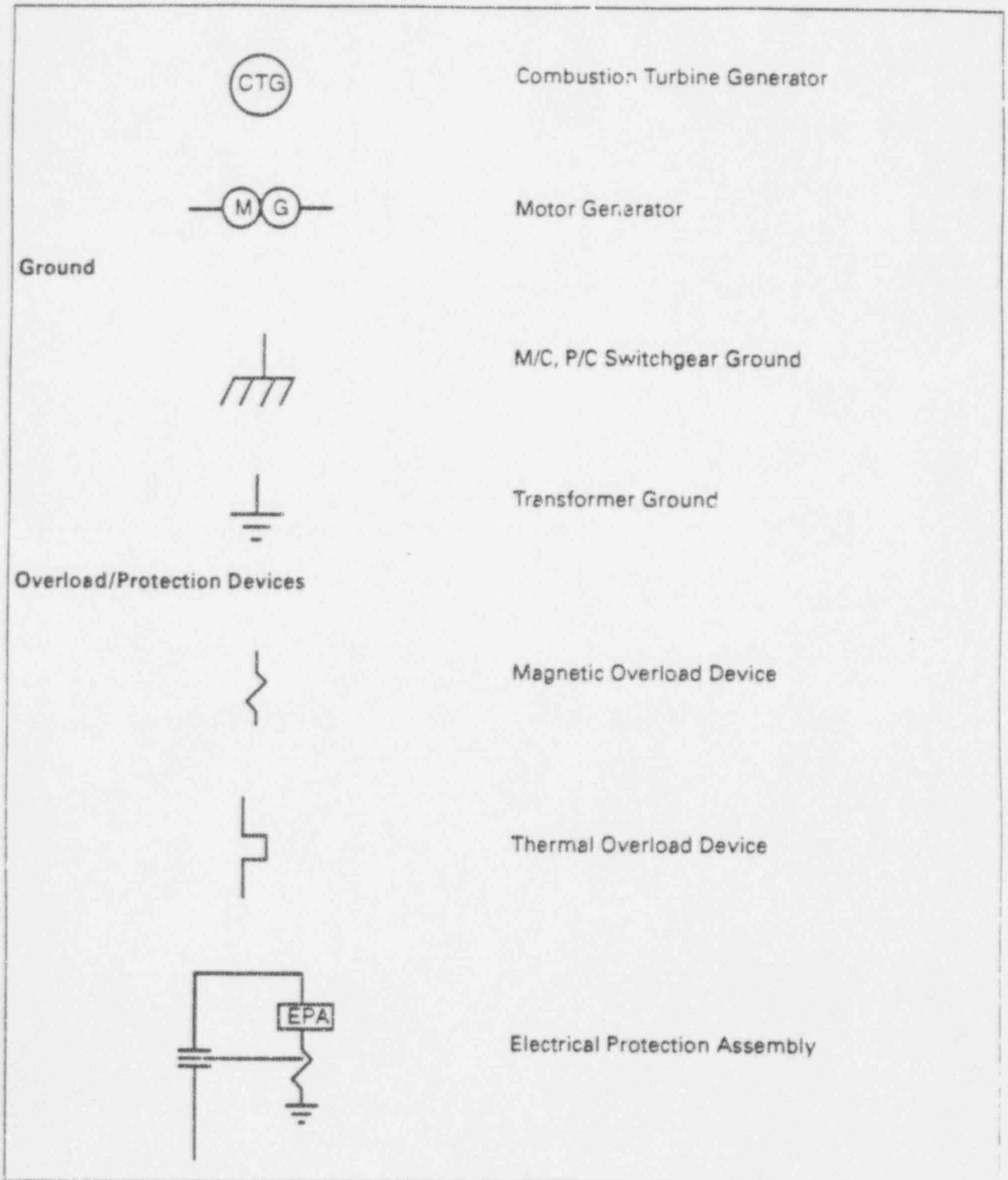
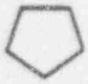
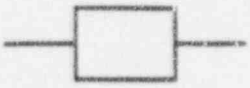
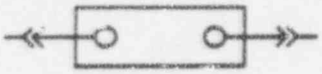


Figure 1.7-3 Graphical Symbols for Use in Electrical SLDs (Sheet 2 of 4)


Special

Circuit Breakers/Disconnect Devices


Main Generator/Switchyard Circuit Breaker


Metal Clad Switchgear Circuit Breaker (Drawout Type)


Air Circuit Breaker (Drawout Type)


Isolated Phase Bus Disconnect Link


Disconnect Switch

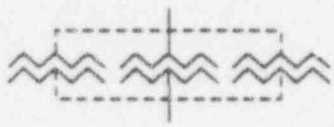
Generators

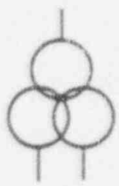
Main Plant Generator

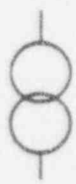
Diesel Generator

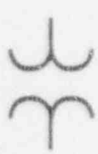
Figure 1.7-3 Graphical Symbols for Use in Electrical SLDs (Sheet 1 of 4)

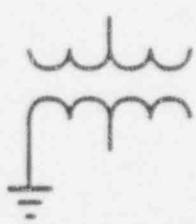
Transformer


Three 1ø


Three winding - 3ø

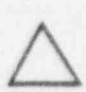

Two winding - 3ø or 1ø


Two winding - 3ø


Two winding - 3ø center tap ground

Note: Symbol in transformer = winding connection type i.e.


Star


Delta

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.1 EPDS No. 10

NRC COMMENT:

In response to comment No. 17 made during the pilot review, GE stated the proposed changes would be made post-amendment 33. This comment is being made to encourage follow-up on that specific item which is the legend in the SSAR for electrical symbols.

GE RESPONSE:

GE understands this prior commitment and will include the promised changes in the next SSAR amendment. Thanks for the reminder.

PROPOSED CHANGES

CDM: None

SSAR: Add electrical symbols list.

ITAAC 2.12.1
9

8A Miscellaneous Electrical Systems

8A.1 Station Grounding and Surge Protection

8A.1.1 Description

The electrical grounding system is comprised of:

(1) An instrument and computer grounding network

(2) An equipment grounding network for grounding electrical equipment (e.g. switchgear, motors, distribution panels, cables, etc.) and selected mechanical components (e.g. fuel tanks, chemical tanks, etc.)

transformers,

(3) A plant grounding grid

(4) A lightning protection network for protection of structures, transformers and equipment located outside buildings

The plant instrumentation is grounded through a separate insulated radial grounding system comprised of buses and insulated cables. The instrumentation grounding systems are connected to the station grounding grid at only one point and are insulated from all other grounding circuits. Separate instrumentation grounding systems are provided for plant analog i.e., relays, solenoids, etc.) and digital instrumentation systems.

The equipment grounding network is such that all major equipment, structures and tanks are grounded with two diagonally opposite ground connections. The ground bus of all switchgear assemblies, motor control centers and control cabinets are connected to the station ground grid through at least two parallel paths. Bare copper risers are furnished for all underground electrical ducts and equipment, and for connections to the grounding systems within buildings. One bare copper cable is installed with each underground electrical duct run, and all metallic hardware in each manhole is connected to the cable.

A plant grounding grid consisting of bare copper cables is provided to limit step and touch potentials to safe values under all fault conditions. The buried grid is located at the switchyard and connected to systems within the buildings by a 500 MCM bare copper loop which encircles all buildings (Figure 8A-1).

Each building is equipped with grounding systems connected to the station grounding grid. As a minimum, every other steel column of the building perimeter will connect directly to the grounding grid.

The plant's main generator is grounded with a neutral grounding device. The impedance of that device will limit the maximum phase current under short-circuit

ITAAC 2.12.1 ... 9

Table 2.12.1 Electric Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
22. The EPD System supplies an operating voltage at the terminals of the Class 1E utilization equipment that is within the utilization equipment's voltage tolerance limits.	22. Analyses for the as-built EPD System to determine voltage drops will be performed.	22. Analyses for the as-built EPD System exist and conclude that the analyzed operating voltage supplied at the terminals of the Class 1E utilization equipment is within the utilization equipment's voltage tolerance limits, as determined by their nameplate ratings.
23. An electrical grounding system is provided for (1) instrumentation, control, and computer systems, (2) electrical equipment (transformers, switchgear, distribution panels, and motors) and (3) mechanical equipment (fuel and chemical tanks). Lightning protection systems are provided for buildings and for structures and transformers located outside of the buildings. Each grounding system and lightning protection system is separately grounded to the plant ground grid.	23. Inspections of the as-built EPD System plant Grounding and Lightning Protection Systems will be conducted.	23. The as-built EDP System instrumentation, control, and computer grounding system, electrical equipment and mechanical equipment grounding system, and lightning protection systems provided for buildings and for structures and transformers located outside of the buildings are separately grounded to the plant ground grid.
24. MCR alarms, displays and controls provided for the EPD System are as defined in Section 2.12.1.	24. Inspections will be conducted on the MCR alarms, displays and controls for the EPD System.	24. Displays and controls exist or can be retrieved in the MCR as defined in Section 2.12.1.
25. RSS displays and controls provided for the EPD System are as defined in Section 2.12.1.	25. Inspections will be conducted on the as-built RSS displays and controls for the EPD System.	25. Displays and controls exist or can be retrieved on the RSS as defined in Section 2.12.1.

Table 2.12.1 Electric Power Distribution System (Continued)

Design Commitment	Inspections, Tests, Analyses and Acceptance Criteria	
	Inspections, Tests, Analyses	**Acceptance Criteria**
8. Medium voltage M/C switchgear, low voltage P/C switchgear, with their respective transformers, and MCCs, and their respective switchgear and MCC feeder and load circuit breakers are sized to supply their load requirements.	8. a. Analyses for the as-built EPD System to determine load requirements will be performed.	8. a. Analyses for the as-built EPD System exist and conclude that the capacities of the Class 1E switchgear, P/C transformers, MCCs, and their respective feeder and load circuit breakers, as determined by their nameplate ratings, exceed their analyzed load requirements.
	b. Tests of the as-built Class 1E M/C and P/C switchgear and MCCs and their respective load circuit breakers will be performed by operating connected Class 1E loads in the ranges of 9% to 10% above and 9% to 10% below design voltage.	b. Connected Class 1E loads operate in the ranges of 9% to 10% above and 9% to 10% below design voltage.
9. , WITH THEIR RESPECTIVE TRANSFORMERS, a. Medium voltage M/C switchgear, low voltage P/C switchgear and MCCs, are rated to withstand fault currents for the time required to clear the fault from its power source.	9. a. Analyses for the as-built EPD System to determine fault currents will be performed.	9. M/Cs a. Analyses for the as-built EPD System exist and conclude that the Class 1E switchgear and MCC, current capacities exceed their analyzed fault currents for the time required, as determined by the circuit interrupting device coordination analyses, to clear the fault from its power source.

ITAAC 2.12.1 comment #9 RL 2/10

Class 1E medium voltage M/C switchgear and low voltage P/C switchgear and MCCs are identified according to their Class 1E division. Class 1E M/C and P/C switchgear and MCCs are located in Seismic Category I structures, and in their respective divisional areas.

Class 1E EPD System cables and raceways are identified according to their Class 1E division. Class 1E divisional cables are routed in Seismic Category I structures and in their respective divisional raceways.

Harmonic Distortion waveforms do not prevent Class 1E equipment from performing their safety functions.

The EPD System supplies an operating voltage at the terminals of the Class 1E utilization equipment that is within the utilization equipment's voltage tolerance limits.

transformers,

An electrical grounding system is provided for (1) instrumentation, control, and computer systems, (2) electrical equipment (switchgear, distribution panels, and motors) and (3) mechanical equipment (fuel and chemical tanks). Lightning protection systems are provided for buildings and for structures and transformers located outside of the buildings. Each grounding system and lightning protection system is separately grounded to the plant ground grid.

The EPD System has the following alarms, displays and controls in the MCR:

(1) Alarms for degraded voltage on Class 1E medium voltage M/C switchgear.

(2) Parameter displays for PMG output voltage, amperes, watts, vars, and frequency.

(3) Parameter displays for EPD System medium voltage M/C switchgear bus voltages and feeder and load amperes.

(4) Controls for the PMG output circuit breaker, medium voltage M/C switchgear feeder circuit breakers, load circuit breakers from the medium voltage M/C switchgear to their respective low voltage P/C switchgear, and low voltage feeder circuit breakers to the low voltage P/C switchgear.

(5) Status indication for the PMG output circuit breaker and the medium voltage M/C switchgear circuit breakers.

The EDP System has the following displays and controls at the Remote Shutdown System (RSS):

(1) Parameter displays for the bus voltages on the Class 1E Divisions I and II medium voltage M/C switchgear.

2.12.1 (14)

Table 2.12.1 Electric Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
22. The EPD System supplies an operating voltage at the terminals of the Class 1E utilization equipment that is within the utilization equipment's voltage tolerance limits. Comment # 19	22. Analyses for the as-built EPD System to determine voltage drops will be performed.	22. Analyses for the as-built EPD System exist and conclude that the analyzed operating voltage supplied at the terminals of the Class 1E utilization equipment is within the utilization equipment's voltage tolerance limits, as determined by their nameplate ratings.
23. An electrical grounding system is provided for (1) instrumentation, control, and computer systems, (2) electrical equipment (switchgear, distribution panels, and motors) and (3) mechanical equipment (fuel and chemical tanks). Lightning protection systems are provided for buildings and for structures and transformers located outside of the buildings. Each grounding system and lightning protection system is separately grounded to the plant ground grid.	23. Inspections of the as-built EPD System plant Grounding and Lightning Protection Systems will be conducted.	23. The as-built EDP System instrumentation, control, and computer grounding system, electrical equipment and mechanical equipment grounding system, and lightning protection systems provided for buildings and for structures and transformers located outside of the buildings are separately grounded to the plant ground grid.
24. MCR alarms, displays and controls provided for the EPD System are as defined in Section 2.12.1.	24. Inspections will be conducted on the MCR alarms, displays and controls for the EPD System.	24. Displays and controls exist or can be retrieved in the MCR as defined in Section 2.12.1.
25. RSS displays and controls provided for the EPD System are as defined in Section 2.12.1.	25. Inspections will be conducted on the as-built RSS displays and controls for the EPD System.	25. Displays and controls exist or can be retrieved on the RSS as defined in Section 2.12.1.

The UATs are sized to supply their load requirements, during design operating modes, of their respective Class 1E divisions and non-Class 1E load groups. UATs are separated from the RAT(s). In addition, UATs are provided with their own oil pit, drain, fire deluge system, grounding, and lightning protection system.

The PMG, its output circuit breaker, and UAT power feeders are separated from the RAT(s) power feeders. The PMG, its output circuit breaker, and UAT instrumentation and control circuits, are separated from the RAT(s) instrumentation and control circuits.

The MPT and its switching station instrumentation and control circuits, from the switchyard(s) to the main control room (MCR), are separated from the RAT(s) and its switching station instrumentation and control circuits.

WITH THEIR RESPECTIVE TRANSFORMERS,

The medium voltage M/C switchgear and low voltage P/C switchgear, with their respective transformers, and the low voltage MCCs are sized to supply their load requirements. M/C and P/C switchgear, and MCCs are rated to withstand fault currents for the time required to clear the fault from the power source. The PMG output circuit breaker, and power feeder and load circuit breakers for the M/C and P/C switchgear, and MCCs are sized to supply their load requirements and are rated to interrupt fault currents.

Class 1E equipment is protected from degraded voltage conditions.

EPD System interrupting devices (circuit breakers and fuses) are coordinated so that the circuit interrupter closest to the fault opens before other devices.

Instrumentation and control power for the Class 1E divisional medium voltage M/C switchgear and low voltage P/C switchgear is supplied from the Class 1E DC power system in the same division.

The PMG output circuit breaker is equipped with redundant trip devices which are supplied from separate, non-Class 1E DC power systems.

EPD System cables and bus ducts are sized to supply their load requirements and are rated to withstand fault currents for the time required to clear the fault from its power source.

For the EPD System, Class 1E power is supplied by three independent Class 1E divisions. Independence is maintained between Class 1E divisions, and also between Class 1E divisions and non-Class 1E equipment.

There are no automatic connections between Class 1E divisions.

2.12.1 (10)

17 Class 1E medium voltage M/C switchgear and low voltage P/C switchgear and MCCs are identified according to their Class 1E division. Class 1E M/C and P/C switchgear and MCCs are located in Seismic Category I structures, and in their respective divisional areas.

19 20 Class 1E EPD System cables and raceways are identified according to their Class 1E division. Class 1E divisional cables are routed in Seismic Category I structure and in their respective divisional raceways.

Harmonic Distortion waveforms do not prevent Class 1E equipment from performing their safety functions.

The EPD System supplies an operating voltage at the terminals of the Class 1E utilization equipment that is within the utilization equipment's voltage tolerance limits.

transformers

An electrical grounding system is provided for (1) instrumentation, control, and computer systems, (2) electrical equipment (switchgear, distribution panels, and motors) and (3) mechanical equipment (fuel and chemical tanks). Lightning protection systems are provided for buildings and for structures and transformers located outside of the buildings. Each grounding system and lightning protection system is separately grounded to the plant ground grid.

The EPD System has the following alarms, displays and controls in the MCR:

(1) Alarms for degraded voltage on Class 1E medium voltage M/C switchgear.

(2) Parameter displays for PMG output voltage, amperes, watts, vars, and frequency.

(3) Parameter displays for EPD System medium voltage M/C switchgear bus voltages and feeder and load amperes.

(4) Controls for the PMG output circuit breaker, medium voltage M/C switchgear feeder circuit breakers, load circuit breakers from the medium voltage M/C switchgear to their respective low voltage P/C switchgear, and low voltage feeder circuit breakers to the low voltage P/C switchgear.

(5) Status indication for the PMG output circuit breaker and the medium voltage M/C switchgear circuit breakers.

The EDP System has the following displays and controls at the Remote Shutdown System (RSS):

(1) Parameter displays for the bus voltages on the Class 1E Divisions I and II medium voltage M/C switchgear.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.1 EPDS No. 9

NRC COMMENT:

ITAAC #23 and CDM design description should be revised as shown in the attached markup.

GE RESPONSE:

GE concurs and proposes the following changes:

a) Attached changes to CDM pages 2.12.1-3 and 2.12.1-12.

b) The necessary supporting SSAR changes to page 8A-1, attached digital instrumentation.

PROPOSED CHANGES

CDM: Per above response.

SSAR: Per above response.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.1 EPDS No. 8

NRC COMMENT:

SSAR TS Section should be clarified as noted in the attached markup.

GE RESPONSE:

GE concurs and will include these changes in the next SSAR amendment. (Also see resonse to EELB comment No. 24.)

PROPOSED CHANGES

CDM: None

SSAR: Per above response. Ver

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (normal preferred and alternate preferred) and the onsite standby power sources (Division I diesel generator (DG), Division II DG, and Division III DG). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 6.9 kV ESF bus (refer to LCO 3.8.9, "Distribution Systems—Operating"). Each ESF bus has two separate and independent preferred (offsite) sources of power and a dedicated onsite DG. Each ESF bus is also connectable to a combustion turbine generator (CTG). The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition. Comment #8

CTG may be substituted for the second (delayed) offsite source

Offsite power is supplied to each of the 6.9 kV ESF buses from the transmission network via two electrically and physically separated circuits. In addition, ~~offsite power can be supplied~~ to any one ESF bus ~~from the CTG~~ (for a limited duration) when the ESF bus is being fed from the reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service, or when the ESF bus is being fed from the unit auxiliary transformer while the reserve auxiliary transformer associated with the ESF bus is out of service. These offsite AC electrical power circuits are designed and located so as to minimize to the extent practicable the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power system and circuits to the onsite Class 1E ESF buses is found in SSAR, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, controls, and

(continued)

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.1 EPDS No. 4

NRC COMMENT:

Values referenced in acceptance criteria for ITAAC numbers 3, 5, 6, 7, 8.b, and 21 are not described in the design description. These should be described. With respect to separation distances in numbers 3, 5, 6, and 7, GE should consider removing the actual distances from the acceptance criteria column. Distances are in the SSAR.

GE RESPONSE:

GE does not concur. The basis for this position are:

a) Per GE/NRC agreements on CDM form, scope and content, it is acceptable to have acceptance criteria (including numerical values) that are not included in the CDM design description. See 12 [illegible] 92 NRC memo [illegible] to [illegible], page 4.

b) It is highly desirable to have an unambiguous, numerical acceptance criteria so GE believes the separation distance in items 3, 5, 6 and 7 should be retained.

c) GE agrees the distances are in the SSAR but this does not preclude their use in a CDM acceptance criterion.

Consequently, GE proposes no CDM changes in response to this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.1 EPDS No. 3

NRC COMMENT:

SSAR descriptions use "mVA and mW" as abbreviations for showing the units of power for equipment such as transformers, DG, CTG and buses. This is inconsistent with drawing 8.3.1. Drawing used "MVA and MW" as abbreviations. SSAR descriptions need to be updated to be consistent with drawing.

GE RESPONSE:

GE concurs and will make the necessary corrections in the next SSAR amendment.

(Changed mVA to MVA two places on page 8.2-13)

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

Vcr

2.12.1 H10

Chapter 8
List of Figures

Chapter 8
List of Tables

Comment 2

...nnectable to a combustion turbine generator (CTG). ...
... systems of any two of the three divisions provide for

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.1 EPDS No. 2

NRC COMMENT:

Incorrect page numbers are referenced on SSAR pages 8.0.iii/iv and v/vi.

GE RESPONSE:

GE concurs and will include the necessary corrections in the SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per above response. (Change pages 8.0 iii/iv and v/vi as requested. jer

2.12.1 #10

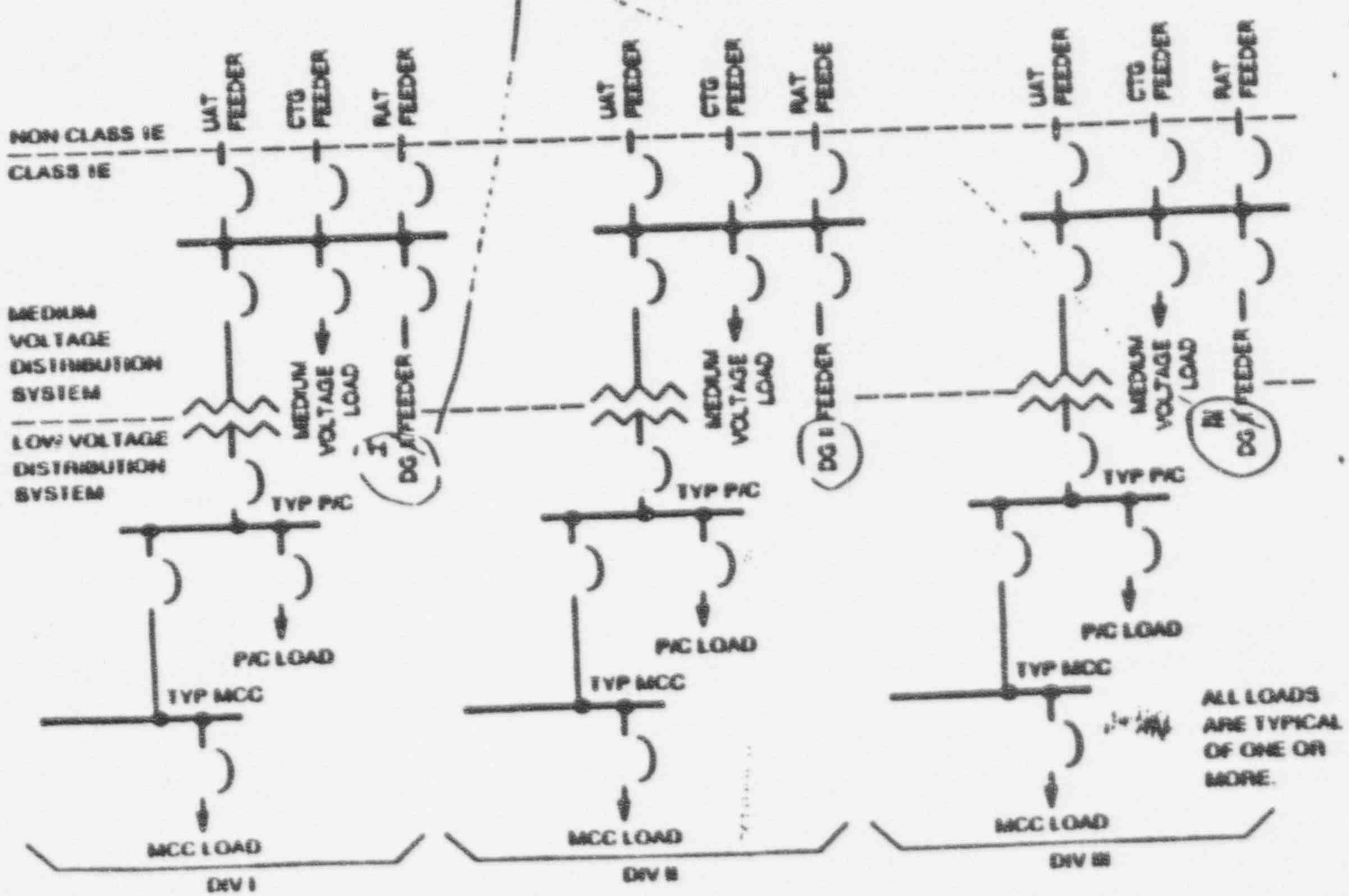


Figure 2.12.1 Class 1E Electrical Power Distribution System

ITAAC 2.12.1
Comment 1

R2 2/18

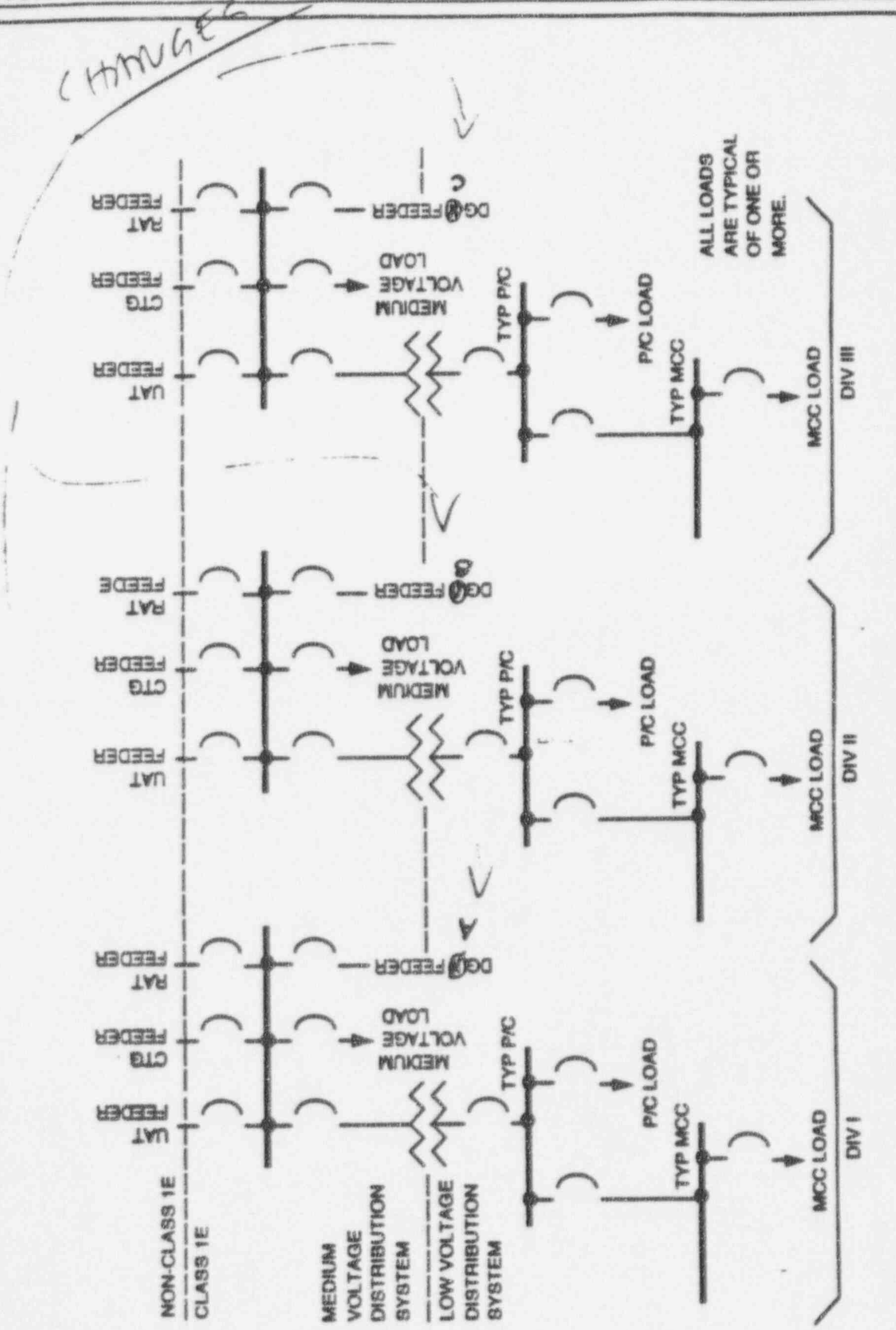


Figure 2.12.1 Class 1E Electrical Power Distribution System

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.1 EPDS No. 1

NRC COMMENT:

Figure 2.12.1 shows "DG II" feeders for all divisions. It should be changed to "DG I, DG II, and DG III" as shown in attached markup. This may conflict with SSAR. See SSAR Section 8.3.1.1.8.3 and Item 4 of SSAR Section 8.3.3.6.2.3.2.

GE RESPONSE:

GE concurs and will modify Figure 2.12.1 to use the terminology "DG A, B, C." This will make the CDM consistent with the SSAR.

PROPOSED CHANGES

CDM: Per attached markup.

SSAR: None

2.11.21

located

(7) Any purified water storage tank shall be provided outdoors with adequate freeze protection and adequate diking and other means to control spill and leakage.

9.2.8.3 System Description (Conceptual Design)

The MWP System consists of both mobile and permanently installed water treatment systems.

The permanently installed system consists of a well, filters, reverse osmosis modules and demineralizers which prepare demineralized water from well water. The demineralized water is sent to storage tanks until it is needed. Pumps are provided to keep the Makeup Water Preparation (MWP) System pressurized at all times. The components of the MWP System are listed in Table 9.2-15 and the system block flow diagram is in Figure 9.2-10.

While it is planned to install both permanent divisions, only one division may be installed if plant water requirements and economic conditions indicate that the second division will not be needed.

Mobile water treatment systems will be used before the permanent system is installed and later if water requirements exceed the capacity of the permanent system or if economic condition make use of mobile equipment attractive compared to operating and maintaining the permanent system.

9.2.8.3.1 Well System

A well, well water storage tank and two well water forwarding pumps are provided which can produce sufficient water to meet the concurrent needs of the MWP System and the PSW System.

9.2.8.3.2 Pretreatment System

Two dual media filters are provided in parallel which are backwashed when needed using one of two backwash pumps and water from a filtered water storage tank. This tank is provided with a heater to maintain a water temperature of at least 10°C at all times. Water may be sent from the filtered water storage tank to the PSW System or to the next components of the MWP System.

9.2.8.3.3 Reverse Osmosis Modules

Chemical addition tanks, pumps and controls are provided to add sodium hexametaphosphate and sodium hydroxide to the filtered water.

Four high pressure, horizontal multistage reverse osmosis (RO) feed pumps provide a feed pressure of approximately 32 kg/cm^2g. Reverse osmosis membranes are arranged in two parallel divisions of two passes each with the permeate of the first passes going to located outdoors

(7) Any purified water storage tank shall be provided ~~outdoors~~ with adequate freeze protection and adequate diking and other means to control spill and leakage.

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9.2.8.3.3 Reverse Osmosis Modules

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FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.21 FREEZE PROTECTION No. 1

NRC COMMENT:

See attached markup for SSAR editorial comment.

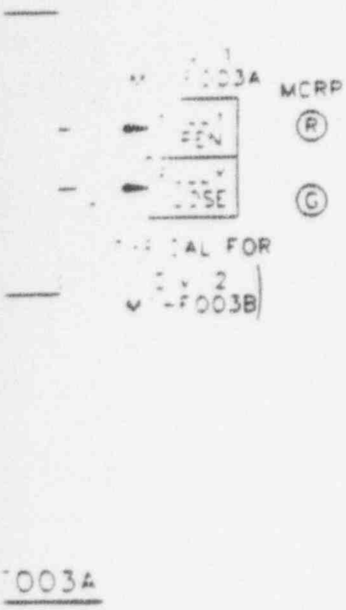
GE RESPONSE:

GE concurs and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment; see attached. ver



HPIN SYSTEM DIVISION-A IS POWERED FROM CLASS 1E DIVISION 1 AND HPIN SYSTEM DIVISION-B IS POWERED FROM CLASS 1E DIVISION 2

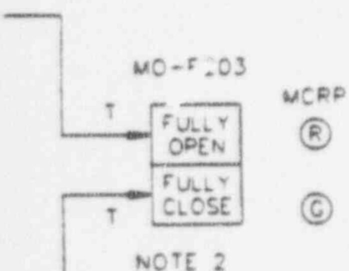
NOTES:

1. ~~EACH HIGH PRESS NITROGEN GAS SUPPLY (HPIN) DIVISION, (DIVISION 1,2) IS POWERED FROM INDEPENDENT CLASS 1E DIVISION AS NOTED.~~

2. THE NON-SAFETY RELATED PORTION OF HPIN IS POWERED FROM NON-CLASS 1E SOURCE.

REFERENCE DOCUMENT:

	MPL NO.
1. HIGH PRESS NITROGEN GAS SUPPLY SYS P&ID	P54-1010



MPL NO. P54-1030

FIGURE 7.3-1D
SHT. 1 OF 3

Figure 7.3-10 HIGH PRESSURE NITROGEN GAS SYSTEM IBD (Sheet 1 of 3)

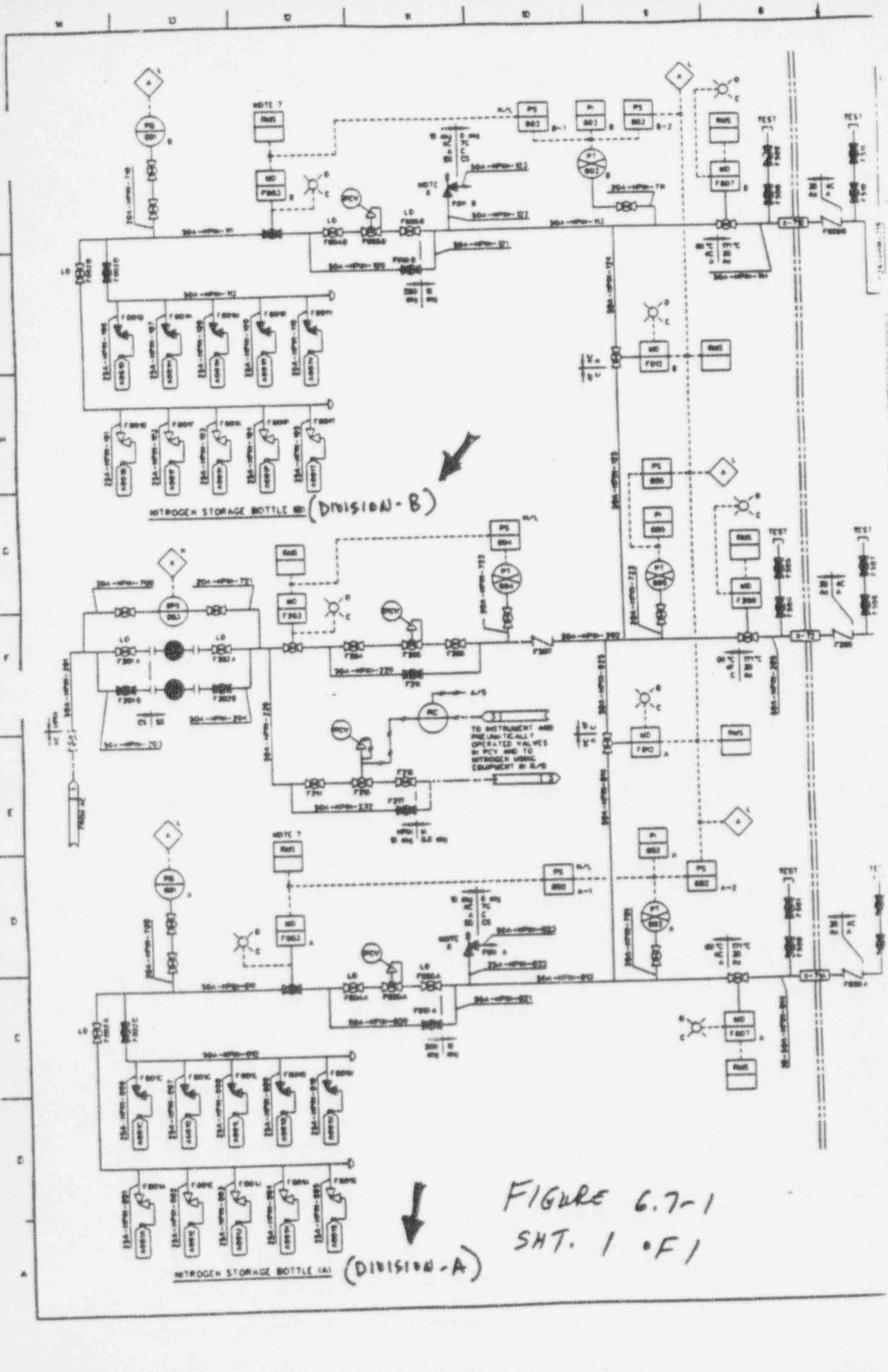


FIGURE 6.7-1
SHT. 1 OF 1

(c) Bypasses and Interlocks

The isolation valves on HPIN System lines serving systems in the containment have motor operators. The isolation valves may be closed to prevent any possible leakage from the containment if a leak occurs in the system outside of the containment.

