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LICENSING REVIEW GROUP ISSUES

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I.1 INTRODUCTION

The italicized information is historical and was provided to support the application for an operating license.

The Licensing Review Group (LRG) was formed in April 1980 to provide a vehicle for expediting the licensing process for General Electric (GE) boiling water reactors (BWR). The group was made up of six utilities, GE, and the consulting firm of KMC. Membership was at both the executive and technical level.

All applicants were in the near-term operating license (NTOL) stage of the licensing process. The basis of establishing the LRG consisted of the fact that most issues for NTOL BWR plants are identical or very similar. It was felt that this common ground could be used advantageously in the NRC review process. The NRC assigned a Project Licensing Manager to interface with the LRG.

All utilities represented in the LRG are identified below. The plants indicated are ordered chronologically in the licensing process, with LaSalle County-1 being the first for which NRC issued a Safety Evaluation Report (SER).

Plant	*Utility*
LaSalle County-1	*Commonwealth Edison Company*
Zimmer	*Cincinnati Gas and Electric Company*
Shoreham	*Long Island Lighting Company*
Susquehanna-1	*Pennsylvania Power and Light Company*
Fermi-2	*Detroit Edison Company*
Columbia Generating Station	*Energy Northwest*

The LRG worked on a lead plant concept with LaSalle County-1 acting as the lead plant. Subsequent to the issuance of the SER for LaSalle, NRC issued SERs for Zimmer, Shoreham, Susquehanna, and Fermi (refer to References 1 through 5).

Interface with staff from various branches of NRC identified issues for the specific branches. Often, the issues consisted of a question or questions previously developed by NRC. Whenever possible, a common position on the issue was developed which was applicable to all plants. In some cases, however, uniqueness of design or other variables precluded a common position.

Plant unique positions were then developed. This appendix is for Columbia Generating Station, but uses common positions when applicable.

The order of presentation for an issue is as follows: The issue is presented, then the details of the issue follow under the "Question" heading. The response is then given. The numbers in parentheses (e.g., 5.4.4, 6.2) reference the applicable sections in the FSAR. Applicable questions are referenced as appropriate since in many instances the issue was previously addressed in a Columbia Generating Station question response.

References:

1. *U.S. Nuclear Regulatory Commission (NRC), NUREG-0519, "Safety Evaluation Report by the Office of Nuclear Reactor Regulation in the Matter of Commonwealth Edison Company, LaSalle County Station, Units No. 1 and 2," Dockets No. 50-373/374.*

2. *NRC, NUREG-0528, Supplement No. 1, "SER by the Office of Nuclear Reactor Regulation, NRC, in the Matter of Cincinnati Gas and Electric Company, William H. Zimmer Nuclear Power Station, Unit 1," Docket No. 50-358.*

3. *NRC, Office of Nuclear Reactor Regulation, NUREG-0420, "SER Related to the Operations of Shoreham Nuclear Power Station, Unit No. 1, Docket No. 50-322, Long Island Lighting Company," April 1981.*

4. *NRC, Office of Nuclear Reactor Regulation, NUREG-0776, "SER Related Operation of Susquehanna Steam Electric Station, Units 1 and 2, Dockets No. 50-387 and 50-388, Pennsylvania Power and Light Company, Allegheny Electric Cooperative, Inc.," April 1981.*

5. *NRC, Office of Nuclear Reactor Regulation, NUREG-0798, "SER Related to the Operation of Enrico Fermi Atomic Power Plant, Unit No. 2, Docket No. 50-341, Detroit Edison Company et al.," July 1981.*

I.2 CONTAINMENT SYSTEMS BRANCH

ISSUE: CSB-1 STEAM BYPASS OF THE SUPPRESSION POOL (6.2.1.1)

Question:

The applicant approach to suppression pool bypass is not consistent with Branch Technical Position CSB 6-5. The applicant must commit to perform a low power surveillance leakage test of the containment at each refueling outage.

Response:

The response to above stated concern is provided in response to Question 031.070.

ISSUE: CSB-2 POOL DYNAMIC LOCA AND SRV LOADS

Question:

The staff has completed its review of the short-term program and developed acceptance criteria. We require that the applicant commit to our acceptance criteria or justify any exceptions taken.

Response:

NRC acceptance criteria as well as the supplements thereto are being reviewed and adhered to where possible. Where exceptions are taken, such as in the case of SRV load definition (see Reference 1), or chugging load definition (see Reference 2), these exceptions are being discussed and reviewed with the staff.

References:

1. *"SRV Loads - Improved Definition and Application Methodology for Mark II Containments" (submitted in August 1980).*

2. *"Chugging Loads - Revised Definition and Application Methodology for -Mark II Containments" (based on 4TCO Test Results) (submitted in July 1981).*

ISSUE: CSB-3 CONTAINMENT PURGE SYSTEM

Question:

A 2-inch vent line exists in the purge system to bleed off excess primary containment pressure during operation. We require the applicant to evaluate this 2-inch bypass purge system in light of the criteria of Branch Technical Position CSB 6-4.

Response:

The 2-inch bypass valves, used for pressure control during operation, are located in parallel with each purge system exhaust valve. These 2 inch-150# globe valves meet all the design requirements of the containment isolation system. They are designed to the same pressure/temperature ratings of the containment and purge valves and are designed to close within 4 sec against the 45 psig containment design pressure. All four bypass valves can be remotely operated from the control room, are designed to close an F, A, and Z isolation signals and are being operationally qualified against applicable seismic and hydrodynamic loads.

ISSUE: CSB-4 COMBUSTIBLE GAS CONTROL (6.2.5)

DELETED

ISSUE: CSB-5 CONTAINMENT LEAKAGE TESTING

DELETED

I.3 CORE PERFORMANCE BRANCH

ISSUE: CPB-1 LOAD ASSESSMENT OF FUEL ASSEMBLY COMPONENTS

Question:

The proposed addition of Appendix A to SRP 4.2 provides guidance for the analysis of fuel assembly components and acceptance criteria for fuel assembly response to externally applied forces. The applicant's fuel assembly capability should be assessed accordingly.

Response:

General Electric has completed development of fuel assembly loads modeling and results acceptance criteria both deemed to be in accordance with the requirements of Appendix A to SRP 4.2. The LRG lead plant (LaSalle) has been evaluated accordingly with acceptable results, which were forwarded to the NRC June 8, 1981. A similar analysis will be performed for Columbia Generating Station (CGS).

ISSUE: CPB-2 WATERSIDE CORROSION

Question:

The applicant has not addressed the potential for fuel corrosion failure similar to that which occurred at the Vermont Yankee plant.

Response:

As indicated in the General Electric presentation given to the NRC in December 1979, the failures appeared to be associated with a metallic incursion in the feedwater. This event has occurred only once in the BWR operating history and is unlikely to reoccur.

Subsequent to this event, General Electric provided an operation recommendation for corrosion product control which should preclude this type of event at CGS. Energy Northwest plans to employ those General Electric operating recommendations which have been proven to be effective at several operating BWR plants for maintaining water quality parameters at or below GE's water quality specification limits.

References:

1. *Letter from R. E. Engel (GE) to M. Tokar (NRC), MFN-172-80, "Corrosion Product Control", dated October 3, 1980.*

ISSUE: CPB-3 CHANNEL BOX WEAR

Question:

Provide more detailed and specific information on the Channel Box Wear concern as applicable to the CGS design.

Response:

General Electric observed wear on the water rods in 8 x 8R fuel assemblies in the fall of 1979. In the referenced letter it was concluded that the observed wear does not affect the functionality of the water rods in the bundle or plant safety.

Since the observed wear General Electric has modified the 8 x 8R water rod design. To improve the margin of reliability of the 8 x 8R fuel design, a modification to the water rod and spacer positioning/water rod has been developed. This modified design has shorter water rod and spacer positioning/water rod lower end plugs, and modified expansion springs on the upper end plugs. These changes have been shown to be effective by successful operation of the short shank 8 x 8 fuel design and from extensive flow-induced vibration testing. This modified water rod concept is being installed on new fuel, such as for CGS, as a prudent means of assuring increased margin of fuel reliability. Thus, the modification does not constitute an unreviewed safety question to CGS based on the criteria given in 10 CFR 50.59.

Reference:

1. *Letter, J. S. Charnley (GE) to T. A. Ippolito (NRC), "Water Rod Lower End Plug Inspection Results," dated July 28, 1980.*

ISSUE: CPB-4 FUEL CLADDING, SWELLING, AND RUPTURE MODELS

Question:

The applicant has not provided information to assure that for the fuel cladding in a LOCA "the degree of swelling and incidence of rupture are not underestimated" as required by Appendix K of 10 CFR 50.46. The procedures proposed in NUREG-0630 introduce additional conservatism and should be utilized to perform supplemental calculations to the current ECCS analyses.

Response:

General Electric recently transmitted supplemental calculations to the NRC, "Fuel Swell and Rupture Model - Experimental Data Review and Sensitivity Studies," May 15, 1981. This

document contains a discussion of the first stress and circumferential strain data applicable to the BWR, and presents results from the sensitivity studies performed comparing the NUREG-0630 models with the current GE models.

Hoop stress versus rupture temperature sensitivity studies were performed using a combination of the two curves (adjusted GE stress curve and NUREG-0630). These studies resulted in a change in PCT of ±10°F. Even though this PCT impact is small, GE proposes to review the current stress model to incorporate the adjusted curve. Implementation of the adjusted curve will be coincidental with implementation of the complete LOCA model improvement package. Also, the document shows that NUREG-0630 perforation strain versus temperature curve is not applicable to BWR fuel and that substitution of a bounding NUREG-0630 curve into the current GE ECCS analysis has negligible effect on the peak clad temperature (PCT). Based on this, it is maintained that the current GE strain model is valid for the BWR and should continue to be used for ECCS calculations at CGS.

Reference:

1. *Letter, R. H. Buchholz (GE) to L. S. Rubenstein (NRC), "General Electric Fuel Clad Swelling and Rupture Model," dated May 15, 1981.*

ISSUE: CPB-5 FISSION GAS RELEASE

Question:

Provide more detailed and specific information on the Fission Gas Release concern as applicable to the CGS design.

Response:

The effects of high burnups and subsequent fission gas release on fuel thermal-mechanical design analyses was addressed in the proprietary General Electric presentation to the NRC on Extended Burnups, March 24, 1981. Burnups to 50 GWd/MT are considered in the stress analyses documented in NEDE-24011-PA. This analysis is applicable to CGS fuel.

ISSUE: CPB-6 STABILITY ANALYSIS

Question:

Please refer to NRC Question 221.009 for this question.

<u>Response</u>:

Please refer to the response to NRC Question 221.009.

ISSUE: CPB-7 CHANNEL BOX DEFLECTION

<u>Question</u>:

The applicant has not referenced General Electric Licensing Topical Report NEDE-21354-P which describes the fuel channel design. Of specific concern is the commitment to control rod driveline friction testing recommended in Section 4.4.2 of NEDE-21354-P.

<u>Response</u>:

To resolve the channel box deflection issue, Energy Northwest has initiated a channel management program for CGS. The elements of this program include:

a. *Compiling complete operating history records for each channel. Data to be collected include channel location, orientation of welded sides, exposure, and control history.*

b. *Compiling complete analytical history records for each channel including fast fluence (>1 MeV) , and flux gradient history.*

c. *Measurement of post-operation channel box deflection.*

Energy Northwest is planning to measure channel box deflection after each refueling outage for selected channels which are discharged to the spent fuel pool. The reuse of discharged channels will be determined based upon these measurements as compared to predetermined criteria. Other items which will be addressed in this program include development of channel manufacturing history data and analytical, predictive capability.

The Channel Management Program has already resulted in some potential improvement in channel operation. Data from Commonwealth Edison measurements which recently became available indicate that major channel bow may be a strong function of channel manufacturing history rather than location of the channel within the core. Their data indicate that prime candidates for channel bow are manufactured from two pieces of stock material not from the same original material batch. Also, Commonwealth Edison channels which experienced major bow, in many cases, were never on the core periphery.

