January 17, 1992

Docket No. 50-605

APPLICANT: General Electric Company (GE)

PROJECT: Advanced Boiling Water Reactor (ABWR)

SUBJECT: SUMMARY OF MEETING ON GE RELIABILITY ASSURANCE PROGRAM

On January 14, 1992, a meeting was held with GE, the staff from the Licensee Performance & Quality Evaluation Branch (LPEB), and the ABWR project manager, to discuss the draft of the ABWR Design Reliability Assurance Program (D-RAP), dated December 19, 1991 (Enclosure 1). Also attending the meeting were the Risk Applications Branch (PRAB) staff and a representative from NUMARC. A list of attendees is included as Enclosure 2. The GE representatives explained the contents of the document, and advised the staff of comments made by NUMARC and the Electric Power Research Institute (EPRI) that will be considered in the next revision of the draft. The LPEB and PRAB staff asked questions to clarify points contained in the submittal to better understand the D-RAP.

Topics discussed during the meeting were: guidance to the owner/operator for the operations phase RAP; reliability assurance activities; definitions of the terms such as risk significance, and goals/targets; GE organizational and administrative aspects of implementing the D-RAP; and the example provided to demonstrate the implementation of the D-RAP.

GE agreed to provide a revision to the draft D-RAP within the next 2 weeks that incorporates NUMARC, EPRI, and the NRC comments, and answers questions raised at the meeting. The NRC staff agreed to hold a conference call to provide early feedback to the revised draft before it is finalized.

(original signed by)
Chester Poslusny, Project Manager
Standardization Project Directorate
Division of Advanced Reactors
and Special Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. ABWR Design Reliability Assurance Program
2. Meeting Attendees List

cc w/enclosures:
See next page

DISTRIBUTION:
See next page

OFC:	LA:PDST:DAR	PM:PDST:DAR	SC:PDST:DAR
NAME:	LLuther	CPoslusny	JNWilson
DATE:	01/17/92	01/17/92	01/17/92

OFFICIAL DOCUMENT COPY: GERAP.CP

DF03

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

January 17, 1992

Docket No. 50-605

APPLICANT: General Electric Company (GE)

PROJECT: Advanced Boiling Water Reactor (ABWR)

SUBJECT: SUMMARY OF MEETING ON GE RELIABILITY ASSURANCE PROGRAM

On January 14, 1992, a meeting was held with GE, the staff from the Licensee Performance & Quality Evaluation Branch (LPEB), and the ABWR project manager, to discuss the draft of the ABWR Design Reliability Assurance Program (D-RAP), dated December 19, 1991 (Enclosure 1). Also attending the meeting were the Risk Applications Branch (PRAB) staff and a representative from NUMARC. A list of attendees is included as Enclosure 2. The GE representatives explained the contents of the document, and advised the staff of comments made by NUMARC and the Electric Power Research Institute (EPRI) that will be considered in the next revision of the draft. The LPEB and PRAB staff asked questions to clarify points contained in the submittal to better understand the D-RAP.

Topics discussed during the meeting were: guidance to the owner/operator for the operations phase RAP; reliability assurance activities; definitions of the terms such as risk significance, and goals/targets; GE organizational and administrative aspects of implementing the D-RAP; and the example provided to demonstrate the implementation of the D-RAP.

GE agreed to provide a revision to the draft D-RAP within the next 2 weeks that incorporates NUMARC, EPRI, and the NRC comments, and answers questions raised at the meeting. The NRC staff agreed to hold a conference call to provide early feedback to the revised draft before it is finalized.

Chester Poslusny

Chester Poslusny, Project Manager
Standardization Project Directorate
Division of Advanced Reactors
and Special Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. ABWR Design Reliability Assurance Program
2. Meeting Attendees List

cc w/enclosures:
See next page

cc: Mr. Patrick W. Marriott, Manager
Licensing & Consulting Services
GE Nuclear Energy
175 Curtner Avenue
San Jose, California 95125

Mr. Robert Mitchell
General Electric Company
175 Curtner Avenue
San Jose, California 95116

Mr. L. Gifford, Program Manager
Regulatory Programs
GE Nuclear Energy
12300 Twirbrook Parkway
Sui 315
Rockville, Maryland 20852

Director, Criteria & Standards Division
Office of Radiation Programs
U. S. Environmental Protection Agency
401 M Street, S.W.
Washington D.C. 20460

Mr. Daniel F. Giessing
U. S. Department of Energy
NE-42
Washington, D.C. 20585

Mr. Steve Goldberg
Budget Examiner
725 17th Street, N.W.
Room 8002
Washington, D.C. 20503

Mr. Frank A. Ross
U.S. Department of Energy, NE-42
Office of LWR Safety and Technology
19901 Germantown Road
Germantown, Maryland 20874

Mr. Raymond Ng
1776 Eye Street, N.W.
Suite 300
Washington, D.C. 20006

Enclosure 1
Draft 12/19/91

ABWR

DESIGN RELIABILITY

ASSURANCE PROGRAM

GE NUCLEAR ENERGY
SAN JOSE, CALIFORNIA

ABWR DESIGN RELIABILITY ASSURANCE PROGRAM

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABWR DESIGN RELIABILITY ASSURANCE PROGRAM

1.0 INTRODUCTION

The ABWR Design Reliability Assurance Program (D-RAP) is a program performed by GE Nuclear Energy (GE-NE) to assure that the ABWR will be operated and maintained in such a way that the reliability assumptions of the probabilistic risk assessment (PRA) apply throughout the plant life. The plant owner/operator will also have a RAP that shows that the plant is being operated and maintained so that safety is not degraded. The PRA evaluates the plant response to initiating events to assure that plant damage has a very low probability and risk to the public is very low. Input to the PRA includes details of the plant design and assumptions about the ability of the plant owner/operator to operate and maintain the plant such that safety related structures, systems and components (SSCs) retain their reliability throughout plant life.

This D-RAP will include the design evaluation of the ABWR. It will identify relevant aspects of plant operation, maintenance, and performance monitoring of plant SSCs to assure safety of the equipment and limited risk to the public.

Also included in the D-RAP is a description of how the D-RAP will apply to one important plant system, the standby liquid control system (SLCS). The SLCS is an example of how the principles of D-RAP will be applied to other systems identified by the PRA as being important to safety.

2. SCOPE

The ABWR D-RAP will include the design evaluation of the ABWR, and it will identify relevant aspects of plant operation, maintenance, and performance monitoring of plant safety related SSCs. The PRA for the ABWR will be used to identify and prioritize those SSCs that are important to prevent or mitigate plant transients or other events that could present a risk to the public.

3. PURPOSE

The purpose of the D-RAP is to assure that the plant safety as quantified by the probabilistic risk analysis (PRA) is achieved by the design and that information is provided to the future owner/operator so that plant safety is maintained through operation and maintenance during the entire plant life.