(d) Redundancy and Diversity

The HPIN System is separated into two mechanically and electrically independent divisions. Each division has instrumentation, controls, and power sources which are separated and independent from each other. One division supplies emergency nitrogen to four ADS valve accumulators, and the other division supplies emergency nitrogen to the remaining four ADS valves. This level of redundancy is sufficient because only the initial LOCA depressurization requires more than four ADS valves, and the Class 1E accumulators have sufficient capacity for one valve operation at drywell design pressure and five valve actuations at normal drywell pressure.

The HPIN storage bottles are in two racks separated from each other. Additionally, in each rack there are two banks of two bottles each. One bank is in service and the second is in standby.

(e) Actuated Devices

Nitrogen is admitted to the system and the non-safety-related portion isolated by operating valves controlled by pressure switches in the HPIN System. These valves can also be operated from the main control room.

All isolation valves can be manually operated from the main control room. Each valve is provided with indicating position lights in the main control room which verify the open and closed positions of the valve.

(f) Separation

The HPIN System is separated into two divisions, each having storage bottles and racks and piping to the ADS accumulators.

EVN

Physical separation of Division ~~I~~ -A and Division ~~II~~ -B systems is obtained by closing valves which interconnect the divisions during normal operation.

Electrical separation is maintained by separate sensors and circuits independent of each other.

System chilled water flow rate and temperature can be checked by readout of locally mounted pressure and temperature gauges at the main control panel.

(h) Environmental Consideration

All components of the HECW System are selected in consideration of the normal and accident environment in which it must operate. The control equipment is seismically qualified and environmentally classified, as discussed in Sections 3.10 and 3.11.

(i) Operational Consideration

The HECW System operation is initiated in the control room by a manual master control switch. Once the system is started, it will continuously operate under all modes of plant operation to supply chilled water to the cooling coils.

Running lights, alarms, flow and temperature indicators, and valve position indicators are available in the control room for the operator to accurately monitor the HECW System operation. Chilled water pumps have running lights. A common trouble alarm is provided for each chiller unit. Surge tank high-high and low-low levels are alarmed. Motor-operated valves have position indicators. Chilled water flows have position indicators.

7.3.1.1.10 High Pressure Nitrogen Gas Supply System—Instrumentation and Controls

(1) System Identification

The High Pressure Nitrogen Gas Supply (HPIN) System provides compressed nitrogen of the required pressure to the ADS SRVs, the MSIVs (for testing only), instruments and pneumatically operated valves in the PCV and other nitrogen-using components in the reactor building (see P&ID in Figure 6.7-1 and the interconnection block diagram in Figure 7.3-10).

(2) Support Systems (Power Source)

The safety-related portion of the HPIN System is powered from the onsite Class 1E AC and DC systems. The safety-related portion is switched automatically to the standby AC power supply during a loss of normal power. The non-safety-related portion is connected to the normal AC power supply.

EVN

HPIN SYSTEM DIVISION-A IS POWERED FROM CLASS 1E DIVISION I AND HPIN SYSTEM DIVISION-B IS POWERED FROM CLASS 1E DIVISION II.

HPIN SYSTEM DIVISION-A IS POWERED FROM CLASS 1E DIVISION I AND HPIN SYSTEM DIVISION-B IS POWERED FROM CLASS 1E DIVISION II

the other. The system satisfies the components' nitrogen demands during all plant operation conditions (normal through faulted).

The safety-related grade portions of the HPIN are capable of being isolated from the nonsafety-related parts and retaining their function during LOCA-related and/or seismic events.

Pipe routing of Division ~~I~~ -A and Division ~~II~~ -B of theHPIN is kept separated by enough space so that a single fire, equipment dropping accident, strike from a single high energy whipping pipe, jet force from a single broken pipe, internally generated missile or wetting equipment with spraying water cannot prevent the other division from accomplishing its safety function. Separation is accomplished by spatial separation or by a reinforced concrete barrier, to ensure separation of each pneumatic division from any systems and components which belong to the other pneumatic division.

6.7.4 Inspection and Testing Requirements

Mandatory periodic inservice inspection of components, in accordance with ASME Section XI, will be conducted to ensure the capability and integrity of the system. Nitrogen quality shall be tested periodically to assure compliance with ANSI MC11.1.

The HPIN containment isolation valves are capable of being tested to assure their operational integrity by manual actuation of a switch located in the control room and by observation of associated position indication lights. Test and vent connections are provided at the containment isolation valves in order to verify their leaktightness. Operation of valves and associated equipment used to switch from the non-safety-related to the safety-related nitrogen supply can be tested to assure operational integrity by manual actuation of a switch located in the control room and by observation of associated position indication lights. Periodic tests of the check valves and accumulators shall be conducted to assure valve operability. Periodic testing of the safety relief valves, the accumulator check valve, and the relief valve if present, shall be conducted to confirm that the nitrogen leakage is within the assumed value of 28 liters per hour for each safety relief valve.

6.7.5 Instrumentation Requirements

A pressure sensor is provided for the safety-related nitrogen supply, and an alarm signals low nitrogen pressure.

A remote manual switch and open/closed position lights are provided in the control room for valve operation and position indication.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.13 HPIN No. 1

NRC COMMENT:

ITAAC item #6 requires each of two HPIN divisions to be powered from the respective Class 1E divisions. This requirement should be included in the HPIN description in SSAR Chapter 6.7.2 or appropriate section in SSAR Chapter 8.

GE RESPONSE:

GE concurs and will add this item to the HPIN description in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment. (See attached) (ver)

9.3.7.1.2 Power Generation Design Bases

The functions of the SAS are to:

(1) Provide a continuous supply of service air for general plant use.

(2) Be capable of supplying backup air to the IAS on an as-needed basis.

9.3.7.2 System Description

The SAS is designed to provide compressed air of suitable quality for non-safety-related functions.

The SAS provides compressed air for tank sparging, filter/demineralizer backwashing, air operated tools and other services requiring air of lower quality than that provided by the IAS. Breathing air requirements are provided by the SAS.

The SAS has two air compressors each sized to provide 50% of the peak air consumption. The compressors are of the oil-less type. The major service air users are listed in Table 9.3-3.
The SAS P&ID is shown on Figure 9.3-7
The SAS process quality requirements are listed below.

EUN

	Service Air
Pressure (design)	7.031 kg/cm^2
Dewpoint (°C)	no requirement

I The ~~IAS~~ SAS containment and penetration and associated isolation valves which are designed to Seismic Category I, ASME Code, Section III, Class 2, Quality Group B and Quality Assurance B requirements.

One of the two air compressors is selected as the lead unit which shall be operated during normal operation. The standby compressor will automatically start when the air pressure at the air receiver drops below the low pressure setpoint. As the air receiver pressure is returned to the normal range, the standby compressor is stopped and the lead unit kept in operation. The assignment for lead and standby air compressors shall be switched periodically. The pressure setpoints for these operational changes are adjustable, depending on air requirements that might exist.

Outside primary containment a manually-operated valve is kept closed and locked during normal plant operation. During refueling, the valve is opened to provide air inside containment. A check valve is provided inside the containment.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.11 SA No. 1

NRC COMMENT:

The SSAR does not reference the Figure 9.3.7, sheets 1 and 2, Service Air System in SSAR Chapter 9.3.7.

GE RESPONSE:

GE concurs and will include this reference in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment. (See attached)

ver

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.9 RSW No. 4

NRC COMMENT:

SSAR Section 9.2.15.1.2, change paragraph to read as follows: "... shutdown; (d) testing; and (3) loss of preferred power."

GE RESPONSE:

GE concurs and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment.

ver

(and/or LOPP) Add in 3 places

Table 2.11.9 Reactor Service Water System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the RSW System is as shown on Figure 2.11.9.	1. Inspections of the as-built system will be conducted.	1. The as-built RSW System conforms with the basic configuration shown in Figure 2.11.9.
2. The ASME Code components of the RSW System retain their pressure boundary integrity under internal pressures that will be experienced during service.	2. A hydrostatic test will be conducted on those Code components of the RSW System required to be hydrostatically tested by the ASME Code.	2. The results of the hydrostatic test of the ASME Code components of the RSW System conform with the requirements in the ASME Code, Section III.
3. On a LOCA signal, any closed valves for standby heat exchangers are automatically opened.	3. Using simulated LOCA signals, tests will be performed on standby heat exchanger inlet and outlet valves.	3. Upon receipt of simulated LOCA signals, the standby heat exchanger inlet and outlet valves open.
4. For each division of RSW, the heat exchanger inlet and outlet valves close upon receipt of a signal indicating Control Building flooding in that division.	4. Using simulated signals, tests will be conducted on the heat exchanger inlet and outlet valves.	4. The heat exchanger inlet and outlet valves close upon receipt of a signal indicating Control Building flooding in that division.
5. Each of the three RSW divisions is powered by its respective Class 1E division. In the RSW System, independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	5. a. Tests will be performed on the RSW System by providing a test signal in only one Class 1E division at a time. b. Inspections of the as-installed Class 1E divisions in the RSW System will be performed.	5. a. The test signal exists only in the Class 1E Division under test in the RSW System. b. Physical separation or electrical isolation exists between Class 1E divisions in the RSW System. Physical separation or electrical isolation exists between Class 1E divisions and non-Class 1E equipment.
6. Each mechanical division of the RSW System (Divisions A, B, C) is physically separated.	6. Inspections of the as-built system will be performed.	6. Each mechanical division of the RSW System is physically separated from other mechanical divisions of the RSW System by structural and/or fire barriers.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.9 RSW No. 3

NRC COMMENT:

Table 2.11.9, change "LOCA" to "LOCA and/or LOPP" for all three parts across the page.

GE RESPONSE:

GE concurs and will include these changes in the revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.9 RSW No. 2

NRC COMMENT:

The CDM describes valves F003 and F005 to have active safety-related functions. In Table 3.9-8 of SSAR, they are classified as "PASSIVE." Resolve this discrepancy.

GE RESPONSE:

The CDM is correct and GE concurs that the SSAR entry needs to be corrected. The necessary changes will be included in the next amendment.

PROPOSED CHANGES

CDM: None

SSAR: Reclassify valves as ACTIVE on Table 3.9-8.

JCr

2.11.9 Reactor Service Water System

Design Description

The Reactor Service Water (RSW) System removes heat from the Reactor Building Cooling Water (RCW) System and rejects this heat to the Ultimate Heat Sink (UHS). The portions of the RSW System that are in the Control Building are within the Certified Design. Those portions of the RSW System that are outside the Control Building are not in the Certified Design. Figure 2.11.9a shows the basic system configuration and scope within the Certified Design. Figure 2.11.9b shows the RSW System control interfaces.

The RSW System provides cooling water flow to either two or three of the RCW System heat exchangers in each division. On a loss-of-coolant accident [illegible] signal, any closed valves for standby heat exchangers are automatically opened and cooling flow is provided to all three heat exchangers in each division.

and/or loss of preferred power (LOCA and/or LOPP)

For each division of the RSW System, the heat exchanger inlet and outlet valves close upon receipt of a signal indicating Control Building flooding in that division.

The RSW System is classified as Seismic Category I and ASME Code Section III, Class 3 and consists of three separate safety-related divisions.

Each of the three RSW divisions is powered by its respective Class 1E division. In the RSW System, independence is provided between Class 1E divisions, and also between the Class 1E divisions and non-Class 1E equipment. Each mechanical division of the RCW system (Divisions A, B, C) is physically separated from the other divisions.

The RSW System has the following main control room (MCR) displays and controls: control and status displays for the valves shown on Figure 2.11.9a. The RSW System components with status displays and control interfaces with the Remote Shutdown System (RSS) are identified in Figure 2.11.9a.

The motor-operated valves (MOVs) shown on Figure 2.11.9a all have active safety-related functions to open and close under differential pressure and fluid flow conditions.

Interface Requirements

Part of the RSW System that are not within the Certified Design shall meet the following requirements:

(1) Design features shall be provided to limit the maximum flood height to 5.0 meters in each RCW heat exchanger room.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.9 RSW No. 1

NRC COMMENT:

Page 2.11.9-1, second paragraph, and page 2.11.9-2, item (3): change "…loss-of-coolant accident (LOCA) signal, … ." to "… loss-of-coolant accident and/or loss of preferred power (LOCA and/or LOPP) signal, … ."

GE RESPONSE:

GE concurs and will include these changes in the revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

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Table 2.11.6 HVAC Emergency Cooling Water System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. Except for the connections to the chemical addition tank, each mechanical division of the HECW System (Divisions A, B, C) is physically separated from the other divisions.	6. Inspections of the as-built HECW System will be conducted.	6. Each mechanical division of the HECW System is physically separated from the other mechanical divisions of the HECW System by structural and/or fire barriers, with the exception connections to the chemical addition tank.
7. Main control room displays and controls provided for the HECW System are as defined in Section 2.11.6.	7. Inspections will be performed on the main control room displays and controls for the HECW System.	7. Displays and controls exist or can be retrieved in the main control room as defined in Section 2.11.6.
8. CVs designated in Section 2.11.6 as having an active safety-related function open, close, or both open and close under system pressure, fluid flow, and temperature conditions.	8. Tests of installed valves for opening, closing, or both opening and closing, will be conducted under system preoperational pressure, fluid flow, and temperature conditions.	8. Based on the direction of the differential pressure across the valve, each CV opens, closes, or both opens and closes, depending upon the valve's safety functions.
9. The pneumatic-operated valves shown in Figures ~~2.11.6a and 2.11.6b~~ 2.11 6a and 2.11.6b fail as follows in the event that either electric power to the valve actuating solenoid is lost or pneumatic pressure to the valve is lost: the differential pressure control valves fail closed, and the flow control valves to the cooling coils fail open.	9. Tests will be performed on the as-built valves by initiating loss of pneumatic pressure and power to the actuating solenoids.	9. The pneumatic actuated valves listed below fail as specified when either electric power to the valve actuating solenoid is lost or pneumatic pressure to the valve is lost: the differential pressure control valves fail closed, and the flow control valves to the cooling coils fail open.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.6 HECW No. 2

NRC COMMENT:

ITAAC 9, the Design Commitment Figures 2.11.3a and 2.11.3b should be 2.11.6a and 2.11.6b.

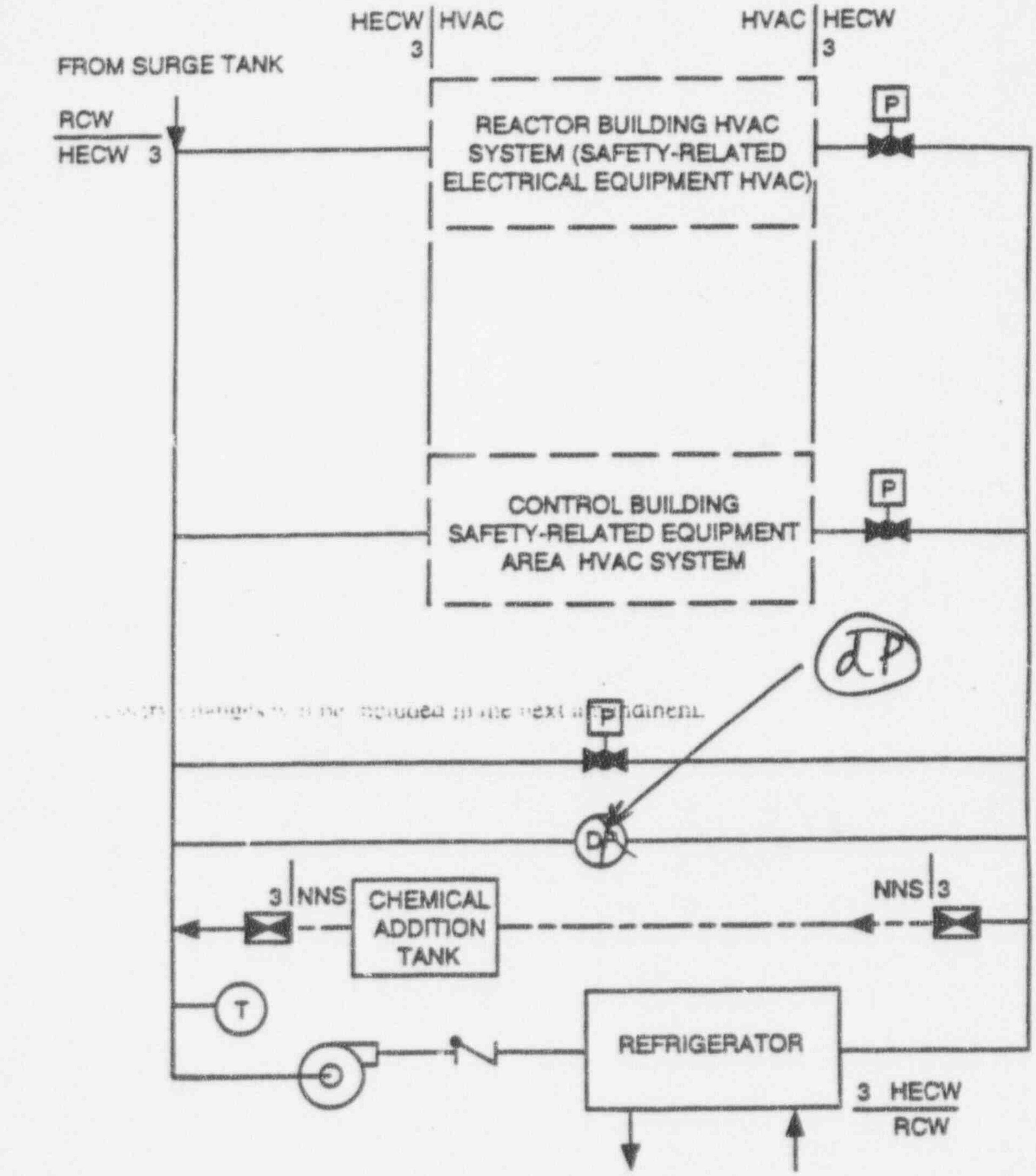
GE RESPONSE:

GE concurs and will include these changes in the revision of 25A5447.

PROPOSED CHANGES

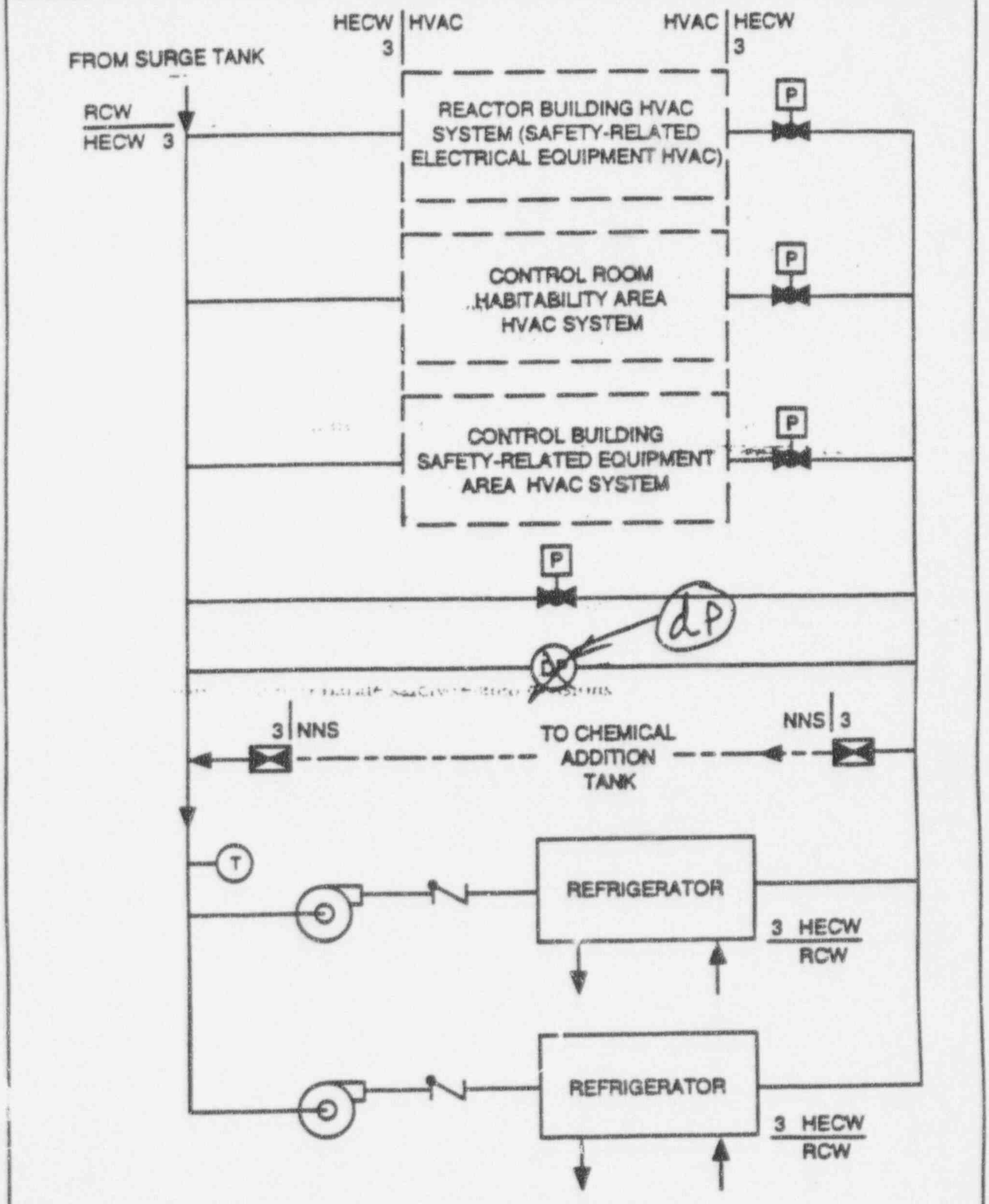
CDM: Per NRC comment; see attached.

SSAR: None



NOTES:
1. DIVISION A IS POWERED FROM CLASS 1E, DIVISION I.

Figure 2.11.6a HVAC Emergency Cooling Water System (HECW-A)



NOTES:
1. THIS FIGURE SHOWS ONE OF TWO SIMILAR DIVISIONS. DIVISIONS B AND C ARE POWERED FROM CLASS 1E, DIVISION II AND III, RESPECTIVELY.

Figure 2.11.6b HVAC Emergency Cooling Water System (HECW-B and C)

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.6 HECW No. 1

NRC COMMENT:

On Figures 2.11.6a and 2.11.6b, DP should be dP.

GE RESPONSE:

GE concurs and will include these changes in the revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.4 TBCWS No. 1

NRC COMMENT:

Figure 2.11.4 shows the surge tank is shared with the HVAC Normal Cooling Water System (HNCW). Whereas on SSAR Figure 9.2-6a, the surge tank is shared with the HNCW and the Hot Water Heating (HWH) Systems. Resolve this discrepancy.

Also, the HWH discussion in section 9.2 was deleted and should be reinserted.

GE RESPONSE:

GE does not believe there is a discrepancy between Figure 2.11.4 and the SSAR Figure 9.2.6a. With NRC concurrence, GE elected to not address the HWH system in Tier 1/CDM. (See Table of Contents for 25A5447 under entry 2.11.16.) Consequently, it would not be appropriate to show this interface on Figure 2.11.4. The SSAR Figure 9.2-6a is correct and will not be modified. Note: Tier 1/CDM is not exclusive; just because the HWH connection is not shown on Figure 2.11.4 does not preclude the actual facility having this feature.

GE does not believe there was ever an SSAR 9.2 entry on the HWH. This system is discussed in SSAR Section 1.2.2.12.16; this is the extent of SSAR HWH treatment.

PROPOSED CHANGES

CDM: None

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.3 RCW No. 2d

NRC COMMENT:

F175, three valves, one for each system.

In accordance with the P&IDs and the CDM figures, these are MOVs supplying cooling water to the fuel pool cooling HX room coolers. Table 3.9-8 of the SSAR describes these valves as "cooling water supply to RHR system HX pressure relief valve." Resolve this discrepancy.

Also, both P&IDs and CDM figures showed a total of two valves, one for RCW-A and the second for RCW-B. Resolve this discrepancy.

GE RESPONSE:

GE believes the CDM figures are correct. The valves are not numbered but Figures 2.11.3a, b show an RCW valve admitting flow to the FPC heat exchanger and room coolers. Consequently, no CDM changes are required.

GE concurs that the Table 3.9-8 entry for valves F175 is incorrect and the necessary changes will be included in the next SSAR amendment.

Additional Response

In addtion, there are duplicate valves F175 on two divisions ~~[illegible]~~ of R~~S~~cW that GE will correct. This change will include a co-ordinated entry in Table 3.9-8.

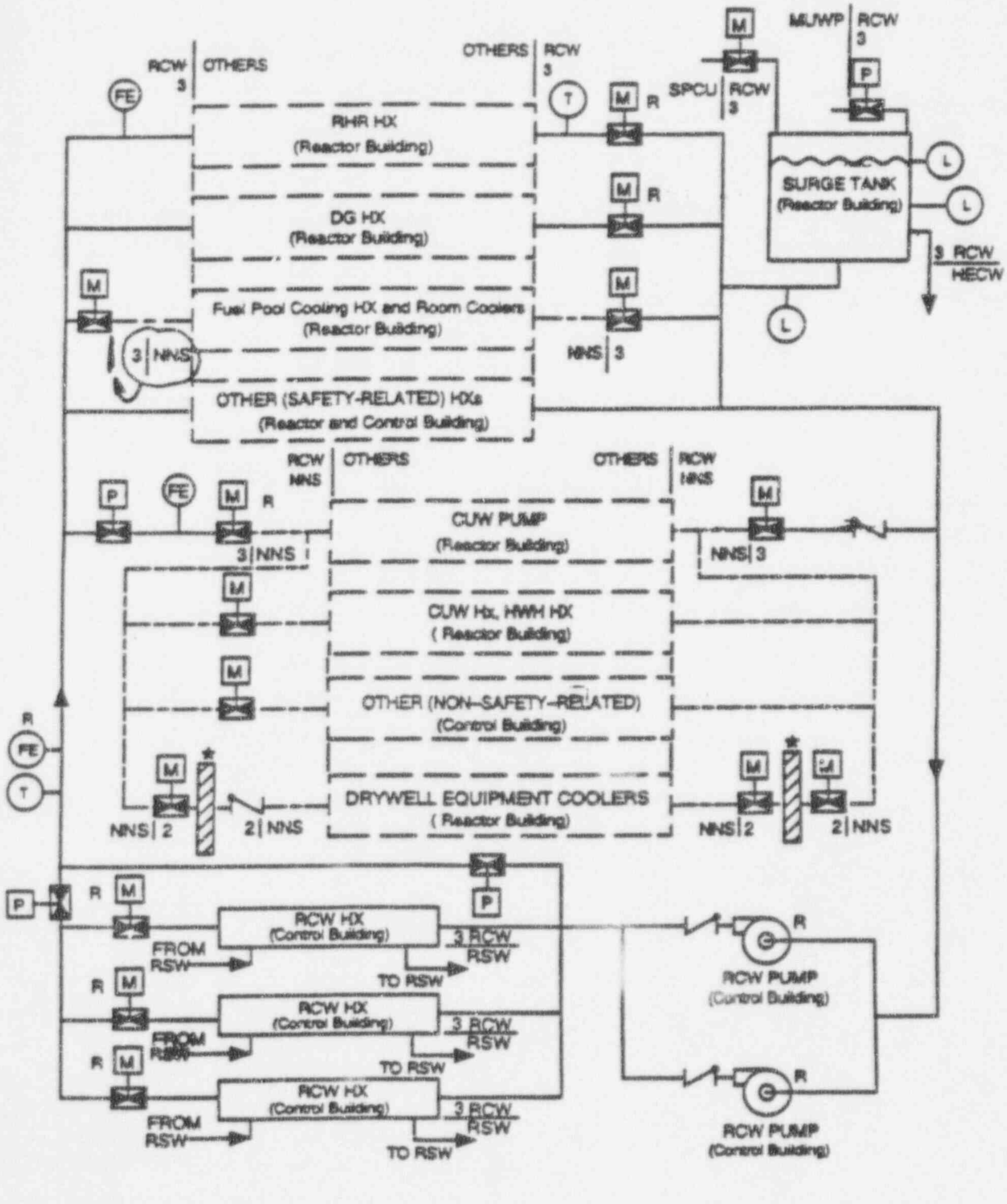
PROPOSED CHANGES

CDM: None

SSAR: Table 3.9-8 corrections and P&ID elimination of duplicate F175 valves.

verif

MOVE THE 3|NNS ITC. OVER



NOTES:

1. THIS DIVISION IS POWERED FROM CLASS 1E DIVISION II, EXCEPT FOR THE CONTAINMENT OUTBOARD ISOLATION VALVE, WHICH IS POWERED FROM DIVISION III.

★ =PRIMARY CONTAINMENT

Figure 2.11.3b Reactor Building Cooling Water System (RCW-B)

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.3 RCW No. 1

NRC COMMENT:

Figure 2.11.3b – relocate piping class break immediately after the MOV before the Fuel Pool Cooling HX.

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comments; see attached.

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.2 MUWC No. 4

NRC COMMENT:

SSAR Section 5.2.9.2, Item (9)

- Add to the first sentence, "radwaste building control room, and Remote Shutdown System."
- Add to the second sentence, "and low water level shall be alarmed in the main control room."

GE RESPONSE:

GE concurs and will include these changes in the next amendment. Ver

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment.

Table 2.11.2 Makeup Water (Condensate) (MUWC) System

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The basic configuration of the MUWC System is as shown on Figure 2.11.2.	1. Inspections of the as-built system will be conducted.	1. The as-built MUWC System conforms with the basic configuration on Figure 2.11.2.
~~2~~ 3. Each of the four MUWC System water level sensors is powered from the respective divisional Class 1E power supply. In the MUWC System, independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	~~2~~ 3. a. Tests will be performed on the MUWC System by providing a test signal in only one Class 1E division at a time. b. Inspections of the as-built Class 1E divisions in the MUWC System will be performed.	~~2~~ 3. a. The test signal exists only in the Class 1E division under test in the MUWC System. b. In the MUWC System, physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class 1E equipment.
~~3~~ 4. Main control room displays provided for the MUWC System are as defined in Section 2.11.2	~~3~~ 4. Inspections will be performed on the main control room displays for the MUWC System.	~~3~~ 4. Displays exist or can be retrieved in the main control room as defined in Section 2.11.2.
~~4~~ 5. RSS displays provided for the MUWC System are as defined in Section 2.11.2.	~~4~~ 5. Inspections will be performed on the RSS displays for the MUWC System.	~~4~~ 5. Displays exist on the RSS as defined in Section 2.11.2.
2. The ASME Code components of the ~~[illegible]~~ MUWC System retain their pressure boundary integrity under internal pressures that will be experienced during service.	2. A hydrostatic test will be conducted on those Code components of the ~~[illegible]~~ MUWC System required to be hydrostatically tested by the ASME Code.	2. The results of the hydrostatic test of the ASME Code components of the ~~[illegible]~~ MUWC System conform with the requirements in the ASME Code, Section III.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.2 MUWC No. 3

NRC COMMENT:

Revise Table 2.11.2 to add the boilerplate ITAAC on hydrostatic testing.

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.2 MUWC No. 2

NRC COMMENT:

Revise Figure 2.11.2 to incorporate the following:

- 3 pumps should be shown, or indicate that this is 1 of 3 pumps.
- A note should be added to Figure 2.11.2 to indicate that RCIC, HPCF, and SPCU take suction from the CST.
- The extraneous piping shown on Figure 2.11.2 should be deleted.

GE RESPONSE:

GE does not concur that any of these NRC comments warrant changes to Figure 2.11.2:

1) The number of MUWC pumps is not of safety significance and does not warrant definition in the CDM.

2) The HPCF suction connection is shown on this figure; the other systems take suction downstream from this point and are correctly shown on CDM Figure 2.4.2.a.

3) GE does not believe there is any "extraneous" piping on Figure 2.11.2.

Consequently, GE proposes no CDM changes in response to this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.2 MUWC No. 1

NRC COMMENT:

Add the following statement to the CDM: "The Condensate Storage Tank (CST) capacity includes sufficient water for operation of the RCIC System during station blackout." Also, it should be verified in an ITAAC.

GE RESPONSE:

GE believes the issue of ABWR station blackout is adequately addressed in the 2.4.4 RCIC CDM entry and need not be addressed in Section 2.11.2. [See response to NRC Comment PDST No. 4] Consequently, GE proposes no changes to 2.11.2 in response to this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.1 MUWP No. 4

NRC COMMENT:

SSAR Table 9.2-3: combine the two sections on pages 9.2-50 and 9.2-51 into a single unit.

GE RESPONSE:

Ver

GE concurs and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment.

2.11.1 Makeup Water (Purified) System

Design Description

The Makeup Water (Purified) (MUWP) System is a distribution system with components located throughout the plant. The MUWP provides demineralized makeup water to the condensate storage tank, the surge tanks which are shared by the Reactor Building Cooling Water System and Heating, Ventilation, and Air Conditioning Emergency Cooling Water System and other plant systems.

The MUWP System consists of distribution piping and valves. Makeup water is supplied to the system by the Makeup Water Preparation System.

The MUWP System is classified as non-safety-related with the exception of the primary containment isolation function which is safety-related. The primary containment pipe penetration and isolation valves are classified as Seismic Category I and ASME Code Class 2.

The outboard containment isolation valve is a manual valve locked closed during ~~normal operation~~. The inboard containment isolation valve is a check valve (CV) that has an active safety-related function to close under system pressure, fluid flow, and temperature conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the MUWP System.

standby, hot standby and power operation.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.11.1 MUWP No. 2

NRC COMMENT:

Section 2.11.1, fourth paragraph, states that the outboard containment isolation valve is locked closed during normal operation. SSAR Section 9.2.10.2 item 7 states "...locked closed during standby, not standby and power operation." This requires clarification.

GE RESPONSE:

GE concurs that:

1) SSAR Section 9.2.10.2 item 7 has a typographical error ("hot" not "not") and this will be corrected in the next amendment. Ver

2) CDM Section 2.11.1 should be changed to be consistent with the SSAR.

PROPOSED CHANGES

CDM: Per attached markup.

SSAR: Correct typographical error in next amendment.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.14.4 SGTS No. 1

NRC COMMENT:

First paragraph: The sentence "SGTS consists of two redundant divisions." has been repeated; delete one.