Based on this information, Energy Northwest has identified which of the CGS channels are manufactured from mismatched halves (75 out of 764) and we have set up special plans to

manage the use of these channels to minimize potential channel bow. These measures include taking advantage of core locations which are not adjacent to control blades and, in addition, identification of locations of minimal exposure and fast flux tilt.

In addition to the above channel management program, Energy Northwest is proposing to take a number of operational actions to monitor channel distortion in the core. Prior to startup after each reload, scram time testing and rod notch testing will be performed. For rods which fail the above test, the pressure test described in NEDE-21534-P (4.4.2) will then be performed.

I.4 INSTRUMENTATION AND CONTROL SYSTEMS BRANCH

ISSUE: ICSB-1 PHYSICAL SEPARATION AND ELECTRICAL ISOLATION (7.1.4, 7.2.3, and 7.6.3)

Question:

In the applicant's design, Class 1E instrumentation do not adhere to adequate separation criteria, have not been qualified, and do not adhere to separation of Class 1E to non-Class 1E instrumentation.

Response:

Columbia Generating Station (CGS) Class 1E instrumentation has been reevaluation to the requirements NUREG-0588, Category II, as described in the Equipment Qualification Report referenced in 3.11. Class 1E instrumentation is adequately separated as described in the response to Question 031.100 and as additionally agreed to in CGS docket letter GO2-81-146, dated June 18, 1981.

ISSUE: ICSB-2 ANTICIPATED TRANSIENT WITHOUT SCRAM (ATWS)

Question:

We require that the applicant agrees to implement plant modifications on a scheduled basis in conformance with the Commission's final resolution of ATWS. In the event that LaSalle starts operation before necessary plant modifications are implemented, we require some interim actions be taken by LaSalle in order to reduce, further, the risk from ATWS events.

The applicant will be required to:

a. *Develop emergency procedures to train operators to recognize an ATWS event, including consideration of scram indicators, rod position indicators, flux monitors, vessel level and pressure indicators, relief valve and isolation valve indicators, and containment temperature, pressure, and radiation indicators.*

b. *Train operators to take action in the event of an ATWS including consideration of immediately manual scramming the reactor by using the manual scram buttons followed by changing rod scram switches to the scram position, stripping the feeder breakers on the reactor protection system power distribution buses, opening the scram discharge volume drain valve, prompt actuation of the*

standby liquid control system, and prompt placement of the RHR in the pool cooling mode to reduce the severity of the containment conditions.

Response:

See the response to RSB-22.

ISSUE: ICSB-3 TEST TECHNIQUES (7.1.4)

Question:

In order to perform routine surveillance testing, it is necessary for the applicant to pull fuses. We consider that this design does not satisfy the requirements of IEEE Standard 279-1971, Paragraphs 4.11 and 4.20.

Response:

The responses to Questions 031.039 and 031.061 address this issue. Part (b) of the response to Question 031.039 is repeated below:

> *"In no instance will it be necessary during testing… to either lift leads or remove fuses."*

ISSUE: ICSB-4 SAFETY SYSTEM SETPOINTS (7.1.4)

Question:

The range of Class 1E system sensors may be exceeded in the worst case combination of setpoint and accuracy.

Response:

a. *All calculated setpoints (taking into account drift) will be within sensor range and will be in accord with Technical Specification Limits.*

b. *Certain setpoints are dependent upon actual plant location or operation (i.e., background radiation) and can only be determined at a later date. If an incompatibility exists with regard to sensor range the instrument will be replaced. This position applies for all instruments where conflicts are detected.*

ISSUE: ICSB-5 DRAWINGS

Question:

The one line drawings and schematics contradict the functional control drawings and system description which are provided in the FSAR. Furthermore, contact utilization charts contradict the actual schematics.

Response:

The contradiction between the drawings and the system descriptions has been eliminated as the result of a major effort spent in rewriting Chapter 7 with this concern in mind. With regard to inconsistencies between the functional control diagrams and schematics, all FSAR drawings and those listed in Chapter 1.7 are updated and distributed every 6 months.

ISSUE: ICSB-6 RCIC CLASSIFICATION

Question:

Refer to Question 031.015 and LRG Issue RSB-6.

Response:

Refer to responses to Question 031.015 and LRG Issue RSB-6.

ISSUE: ICSB-7 SAFETY-RELATED DISPLAY (7.5)

Question:

The design of the safe shutdown indication does not satisfy the requirements of IEEE Standard 279-1971, Paragraph 4.10.

Response:

CGS safety-related display instrumentation will be designed to comply with the requirements of Regulatory Guide 1.97, Revision 2. Section 7.5 has been amended to discuss the degree of conformance for CGS for each indication applicable as described in Regulatory Guide 1.97 and IEEE Standard 279-1971.

ISSUE: ICSB-8 ROD BLOCK MONITOR (7.6)

Question:

The applicant does not agree that the rod block monitor is a protection system.

Response:

The NRC has conducted an extensive review of the RMCS including refueling interlocks RBM, RWM, RSCS on various dockets. Plants with open items having similar designs will be conformed to the Zimmer design (i.e., the resolution will be reviewed and resolution bases if applicable will be incorporated).

The Zimmer design review has been completed and the issue resolved. This closure basis will be relied upon. CGS system is similar to the design proposed for the Zimmer plant as delineated below:

a. *The four flow monitors are interconnected by armored cable and shield cables and there are open spaces around the cables which penetrate fire barriers between redundant channels.*

b. *Both rod block monitor channels are connected by data buses which are enclosed in a metal shield and run along the top of the cabinet.*

c. *The wiring of the rod block monitor bypass switch satisfies the CGS separation criteria.*

d. *The rod block monitor is a modified design and contains multiplexing circuitry which interfaces with the new reactor manual control system.*

Items a, b, and c have been verified at CGS site as to their existence. The NRC met with General Electric on Item d. and the staff has approved the current design and transient analysis with the addition of periodic technical specification testing to assure system operability. * *CGS will include a surveillance requirement in the Technical Specification for the rod block monitor.*

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* *A GE/NRC generic meeting was held in Bethesda on January 22, 1981 to discuss the new reactor manual control system utilized on most NTOL plants. The NRC has been concerned for many years about the appropriateness of utilizing the RBM (not fully safety grade) in transient mitigation.*

ISSUE: ICSB-9 MSIV LEAKAGE CONTROL SYSTEM

Question:

We identified a single failure to the MSIV leakage control system which could lead to possible failure of the system during testing or operation.

Response:

Please see the revised response to Question 031.076.

I.5 MATERIALS ENGINEERING BRANCH

ISSUE: MTEB-1 PRESERVICE AND INSERVICE INSPECTION OF CLASS 1, 2, AND 3 COMPONENTS PER 10 CFR 50.55a(g)

Question:

Preservice and inservice inspection of Class 1, 2, and 3 components have not been submitted.

Response:

The response to the above stated concern is provided in the response to Question 121.010.

ISSUE: MTEB-2 EXEMPTIONS FROM APPENDIX G AND H TO 10 CFR 50
MTEB-3 (5.1.4) (5.3.2) (5.3.3)

Question:

The Columbia Generating Station (CGS) reactor vessel does not meet the specific requirements of Appendix G and H to 10 CFR 50. Identify and justify your exemptions.

Response:

CGS, as a member of the Licensing Review Group (LRG), has submitted information of fracture toughness and surveillance program requirements to show compliance with Appendix G and H to 10 CFR 50. This submittal (Reference 1) was similar to that which has been approved by the NRC for the preceding LRG members (LaSalle County, Susquehanna, Shoreham, Zimmer, and Fermi-2).

Reference:

1. *Letter GO2-81-532, G. D. Bouchey to A. Schwencer, "Appendix G and H Information, Responses to Materials Engineering Branch - Component Integrity Section," dated December 18, 1981.*

ISSUE: MTEB-4 REACTOR TESTING AND COOLDOWN LIMITS (5.3)

Question:

Insufficient information has been submitted for us to assess that the methods used to provide stress intensity values, are equivalent to those obtained from Appendix G of ASME Code; clarification and justification of the methods used to construct the operating pressure temperature limits should be provided.

Response:

CGS has provided information to show compliance with the methods of Appendix G of Section III of the ASME Boiler and Pressure Code (Summer 1972 Addenda). Compliance with Appendix G for this vessel is to provide operating limitations on pressure and temperature based on fracture toughness. These operating limits assure that a margin of safety against a nonductile failure of this vessel is the same as that for a vessel built to the Summer 1972 Addenda.

The specific temperature limits for operation when the core is critical are based on an approved modification to 10 CFR 50, Appendix G, Paragraph IV.A.2.c. The approved modification and justification for it is given in GE Licensing Topical Report NEDO-21778-A (Reference 1).

See Reference 1 to MEB-2 and MEB-3.

Reference:

1. Letter to Dr. G. G. Sherwood (GE) from Olan V. Parr (NRC), "Review of General Electric Topical Report, Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors," November 13, 1978 (see GE Transmittal T-1727).

ISSUE: MTEB-5 GENERAL DESIGN CRITERION 51

Question:

The applicant must demonstrate that the primary containment pressure boundary at CGS meets the requirements of General Design Criterion 51 of 10 CFR 50.

<u>Response</u>:

GDC-51 requires that under operating, maintenance, testing, and postulated accident conditions (1) the ferritic materials of the containment pressure boundary behave in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized.

The CGS containment system includes a ferritic steel primary containment vessel and head enclosed by a reinforced concrete shield structure. The ferritic materials of the containment pressure boundary that were considered in the evaluation for compliance to GDC-51 are those that have been applied in the fabrication of the containment vessel and head, equipment hatch, personnel lock, and penetrations and components of the fluid system including valves required to isolate the system. These components are the parts of the containment system that are not backed by concrete and must sustain loads during the performance of the containment function under the conditions cited by GDC-51.

CGS containment pressure boundary is comprised of ASME Code Class I, Class 2, and MC components. Based upon the review performed by the NRC, it was determined that the fracture toughness requirements in ASME Code Editions and Addenda typical of those used in the design of the CGS containment may not ensure compliance with GDC-51 for all areas of the containment pressure boundary. The basis for this decision was that the fracture toughness criteria that had been applied in construction differ in Code classifications and Code Edition and Addenda. Therefore, the Class I, Class 2, and Class MC components of the CGS containment pressure boundary were reviewed according to the fracture toughness requirements of the Summer 1977 Addenda of Section III for Class 2 components and fracture toughness data presented in NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing of PWR Steam Generator and Reactor Coolant Pump Supports."

Based on review of the available fracture toughness data and material fabrication histories, and the use of correlations between metallurgical characteristics and material fracture toughness, it was concluded that the ferritic materials in the CGS containment pressure boundary meet the fracture toughness requirements that are specified for Class 2 components by the 1977 Addenda of Section III of the ASME Code. Compliance with these Code requirements provide reasonable assurance that the CGS reactor containment pressure boundary materials will behave in a non-brittle manner, that the probability of rapidly propagating fracture will be minimized, and that the requirements of GDC-51 are satisfied.

I.6 MECHANICAL ENGINEERING BRANCH

ISSUE: MEB-1 ASYMMETRICAL LOCA AND SSE AND ANNULUS PRESSURIZATION LOADS ON REACTOR VESSEL INTERNALS AND SUPPORTS (3.9.2)

Question:

Document your reevaluation of the safety-related systems and components based upon the load combinations, response combination methodology, and acceptance criteria required by us as presented at our meeting of December 12, 1978. (Reference letter dated September 18, 1978.)

Response:

This issue was discussed at the Mechanical Engineering Branch (MEB) Safety Evaluation Report (SER) meeting held September 29 through October 1, 1981, for Columbia Generating Station (CGS). Load combinations and acceptance criteria are provided in the responses to the MEB SER questions 23 and 25, presented at that meeting (see Table MEB-1-1). Results of the reevaluation will be provided in the New Loads update of 3.9, to be provided in a future amendment.