4. OBJECTIVE

The objective of the D-RAP is to identify those plant components that are significant contributors to safety, as shown by the PRA, and to assure that plant design provides SSCs at least as reliable as that assumed in the PRA. The D-RAP will also specify operation, maintenance and monitoring requirements that will assure that such components can be expected to operate throughout plant life at least as reliably as assumed in the PRA.

A major component of plant reliability assurance is risk-focused maintenance, by which maintenance resources are focused on those components that enable the ABWR systems to fulfill their essential safety functions and on components whose failure may initiate challenges to safety systems. This focus of maintenance will have a beneficial impact in decreasing risk.

5. SSC IDENTIFICATION/PRIORITIZATION

The PRA prepared for the ABWR is the source for identifying risk-critical SSCs that should be considered for design improvement and/or risk-focused maintenance. The way the PRA is used is demonstrated in Figure 1. Those PRA cutsets that contribute to core damage frequency (CDF) are identified; the top cutsets that contribute significantly to the CDF are selected for evaluation of component failures. Components whose failures are involved in the top cutsets are identified. Of these, those components that may be critical as determined by consideration of aging and common cause failures are also identified. The result is a list of risk-critical components for further consideration.

Prioritization of the SSCs identified by the PRA is also obtained from the PRA. Those SSCs with greater contribution to the CDF will be given more attention

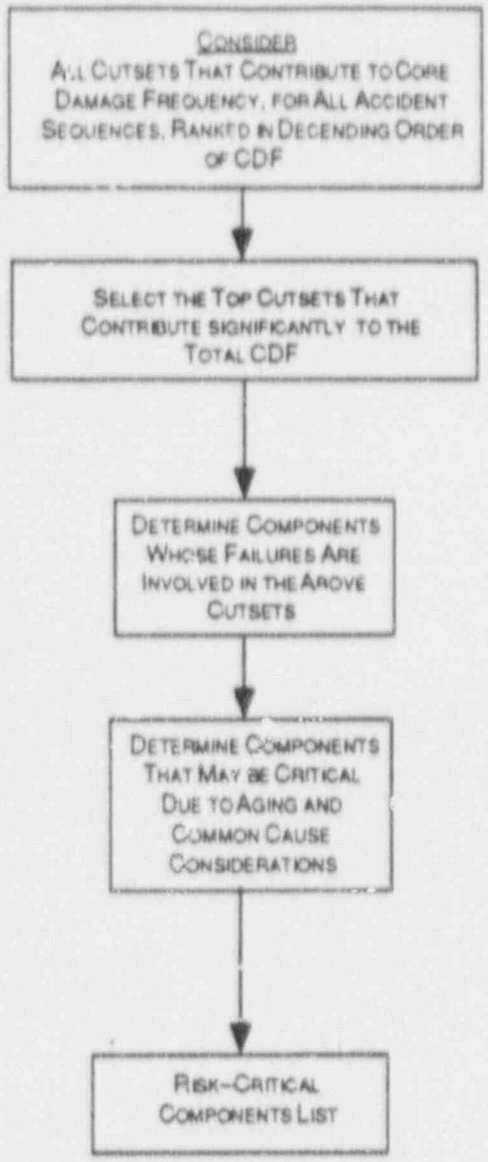

Figure 1. PRA Process for Risk–Critical Component Determination

with regard to possible redesign and with regard to identifying appropriate maintenance tasks to limit the failure probability.

6. DESIGN CONSIDERATIONS

The reliability of risk-critical SSCs, which are identified in the PRA, will be evaluated at the design stage by appropriate design reviews and reliability analyses of the identified equipment. Current data bases will be used to identify appropriate values for failure rates of equipment as designed, and these failure rates will be compared with those used in the PRA. Normally the failure rates will be the same, but some may differ because of recent design changes. Whenever failure rates of designed equipment are significantly greater than those used in the PRA, an evaluation will be performed to determine that the equipment is acceptable or that it must be redesigned to achieve a lower failure rate.

For those risk-critical SSCs contributing a large fraction of the total CDF, as indicated by PRA calculations, component redesign will be considered as a way to reduce the CDF contribution. (If the CDF is acceptably low, little effort will be expended toward redesign.) If there are no practical ways to redesign component, alternate SSC designs incorporating such features as redundant components or backup systems will be evaluated. If there are practical ways to redesign a risk-critical SSC, it will be redesigned and the change in PRA results will be calculated. Following the redesign phase, dominant SSC failure modes will be identified so that protection against such failure modes can be accomplished by appropriate maintenance. The design considerations that go into determining an acceptable, reliable design and the SSCs that must be considered for reliability focused maintenance are shown in Figure 2.

GE-NE will identify to the plant owner/operator the risk-critical SSCs and the reliability assumed for them in the PRA. GE-NE will also outline a RAP for the plant owner/operator to follow to assure that PRA results will be achieved over the life of the plant.