GE RESPONSE:

GE concurs and will make this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

Table 2.12.17 Lighting and Servicing Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
10. Class 1E or Associated Class 1E lighting distribution system equipment is identified according to its Class 1E division and is located in Seismic Category I structures, and in its respective divisional areas (except for features in design commitment No. 3, 4 and 6).	10. Inspections of the as-built Class 1E and Associated Class 1E lighting systems will be conducted.	10. The as-built Class 1E and Associated Class 1E lighting distribution system equipment is identified according to its Class 1E division and is located in Seismic Category I structures, and in its respective divisional areas (except for features in design commitment No. 3, 4 and 6).
11. Class 1E or Associated Class 1E lighting system cables and raceways, are identified according to their Class 1E division.	11. Inspections of the as-built Class 1E and Associated Class 1E lighting system cables and raceways will be conducted.	11. The as-built Class 1E and Associated Class 1E lighting system cables and raceways are identified according to their Class 1E division.
12. Class 1E or Associated Class 1E lighting system cables are routed in their respective divisional raceways and in Seismic Category I structures.	12. Inspections of the as-built Class 1E and Associated Class 1E lighting system cables and raceways will be conducted.	12. The as-built Class 1E and Associated Class 1E lighting system cables are routed in their respective divisional raceways and in Seismic Category I structures.
13. Associated Class 1E DC emergency lighting system cables are not routed with any other cables and are specifically identified as DC lighting.	13. Inspections of the as-built Associated Class 1E DC emergency lighting system cables will be conducted.	13. Associated Class 1E DC emergency lighting system cables are not routed with any other cables and are specifically identified as DC lighting.

Table 2.12.17 Lighting and Servicing Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
7. Each Class 1E guide lamp unit is a self-contained, battery pack unit containing a rechargeable battery with a minimum 8-hour capacity. The Class 1E guide lamp units are supplied AC power from the same power source that supplies the Associated Class 1E AC standby lighting system in the area in which they are located.	7. a. Inspections of the as-built Class 1E guide lamp units will be conducted. b. Tests on the as-built Class 1E guide lamp units will be conducted by providing a test signal in only one Class 1E division at a time.	7. a. The Class 1E guide lamp units are self-contained, battery pack units containing a rechargeable battery with a minimum 8-hour capacity. b. The Class 1E guide lamp units are supplied AC power from the same power source that supplies the Associated Class 1E AC standby lighting system in the area in which it is located. The Class 1E guide lamp units are turned on when the Associated Class 1E AC standby lighting system in the area in which they are located is lost.
8. Lighting circuits, excluding lighting fixtures, that are connected to a Class 1E power source are identified as Associated Class 1E circuits and treated as Class 1E circuits.	8. Inspections of the Associated Class 1E lighting circuits will be conducted.	8. The as-built Associated Class 1E lighting circuits are identified as Associated Class 1E circuits and treated as Class 1E circuits.
9. In the LSPS, independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	9. a. Tests on the LSPS will be conducted by providing a test signal in only one Class 1E division at a time. b. Inspections of the as-built Class 1E divisions in the LSPS will be conducted.	9. a. A test signal exists in only the Class 1E division under test in the LSPS. b. In the LSPS, physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class 1E equipment.

nc 7/13

Table 2.12.17 Lighting and Servicing Power Supply

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the LSPS is described in Section 2.12.17.	1. Inspections of the as-built system will be conducted.	1. The as-built LSPS conforms with the basic configuration described in Section 2.12.17.
2. Each division of Associated ~~Class 1E~~ AC standby lighting is supplied power from its respective Class 1E division.	2. Tests on the Associated ~~Class 1E~~ AC standby lighting will be conducted by providing a test signal in only one Class 1E division at a time.	2. The as-built Associated ~~Class 1E~~ AC standby lighting is supplied power only from its respective Class 1E division.
3. The Associated ~~Class 1E~~ AC standby lighting in the MCR is supplied from Divisions II and III.	3. Tests on the Associated ~~Class 1E~~ AC standby lighting will be conducted by providing a test signal in only one Class 1E division at a time.	3. The as-built Associated ~~Class 1E~~ AC standby lighting in the MCR is supplied from Divisions II and III.
4. The Associated ~~Class 1E~~ AC standby lighting in the Division IV battery room and other Division IV instrumentation and control areas is supplied from Division II.	4. Tests on the Associated ~~Class 1E~~ AC standby lighting will be conducted by providing a test signal in only one Class 1E division at a time.	4. The as-built Associated ~~Class 1E~~ AC standby lighting in the Division IV battery room and other Division IV instrumentation and control areas is supplied from Division II.
5. Each division of Associated ~~Class 1E~~ DC emergency lighting is supplied power from its respective Class 1E division.	5. Tests on the Associated ~~Class 1E~~ DC emergency lighting will be conducted by providing a test signal in only one Class 1E division at a time.	5. The as-built Associated ~~Class 1E~~ DC emergency lighting is supplied power from its respective Class 1E division.
6. The Associated ~~Class 1E~~ DC emergency lighting in the MCR is supplied from Divisions II and III.	6. Tests on the Associated ~~Class 1E~~ DC emergency lighting will be conducted by providing a test signal in only one Class 1E division at a time.	6. The as-built Associated ~~Class 1E~~ DC emergency lighting in the MCR is supplied from Divisions II and III.

The guide lamp light system serves stairways, exit routes, and major control areas (MCR and Remote Shutdown System (RSS) areas). Each Class 1E guide lamp unit is a self-contained battery pack unit containing a rechargeable battery with a minimum 8-hour capacity. The Class 1E guide lamp units are supplied AC power from the same power source that supplies the Associated ~~Class 1E~~ AC standby lighting system in the area in which they are located. The non-Class 1E guide lamp units in non-safety-related plant areas are supplied power by the non-Class 1E system.

Lighting circuits, excluding lighting fixtures, that are connected to a Class 1E power source are identified as Associated ~~Class 1E~~ circuits and are treated as Class 1E circuits. In the LSPS, independence is provided between Class 1E divisions, and also between Class 1E divisions and non-Class 1E equipment.

Class 1E or Associated ~~Class 1E~~ lighting distribution system equipment is identified according to its Class 1E division and is located in Seismic Category I structures, and in its respective divisional areas.

Class 1E or Associated ~~Class 1E~~ lighting system cables and raceways are identified according to their Class 1E division. Class 1E or Associated ~~Class 1E~~ lighting system cables are routed in their respective divisional raceways and in Seismic Category I structures. Associated ~~Class 1E~~ DC emergency lighting system cables are not routed with any other cables and are specifically identified as DC lighting.

Class 1E equipment is classified as Seismic Category I.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.17 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Lighting and Servicing Power Supply.

2.12.17 Lighting and Servicing Power Supply

Design Description

The Lighting and Servicing Power Supply (LSPS) consists of multiple lighting systems and a non-Class 1E service power supply system. The non-Class 1E service power supply system supplies power to non-Class 1E loads which are not required for plant power operation.

There are four lighting systems: the normal alternating current (AC) lighting system, the standby AC lighting system, the emergency direct current (DC) lighting system, and the guide lamp lighting system.

The normal AC lighting system provides lighting needed for operation, inspection, and repairs during normal plant operation in areas containing non-safety related equipment. The normal lighting system is part of the plant's non-safety-related systems and is supplied by the non-Class 1E power system buses.

The AC standby lighting system is comprised of the non-Class 1E AC standby lighting system and the Associated ~~Class 1E~~ AC standby lighting system. The non-Class 1E AC standby lighting system serves both safety-related and non-safety-related areas and their passageways and stairwells and is powered by the plant investment protection (PIP) buses. The Associated ~~Class 1E~~ AC standby lighting system serves the safety-related divisional areas and the passageways and stairwells leading to the divisional areas.

Each division of Associated ~~Class 1E~~ AC standby lighting is supplied power from its respective Class 1E division (Division I, II, and III). The Associated ~~Class 1E~~ AC standby lighting in the main control room (MCR) is supplied from divisions II and III. The Associated ~~Class 1E~~ standby AC lighting in the division IV battery room and other division IV instrumentation and control areas is supplied from division II.

The DC emergency lighting system is comprised of the non-Class 1E DC emergency lighting system and the Associated ~~Class 1E~~ DC emergency lighting system. The DC emergency lighting system provides DC backup lighting, when AC lighting is lost, until the normal or standby lighting systems are energized. The non-Class 1E DC emergency lighting system supplies the lighting needed in plant areas containing non-safety-related equipment and is supplied by the non-Class 1E DC system. The Associated ~~Class 1E~~ DC emergency lighting system supplies the lighting needed in plant areas containing safety-related equipment.

Each division of Associated ~~Class 1E~~ DC emergency lighting is supplied by power from its respective Class 1E division (Divisions I, II, III, and IV). The Associated ~~Class 1E~~ DC emergency lighting in the MCR is supplied from divisions II and III.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.17 LIGHTING AND SERVICE POWER No. 6

NRC COMMENT:

SSAR and CDM use different terminologies. SSAR refers to "Class 1E Associated lighting" whereas CDM refers to "Associated Class 1E lighting." Clarification should be provided – specifically, use of associated is acceptable when discussing circuits, however, GE should be consistent.

GE RESPONSE:

GE concurs that a consistent term should be used and proposes to change the SSAR and CDM by deleting the "Class 1E" and using lower-case "associated."

PROPOSED CHANGES

CDM: Per attached markup of Section 2.12.17.

SSAR: Changes to support proposed approach. GE ~~to~~ ~~walk~~ ~~through~~.

VER

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.16 COMMUNICATION No. 6 (Continued)

GE RESPONSE: (Continued)

SSAR Section 9.5.2.2.1 lists plant areas where paging equipments (handsets and speakers) are located. These areas are at or within various buildings as follows:

a) Reactor Building (R/B) (includes main control room, fuel replacement area, periphery of control rods hydraulic units, elevators)

b) Turbine Building (T/B) (includes turbine operation area, feed water pump room, elevators)

c) Service Building (S/B) includes electrical equipment room

d) Exteriors of plant buildings (includes switching station)

The SSAR Figure 9.5-2 shows all four areas listed above. The figure erroneously shows Hx/B (heat exchanger building) which will be deleted in the next SSAR update. With this update the SSAR text and Figure 9.5-2 will be consistent.

Sound-Powered Telephone System Location and Label

As described in Section 9.5.2.2.2 the sound-powered patch panel is located outside the main control room. The portable telephone units are to be provided and located by the COL applicant. Thus Figure 9.5-2 shows only a sketch outline of the sound-powered telephone system. The sub-caption "communication facilities board for maintenance" will be revised in the next SSAR amendment to read "sound-powered communication facilities board."

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.16 COMMUNICATION No. 6

NRC COMMENT:

Paging Facilities SSAR 9.5.2.2.1, Figure 9.5-2 lists paging equipment as T/B, R/B, Hx/B, S/B, Switching Station and outdoors. Acronyms are not listed for T/B, Hx/B, S/B and locations are not consistent with the ITAAC or SSAR descriptions. Locations are not shown on SSAR Figure 9.5.2 for the sound powered phone system and system is labeled as the communication facilities board for maintenance.

GE RESPONSE:

GE proposes to make the following SSAR changes in response to this NRC comment. No CDM changes are proposed.

Paging Facilities Locations/Acronyms

Acronyms for T/B, R/B and S/B will be added to the SSAR Table of Contents starting on page iv.

ITAAC is an upper level (Tier 1) CDM and as such provides only a broad description ("buildings and outside areas") for the paging facilities locations. (No specific building locations are necessary to be identified nor they are listed in the ITAAC.)
(Continued on next page…)

PROPOSED CHANGES

CDM: None

SSAR: Per above resonse.

UCR

Table 2.12.14 Vital AC Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
8. Class 1E Vital AC Power Supply system distribution panels are rated to withstand fault currents for the time required to clear the fault from its power source.	8. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed.	8. Analyses for the as-built Class 1E Vital AC Power Supply system distribution panels exist and conclude that the current capacities of the distribution panels, exceed their analyzed fault currents for the time required, as determined by the circuit interrupting device coordination analyses, to clear the fault from its power source.
9. Class 1E Vital AC Power Supply system distribution panel circuit breakers and fuses are rated to interrupt fault currents. (circuit breakers and fuses)	9. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed.	9. Analyses for the as-built Class 1E Vital AC Power Supply distribution system exist and conclude that the analyzed fault currents do not exceed the distribution system circuit breakers and fuses interrupt capabilities, as determined by their nameplate ratings.
10. Class 1E Vital AC Power Supply system interrupting devices are coordinated so that the circuit interrupter closest to the fault opens before other devices.	10. Analyses for the as-built Class 1E distribution system to determine circuit interrupting device coordination will be performed.	10. Analyses for the as-built Class 1E Vital AC Power Supply system circuit interrupting device coordination exist and conclude that the analyzed circuit interrupter closest to the fault will open before other devices.
11. Class 1E Vital AC Power Supply system cables are sized to supply their load requirements.	11. Analyses for the as-built Class 1E distribution system cables to determine their load requirements will be performed.	11. Analyses for the as-built Class 1E Vital AC Power Supply system cables exist and conclude that the capacities of the distribution system cables exceed, as determined by their cable ratings, their analyzed load requirements.

Table 2.12.15 Instrument and Control Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
8. Class 1E Instrument and Control Power Supply system distribution panel circuit breakers and fuses are rated to interrupt fault currents.	8. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed. (circuit breakers and fuses)	8. Analyses for the as-built Class 1E Instrument and Control Power Supply distribution system exist and conclude that the analyzed fault currents do not exceed the distribution system circuit breakers and fuses interrupt capabilities, as determined by their nameplate ratings.
9. Class 1E Instrument and Control Power Supply system interrupting devices are coordinated so that the circuit interrupter closest the fault opens before other devices.	9. Analyses for the as-built Class 1E distribution system to determine circuit interrupting device coordination will be performed.	9. Analyses for the as-built Class 1E Instrument and Control Power Supply system circuit interrupting device coordination exist and conclude that the analyzed circuit interrupter closest to the fault will open before other devices.
10. Class 1E Instrument and Control Power Supply system cables are sized to supply their load requirements.	10. Analyses for the as-built Class 1E distribution system cables to determine their load requirements will be performed.	10. Analyses for the as-built Class 1E Instrument and Control Power Supply system cables exist and conclude that the capacities of the distribution system cables exceed, as determined by their cable ratings, their analyzed load requirements.
11. Class 1E Instrument and Control Power Supply system cables are rated to withstand fault currents for the time required to clear the fault from its power source.	11. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed.	11. Analyses for the as-built Class 1E Instrument and Control Power Supply system cables exist and conclude that the distribution system cable current capacities exceed their analyzed fault currents for the time required, as determined by the circuit interrupting device coordination analyses, to clear the fault from its power source.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.15 I&C POWER No. 3

NRC COMMENT:

Comment No. 2 also applies to Design Commitment No. 9 and the related tests and acceptance criteria. Unless the appropriate types of interrupting devices (typically fuses) are selected, this design requirement can not be met.

GE RESPONSE:

GE concurs and will modify item 9 in the next revision of 25A5447. (Same change has also been applied to Table 2.12.14, item No. 10.)

PROPOSED CHANGES

CDM: See attached markups.

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.15 I&C POWER No. 2

NRC COMMENT:

Page 2.12.15-1, last paragraph-Selectively between interrupting devices is required; however this is difficult or almost impossible to achieve between molded-case circuit breakers, since their instantaneous trips are not adjustable. Figure 2.12.15 needs to be revised to employ other types of interrupting devices or this requirement needs to be eliminated or a disclaimer added.

GE RESPONSE:

GE proposes to address this NRC concern by modification of the circuit breaker definition provided in CDM Appendix A. See markup attached to response to comment No. 1 Section 2.12.15..

PROPOSED CHANGES

CDM: Per markup of page A-4 attached to response to comment No. 1, Section 2.12.15.

SSAR: None

Table 2.12.14 Vital AC Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
8. Class 1E Vital AC Power Supply system distribution panels are rated to withstand fault currents for the time required to clear the fault from its power source.	8. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed.	8. Analyses for the as-built Class 1E Vital AC Power Supply system distribution panels exist and conclude that the current capacities of the distribution panels, exceed their analyzed fault currents for the time required, as determined by the circuit interrupting device coordination analyses, to clear the fault from its power source.
9. Class 1E Vital AC Power Supply system distribution panel circuit breakers and fuses are rated to interrupt fault currents.	9. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed.	9. Analyses for the as-built Class 1E Vital AC Power Supply distribution system exist and conclude that the analyzed fault currents do not exceed the distribution system circuit breakers and fuses interrupt capabilities, as determined by their nameplate ratings.
(circuit breakers and fuses) 10. Class 1E Vital AC Power Supply system interrupting devices are coordinated so that the circuit interrupter closest to the fault opens before other devices.	10. Analyses for the as-built Class 1E distribution system to determine circuit interrupting device coordination will be performed.	10. Analyses for the as-built Class 1E Vital AC Power Supply system circuit interrupting device coordination exist and conclude that the analyzed circuit interrupter closest to the fault will open before other devices.
11. Class 1E Vital AC Power Supply system cables are sized to supply their load requirements.	11. Analyses for the as-built Class 1E distribution system cables to determine their load requirements will be performed.	11. Analyses for the as-built Class 1E Vital AC Power Supply system cables exist and conclude that the capacities of the distribution system cables exceed, as determined by their cable ratings, their analyzed load requirements.

Table 2.12.15 Instrument and Control Power Supply (Continued)

	Inspections, Tests, Analyses and Acceptance Criteria	
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
8. Class 1E Instrument and Control Power Supply system distribution panel circuit breakers and fuses are rated to interrupt fault currents.	8. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed.	8. Analyses for the as-built Class 1E Instrument and Control Power Supply distribution system exist and conclude that the analyzed fault currents do not exceed the distribution system circuit breakers and fuses interrupt capabilities, as determined by their nameplate ratings.
9. Class 1E Instrument and Control Power Supply system interrupting devices (circuit breakers and fuses) are coordinated so that the circuit interrupter closest the fault opens before other devices.	9. Analyses for the as-built Class 1E distribution system to determine circuit interrupting device coordination will be performed.	9. Analyses for the as-built Class 1E Instrument and Control Power Supply system circuit interrupting device coordination exist and conclude that the analyzed circuit interrupter closest to the fault will open before other devices.
10. Class 1E Instrument and Control Power Supply system cables are sized to supply their load requirements.	10. Analyses for the as-built Class 1E distribution system cables to determine their load requirements will be performed.	10. Analyses for the as-built Class 1E Instrument and Control Power Supply system cables exist and conclude that the capacities of the distribution system cables exceed, as determined by their cable ratings, their analyzed load requirements.
11. Class 1E Instrument and Control Power Supply system cables are rated to withstand fault currents for the time required to clear the fault from its power source.	11. Analyses for the as-built Class 1E distribution system to determine fault currents will be performed.	11. Analyses for the as-built Class 1E Instrument and Control Power Supply system cables exist and conclude that the distribution system cable current capacities exceed their analyzed fault currents for the time required, as determined by the circuit interrupting device coordination analyses, to clear the fault from its power source.

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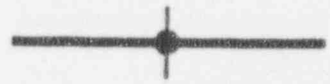
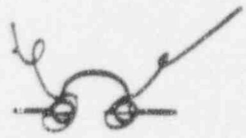
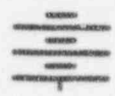
Connection to bus 

Circuit ~~breaker~~ Interrupting Device 

Transformer 

Battery 

Note 1: Devices shown do not denote either open or closed position.
Note 2: Circuit Interrupting Devices may consist of circuit breakers, fuses or a combination of breakers and fuses.

Building

Divisional Barrier (Note 2) 

Door (Note 1 & 3) 

Door (Note 3) 

Door (Note 3) 

Elevator 

Grating Floor 

Grid line identifier (for information only) 

Grid line intersection (for information only) 

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.15 I&C Power No. 1

NRC COMMENT:

Figure 2.12.15 and SSAR Figure 8.3-2 do not agree in regard to the type of breakers utilized. Revise the SSAR figure to show non-drawout breakers.

GE RESPONSE:

GE concurs and will make the necessary SSAR changes as part of the next amendment. See response to comment No. 1, Section 2.12.12. GE also plans to modify the CDM circuit breaker definition in Appendix A. See attached markup. The CDM changes will include previously overlooked "circuit breakers and fuses" changes. See attached.

PROPOSED CHANGES

CDM: Per attached markup.

SSAR: See response to comment No. 1, Section 2.12.12.

(cont)

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.14 VITAL AC No. 1

NRC COMMENT:

Why are drawout type molded case circuit breakers shown on SSAR Figure 8.3.3?

GE RESPONSE:

GE concurs that SSAR changes are necessary and will include these changes in the next SSAR amendment. See response to Section 2.12.12 comment No. 1.

PROPOSED CHANGES

CDM: None

SSAR: Per response to comment 2.12.12 No. 1.

generator is ready to accept load (i.e., voltage and frequency are within normal limits and no lockout exists, and the normal and alternate preferred supply breakers are open), the diesel-generator breaker is signalled to close, following the tripping of the large motors. This accomplishes automatic transfer of the Class 1E bus to the diesel generator. Large motor loads will be sequence started as required and shown on Table 8.3-4.

(2) **Loss of Coolant Accident (LOCA)**—When a LOCA occurs, the standby diesel generator is started and remains in the standby mode (i.e. voltage and frequency are within normal limits and no lockout exists) unless a LOPP signal is also present as discussed in (3) and (4) below. In addition, with or without a LOPP, the load sequence timers are started if the 6.9 kV emergency bus voltage is greater than 70%, and loads are applied to the bus at the end of preset times.

Each load has an individual load sequence timer which will start if a LOCA occurs and the 6.9 kV emergency bus voltage is greater than 70%, regardless of whether the bus voltage source is normal or alternate preferred power or the diesel generator. The load sequence timers are part of the low level circuit logic for each LOCA load and do not provide a means of common mode failure that would render both onsite and offsite power unavailable. If a timer failed, the LOCA load could be applied manually provided the bus voltage is greater than 70%.

(3) **LOPP following LOCA**—If the bus voltage (normal or alternate preferred power) is lost during post-accident operation, transfer to the diesel generator occurs as described in (1) above.

(4) **LOCA following LOPP**—If a LOCA occurs following loss of the normal or alternate preferred power supplies, the LOCA signal sequences ESF equipment onto the bus as required. Running loads are not tripped. Automatic (LOCA + LOPP) time delayed load sequencing assures that the diesel-generator will not be overloaded.

(5) **LOCA when diesel generator is parallel with preferred power source during test**—If a LOCA occurs when the diesel generator is paralleled with either the normal preferred power or the alternate preferred power source, the D/G will automatically be disconnected from the 6.9 kV emergency bus regardless of whether the test is being conducted from the local control panel or the main control room.

protective devices which shut down the diesel are the generator differential relays, and the engine over-speed trip. These protection devices are retained under accident conditions to protect against possible, significant damage. Other protective relays, such as loss of excitation, anti-motoring (reverse power), over-current voltage restraint, low jacket water pressure, high jacket water temperature, and low-lube oil pressure, are used to protect the machine when operating in parallel with the normal power system, and during periodic tests. The relays are automatically isolated from the tripping circuits during LOCA conditions when there is a concurrent LOPP signal. However, all of these bypassed parameters are annunciated in the main control room (Subsection 8.3.1.1.8.5). The bypasses and protective relays are testable and meet all IEEE-603 requirements, and are manually reset as required by Position 1.8 of Regulatory Guide 1.9. No trips are bypassed during LOPP or testing. See Subsection 8.3.4.22 for COL license information.

Synchronizing interlocks are provided to prevent incorrect synchronization whenever the diesel generator is required to operate in parallel with the preferred power supply (see Section 5.1.4.2 of IEEE-741). Such interlocks are capable of being tested, and shall be periodically tested per Section 8.3.4.23).

8.3.1.1.7 Load Shedding and Sequencing on Class 1E Buses

This subsection addresses Class 1E Divisions I, II, and III. Load shedding, bus transfer and sequencing on a 6.9 kV Class 1E bus is initiated on loss of bus voltage. Only LOPP signals (≤70% bus voltage) or degraded voltage signals are used to trip the loads. However, the presence of a LOCA during LOPP reduces the time delay for initiation of bus transfer from 3 seconds to 0.4 seconds. The Class 1E equipment is designed to sustain operation for this 3-second period without damage to the equipment. The load sequencing for the diesels is given on Table 8.3-4.

Load shedding and bus ready-to-load signals are generated by the under-voltage relays monitoring the Class 1E medium voltage switchgear buses. Individual timer start and reset signals for the LOPP condition are generated, for each major LOPP load, by the bus under-voltage relays. Individual timer start and reset signals for the LOCA condition are generated, for each major LOCA load, by the Safety System Logic and Control (SSLC) system. Table 8.3-4 defines which loads are sequenced onto the diesel generator for the LOPP and LOPP + LOCA conditions. (i.e. if a LOCA signal is not present, only LOPP loads are sequenced).

(1) **Loss of Preferred Power (LOPP)**—The 6.9 kV Class 1E buses are normally energized from the normal or alternate preferred power supplies. Should the bus voltage decay to ≤ 70% of its nominal rated value, a bus transfer is initiated and the signal will trip the supply breaker, and start the diesel generator. (6.9 kV) When the bus voltage decays to 30%, large pump motor breakers are tripped. The transfer then proceeds to the diesel generator. If the standby diesel

Table 2.12.13 Emergency Diesel Generator System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. When LOCA and LOPP signals exist, AND REQUIRED MOTOR LOADS ARE TRIPPED, the DG automatically connects to its respective divisional bus. After a DG connects to its respective bus, the LOCA loads are automatically sequenced onto the bus.	6. Tests on the as-built DG Systems will be conducted by providing simulated LOCA and LOPP signals.	6. In the as-built DG Systems, when LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. The automatic load sequence begins at ≤ 20 seconds. Following application of each load, the bus voltage does not drop more than 25% measured at the bus. Frequency is restored to within 2% of nominal, and voltage is restored to within 10% of nominal within 60% of each load sequence time interval. The HPCF and RHR loads are sequenced on to the bus in ≤ 36 seconds for design basis events.
7. A manual start signal from the MCR or from the local control station in the DG area starts a DG. After starting, the DG remains in a standby mode, unless a LOPP signal exists.	7. Tests on the as-built DG Systems will be conducted by providing a manual start signal from the MCR and from the local control station, without a LOPP signal.	7. As-built DGs automatically start on receiving a manual start signal from the MCR or from the local control station, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds and remain in the standby mode.
8. When a DG is operating in parallel (test mode) with offsite power, a loss of the offsite power source used for testing or a LOCA signal overrides the test mode by disconnecting the DG from its respective divisional bus.	8. Tests on the as-built DG Systems will be conducted by providing simulated loss of offsite power and LOCA signals while operating the DGs in the test mode.	8. When the as-built DG Systems are operating in the test mode with offsite power and a loss of offsite power or a LOCA signal is received, DGs automatically disconnect from their respective divisional buses.

Table 2.12.13 Emergency Diesel Generator System

	Inspections, Tests, Analyses and Acceptance Criteria	
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the DG System is described in Section 2.12.13.	1. Inspection of the as-built system will be conducted.	1. The as-built DG System conforms with the basic configuration described in Section 2.12.13.
2. The DGs are sized to supply their load demand following a LOCA.	2. Analyses to determine DG load demand, based on the as-built DG load profile, will be performed.	2. Analyses for the as-built DG systems exist and conclude that the DG System capacities exceed, as determined by their nameplate ratings, their load demand following a LOCA.
3. DG air start receiver tanks have capacity for five DG starts without recharging their tanks.	3. Tests on the as-built DG Systems will be conducted by starting the DGs five times.	3. As-built DGs start five times without recharging their air start receiver tanks.
4. (load shedding and) A LOPP signal (bus under-voltage) from an EPD System medium voltage divisional bus automatically starts its respective DG, and initiates automatic connection of the DG to its divisional bus. A DG automatically connects to its respective bus when DG rated voltage and frequency conditions are established (AND REQUIRED MOTOR LOADS ARE TRIPPED.) After a DG connects to its respective bus, the non-accident loads ~~are~~ automatically sequenced onto the bus.	4. Tests on the as-built DG Systems will be conducted by providing a simulated LOPP signal.	4. As-built DGs automatically start on receiving a LOPP signal, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds, automatically connect to their respective divisional bus, (, AFTER REQUIRED MOTOR LOADS ARE TRIPPED,) and sequence their non-accident loads onto the bus.
5. LOCA signals from the RHR (Division I) and HPCF (Divisions II and III) System automatically start their respective divisional DG. After starting, the DGs remain in a standby mode (i.e. running at rated voltage and frequency, but not connected to their busses), unless a LOPP signal exists.	5. Tests on the as-built DG Systems will be conducted by providing a simulated LOCA signal, without a LOPP signal.	5. As-built DGs automatically start on receiving a LOCA signal, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds, and remain in the standby mode.

NOTE: This is inapplicable to other change deleting ±10%

2.12.13 Emergency Diesel Generator System

Design Description

The Emergency Diesel Generator (DG) System consists of three diesel engines and their respective combustion air intake system, starting air system, fuel oil system (from the day tank to the engine), lubricating oil system, engine jacket cooling water system, engine exhaust system and silencer, governor system, and generator with its excitation and voltage regulation systems.

The three DGs are classified as Class 1E, safety-related and supply standby AC power to their respective Class 1E Electrical Power Distribution (EPD) System divisions (Divisions I, II, and III). The DG connections to the EPD System are shown on Figure 2.12.1.

The DGs are sized to supply their load demand following a loss-of-coolant accident (LOCA). The DG air start receiver tanks are sized to provide five DG starts without recharging their tanks.

LOAD SHEDDING AND

AND REQUIRED MOTOR LOADS ARE TRIPPED.

A loss of preferred power (LOPP) signal (bus under-voltage) from an EPD System medium voltage divisional bus automatically starts its respective DG, and initiates automatic connection of the DG to its divisional bus. A DG automatically connects to its respective bus when DG rated voltage and frequency conditions are established. After a DG connects to its respective bus, the non-accident loads are automatically sequenced onto the bus.

AND REQUIRED MOTOR LOADS ARE TRIPPED,

LOCA signals from the Residual Heat Removal (RHR) (Division I) and High Pressure Core Flooder (HPCF) (Divisions II and III) systems automatically start their respective divisional DG. After starting, the DGs remain in a standby mode (i.e. running at rated voltage and frequency, but not connected to their busses), unless a LOPP signal exists. When LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. After a DG connects to its respective bus, the LOCA loads are automatically sequenced onto the bus.

A manual start signal from the main control room (MCR) or from the local control station in the DG area starts a DG. After starting, the DG remains in a standby mode, unless a LOPP signal exists.

DGs start, attain rated voltage and frequency, and are ready to load in ≤ 20 seconds after receiving an automatic or manual start signal.

When a DG is operating in parallel (test mode) with offsite power, a loss of the offsite power source used for testing or a LOCA signal overrides the test mode by disconnecting the DG from its respective divisional bus.

CDM SECTION AND COMMENT No.: 2.12.13 EDG No. 14

NRC COMMENT:

Page 2.12.13-1, fourth paragraph, states that the EDG is automatically connected to its respective divisional bus upon an undervoltage condition. However, this is not really true because in accordance with page 8.3-16, item 1 of the SSAR, it is necessary for large motors to trip first at a bus voltage equal to 30% before the EDG output breaker is closed. See comment 6 above on the same aspect.

GE RESPONSE:

GE does not concur that any CDM changes are necessary. An undervoltage condition initiates auto-connection. The primary condition for connection to the bus is DG voltage and frequency. Other logic conditions associated with this process are considered detail plant design and thus not appropriate CDM topics. Consequently, GE proposes no changes in response to this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

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Table 2.12.13 Emergency Diesel Generator System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. When LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. After the DG connects to its respective bus, the LOCA loads are automatically sequenced onto the bus.	6. Tests on the as-built DG Systems will be conducted by providing simulated LOCA and LOPP signals.	6. In the as-built DG Systems, when LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. The automatic load sequence begins at ≤ 20 seconds. Following application of each load, the bus voltage does not drop more than 25% measured at the bus. Frequency is restored to within 2% of nominal, and voltage is restored to within 10% of nominal within 80% of each load sequence time interval. The HPCF and RHR loads are sequenced on to the bus in ≤ 36 seconds for design basis events.
7. A manual start signal from the MCR or from the local control station in the DG area starts a DG. After starting, the DG remains in a standby mode, unless a LOPP signal exists. (i.e. running at ~~rated~~ required voltage and frequency)	7. Tests on the as-built DG Systems will be conducted by providing a manual start signal from the MCR and from the local control station, without a LOPP signal.	7. As-built DGs automatically start on receiving a manual start signal (from the MCR or from the local control station, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds and remain in the standby mode.
8. When a DG is operating in parallel (test mode) with offsite power, a loss of the offsite power source used for testing or a LOCA signal overrides the test mode by disconnecting the DG from its respective divisional bus.	8. Tests on the as-built DG Systems will be conducted by providing simulated loss of offsite power and LOCA signals while operating the DGs in the test mode.	8. When the as-built DG Systems are operating in the test mode with offsite power and a loss of offsite power or a LOCA signal is received, DGs automatically disconnect from their respective divisional buses.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.13 EDG No. 13

NRC COMMENT:

Revise design commitment No. 7 as shown in the attached markup.

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447. (See response to 2.12.13 comment 1b.)

PROPOSED CHANGES

CDM: Per markup attached to resonse to comment 2.12.13, 1b.

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.13 EDG No. 10

NRC COMMENT:

Last paragraph of TS bases Section B 3.8.1 should be revised to include power factor of DG.

GE RESPONSE:

GE concurs and will include this change in the next SSAR amendment. (See response to EELB comment No. 25.)

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

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Table 2.12.13 Emergency Diesel Generator System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the DG System is described in Section 2.12.13.	1. Inspection of the as-built system will be conducted.	1. The as-built DG System conforms with the basic configuration described in Section 2.12.13.
2. The DGs are sized to supply [illegible] demand following a LOCA.	2. Analyses to determine DG load demand, based on the as-built DG load profile, will be performed.	2. Analyses for the as-built DG systems exist and conclude that the DG System capacities exceed by 10%, as determined by their nameplate ratings, their load demand following a LOCA.
3. DG air start receiver tanks have capacity for five DG starts without recharging their tanks.	3. Tests on the as-built DG Systems will be conducted by starting the DGs five times.	3. As-built DGs start five times without recharging their air start receiver tanks.
4. A LOPP signal (bus under-voltage) from an EPD System medium voltage divisional bus automatically starts its respective DG, and initiates automatic connection of the DG to its divisional bus. A DG automatically connects to its respective bus when DG rated voltage and frequency conditions are established. After a DG connects to its respective bus, the non-accident loads are automatically sequenced onto the bus.	4. Tests on the as-built DG Systems will be conducted by providing a simulated LOPP signal.	4. As-built DGs automatically start on receiving a LOPP signal, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds, automatically connect to their respective divisional bus, and sequence their non-accident loads onto the bus.
5. LOCA signals from the RHR (Division I) and HPCF (Divisions II and III) System automatically start their respective divisional DG. After starting, the DGs remain in a standby mode (i.e. running at rated voltage and frequency, but not connected to their busses), unless a LOPP signal exists.	5. Tests on the as-built DG Systems will be conducted by providing a simulated LOCA signal, without a LOPP signal.	5. As-built DGs automatically start on receiving a LOCA signal, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds, and remain in the standby mode.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.13 EDG No. 2

NRC COMMENT:

SSAR Section 8.3.1.1.8.2, item No. 14 states that "the maximum loads expected to occur for each division do not exceed 90% of the continuous power output rating of the diesel generator." This information should be incorporated in CDM and ITAAC No. 2 should be revised accordingly. See attached.

GE RESPONSE:

GE does not concur. This position is based on what GE believes is an earlier GE/NRC agreement that it is neither appropriate nor necessary for plant and equipment margins to be addressed in the CDM. Consequently, GE proposes no changes in response to this NRC comment.

PROPOSED CHANGES

CDM: None

SSAR: None

8.3.1.1.8.3 ABWR SSAR

Insert A

(18) Bus Voltage and frequency regulation will assure an operating voltage and frequency at the terminals of the Class 1E utilization equipment that is within the utilization equipments' tolerance limits.

Insert A

(17) Bus voltage and frequency will recover to 6.9 kV±10% at 60±2% Hz within 10 seconds following trip and restart of the largest load.

(~~18~~ 19) Each of the above design criteria has the capability of being periodically verified (Subsection 8.3.4.36). However, note exception for Item (10).

8.3.1.1.8.3 Starting Circuits and Systems

Diesel generators I, II and III start automatically on loss of bus voltage. Under-voltage relays are used to start each diesel engine in the event of a drop in bus voltage below preset values for a predetermined period of time. Low-water-level switches and drywell high-pressure switches in each division are used to initiate diesel start under accident conditions. Manual start capability is also provided and shall be periodically verified (Subsection 8.3.4.36). The Class 1E batteries provide power for the diesel control and protection circuits. The transfer of the Class 1E buses to standby power supply is automatic, should this become necessary, on loss of preferred power. After the breakers connecting the buses to the preferred power supplies are open, the diesel-generator breaker is closed when required generator voltage and frequency are established.