Table MEB-1-1

Load Combination and Acceptance Criteria for ASME Code Class 1, 2, and 3 NSSS Piping and Equipment

Load Combination	*Design Basis*	*Evaluation Basis*	*(Service Level)*
$N + SRV_{(ALL)}$	*Upset*	*Upset*	*(B)*
$N + OBE$	*Upset*	*Upset*	*(B)*
$N + OBE + SRV_{(ALL)}$	*Emergency*	*Upset*	*(B)*
$N + SSE + SRV_{(ALL)}$	*Faulted*	*Faulted**	*(D)*
$N + SBA + SRV$	*Emergency*	*Emergency**	*(C)*
$N + IBA + SRV$	*Faulted*	*Faulted**	*(D)*
$N + SBA + SRV_{(ADS)}$	*Emergency*	*Emergency**	*(C)*
$N + SBA + OBE + SRV_{(ADS)}$	*Faulted*	*Faulted**	*(D)*
$N + IBA + OBE + SRV_{(ADS)}$	*Faulted*	*Faulted**	*(D)*
$N + SBA/IBA + SSE + SRV_{(ADS)}$	*Faulted*	*Faulted**	*(D)*
$^{**}N + LOCA + SSE$	*Faulted*	*Faulted**	*(D)*

LOAD DEFINITION LEGEND

Normal (N) - *Normal and/or abnormal loads depending on acceptance criteria.*

OBE - *Operational basis earthquake loads.*

SSE - *Safe shutdown earthquake loads.*

SRV - *Safety/relief valve discharge induced loads from two adjacent valves (one valve actuated when adjacent valve is cycling).*

SRV_{ALL} - *The loads induced by actuation of all safety/relief valves which activate within milliseconds of each other (e.g., turbine trip operational transient).*

Table MEB-1-1 (Continued)

SRV_{ADS}	-	*The loads induced by the actuation of safety/relief valves associated with automatic depressurization system which activate within milliseconds of each other during the postulated small or intermediate size pipe rupture.*
LOCA	-	*The loss-of-coolant accident associated with the postulated pipe rupture of large pipes (e.g., main steam, feedwater, recirculation piping).*
$LOCA_1$	-	*Pool swell drag/fallout loads on piping and components located between the main vent discharge outlet and the suppression pool water upper surface.*
$LOCA_2$	-	*Pool swell impact loads on piping and components located above the suppression pool water upper surface.*
$LOCA_3$	-	*Oscillating pressure induced loads on submerged piping and components during condensation oscillations.*
$LOCA_4$	-	*Building motion induced loads from chugging.*
$LOCA_5$	-	*Building motion induced loads from main vent air clearing.*
$LOCA_6$	-	*Vertical and horizontal loads on main vent piping.*
$LOCA_7$	-	*Annulus pressurization loads.*
SBA	-	*The abnormal transients associated with a small break accident.*
IBA	-	*The abnormal transients associated with an intermediate break accident.*

* *All ASME Code Class 1, 2, and 3 piping systems which are required to function for safe shutdown under the postulated events shall meet the requirements of NRC's "Interim Technical Position Function Capability of Passive Components" - by MEB.*

** *The most limiting case combination among $LOCA_1$ through $LOCA_7$.*

ISSUE: MEB-2 PREOPERATIONAL VIBRATION ASSURANCE PROGRAM (3.9.2, 3.9.5)

Question:

Additional information is required concerning the basis for the allowable vibration amplitude derived and clarification of the use of twice this allowable is acceptable.

Response:

This item has been closed by MEB prior to LRG review. It is not documented in lead plant or subsequent plant SERs. For additional information see responses to Questions 110.022, 110.023, and 110.024.

ISSUE: MEB-3 DYNAMIC RESPONSE COMBINATION USING THE SRSS TECHNIQUE

Question:

We are studying the problem of utilizing the square-root-of-the-sum-of-the-squares (SRSS) for determining responses other than LOCA and SSE as you have used. By not utilizing the absolute sum method, the review may be extended if we do not agree that the SRSS methodology is applicable.

Response:

The response to this issue was provided during the Mechanical Engineering Branch meeting for CGS, September 29 through October 1, 1981. (See Attachment 1.)

ATTACHMENT 1

Question No. 26
(3.9.3.1)

The methods of combining responses to all of the loads requested in (a) above is required. Our position in this issue for Mark II plants is outlined in NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses". However, since the primary containment for the CGS plant is a free-standing steel pressure vessel and the plant is in a higher seismic zone, the staff will require that the criteria in Section 4 of NUREG-0484, Revision 1, "Criteria for Combination of Dynamic Responses Other Than Those of SSE and LOCA," be satisfied if the square-root-of-the-sum-of-the-squares method of combining these responses is used. (Reference Regulatory Position E (2) in the enclosure to a letter from J. R. Miller, NRC, to Dr. G. G. Sherwood, GE, "Review of General Electric Topical Report NEDE-24010-P," dated June 19, 1980.) The conclusions of NUREG-0484, Revision 1, are based on the studies performed by GE in NEDE-24010-P and BNL in NUREG/CR-1330. The applicant must demonstrate that an SRSS combination of dynamic responses achieves the 84% nonexceedance probability level because of the difference in containment and seismic level which were not included in the earlier studies.

Response:

When a seismic response from a high seismic input, like that from Hanford, is combined with another dynamic response (e.g., SRV discharge loads), depending on the relative magnitudes of the two responses being combined, the shape of the cumulative distribution function (CDF) of the combined response will change. If the maximum magnitude of one of the responses is very large compared to the other response being combined, the CDF curve will almost be vertical and it is immaterial if these two responses are combined using the SRSS or the Absolute Sum (ABS) rule. However, if the maximum magnitudes of the two responses are about equal, use of SRSS vs. ABS rule to combine the responses will cause significant difference in the combined response. In addition, in this case, the CDF curve will be more like S-shaped with the non-exceedance probability (NEP) of SRSS being close to 84%. In the generic Mark II study, examples from both such cases were considered with more examples from the case with responses of comparable magnitudes. This study showed that all these Mark II cases meet the requirements of NUREG-0484. Hence the GE Topical Report NEDE-24010-P, "Technical Bases for the Use of SRSS Method for Combining Dynamic Loads for Mark II Plants," is also applicable to CGS with high seismic input.

The impact of the free-standing steel primary containment is discussed in the areas as follows:

a. *Vessel and Internals*

   Vessel and internals are not attached to and not affected by the steel containment.

b. *Piping Systems and Floor Mounted Equipment*

   The dynamic input to these components at their containment support locations may be affected by the steel containment response to the dynamic loads under consideration and hence, may be different from that obtained from concrete containment. However, the frequencies contributing to the responses of major structures and components in both types of plants will not be significantly different but will fall into the same general range.

The structural frequencies will only determine the magnitude of amplification or attenuation of the response. For multi-frequency random-type dynamic loads, the components of input loads whose frequencies coincide with the structural natural frequencies will be amplified and these components will dominate the response. Although the predominant response of a particular structural component may vary somewhat in frequency between the concrete and steel containment configuration, the variances are expected to be small for the range of frequencies of interest for major structures because of the similarities in systems, types of structural configurations, construction materials, and massiveness of buildings. Therefore, key characteristics of the responses (duration of strong response motion and number of peaks) are primarily determined by the input component loads to the structure, and because of the similarity of the dynamic nature of the input loads due to earthquake, SRV, and LOCA for both types of containment, their structural responses will have similar dynamic characteristics. Hence, the response of the mechanical components and piping systems supported from the two types of containments will also be similar. Hence, the use of SRSS combinations for combining the dynamic responses for the CGS application will be demonstrated to meet the 84% non-exceedance probability level.

ISSUE: MEB-4 OBE PLUS SRV FATIGUE ANALYSIS

Question:

Clarify your consideration of the cyclic loadings due to the operating basis earthquake (OBE) and safety/relief valve actuation in your NSSS fatigue analysis.

Response:

For the NSSS piping, 50 peak OBE cycles are used. For other NSSS equipment and components, a generic study serves as the basis for 10 peak OBE cycles. As shown in Reference 1, 10 peak OBE cycles can envelope the cumulative fatigue damage of hundreds of less severe earthquake cycles. Section 3.9 of the FSAR was revised to reflect this position.

The methodologies used to evaluate the fatigue effects due to combined SRV and OBE loads are documented in Reference 2. In the fatigue analysis of NSSS equipment, piping, reactor pressure vessel, and RPV internal components, the actual calculated loads due to OBE and SRV are combined to show compliance with upset limits of fatigue.

References:

1. *Letter from R. Artigas to R. Bosnak, "Number of OBE Fatigue Cycles in the BWR NSSS Design," September 17, 1981.*

2. *Letter from R. B. Johnson to R. Bosnak, "GE Position on Fatigue Analysis," June 29, 1981.*

ISSUE: MEB-5 STRESS CORROSION CRACKING OF STAINLESS STEEL COMPONENTS - DESIGN MODIFICATION

Question:

You are requested to review all ASME Code Class 1, 2, and 3 pressure boundary piping, safe ends and fitting material, including weld metal at your facility to determine if the material selection, processing guidelines, or inspection requirements set forth in NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," are satisfied.

Response:

The response to the above stated concern is provided in the response to NUREG-0313, Revision 1, which was submitted to the NRC September 2, 1981, via GO2-81-268,

G. D. Bouchey to A. Schwencer, "Hardship Exemption Request for Implementation of NUREG-0313, Revision 1."

ISSUE: MEB-6 PUMP AND VALVE OPERABILITY ASSURANCE PROGRAM (3.9.3.2)

Question:

Additional information has been requested regarding your analytical and testing methods for your pump and valve operability assurance program.

Response:

a. Pumps

In addition to the tests called for in the FSAR, active safety-related pumps have been analyzed to find the natural frequencies of the pump. When these frequencies were above the ZPA of the seismic floor response spectra, static analyses were performed on the pumps. When the analyses established that the resultant stresses in the pumps were below allowables and the deflections under these loads were less than clearances between moving parts, operability was established. No pumps have been identified which need to have additional testing or analysis to establish operability.

b. Valves

In addition to the tests mentioned in the response to Question 110.032, seismic analyses have been and are being performed on the active safety-related valves which were not prototypically tested. The tests, along with the analysis showing clearance at critical points, demonstrate operability under normal plus SSE loading.

Where the analyses do not show clearances, the valves are being retested as part of the requalification program. If the test and/or analyses did not include hydrodynamic loads where applicable, the valves are being retested or reanalyzed using the proper loading as part of the requalification program.

Where valve accelerations resulting from piping analyses are not yet known, the peak acceleration for frequencies over 8 hz on the 0.005 damping floor response spectra is used as input acceleration for valve analysis and testing. The acceptability of this criteria are being established by comparing piping analysis accelerations to these peaks. The test reports, analyses, and requalification

plans were made available and audited by the NRC-SQRT (Seismic Qualification Review Team) and NRC-PVORT (Pump and Valve Operability Review Team) during November 1982.

ISSUE: MEB-7 BOLTED CONNECTIONS FOR SUPPORTS (3.9.3)

Question:

You have not provided the allowable limits for buckling for the reactor vessel support skirt subjected to faulted conditions. In addition, we requested information concerning the design of support bolts and bolted connections.

Response:

The responses to Questions 24 (Attachment 1) and 42 (Attachment 2) from the CGS draft SER respond to this issue.

ATTACHMENT 1

Question No. 24
(3.9.3.1)

Several references are made in Table 3.9.2(a) through 3.9.2(ac) to allowable stresses for bolting. Specifically, what loading combinations and allowable stress limits are used for bolting for (a) equipment anchorage, (b) component supports, and (c) flange connections. Where are these limits defined?

Response:

a. *Floor Mounted Equipment*

1. *Equipment Anchorage Bolting*

The floor anchored mechanical equipment (pumps, heat exchangers, and RCIC turbine) in GE's scope of supply are mounted on a concrete floor or a steel structure. The design of concrete anchor bolts for the equipment mounted on concrete floor, and the responsibility to prescribe and meet the necessary codes and stress limits are in the AE's scope of supply. The design of attachment bolts for the equipment mounted on steel structure, and the responsibility to prescribe and meet the necessary codes and stress limits are also in the AE's scope of supply. GE works with the interface limit of 10,000 psi in tension or shear for the only purpose of sizing bolt holes in the equipment base, based on the required nominal size and number of bolts for maximum loads.