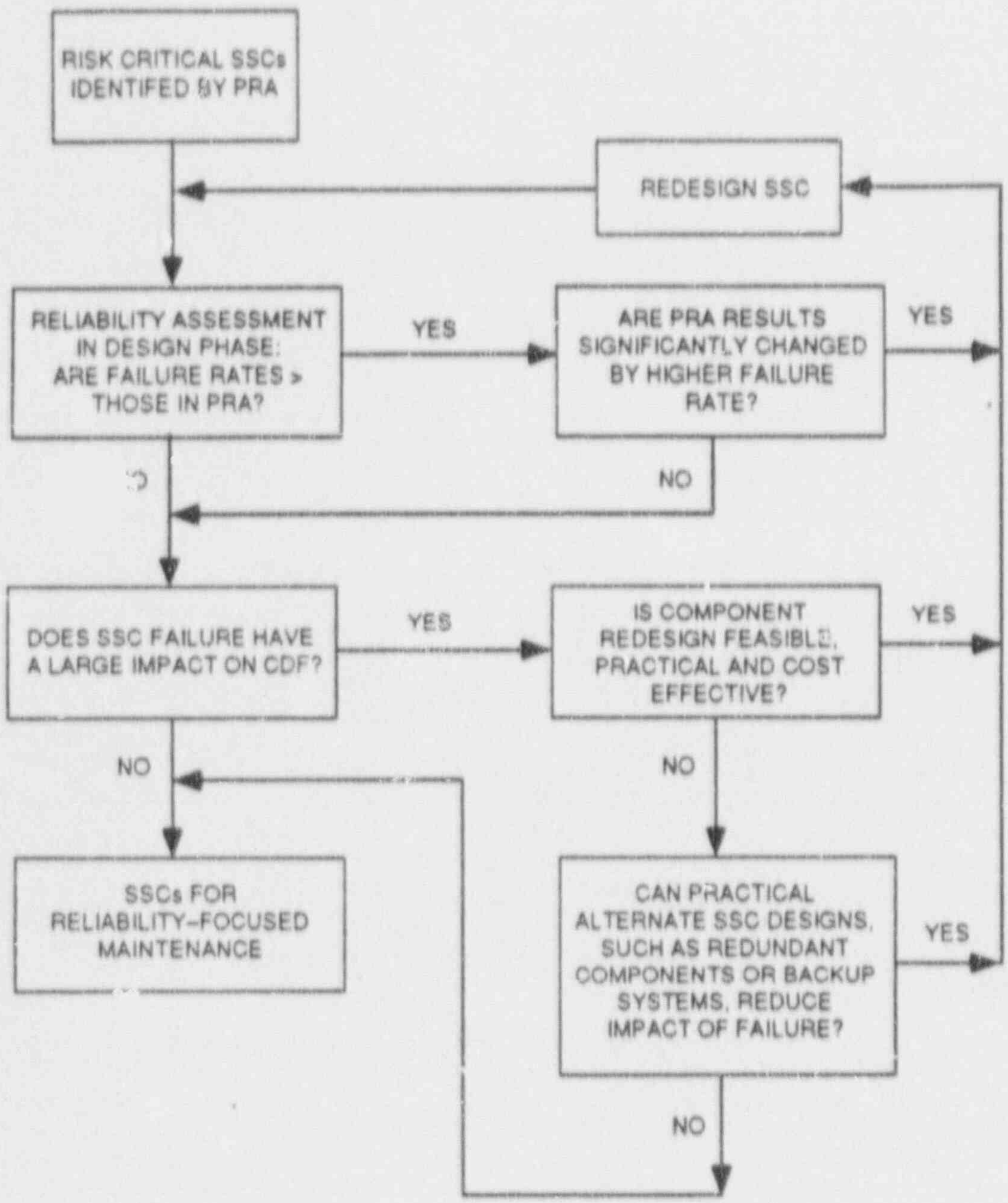

Figure 2. Design Evaluation for SSCs

7. DEFINING FAILURE MODES

The determination of dominant failure modes of risk-critical SSCs will include historical information, analytical models and existing requirements. Many BWR systems and components have compiled a significant historical record, so an evaluation of that record comprises Assessment Path A in Figure 3. Details of Path A are shown in Figure 4.

For those SSCs for which there is not an adequate historical basis to identify critical failure modes, an analytical approach is necessary, shown as Assessment Path B in Figure 3. The details of Path B are given in Figure 5. The failure modes identified in Paths A and B are then reviewed with respect to the existing maintenance activities in the industry and the maintenance requirements, Assessment Path C in Figure 3. Detailed steps in Path C are outlined in Figure 6.

b. RELIABILITY FOCUSED MAINTENANCE

Once the dominant failure modes are determined for risk-critical SSCs, an assessment is required to determine the appropriate maintenance activities that will assure acceptable performance during plant life. Such maintenance may consist of periodic surveillance inspections or tests, monitoring of SSC performance, and/or periodic preventive maintenance (Ref. 1). The decision tree covering these maintenance areas, is shown in Figure 7. As indicated, some SSCs may require a combination of maintenance activities to assure that their performance matches that assumed in the PRA.

Periodic testing of SSCs may include startup of standby systems, surveillance testing of instrument circuits to assure that they will respond to appropriate signals, and inspection of passive components (such as tanks and pipes) to show that they are intact and available to perform as designed. Performance monitoring, including condition monitoring can consist of measurement of output (such as pump flow rate or heat exchanger temperatures), measurement of magnitude of an important variable (such as vibration or temperature), and testing for abnormal conditions (such as oil degradation or local hot spots).