Diesel generators I, II and III are designed to start and attain rated voltage and frequency within 20 seconds. The generator, and voltage regulator are designed to permit the unit to accept the load and to accelerate the motors in the sequence within the time requirements. The voltage drop caused by starting the large motors does not exceed the requirements set forth in Regulatory Guide 1.9, and proper acceleration of these motors is ensured. Control and timing circuits are provided, as appropriate, to ensure that each load is applied automatically at the correct time. The design provides capability for periodic verification of these criteria, as indicated in Subsection 8.3.1.1.8.2(18). Each diesel generator set is provided with two independent starting air systems.

8.3.1.1.8.4 Automatic Shedding, Loading and Isolation

The diesel generator is connected to its Class 1E bus only when the incoming preferred source breakers have been tripped (Subsection 8.3.1.1.7). Under this condition, major loads are tripped from the Class 1E bus, except for the Class 1E 480V power center feeders, before closing the diesel generator breaker.

The large motor loads are later re-applied sequentially and automatically to the bus after closing of the diesel-generator breaker.

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2.12.13

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AC 4,5,7

IN ≤ 20 SECONDS AND ATTAIN A voltage AND FREQUENCY which will ASSURE AN operating voltage AND FREQUENCY at the terminals of the Class 1E utilization equipment that is within the utilization equipments tolerance limits,

Table 2.12.13 Emergency Diesel Generator System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. When LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. After a DG connects to its respective bus, the LOCA loads are automatically sequenced onto the bus.	6. Tests on the as-built DG Systems will be conducted by providing simulated LOCA and LOPP signals.	6. In the as-built DG Systems, when LOCA and LOPP signals exist, the DG automatically connects to its respective divisional bus. The automatic load sequence begins at ≤ 20 seconds. Following application of each load, the bus voltage does not drop more than 25% measured at the bus. Frequency is restored to within 2% of nominal, and voltage is restored to within 10% of nominal within 60% of each load sequence time interval. The HPCF and RHR pump motor loads are sequenced on to the bus in ≤ 36 seconds for design basis events.
7. A manual start signal from the MCR or from the local control station in the DG area starts a DG. After starting, the DG remains in a standby mode (i.e. running at rated voltage and frequency, but not connected to their busses), unless a LOPP signal exists.	7. Tests on the as-built DG Systems will be conducted by providing a manual start signal from the MCR and from the local control station, without a LOPP signal.	7. As-built DGs INSERT A automatically start on receiving a manual start signal from the MCR or from the local control station, ~~attain rated voltage (±10%), and rated frequency (±2%) in ≤ 30 seconds~~ and remain in the standby mode.
8. When a DG is operating in parallel (test mode) with offsite power, a loss of the offsite power source used for testing or a LOCA signal overrides the test mode by disconnecting the DG from its respective divisional bus.	8. Tests on the as-built DG Systems will be conducted by providing simulated loss of offsite power and LOCA signals while operating the DGs in the test mode.	8. When the as-built DG Systems are operating in the test mode with offsite power and a loss of offsite power or a LOCA signal is received, DGs automatically disconnect from their respective divisional buses.

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Table 2.12.13 Emergency Diesel Generator System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the DG System is described in Section 2.12.13.	1. Inspection of the as-built system will be conducted.	1. The as-built DG System conforms with the basic configuration described in Section 2.12.13.
2. The DGs are sized to supply their load demand following a LOCA.	2. Analyses to determine DG load demand, based on the as-built DG load profile, will be performed.	2. Analyses for the as-built DG systems exist and conclude that the DG System capacities exceed, as determined by their nameplate ratings, their load demand following a LOCA.
3. DG air start receiver tanks have capacity for five DG starts without recharging their tanks.	3. Tests on the as-built DG Systems will be conducted by starting the DGs five times.	3. As-built DGs start five times without recharging their air start receiver tanks.
4. A LOPP signal (bus under-voltage) from an EPD System medium voltage divisional bus automatically starts its respective DG, and initiates automatic connection of the DG to its divisional bus. A DG automatically connects to its respective bus when DG rated voltage and frequency conditions are established. After a DG connects to its respective bus, the non-accident loads are automatically sequenced onto the bus.	4. Tests on the as-built DG Systems will be conducted by providing a simulated LOPP signal.	Insert A 4. As-built DGs automatically start on receiving a LOPP signal~~, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds~~, automatically connect to their respective divisional bus, and sequence their non-accident loads onto the bus.
5. LOCA signals from the RHR (Division I) and HPCF (Divisions II and III) System automatically start their respective divisional DG. After starting, the DGs remain in a standby mode (i.e. running at rated voltage and frequency, but not connected to their busses), unless a LOPP signal exists.	5. Tests on the as-built DG Systems will be conducted by providing a simulated LOCA signal, without a LOPP signal.	Insert A 5. As-built DGs automatically start on receiving a LOCA signal~~, attain rated voltage (±10%), and rated frequency (±2%) in ≤ 20 seconds~~, and remain in the standby mode.

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.13 EDG No. 1b

NRC COMMENT:

Acceptance values (±10%) voltage and ±2% frequency) should be deleted from ITAACs 4, 5, and 7 since the design requirement is to establish rated voltage and frequency. The above tolerance requirements are specified only during loading.

GE RESPONSE:

Per verbal GE/NRC agreement, GE plans to make the CDM changes shown on the attached marked-up pages 2.12.13-3 and 2.12.13-4.

PROPOSED CHANGES

CDM: Per attached markups.

SSAR: None

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.12 DC POWER No. 2

NRC COMMENT:

One line diagram symbol legend needs to be added to SSAR Section 1.7 as committed by GE in response to pilot review comments 10 and 11.

GE RESPONSE:

GE plans to implement this prior commitment into the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.12 DC POWER No. 1

NRC COMMENT:

GE response to comment No. 9 of pilot review is not fully implemented. Figure 8.3.4 sheet 3 as well as other affected drawings (AC and DC systems) should be revised to show non-drawout type MCCBs.

GE RESPONSE:

GE concurs and plans to make the necessary changes in SSAR Figures 8.3-2, 8.3-3, sheets 1 and 2, and 8.3-4. The change is to remove "drawout."

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

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Table 2.12.11 Combustion Turbine Generator

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the CTG is described in Section 2.12.11.	1. Inspections of the as-built CTG will be conducted.	1. The as-built CTG conforms with the basic configuration described in Section 2.12.11.
2. The CTG can supply power to the non-Class 1E busses or to the Class 1E divisional busses.	2. Tests on the as-built CTG will be conducted by connecting the CTG to the non-Class 1E PIP busses and to the Class 1E divisional busses.	2. The as-built CTG can supply power to the non-Class 1E PIP busses or to the Class 1E divisional busses.
3. The CTG capacity to supply power is at least as large as the capacity of a DG.	3. Inspections of the as-built CTG and DGs will be conducted.	3. The as-built CTC capacity to supply power is at least as large as the capacity of a DG, as determined by the CTG and DG nameplate ratings.
4. MCR displays and controls provided for the CTG are as defined in Section 2.12.11.	4. Inspections will be conducted on the MCR displays and controls for the CTG.	4. Displays and controls exist or can be retrieved in the MCR as defined in Section 2.12.11.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.11 CTG No. 8

NRC COMMENT:

Table 2.12.11, item 1, replace 2.12.1 with 2.12.11.

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per attached.

SSAR: None

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.11 CTG No. 6

NRC COMMENT:

Design Description states that "CTG is located in a non-safety related area of the plant." SSAR Section 9.5.11.3 states that "Adequate protection of the CTG against sabotage is provided by locating the unit inside the security protected area." Design Description should be revised to show that the CTG is located in the protected area of the plant and an ITAAC should be provided to verify this location.

GE RESPONSE:

GE does not concur. The CTG is not a safety-related component and there is no basis of need for CDM treatment of CTG location. Consequently, GE proposes no changes in response to this NRC comment.

~~ADD TO~~ CHANGE CDM TO SAY "THE CTG IS LOCATED OUTSIDE THE REACTOR BUILDING"

PROPOSED CHANGES

CDM: None

SSAR: None

CFC

Section 2.12.10 Comment No. 3

Comment:

IEEE 317 "IEEE Standard for Electrical Penetration Assembly in Containment Structure for Nuclear Power Plant" should be referenced in SSAR for meeting design, construction, qualification, test and installation of electrical penetration assemblies.

Resolution: IEEE STANDARD IS REFERENCED IN SSAR TABLE 1.8-21 AND SECTION 8.3.3.7

ALSO SEE COMMENT 26 of Fox's package

Done

JCR

Section 8.3.3.7

Insert A

(6) Electrical penetrations are designed and tested in accordance with IEEE 317 and Section 6.2.6.2 Containment Penetration Leakage Rate Test (Type B).

section 8.3.3.7

below the maximum continuous current capacity of the penetration. Such devices must be located in separate panels or be separated by barriers and must be independent such that failure of one will not adversely affect the other. Furthermore, they must not be dependent on the same power supply.

(5) A demonstration of leak tightness under the severe accident containment pressure and temperature loadings described in Subsection 19F.3.2.2.

Insert A

Protective devices designed to protect the penetrations are capable of being tested, calibrated and inspected (see Subsection 8.3.4.4).

8.3.3.8 Fire Protection of Cable Systems

The basic concept of fire protection for the cable system in the ABWR design is that it is incorporated into the design and installation rather than added onto the systems. By use of fire resistant and non-propagating cables, conservative application in regard to ampacity ratings and raceway fill, and by separation, fire protection is built into the system. Cables are rated to withstand fault currents until the fault is cleared. Short circuit analysis will be performed in accordance with IEEE 141 and/or other acceptable industry standards or practices to determine fault currents. Fire suppression systems (e.g., automatic sprinkler systems) are provided as listed in Table 9.5.1-1.

8.3.3.8.1 Resistance of Cables to Combustion

The electrical cable insulation is designed to resist the onset of combustion by limiting cable ampacity to levels which prevent overheating and insulation failures (and resultant possibility of fire) and by choice of insulation and jacket materials which have flame-resistive and self-extinguishing characteristics. Polyvinyl chloride or neoprene cable insulation is not used in the ABWR. All cable trays are fabricated from noncombustible material. Base ampacity rating of the cables was established as published in IPCEA-46-426/IEEE-S-135 and IPCEA-54-440/ NEMA WC-51. Each coaxial cable, each single conductor cable and each conductor in multiconductor cable is specified to pass the vertical flame test in accordance with UL-44.

In addition, each power, control and instrumentation cable is specified to pass the vertical tray flame test in accordance with IEEE-383.

Power and control cables are specified to continue to operate at a conductor temperature not exceeding 90°C and to withstand an emergency overload temperature of up to 130°C in accordance with IPCEA S-66-524/NEMA WC-7 Appendix D. Each power cable has stranded conductor and flame-resistive and radiation-resistant covering. Conductors are specified to continue to operate at 100% relative humidity with a service life expectancy of 60 years ~~(See 8.3.4.5)~~. Also, Class 1E cables are designed and qualified to survive the LOCA ambient condition at the end of the 60-yr. life span.

25	(Reference: Comment #10 of the ABWR ITAAC Independent Review Comments ITAAC No. 2.12.13, Emergency Diesel Generator System) Add the following to the last paragraph of the background section of the Technical Specification Bases B 3.8.1: "@ 0.8 power factor." The revised paragraph should read as follows: Ratings for DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating for each DG is 5000 kW @ 0.8 power factor, with 10% overload permissible for up to 2 hours in any 24 hour period.		
26	(Reference: Comments 3 and 4 of the ABWR ITAAC Independent Review Comments, ITAAC No. 2.12.10, Electrical Wiring Penetration) Add the following design commitments to Section 8.3.3.7 of SSAR Amendment 33: The design of electrical penetrations includes the capability to periodically verify the pressure boundary of containment penetrations (Subsection 8.3.4.5). Electrical penetrations are designed and tested in accordance with industry recommended practice as defined in IEEE 317. Add the following commitment to Section 8.3.4.5 of SSAR Amendment 33: Appropriate plant procedures shall include periodic testing of the leak tightness of containment electrical penetrations to demonstrate their capability for maintaining the pressure boundary of containment in accordance with their required safety function.	Comment partially incorporated: ADD to 8.3.3.7 "Electrical Penetrations are designed and tested in accordance with IEEE 317 and Section 6.2.6.2 Containment Penetration Leakage Rate Test (Type B)" COL action item is not warranted since requirements are defined in 10CFR 50 Appendix J. (Section 6.2.6.2	3

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CFC

Section 2.12.10 Comment No. 3

Comment:

IEEE 317 "IEEE Standard for Electrical Penetration Assembly in Containment Structure for Nuclear Power Plant" should be referenced in SSAR for meeting design, construction, qualification, test and installation of electrical penetration assemblies.

Resolution: IEEE STANDARD IS REFERENCED IN SSAR TABLE 1.8-21 AND SECTION 8.3.3.7

ALSO SEE COMMENT 26 of Fox's package

Done

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.12.10 WIRING PENETRATION No. 3

NRC COMMENT:

IEEE 317 "IEEE Standard for Electrical Penetration Assembly in Containment Structure for Nuclear Power Plant" should be referenced in SSAR for meeting design, construction, qualification, test and installation of electrical penetration assemblies.

GE RESPONSE:

See GE response to NRC reviewer comment EELB number 26.

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: SSAR SECTION 8.2 No. 2

NRC COMMENT:

In responding to comment No. 20 on ITAAC 2.12.1, GE incorrectly changes SSAR Figure 8.2.1 (sheet 2). "Gas Combustion Turbine Generator" should just be "Combustion Turbine Generator."

GE RESPONSE:

GE concurs and will include the necessary corrections in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: SSAR SECTION 8.2 No. 1

NRC COMMENT:

In responding to comment No. 24 on ITAAC 2.12.1, GE incorrectly interjected the letter "B" between "isolated" and "phase" in the next to the last paragraph on page 8.2-2.

GE RESPONSE:

GE concurs and will include the necessary corrections in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

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Figure 1.7-3 Graphical Symbols for Use in Electrical SLDs (Sheet 4 of 4)


Fuse

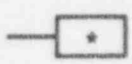
DC Supply


Station Battery


Full Wave Rectifier

Devices


Current Transformer (CT)


* Function Identifier

STD	-	Static trip device
27D	-	DC under voltage relay
64	-	Ground detector relay
76	-	DC overcurrent relay
84	-	Selector switch


* Monitoring Function

V	-	Voltmeter
A	-	Ampmeter

Abbreviations

M/C	Metal Clad
P/C	Power Center
MCC	Motor Control Center
R/B	Reactor Building
C/B	Control Building
T/B	Turbine Building
RW/B	Radwaste Building
UHS	Ultimate Heat Sink

RL 2/9 + 7/22

Table 3.1 Human Factors Engineering (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Design Acceptance Criteria**
5.	5.	5.
a. HSI Design Implementation Plan shall be developed which establishes that human engineering principles and criteria shall be applied in the design definition and evaluation of the HSI.	a. The HSI Design Implementation Plan shall be reviewed.	a. The HSI Design Implementation Plan shall establish: (1) The methods and criteria for HSI ~~equipment~~ design, (2) That the HSI design shall implement the information and control requirements: (a) developed through the task analyses, including the displays, controls and alarms necessary for the execution of those tasks identified in the task analyses as being critical tasks and, (b) defined in Table 2.7.1.a. (3) The methods for comparing the consistency of the HSI human performance, equipment design and associated workplace factors with that modeled and evaluated in the completed task analysis. (4) The HSI design criteria and guidance for control room operations during periods of maintenance, test and inspection. (5) The test and evaluation methods for resolving HFE/HSI design issues. These test and evaluation methods shall include the criteria to be used in selecting HFE/HSI design and evaluation tools.

in accordance with accepted human factors practices and principles

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 9

NRC COMMENT:

Apply Comment No. 5 to 5.a(1).

GE RESPONSE: REVISED

~~GE does not concur. See response to NRC comment 3.1 No. 5.~~

GE concurs and will include this change in the next revision of 25A5447

PROPOSED CHANGES

CDM: ~~None~~ Per NRC comment; see attached

SSAR: None

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Table 3.1 Human Factors Engineering (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Design Acceptance Criteria**
4.	4.	4.
a. A Task Analysis Implementation Plan shall be developed which establishes that task analysis shall be conducted and used to identify the behavioral requirements of the tasks the personnel are required to perform in order to achieve the functions allocated to them. The task analysis shall be used to maintain human performance requirements within human capabilities; be used as an input for developing personnel skill, personnel training, and system communication requirements and as an input to the evaluation of established plant operations control room staffing levels; and form the basis for specifying the requirements for the displays, data processing and controls needed to carry out tasks.	a. The Task Analysis Implementation Plan shall be reviewed.	a. The Task Analysis Implementation Plan shall establish: (1) The methods and criteria for conduct of the task analyses in accordance with accepted human factors practices and principles (2) The scope of the task analysis which shall include operations performed at the operator interface in the MCR and at the RSS. The analyses shall be directed to the range of plant operating modes, including startup, normal operations, abnormal operations, transient conditions, low power and shutdown conditions. The analyses shall also address operator interface operations during periods of maintenance, test and inspection of plant systems and equipment, including HSI equipment. (3) That the analysis shall be used to identify which tasks are critical to safety.

ABWR DESIGN CERTIFICATION

FEBRUARY 1994

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 7

NRC COMMENT:

Apply Comment No. 5 to 4.a(1).

GE RESPONSE: REVISED

~~GE does not concur. See response to NRC comment 3.1 No. 3.~~

GE concurs and will include this change in the next revision of 25A5447

PROPOSED CHANGES

CDM: ~~None~~ Per NRC comment; see attached

SSAR: None

Table 3.1 Human Factors Engineering (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Design Acceptance Criteria**
3.	3.	3.
a. An Allocation of Function Implementation Plan shall be developed which establishes the methods for allocating functions to personnel, system elements, and personnel-system combinations.	a. The Allocation of Function Implementation Plan shall be reviewed.	a. The Allocation of Function Implementation Plan shall establish: (1) The methods and criteria for the execution of function allocations (2) That aspects of system and functions definition shall be analyzed in terms of resulting human performance requirements based on the user population. (3) That the allocation of functions to personnel, system elements, and personnel system combinations shall reflect: (a) Sensitivity, precision, time, and safety requirements. (b) Reliability of system performance. (c) The number and the necessary skills of the personnel required to operate and maintain the system. (4) That allocation criteria, rationale, analyses, and procedures shall be documented.

in accordance with accepted human factors practices and principles

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 6

NRC COMMENT:

Apply Comment No. 5 to 3.a(1)

GE RESPONSE: REVISED

~~GE does not concur. See response to NRC comment 3.1 No. 3.~~

GE concurs and will include this change in the next revision of 25A 5447.

PROPOSED CHANGES

CDM: ~~None~~ Per NRC comment; see attached.

SSAR: None

Table 3.1 Human Factors Engineering (Continued)

Design Commitment	Inspections, Tests, Analyses and Acceptance Criteria: Inspections, Tests, Analyses	Inspections, Tests, Analyses and Acceptance Criteria: Design Acceptance Criteria
2. a. A System Functional Requirements Analysis Implementation Plan shall be developed which establishes that plant system requirements shall be analyzed to identify those functions which must be performed to satisfy the objectives of each functional area. System function analysis shall determine the objective, performance requirements, and constraints of the design, and establish the functions which must be accomplished to meet the objectives and required performance.	2. a. The System Functional Requirements Analysis Implementation Plan shall be reviewed.	2. a. The System Functional Requirements Analysis Implementation Plan shall establish: (1) Methods and criteria for conducting the System Functional Requirements Analysis. (2) That system requirements shall define the system functions and those system functions shall provide the basis for determining the associated HSI performance requirements. (3) That functions critical to safety shall be identified. (4) That descriptions shall be developed for each of the identified functions and for overall system configuration design itself. Each function shall be identified and described in terms of inputs (observable parameters which will indicate system status), functional processing (control process and performance measures required to achieve the function), functional operations (including detecting signals, measuring information, comparing one measurement with another, processing

in accordance with accepted human factors practices and principles.

RC 7/?8

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 5

NRC COMMENT:

Design acceptance criteria 2.a(1) on page 3.1-7 should add the following words (from the SSAR) "… in accordance with accepted human factors practices and principles."

GE RESPONSE: REVISED

~~GE does not concur. See response to NRC comment 3.1 No. 3.~~

GE concurs and will include this change in the next revision of 25A 5447

PROPOSED CHANGES

CDM: ~~None~~ Per NRC comment; see attached

SSAR: None

Table 3.1 Human Factors Engineering

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Design Acceptance Criteria**
1.	1.	1.
a. A multi-disciplinary HFE Design Team shall be established and be comprised of personnel with expertise in HFE and in other technical areas relevant to the HSI design, evaluation and operation.	a. The composition of the HFE Design Team shall be reviewed.	a. The HFE design team shall be comprised of the following expertise: (1) Technical Project Management (2) Systems Engineering (3) Nuclear Engineering (4) Control and Instrumentation Engineering (5) Architect Engineering (6) Human Factors (7) Plant Operations (8) Computer Systems Engineering (9) Plant Procedure Development (10)Personnel Training
b. An HFE Program Plan shall be developed which establishes that the human-system interfaces shall be developed, designed, and evaluated based upon human factors systems analysis and shall reflect human factors principles. The HSI scope shall apply to the MCR and RSS.	b. The HFE Program Plan shall be reviewed. in accordance with accepted human factors practices and principles..	b. The HFE Program Plan shall establish: (1) Methods and criteria for the HSI development, design and evaluation. (2) Methods for addressing: (a) The ability of the operating personnel to accomplish assigned tasks. (b) Operator workload levels and vigilance.

CDM SECTION AND COMMENT No.: 3.1 HFE No. 3 (Continued)

GE RESPONSE: (Continued)

2) The SSAR material supporting the CDM 3.1 entry does use this phrase and includes extensive material that defines what it is intended to encompass (see SSAR Chapter 18).

Consequently, GE proposes no changes to the CDM in response to this NRC question.

REVISED.

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 3

NRC COMMENT:

Design acceptance criteria 1.b.(1) on page 3.1-4 should have the following words (from the SSAR) added "… in accordance with accepted human factors practices and principles."

GE RESPONSE: REVISED

~~GE does not concur. During development of the 3.1 HFE DAC material, there were GE/NRC discussions as to whether this phrase should be included in CDM Section 3.1. It was GE's understanding that this issue was resolved (in 1992) with the mutual GE/NRC concurrence that it was not appropriate or necessary to use these words. The basis for this determination were:~~

~~1) The phrase lacks specificity and unambiguity and is thus not an appropriate CDM acceptance criteria.~~

~~(Continued on next page…)~~

GE concurs and will include this change in the next revision of 25A5447

PROPOSED CHANGES

CDM: ~~None~~ Per NRC comment; see attached

SSAR: None

Table 2.15.6 Fire Protection System

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The basic configuration for the FPS is defined in Section 2.15.6	1. Inspections of the as-built FPS will be conducted.	1. The as-built configuration of the FPS is in accordance with Section 2.15.6.
2. Fire detection and alarm systems are provided in all fire areas.	2. Inspection and testing of the as-built detectors will be performed using simulated fire conditions.	2. The detectors respond to the simulated fire conditions.
3. The FPS for the Reactor and Control Buildings supplies a minimum flow of 1893 ~~[illegible]~~ liters/min at a pressure greater than 4.57 kg/cm^{2}g at the most hydraulically remote hose connection in either the Reactor or Control Building.	3. Tests will be conducted of the as-built FPS.	3. The FPS for the Reactor and Control Buildings supplies a minimum flow of 1893 ~~[illegible]~~ liters/min at a pressure greater than 4.57 kg/cm^{2}g at the most hydraulically remote hose connection in either the Reactor or Control Building.
4. Automatic foam-water extinguishing systems are provided for the diesel generator and day tank rooms.	4. Inspections of the as-built foam-water extinguishing systems will be conducted. The automatic logic will be tested using simulated fire conditions.	4. The automatic foam-water suppression systems are present and initiation logic is actuated under simulated fire conditions.
5. The sprinkler systems and the standpipe systems in the Reactor and Control Buildings and the portions of the FPS water supply system identified in Figure 2.15.6 remain functional following an SSE.	5. Seismic analyses of the as-built FPS will be performed.	5. An analysis report exists which concludes that as-built sprinkler systems and the standpipe systems in the Reactor and Control Buildings and the portions of the FPS water supply system identified in Figure 2.15.6 remain functional following an SSE.
6. The fire detection and alarm systems are supplied with power from a non-Class 1E uninterruptible power supply.	6. Inspections of the as-built FPS will be conducted.	6. The FPS is supplied with power from a non-Class 1E uninterruptible power supply.
7. MCR alarms and displays provided for the FPS are as defined in Section 2.15.6.	7. Inspections will be performed on the MCR alarms, and displays for the FPS.	7. Alarms and displays exist or can be retrieved in the MCR as defined in Section 2.15.6.
8. Two fire water supply system pumps provide 5678 ~~[illegible]~~ liters/min flow each at a differential pressure of 8.8 kg/cm^2 ~~g~~.	8. Tests will be conducted of the as-built FPS pumps in a test facility.	8. Two fire water supply system pumps provide 5678 ~~[illegible]~~ liters/min flow each at a differential pressure of 8.8 kg/cm^2 ~~g~~.

TL 3/2

2.15.6 Fire Protection System

Design Description

The Fire Protection System (FPS) detects, alarms and extinguishes fires. Fire detection and alarm systems are provided in all fire areas. The FPS consists of a motor driven pump, a diesel drive pump, sprinkler systems, standpipes and hose reels, and portable extinguishers. The foam systems are also used for special applications. The basic configuration of the FPS water supply system is shown on Figure 2.15.6. The FPS provides fire protection for the Reactor Building, Control Building, Turbine Building, Radwaste Building, and other plant buildings.

Areas covered by sprinklers or foam systems are also covered by the manual hose system. Areas covered only by manual hoses can be reached from at least two hose stations. A hose reel and fire extinguisher are located no greater than 30.5m from any location within the buildings.

The FPS is classified as non-safety-related. The sprinkler systems and the standpipe systems in the Reactor and Control Buildings and portions of the FPS water supply system identified in Figure 2.15.6 remain functional following a safe shutdown earthquake (SSE). These portions of the water supply are separated from the remainder of the system by valves as shown in Figure 2.15.6.

Fresh water is used for the water supply system. Two sources with a minimum capacity of 1140 m^3 for each source are provided. A minimum of 456 m^3 is reserved for use by the portion of the suppression system used for the Reactor and Control Buildings. Both the diesel driven pump and motor driven pump independently supply a minimum flow of ~~[illegible]~~ 1893 liters/min at a pressure greater than 4.57 kg/cm^2g at the most hydraulically remote hose connection in either the Reactor or Control Building. The two fire water pumps provide ~~[illegible]~~ 5678 liters/min flow each at a differential pressure of 8.8 kg/cm^2.

A fire water supply connection to the Residual Heat Removal System piping is provided from the portion of the FPS used for the Reactor and Control Buildings to provide an AC independent water addition system mode of the RHR System for reactor vessel injection or drywell sprays.

Automatic foam water extinguishing systems are provided for the diesel generator rooms and day tank rooms.

Fire detection and alarm systems are supplied with power from a non-Class 1E uninterruptible power supply.

The FPS has the following displays and alarms in the Main Control Room (MCR):

(1) Detection system fire alarms.

The two fire water supply pumps provide 5678 L/min flow from each pump at a differential pressure of 8.8 kg/cm².

(6) Smoke detectors

(7) Alarms

(8) Fire barriers

(9) Fire stops

(10) Portable fire extinguishers

(11) Portable breathing apparatus

(12) Smoke and heat ventilation systems

(13) Associated controls and appurtenances

The suppression systems for the buildings and the plant yard are shown in the following figures:

Area	Figures
Reactor Building	9A.4-1 thru 9A.4-10
Control Building	9A.4-11 thru 9A.4-16
Turbine Building	9A.4-17 thru 9A.4-21
Service Building	9A.4-22 thru 9A.4-27
Radwaste Building	9A.4-28 thru 9A.4-32
Plant Yard	9.5-5

9.5.1.3.2 Fire Suppression System Requirements

~~The maximum fire water requirement for the Reactor Building is 5678 L/min at 8.8 kg/cm²~~. This requirement will meet the needs of NFPA 13 wet standpipe flow demand of 1893 L/min at a residual pressure of 4.57 kg/cm² at the ~~uppermost~~ most ~~standpipe~~. The standpipe and sprinkler system are designed to meet the requirements of NFPA 13 and 14. In addition, the sprinkler systems and the portions of the wet standpipe system within the Control and Reactor Buildings and one train of the fire suppression water supply system analyzed to remain functional following a safe shutdown earthquake. They are also designed to meet the requirements of ANSI B31.1, Power Piping. The remainder of the fire suppression systems are designed to the appropriate fire protection codes as listed.

(hydrant valley hose connections) in plant buildings

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.15.6 FPS No. 1

NRC COMMENT:

ITAAC item No. 3 includes minimum flows for the Reactor and Control Buildings. The SSAR, section 9.5.1.3.2, Fire Suppression System Requirements, specifies the Reactor Building. Resolve discrepancy.

The SSAR has been modified to indicate that the requirement applies to all plant buildings.

specifically limited to the R/B and C/B because of their safety significance.

GE RESPONSE:

The CDM is ~~correct in that the flow rate is applicable to both buildings~~. Th~~e SSAR will be corrected in the next amendment~~. See attached markup The changes will include additional SSAR clarification and minor supporting CDM changes as, also shown on the attached

PROPOSED CHANGES

CDM: ~~None~~ See attached.

SSAR: See attached.

with controlled temperature to insure the comfort and safety of plant personnel and the integrity of equipment and components. The Reactor Building HVAC System is composed of the following subsystems:

(1) R/B Secondary Containment HVAC System

(2) R/B Safety-Related Equipment HVAC System

(3) R/B Non-Safety-Related Equipment HVAC System

(4) R/B Safety-Related Electrical Equipment HVAC System

(5) R/B Safety-Related Diesel Generator HVAC System

(6) R/B Primary Containment Supply/Exhaust System

(7) R/B Mainsteam Tunnel HVAC System

(8) R/B Reactor Internal Pump ASD Control Panel HVAC System

9.4.5.1 R/B Secondary Containment HVAC System

9.4.5.1.1 Design Bases

9.4.5.1.1.1 Safety Design Bases

Except for the secondary containment inboard and outboard isolation damper, the system is classified as non-safety-related.

The R/B Secondary Containment HVAC System is designed to isolate the secondary containment in a harsh environment with redundant Seismic Category I inboard and outboard safety-related dampers, but otherwise has no other safety-related function as defined in Section 3.2. Failure of the system does not compromise any safety-related equipment or component and does not prevent safe reactor shutdown. Provisions are incorporated to minimize release of radioactive substances to atmosphere and to prevent operator exposure.

9.4.5.1.1.2 Power Generation Design Bases

The Secondary Containment HVAC System is designed to provide an environment with controlled temperature and airflow patterns to insure both the comfort and safety of plant personnel and the integrity of equipment and components.

~~The secondary containment is maintained at a negative pressure with respect to the outside atmosphere.~~

A negative pressure of 6.4 mm water gauge is normally maintained in the secondary containment relative to the outside atmosphere.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.15.5 HVAC No. 14

NRC COMMENT:

Revise SSAR Section 9.4.5.1.1.2 to state "A negative pressure of 6.4 mm water gauge is normally maintained in the secondary containment relative to the outdoor atmosphere" as stated in SSAR Section 6.5.1.3.1, first paragraph.

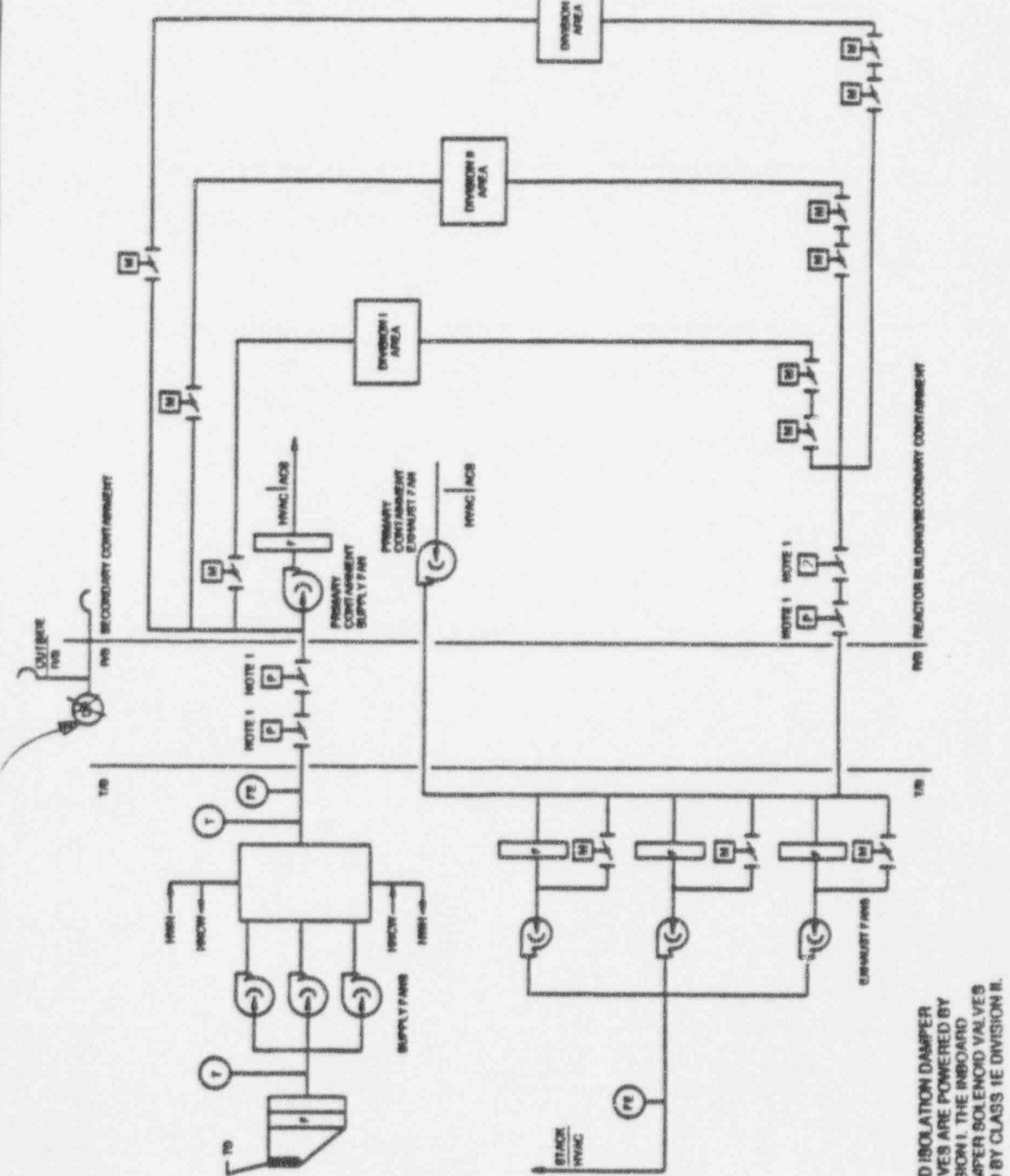
GE RESPONSE:

~~Later~~ GE concurs and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment; see attached.



NOTES:
1. THE OUTBOARD ISOLATION DAMPER SOLENOID VALVES ARE POWERED BY CLASS 1E DIVISION I. THE INBOARD ISOLATION DAMPER SOLENOID VALVES ARE POWERED BY CLASS 1E DIVISION II.

Figure 2.15.5j Reactor Building Secondary Containment HVAC System

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.15.5 HVAC No. 13

NRC COMMENT:

Revise ITAAC Figure 2.15.5j to state "dP," not "DP" for the differential pressure instrument.

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comments; see attached.