2. *Component Support Bolting*

(a) *RWCU Pump*

The support bolting of this non-safety essential pump is designed for the effects of pipe load and SSE load to the requirements of the ASME code, Section III, Appendix XVII. The stress limits of 0.41Sy for tension and 0.15Sy for shear are used.

(b) *RCIC Turbine*

The pump-to-base plate bolting is designed as follows:

(1) *Normal Plus Upset*

a) *Primary membrane:*

1.0S

b) *Primary membrane plus bending:*

1.5S,where S is the allowable stress limit per the ASME Code Section III, Appendix I, Table 1-7.3.

(2) *Emergency or Faulted*

Stresses shall be less than 1.2 times the allowable limits for "Normal plus Upset" given above.

(c) *Flanged Connection Bolting*

There are no flange type connections in component supports.

b. *Piping Supports and Pipe Mounted Equipment (Valves and Pump) Supports*

The supports are hanger and snubber type (including clamps) linear standard components as defined by the ASME Code Section III, Subsection NF. The bolts used in these supports meet criteria of NF-3280 for Service Levels A and B and NF-3230 for Service Levels C and D. (Note: NF-3280 is applicable to bolting for Service Levels A and B. NF-3230 is applicable to linear supports; it refers to Appendix VII which is applicable to bolting for Service Levels C and D.)

ATTACHMENT 2

<u>Question No. 42</u>
(3.9.3.4)

The applicant's response to NRC Question 110.029 is not completely acceptable. Paragraph 3.9.3.4 implies that the reactor vessel support skirt was designed to an allowable compressive load of 0.8 material yield stress. It is not clear how the applicant's design would meet the staff's acceptable allowable load of two-thirds of critical buckling load. In addition, the applicant has assumed the critical buckling stress as the material yield stress at temperature. Provide basis for this assumption.

<u>Response</u>:

This issue was addressed and approved by the NRC on the Susquehanna DSER docket.

Refer to the response to Susquehanna DSER 3.9.3-6. A similar response is provided as follows:

Per GE design specification, the permissible compressive load on the reactor vessel support skirt cylinder (plate and shell type component support) was limited to 90% of the load which produces yield stress, divided by the safety factor for the condition being evaluated. The effects of fabrication and operational eccentricity was included. The safety factor for faulted conditions was 1.125.

An analysis of reactor pressure vessel support skirt buckling for faulted conditions shows that the support skirt has the capability to meet ASME Code Section III, Paragraph F-1370(c) faulted condition limits of 0.67 times the critical buckling strength of the support at temperature assuming that the critical buckling stress limit corresponds to the material yield stress at temperature. The faulted condition analyzed included the compressive loads due to the design basis maximum earthquake, the overturning moments and shears due to the jet reaction load resulting from a severed pipe, and the compressive effects on the support skirt due to the thermal and pressure expansion of the reactor vessel. The expected maximum earthquake loads for the Hanford 2 reactor vessel support skirt are less than 50% of the maximum design basis loads used in the buckling analysis described; therefore, the expected faulted loads are well below the critical buckling limits of Paragraph F-1370(c) for this reactor vessel support skirt. The expected earthquake loads for this reactor were determined using the seismic dynamic analysis methods described in Section 3.7.

Based on currently defined faulted condition loads including annulus pressurization and SSE loads, the maximum compressive stress in the support skirt for axial and bending loads is less than the upset condition allowables determined by the methods of NB-3133.6 of the ASME Code. This assures satisfactory margin against buckling for the faulted condition loads.

ISSUE: MEB-8 PUMP AND VALVE INSERVICE TEST PER 10 CFR 50.55a(g)

Question:

You have not submitted your proposed program for the inservice testing of pumps and valves as required by 10 CFR 50.55a(g).

Response:

The CGS pump and valve inservice test program plant was submitted to the NRC via letter GO2-81-322, G. D. Bouchey to A. Schwencer, "Pump and Valve Test Program Plan," dated October 1, 1981.

ISSUE: MEB-9 REVIEW OF IN SITU TEST PROGRAM OF THE SAFETY/RELIEF VALVE

Question:

No specific question identified for this issue.

Response:

Extensive in-plant SRV actuation test programs have been implemented at Caorso (Italy) and Tokai-2 (Japan), two BWR plants with Mark II containment configuration and equipped with x-quenchers of a design essentially identical to those used in CGS. Test results from the above programs, which are available to the NRC, have been used to develop an improved SRV discharge load definition for specific application to CGS (see Report, "SRV Loads, Improved Definition for Mark II Containments, Proprietary Section") and to confirm that the difference between bulk pool temperature and local pool temperature at the quencher discharge is within the value assumed in the suppression pool temperature transient analysis for CGS. As stated in Reference 3, implementation of additional SRV tests to measure or confirm the adequacy of the SRV load definition is unnecessary, but an in-plant test to measure local to bulk pool temperature difference will be performed.

References:

1. *Letter GO2-80-172, D. L. Renberger to B. J. Youngblood, "Submittal of SRV Report," dated August 8, 1980.*

2. *Letter, J. J. Verderber to B. J. Youngblood, "Submittal of Proprietary SRV Report," dated August 27, 1980.*

3. *Letter GO2-81-524, G. D. Bouchey to A. Schwencer, "Suppression Pool Temperature Transient Analysis and In-Plant SRV Test," dated December 15, 1981.*

ISSUE: MEB-10 CRACKING OF JET PUMP HOLD-DOWN BEAMS

Question:

Additional information is required concerning the actions being taken by the licensee to preclude cracking of the jet pump hold-down beams.

Response:

As discussed in response to IE Bulletin 80-07, CGS will comply with the GE generic resolution. Since the jet pump hold-down beams have already been installed, CGS will reduce the beam preload from 30 kips to 25 kips which is expected to increase beam operating time to crack initiation at the 2.5% probability level to a range of 19 to 40 years. Also, during operation, periodic inspections will be conducted as part of our overall in-service inspection program. Inspection frequencies will be developed in the future based on lead plant inspection results and the results of future testing at General Electric. (See Reference 1.)

References:

1. *Letter, G. D. Bouchey to R. L. Tedesco, GO2-80-279, "Cracking of BWR Jet Pump Hold Down Beams," dated December 4, 1980.*

ISSUE: MEB-11 CONTROL ROD DRIVE RETURN LINE

Question:

We have not completed our review of GE Topical Report NEDE-21821-2A addressing reactor feedwater nozzle/sparger design modification for cracks nor have we completed GE's generic modification to the control rod drive return nozzle. This may require additional request for information.

Response:

Energy Northwest's response to NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Line Nozzle Cracking," has been completed. The current status of our position on the CRD cracking problem is as follows:

a. CRD return line has been cut and capped as allowed by NUREG-0619, page 31.

b. CRD return line has been rerouted through redundant equalizing valves to the exhaust water header.

c. The control rod drive preoperational test will demonstrate that the system is fully operational and that all components including the hydraulic drive mechanisms, pumps, and flow control valves function properly. The CRD system will be configured with the modifications noted in the NRC concern.

d. In order to assure satisfactory system operation with the single failure of an equalizing valve, the proposed design modification will include the addition of two equalizing valves installed in a parallel configuration. The failure of either valve will not impair CRD operation for any foreseen operating or accident condition.

e. There will be no increased potential for carbon steel corrosion products to be deposited in the drives. All lines in the CGS hydraulic system after the drive water filters are made of stainless steel.

f. The NRC requested GE by letter of January 28, 1980, to recalculate the makeup flow capacity for the 251-inch BWR-5 without the CRD return line. This generic information has been provided by letter of May 2, 1980, from R. L. Gridley, GE, to D. G. Eisenhut, NRC, concurrently with this docketed response for LaSalle. The results indicate that the 251-inch BWR-5 CRD system without a return line (capped Nozzle 10) can achieve a vessel makeup flow in excess of its calculated boiloff rate of 180 gpm. This confirms the same boiloff rate as previously documented in a March 14, 1979, submittal from GE. Furthermore, since the CRD system is not designed to perform an ECCS function, the additional testing to demonstrate the required return flow capacity to the vessel is not warranted.

ISSUE: MEB-12 CONFIRMATORY PIPING ANALYSIS

__Question__:

This item is comprised of two issues:

a. The NRC requires piping system data for the purpose of running confirmatory stress calculations to assure compliance with IE Bulletin 79-14.b.

b. *Documentation of the preoperational vibration test program for all ASME, Section III, Class 1, 2, and 3 high energy piping systems and all Seismic Category I portions of moderate and high energy piping systems.*

Response:

a. *A summary of CGS inspection program and the design control measures utilized to assure an adequate design for the Seismic Category I piping systems are contained in a letter from D. L. Renberger to R. H. Engelken," WPPSS Nuclear Project No. 2, IE Bulletin 79-14," dated September 7, 1979 (Reference 1). Presently, CGS has an established program to develop as-built drawings documenting the final configuration of the piping systems together with their supports. The preparation of the as-built drawings is currently underway and these as-built drawings will provide the basis for the final design assessment of the piping systems. However, in order for NRC to proceed with the confirmatory piping analysis and to verify the compliance of the design data with the as-built configuration, Reference 3 provided the necessary piping design data as requested in Reference 2.*

b. *The preoperational/startup piping vibration program includes all Class 1, 2, and 3 high energy piping systems inside Seismic Category I structures or those portions of high energy systems whose failures could adversely affect the functioning of safety-related structures, systems, or components. The program also includes all Seismic Category I portions of moderate energy piping systems outside containment.*

All systems contained in the preoperational/startup vibration program, as documented in Section 14.2, are operated at rated flow and the piping system is either visually inspected or monitored for steady state vibration by remote readout transducers. If during this initial system operation visual observation indicated that piping vibration is significant, measurements are made with a hand-held vibrograph. The results will then be reviewed by the appropriate engineering group to determine the acceptability of the measured vibration values. For the main steam, recirculation, feedwater, RCIC,and SRV discharging piping, the measured vibration is compared against test acceptance criteria. The results are also reviewed by the responsible piping design organization to confirm proper system performance. Documentation of the test results and engineering evaluation performed on them becomes a part of the Startup Test Program files. A summary report is generated and would be available for NRC review following commercial operation.

<u>*References:*</u>

1. *Letter from D. L. Renberger to R. H. Engelken, "WPPSS Nuclear Project No. 2, IE Bulletin 79-14," dated September 7, 1979, GO2-79-156.*

2. *Letter from R. L. Tedesco to R. L. Ferguson, "Confirmatory Piping Analysis for WNP-2," dated June 22, 1981.*

3. *Letter G. D. Bouchey to L. J. Auge (Manager, Energy Technology Center), dated September 9, 1981, GO2-81-279.*

I.7 POWER SYSTEMS BRANCH

ISSUE: PSB-1 LOW OR DEGRADED GRID VOLTAGE

Question:

The electrical system does not meet our requirements for protection under low or degraded voltage conditions.

Response:

NRC requirements for protection under low or degraded voltage conditions are detailed in Question 040.036 which references revised 8.3.1.1.1 and 8.3.1.2.4.3.

ISSUE: PSB-2 TEST RESULTS FOR THE DIESEL GENERATORS (8.3.2)

Question:

Test results for the diesel generators to indicate margin have not been submitted.

Response:

PSB-2 identifies two margin tests to be accomplished during the preoperational testing of the diesels. The first, a "steady-state margin test," involves loading the unit in excess of the total design accident loads to demonstrate some margin over the total design requirements. The other test, a "start-load margin test," involves applying a step function load in excess of the largest motor to demonstrate the start-load capability of the set with some margin.

Preoperational testing of Columbia Generating Station (CGS) emergency diesels will include subjecting the diesels to 100% rated load as well as loading the units to their two-hour rating, both of which are larger than the combined design accident loads.

During the loss of power tests, occurring during the preoperational testing phase, a test will be made to demonstrate the start-load capability of the units over that which is required. This test involves loading the diesel generator to 100% design load and dropping the largest motor on the associated bus. This motor will then be restarted. This test demonstrates the diesel generator unit has the capability to start the largest motor on its respective bus while concurrently feeding the rest of the bus loads and still remain within the voltage and frequency requirements of Regulatory Guide 1.9.