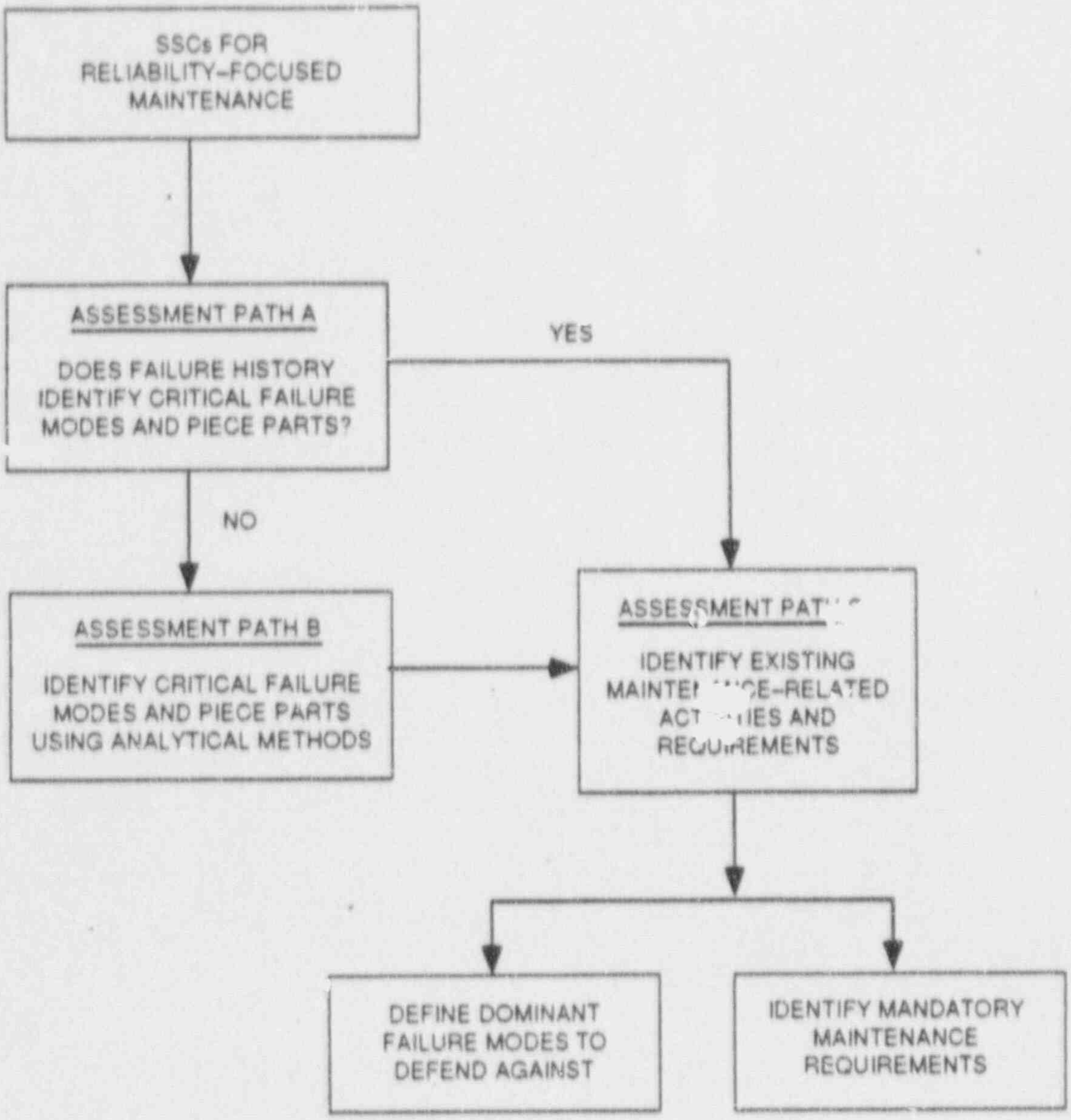

Figure 3. Process for Determining Dominant Failure Modes of Risk–Critical SSCs

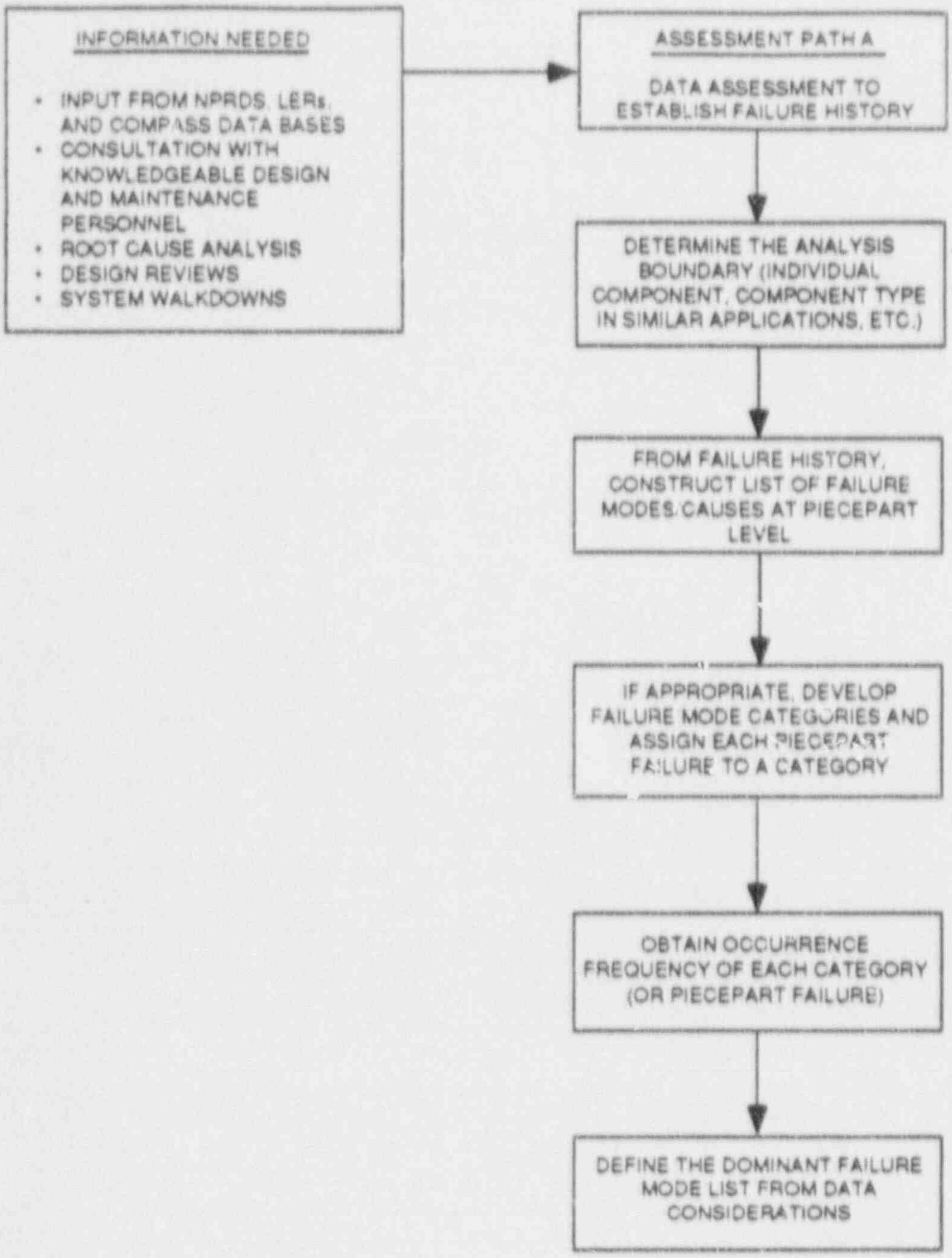

Figure 4. Use of Failure History to Define Failure Modes