SSAR: None

R2 2/21

Table 2.15.5e Reactor Building Safety-Related Diesel Generator HVAC System

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The basic configuration of the R/B Safety-Related DG HVAC System is as shown on Figure 2.15.5l.	1. Inspections of the as-built system will be conducted.	1. The as-built R/B Safety-Related DG HVAC System conforms with the basic configuration shown on Figure 2.15.5l.
2. On receipt of a DG start signal, ~~at least one DG supply fan starts.~~ , both DG supply fans start.	2. Tests will be conducted on each division of the as-built R/B Safety-Related DG HVAC System using a simulated DG start signal.	2. On receipt of a DG start signal, ~~at least one DG supply fan starts.~~ , both DG supply fans start.
3. Each of the three divisions of the R/B Safety-Related DG HVAC System is powered from the respective Class 1E division as shown on Figure 2.15.5l. In the R/B safety-related DG HVAC system, independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	3. a. Tests will be performed on the R/B Safety-related DG HVAC System by providing a test signal in only one Class 1E division at a time. b. Inspection of the as-built Class 1E divisions in the R/B Safety-Related DG HVAC System will be performed.	3. a. The test signal exists only in the Class 1E division under test in the R/B Safety-Related DG HVAC System. b. In the R/B Safety-Related DG HVAC System, physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class 1E equipment
4. Each mechanical division of the R/B Safety-Related DG HVAC System (Divisions A, B and C) is physically separated from the other divisions.	4. Inspections of the as-built R/B Safety-Related DG HVAC System will be conducted.	4. Each mechanical division of the R/B Safety-Related DG HVAC System is physically separated from the other mechanical divisions of the R/B Safety-Related DG HVAC System by structural and/or fire barriers.
5. Main control room displays and controls provided for R/B Safety-Related DG HVAC System are as defined in Section 2.15.5.	5. Inspections will be performed on the main control room displays and controls for the R/B Safety-Related DG HVAC System.	5. Displays and controls exist or can be retrieved in the main control room as defined in Section 2.15.5.

Fire dampers with fusible links in HVAC duct work close under air flow conditions.

The R/B Safety-Related Electrical Equipment HVAC System has the following displays and controls in the main control rooms:

(1) Controls and status indication for the active safety-related components shown on Figures 2.15.5f, 2.15.5g, and 2.15.5h.

(2) Parameter displays for the instruments shown on Figures 2.15.5f, 2.15.5g and 2.15.5h.

R/B Safety-Related Diesel Generator HVAC System

The R/B Safety-Related DG HVAC System provides ventilation for the DG rooms when the DGs operate, and consists of three independent divisions. Each division consists of a filter unit and two supply fans. Figure 2.15.5i shows the basic system configuration and scope.

The R/B Safety-Related DG HVAC System is classified as safety-related.

On receipt of a DG start signal, ~~at least one DG supply fan starts.~~ (both DG supply fans start.) When the DG is operating, the R/B Safety-Related DG HVAC System and the R/B Safety-Related Electrical Equipment HVAC System maintain the temperature below 45°C.

Safety Design Bases

The R/B Safety-Related DG HVAC System is classified as Seismic Category I. The R/B Safety-Related DG HVAC System is located in the Reactor Building.

Each of the three divisions of the R/B Safety-Related DG HVAC System is powered from the respective Class 1E division as shown on Figure 2.15.5i. In the R/B Safety-Related DG HVAC System, independence is provided between Class 1E divisions, and also between the Class 1E divisions and non-Class 1E equipment.

Each mechanical division of the R/B Safety-Related DG HVAC System (Divisions A, B, C) is physically separated from the other divisions.

The R/B Safety-Related DG HVAC System has the following displays and controls in the main control room:

(1) Controls and status indication for the active safety-related components shown on Figure 2.15.5i.

R/B Secondary Containment HVAC System

The R/B Secondary Containment HVAC System provides heating and cooling for the secondary containment. Figure 2.15.5j shows the basic system configuration and scope.

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.15.5 HVAC No. 12

NRC COMMENT:

Revise CDM design description on page 2.15.5-7 to state "On receipt of a DG start signal, both DG supply fans start. A space thermostat controls allow at least one fan in operation."

GE RESPONSE: GE concurs that the CDM should be ~~Der~~ modified to state that both DG supply fans start. See attached markups. GE does not concur that DG supply fan control logic is an appropriate CDM topic. The key, top-level safety-related feature is that the supply fans start. Consequently, GE does not propose to include the second NRC sentence in the CDM.

PROPOSED CHANGES

CDM: Per attached.

SSAR: None

Table 2.15.5a Control Room Habitability Area HVAC System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
7. Each of the two CRHA System divisions is powered from the respective Class 1E division as shown on Figure 2.15.5a. In the CRHA HVAC System, independence is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E equipment.	7. a. Tests will be performed on the CRHA HVAC System by providing a test signal in only one Class 1E division at a time. b. Inspection of the as-built Class 1E divisions in the CRHA HVAC System will be performed.	7. a. The test signal exists only in the Class 1E division under test in the CRHA HVAC System. b. In the CRHA HVAC System, physical separation or electrical isolation exists between Class 1E divisions. Physical separation or electrical isolation exists between these Class 1E divisions and non-Class equipment.
8. Each mechanical division of the CRHA HVAC System (Division B and C) is physically separated from the other division, except for the common ducts in the MCAE.	8. Inspections of the as-built CRHA HVAC System will be performed.	8. Each mechanical division of the CRHA HVAC System is physically separated from the other mechanical division of the CRHA HVAC System by structural and/or fire barriers.
9. Fire dampers with fusible links in HVAC duct work close under air flow conditions.	9. Type tests of fire dampers in a test facility will be performed for closure under system air flow conditions.	9. Fire dampers close under system air flow conditions.
10. Main control room displays and controls provided for CRHA HVAC System are as defined in Section ~~14~~ 2.15.5	10. Inspections will be performed on the main control room displays and controls for the CRHA HVAC System.	10. Displays and controls exist or can be retrieved in the main control room as defined in Section 2.15.5.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.15.5 HVAC No. 4

NRC COMMENT:

Revise ITAAC Table 2.15.5d, Item 10, to state "Section 2.15.5" not "Section t14."

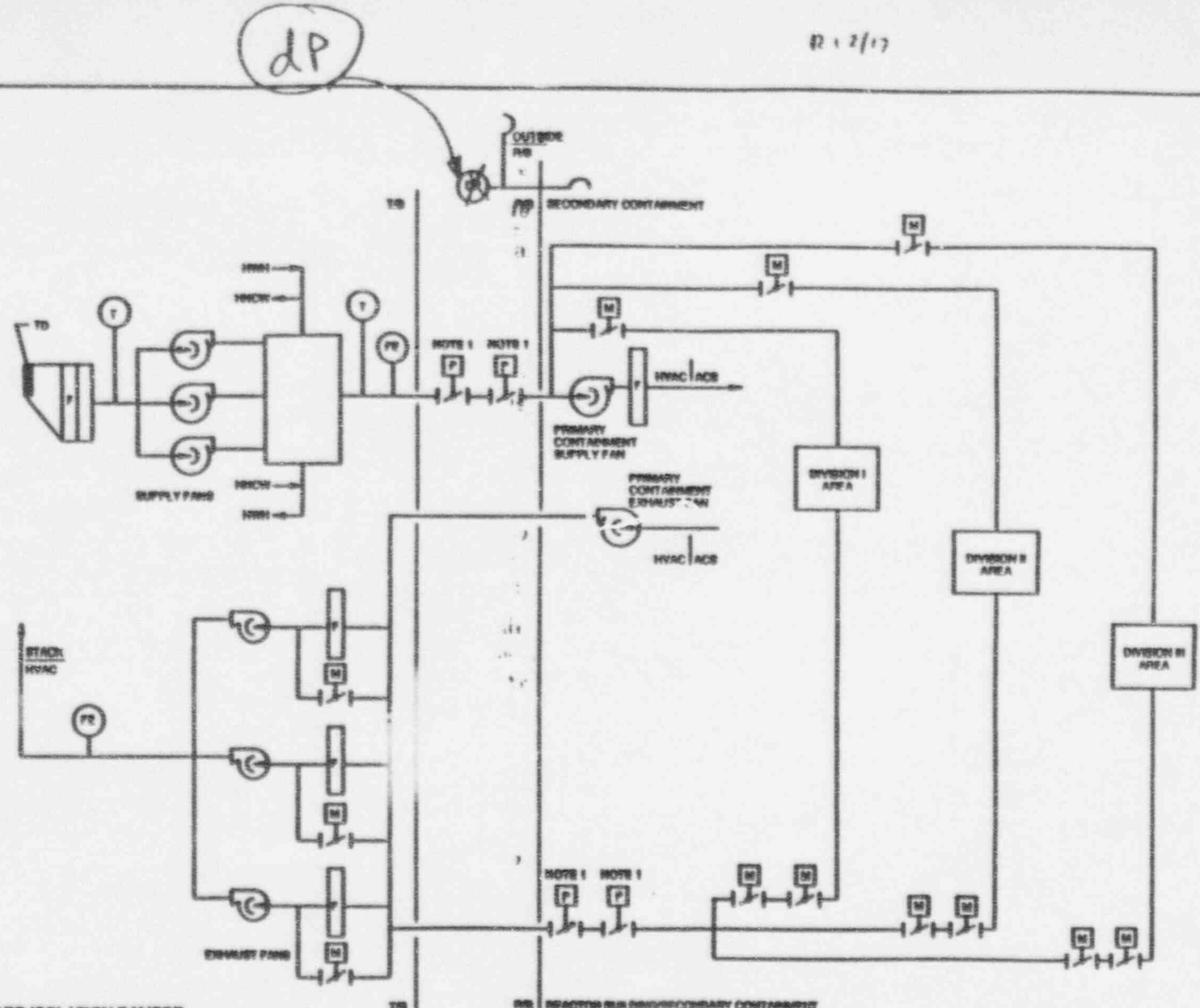
GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

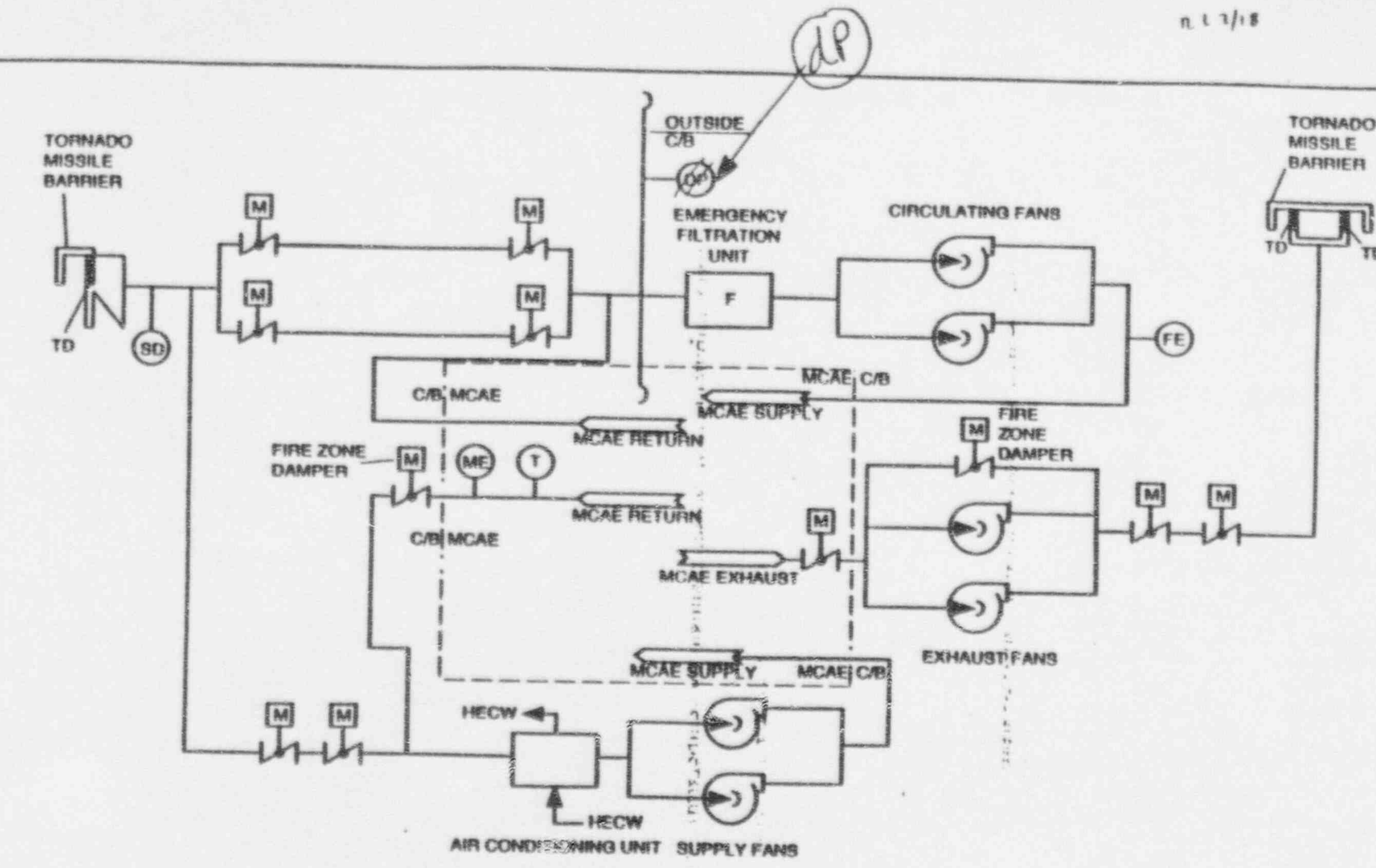
SSAR: None



NOTES:
1. THE OUTBOARD ISOLATION DAMPER SOLENOID VALVES ARE POWERED BY CLASS 1E DIVISION I. THE INBOARD ISOLATION DAMPER SOLENOID VALVES ARE POWERED BY CLASS 1E DIVISION II.

Figure 2.15.5j Reactor Building Secondary Containment HVAC System

n. L 7/18



NOTES:
1. THIS FIGURE SHOWS ONE OF TWO IDENTICAL DIVISIONS. ELECTRICAL POWER LOADS FOR THE COMPONENTS OF DIVISION B ARE POWERED FROM CLASS 1E DIVISION II. ELECTRICAL POWER LOADS FOR THE COMPONENTS OF DIVISION C ARE POWERED FROM CLASS 1E DIVISION III.

Figure 2.15.5a Control Room Habitability Area HVAC System

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.15.5 HVAC No. 3

NRC COMMENT:

1. Revise ITAAC Figure 2.15-5b to state "dP" not "DP" for differential instrumentation.

GE RESPONSE:

GE believes CDM Figures 2.15.5a and 2.15.5j need this correction and will include changes in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per attached.

SSAR: None

Inspections, Tests, Analyses and Acceptance Criteria

For portions of the CRHA HVAC system within the Certified Design, Table 2.15.5a provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the CRHA HVAC Systems.

able 2.15.5b provides definition of the inspections, tes and analyses, together with associated acceptance criteria which will be undertaken for the Control Building Safety-Related Equipment Area HVAC System.

Table 2.15.5c provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Building Safety-Related Equipment HVAC System.

Table 2.15.5d provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Building Safety-Related Electrical Equipment HVAC System.

Table 2.15.5e provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Building Safety-Related DG HVAC System.

Table 2.15.5f provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Building Secondary Containment HVAC System.

Table 2.15.5g provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Building Primary Containment Supply/Exhaust System.

Table 2.15.5h provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Building Main Steam Tunnel HVAC System.

Table 2.15.5i provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Building Non-Safety-Related Equipment HVAC System.

Table 2.15.5j provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Reactor Internal Pump ASD Control Panel HVAC System.

Table 2.15.5k provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Turbine Island HVAC System.

Table 2.15.5l provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the Radwaste Building HVAC System.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.15.5 HVAC No. 1

NRC COMMENT:

Revise CDM 2.15.5, page 2.15.5-12 to include ITAAC "Table 2.15-5b" description.

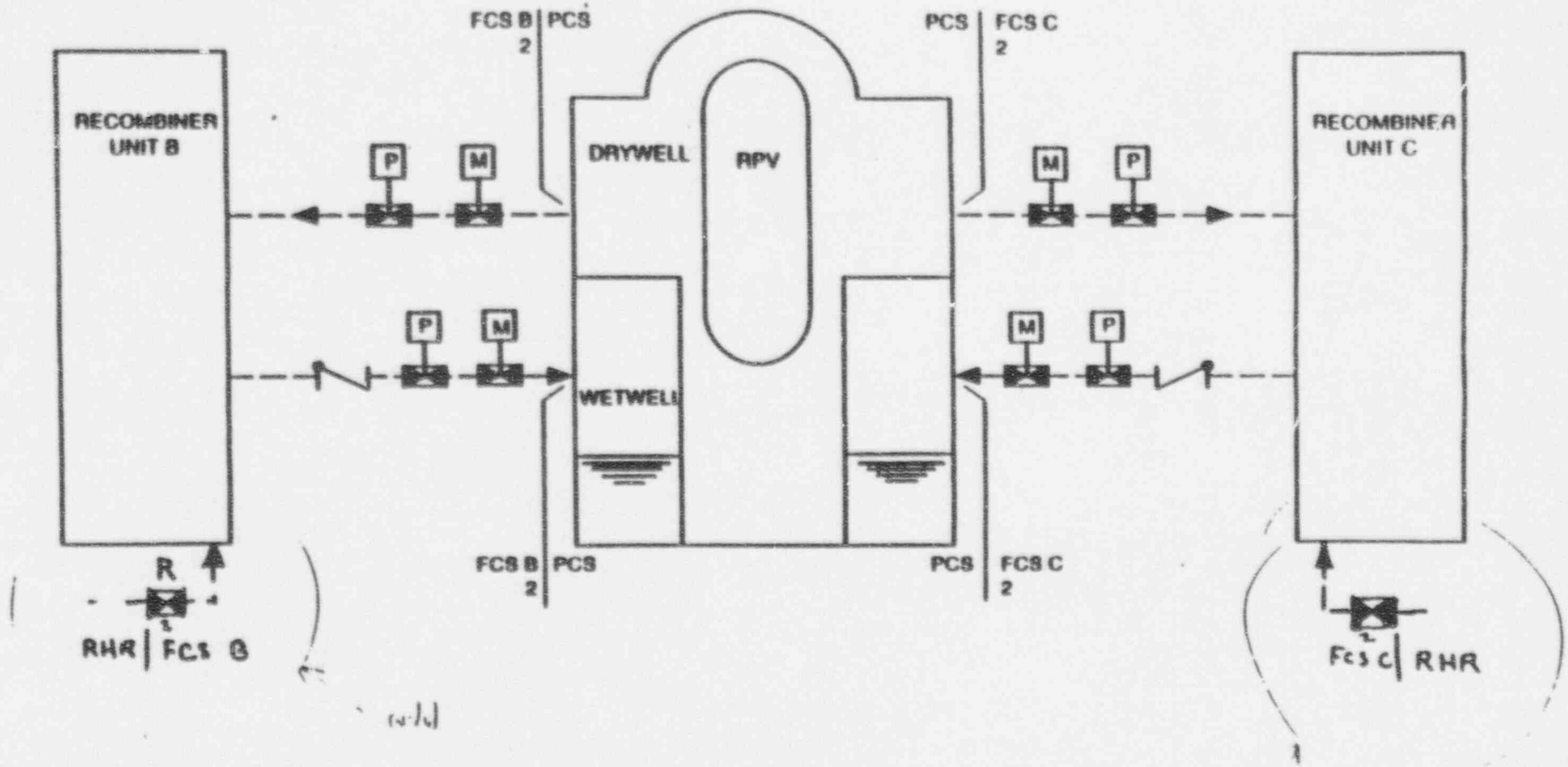
GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None



NOTE:
1. CLASS 1E ELECTRICAL POWER FOR FCS UNIT B IS SUPPLIED FROM DIVISION II EXCEPT FOR THE PNEUMATIC ISOLATION VALVE DUAL SOLENOIDS, WHICH IS DIVISIONS I AND III. UNIT C IS SUPPLIED FROM DIVISION III EXCEPT FOR THE OUTBOARD PNEUMATIC ISOLATION VALVE DUAL SOLENOIDS, WHICH IS DIVISION I AND II.

Figure 2.14.8 Flammability Control System

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.14.8 FCS No. 3

NRC COMMENT:

The CDD describes the cooling water requirements for operation of the FCS after a LOCA. Figure 2.14.8 needs to be revised to reflect the RHR interface with the FCS.

GE RESPONSE:

GE concurs and will include this interface in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.14.8 FCS No. 2

NRC COMMENT:

The CDD describes how the FCS component interfaces with the Remote Shutdown System. Figure 2.14.8 needs to be revised to reflect the RSS interfaces.

GE RESPONSE:

GE concurs and will include this RSS interface in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comments; see attached.

SSAR: None

Table 6.2-7 Containment Isolation Valve Information Atmospheric Control System

Valve No.	T31-F805A/B	T31-D001	T31-D002
SSAR Figure	6.2-39 (Sheet 3)	6.2-39 (Sheet 1)	6.2-39 (Sheet 1)
Applicable Basis	RG 1.11	GDC 56	GDC 56
Fluid	WW Atmosphere	WW Atmosphere	WW Atmosphere
Line Size	20A	250A	250A
ESF	No	Yes	Yes
Leakage Class	(a)	N/A	N/A
Location	O	O	O
Type C Leak Test	No(m)	No(~~c~~) (P)	No(~~c~~) (P)
Valve Type	Gate	Rupture Disk	Rupture Disk
Operator	Solenoid	Self	Self
Primary Actuation	Electric	N/A	N/A
Secondary Actuation	N/A	N/A	N/A
Normal Position	Open	Close	Close
Shutdown Position	Open	Close	Close
Post-Accident Position	Open	Open	Open
Power Fail Position	Open	N/A	N/A
Containment Isolation Signal(c)	~~N/A~~ RM	N/A	N/A
Closure Time (sec)	N/A	N/A	N/A
Power Source (Div)	N/A	N/A	N/A

See page 6.2-164 for notes

Table 6.2-7 Containment Isolation Valve Information Atmospheric Control System

Valve No.	T31-F745A/B	T31-F801A/B	T31-F803A/B
SSAR Figure	6.2-392 (Sheet 2)	6.2-39 (Sheet 3)	6.2-39 (Sheet 3)
Applicable Basis	RG 1.11	RG 1.11	RG 1.11
Fluid	SP H_2O	DW Atmosphere	DW Atmosphere
Line Size	20A	20A	20A
ESF	No	No	No
Leakage Class	(b)	(b)	(b)
Location	O	O	O
Type C Leak Test	No(m)	No(m)	No(m)
Valve Type	Gate	Gate	Gate
Operator	Solenoid	Solenoid	Solenoid
Primary Actuation	Electric	Electric	Electric
Secondary Actuation	N/A	N/A	N/A
Normal Position	Open	Open	Open
Shutdown Position	~~Open~~	Open	Open
Post-Accident Position	Open	Open	Open
Power Fail Position	Open	Open	Open
Containment Isolatiopn Signal (c)	~~N/A~~ RM	~~N/A~~ RM	~~N/A~~ RM
Closure Time (sec)	N/A	N/A	N/A
Power Source (Div)	N/A	N/A	N/A
See page 6.2-164 for notes			

EVN

Table 6.2-7 Containment Isolation Valve Information Atmospheric Control System

Valve No.	T31-F737A-~~D~~B	T31-F739A-D	T31-F741A-D	T31-F743A/B
SSAR Figure	6.2-39 (Sheet 3)	6.2-39 (Sheet 2)	6.2-39 (Sheet 3)	6.2-39 (Sheet 2)
Applicable Basis	RG 1.11	RG 1.11	RG 1.11	RG 1.11
Fluid	WW Atmosphere	WW Atmosphere	SP H_2O	WW Atmosphere
Line Size	20A	20A	20A	20A
ESF	No	No	No	No
Leakage Class	(a)	(a)	(a)	(a)
Location	O	O	O	O
Type C Leak Test	No(m)	No(m)	No(m)	No(m)
Valve Type	Gate	Gate	Gate	Gate
Operator	Solenoid	Solenoid	Solenoid	Solenoid
Primary Actuation	Electric	Electric	Electric	Electric
Secondary Actuation	N/A	N/A	N/A	N/A
Normal Position	Open	Open	Open	Open
Shutdown Position	Open	Open	Open	Open
Post-Accident Position	Open	Open	Open	Open
Power Fail Position	Open	Open	Open	Open
Containment Isolation Signal (c)	~~N/A~~ RM	~~N/A~~ RM	~~N/A~~ RM	~~N/A~~ RM
Closure Time (sec)	N/A	N/A	N/A	N/A
Power Source (Div)	N/A	N/A	N/A	N/A

See page 6.2-164 for notes

EVN

EVN

F033A|B

F035A-D

Table 6.2-7 Containment Isolation Valve Information Atmospheric Control System

Valve No.	T31-F731	T31-~~F733A/B~~	T31-~~F734~~A-D	T31-F010	T31-F011
SSAR Figure	6.2-39 (Sheet 3)	6.2-39 (Sheet 3)	6.2-39 (Sheet 3)	6.2-39 (Sheet 1)	6.2-39 (Sheet 1)
Applicable Basis	RG 1.11	RG 1.11	RG 1.11	GDC 56	GDC 56
Fluid	DW Atmosphere	DW Atmosphere	DW Atmosphere	Air or N_2	Air or N_2
Line Size	20A	20A	20A	250A	550A
ESF	No	No	No	Yes	Yes
Leakage Class	(a)	(a)	(a)	(a)	(a)
Location	O	O	O	O	O
Type C Leak Test	No(m)	No(m)	No(m)	Yes(e)	Yes(e)
Valve Type	Gate	Gate	Gate	Butterfly	Butterfly
Operator	Solenoid	Solenoid	Solenoid	Pneumatic	Pneumatic
Primary Actuation	Electric	Electric	Electric	Electric	Electric
Secondary Actuation	N/A	N/A	N/A	Manual	Manual
Normal Position	Open	Open	Open	Open	Close
Shutdown Position	Open	Open	Open	Open	Close
Post-Accident Position	Open	Open	Open	Open	Close
Power Fail Position	Open	Open	Open	Open	Close
Containment isolation Signal (c)	~~N/A~~ RM	~~N/A~~ RM	~~N/A~~ RM	RM	A, K XX, YY
Closure Time (sec)	N/A	N/A	N/A	<20 Sec.	<20 Sec.
Power Source (Div)	N/A	N/A	N/A	I	III

See page 6.2-164 for notes

EVN

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.14.6 ACS No. 4

NRC COMMENT:

SSAR Table 6.2-7 pages 6.2-149 and 150:

a) valves T31-F32A/B and T31-F734A/D are listed as gate valves and are equipped with solenoid/electric operators. P&ID 6.2-39, Sheet 3 of 3 showed these as manually operated globe valves.

b) valves T31-F737A-D implies 4 valves whereas on P&ID, only valves A and B are shown.

Resolve discrepancies.

GE RESPONSE:

GE concurs that these SSAR issues need to be clarified and will include the necessary changes in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Clarification per NRC comment. (See attached)

Verified as marked-up by GE.

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.14.4 SGTS No. 3

NRC COMMENT:

Figure 6.5-1 (Sh 2 of 3) and (3 of 3), coordinates 4/F: change the title of "EXHAUST" to "PROCESS."

GE RESPONSE:

GE concurs and will make this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comment.

Section 3.11 and is applicable to SGTS components. Dynamic qualification is addressed in Sections 3.9 and 3.10 for Seismic Category I equipment.

6.5.1.5 Instrumentation

Appendix 6B provides a discussion of the instrumentation for the SGTS. Control and instrumentation for the SGTS is also discussed in Subsections 7.3.1.1.5 and 7.3.2.5.

6.5.1.6 Materials

The construction materials used for the SGTS are compatible with normal and accident environments postulated for the area in which the equipment is located. The construction materials used in the dryer and filter trains are consistent with the recommendations of Regulatory Guide 1.52 and its references.

6.5.1.7 Operability and Effectiveness

Efficiency in the usual sense, can not be measured for adsorption systems. Adsorption is time dependent and therefore instantaneous containment-removal efficiency is meaningless. True efficiency tests are run on small, representative samples (test canisters) of the adsorbent using a radioactivity tagged tracer gas having similar properties and composition of those of the containment of interest (e.g., radioactive elemental iodine or methyl iodine). Because of the difficulty in handling radioactive materials, this type of test is generally not made in the field. The in-place field tests of installed systems are leak tests only. The iodine removal efficiency tests are carried out in a laboratory duplicating the field conditions as closely as possible.

The double filter train design for the SGTS depends on stationary components for normal (Routine) and accident operation. The pre-filter assembly is filled with glass fibers as are the pre and after HEPA filters. The charcoal iodine adsorber bed is located between the HEPA filters. All are located in a welded housing making up the filter train. The redundant active space heaters and fans operate only in the standby mode of the SGTS to dry the charcoal and maintain low relative humidity in the sealed train. Readiness for design operation is assured by effective surveillance tests.

The filter train availability depends on the stationary components replacement. The filter fiber glass sections are modularized for ease in handling. The charcoal is replaced by dumping old charcoal from below the bed and refilling with new charcoal from above. The integrity of the charcoal bed structure is maintained by limiting the moisture content of the charcoal in standby. The charcoal bed is oversized to reduce heating and weathering or aging effects. The bed has $\boxed{795\ kg}$ of charcoal and is 150% thick over the calculated 335 kg. required for adequate adsorber saturation and combustion protection.

OK IF P. 6.5-6 IS CHANGED TO NOMINAL 794 kg.

nominal 794 kg

Building ventilation exhaust radiation monitors during de-inerting, SGTS may be placed into service.

If purging (i.e., de-inerting) through the HVAC will [or does] result in a trip from the ventilation exhaust radiation monitors, then de-inerting will be [re-]initiated at a reduced rate through the SGTS. Use of SGTS during de-inerting is expected to be infrequent.

The design basis condition for the relevant dose analyses assumes that the large ventilation valves are closed, because the probability of a LOCA occurring at the same time the ventilation valves are open is very small. The large ventilation valves are, in fact, closed throughout normal plant operation except during inerting and de-inerting. The LOCA dose analyses do not assume any release from open containment isolation valves, either through the SGTS or through the normal ventilation system.

CHANGE "VALVES" TO DAMPERS"

A realistic assessment of plant capability in support of the exclusion indicates that the ventilation valves, if open, would be isolated before significant fission products are transported to the containment atmosphere. "Significant" means fission products above that normally present in the primary system. A period much longer than the closing time of the ventilation valves would be required to generate conditions leading to the release of TID 14844-like source terms. Therefore, should a LOCA occur when the ventilation valves are open (valves expected to be open only during inerting or de-inerting), little fission product release to the environment would actually occur. Therefore, the plant design and analysis in this regard is conservative and bounds releases actually expected in the event of a LOCA.

6.5.1.4 Tests and Inspection

The SGTS and its components are periodically tested during construction and operation. These tests fall in three categories:

(1) Environmental qualification tests

(2) Acceptance tests as defined in ASME N509 and N510

(3) Periodic surveillance tests

The above tests are performed in accordance with the objectives of Regulatory Guide 1.52 and its references. Acceptance tests (including pre-operational tests) and periodic surveillance tests are defined and extensively described in ASME N509 and ASME N510. Testing requirements in ASME N509 are generally located in Section 5, "Components." ASME N510 provides details of each component functional test. These tests are summarized in Table 9-1 of ASME N509 and Table 1 of ASME N510. Specific surveillance testing requirements for SGTS are provided in Technical Specification 3.6.4.3 (Chapter 16). Environmental qualification testing is discussed in

[TAKE OUT] 3

maintenance or operating personnel activity or an incredible malfunction of the space heaters. In this case, a fire in the SGTS charcoal, like in the offgas system, would be a matter of plant availability and not of plant safety. The space heaters, located inside the SGTS filter housing, are powered only during SGTS standby and not during system operation. Therefore, the space heaters are not a potential cause of fire (and SGTS unavailability) when the SGTS is required to meet the licensing-basis release limits (and presumably inaccessible for repair).

Note that the space heaters each have a small fan which better distributes the heat and minimizes local warming by providing a more uniform temperature throughout the filter housing. This uniform heating further reduces the risk of fire by lowering local temperatures around the space heater and by improving the accuracy of the temperature measurements (used to detect high temperature) taken at necessarily discrete points within the filter housing.

(4) Degradation of the charcoal effectiveness between charcoal efficiency surveillance tests is not likely to occur. During normal operation, the filter is isolated, and valves upstream and downstream of the filter train are closed. Therefore, during SGTS standby, the potential for impurities entering the filter train and unacceptably reducing charcoal efficiency is small. DAMPER

The ABWR SGTS charcoal bed thickness has been increased 5 cm to 15 cm as compared to the GESSAR II design. The additional 5 cm of charcoal provide an effective measure of protection against weathering or aging effects when the SGTS is placed into operation.

In addition to the increased charcoal bed depth, significantly more charcoal is provided than is required to meet the 2.5 mg iodine per gram carbon requirement. This added charcoal is used to meet the requirement specifying a residence time of 0.25 sec per 5 cm of bed depth. Approximately 332 kg of charcoal is required based on iodine loading calculated per Regulatory Guide [illegible] requirements, a 100% efficient charcoal adsorber, and no MSIV leakage. [illegible] SGTS charcoal adsorber is required to meet a 732 m/hr face velocity, which results in a normal 794 kg of charcoal assembly using a conservatively high 561 kg/m^3 charcoal density with 6800 m^3/hr fan size, meeting the 0.25 sec per 5 cm of bed depth (732 m/hr) requirement of Regulatory Guide 1.52 (Position C.3.i), and using a conservatively high 561 kg/m^3 charcoal density. The weight of charcoal will be adjusted to be consistent with the purchased charcoal density (usually less than 481 kg/m^3) and any dead space in the adsorber section itself.

THIS SHOULD BE "NOMINAL 794 kg"

(3)

6.5.1.2 System Design

6.5.1.2.1 General

The SGTS P&ID is provided as Figure 6.5-1.

6.5.1.2.2 Component Description

Table 6.5-1 provides a summary of the major SGTS components. The SGTS consists of two parallel and redundant filter trains. The two SGTS trains are located in two adjacent rooms. Each train is protected for fire, flood, pipe break and missiles. The electrical separation is provided by connecting the two trains to Divisions 2 and 3 electric power. The two trains are mechanically separated also. Suction is taken from the secondary containment, including above the refueling area, or from the primary containment via the Atmospheric Control System (ACS). The treated discharge goes to the main plant stack.

The SGTS consists of the following principal components:

(1) Two filter trains, each consisting of a of a moisture separator, an electric process heater, a prefilter, a high efficiency particulate air (HEPA) filter, a charcoal adsorber, a second HEPA filter, space heaters, and a cooling fan for the removal of decay heat from the charcoal.

(2) ~~Two independent process fans~~ located downstream of each filter train.

"A PROCESS FAN IS" OK

6.5.1.2.3 SGTS Operation

6.5.1.2.3.1 Automatic

Upon receipt of a high drywell pressure signal or a low reactor water level signal, or when high radioactivity is detected in the secondary containment or refueling floor ventilation exhaust, both SGTS trains are automatically actuated and one train is manually placed in the Standby mode. When the operation of both the trains is assured, one train is placed in the Standby mode. In the event that a malfunction disables an operating train, the standby train is automatically initiated.

6.5.1.2.3.2 Manual

T/PD

The SGTS is on standby during normal plant operation.It may be manually initiated for primary containment de-inerting in accordance with the Technical Specifications when required to limit the discharge of contaminants to the environment within 10CFR20 limits. Normal operation of the SGTS while the plant is in the startup, power, hot standby, and hot shutdown modes of operation is much less than 90 hours per year for both trains combined. However, if 90 hours of operation per year for either train (excluding tests) is to be exceeded, the COL applicant is required to demonstrate that

Section 3.11 and is applicable to SGTS components. Dynamic qualification is addressed in Sections 3.9 and 3.10 for Seismic Category I equipment.

6.5.1.5 Instrumentation

Appendix 6B provides a discussion of the instrumentation for the SGTS. Control and instrumentation for the SGTS is also discussed in Subsections 7.3.1.1.5 and 7.3.2.5.

6.5.1.6 Materials

The construction materials used for the SGTS are compatible with normal and accident environments postulated for the area in which the equipment is located. The construction materials used in the dryer and filter trains are consistent with the recommendations of Regulatory Guide 1.52 and its references.