The HPCS diesel generator will not be required to fulfill the requirements of Regulatory Guide 1.9, with respect to the voltage and frequency drop, during this particular test as clarified in 8.3.1.2.1.4. Preoperational test results will be available for NRC review during the normal inspection enforcement period.

ISSUE: PSB-3 CONTAINMENT ELECTRICAL PENETRATIONS

Question:

The reactor electrical penetrations do not conform to Regulatory Guide 1.63 and test results do not demonstrate that the electrical penetrations can maintain their integrity for maximum fault current.

Response:

NRC concerns regarding electrical penetration capability under maximum fault (short circuit) conditions are expressed in LaSalle FSAR Question 040.106. That question addresses the effect upon containment integrity of fault current i^2t, assuming failure of the circuit primary protective overcurrent device.

LaSalle's response took credit for the fusing properties of cable external to the penetration conductors to provide overcurrent protection backup to the primary overcurrent device. The response reflected a common Licensing Review Group (LRG) position.

The LaSalle SER rejects the LRG position, advising that credit cannot be given for assumed equipment failure (cable fusing). It mandates that fault current protection devices (circuit breakers and/or fuses) to backup the primary over-current protective devices be provided as required to limit fault current surges to levels less than those for which the penetrations are qualified.

NRC concerns in this area are addressed to CGS in Questions 040.031 and 040.035. These questions were not as explicit regarding the NRC concern as was the question addressed to LaSalle. The CGS response to Question 040.035 predated much of the NRC/LaSalle dialogue and requires revision.

The original response to Question 040.034 provided data indicating the capability of penetration primary overcurrent protective devices to clear faults before penetration i^2t capability is exceeded.

Additional analysis has been performed to determine the maximum i^2t available at electrical penetrations for the case of failure of the circuit primary protective devices to function, which requires the backup overcurrent protective device to clear the fault. Where the analysis

demonstrates that penetration i^2t capability is exceeded, a second overcurrent protective device has been added in series with the circuit primary overcurrent protective device.

The responses to Question 040.034 and 040.035 have been revised to reflect the results of this analysis.

ISSUE: PSB-4 ADEQUACY OF THE 120 V AC RPS POWER SUPPLY (8.3.1.1.6)

Question:

The applicant committed to the generic resolution, or to expedite their license, will commit to the surveillance requirements which were applied to Hatch-2.

Response:

Energy Northwest is committed to implement, prior to fuel loading, the RPS MG set design modification developed by General Electric for generic application. The FSAR has been revised to reflect the design modification.

ISSUE: PSB-5 THERMAL OVERLOAD MARGIN

Question:

We require the applicant to provide the detailed analysis and/or criteria which was used to select setpoints for the thermal overload protection devices for valve motors in safety systems and the details as to how these devices will be tested.

Response:

Motor thermal overloads for Class 1E motor-operated valves (MOVs) are chosen two sizes larger than those which would be required based upon normal full load running current. The resultant overload protection (approximately 140% of motor full load current) permits MOVs to operate for extended periods of time at moderate overloads; tripping occurs just prior to motor damage.

Class 1E motor control centers are located in environmentally controlled rooms such that overload ambient temperature variation is not a significant factor.

Initial testing of overload heaters serving safety-related MOVs is performed by Energy Northwest during the Test and Startup Program. This testing is accomplished by injecting a

test current through the overload device, thus, simulating an overcurrent of the motor operator and verifying that the device stops valve travel by deenergizing the motor starter and/or alarms at the appropriate alarm panel, as applicable. Acceptance criteria for these tests are derived by manufacturers' curves for the devices or applicable codes and standards where available.

Periodic surveillance testing of thermal overloads serving safety-related MOVs will be in accordance with the CGS technical specifications. A representative sample of at least 25% will be tested at least once per 18 months, such that all will be tested once per six years. The test itself will be essentially the same as that described above.

ISSUE: PSB-6 RELIABILITY OF DIESEL GENERATOR

Question:

No specific question identified for this issue.

Response:

The reliability of starting and accepting design load in the required time was fully demonstrated for the Div. 1 and Div. 2 D-Gs by the successful completion of the 300 Start Qualification Test performed on D-G Unit 1 in accordance with NRC BTP-EICSB-2 prior to shipment. The reliability of the HPCS D-G has been verified by a prototype test on an eventually identical unit. See Reference 4.

In response to other concerns on the reliability of all the D-G units, see the responses to, Questions 040.080 through 040.089.

The HPCS D-G (Div. 3) has been given preoperational tests to demonstrate the reliability of starting and accepting design load in the required time, and that the system has adequate margin in all respects, such as starting time, accelerating time, engine torque, and long-term carrying capability.

The 300 Start Qualification Test Report for D-G Unit 1 is available for the NRC's review at the plant site. See Reference 2.

The HPCS D-G (Div. 3) Site Preoperational Test Report is available to the NRC for review at the plant site. See Reference 3.

References:

1. *NRC Branch Technical Position EICSB-2*

2. *Prototype 300 Start Qualification Test Report, B&R File No. 53-00-7014 and 53-00-7015.*

3. *HPCS D-G Acceptance Test, PT-7.2-A*

4. *GE Document No. NEDO-10905-3, Licensing Topical Report-High-Pressure Core Spray System Power Supply Unit.*

ISSUE: PSB-7 PERIODIC DIESEL GENERATOR TESTING

Question:

Diesel generator testing once every 18 months is required by Regulatory Guide 1.108.

Response:

The Technical Specifications for CGS comply with Regulatory Guide 1.108 requirements for testing the diesel generators on 18-month intervals. In addition, a test has been included to verify that after an interruption of onsite power the loads are shed from the emergency buses and that subsequent loading of the onsite sources is through the load sequencer. See the response to Question 040.037.

I.8 REACTOR SYSTEMS BRANCH

ISSUE: RSB-1 INTERNALLY GENERATED MISSILES
(3.5.1)

Question:

The applicant has not supplied the information to show that all safety-related systems and components within the containment, including the containment, are protected from missiles.

With regard to missiles sizes of concern, what is the valve size below which, if failure should occur in a high pressure system, damage to other components within the primary containment would not be significant? State criteria used to determine this size. Identify all valves in the primary containment larger than this size and identify the missile protection provided for each valve (either physical location or barrier).

Response

All safety-related systems and components at Columbia Generating Station (CGS) are protected from credible plant. A response identifying criteria and methodology and the final results for inside and outside containment in the third quarter of 1982 (letter no. GO2-82-672).

Valve parts are not postulated as credible missile sources if double retention features exist or bonnet bolting is shown to have high margins of safety. All valves in our plant were evaluated on this basis and it was concluded that valves are not credible missile sources.

ISSUE: RSB-2 CONTROL ROD SYSTEM
(4.6.2)

Question:

As a result of eliminating the control rod drive system return line, we are reviewing generically with regard to the impact on control rod drive system performance. Consequently, we require the applicant to submit system performance data directly applicable to CGS and will require the applicant to conform to the conclusion of the generic study as applicable to CGS.

Response:

See the response to MEB-11.

See also the revised response to Question 211.019.

References:

1. *Letter, G. G. Sherwood (GE) to E. G. Case (NRC), "Control Rod Drive (CRD) Return Line Removal," dated January 27, 1978.*

2. *Letters, G. G. Sherwood (GE) to V. Stello (NRC) and R. J. Mattson (NRC), "Control Rod Drive (CRD) Return Line Removal," dated July 14, 1978.*

3. *Letters, G. G. Sherwood (GE) to V. Stello (NRC) and R. J. Mattson (NRC), "Control Rod Drive (CRD) Return Line Removal," dated February 22, 1979.*

ISSUE: RSB-3 SAFETY/RELIEF VALVES
(5.2.2 and 6.3.2)

Question:

Additional information is required both for qualification test and operating experience with the applicant's safety/relief valves.

Response:

The response to the above stated concern is provided in the revised response to Question 211.051. Also refer to response to Question 211.209.

ISSUE: RSB-4 TRIP OF RECIRCULATION PUMPS TO MITIGATE ATWS
(5.2.2)

Question:

We require reperformance of the overpressure analysis to consider the effect of the ATWS RPT.

Response:

Section 5.2.2 was revised as part of the ODYN analysis which has been submitted to the NRC.

This section incorporates the confirmatory analysis of the overpressure protection report including the ATWS recirculation pump trip. Also see revised response 15.8 and response to Question 211.049.

ISSUE: RSB-5 DETECTION OF INTERSYSTEM LEAKAGE (5.2.5)

Question:

We requested that the applicant show how it intends to detect leakage from the reactor coolant systems into both the low pressure coolant injection (3 trains) and low pressure core spray systems as required by Regulatory Guide 1.45.

Response:

Intersystem leakage will be detected by pressure instrumentation with control room readout in accordance with Regulatory Guide 1.45. The response to CGS FSAR Question 211.009 provides information on this issue.

ISSUE: RSB-6 REACTOR CORE ISOLATION COOLING PUMP SUCTION

Question:

The applicant must supply further information to determine whether the RCIC pump suction has to be automatically switched from the condensate storage tank to the suppression pool in the event of a safe shutdown earthquake and concomitant failure of the condensate storage tank.

Response:

As stated in the response to Question 211.046, an automatic safety-grade switchover to a Seismic Category I supply (suppression pool) has been provided. A description of the automatic switchover has been provided in the response to Question 211.146.

ISSUE: RSB-7 SHUTDOWN UNINTENTIONALLY OF THE REACTOR CORE ISOLATION COOLING SYSTEM

Question:

Show how the design of the RCIC protection system prevents unintentional shutdown of the system, when the system is required, because of spurious ambient temperature signals from areas in and around the system (especially in the RCIC pump room)

Response:

See the revised response to Question 211.010.

ISSUE: RSB-8 RHR ALTERNATE SHUTDOWN DEMONSTRATION

Question:

The applicant must perform tests to show that flow through the safety/relief valves is adequate to provide the necessary fluid relief required consistent with the analyses reported in Section 15.2.9 of the FSAR.

Response:

Refer to the revised response to Question 211.025. Also, NUREG-O737, Item II D.1 is related to Issue RSB-8. A discussion on NUREG-O737 items is contained in Appendix B.

ISSUE: RSB-9 CATEGORIZATION OF VALVES WHICH ISOLATE RHR FROM REACTOR COOLANT SYSTEM (5.4.2)

Question:

We require that the valves which serve to isolate the residual heat removal system from the reactor coolant system be classified Category A/C in accordance with the provisions of Section XI of the ASME code.

Response:

Please refer to RSB-13.

ISSUE: RSB-10 AVAILABLE NET POSITIVE SUCTION HEAD

Question:

The applicant must verify that the suction lines in the suppression pool leading to the ECCS pumps are designed to preclude adverse vortex formation and air injection which could effect pumps performance.

Response:

All ECCS suction lines in the suppression pool have been designed with large diameter piping (24 inches) to reduce inlet velocity. In the worst conceivable case, where there is a leak from an ECCS pump suction line into the largest of the ECCS pump rooms, the water level in the suppression pool is calculated to equalize at elevation 455'-9". In the calculation, no credit is taken for makeup to the suppression pool nor for pumping water leaking into the affected room/ suppression pool. The RCIC pump suction is an 8-inch pipe. The submergence of the top edge of the suction piping with suppression pool water level at 455 ft-9 in. is as follows:

		Penetrations	Depth (C.L.)	Submergence
RHR Loop	"A"	(X-35)	447'-0"	7.8'
	"B"	(X-32)	447'-0"	7.8'
	"C"	(X-36)	447'-7"	7.2'
LPCS		(X-34)	447'-7"	7.2'
HPCS		(X-31)	438'-9"	16.0'
RCIC		(X-33)	452'-0"	3.4'

The minimum depth at which vortex formation at the suction inlets will be prevented is:

	Flow Rate (max)	Velocity	Submergence
RHR	8000 gpm	5.674 fps	2.41'
LPCS	7800 gpm	5.533 fps	2.35'
HPCS	7175 gpm	5.089 fps	2.16'
RCIC	600 gpm	3.295 fps	0.84'

The RCIC pump suction will have 2.5 ft of submergence. The inlet to each of the ECCS lines is at least 5 ft deeper than required to preclude vortexing, and therefore, vortex formation is not considered a problem.