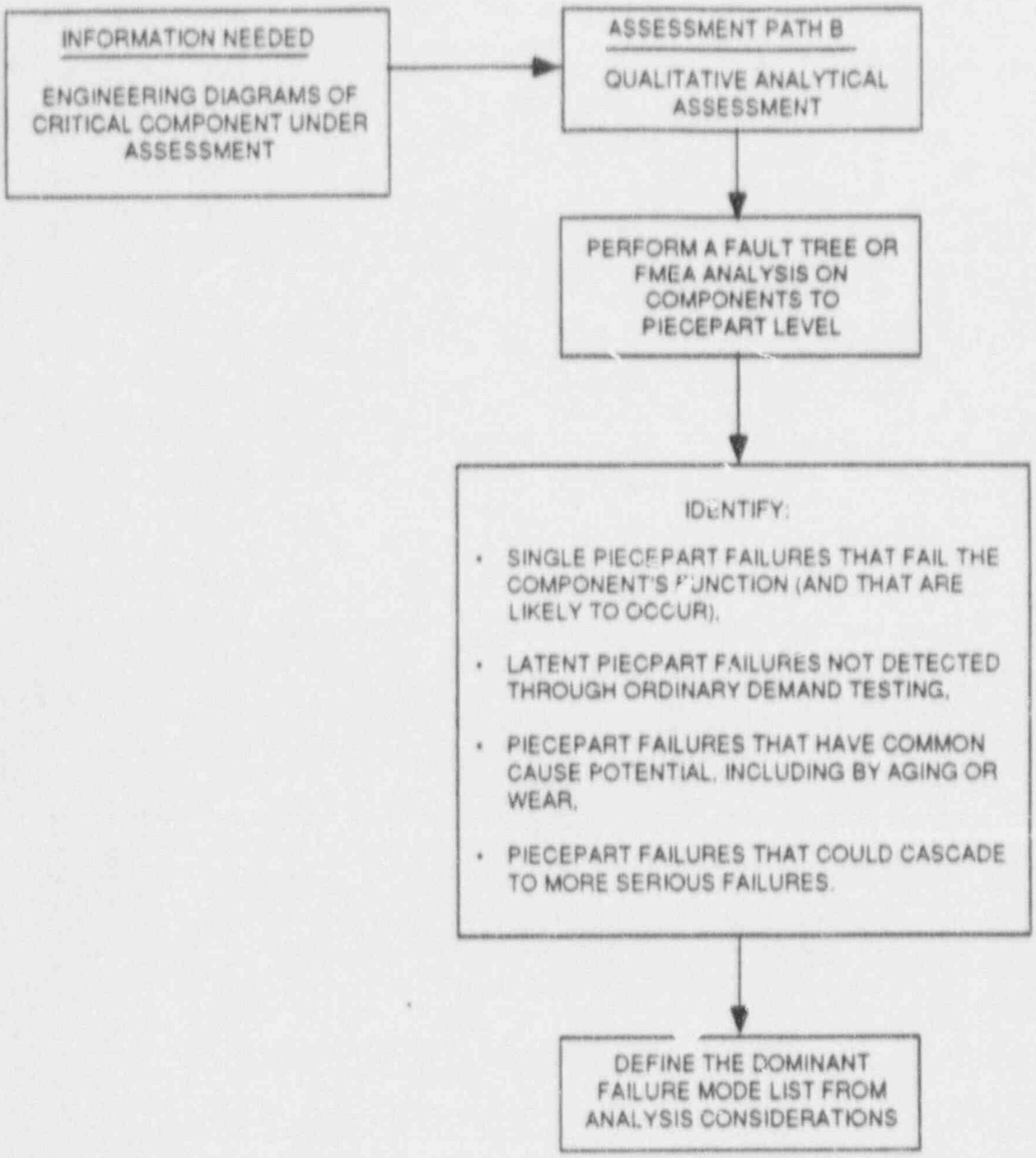

Figure 5. Analytical Assessment to Define Failure Modes

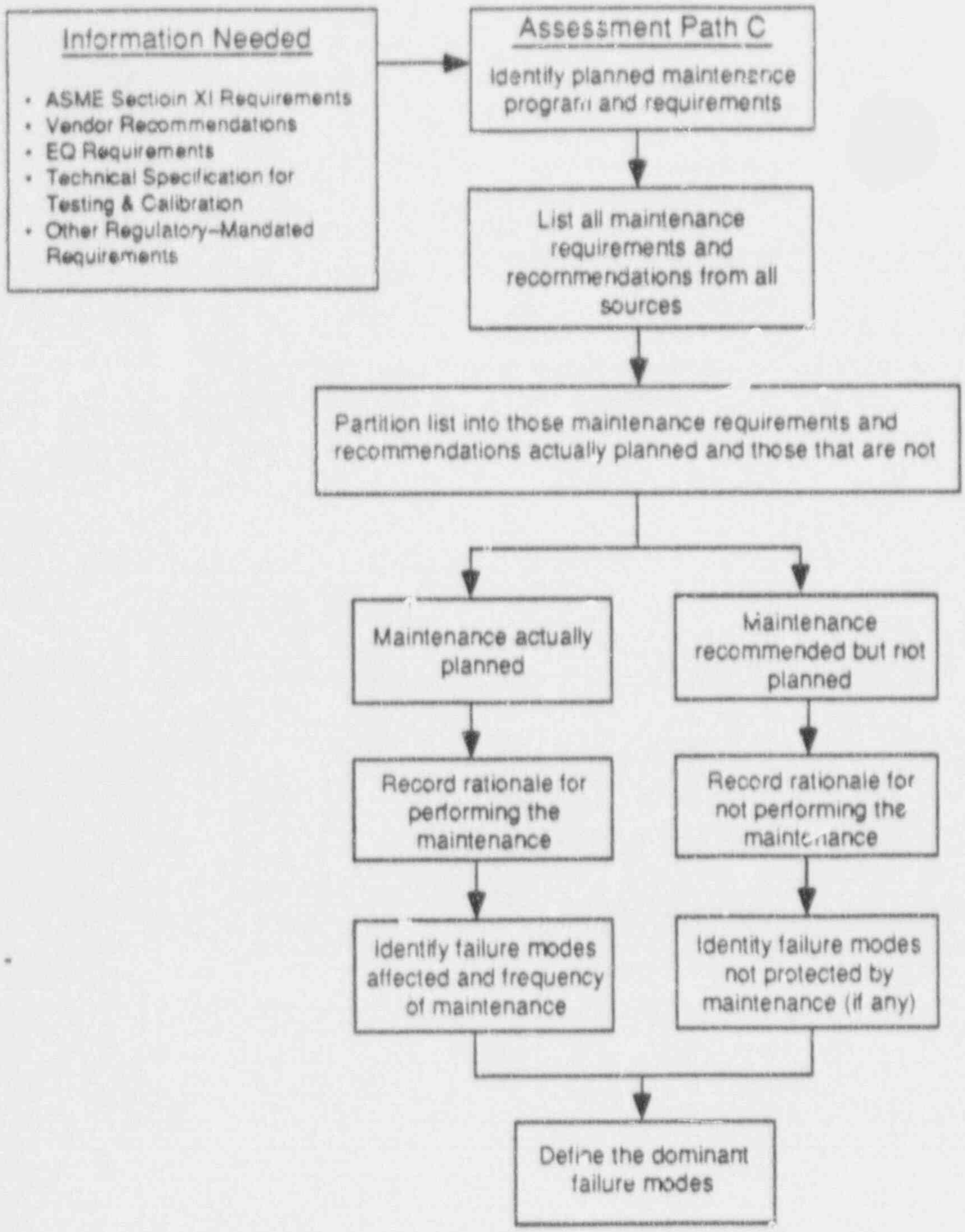

Figure 6. Inclusion of Maintenance Requirements in the Definition of Failure Modes