6.5.1.7 Operability and Effectiveness

Efficiency in the usual sense, can not be measured for adsorption systems. Adsorption is time dependent and therefore instantaneous containment removal efficiency is meaningless. True efficiency tests are run on small, representative samples (test canisters) of the adsorbent using a radioactivity tagged tracer gas having similar properties and composition of those of the containment of interest (e.g., radioactive elemental iodine or methyl iodine). Because of the difficulty in handling radioactive materials, this type of test is generally not made in the field. The in-place field tests of installed systems are leak tests only. The iodine removal efficiency tests are carried out in a laboratory duplicating the field conditions as closely as possible.

The double filter train design for the SGTS depends on stationary components for normal (Routine) and accident operation. The pre-filter assembly is filled with glass fibers as are the pre and after HEPA filters. The charcoal iodine adsorber bed is located between the HEPA filters. All are located in a welded housing making up the filter train. The redundant active space heaters and fans operate only in the standby mode of the SGTS to dry the charcoal and maintain low relative humidity in the sealed train. Readiness for design operation is assured by effective surveillance tests.

The filter train availability depends on the stationary components replacement. The filter fiber glass sections are modularized for ease in handling. The charcoal is replaced by dumping old charcoal from below the bed and refilling with new charcoal from above. The integrity of the charcoal bed structure is maintained by limiting the moisture content of the charcoal in standby. The charcoal bed is oversized to reduce heating and weathering or aging effects. The bed has ~~796 kg~~. of charcoal and is 150% thick over the calculated 335 kg. required for adequate adsorber saturation and combustion protection.

nominally 794 kg.

Building ventilation exhaust radiation monitors during de-inerting, SGTS may be placed into service.

If purging (i.e., de-inerting) through the HVAC will [or does] result in a trip from the ventilation exhaust radiation monitors, then de-inerting will be [re-]initiated at a reduced rate through the SGTS. Use of SGTS during de-inerting is expected to be infrequent.

The design basis condition for the relevant dose analyses assumes that the large ventilation valves are closed, because the probability of a LOCA occurring at the same time the ventilation valves are open is very small. The large ventilation valves are, in fact, closed throughout normal plant operation except during inerting and de-inerting. The LOCA dose analyses do not assume any release from open containment isolation valves, either through the SGTS or through the normal ventilation system.

A realistic assessment of plant capability in support of the exclusion indicates that the ventilation valves, if open, would be isolated before significant fission products are transported to the containment atmosphere. "Significant" means fission products above that normally present in the primary system. A period much longer than the closing time of the ventilation valves would be required to generate conditions leading to the release of TID 14844-like source terms. Therefore, should a LOCA occur when the ventilation valves are open (valves expected to be open only during inerting or de-inerting), little fission product release to the environment would actually occur. Therefore, the plant design and analysis in this regard is conservative and bounds releases actually expected in the event of a LOCA.

Change "VALVES" to "BUTTERFLY VALVES"

6.5.1.4 Tests and Inspection

The SGTS and its components are periodically tested during construction and operation. These tests fall in three categories:

(1) Environmental qualification tests

(2) Acceptance tests as defined in ASME N509 and N510

(3) Periodic surveillance tests

The above tests are performed in accordance with the objectives of Regulatory Guide 1.52 and its references. Acceptance tests (including pre-operational tests) and periodic surveillance tests are defined and extensively described in ASME N509 and ASME N510. Testing requirements in ASME N509 are generally located in Section 5, "Components." ASME N510 provides details of each component functional test. These tests are summarized in Table 9-1 of ASME N509 and Table 1 of ASME N510. Specific surveillance testing requirements for SGTS are provided in Technical Specification 3.6.4.3 (Chapter 16). Environmental qualification testing is discussed in

maintenance or operating personnel activity or an incredible malfunction of the space heaters. In this case, a fire in the SGTS charcoal, like in the offgas system, would be a matter of plant availability and not of plant safety. The space heaters, located inside the SGTS filter housing, are powered only during SGTS standby and not during system operation. Therefore, the space heaters are not a potential cause of fire (and SGTS unavailability) when the SGTS is required to meet the licensing-basis release limits (and presumably inaccessible for repair).

Note that the space heaters each have a small fan which better distributes the heat and minimizes local warming by providing a more uniform temperature throughout the filter housing. This uniform heating further reduces the risk of fire by lowering local temperatures around the space heater and by improving the accuracy of the temperature measurements (used to detect high temperature) taken at necessarily discrete points within the filter housing.

(4) Degradation of the charcoal effectiveness between charcoal efficiency surveillance tests is not likely to occur. During normal operation, the filter is isolated, and [redacted] upstream and downstream of the filter train are closed. Therefore, during SGTS standby, the potential for impurities entering the filter train and unacceptably reducing charcoal efficiency is small.

dampers

... fission product release to the environment would actually occur

The ABWR SGTS charcoal bed thickness has been increased 5 cm to 15 cm as compared to the GESSAR II design. The additional 5 cm of charcoal provide an effective measure of protection against weathering or aging effects when the SGTS is placed into operation.

In addition to the increased charcoal bed depth, significantly more charcoal is provided than is required to meet the 2.5 mg iodine per gram carbon requirement. This added charcoal is used to meet the requirement specifying a residence time of 0.25 sec per 5 cm of bed depth. Approximately 332 kg of charcoal is required based on iodine loading calculated per Regulatory Guide 1.3 requirements, a 100% efficient charcoal adsorber, and no MSIV leakage. The SGTS charcoal adsorber is required to meet a 732 m/hr face velocity, which results in a [illegible] 794 kg of charcoal assembly using a conservatively high 561kg/m^3 charcoal density with 6800 m^3/hr fan size, meeting the 0.25 sec per 5 cm of bed depth (732 m/hr) requirement of Regulatory Guide 1.52 (Position C.3.i), and using a conservatively high 561kg/m^3 charcoal density. The weight of charcoal will be adjusted to be consistent with the purchased charcoal density (usually less than 481 kg/m^3) and any dead space in the adsorber section itself.

nominal

6.5.1.2 System Design

6.5.1.2.1 General

The SGTS P&ID is provided as Figure 6.5-1.

6.5.1.2.2 Component Description

Table 6.5-1 provides a summary of the major SGTS components. The SGTS consists of two parallel and redundant filter trains. The two SGTS trains are located in two adjacent rooms. Each train is protected for fire, flood, pipe break and missiles. The electrical separation is provided by connecting the two trains to Divisions 2 and 3 electric power. The two trains are mechanically separated also. Suction is taken from the secondary containment, including above the refueling area, or from the primary containment via the Atmospheric Control System (ACS). The treated discharge goes to the main plant stack.

The SGTS consists of the following principal components:

(1) Two filter trains, each consisting of a of a moisture separator, an electric process heater, a prefilter, a high efficiency particulate air (HEPA) filter, a charcoal adsorber, a second HEPA filter, space heaters, and a cooling fan for the removal of decay heat from the charcoal.

(2) ~~Two independent process fans~~ located downstream of each filter train.

A process fan is

6.5.1.2.3 SGTS Operation

6.5.1.2.3.1 Automatic

Upon receipt of a high drywell pressure signal or a low reactor water level signal, or when high radioactivity is detected in the secondary containment or refueling floor ventilation exhaust, both SGTS trains are automatically actuated and one train is manually placed in the Standby mode. When the operation of both the trains is assured, one train is placed in the Standby mode. In the event that a malfunction disables an operating train, the standby train is automatically initiated.

6.5.1.2.3.2 Manual

The SGTS is on standby during normal plant operation.It may be manually initiated for primary containment de-inerting in accordance with the Technical Specifications when required to limit the discharge of contaminants to the environment within 10CFR20 limits. Normal operation of the SGTS while the plant is in the startup, power, hot standby, and hot shutdown modes of operation is much less than 90 hours per year for both trains combined. However, if 90 hours of operation per year for either train (excluding tests) is to be exceeded, the COL applicant is required to demonstrate that

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 2.14.4 SGTS No. 2

NRC COMMENT:

SSAR Section 6.5: see attached pages for comments.

GE RESPONSE:

GE concurs with all NRC comments and will include these changes in the next SSAR amendment.

[Except for SSAR page 6.5-8 where the term "valve" will be changed to "butterfly valve" to be consistent with SSAR Figure 6.2-39]

Master SSAR says "dampers". Otherwise, verified. P&ID is right as per GE

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comments; see attached.

2.14.4 Standby Gas Treatment System

Design Description

The Standby Gas Treatment System (SGTS) is used to filter the gaseous effluent from either the primary or secondary containment. The purpose of the SGTS is to limit the discharge of radioactivity to the environment on receipt of a signal from the Leak Detection System (LDS). SGTS consists of two redundant divisions. ~~SGTS consists of two redundant divisions.~~ Figure 2.14.4 shows the basic system configuration and scope.

The SGTS is classified as safety-related.

Each division of the SGTS (except cooling fan and associated damper) is automatically initiated by signals from the LDS. Each SGTS division can be manually initiated from Main Control Room (MCR).

The SGTS maintains a negative pressure of 6.35 mm water gauge or greater in the secondary containment relative to the outdoor atmosphere within 20 minutes when the secondary containment is isolated. Each SGTS process fan capacity is at least 6800 m^3/hr (21°C and 1 atmosphere abs.) with the secondary containment not isolated. The absorber efficiency for removal of all forms of iodine (elemental, organic, particulate, and hydrogen iodide) from the influent stream is at least 99%.

After SGTS initiation, each cooling fan starts automatically when a signal indicates that the process fan in that division is not operating.

The SGTS has four safety-related differential pressure sensors for monitoring secondary containment pressure with respect to ambient pressure outside. One sensor is located on each of the four sides of the Reactor Building.

The SGTS is classified as Seismic Category I.

The SGTS is located in the Reactor Building.

The SGTS Division B is powered from Class 1E Division II, except for the cooling fan and associated damper, which is powered by Class 1E Division III. The SGTS Division C is powered from Class 1E Division III, except for the cooling fan and associated damper, which is powered by Class 1E Division II. Each of the four differential pressure sensors is powered from its respective Class 1E division. In the SGTS, independence is provided between Class 1E divisions and also between the Class 1E divisions and non-Class 1E equipment.

Except for the common connection to the plant stack, each mechanical division of the SGTS (Divisions B and C) is physically separated from the other division.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 10

NRC COMMENT:

Design acceptance criteria 5.a(1) should delete the word "equipment" so that HSI is not limited to equipment.

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

Rl 2/9

Table 3.1 Human Factors Engineering (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Design Acceptance Criteria**
5.	5.	5.
a. HSI Design Implementation Plan shall be developed which establishes that human engineering principles and criteria shall be applied in the design definition and evaluation of the HSI.	a. The HSI Design Implementation Plan shall be reviewed.	a. The HSI Design Implementation Plan shall establish: (1) The methods and criteria for HSI [illegible] design. (2) That the HSI design shall implement the information and control requirements: (a) developed through the task analyses, including the displays, controls and alarms necessary for the execution of those tasks identified in the task analyses as being critical tasks and, (b) defined in Table 2.7.1.a. (3) The methods for comparing the consistency of the HSI human performance, equipment design and associated workplace factors with that modeled and evaluated in the completed task analysis. (4) The HSI design criteria and guidance for control room operations during periods of maintenance, test and inspection. (5) The test and evaluation methods for resolving HFE/HSI design issues. These test and evaluation methods shall include the criteria to be used in selecting HFE/HSI design and evaluation tools.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 12

NRC COMMENT:

Apply Comment No. 5 to 6.a(1).

GE RESPONSE: REVISED

GE does not concur. See response to NRC comment 3.1 No. 3.

GE concurs and will include this change in the next revision of 25A5447

PROPOSED CHANGES

CDM: ~~None~~ Per NRC comment; see attached

SSAR: None

Table 3.1 Human Factors Engineering (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Design Acceptance Criteria**
b. The HSI design shall be implemented.	b. The HSI design implementation shall be reviewed.	b. The HSI design implementation and analyses, as corrected to account for nonconformances, are conducted in accordance with the requirements of the Human Factors Engineering Program Plan and the HSI Design Implementation Plan,
6.	6.	6.
a. A Human Factors Verification and Validation (V&V) Implementation Plan shall be developed which establishes that the HSI design shall be evaluated as an integrated system using HFE evaluation principles, procedures and criteria.	a. The Human Factors V&V Plan shall be reviewed.	a. The Human Factors V&V Implementation Plan shall establish: (1) The methods and criteria for conducting the Human factors V&V. (2) That scope of the evaluations of the integrated HSI shall include: (a) The HSI (including both the interface of the operator with the HSI equipment hardware and the interface of the operator with the HSI equipment's software driven functions). (b) The Plant and Emergency Operating Procedures. (c) The HSI work environment.

in accordance with accepted human factors practices and principle

AL 7/25

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.1 HFE No. 13

NRC COMMENT:

Design acceptance criteria 6.a.(4), page 3.1-15, correct typo to change "ask" to "task."

GE RESPONSE:

GE concurs and will include this change in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comment; see attached.

SSAR: None

fe 2/11

Table 3.1 Human Factors Engineering (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Design Acceptance Criteria**
6.a.Continued	6.a. Continued task	6.a. Continued (3) That evaluations of the HSI equipment shall be conducted to confirm that the controls, displays, and data processing functions identified in the task analyses are provided. (4) That integration of HSI equipment with each other, with the operating personnel and with the Plant and Emergency Operating Procedures shall be evaluated through the conduct of dynamic task performance testing. The dynamic task performance tests and evaluations shall have as their objectives: (a) Confirmation that the identified critical functions can be achieved using the integrated HSI design. (b) Confirmation that the HSI design and configuration can be operated using the established MCR staffing levels.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

Vri

CDM SECTION AND COMMENT No.: 3.1 HFE No. 15

NRC COMMENT:

SSAR page 18C-1, paragraph 1 references section 18.5 (Operator Interface Design Implementation Requirements). This appears to be an incorrect reference. Section 18.5 is Remote Shutdown System.

GE RESPONSE:

GE concurs that this is an incorrect reference and will modify the SSAR per the attached.

PROPOSED CHANGES

CDM: None

SSAR: Per attached markup.

18.7 (Detailed Design of the Operator Interface System)

18C Operator Interface Equipment Characterization

This Appendix contains a characterization of one operator interface system which has been designed to meet the design requirements as specified in Section 18.4. The key features of the design are discussed. The design characterized in this appendix does not necessarily represent the final design. The final design must be established based upon the requirements of Section 18.5 (Operator Interface Design Implementation Requirements), which is the responsibility of the COL applicant.

18C.1 Control Room Arrangement

The conceptual main control room contains the main control console, the large display panel, the supervisor's console, the assistant shift supervisor's desk, a large table and various other desks, peripheral equipment and storage space. The arrangement of these items of equipment and furniture is shown in Figure 18C-1. The spatial arrangement of the main control console, large display panel and supervisor's console is a standard design feature, as discussed in Subsection 18.4.2.15. Figure 18C-1 illustrates this standard arrangement.

18C.2 Main Control Room Configuration

The conceptual main control panel is configured as shown in a plan view in Figure 18C-2. As shown in Figure 18C-2, the configuration is that of a shallow, truncated V with desk space attachments at the ends of both wings. The dimensions are such that two operators can comfortably work at the console at all times.

A cross-sectional view of the main console is shown in Figure 18C-3. This is a cross-section at points A-A, indicated in Figure 18C-2. This view gives an indication of the console height and the depth of the console desk surface. The dashed lines indicate the position of the computer driven VDUs, which, in this concept, are CRTs.

A second cross-sectional view, at points B-B, as indicated in Figure 18C-2, is shown in Figure 18C-4. This view shows the cross-sectional shape of the console in the desk areas.

Figure 18C-4 shows a larger, more detailed version of the schematic shown in Figure 18C-2. This detail includes the identification and arrangement of the equipment installed on the main control console. This equipment includes computer-driven CRTs, flat panel display devices, panels of dedicated function switches and analog displays for selected equipment (e.g., Standby Liquid Control System and the main generator). The flat panel display devices are driven by dedicated microprocessors and, thus, are independent of the process computer.

In general, the conceptual equipment arrangement on the main console is (1) safety-related and NSS on the left, (2) overall plant supervision in the center and (3) balance of plant on the right.

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.2 RAD. PRO. No. 4b

NRC COMMENT:

SSAR Section 12.3.2.3 alludes to an Area Monitor in the spent fuel pool cleanup room. Could not locate one on the P&IDs or on the ARM equipment list.

GE RESPONSE:

~~GE believes the SSAR adequately addresses the issue of area radiation monitors in the spent fuel storage pool area. (The NRC comment uses the term "spent fuel pool cleanup room" but GE assumes the NRC comment relates to the spent fuel pool area as discussed in SSAR Section 12.3.2.3(4), page 12.3-20). Table 12.3-3 identifies two area radiation monitoring units in this area, Units 3 and 4 and both of these units are shown on the SSAR Figure 12.3-62 (as Units 3 and 4). Consequently, GE proposes no changes in response to this NRC comment.~~

GE Agrees. ~~[illegible]~~ SSAR TO BE REVISED.

PROPOSED CHANGES

CDM: None

SSAR: ~~None~~ See attached

Subject: Fuel Components Area Rad Monitor, Rev 1

Message: Reference to ABWR SSAR Subsection 12.3.2.3 (4) Fuel Components. This paragraph is subject to misinterpretation and is therefore being revised as follows:

> The fuel storage pool is designed to insure that the dose rate around the pool area is less than 10 μSv/hr (1mR/hr). In the event of an anticipated operational occurrence where the fuel sustains significant damage, such as a fuel drop accident, airborne dose rates in the pool area may significantly exceed this dose rate. Egress from this area can be successfully accomplished well before dose rates exceed moderate levels (250 μSv/hr) since the local area radiation monitors will alarm in the area.

Note that the sentence in the original paragraph referring to the pump area has been deleted. The fuel pool pumps in the ABWR are in a radiation restricted area at the 18,100 mm level in the north west corner of the building.

verify

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.2 RAD. PROD. No. 4c

NRC COMMENT:

SSAR Section 12.3.2.2.1(10), 1st sentence, "gr/cm^3" should read "gm/cm^3."

GE RESPONSE:

GE concurs and will correct this typographical error in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comments; see attached.

(d) Separating radioactive and nonradioactive pipes for maintenance purposes

(6) To maintain acceptable levels at the valve stations, motor-operated or diaphragm valves are used where practical. For valve maintenance, provision is made for draining and flushing associated equipment so that radiation exposure is minimized. If manual valves are used, provision is made for shielding the operator from the valve by use of shield walls and valve stem extensions, where practicable.

(7) Shielding is provided to permit access and occupancy of the control room to ensure that plant personnel exposure following an accident does not exceed the guideline values set forth in 10CFR50 Appendix A, Criterion 19. The analyses of the doses to control room personnel for the design basis accidents are included in Chapter 15.

(8) The dose at the site boundary as a result of direct and scattered radiation from the turbine and associated equipment is considered.

(9) In selected situations, provisions are made for shielding major radiation sources during inservice inspection to reduce exposure to inspection personnel. For example, steel platforms are provided for ISI of the RPV nozzle welds and associated piping.

gm

(10) The primary material used for shielding is concrete at a density of 2.3 g/cm^3. Concrete used for shielding purposes is designed in accordance with Regulatory Guide 1.69. Where special circumstances dictate, steel, lead, water, lead-loaded silicone foam, or a boron-laced refractory material is used.

(11) There is no field-routed piping in the ABWR design. Large and small piping, as well as instrument tubing, are routed by designers as indicated in the preceding paragraph (5).

12.3.2.2.2 Method of Shielding Design

The radiation shield wall thicknesses are determined using basic shielding data and proven shielding codes. A list of the computer programs used is contained in Table 12.3-1. The shielding design methods used also rely on basic radiation transport equations contained in Reference 12.3-1. The sources for basic shielding data, such as cross sections, buildup factors, and radioisotope decay information, are listed in References 12.3-2 through 12.3-10.

The shielding design is based on the plant operating at maximum design power with the release of fission products resulting in a source of 100,000 μCi/sec of noble gas after a 30-minute decay period, and the corresponding activation and corrosion product

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ABWR DESIGN CERTIFICATION

FEBRUARY 1994

Verified

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.2 RAD. PRO. No. 4d

NRC COMMENT:

See markup to correct typos on attached section 12A.

GE RESPONSE:

GE concurs that Section 12.A contains typographical errors needing correction. See attached. Note: This markup includes some additional changes not identified by the NRC.

ultimately be outflow from the compartment but may also take the

PROPOSED CHANGES

CDM: None

SSAR: Per attached markup.

GE - PROPOSED SSAR UPDATE 1/2

λ_i = Radionuclide decay constant

Evaluation Parameters

The following parameters require evaluation on a case-by-case basis dictated by the physical parameters and processes germane to the modeling process:

(1) S_{ij} is defined as the source rate for radionuclide i into the compartment. Typically, these sources take the form of:

(a) Inflow of contaminated air from an upstream compartment. Given the concentration of radionuclide i, c_i, in this air and a flow rate of "r", the source rate then becomes $S_{ij} = rc_i$.

(b) Production of airborne radionuclides from equipment. This typically takes two forms, gaseous leakage and liquid leakage.

(i) For gaseous leakage sources, the source rate is equal to the concentration of radionuclide i, c_i, and the leakage rate, "r", or $S_{ij} = rc_i$.

(ii) For liquid sources, the source rate is similar but more complex. Given a liquid concentration c_i and a leakage rate, "r", the total release from the leak is rc_i. The fraction of this release which then becomes airborne is typically evaluated by a partition factor, P_f which may be conservatively estimated from:

Noble Gases

$$P_f = 1$$

All others

$$P_f = \frac{h_t - h_f}{h_s - h_f}$$

where:

h_t = Saturated liquid enthalpy

h_f = Saturated liquid enthalpy at one atmosphere = 100.10 kcal/kg

h_s = Saturated vapor enthalpy at one atmosphere = 639.18 kcal/kg

Therefore, the liquid release rate becomes, rc_iP_f.

Vri

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(2) R_{ijk} is defined as the removal rate constant and typically consists of:

(a) Exhaust rate from the compartment. This term considers not only the exhaust of any initially contaminated air, but also any clean air which may be used to dilute the compartment air.

(b) Compartment filter systems are treated by the equation:

$$R_{ijk} = (1-F_i) * r_i$$

where

r_i = Filter system flow rate

F_i = Filter efficiency for radionuclide i

(c) Other removal factors on a case-by-case basis which may be deemed reasonable and conservative.

Example Calculation

3

(Values used below are examples only and should not be used in any actual evaluation.) This example will look at I-131 in a compartment 6.1 × 6.1 × 7.6 = 282.80 m^3 = V. First, all primary sources of radionuclides need to be identified and categorized.

(1) Flow into the compartment equals 424.8 m^3/hr with the input I-131 concentration equal to $2 \times 10^{-10} \mu Ci/ml$ (from upstream compartments) or $2.4 \times 10^{-11} Ci/sec$. No other sources of air either contaminated or clean air are assumed.

(2) The compartment contains a pump carrying reactor coolant with a maximum specified leakage rate of 0.000034 m^3/hr at ~~275.6~~°C.
287.8

(a) Conservatively it can be estimated based upon properties from steam tables (Note 1) that under these conditions 44% of the liquid will flash to steam and become airborne. Along with the flashing liquid, it is assumed that a proportional amount of I-131 will become airborne; therefore, $P_f = 0.44$.

(b) Using the design basis iodine concentrations for reactor water from Table 11.1-2 of 0.016µ Ci/gm of I-131, it is calculated that the pump is providing a source of I-131 of $5.0 \times 10^{-11} Ci/sec$ to the air (Note 2).

Second, the sinks for airborne material need to be identified. This example includes only exhaust which is categorized as flow out of the compartment at 150% per hour or 4.2×10^{-4} per second.

Verified

3/6

Therefore, for an equilibrium situation, the I-131 airborne concentration from this liquid source would be calculated from the following equation:

$$A = \frac{1}{V} S_1/(\lambda + R_1) + S_2/(\lambda + R_2)$$

where

V = Volume of containment = 286.5 m

S_1 = Source rate in Curies per second = 5.0×10^{-11} Ci/sec from liquid

S_2 = Source rate from inflow = 2.4×10^{-11} Ci/sec

λ = Isotope decay constant in units per second = 9.977×10^{-7}/sec

R_1 = R_2 = removal rate constant per second (exfiltration) = 4.2×10^{-4} per second

A = 6.2×10^{-10} µCi/ml of I-131.

NOTE:

(1) The assumption of 44% flashing at ~~273.6~~ 287.8°C is extremely conservative; see Reference 12A-1 for a discussion of fission product transport.

(2) Water density assumed at 0.743 gm/cm^3 based upon standard tables for water at ~~273.6~~°C. 287.8

12A.2 References

12A-1 Paquette, et al, *Volatility of Fission Products During Reactor Accidents*, Journal of Nuclear Materials, Vol 130 Pg 129–138, 1985.

1/0

Therefore, for an equilibrium situation, the I-131 airborne concentration from this liquid source would be calculated from the following equation:

$$\underline{\bar{A}} = S_1/(\lambda + R_1) + S_2/(\lambda + R_2)$$

where

S_1	=	Source rate in Curies per second = 5.0×10^{-11} Ci/sec from liquid
S_2	=	Source rate from inflow = 2.4×10^{-11} Ci/sec
	=	Isotope decay constant in units per second = 9.977×10^{-7}/sec
R_1	=	R_2 = removal rate constant per second (exfiltration) = 4.2×10^{-4} per second.
$\bar{A}$	=	6.2×10^{-10} μCi/ml of I-131.

NOTE:

(1) The assumption of 44% flashing at 273.6°C is extremely conservative; see Reference 12A-1 for a discussion of fission product transport.

(2) Water density assumed at 0.743 gm/cm^3 based upon standard tables for water at 273.6°C.

12A.2 References

12A-1 Paquette, et al, *Volatility of Fission Products During Reactor Accidents*, Journal of Nuclear Materials, Vol 130 Pg 129–138, 1985.

12A Appendix 12A Calculation of Airborne Radionuclides

12A.1 Calculation of Airborne Radionuclides

This appendix presents a simplified methodology to calculate the airborne concentrations of radionuclides in a compartment. This methodology is conservative in nature and assumes that diffusion and mixing in a compartment is basically instantaneous with respect to those mitigating mechanisms such as radioactive decay and other removal mechanisms. The following calculations need to be performed on an isotope-by-isotope basis to verify that airborne concentrations are within the limits of 10CFR20:

(1) For the compartment, all sources of airborne radionuclides need to be identified such as:

(a) Flow of contaminated air from other areas

(b) Gaseous releases from equipment in the compartment

(c) Evolution of airborne sources from sumps or water leaking from equipment

(2) Second, the primary sinks of airborne radionuclides need to be identified. This will primarily be outflow from the compartment but may also take the form of condensation onto room coolers.

(3) Given the above information the following equation will calculate a conservative concentration.

$$C_i = \frac{1}{V}\sum_j \frac{S_{ij}}{\left(\lambda_i + \sum_k R_{ijk}\right)}$$

Where:

C_i = Concentration of the i^{th} radionuclides in the room

V = Volume of room

S_{ij} = The j^{th} source (rate) of the i^{th} radionuclide to the room. These sources are discussed below.

R_{ijk} = The k^{th} removal constant for the j^{th} source and the i^{th} radionuclide as discussed below.

λ_i = Radionuclide decay constant

Evaluation Parameters

The following parameters require evaluation on a case-by-case basis dictated by the physical parameters and processes germane to the modeling process:

(1) S_{ij} is defined as the source rate for radionuclide i into the compartment. Typically, these sources take the form of:

(a) Inflow of contaminated air from an upstream compartment. Given the concentration of radionuclide i, c_i, in this air and a flow rate of "r", the source rate then becomes $S_{ij} = rc_i$.

(b) Production of airborne radionuclides from equipment. This typically takes two forms, gaseous leakage and liquid leakage.

(i) For gaseous leakage sources, the source rate is equal to the concentration of radionuclide i, c_i, and the leakage rate, "r", or $S_{ij} = rc_i$.

(ii) For liquid sources, the source rate is similar but more complex. Given a liquid concentration c_i and a leakage rate, "r", the total release from the leak is rc_i. The fraction of this release which then becomes airborne is typically evaluated by a partition factor, P_f which may be conservatively estimated from:

Noble Gases

$$P_f = 1$$

All others

$$P_f = \frac{h_t - h_f}{h_s - h_f}$$

where:

h_t = Saturated liquid enthalpy

h_f = Saturated liquid enthalpy at one atmosphere = 100.10 kcal/kg

h_s = Saturated vapor enthalpy at one atmosphere = 639.18 kcal/kg

Therefore, the liquid release rate becomes, rc_iP_f.

(2) R_{ijk} is defined as the removal rate constant and typically consists of:

(a) Exhaust rate from the compartment. This term considers not only the exhaust of any initially contaminated air, but also any clean air which may be used to dilute the compartment air.

(b) Compartment filter systems are treated by the equation:

$$R_{ijk} = (1-F_i)^{*} r_i$$

where

r_i = Filter system flow rate

F_i = Filter efficiency for radionuclide i

(c) Other removal factors on a case-by-case basis which may be deemed reasonable and conservative.

Example Calculation

(Values used below are examples only and should not be used in any actual evaluation.) This example will look at I-131 in a compartment 6.1 × 6.1 × 7.6 = 282.80 m^3 = V. First, all primary sources of radionuclides need to be identified and categorized.

(1) Flow into the compartment equals 424.8 m^3/hr with the input I-131 concentration equal to $2 \times 10^{-10} \mu Ci/ml$ (from upstream compartments) or $2.4 \times 10^{-11} Ci/sec$. No other sources of air either contaminated or clean air are assumed.

(2) The compartment contains a pump carrying reactor coolant with a maximum specified leakage rate of 0.000034 m^3/hr at 273.6°C.

(a) Conservatively it can be estimated based upon properties from steam tables (Note 1) that under these conditions 44% of the liquid will flash to steam and become airborne. Along with the flashing liquid, it is assumed that a proportional amount of I-131 will become airborne; therefore, P_f = 0.44.

(b) Using the design basis iodine concentrations for reactor water from Table 11.1-2 of 0.016μ Ci/gm of I-131, it is calculated that the pump is providing a source of I-131 of $5.0 \times 10^{-11} Ci/sec$ to the air (Note 2).

Second, the sinks for airborne material need to be identified. This example includes only exhaust which is categorized as flow out of the compartment at 150% per hour or 4.2×10^{-4} per second.

3.2 01.

Therefore, for an equilibrium situation, the I-131 airborne concenuration from this liquid source would be calculated from the following equation:

$$\lambda C = \frac{1}{V} S_1/(\lambda + R_1) + S_2/(\lambda + R_2)$$

X

where

V = Room volume = 282 80 m^3 X

S_1 = Source rate in Curies per second = 5.0×10^{-11} Ci/sec from liquid

S_2 = Source rate from inflow = 2.4×10^{-11} Ci/sec

λ = Isotope decay constant in units per second = 9.977×10^{-7}/sec X

R_1 = R_2 = removal rate constant per second (exfiltration) = 4.2×10^{-4} per second

λC = 6.2×10^{-10} µCi/ml of I-131. X

NOTE:

(1) The assumption of 44% flashing at 273.6°C is extremely conservative; see Reference 12A-1 for a discussion of fission product transport.

(2) Water density assumed at 0.743 gm/cm^3 based upon standard tables for water at 273.6°C.

12A.2 References

12A-1 Paquette, et al, *Volatility of Fission Products During Reactor Accidents*, Journal of Nuclear Materials, Vol 130 Pg 129–138, 1985.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.2 RAD. PRO. No. 4f

NRC COMMENT:

SSAR Section 12.3.4.3, third paragraph is confusing – "point" should be changes to "any point."

GE RESPONSE:

GE concurs that this statement should be clarified and will include the attached change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per attached markup.

defined in Sections 9.1 and 9.2. The COL applicant must verify and certify that the design meets the criteria specified in Subsection 12.3.7.3.

The detectors and radiation monitors are responsive to gamma radiation over an energy range of 80 keV to 7 MeV. The energy dependence ~~will not exceed 20% of point from 100 keV to 3 MeV~~. The overall system design accuracy is within 9.5% of equivalent linear full-scale recorder output for any decade.

from 100 keV to 3 MeV is accurate within ± 20%.

The alarm setpoints will be established in the field by the COL applicant, as specified in Subsection 12.3.7.2, following equipment installation at the site. The exact settings will be based on sensor location, background radiation levels, expected radiation levels, and low occupational radiation exposures. The high radiation alarm setpoint for each channel is set slightly above the background radiation level that is normal to the area.

The area radiation monitoring instrumentation is designed to provide early detection and warning for personnel protection to insure that occupational radiation exposures will be as low as is reasonably achieved (ALARA) in accordance with guidelines stipulated in Regulatory Guide 8.2 and 8.8.

The Area Radiation Monitoring System includes instrumentation provided to assess the radiation conditions in crucial areas in the Reactor Building (the RHR equipment areas) where access may be required to service the safety-related equipment during post-LOCA per Regulatory Guide 1.97.

12.3.5 Post-Accident Access Requirements

The locations requiring access to mitigate the consequences of an accident during the 100-day post-accident period are the control room, the technical support center, the remote shutdown panel, the primary containment sample station (Post-Accident Sample System), the health physics facility (counting room), and the nitrogen gas supply bottles. Each area has low post-LOCA radiation levels. The dose evaluations in Subsection 15.6.5 are within regulatory guidelines.

Access to vital areas throughout the Reactor Building/Control Building/Turbine Building complex is controlled via the Service Building. Entrance to the Service Building and access to the other areas are controlled via double-locked secured entry ways. Access to the Reactor Building is via two specific routes, one for clean access and the second for controlled access. During an event such as a design basis accident, the Service Building/Control Building are maintained under filtered HVAC at a positive pressure with respect to the environment. Air infiltration is minimized by positive flow via double entry ways. Therefore, radiation exposure is limited to gamma shine from the Reactor Building, Turbine Building, main steamline access corridor, and skyline. This shine is minimized by locating highly populated areas below ground.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.2 RAD. PRO. No. 4h

NRC COMMENT:

SSAR Table 15.7.1 should be revised to indicate 400, 000 uCi/sec Offgas Release Rate, 100,000 uCi/sec Design Basis Rate and 400,000 uCi/sec Maximum TS instead of the current 400,000; 100,00'; and 400,00 uCi/sec respectively.

GE RESPONSE:

GE concurs that Table 15.7.1 contains typographical errors and will correct them in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per NRC comments; see attached.

Table 15.7-1 Offgas System Failure Accident Parameters

I. Data and Assumptions Used to Estimate Source Terms	
A. Power Level	4005MWt
B. Offgas Release Rate	~~400,00~~ 400,000 µCi/sec (referenced to 30 min)
C. Charcoal Mass	Guard Tank, 4,721 kg
D. Charcoal Delay[1]	
Kr	2.07 hr
Xe	36.9 hr
E. Duration of Release	30 min
F. Design Basis Rate	~~100,00~~ 100,000 µCi/sec
G. Maximum Technical Specification Rate	~~400,00~~ 400,000 µCi/sec
II. Dispersion and Dose Rate	
A. Meteorology	Table 15.7-3
B. Dose Methodology	Reference 15.7-1
C. Dose Conversion Assumptions	Reference 15.7-1, RG 1.109
D. Activity Releases	Table 15.7-2
E. Dose Evaluations	Table 15.7-3

Note 1: Charcoal Delay calculated based upon charcoal mass using equation 1.5.1.6 of NUREG-001`6 and K_d's taken from 1.5.2.19 and 1.5.2.20 of NUREG-0016.

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.3 PIPING No. 1

NRC COMMENT:

Correct attached CDM typo.

GE RESPONSE:

GE concurs and will include these corrections in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per NRC comments; see attached.

SSAR: None

3.3 1

For those piping systems using austenitic stainless steel materials as permitted by the design specification, the stainless steel piping material and fabrication process shall be selected to reduce the possibility of cracking during service. Chemical, fabrication, handling, welding, and examination requirements that reduce cracking shall be met.

Piping system supports shall be designed to meet the requirements of ASME Code Subsection NF.

For piping systems, the pipe applied loads on attached equipment shall be calculated and shown to be less than the equipment allowable loads.