See also the response to Question 211.062 for further information.

ISSUE: RSB-11 ASSURANCE OF FILLED ECCS LINE (6.3.2)

Question:

Instrumentation is not sufficiently sensitive to detect voids at the top of ECCS pipe lines. The applicant must provide adequate instrumentation to assure filled ECCS lines.

Response:

Filled ECCS lines are assured by:

a. *Jockey pump system on same division as system being filled,*
b. *Pressure switch on pump discharge with control room annunciation,*
c. *Technical Specification surveillance - upon high point vents to check for air.*

See also the response to Question 211.079 for additional information.

ISSUE: RSB-12 OPERABILITY OF ADS

Question:

Show that the air supply to the ADS is sufficient for the extended operating time required and is assured by reliability data that the ADS will function as required.

Response:

Safety-related backup to the CIA system is provided by redundant, independent nitrogen gas bottle banks. Upon loss of CIA, the system will be automatically isolated as the backup nitrogen supply is automatically fed into the system. The nitrogen bottle supply is sized for a 30-day supply to the seven ADS valves. The nitrogen supply can farther be backed up by a portable auxiliary nitrogen supply (if necessary) which can be connected outside the reactor building. Please refer to Section 9.3.1.2.2 and the responses to Questions 031.121 and 211.048.

ISSUE: RSB-13 LEAKAGE RATE TESTING OF VALVES USED TO ISOLATE REACTOR COOLANT SYSTEM (5.3.2)

DELETED

ISSUE: RSB-14 OPERABILITY OF ECCS PUMPS (6.3.2)

Question:

The applicant must provide assurance that the ECCS pumps can function for an extended time (maintenance free) under the most limiting post-LOCA conditions.

Response:

This issue has been closed on Zimmer, Shoreham, and LaSalle dockets on the basis of information presented in response to NRC questions. Similar information has been provided on the rest of the dockets. The response to CGS Question 211.072 has been revised to include the latest information available.

NUREG-0737 Task II.B.2 is related to the issue discussed above and is addressed in Appendix B of the FSAR. The shielding evaluation referred to in Appendix B will show that the ECCS pumps will operate for the accident duration (assumed to be six months), using the source terms from II.B.2.

ISSUE: RSB-15 ADDITIONAL LOCA BREAK SPECTRUM (6.3)

Question:

The staff does not concur that the Zimmer LOCA analysis is an appropriate break spectrum for CGS because of: 1) higher power level in CGS, 2) different fuel assembly design in CGS, and 3) higher PCTs predicted for CGS.

The staff requires that the applicant provide the following LOCA analyses to complete the break spectrum:

a. *One additional recirculation line break with a C_D coefficient 0.6 times the DBA, using the large break model analysis.*

b. *One additional recirculation line break (0.02 ft^2) using the small break model analysis.*

Response:

This issue has been closed on the LaSalle docket on the basis of information presented in response to NRC questions. Similar information has been provided in the revised response to CGS FSAR Question 211.068.

ISSUE: RSB-16 LOCA ANALYSIS
(6.3.4)

Question:

You have analyzed the effect on the DBA-LOCA of instantaneous closure of the flow control valve (FCV) in the unbroken loops. This overly conservative result indicated an increase in peak clad temperature (PCT) of 300°F which, if added to the DBA-L0CA PCT, would be in excess of the maximum PCT criterion of 10 CFR 50.46.

Response:

The response to this issue was provided in Amendment No. 11 as a response to Question 211.083. The response to this question is summarized and expanded upon below.

FCV closure in the unbroken loop is not expected to occur during the LOCA event. However, even if the FCV were signaled to close for some unlikely reason (LOCA plus two failures: failure of drywell high pressure signal such that FCV lockup does not occur, and failure of FCV controls), backup electronic velocity-limiters are included in the recirculation control system to limit FCV velocity to 10 ± 1% actuator stroke rate. Additional multiple specific component failures in these limiters must occur to cause full closure of the FCV at velocities in excess of this value. The combined probability of occurrence of these specific failure modes during LOCA is less than 10^{-6} per year. Accordingly, the electronically limited rate of 10 ± 1% of FCV actuator stroke/rate is considered a realistic yet conservative closure rate.

Using approved standard licensing models, ECCS analyses were performed to determine the effect (sensitivity) on peak cladding temperature from FCV closure at the 11% per second rate. The calculated maximum peak temperature increase was ≤45°F for CGS. This contrasts markedly with the approximate 300°F rise in cladding temperature associated with an arbitrary assumption of instant closure of the FCV, as was cited on another BWR/5 docket.

Thus, the peak cladding temperature effect is concluded to be very small. The probability of FCV fast closure simultaneously with a LOCA is extremely remote. Accordingly, fast FCV closure in conjunction with the DBA-LOCA is not expected to occur and need not be compared to the maximum PCT criterion of 10 CFR 50.46.

ISSUE: RSB-17 OPERATOR ACTION, ANALYSIS OF CRACK IN THE RHR LINE (6.3.4)

Question:

Provide the following information related to pipe breaks or leaks in high or moderate energy lines outside containment associated with the RHR system when the plant is in a shutdown cooling mode.

a. Provide the discharge rate from pipe breaks for the systems outside containment used to maintain core cooling. This valve should be consistent with the requirements of SRP 3.6.1 and BTP APCSB 3-1.

b. Determine the time frame available for recovery based on these discharge rates and their effect on core cooling.

c. Describe the alarms available to alert the operator to the event, the recovery procedures to be utilized by the operator, and the time available for operator action.

A single failure criterion consistent with SRP 3.6.1 and BTP ABCSB 3-1 should be applied in the evaluation of the recovery procedures utilized.

Response:

a. The RHR system is a low pressure system, and all of the piping outside of the primary coolant pressure boundary is classified as "moderate energy" piping and, according to the NRC standards cited, only cracks (i.e., not breaks) are considered in moderate energy piping. Reactor vessel pressure must be decreased to below 135 psig before the RHR system can be connected to the reactor vessel. The largest suction pipe is 24 in. Schedule 40 pipe. A crack in this pipe corresponding to the maximum crack size would produce a flow rate of 1443 gpm, with no allowance for flow reduction due to two-phase flow. This is the maximum possible in any RHR system pipe. A crack of this magnitude would be detected by the leak detection system or area radiation detectors and sump alarms. Isolation of the reactor would occur by operator action, or automatically from the leak detection system or from the reactor protection system on Level 3 reactor water level.

b. If a break should occur in one RHR shutdown cooling loop outside the containment during shutdown, the following action is taken upon detection and isolation. The main steam isolation valves will be reopened and reactor excess

steam will blow down to the main condenser until the shutdown cooling process via the other RHR loop is established. Time: less than 1 hour.

The redundant shutdown cooling loop components are also not assumed to fail under the cited NRC requirements of BTP APCSB 3-1.

If the pipe crack should occur in the common manifold supplying both redundant loops, the isolation mechanism is the same as before, but recovery would require reversion to the alternate shutdown configuration discussed in Section 15.2.9. In this configuration, vessel water is circulated from the suppression pool to the RHR heat exchanger to the vessel with return to the suppression pool via the ADS discharge lines. Time: less than 1 hour.

If the pipe crack should occur in the RHR service water piping, sump alarms would result in operator isolation of that loop and establishment of cooling in the redundant shutdown loop. Time: less than 1 hour.

In evaluating the above analysis, the following is also offered. If the main condenser vacuum has been lost and the MSIVs are already closed prior to the crack occurrence, reestablishment of condenser vacuum, MSIV reopening, vessel inventory control, and restart of steam dump to the main condenser is possible in about 2 hours. Vessel inventory can be controlled by overflow through the reactor water cleanup system if too high, and by use of feedwater pumps or HPCS/LPCS/LPCI if too low. Vessel pressure is controlled by manual operation of safety/relief valves on MSIV closure as required.

c. The alarms available have been described in the response to part (a) and part (b) of this question. The recovery procedures to be utilized by the operator, and the time available for operator action are provided below.

A special analysis was made by a hypothesized crack in the BWR suction line outside of primary containment during operation in the shutdown cooling mode. This analysis was performed with the standard GE LOCA models. For this event, the realistic or actual system conditions are as follows:

> *No high pressure systems are available for water inventory restoration, i.e., no feedwater, no HPCS, and no RCIC, but the reactor water level is at normal elevation at the start of this event. Vessel pressure is less than 150 psia and the MSIVs are closed at the start of this event. The decay heat is approximately 1% of rated power, i.e., approximately 4 hours have elapsed subsequent to reactor scram or shutdown.*

For a conservative solution to this hypothetical event, the following sequence of events and conditions were assumed to exist or ensue from the hypothesized crack in the suction line:

a. Crack occurs in the RHR lines water; level decreases to reactor vessel Level 3; then RHR isolation commences and is completed 40 seconds later.

b. System pressure rises as a result of the isolation to where the vessel pressure reaches the SRV setpoint, thus causing them to open, blow down, and reclose.

c. Inventory depletion results from blowdown and from leakage out of these cracked lines.

d. The operator manually actuates ADS to reduce vessel pressure to where the low pressure ECCS can replenish the water inventory.

e. Water level is restored to within normal limits to protect the core from over temperature.

Results are presented in Figures I.8-1 through I.8-4 for a bounding calculation of this event. The standard Appendix K assumptions were used along with these conservative initial conditions.

a. The timing index was started at the RHR isolation (when Level 3 was attained) to neglect the time for the level to fall from normal water level to Level 3 (about 2 minutes).

b. An initial pressure of 1055 psia was assumed to neglect the pressure rise time from the 150 psia (pressure permissive for shutdown cooling) upon completion of the RHR isolation to the 1055 pressure attainment. This results in increased mass loss during the 40-second isolation period due to greater driving pressure. It also decreases the time increment needed for pressure to attain the relief valve setpoint.

c. The analysis assumes that scram occurs coincident with the start of the timing instead of 4 hours earlier. This assumption maximizes the peak clad temperature and steam production during the transient thus driving more fluid from the vessel and prolonging the blowdown phase.

d. Only one LPCS and one LPCI loop were assumed to be available throughout the event. Operator action does not include possible diversion of the other two LPCI loops from the RHR mode.

e. The crack area used in the analysis is defined consistently with the MEB 3-1 guidance for crack size. This crack area is consistent with FSAR postulates.

Results from this conservative analysis show that more than 20 minutes are available for the operator to depressurize the vessel. Once the system pressure is below the LPCI or LPCS shutoff head, the reactor water level is restored to normal limits very rapidly. The maximum clad temperature is much less than the arbitrary 2200°F limitation.

ISSUE: RSB-18 LOCA ANALYSIS - DIVERSION OF LOW PRESSURE COOLANT INJECTION SYSTEM (6.3.4)

Question:

The issue is… "If low pressure coolant injection diversion prior to ten minutes is allowed by design, then procedural restrictions alone are not sufficient unless analyses are submitted which show compliance with 10 CFR 5O.46 for diversion earlier than ten minutes."

Response:

Analyses of BWR performance following a small break LOCA and LOCA mitigation under degraded conditions have been performed by General Electric as a part of the BWR Owners' Group program. Analyses bases, assumptions, and conclusions are discussed in GE report NEDO-24708A, Revision 1, December 1980, entitled, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors." Reference is made to 3.1.1 (Small Break LOCA) and 3.5.2 (Inadequate Core Cooling). It should be noted that these analyses were performed utilizing "realistic" assumptions as defined in 3.1.1.2 and 3.5.2.4. The conclusion, 3.5.2.1.8, summarizes the capability of the BWR to maintain adequate core cooling, even under severely degraded conditions resulting from multiple failures and operator errors, following a loss of inventory either through a pipe break or through the safety relief/valve.

Based on the first group of analyses presented, it was concluded that for any plant and any loss of inventory event, the ability of ADS and one low pressure ECC system provides adequate core cooling if no high pressure injection is available. These analyses covered the case of multiple mechanical or electrical failures and operator errors that might have caused the failure of the system, assumed to be unavailable.