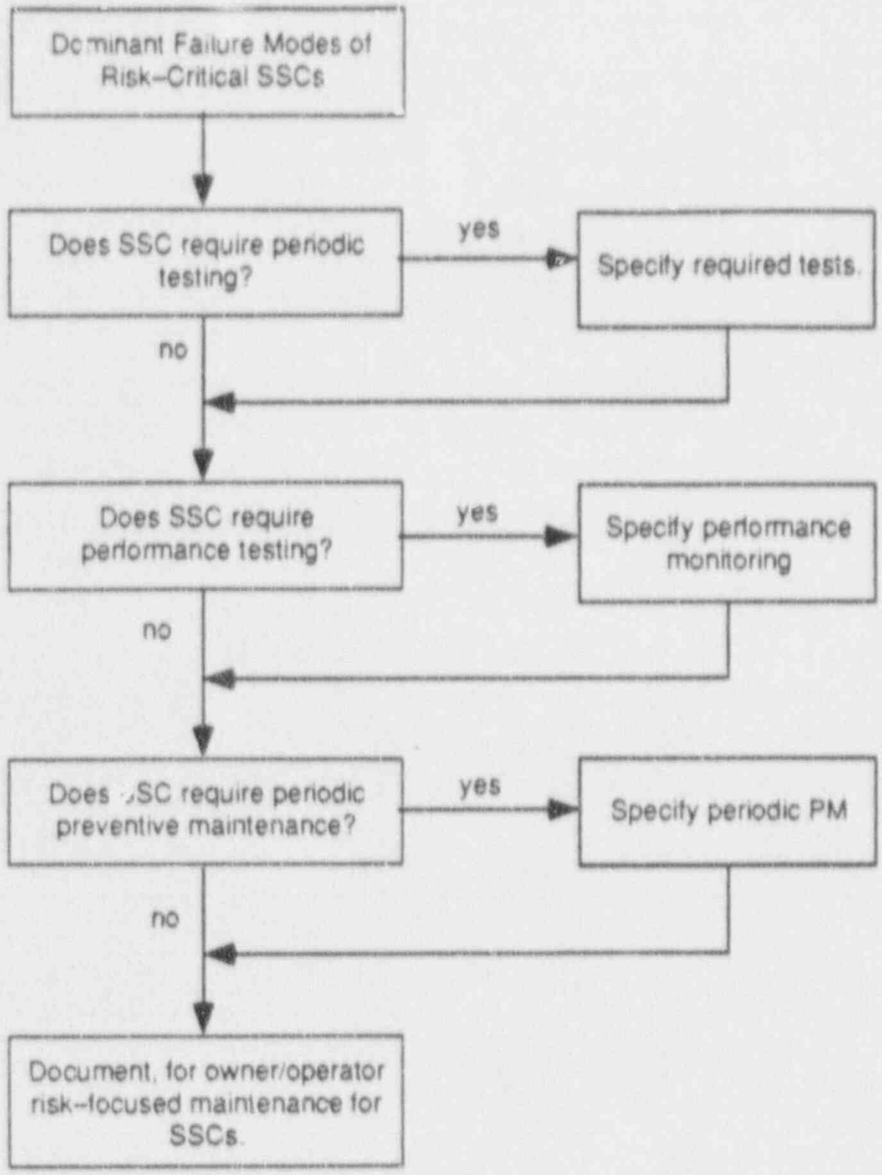

Figure 7. Identification of Critical SSC Maintenance Requirements

Periodic preventive maintenance is an activity performed at regular intervals to preclude problems that could occur before the next PM interval. This could be regular oil changes, replacement of seals and gaskets or refurbishment of equipment subject to wear or age related degradation.

Any planned maintenance activities must be integrated with the regular operating plans so that they do not disrupt normal operation. Maintenance that will be performed more frequently than refueling outages must be planned so as to not disrupt operation or be likely to cause reactor scram. Maintenance planned for performance during refueling outages must be conducted in such a way that it will have little or no impact on outage length or on other maintenance work.

9. OWNER/OPERATOR'S RELIABILITY ASSURANCE PROGRAM

The RAP that will be implemented by the ABWR owner/operator will also be designed by that organization. However, GE-NE will provide an outline of the RAP for the owner/operator. This outline will identify the areas of maintenance activities that should be included in the RAP. Several such areas are discussed below.

9.1 Reliability Performance Monitoring: The monitoring of safety related SSCs during plant operation will be specified in the owner/operator's RAP. GE-NE will recommend the type and frequency of monitoring that will be required for each SSC identified as important to the achievement of the safety.

9.2 Reliability Methodology: The method by which the plant owner/operator will compare plant data to the SSC data in the PRA will be recommended by GE-NE.

9.3 Problem Prioritization: GE-NE will specify, for each of the safety related SSCs, the importance of that item as a contributor to the CDF calculated by the PRA. This will assist the owner/operator in assigning priorities to problems that are detected with such equipment.

9.4 Root Cause Analysis: Any important problems that are identified by the owner/operator regarding reliability of safety related SSCs must be evaluated to determine the root causes, those causes which, after correction, will not recur to again degrade the reliability of equipment. The basic elements of such root cause analysis will be identified by GE-NE, and the detailed root cause analysis techniques will be specified by the owner/operator.

9.5 Corrective Action Determination: The corrective actions required to restore equipment to its required functional capability and reliability will be determined by the owner/operator, based on the results of problem identification and root cause analysis. Part of the determination of proper corrective action will be an evaluation of the future reliability of the equipment and comparison with the specified reliability given in item 9.1, above.

9.6 Corrective Action Implementation: The implementation of corrective action that is determined in item 9.5, above, will be performed by the owner/operator. GE-NE will identify to the owner/operator a list of precautions that must be observed when performing corrective action on safety related equipment so that plant safety is not compromised during such work.

9.7 Corrective Action Verification: When problems with safety related equipment are corrected, the owner/operator must ascertain that the equipment now functions correctly. The operations and maintenance (O & M) manuals for safety related equipment will have equipment checkout procedures that must be followed after maintenance to assure that such equipment will perform its safety functions. GE-NE will provide an outline of such checkout procedures for all such equipment.

9.8 Plant Aging Safety related equipment will be designed for the full design life of the ABWR (60 years). Any such equipment that is expected to undergo age related degradation will have such phenomena identified by GE-NE in the D-RAP. The need for replacement or refurbishment of equipment as it ages will be specified in the O & M manuals.

9.9 Feedback to Designer The plant owner/operator will periodically compare performance of safety related equipment to that specified in GE-NE's PRA and D-RAP, as mencioned in item 9.3, above. The outline for the owner/operator's RAP (item 9.1, above) will contain a request regarding feedback of plant SSC performance data to GE-NE in those cases that consistently show SSC performance below that specified.

9.10 Programmatic Interfaces The D-RAP performed by GE-NE will be primarily concerned with the design of the ABWR. The D-RAP will interface with design of all equipment related to plant safety through design reviews and plant status reviews. It will also interface through procedure reviews, for initial equipment, with quality assurance and procurement.

The plant owner/operator's RAP will address the interfaces with construction, startup testing, operations, maintenance, engineering, safety, licensing, quality assurance and procurement of replacement equipment. An outline of such interfaces will be provided to the owner/operator by GE-NE.

10. D-RAP IMPLEMENTATION

An example of implementation of the D-RAP is given by consideration of the standby liquid control system (SLCS). The purpose of the SLCS is to inject neutron absorbing poison into the reactor, upon demand, providing a backup reactor shutdown capability independent of the control rods. The system is capable of operating over a wide range of reactor pressure conditions. The SLCS may or may not be identified by the final PRA as a significant contributor to CDF or to offsite risk.

10.1 SLCS Description

During normal operation the SLCS is on standby, only to function in event the operators are unable to control reactivity with the normal control rods. The SLCS consists of a boron solution storage tank, two positive displacement pumps, two motor operated injection valves (provided in parallel for redundancy), and associated piping and valves used to transfer .rated water from the storage tank to the reactor pressure vessel (RPV).

The borated solution is discharged through the 'B' high pressure core flooder (HPCF) subsystem sparger. A schematic diagram of the SLCS, showing major system components, is presented in Figure 8. Some locked open maintenance valves and some check valves are not shown. Key equipment performance requirements are:

a.	Pump flow	50 gpm per pump
b.	Maximum reactor pressure (for injection)	1250 psig
c.	Pumpable volume in storage tank (minimum)	6100 U.S. gal

Design provisions to permit system testing include a test tank and associated piping and valves. The tank can be supplied with demineralized water which can be pumped in a closed loop through either pump or injected into the reactor.