Analytical methods and load combinations used for analysis of piping systems shall be referenced or specified in the ASME Code Certified Stress Report. Piping systems and their supports shall be mathematically modeled to provide results for piping system frequencies up to the analysis cutoff frequency. Computer programs used for piping system dynamic analysis shall be benchmarked.

typo

Systems, structures and components that shall be required to be functional during and following an SSE shall be protected against the dynamic effects associated with postulated high energy pipe breaks in Seismic Category I and NNS piping systems. The Pipe Break Analyses Report shall specify the criteria used to postulate breaks and the analytical methods used to perform the pipe break analysis. For postulated pipe breaks, the Pipe Break Analysis Report shall confirm: (1) piping stresses in the containment penetration area shall be within their allowable stress limits, (2) pipe whip restraints and jet shield designs shall be capable of mitigating pipe break loads, and (3) loads on safety-related systems, structures and components shall be within their design loads limits. Piping systems that shall be qualified for leak-before-break design may exclude design features to mitigate the dynamic effects from postulated high energy pipe breaks.

typo

Structures, systems, and components that shall be required to be functional during and following an SSE shall be protected against the effects of spraying, flooding, pressure and temperature due to pstulated pipe breaks and cracks in Seismic Category I and NNS piping systems.

Piping systems shall be designed to provide clearance from structures, systems, and components where necessary for the accomplishment of the structure, system, or component's safety function as specified in the respective structure or system Design Description.

The as-built piping shall be reconciled with the piping design required by this section.

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.4 I&C DAC No. 2.1 AND 2.4

NRC COMMENT:

CDM 3.4B Instrumentation Setpoint Methodology, page 3.4-9. SSAR 7.1.2.10.9 Regulatory Guide 1.105, Instrumentation setpoints. CDM description is inconsistent with the standard and regulatory guide:

1) The CDM references a "nominal trip setpoint." This term is not defined in RG 1.105 or ISA 67.04-1982. See attached.

GE RESPONSE:

~~Later~~ see following draft response on pages PQ 1&2

PROPOSED CHANGES

CDM: None

SSAR: None

(PQ) 1/~

An important principle guiding preparation of the CDM is that this document is a top-level summary of the broader design defined in the SSAR. This includes the principle that CDM technical terminology should be the same as that used in the SSAR. This principle was observed when preparing the technical information on Instrument Setpoint Methodology in CDM Section 3.4. Specifically the CDM terminology is the same as the SSAR terminology defined in the GE Report NEDC-31336, General Electric Instrument Setpoint Methodology, Nov. 1986, Julie Leong. This GE report is identified in SSAR Table 1.6-1 as a report that is incorporated INSERT into the SSAR by reference. The GE report has been reviewed by NRC and found acceptable. See attached NRC letter dated 2/9/93, MFN-027-93. The staff's safety evaluation attached to this letter also discusses the

(PQ) (2/2)

adequacy of GE's setpoint terminology.

In summary, GE believes the SSAR and CDM use consistent terminology for setpoint methodology and no changes are proposed in response to this NRC comment.

INSERT In addition, this report is referenced by SSAR Section 7.3.2.1a.2, as provided

... Safety Limit and the Analytical Limit is described ...

in the methodology for establishing instrument setpoints. ~~[illegible]~~

CDM SECTION AND COMMENTS No.: 3.4 I&C DAC No. 2.1 AND 2.4 (Continued)

NRC COMMENT: (Continued)

4) A definition of allowable value is not given in ISA ~~76~~ 67.04-1982. RG 1.105 endorses the figure description as depicted in ISA 67.04-1982. The allowable value description listed in the CDM material is inconsistent with the standard (both 1982 and 1987) and RG 1.105. See attached.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

February 9, 1993
MFN-027-93

RECEIVED
FEB 18
D.J. ROB

Mr. David J. Robare, Manager
Plant Licensing Services
General Electric Nuclear Energy
175 Curtner Avenue
San Jose, California 95125

Dear Mr. Robare:

SUBJECT: GENERAL ELECTRIC COMPANY (GE) TOPICAL REPORT NEDC-31336 "GENERAL ELECTRIC INSTRUMENTATION SETPOINT METHODOLOGY"

We have completed our review of the subject topical report submitted by General Electric in October 1986. Enclosure 1 provides our Safety Evaluation Report (SER) in which we conclude that:

1. Although NEDC-31336 is an important reference for understanding how GE selects instrumentation setpoints, the topical report is not to be used by any plant to validate their individual setpoints. That is, each plant must provide its own plant unique analysis for the setpoints. The examples given in the topical report are used by GE only to show the safety margins and typical channel errors that might be expected. Since plants have different instruments, environments, seismic and other requirements, only examples have been provided by GE in this report.

2. Where instruments are used that are different from those presented in NEDC-31336, the licensee must demonstrate that drift is, or is not random, it is normally distributed and can be quantified.

3. The general methods used by GE in selecting instrumentation setpoints are acceptable.

4. The use of single-sided confidence tests is only acceptable for those channels that provide trips in one direction.

5. NEDC-31336 is only acceptable for determining instrumentation trip setpoints (not evaluating indicators) using equipment that is not in a harsh (e.g. accident) environment.

In accordance with procedures established in NUREG-0390 "Topical Report Review Status," we request that the BWR Owners Group publish NEDC-31336 within 3 months of receipt of this letter. The accepted proprietary version should (1) incorporate this letter and the enclosed Safety Evaluation Report between the title page and the abstract and (2) include an -A (designated accepted) following the report identification symbol.

Should our acceptance criteria or regulations change so that our conclusions as to the acceptability of the report are no longer valid, the BWR Owners Group and/or the applicants referencing this topical report will be expected to revise and resubmit their respective documentation, or submit justification for the continued applicability of the topical report without revision of its documentation.

Sincerely,

Bruce A. Boger, Director
Division of Reactor Controls
and Human Factors
Office of Nuclear Reactor Regulation

Enclosure:
Safety Evaluation Report

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TOPICAL REPORT

INSTRUMENTATION SETPOINT METHODOLOGY

GENERAL ELECTRIC COMPANY

NEDC - 31336

1.0 INTRODUCTION

This report provides the basis for acceptance of and limits on the acceptance of the topical report submitted by General Electric (GE) describing the basis for instrumentation (trip) setpoint selection for instruments that are not operated in a harsh environment. The criteria for approving the topical report are General Design Criterion 20, 10 CFR Part 50.36 and Part 50.46.

1.1 DESIGN FEATURES AND PARAMETERS

Since 1976, considerable interest has been expressed about how setpoints are selected in nuclear power plants. Of particular concern is the adequacy of the setpoints with regard to assumptions made in the accident simulations. The result of this interest was publication of proprietary topical reports by the nuclear steam suppliers, revisions of industry standards for setpoint calculations and revision to Regulatory Guide 1.105 "Instrument Setpoints for Safety Related Systems." This regulatory guide endorses ISA-S67.04-1982 "Setpoints for Nuclear Safety Related Instrumentation Used in Nuclear Power Plants."

The topical report that is the subject of this safety evaluation report (SER) was originally published in October 1986 and was subject to minor revisions in early 1992. However, the work involved in the development of this topical is a continuation of efforts that have been the subject of previous staff SERs (e.g. "Staff Report on Setpoint Methodology for General Electric Supplied Protection System Instrumentation" dated May 15, 1984).

2.0 EVALUATION

2.1 General Comments

The current topical report is an important document that is critical to the understanding of how GE selects setpoints. However, in the April 8, 1992 responses to the staff's questions on NEDC-31336, GE states that the examples used in the topical report "are not to be used by any plant to validate their individual setpoints. That is, each plant must provide their own plant unique analysis for the setpoints.... The examples are used to show the safety margins and typical channel errors that might be expected. Since plants have different instruments, environments, seismic and other requirements only examples have been provided."

The remainder of this evaluation is devoted to a review of the individual sections of the topical report. Section 5 "References" was not reviewed.

2.2 Section 1 "Instrument Setpoint Methodology"

This section starts with a general description of how setpoints are established. The general description is followed by a set of definitions of terms that are used in the methodology. Next, the methods identify the relationship between the different setpoints and the required data that form the terms of the calculations. Finally, the combining of terms to generate and test the setpoints is discussed.

The definitions used in the topical are in general agreement with recognized industry standards such as ISA-S67.04-1982. Table I provides a quick cross reference between the definitions in a top down sequence.

TABLE I

NEDC-31336	ISA-S67.04-1982	RG 1.105
Licensing Safety Limit	Safety Limit	Safety Limit
Analytical Limit	Not Defined	Not Defined
Allowable Value (Tech Spec Limit)	Not Defined	Not Defined
Nominal Trip Setpoint	Setpoint	Upper Limit Setpoint
Steady State Operating	Not Defined	Not Defined

Although the analytical limit and allowable value are not defined in ISA-S67.04-1982, they are described. The descriptions of these setpoints are similar to the definitions used in the topical report. However, the definitions used by GE, in some instances, distribute the error terms differently. For example, a term used by GE in calculating the margin between the Licensing Safety Limit and the Analytical Limit is described as part of the margin between the Safety Limit and the Allowable value in ISA-S67.04-1982. The following definitions used by GE are acceptable to the staff.

"Analytical Limit (AL): The value of the sensed process variable established as part of the safety analysis prior to or at the point which a desired action is to be initiated to prevent the safety process variable from reaching the associated licensing safety limit."

"Allowable Value (AV) (Technical Specification Limit): The limiting value of the sensed process variable at which the trip setpoint may be found during instrument surveillance. Usually prescribed as a license condition."

Although the sequence of the terms used by GE in the development of the various setpoints may be different, the following data are required and are consistent with the data needs of ISA-S67.04-1982. These mandatory data terms are:

Analytical Limit
Channel Instrument Accuracy
Channel Calibration Accuracy
Channel Instrument Drift
Process Measurement Accuracy
Primary Element Accuracy

Most of these error allowances are defined to include subterms. The use of these terms is typical of other vendor methods and consistent with industry standards. Therefore, they are acceptable to the staff.

The numerical methods for using accuracy and drift terms to calculate the lower order setpoints (as identified in Table I above) involve formulations that are consistent with the definitions used. Independent, random, and normally distributed variables are combined by the square root of the sum of the squares. Non-random (biased) and dependent variables are summed algebraically. The methods are designed to result in a 95 per cent probability of providing a channel trip before the process variable reaches the analytical limit, considering drift, assuming a one-sided normal distribution and a 95 per cent confidence level. With the exception of using a single sided test, these methods are consistent with industry practice and are, therefore, acceptable to the staff. The use of a single-sided test to define the probability that a trip will occur between two limits (e.g. Nominal Trip Setpoint and Allowable Value) is acceptable to the staff within the context of this topical report. The probability of a false trip (early trip) is a separate calculation when determining whether a technical specification setpoint will be satisfied. However, the use of a single-sided test for instrument channels that provide trips or permissives for increasing and decreasing variables (e.g. reactor level) is not supported by analysis and is not consistent with the general approach reflected in the current industry practice. The staff, therefore, finds this set point methodology for increasing and decreasing variable unacceptable. Similarly, the use of a single sided test for safety-related indicators and recorders is unacceptable.

The determination of nominal trip setpoints includes consideration of the following factors:

Design Basis Analytical Limit

In the case of setpoints that are directly associated with an abnormal plant transient or accident analyzed in the safety analysis, a design basis analytical limit is established as part of the safety analysis. The design basis analytical limit is the value of the sensed process variable prior to or at the point which a desired action is to be initiated. This limit is set so that associated licensing safety limits are not exceeded, as confirmed by plant design basis performance analysis.

Allowable Value SEE ENCLOSED STANDARD

An allowable value is determined from the analytical limit by providing allowances for the specified or expected calibration capability, the accuracy of the instrumentation, and the measurement errors. The allowable value is the limiting value of the sensed process variable at which the trip setpoint may be found during instrument surveillance.

Nominal Trip Setpoint SEE ENCLOSED STANDARD

The nominal trip setpoint value is calculated from the analytical limit by taking into account instrument drift in addition to the instrument accuracy, calibration capability, and the measurement errors. The nominal trip setpoint value is the limiting value of the sensed process variable at which a trip action will be set to operate at the time of calibration.

Signal Processing Devices in the Instrument Channel

Within an instrument channel, there may exist other components or devices that are used to further process the electrical signal provided by the sensor (e.g., analog-to-digital converters, signal conditioners, temperature compensation circuits, and multiplexing and demultiplexing components). The worst-case instrument accuracy, calibration accuracy, and instrument drift contributions of each of these additional signal conversion components are separately or jointly accounted for when determining the characteristics of the entire instrument loop.

5) Not all parameters have an associated design basis analytical limit (e.g., main steamline radiation monitoring). An allowable value may be defined directly based on plant licensing requirements, previous operating experience or other appropriate criteria. The nominal trip setpoint is then calculated from this allowable value, allowing for instrument drift. [Where appropriate, a nominal trip setpoint may be determined directly based on operating experience.] ISA 67.04 1994 - ONCE INSTALLED HISTORICAL RESULTS MAY BE EVALUATED AND SETPTS REVISED.

Procedures will be used that provide a method for establishing instrument nominal trip setpoint and allowable value. Because of the general characteristics of the instrumentation and processes involved, two different methods are applied:

(1) Computational

(2) Historical data

INCONSISTENT WITH PREVIOUS PAGE

The computational method is used when sufficient information is available regarding a dynamic process and the associated instrumentation. The procedure takes into account channel instrument accuracy, calibration accuracy, process measurement accuracy, primary element accuracy, and instrument drift. If the resulting nominal trip setpoint and allowable value are not acceptable when checked to ensure that they will not result in an unacceptable level of trips caused by normal operational transients, then more rigorous statistical evaluation or the use of actual operational data may be considered.

Some setpoint values have been historically established as acceptable, both for regulatory and operational requirements. These setpoints have non-critical functions or are intended to provide trip actions related to gross changes in the process variable. The continued recommendation of these historically accepted setpoint values is another method for establishing nominal trip setpoint and allowable values. This approach is only valid where the governing conditions remain essentially unaltered from those imposed previously and where the ~~historical values have been adequate for their~~ intended functions.

The setpoint methodology plan requires that activities related to instrument setpoints be documented and stored in retrievable, auditable files.

Equipment Qualification (EQ)

Qualification of safety-related instrumentation and control equipment is implemented by a program that assures this equipment is able to complete its safety-related function under the environmental conditions that exist up to and including the time the equipment has finished performing that function. Qualification specifications consider conditions that exist during normal, abnormal, and design basis accident events in terms of their cumulative effect on equipment performance for the time period up to the end of equipment life.

The material discussed herein identifies an EQ program that addresses the spectrum of design basis environmental conditions that may occur in plant areas where I&C equipment is installed. Not all safety-related I&C equipment will experience all of these conditions; the intent is that qualification be performed by selecting the conditions applicable to each particular piece of equipment and performing the necessary qualification.

As-built I&C components are environmentally qualified if they can withstand the environmental conditions associated with design basis events without loss of their safety functions for the time needed to be functional. Safety-related I&C components are designed to continue normal operation after loss of HVAC. The environmental conditions are as follows, as applicable to the bounding design basis events: Expected time-dependent temperature and pressure profiles, humidity, chemical effects, radiation, aging, seismic events, submergence, and synergistic effects which have a significant effect on equipment performance.

I&C equipment environmental qualification is demonstrated through analysis of the environmental conditions that would exist in the location of the equipment during and following a design basis accident and through a determination that the equipment is qualified to withstand those conditions for the time needed is functional. This determination may be demonstrated by:

(1) Type testing of an identical item of equipment under identical or similar conditions with a supporting analysis to show that the equipment to be qualified.

(2) Type testing of a similar item of equipment with a supporting analysis to show that the equipment is qualified.

(3) Experience with identical or similar equipment under similar conditions with a supporting analysis to show that the equipment is qualified.

(4) Analysis in combination with partial type test data that supports the analytical assumptions and conclusions to show that the equipment is qualified.

The installed condition of safety-related I&C equipment is assured by a program whose objective is to verify that the installed configuration is bounded by the test configuration and test conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.4, Items 7 through 15, provides a definition of the inspections, tests and analyses, together with associated acceptance criteria, which will be used to demonstrate compliance with the above commitments for hardware and software development, electromagnetic compatibility, instrument setpoint methodology, and equipment qualification.

C. Diversity and Defense-in-Depth Considerations

Subsection B discusses processes for developing hardware and software qualification programs that will assure a low probability of occurrence of both random and common-mode system failures for the installed ABWR I&C equipment. However, to address the

1 PURPOSE

The purpose of the standard is to develop a basis for establishing setpoints for actions determined by the design basis for protection systems and to account for instrument errors and drift in the channel from the sensor through and including the bistable trip device.

2 SCOPE

This standard defines minimum requirements for assuring that setpoints are established and held within specified limits in nuclear safety-related instruments in nuclear power plants.

3 DEFINITIONS

Accuracy - Degree of conformity of an indicated value to a recognized accepted standard value, or ideal value. [1]

Design Basis - The Design Basis for protection systems for nuclear power generating stations is delineated in IEEE Standard 279-1971, "IEEE Standard for Protection Systems for Nuclear Power Generating Stations," Part 3, Design Basis.

Drift - An undesired change in the output-input relationship over a period of time. [1,11]

Dynamic response - The behavior of the output of a device as a function of the input, both with respect to time. [1]

Foldover - A characteristic of the steady-state or dynamic conditions of a device for which, at a point, a further change in the input signal produces an output signal which reverses its direction from the specified input-output relationship.

Hysteresis - That property of an element evidenced by the dependence of the value of the output, for a given excursion of the input, upon the history of prior excursions and the direction of the current traverse. [1]

Instrument channel - An arrangement of components and modules as required to generate a single protective action signal when required by a generating station condition. A channel loses its identity where single protective action signals are combined. [2]

Instrument range - The region between the limits within which a quantity is measured, received, or transmitted, expressed by stating the lower and upper range values. [1]

Limiting Safety System Setting (LSSS) - Limiting Safety System Settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. [3]

Note: For the purposes of this standard, the phrase "nuclear reactors" used in this definition should be understood to mean "nuclear power plants."

Protective action - The initiation of a signal or operation of equipment within the protection system, or protective action system, for the purpose of accomplishing a protective function in response to a generating station condition having reached a limit specified in the design basis. [4]

Protective function - The sensing of one or more variables associated with a particular generating station condition, the signal processing, and the initiation and completion of the protective action within the values of the variables established in the design basis. [2]

Protection system - The electrical and mechanical devices (measured process variables to protective action system input terminals) involved in generating those signals associated with the protective functions. These signals include those that initiate reactor trip, engineered safety features, and auxiliary supporting features. [4]

Repeatability - The closeness of agreement among a number of consecutive measurements of the output for the same value of the input under the same operating conditions, approaching from the same direction, for full range traverses. [1]

Nuclear safety-related instrumentation - That which is essential to:

(1) emergency reactor shutdown;
(2) containment isolation;
(3) reactor core cooling;
(4) containment or reactor heat removal;
(5) prevent or mitigate a significant release of radioactive material to the environment; or is otherwise essential to provide reasonable assurance that a nuclear power plant can be operated without undue risk to the health and safety of the public.

Saturation - A characteristic of the steady state or dynamic conditions of a device under which, at a point, a further change in the input signal, produces no additional change in the output signal.

Sensor - That portion of a channel which responds to changes in a plant variable or condition, and converts the measured process variable into an instrument signal.

Setpoint - A predetermined level at which a bistable device changes state to indicate that the quantity under surveillance has reached the selected value. [5]

Test interval - The elapsed time between the initiation of identical tests on the same sensor, channel, train, load group, or other specified system or device. [5]

4 ESTABLISHMENT OF SETPOINTS

Setpoints in nuclear safety-related instruments shall be selected to provide sufficient margin between the trip setpoint and the safety limits to account for accuracies, drift, uncertainties and dynamic responses. Detailed requirements for safety-related instrument setpoint relationships are given in the sections which follow as illustrated in Figure 1.

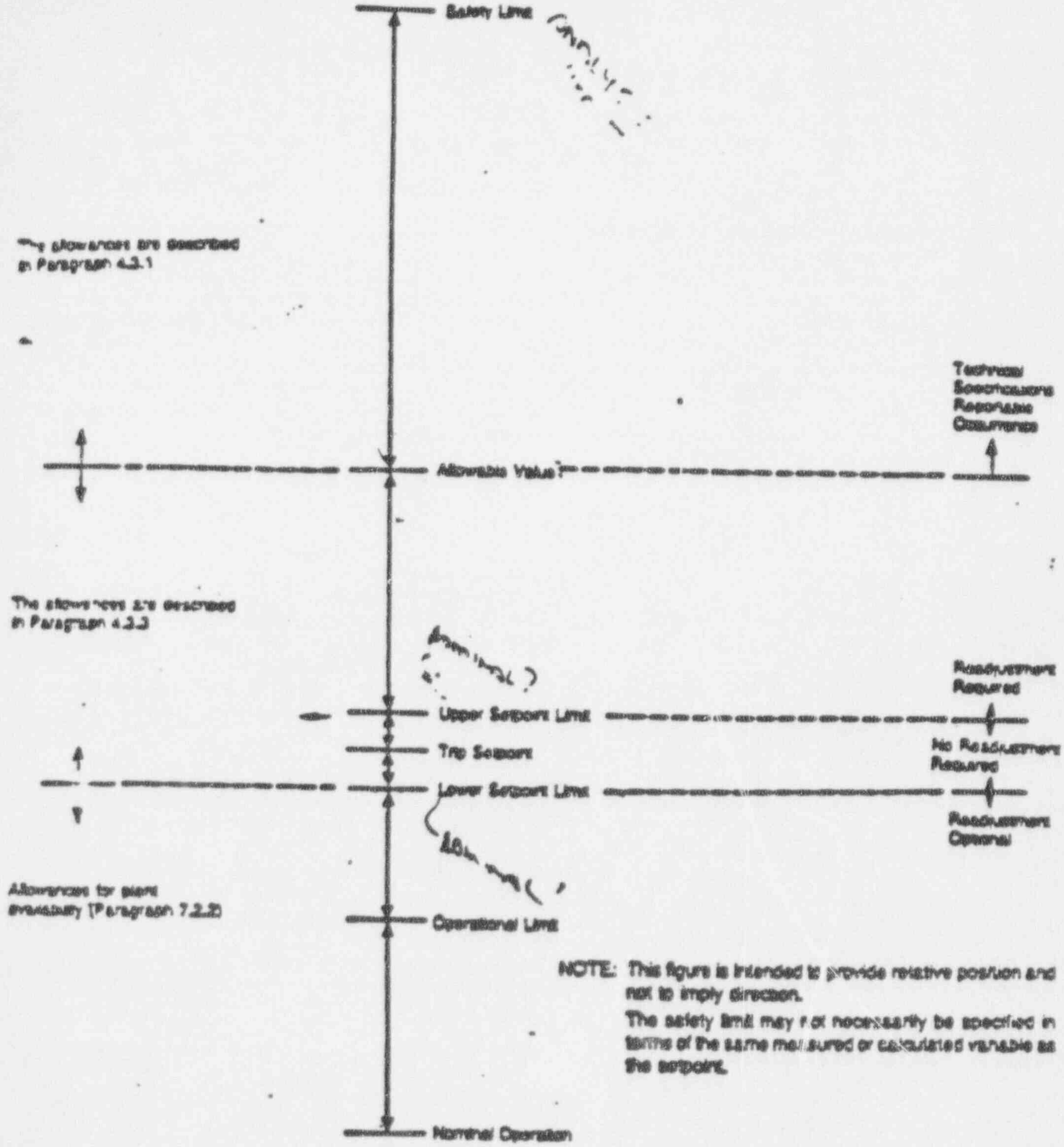


Figure 1. Nuclear Safety-Related Instrument Setpoints Relationships

4.1 Safety Limits

Safety limits for nuclear reactors are limits upon important process variables which are found to be necessary to reasonably protect the integrity of certain of the physical barriers which guard against the uncontrolled release of radioactivity. [3] The safety limit may not necessarily be specified in terms of the same measured or calculated variable as the setpoint. For example, a setpoint using temperature as a measured variable may be related to a safety limit specified in terms of Departure from Nucleate Boiling Ratio (DNBR).

4.2 Safety Analysis

The conclusions of the safety analyses are assured in part by establishing appropriate safety system setpoints to be stated in the technical specifications and maintained through operating procedures. The selection of setpoints for safety-related instruments shall be documented or referenced in the basis for the technical specifications including the parameters and assumptions upon which the setpoint selection was based.

4.3 Limiting Safety System Settings

Limiting Safety System Settings (LSSS) shall be selected such that operation within LSSS provides assurance that the physical barriers will not be damaged beyond acceptable limits during anticipated operational occurrences and accidents. For each LSSS a trip setpoint and an associated allowable value shall be established. (See Figure 1.)

4.3.1 The allowances between the allowable value and the safety limit shall include the following items unless they are included in the determination of the safety limit:

(1) Accuracy (including drift) of components not tested when setpoint is measured. Setpoint measurements shall be made by:

(a) Perturbing the monitored variable (the same or a substitute process variable), and noting the point at which a channel trip occurs, or:

(b) Substituting a known signal in the instrument channel as close to the monitored variable as practical and noting the point at which a channel trip occurs. Justification for selecting item (b) over (a) shall be documented.

(2) Accuracy of test equipment for:

(a) Measuring setpoints

(b) Calibrating sensors for the case where sensors are not included in setpoint measurements.

(3) Process measurement accuracy. Examples are the effect of fluid stratification on temperature measurement and the effect of changing fluid density on level measurements.

(4) The effects of potential transient overshoot determined in the design basis events analyses.

(5) The effects of the time response characteristics of the total instrument channel, including the sensor.

(6) Environmental effects on equipment accuracy or time response characteristics caused by anticipated operational occurrences or accidents for those systems required to mitigate the consequences of such events.

The above items shall be combined in one of the following five ways:

(1) Algebraically,
(2) Square root of the sum of the squares,
(3) Statistically,
(4) Probabilistically, or
(5) Combinations of 1 thru 4.

Justification shall be provided for the adequacy of the method used.

4.3.2 Where items listed in Paragraph 4.3.1 are accounted for by compensating the signal(s) representing the monitored variable(s) prior to comparison with the trip setpoint, these items need not be considered in the allowance between the safety limit and the allowable value.

4.3.3 <u>The trip setpoint shall be a value which allows margin for drift and adjustment.</u> The trip setpoint shall be chosen so that the corresponding allowable value is not exceeded due to the following:

(1) Drift of that portion of the instrument channel which is tested when the setpoint is determined.

(2) Actual setting of the setpoint within an allowable tolerance of upper and lower setpoint limits. (See Figure 1.)

The band between upper and lower setpoint limits shall account for the ability to adjust the setpoint and minimize the need for frequent adjustments.

5 INSTRUMENT PERFORMANCE AND SETPOINT SETTING

Setpoints shall be specified in units of the monitored value.

Instrument performance requirements shall be specified such that during the interval between setpoint tests the actual setpoint does not exceed the allowable value due to expected drift.

Instrument performance requirements shall be specified for that portion of the instrument channel not tested (Paragraph 4.3.1) such that the parameters remain within the values assumed in the determination of the allowable value.

(1) acc. of comp. not calibrated → — safety limit
— allowable value
(2) test equipment
(3) process measurement accuracy
(4) ... (6) environmental effects

Setpoints shall be located in that portion of the instrument's range which has the required accuracy.

Instrument performance requirements shall be specified such that as long as the process variable exceeds the setpoint, the protective action of that instrument channel is not negated by saturation, foldover, or any other cause for expected values of the process variable.

Instrumentation calibration correction factors shall be identified and documented. Correction factors which have been incorporated in the determination of the setpoint (for example, to compensate for differences in physical location, temperature or pressure between the required point of measurement and actual sensor location) shall be separately identified.

6 QUALIFICATION

The nuclear safety-related instrumentation hardware and software qualification shall be documented and available to verify all parameters used in determining the setpoints, including:

(1) The value of setpoint drift during proposed test intervals due to expected exposure to normal operating temperature, pressure, humidity, power variation, electromagnetic interference, vibration, seismic acceleration and radiation exposure.

(2) The time response characteristics or other response characteristics of the instrument channel.

(3) The instrument channel performance such as accuracy, repeatability and hysteresis at the trip setpoint and at the allowable value under design basis conditions.

These requirements are supplemental to those of IEEE Standard 323-1974. [10]

7 MAINTENANCE OF SETPOINTS

Maintenance of setpoints shall include all actions taken to assure that the instrumentation is installed and continues to operate within the design requirements used to establish the setpoints. The following sections address those aspects of nuclear safety-related instrument setpoint maintenance that are necessary to support the establishment of the allowable values and trip setpoints as described in Section 4. Specific guidance for implementing each of the following maintenance activities can be found in other industry standards (See references 6 through 9, for examples.)

7.1 Installation

Installation requirements shall include:

(1) Receipt, storage and handling provisions to prevent instrumentation degradation.

(2) Provisions for necessary access and other design features to assure setpoint maintenance.

7.2 Operation

7.2.1 Initial Calibration and Operation

Nuclear safety-related instrument channels shall be calibrated, functionally tested and set at their trip setpoint as soon as practicable after installation and again prior to initial criticality, where practical, to determine if the drift rate of the channel meets design requirements. Inability to perform these tests shall be justified and documented.

If within this period the drift rate of the channel fails to meet the design requirements, an evaluation shall be conducted to determine the cause. The evaluation shall include consideration of the installation (including all possible environmental effects), adequacy of the supplied instrumentation, accuracy of calibration, and calibration techniques. This evaluation shall provide the basis for proper and timely resolution and shall be documented.

7.2.2 Periodic Testing

Testing of safety-related instrumentation shall be in accordance with the technical specifications. Written procedures shall be used to verify the proper operation of the instrumentation, including each instrument channel's compliance with design requirements related to setpoints. These procedures shall include, as a minimum, requirements to record sufficient data on each channel to determine the true setpoint in terms of measured or derived process variables, before any adjustments are made.

If the "as found" setpoint indicates the setpoint is within the "no readjustment" band (See Figure 1.) or that calculations based on the analog value would result in setpoints within the "no readjustment" band, documentation of the results is the only required action. If the "as found" setpoint exceeds the upper setpoint limit, readjustment shall be performed to bring this channel back within the "no readjustment" band. The "as found" and "as left" setpoint shall be recorded. If the "as found" setpoint was also beyond the allowable value, a review shall be conducted immediately to determine the availability of the other redundant channels of the same protective function and their setpoints. Based on this review and subsequent evaluation, it may be necessary to decrease the time between tests in order to ensure proper operation. A review of the parameters verified in Paragraph 7.2.1, above shall be required to determine the cause. The action taken when the allowable value has been exceeded shall be based on the measured drift rates determined by previous "as left" and current "as found" data.

This evaluation shall be documented.

If subsequent tests show the allowable value continues to be exceeded the following shall be considered:

(1) Upgrading the instrument system
(2) Revising the required tolerances for the trip setpoint
(3) Revising the upper setpoint limit and lower setpoint limit ("no readjustment" band)
(4) Revising the test interval.

unnecessary

This evaluation shall be documented.

If the "as found" setpoint is [illegible] the lower setpoint limit, readjustment may be made to avoid [illegible] trips, but is not mandatory. The "as found" and "as [illegible] setpoints shall be recorded.

Should these data indicate drift rates considerably less than originally expected, testing intervals or tolerances may be revised accordingly, with suitable justification and documented.

7.3 Test Equipment

A system shall be established to ensure the accuracy and adequacy of the test equipment used to verify setpoints and calibration of safety-related instrumentation. Calibration records shall identify all test equipment by serial number. The test equipment shall be calibrated at specified intervals and shall be traceable to the U.S. National Bureau of Standards or have a known valid relationship to physical standards. If test equipment is found out of tolerance, an evaluation shall be conducted to determine the effect on safety-related instrumentation calibrated with the equipment since its last calibration. The evaluation including corrective action taken shall be documented. The accuracy of the test equipment used shall equal or exceed that required of the instrumentation under test.

7.4 Repair and Replacement

Replacements of material, parts and components shall be "in kind." Substitutions shall be evaluated and documented to assure equal or better performance than that provided in the design basis.

REFERENCES

1. Definition per ISA - S51.1 (1976) "Process Instrumentation Terminology."
2. Definition per IEEE Standard 279-1971 "Criteria for Protection Systems for Nuclear Power Generating Stations."
3. Definition per "Code of Federal Regulations" Title 10, Part 50, Issued January 1, 1978, Paragraph 50.36.
4. Definition per IEEE Trial Use Standard 603-1977 "Criteria for Safety Systems for Nuclear Power Generating Stations."
5. Definition per IEEE Standard 380-1975 "Definitions of Terms Used in IEEE Standards on Nuclear Power Generating Stations."
6. IEEE Standard 338-1975, "IEEE Standard Criteria for the Periodic Testing of Nuclear Power Generating Station Class 1E Power and Protection Systems."
7. ANSI N45.2-1977, "Quality Assurance Program Requirements for Nuclear Power Plants."
8. IEEE Standard 352-1975, "IEEE Guide for General Principles of Reliability Analysis of Nuclear Power Generating Station Protection Systems."
9. IEEE Standard 498-1975, "IEEE Standard Supplementary Requirements for the Calibration and Control of Measuring and Test Equipment Used in the Construction and Maintenance of Nuclear Power Generating Stations."
10. IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations."
11. The committee chose this specific definition for drift to explain the output-input relationship of a safety-related instrument channel.

INFORMATIVE REFERENCES

The Instrument Society of America (ISA) has developed standards for the nuclear industry through the SP67 Nuclear Power Plant Standards Committee (NPPSC).

ANSI/ISA-67.01-1981, "Transducer and Transmitter Installation for Nuclear Safety Applications."
ISA-S67.02, "Nuclear-Safety-Related Instrument Sensing Line Piping and Tubing Standards for Use in Nuclear Power Plants."

[illegible] system startup. It is also [illegible] Floor drains [illegible] potential radioactivity are provided [illegible] collection system [illegible] cleanouts are provided, when practicable, [illegible] each vertical riser [illegible] where the change in direction in [illegible] 90° [illegible] change is 135° or greater [illegible] 50 feet. [illegible] drains [illegible] cleanout points [illegible] piping and [illegible] their access covers flush [illegible] safety-related [illegible] charcoal filters in the vents. In the event of a LOCA [illegible] automatically isolated to preclude the uncontrolled release of primary coolant outside the PCV.

9.3.8.2.5 Tests and Inspections

[illegible] Reactor Building floor and [illegible] following instruments and controls:

1. High and low level switches are provided on each sump pump to start and stop the sump pumps automatically. A high-high level switch set at a higher level starts the second pump and simultaneously actuates an alarm in the main control room.

2. Leak detection is effected by monitoring the frequency and duration of pump runs.

9.3.9 Hydrogen Water Chemistry System

9.3.9.1 Design [illegible]

9.3.9.1.1 Safe[illegible] Basis

The [illegible]gen Water Chemistry (HWC) System is non-nuclear, non-safety-related and is required to be safe and reliable, consistent with the requirement of using hydrogen gas. The hydrogen piping in the Turbine Building shall be designed in accordance with the guidance Regulatory Guide 1.29 "Seismic Design Classifications", Section C.2 and comply with modified BTP CMEB 9.5-1, Part C.5.d(5).

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY
REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: 3.4 I&C DAC No. 5

NRC COMMENT:

Figure 4.3c, page 3.4-19 "NMS" should be blocked in with input designated to be consistent. See attached.