The second set of analyses addressed the condition of the vessel being at high pressure with a low water level. It was shown that operator actions either to initiate high pressure systems or to depressurize the vessel and initiate at least one low pressure system, terminate this condition

and assure adequate core cooling. The analyses showed that even for such severely degraded transients, there is sufficient time for operator action to mitigate the consequences.

The third set of analyses addressed the condition of the vessel being at low pressure with a low water level but with the low pressure systems not injecting. It was shown that operator actions either to start the low pressure systems injecting into the vessel or to initiate the high pressure systems, terminate this condition and assure adequate core cooling.

For all analyses, it was shown that the process variable information available to the operator in the control room is sufficient to adequately warn of an inventory threatening event and to present the information the operator needs to assure that appropriate actions are taken to maintain adequate core cooling. The control room indications will not mislead the operator when taking corrective actions. Even under the extremely degraded conditions considered in these analyses, the BWR requires only the most basic operator actions to mitigate the consequences of an inventory threatening event.

If the operator were to divert LPCI prior to ten minutes post-LOCA, such an action would be considered an operator error. Since the current ECCS performance evaluation already assumes the accident, a loss of offsite power and a worst active single failure, an additional operator error is considered to be an additional Appendix K assumption. It is therefore appropriate that the "realistic" assumption analyses be considered for this situation as stated in the conclusion in NEDO-24708A "for any plant and any loss of inventory event, the adequate availability of ADS and one low pressure ECC system provides adequate core cooling…"

This analysis is deemed acceptable to provide satisfactory assurance of acceptable event consequences, in consideration of the equipment failures and operator errors assumed.

To resolve the concern of the NRC staff that premature diversion of low pressure coolant injection (LPCI) flow to containment sprays could adversely effect core cooling, the CGS symptom based emergency procedures will be carefully constructed to caution the operator against such diversion unless "adequate core cooling is assured." These procedures, which were developed with the assistance of the BWR Owners' Group and reviewed and accepted by the NRC staff, clearly identify LPCI diversion as secondary to the core cooling requirements except in those instances, outside the plant design envelope, which involve multiple failures and for which maintenance of containment integrity is required to minimize risk to the environment.

ISSUE: RSB-19 FAILURE OF FEEDWATER HEATER
(15.1)

Question:

The applicant's analysis for the failure of the feedwater heater indicates that the temperature drop is no greater than 100°F. At a domestic boiling water reactor an actual feedwater temperature occurred which demonstrated a temperature difference of 150°F. The applicant must justify the decrease in temperature drop used for this event or recalculate the transient by using a justified temperature decrease to assure conformance with applicable criteria.

Response:

Refer to revised response to Question 211.087.

ISSUE: RSB-20 USE OF NONRELIABLE EQUIPMENT IN ANTICIPATED OPERATIONAL TRANSIENTS
(15.1)

Question:

In analyzing anticipated operational transients, the applicant took credit for equipment which has not been shown to be reliable. Our position is that this equipment be identified in the technical specifications with regard to availability, setpoints, and surveillance testing. The applicant must submit its plan for implementing this requirement along with any system modification that may be required to fulfill the requirement.

Response:

The response to the above stated concern is provided in response to Questions 211.085, 211.086, and 211.155.

ISSUE: RSB-21 USE OF NON-SAFETY GRADE EQUIPMENT IN SHAFT SEIZURE ACCIDENT
(15.3)

Question:

The applicant included the use of non-safety grade equipment in his analysis for shaft seizure and shaft break accidents. We require that these accidents be reanalyzed without allowance for the use of non-safety grade equipment.

<u>Response</u>:

The response to the above stated concern is provided in the revised response to Question 211.092. Questions 211.185 and 211.211 also reference this concern.

ISSUE: RSB-22 ATWS
(15.2.1)

<u>Question</u>:

We require that the applicant agrees to implement plant modifications on a scheduled basis in conformance with the Commission's final resolution of ATWS. In the event that LaSalle starts operation before necessary plant modifications are implemented, we require some interim actions be taken by LaSalle in order to further reduce the risk from ATWS events. The applicant will be required to:

a. Develop emergency procedures to train operators to recognize an ATWS event, including consideration of scram indicators, rod position indicators, flux monitors, vessel level and pressure indicators, relief valve and isolation valve indicators, and containment temperature, pressure, and radiation indicators.

b. Train operators to take action in the event of an ATWS including consideration of immediately manual scramming the reactor by using the manual scram buttons followed by changing rod scram switches to the scram position, stripping the feeder breakers on the reactor protection system power distribution buses, opening the scram discharge volume drain valve, prompt actuation of the standby liquid control system, and prompt placement of the RHR in the pool cooling mode to reduce the severity of the containment conditions.

<u>Response</u>:

See 1.5.1.1.2 for a discussion of CGS modifications which addresses compliance to the final ATWS rule. The required procedure development and operator training were accomplished prior to fuel load.

ISSUE: RSB-23 PEACH BOTTOM TURBINE TRIP TESTS
(4.4.1, 4.4.2)

Question:

These tests have been evaluated and assessed using the ODYN computer code.

Response:

The NRC has completed their review of the ODYN Code. See the Safety Evaluation Report letter of November 4, 1980.

Also, see Chapters 4 and 15. The appropriate sections of these chapters have been revised utilizing results of re-analysis of required transients using the ODYN Code. See the revised response to Question 211.049.

Refer also to RSB-4.

ISSUE: RSB-24 MCPR
(4.4.1, 4.4.2, 15.1)

Question:

After completion of over-pressure analysis, the minimum critical power ratio must be recalculated taking into consideration the turbine trip without bypass event.

The transient of generator load rejection without bypass results in an MCPR equal to 1.02 which is below the safety limit of 1.06. The applicant classified this event an infrequent occurrence which would allow some fuel damage. We do not concur with this classification for this event, and we require that the operating limit be modified to satisfy the MCPR limit of 1.06.

Response:

The response to the above stated concern is provided in revised response to Question 211.084.

ISSUE: RSB-25 GEXL CORRELATION

Question:

Although we conclude that the GEXL correlation is acceptable for initial core load, we are concerned that GEXL correlation may not be conservative for reload operation.

Response:

Columbia Generating Station will use the applicable correlation to predict the onset of transition boiling for all reloads.

ISSUE: RSB-26 STABILITY EVALUATION

Question:

Please refer to NRC Question 221.009 for this question.

Response:

Please refer to the response to NRC Question 221.009.

ISSUE: RSB-27 SCRAM DISCHARGE VOLUME

Question:

The applicant should assess, reevaluate, and possibly modify the present scram system in light of the incident at Browns Ferry 3, where a manual scram failed to insert all control rods.

Response:

The CGS scram discharge volume (SDV) design has been evaluated against the NRC generic study "BWR Scram Discharge System Safety Evaluation" of December 1, 1980. The results of this evaluation indicated that the current CGS scram discharge system design was acceptable with implementation of some minor modifications. A summary of the evaluation results and the required modifications are provided below.

a. *Hydraulic Coupling - The current SDV design provides two separate scram discharge volume headers, with an integral instrumented volume (IV) at the end of each header. This design configuration ensures a direct hydraulic couple between the SDVs and IVs.*

b. *Instrumentation - The existing level sensors (six total) are all of one design, i.e., float type (magnetrol) level switches. To meet the specified requirements, six additional diverse level sensors will be added to provide full redundancy for level monitoring and scram initiation. In addition, all level instrumentation will be relocated and repiped directly to the IVs rather than being connected to the vent and drain lines.*

c. *Vent and Drain Lines - The CGS design incorporates an independent vent and drain system for the SDV. The scram discharge headers are presently vented directly to the reactor building atmosphere and the system drain is piped directly from the bottom of the IVs to the building's radioactive drain system. A second vent valve and drain valve will be added to provide redundant SDV isolation during a reactor scram.*

d. *Surveillance Testing - Additional surveillance test procedures will be implemented to ensure operability of the level instruments, vent and drain isolation valves, as well as the overall system.*

Please refer to response to Question 010.041.

ISSUE: RSB-28 SRV SURVEILLANCE

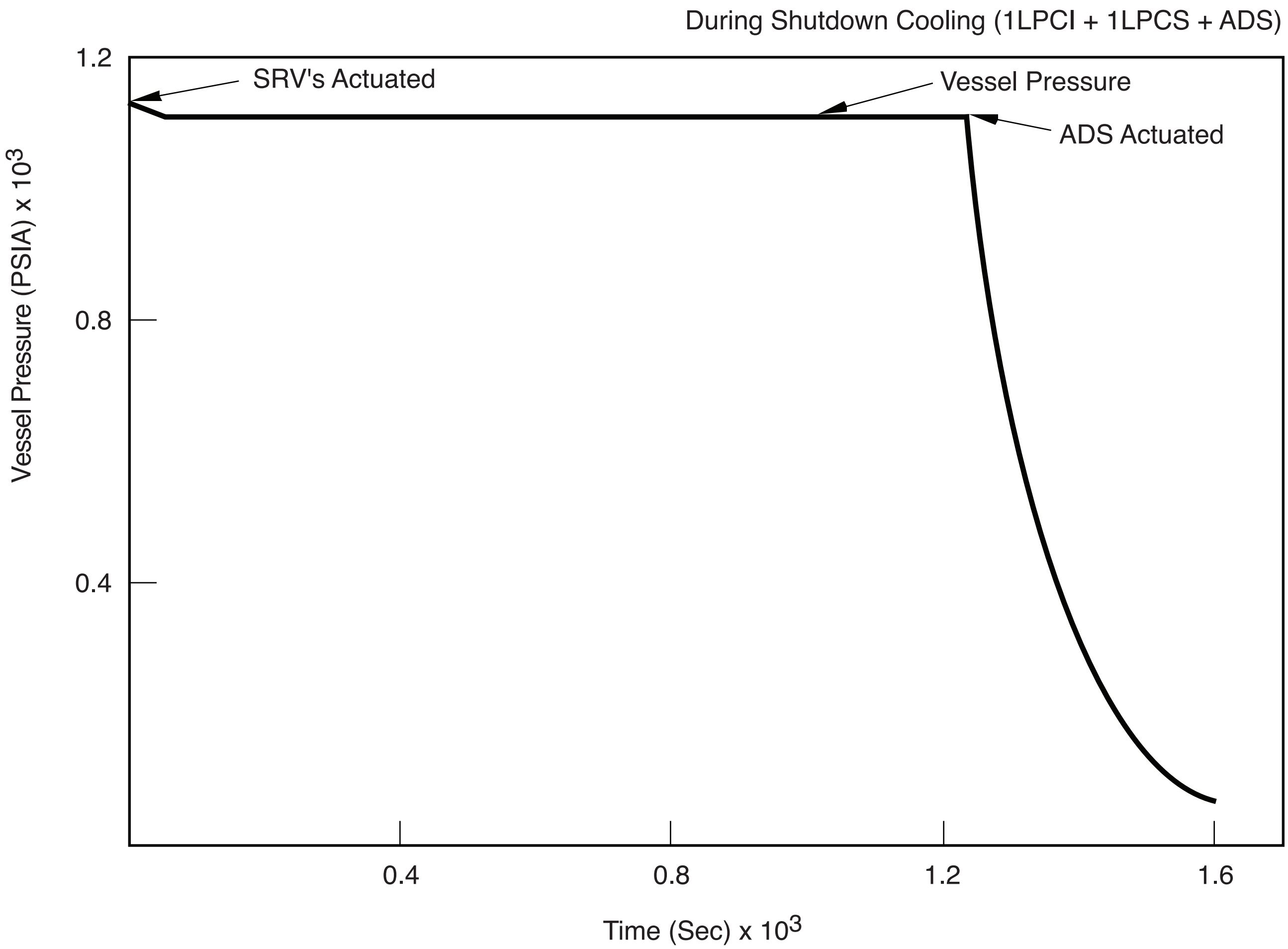
Question:

A safety/relief valve surveillance program should be developed to record operating and maintenance experience to facilitate identification of generic safety/relief valve problems.