The SLCS uses a dissolved solution of sodium pentaborate as the neutron-absorbing poison. This solution is held in a heated storage tank to maintain the solution above its saturation temperature. The SLCS solution tank, a test water tank, the two positive displacement pumps, and associated valving are located in the secondary containment on the floor elevation below the operating floor. This is a Seismic Category I structure, and the SLCS equipment is protected from phenomena such as earthquakes, tornados, hurricanes and floods as well as from internal postulated accident phenomena. In this area, the SLCS is not subject to conditions such as missiles, pipe whip, and discharging fluids.

The pumps are capable of producing discharge pressure to inject the solution into the reactor when the reactor is at high pressure conditions corresponding to the system relief valve actuation. Signals indicating storage tank liquid level, tank outlet valve position, pump discharge pressure and injection valve position are available in the control room.

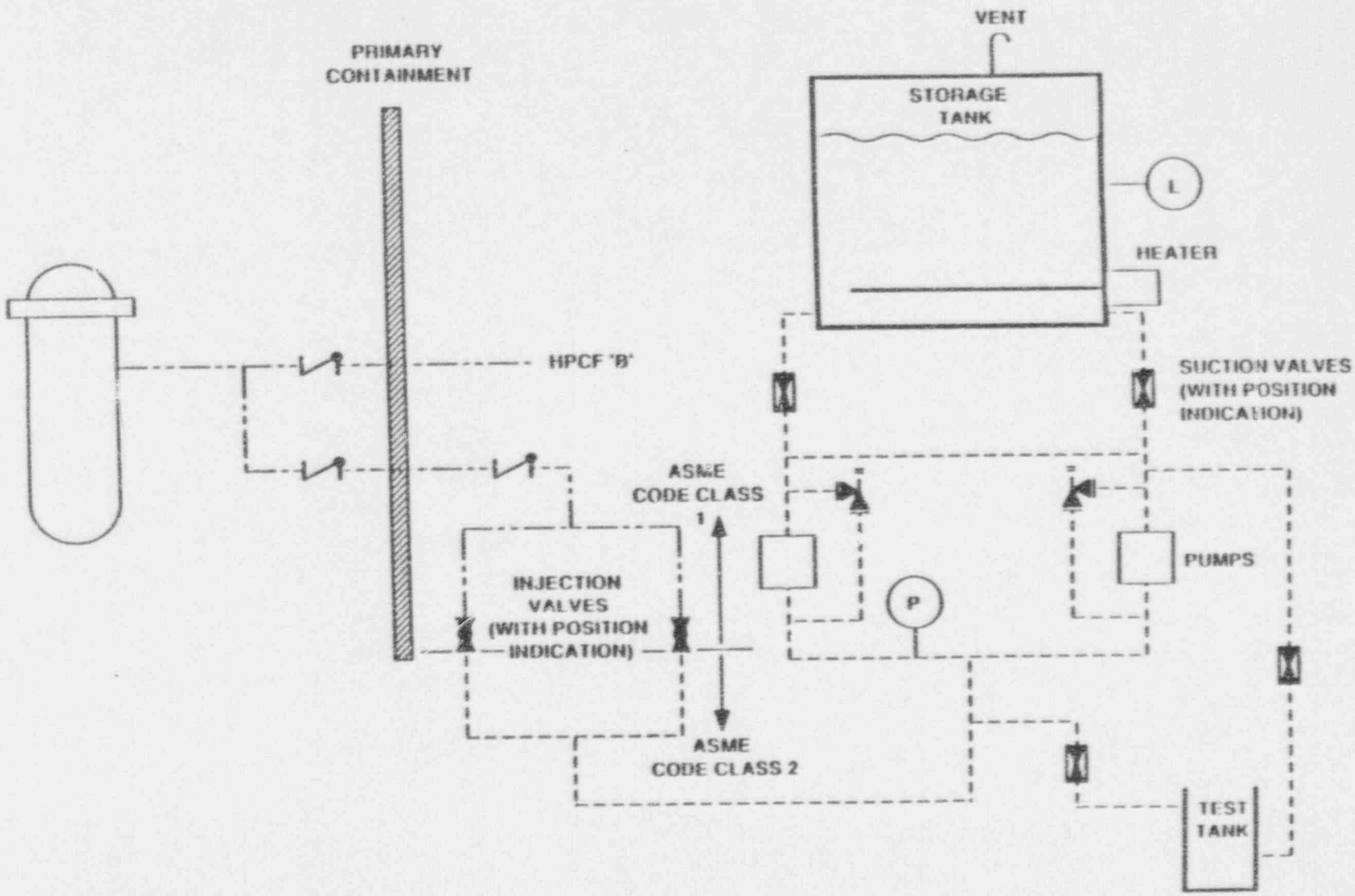

Figure 8. Standby Liquid Control System (Standby Mode)

The pumps, heater, valves and controls are powered from the standby power supply or normal offsite power. The pumps and valves are powered and controlled from separate buses and circuits so that single active failure will not prevent system operation. The power supplied to one motor operated injection valve, storage tank discharge valve, and injection pump is from Division I, 480 VAC. The power supply to the other motor-operated injection valve, storage tank outlet valve, and injection pump is from Division II, 480 VAC. The power supply to the tank heaters and heater controls is connectable to a standby power source. The standby power source is Class 1E from an on-site source and is independent of the off-site power.

All components of the system which are required for injection of the neutron absorber into the reactor are classified Seismic Category I. All major mechanical components are designed to meet ASME Code requirements as shown below.

Component	ASME Code Class	Design Conditions Pressure	Temperature
Storage Tank	2	Static Head	150 F
Pump/Motor	2	1560 psig	150 F
Injection Valves	1	1560 psig	150 F
Piping Inboard of Injection Valves	1	1250 psig	575 F

The installation and preoperational inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the SLCS are given in Table 1.

Table 1. SLCS Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The minimum average poison concentration in the reactor after operation of the SLCS shall be equal to or greater than 850 ppm.	1. Construction records, revisions and plant visual examinations will be undertaken to assess as-built parameters listed below for compatibility with SLCS design calculations. If necessary, an as-built SLCS analysis will be conducted to demonstrate the acceptance criteria is met.	1. It must be shown the SLCS can achieve a poison concentration of 850 ppm or greater assuming a dilution due to non-uniform mixing in the reactor and accounting for dilution in the RHR shutdown cooling systems. This concentration must be achieved under system design basis conditions.
	Critical Parameters:	**Validation Attributes**
	a. Storage tank pumpable volume	Storage tank pumpable volume range 6100-6800 gal.
	b. RPV water inventory at 70 F	RPV water inventory < 1,000,000 lb
	c. RHR shutdown cooling system water inventory at 70 F	RHR shutdown cooling system inventory < 287,000 lb
2. A simplified system configuration in shown in Figure 8.	2. Inspections of installation records together with plant walkdowns will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figure 8.	2. The system configuration is in accordance with Figure 8.