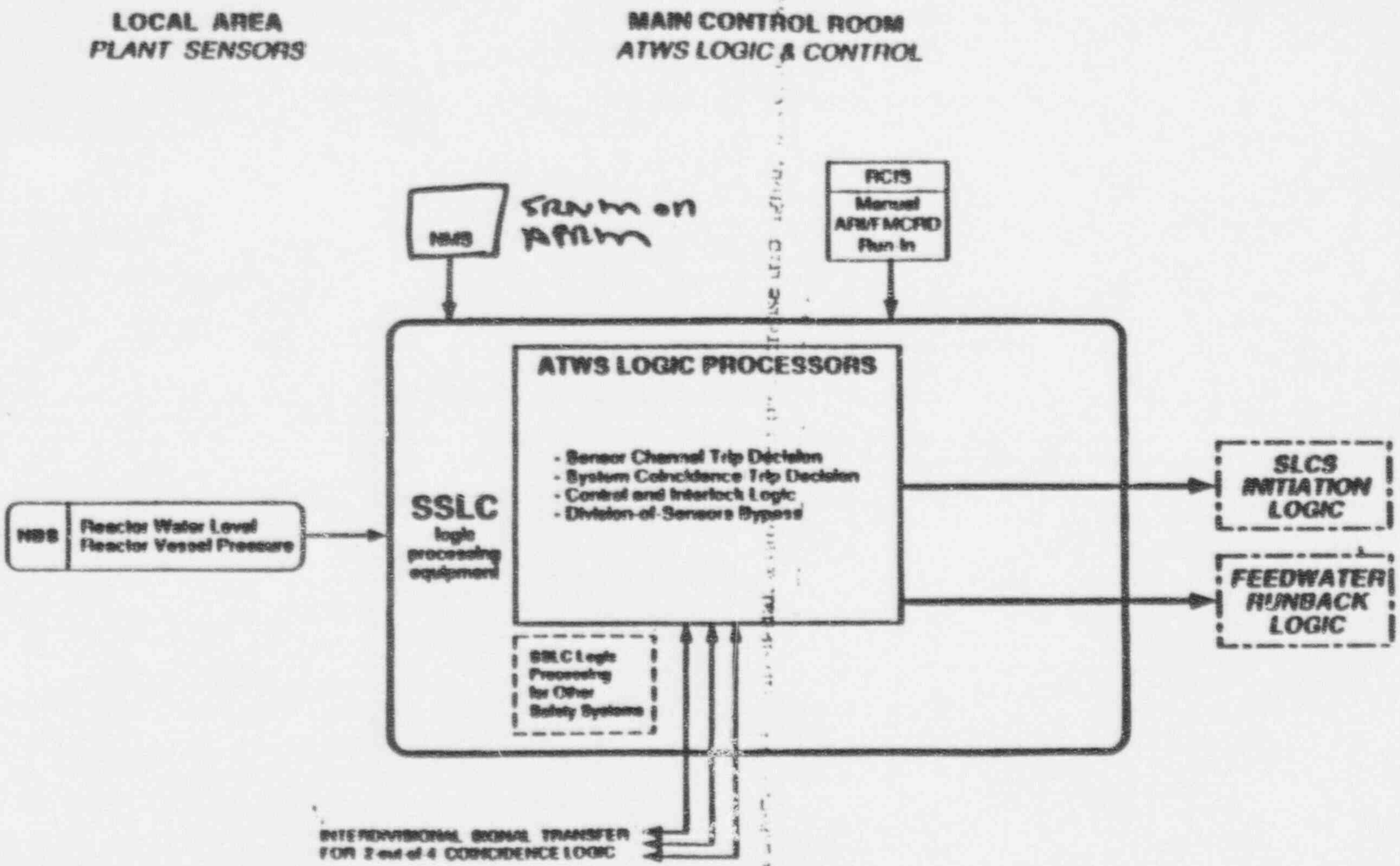
GE RESPONSE:

~~Later~~ GE concurs that the NMS acronym should be enclosed in a box and should indicate that the signal is an SRNM permissive. The attached changes will be included in the next revision of 25A5447.

PROPOSED CHANGES

CDM: Per attached markup.

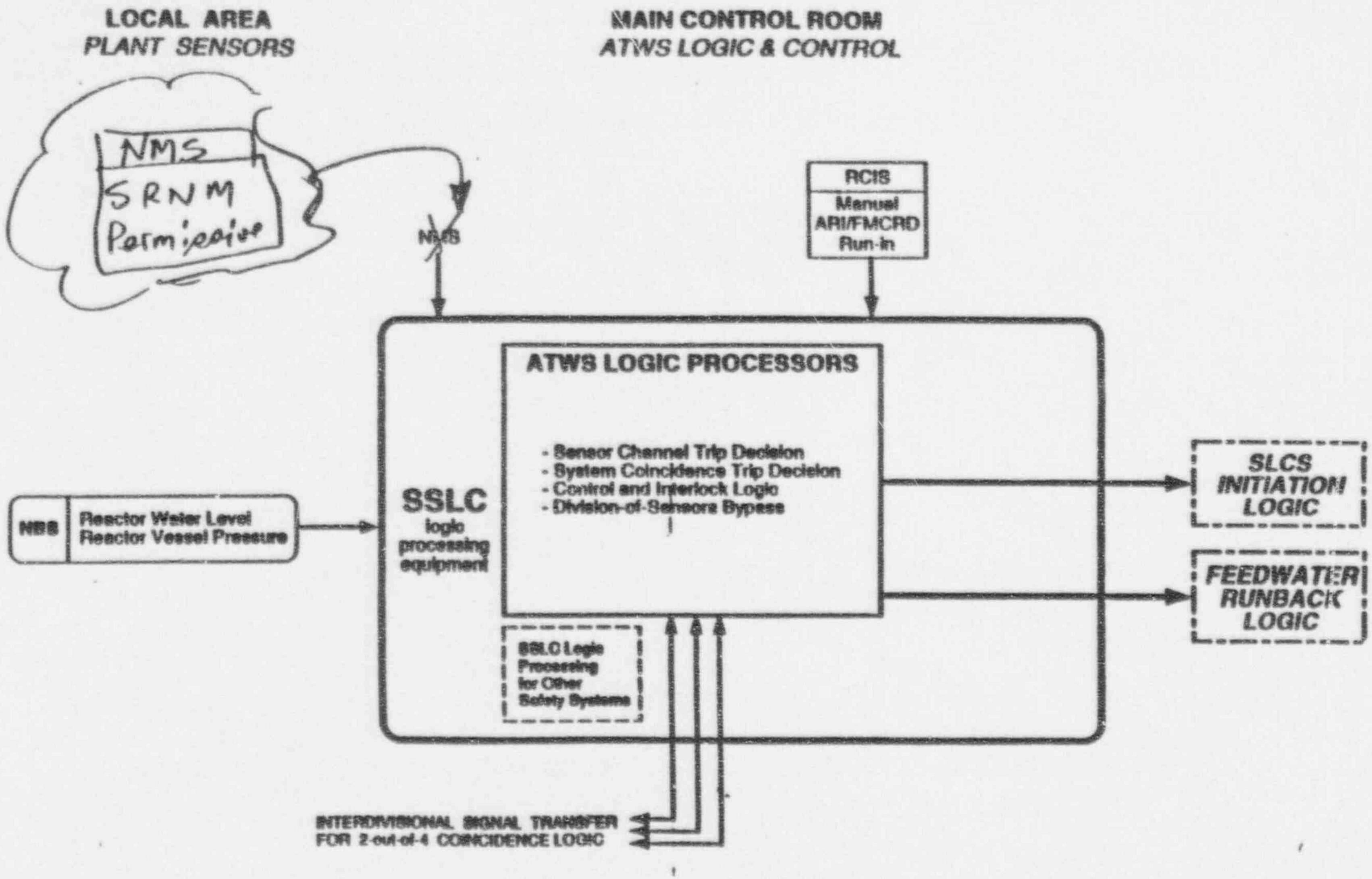
SSAR: None.



Notes:
1 Diagram represents one of four ATWS divisions.
2 Remaining ATWS functions are processed as part of Recirculation Flow Control System logic and Nuclear Boiler System logic.

Figure 3.4c Anticipated Transient Without Scram (ATWS) Control Interface Diagram

RL 2/21



Notes:
1. Diagram represents one of four ATWS divisions.
2. Remaining ATWS functions are processed as part of Recirculation Flow Control System logic and Nuclear Boiler System logic.

Figure 3.4c Anticipated Transient Without Scram (ATWS) Control Interface Diagram

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC COMMENTS ON
SSAR AMENDMENT 33 AND CDM REVISION 2

CDM SECTION: 3.4-5 I&C DESIGN

NRC COMMENT:

Attached NRC comment on page 3.4-5.

COMMENT TYPE: 2

GE RESPONSE:

GE agrees that the CDM and SSAR needs to be clarified regarding the neutron flux permissive input to the ATWS logic. This modification involves identifying in CDM section 2.2.5 – NMS an LPRM and APRM flux permissive and then using this term in the interfacing systems (2.1.2-NB5 and 3.4 I&C Design)

PROPOSED CHANGES

CDM: See attached markups.

SSAR: Change package to be included in Amendment ~~3A~~ 34 (copies not attached).

SSAR not changed

Need to see All ... be N.C.

CNPO 7/15 GE verify

Bypassing of any single division of output trip logic (i.e., taking a logic channel out of service) is also accomplished by means of the bypass unit. This type of bypass is limited to the fail-safe (de-energize-to-operate) reactor trip and MSIV closure functions, since removal of power from energize-to-operate signal processors is sufficient to remove that channel from service.

When a trip logic output bypass is made, the TLU trip output in a division is inhibited from affecting the output load drivers by maintaining that division's load drivers in an energized state. Thus, the 2-out-of-4 logic arrangement of output load drivers for the RPS and MSIV functions effectively becomes 2-out-of-3 while the bypass is maintained.

Bypass status is indicated in the main control room until the bypass condition is removed. An electrical interlock rejects attempts to remove more than one SSLC division from service at a time.

ESF1 and ESF2 logic are each processed in two redundant channels within each divisional train of ESF equipment. In order to prevent spurious actuation of ESF equipment, final output signals are voted 2-out-of-2 at the remote multiplexing units by means of series-connected load drivers at the RMU outputs. However, in the event of a failure detected by self-test within either processing channel, a bypass (ESF output channel bypass) is applied automatically (with manual backup) such that the failed channel is removed from service. The remaining channel provides 1-out-of-1 operation to maintain availability during the repair period. Channel failures are alarmed in the main control room. If a failed channel is not automatically bypassed, the operator is able to manually bypass the channel by a hardwired connection from the main control room.

A portion of the anticipated transient without scram (ATWS) mitigation features is provided by SSLC circuitry, with initiating conditions as follows:

BTTS
ATWS Permissive?

(1) Initiation of automatic Standby Liquid Control System (SLCS) injection: High dome pressure and average power range monitor (APRM) not downscale for 3 minutes or greater, or low reactor water level and APRM not downscale for 3 minutes or greater.

(2) Initiation of feedwater runback: High dome pressure and startup range neutron monitoring (SRNM) not downscale for 2 minutes or greater. Reset permitted only when both signals drop below the setpoints.

These ATWS features are implemented in four divisions of SSLC control circuitry that are functionally independent and diverse from the circuitry used for the Reactor Protection System (Figure 3.4c).

SSLC has the following alarms, displays, and controls in the main control room:

(1) SSLC signal processor inoperative (INOP)

REVISED 2/21

Signals from all four divisions for low reactor water level and high drywell pressure and Division I control logic signal actuate one set of pilots, and sensors from all four divisions for low reactor water and high drywell pressure and Division II control logic signal actuate the second set of pilots, either of which initiates the opening of the ADS SRVs.

ADS initiation is accomplished by redundant trip channels arranged in two divisionally separated logics that control two separate solenoid-operated pneumatic pilots on each ADS SRV. Either pilot can operate the ADS valve. These pilots control the pneumatic pressure applied by the accumulators and the High Pressure Nitrogen Gas Supply (HPIN) System. The DC power for the logic is obtained from the SSLC Divisions I and II.

For anticipated transient without scram (ATWS) mitigation, the ADS has an automatic and manual inhibit of the automatic ADS initiation. Automatic initiation of ADS is inhibited unless there is a coincident low reactor water level signal and an average power range monitors (APRMs) ~~downscale signal~~. There are main control room switches for the manual inhibit of automatic initiation of ADS.

ATWS permissive signal from the Neutron Monitor System

The ADS can also be initiated manually. On a manual initiation signal, concurrent with positive indication of at least one RHR or one HPCF pump is running, the ADS function is initiated.

NBS Instrumentation

The NBS contains the instrument lines and instrumentation for monitoring the reactor pressure and water level. For drywell pressure, turbine inlet pressure, main condenser vacuum, and RPV metal temperature, the NBS contains the sensors. Figure 2.1.2e shows the drywell pressure and RPV instrumentation in the NBS.

The mechanical portion of each division of the safety-related NBS instrumentation located in the Reactor Building is physically separated from the other divisions.

The reactor vessel outside surface (metal) temperatures are measured at the head flange and the bottom head locations.

Figure 2.1.2e shows the water level instrumentation. The instruments that sense the water level are differential pressure devices calibrated for specific RPV pressure and temperature conditions. Instrument zero for the RPV water level ranges is the top of the active fuel. The RPV water level instrumentation considers the effects of dissolved non-condensable gasses in the RPV water level instrumentation lines.

With the exception of turbine inlet pressure sensor and main condenser vacuum sensor located in the Turbine Building, the NBS instrumentation is located in the drywell, the steam tunnel and the Reactor Building.

Table 2.1.2 Nuclear Boiler System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
13. For ATWS mitigation, the ADS has an automatic and manual inhibit of the automatic ADS initiation. ATWS permissive signal present	13. a. The tests defined in item 12a will be conducted with a simulated APRM ~~not-downscale signal~~. b. The test defined in 12a will be conducted with the ADS manual inhibit device set to inhibit.	13. a. ADS actuation does not occur. b. ADS actuation does not occur.
14. The ADS can be initiated manually.	14. Tests will be conducted by initiating each ADS division manually, concurrent with a simulated RHR or HPCF pump running signal.	14. Upon receipt of a manual initiation signal, an ADS actuation signal is generated to the associated ADS valve solenoids.
15. The RPV water level instrumentation considers the effects ~~the effects~~ of dissolved non-condensable gasses in the RPV water instrument lines.	15. Analyses of the as-built RPV water level instrumentation will be performed using available test data and/or operating experience.	15. An analysis output exists which concludes that the RPV water level instrumentation considers the effects of dissolved non-condensable gasses in the RPV water level instrument lines.
16. The mechanical portion of each division of the safety-related NBS instrumentation located in the Reactor Building is physically separated from the other divisions.	16. Inspections of the as-built NBS instrumentation will be conducted.	16. The mechanical portion of each NBS instrumentation division is physically separated from the other divisions by structural and/or fire barriers.
17. The MSL drain lines from the MSLs to the main condenser are seismically analyzed to withstand the SSE.	17. An inspection of the stress report containing the dynamic analysis of the piping will be conducted.	17. A stress report exists. This report documents that a dynamic seismic analysis has been performed.

*

Bypassing of any single division of output trip logic (i.e., taking a logic channel out of service) is also accomplished by means of the bypass unit. This type of bypass is limited to the fail-safe (de-energize-to-operate) reactor trip and MSIV closure functions, since removal of power from energize-to-operate signal processors is sufficient to remove that channel from service.

When a trip logic output bypass is made, the TLU trip output in a division is inhibited from affecting the output load drivers by maintaining that division's load drivers in an energized state. Thus, the 2-out-of-4 logic arrangement of output load drivers for the RPS and MSIV functions effectively becomes 2-out-of-3 while the bypass is maintained.

Bypass status is indicated in the main control room until the bypass condition is removed. An electrical interlock rejects attempts to remove more than one SSLC division from service at a time.

ESF1 and ESF2 logic are each processed in two redundant channels within each divisional train of ESF equipment. In order to prevent spurious actuation of ESF equipment, final output signals are voted 2-out-of-2 at the remote multiplexing units by means of series-connected load drivers at the RMU outputs. However, in the event of a failure detected by self-test within either processing channel, a bypass (ESF output channel bypass) is applied automatically (with manual backup) such that the failed channel is removed from service. The remaining channel provides 1-out-of-1 operation to maintain availability during the repair period. Channel failures are alarmed in the main control room. If a failed channel is not automatically bypassed, the operator is able to manually bypass the channel by a hardwired connection from the main control room.

A portion of the anticipated transient without scram (ATWS) mitigation features is provided by SSLC circuitry, with initiating conditions as follows:

(1) Initiation of automatic Standby Liquid Control System (SLCS) injection: High dome pressure and ~~average power range monitor (APRM) not downscale~~ for 3 minutes or greater, or low reactor water level and ~~APRM not downscale~~ for 3 minutes or greater.
SRNM ATWS PERMISSIVE
startup ~~neutron~~ range neutron monitor (SRNM) ATWS PERMISSIVE

(2) Initiation of feedwater runback: High dome pressure and startup range neutron monitoring (SRNM) ~~not downscale~~ ATWS permissive for 2 minutes or greater. Reset permitted only when both signals drop below the setpoints.

These ATWS features are implemented in four divisions of SSLC control circuitry that are functionally independent and diverse from the circuitry used for the Reactor Protection System (Figure 3.4c).

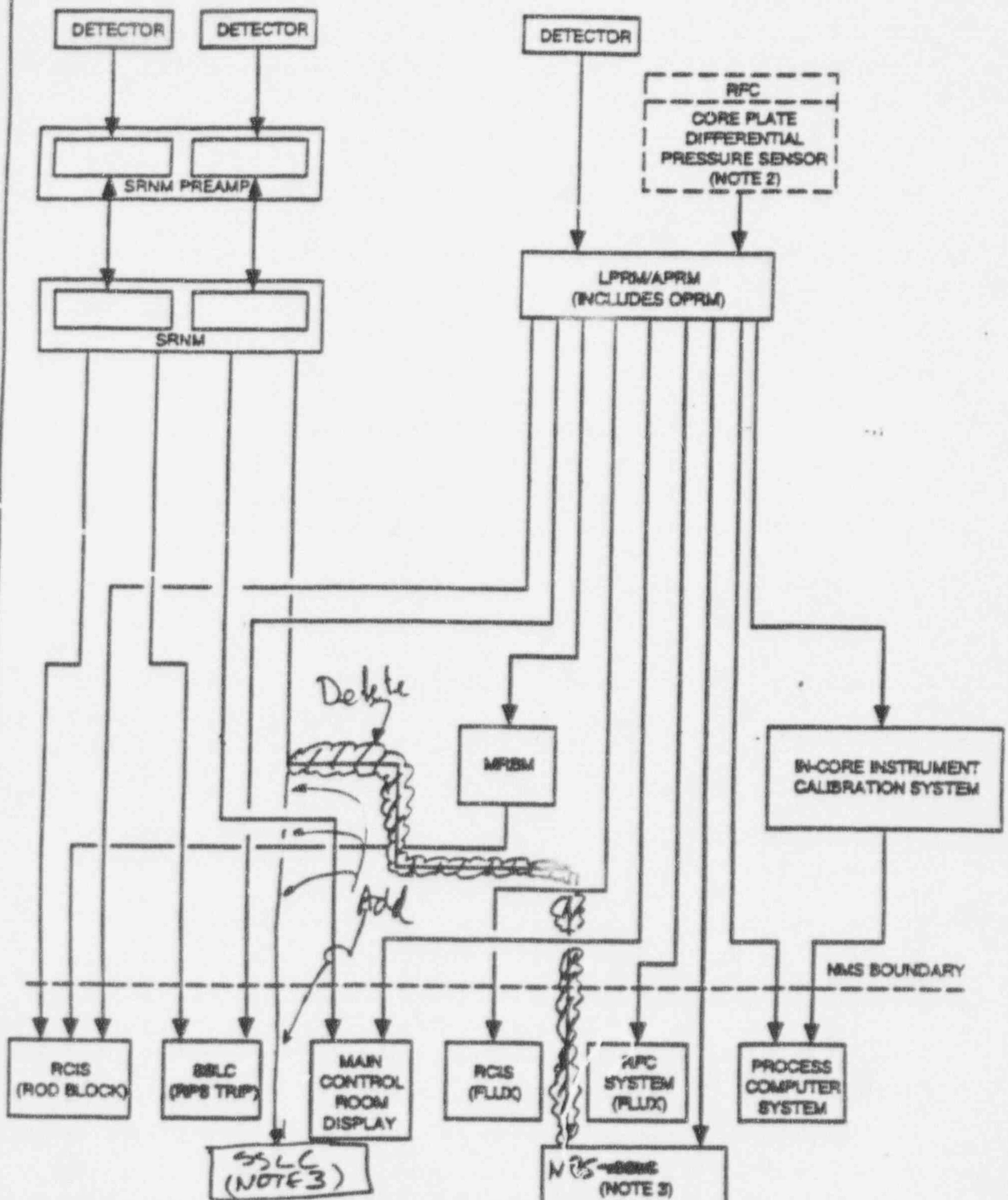
SSLC has the following alarms, displays, and controls in the main control room:

(1) SSLC signal processor inoperative (INOP).

Table 3.4 Instrumentation and Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
Safety System Logic and Control		
5. A portion of the anticipated transient without scram (ATWS) mitigation features is provided by SSLC circuitry, with initiating conditions as follows: a. Initiation of automatic SLCS injection on high dome pressure and ~~APRM not downscale~~ SRNM ATWS permissive for 3 minutes or greater, or low reactor water level and ~~APRM not downscale~~ SRNM ATWS permissive for 3 minutes or greater. b. Initiation of feedwater runback on high dome pressure and SRNM ~~not downscale~~ ATWS permissive for 2 minutes or greater. Reset is permitted only when both signals drop below the setpoints.	5. Tests will be conducted using simulated input signals for the process variables used by the ATWS logic. For feedwater runback logic, reset attempts will be made before initiating test signals drop below setpoints.	5. Four redundant output signals occur for each of the following ATWS mitigating functions (one set in each of the four divisions of ATWS outputs) that lead to initiation of these functions: a. Initiation of automatic SLCS injection on high dome pressure and ~~APRM not downscale~~ SRNM ATWS permissive for 3 minutes or greater, or low reactor water level and ~~APRM not downscale~~ SRNM ATWS permissive for 3 minutes or greater. b. Initiation of feedwater runback on high dome pressure and SRNM ~~not downscale~~ ATWS permissive for 2 minutes or greater. Reset is permitted only when both signals drop below the setpoints.
6. Main control room alarms, displays and controls provided for SSLC are as defined in Section 3.4.	6. Inspections will be performed on the main control room alarms, displays and controls for SSLC	6. Alarms, displays and controls exist or can be retrieved in the main control room as defined in Section 3.4.



NOTES:
1. DIAGRAM REPRESENTS ONE OF FOUR NMS DIVISIONS.
2. USED FOR RAPID CORE FLOW DECREASE TRIP.
3. SRNM AND APRM ATWS PERMISSIVE SIGNALS TO SSLC AND NBS
4. INTERCONNECTIONS MAY BE FIBER-OPTIC OR METALLIC.

Figure 2.2.5 Neutron Monitoring System

The automated in-core instrument calibration system provides local power information at various core locations that correspond to LPRM locations. The automated in-core instrument calibration system uses its own set of in-core detectors for local power measurement and provides local power information for three-dimension core power determination and for the calibration of the LPRMs. The measured data are sent to the Process Computer System for such calculation and LPRM calibration.

The MRBM uses LPRM signals to detect local power change during the rod withdrawal. If the averaged LPRM signal exceeds a preset rod block setpoint, a control rod block demand is issued.

Figure 2.2.5 shows the configuration of each NMS division.

Each of the four divisions of the SRNM, LPRM and APRM instruments is powered by its respective divisional Class 1E power supplies. In the NMS outside the primary containment, independence is provided between Class 1E divisions, and also between the Class 1E divisions and non-Class 1E equipment.

The SRNM and APRM trip signal outputs are in four divisions. The SRNM trip and the APRM trip logic are independent from each other. The SRNM generates a high neutron flux trip or a short period trip signal. Any single SRNM channel trip causes a trip in its division. The APRM can generate a high neutron flux trip, a simulated thermal power (STP) trip signal, a rapid core flow decrease trip signal, or a core power oscillation trip signal. The NMS provides these trip signals to the Reactor Protection System (RPS).

The SRNM and APRM are fail-safe in the event of loss of electrical power to any division of their logic.

The NMS bypass function is performed within the NMS. Within the NMS, the bypass functions of the SRNM and the APRM are separate and independent from each other. The SRNM channels are grouped into three bypass groups. Individual SRNM channels can be bypassed. At any one time, up to three SRNM channels can be bypassed. At any one time, only one APRM channel can be bypassed. A bypassed SRNM channel or a bypassed APRM channel does not cause a trip output sent to the RPS.

The NMS provides an SRNM ~~and APRM~~ flux permissive signals to the Safety System Logic and Control (SSLC) and an APRM flux permissive signal to the Nuclear Boiler System (NBS) as part of the ~~SSLC~~ anticipated transient without scram (ATWS) logic. The SRNM and APRM flux permissive signals from the NMS indicate when the reactor power level is above or below the setpoint in order to allow or disallow the initiation of ATWS mitigation features.

The NMS has the following displays and controls in the main control room:

(1) SRNM, LPRM, and APRM neutron flux displays.

FEBRUARY 1994

Verified EXCEPT as noted!

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: Miscellaneous

NRC COMMENT:

not included

1. SSAR Acronym use: revise SSAR list as marked-up for VAC and VDC. SSAR list needs to reflect PRA as Probabilistic Risk Assessment. SSAR acronym list is incomplete, such as: TN, MPT, PIP, D/G, IED, NBS, UAT, PMG, M/C, RAT, SBO, MVA. Recommend total SSAR search to identify all missing acronyms.

no description

GE RESPONSE:

GE has conducted an SSAR acronym search. All of the above acronyms are now included in the expanded list.

PROPOSED CHANGES

CDM: None

SSAR: Per above response

VRC

Verify

List of Acronyms (Continued)

TCS	Turbine Control System
TCV	Turbine Control Valve
TCW	Turbine Building Cooling Water (System)
TGSS	Turbine Gland Sealing System
THA	Time-History Accelerographs
TIP	Traversing Incore Probe or Traversing Ion Chamber
TIU	Technician Interface Unit
TLU	Trip Logic Unit
TRS	Test Response Spectra
TSC	Technical Support Center
TSV	Turbine Stop Valve
TSW	Turbine Service Water
U/D	Upper Drywell
UHS	Ultimate Heat Sink
UPS	Uninterruptible Power System
USE	Upper Shelf Energy
USMA	Uniform Support Motion Response Spectrum Analysis
USNRC	United States Nuclear Regulatory Commission
VAC	Volts Direct Current switch ✓
VDC	Volts Alternating Current
VDU	Video Display Unit
VLC	Vent Line Clearing
VWO	Valves-Wide-Open
WDSC	Wetwell and Drywell Spray Cooling (Mode of RHR)
WDVB	Wetwell-to-Drywell Vacuum Breaker
WDVBS	Wetwell-to-Drywell Vacuum Breaker System
ZIS	Zinc Injection System
ZSI	Zone Selective Interlocks

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: Miscellaneous

NRC COMMENT:

3. SSAR page 9.3-9, revise as marked-up - see attached.

P9.3-19

GE RESPONSE:

GE concurs and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per above responce.

~~Being Made~~

Need staff clarif.

for lead unit and standby unit of air compressors and dryers shall be switched periodically. The pressure setpoints for these operational changes are adjustable, depending on air requirements that might exist.

During normal operation, the nonsafety-related nitrogen users within containment are downstream of P52-F277 and P54-F208. (The safety-related nitrogen users are downstream of P54-F008A and B.) Should the AC/HPIN Systems become unable to supply nitrogen to the non-safety-related users downstream of P52-F277, the operator may remote manually open P52-F257 to supply instrument air to these users (Figure 20.3-55).

During refueling, the IAS provides compressed air instead of nitrogen gas to the users located inside containment in Figure 9.3-6.

Acceptance Criterion II.1 of SRP Section 9.3.1 requires that the maximum particle size of 3 microns in the air stream at the instrument. The corresponding maximum particle size for the ABWR design is 5 microns. Experience to date for plants with a maximum filtered particle size of 5 microns in the compressed gases has been very satisfactory.

All equipment using instrument air shall be capable of operating with air of the quality listed above.

9.3.6.3 Safety Evaluation

The operation of the IAS is not required to assure any of the following:

(1) Integrity of the reactor coolant pressure boundary.

(2) Capability to shut down the reactor and maintain it in a safe shutdown condition.

(3) Ability to prevent or mitigate the consequences of accidents which can result in potential offsite exposures comparable to the guideline exposures of 10CFR100.

However, the IAS incorporates features that assure this operation over the full range of normal plant operations. If IAS pressure falls below a desired limit, air from the Service Air System (SAS) is automatically added from a tie-line. An air receiver is provided to maintain air supply pressure if all of the IAS and SAS compressors fail. Pneumatic-operated devices are designed for a failsafe mode and do not require continuous air supply under emergency or abnormal conditions.

The instrument air system does orivide air service to a number of safety-related systems and components. The loss of air to these systems will result in current or new valve positions. These positions have been evaluated. The subject system safety functions have

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ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: Miscellaneous

NRC COMMENT:

4. SSAR pages 9.3-26 and 9.3-27 are not continuous, information is missing in section 9.3.8.2.3 that should be added to SSAR.

GE RESPONSE:

GE concurs and will correct this situation in the next SSAR amendment

PROPOSED CHANGES

CDM: None

SSAR: Per above response

(3) **Provision of Spare Pumps**—All sumps which process radioactive wastes are supplied with two pumps each. Each pump is sized to handle the maximum anticipated flow into the sump. Thus, each sump has one operating pump and one pump on standby.

(4) **Leak Detection**—The Reactor Building and drywell sumps have instrumentation which permits detection of excessive leakage and provides for an alarm upon high leakage rates.

(5) **Sump Coolers**—The Reactor Building drywell equipment drain sumps each have provisions for measuring their sump liquid temperature and automatically recirculating the sump contents through a drain cooler to cool the sump contents if the temperature exceeds 60°C. In the event of a LOCA signal, all drywell sump pumps are automatically isolated, to preclude the possible uncontrolled release of primary coolant.

(6) **Detergent Drains**—The detergent drain sump collects laundry and shower drains. The detergent drains are transferred to the detergent drain tanks in the Radwaste System. These detergent wastes are kept separate from other wastes, since detergent wastes are processed in a separate process train in the Radwaste System.

9.3.8.2.3 Component Description

Drain System components are as follows:

(1) **Collection Piping**— In all area of potential radioactive contamination, the collection system piping for the liquid system is of stainless steel for embedded and chemical drainage, and carbon steel for suspended drainage. Offsets in the piping are provided, where necessary, for radiation shielding. In general, the fabrication and installation of the piping provides for a uniform slope that causes gravity flow to the appropriate sump. During construction, equipment drain piping is terminated not less than 5 cm above the finished floor or drain receiver at each location where the discharge from equipment is to be collected. The connections to the individual equipment are made after the equipment is installed in its proper location.

(2) **Collection Sumps** (potentially radioactive drains)—These sumps are provided with a well-fitting, but not gastight, steel plate access cover for convenient maintenance access, as well as to minimize airborne contamination.

(3) **Equipment Drains**—Equipment that may be pressurized during drainage, and that drains via direct or indirect drain connection to the floor drain system, is designed so that the equipment discharge flow does not exceed the gravity flow capacity of the drainage header at atmospheric pressure.

(4)

during system startup. It is also installed, as required, to preserve the integrity of the drainage systems. Floor drains in areas not restricted because of potential radioactivity are provided with caulked or threaded connections.

(5) Cleanouts—In collection system piping from areas of potential radioactivity, cleanouts are provided, when practicable, at the base of each vertical riser where the change of direction in horizontal runs is 90°, at offsets where the aggregate change is 135° or greater, and at maximum intervals of 50 feet. Equipment hubs and floor drains are also used as cleanout points. Cleanouts are welded directly to the piping and located with their access covers flush with the finished floor or wall.

9.3.8.2.4 Safety Evaluation

The Drain Transfer System is not safety-related. Sumps designated as containing radioactive wastes are equipped with charcoal filters in the vents. In the event of a LOCA signal, all drywell sumps are automatically isolated to preclude the uncontrolled release of primary coolant outside the PCV.

9.3.8.2.5 Tests and Inspections

Drywell and Reactor Building floor and equipment drain sumps are provided with the following instruments and controls:

(1) High and low level switches are provided on each sump pump to start and stop the sump pump automatically. A separate high-high level switch set at a higher level starts the second pump and simultaneously actuates an alarm in the main control room.

(2) Leak detection is effected by monitoring the frequency and duration of pump runs.

9.3.9 Hydrogen Water Chemistry System

9.3.9.1 Design Bases

9.3.9.1.1 Safety Design Basis

The Hydrogen Water Chemistry (HWC) System is non-nuclear, non-safety-related and is required to be safe and reliable, consistent with the requirement of using hydrogen gas. The hydrogen piping in the Turbine Building shall be designed in accordance with the guidance Regulatory Guide 1.29 "Seismic Design Classifications", Section C.2 to comply with modified BTP CMEB 9.5-1, Part C.5.d(5).

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: Miscellaneous

NRC COMMENT:

5. SSAR Table 14.3-10, clarify the statement at top of page with respect to RCIC and HPCF suction piping as outlined in mark-up.

GE RESPONSE:

GE proposes to delete the ~~RCIC, HPCF~~ LPFL acronyms

PROPOSED CHANGES

CDM: None

SSAR: Per the above response

FEBRUARY 1994

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

GE needs to work through

CDM SECTION AND COMMENT No.: Miscellaneous

NRC COMMENT:

2. SSAR Section 14.2.12.1.45c used loss of offsite power (LOP) for loss of preferred power (LOPP). Revise to be consistent with CDM and other SSAR sections.

GE RESPONSE:

GE concurs and will include this change in the next SSAR amendment

PROPOSED CHANGES

CDM: None

SSAR: Per above response.

VCU

James/Bogue
3/2/96

Table 14.3-10 TMI Issues (Continued)

SSAR Entry	Parameter	SSAR Value
	RCIC and HPCF Do not Share Any Common Suction Piping with RHR	
	RCIC STET	—
	HPCF	—
	ECCS Have Minimum Flow Protection for All Operating Modes	
	RCIC	—
	HPCF	—
	RHR	—
	Number of RCW Divisions	3
	Individual ECCS Pumps Can be Isolated Without Affecting Other ECCS Pumps	
	RCIC	—
	HPCF	—
	RHR	—
	ABWR has Water Level Measurement Directly on the Vessel	—
	Containment Sprays are Manually Initiated	—
	Essential Equipment Inside the Containment is Qualified for Harsh Environment	—
	ADS Automatically Depressurizes the Vessel on Low Water Level	—
	ABWR has Manual Vessel Depressurization Capability	—
1A.2.34	III.D.1.1(1) Review Information Submitted by Licensee Pertaining to Reducing Leakage from Operating Systems	
	Inboard and Outboard Isolation Valves on All Lines Which Penetrate Primary Containment	—
	ABWR has a Leak Detection and Isolation System	—
	MSIV Closure on:	
	High Temperature in Steam Tunnel	—
	High Temperature in Turbine Building	—
	High Radiation in HVAC Air Exhaust Results In:	
	Closure of HVAC Air Ducts to Reactor Building	—
	Closure of Containment Purge and Vent Lines	—

FEBRUARY 1994 Verify

ABWR DESIGN CERTIFICATION

GE RESPONSES TO NRC INDEPENDENT QUALITY REVIEW GROUP COMMENTS ON THE CDM AND SSAR

CDM SECTION AND COMMENT No.: Miscellaneous

NRC COMMENT:

6. SSAR page 7.3-3, revise as shown on markup.

GE RESPONSE:

GE concurs and will include this change in the next SSAR amendment.

PROPOSED CHANGES

CDM: None

SSAR: Per the above response

optical fiber data link to the logic processing units in the main control room. All four transmitter signals are fed into the two-out-of-four logic for each of the two divisions (II & III). The initiation logic for HPCF sensors is shown in Figure 7.3-1.

Drywell pressure is monitored by four pressure transmitters in the same four-division configuration described above. 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 two-out-of-four trip logic shown in Figure 7.3-1.

The HPCF System is initiated on receipt of a reactor vessel low water level signal (Level 1.5) or drywell high-pressure signal from the trip logic. The HPCF System reaches its design flow rate within 36 seconds of receipt of initiation signal. Makeup water is discharged to the reactor vessel until the reactor high water level is reached. The HPCF System then automatically stops flow by closing the injection valve if the high water level signal is available.

This valve will reopen if reactor water level subsequently decreases to the low initiation level. The system is arranged to allow automatic or manual operation. The HPCF initiation signal from the NBS also initiates the standby diesels in the respective divisions.

An AC motor-operated valve and a check valve are provided in both branches of the pump suction. The pump suction can be aligned through one branch to the condensate storage tank or aligned through the other branch to 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 HPCF initiation signal, the condensate storage tank suction valves are automatically signaled to open (they are normally in the open position unless the suppression pool suction valves are open). If the water level in the condensate storage tank falls below a preselected level, first the suppression pool suction valves automatically open and then the condensate storage tank suction valves automatically close. Four level transducers (one in each electrical division) are used to detect low water level in the condensate storage tank. Any two-out-of-four transducers can cause the suppression pool suction valves to open and the condensate storage tank valves to close. The suppression pool suction valves also automatically open if high water level is detected in the suppression pool. Four level transducers (one in each electrical division) monitor this water level and

fails