Response:

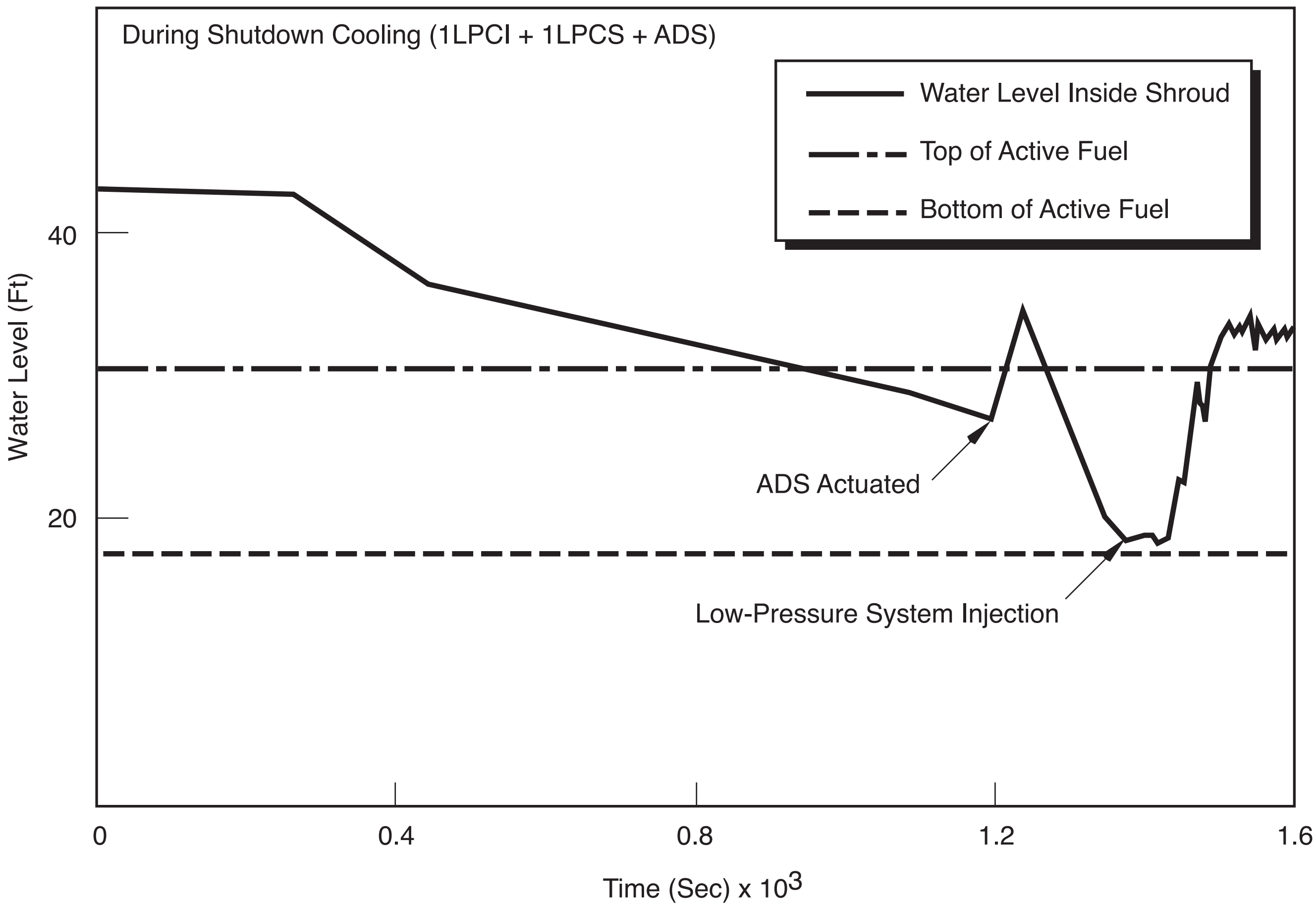
CGS will develop a surveillance program for safety/relief valves similar to that being developed by the BWR Owners' Group submitted to the NRC by letter GO2-81-563, G. D. Bouchey to A. Schwencer, "LRG Appendix I," dated December 30, 1981.

The CGS safety/relief valve surveillance program will be available for onsite review.

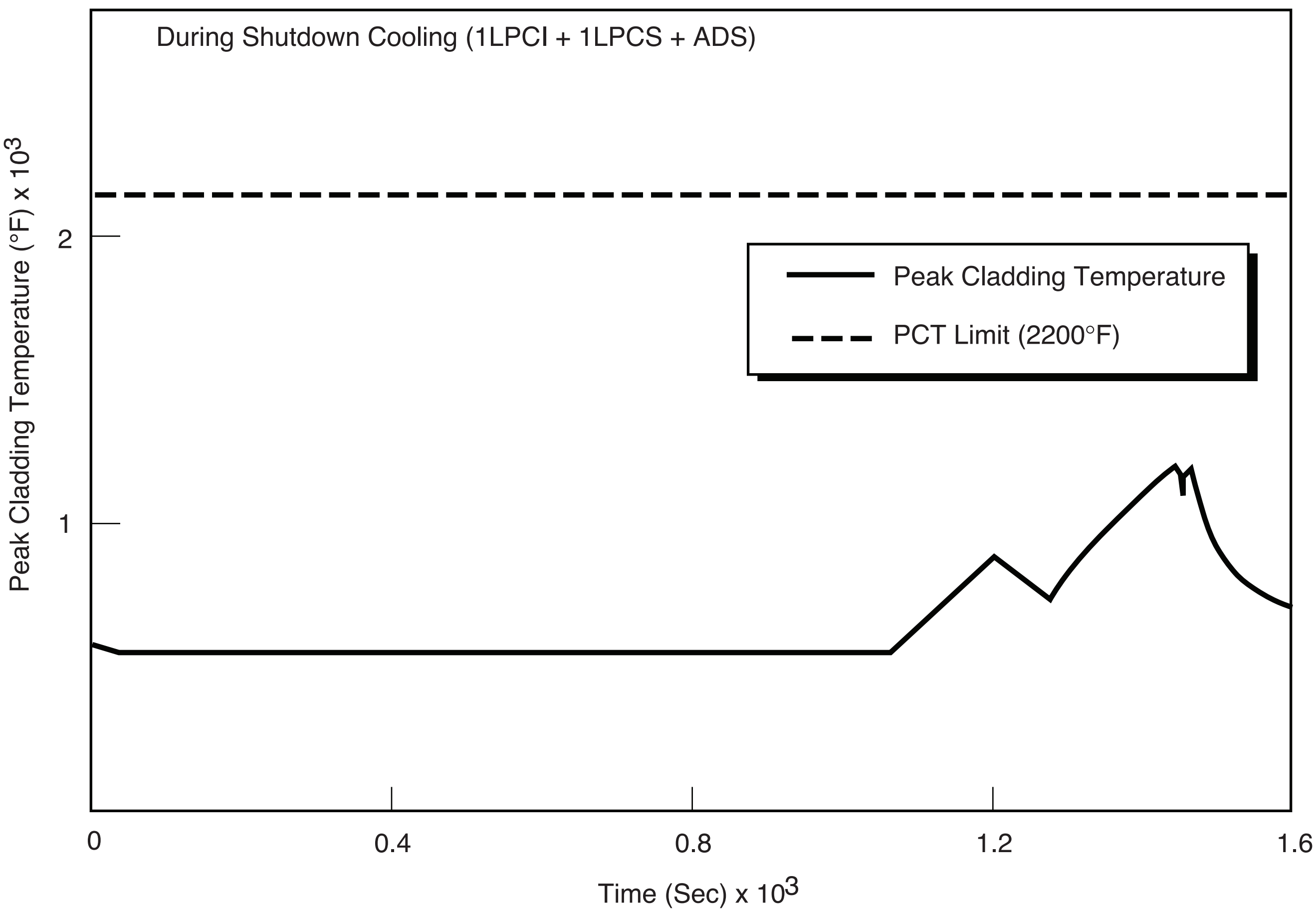


Vessel Pressure Versus Time for a Crack in the RHR Line

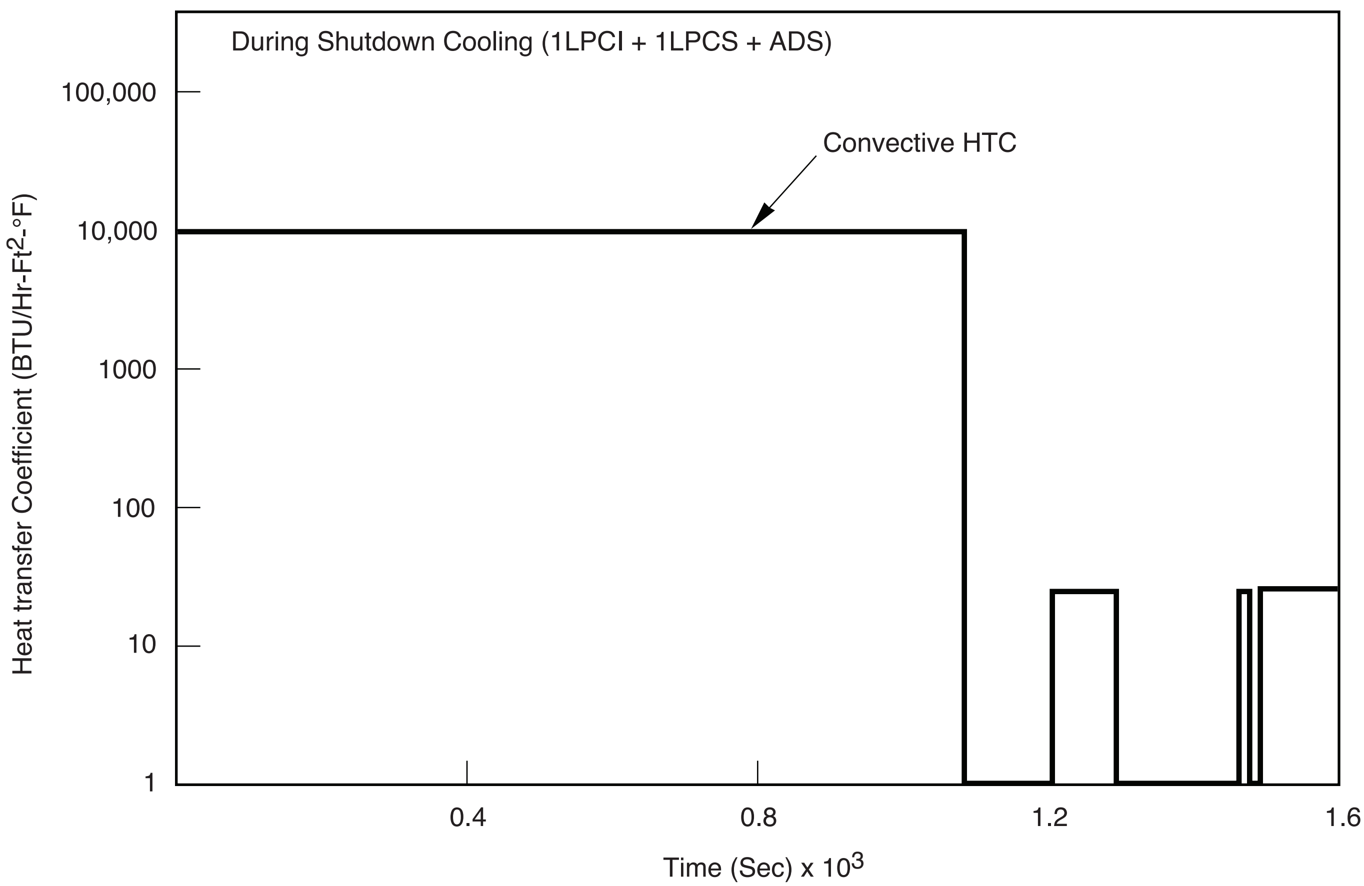
Draw. No. 970187.15 | Rev. | Figure I.8-1



Water Level Versus Time for a Crack in the RHR Line



Peak Cladding Temperature Versus Time for a Crack in the RHR Line



HTC at PCT Node Versus Time for a Crack in the RHR Line

Draw. No. 970187.18 | Rev. | Figure I.8-4