Table 1. SLCS Inspections, Tests, Analyses and Acceptance Criteria (Cont.)

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. Each SLCS pump shall be capable of delivering 50 gpm of solution against the elevated pressure conditions which can exist in the reactor during events involving SLCS initiation.	3. System preoperation tests will be conducted to demonstrate acceptable pump and system performance. These tests will involve establishing test conditions that simulate conditions which will exist during an SLCS design basis event.	3. It must be shown that the SLCS can inject 100 gpm (two pump operation) against a reactor pressure of 1250 psig.
4. The system is designed to permit in-service functional testing of SLCS.	4. Field tests will be conducted after system installation to confirm that in-service system testing can be performed.	4. Using normally installed controls, power supplies and other auxiliaries, the system has the capability to: a. Pump tests in a closed loop on the test tank and b. Reactor pressure vessel injection tests using demineralized water from the test tank.
5. The pump, heater, valves and controls can be powered from the standby AC power supply as described in Section 10.	5. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	5. The installed equipment can be powered from the standby AC power supply.

10.2 SLCS Operation

The SLCS is initiated by one of three means: (a) manually initiated from the main control room, (b) automatically initiated if conditions of RPV pressure above 1125 psig and startup range neutron monitor (SRNM) above 5% exist for 3 minutes, or (c) automatically initiated if conditions of RPV water level below the level 2 setpoint and startup range neutron monitor (SRNM) above 5% exist for 3 minutes. The SLCS provides borated water to the reactor core to compensate for the various reactivity effects during the required conditions. To meet its reactivity objective, it is necessary to inject a quantity of boron which produces a minimum concentration of 850 ppm of natural boron in the reactor core at 20 C. To allow for potential leakage and imperfect mixing in the reactor system, an additional 25% (220 ppm) margin is added to the above requirement. The required concentration is achieved accounting for dilution in the RPV with normal water level and including the volume in the residual heat removal shutdown cooling piping. This quantity of boron solution is the amount which is above the pump suction shutoff level in the storage tank thus allowing for the portion of the tank volume which cannot be injected.

10.3 SLCS Fault Tree

The top level fault tree for the SLCS is shown in Figure 9, with the top gate defined as failure to deliver 50 gpm of borated water from the storage tank to the RPV. Details providing input to most of the events in Figure 9 are contained in the several additional branches to the fault tree.

Normally the risk significant SSCs would be determined from the total plant reliability analysis (fault trees and event trees), but in this example results of the system fault tree are given in Table 2. Six cutsets, or combinations of events leading to system failure, combine to contribute a large fraction of the total system failure probability. Seven events or failures contribute to these top six cutsets, so the SSCs contributing to these events should be considered as candidates for redesign or for risk focused maintenance.

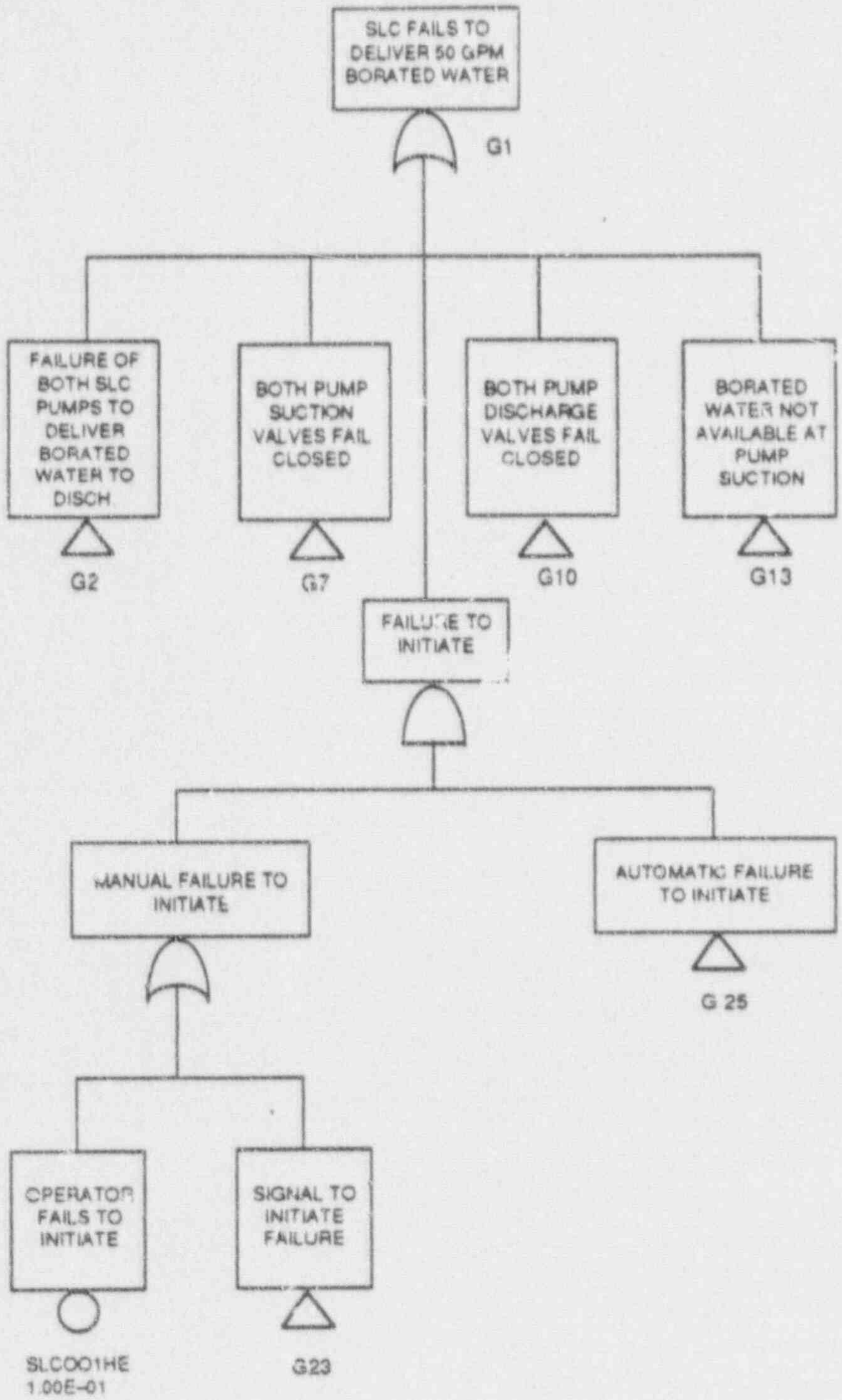

Figure 9. Standby Liquid Control System Top Level Fault Tree

Table 2. Top Level Cutsets for SLCS Failure

CUTSET	EVENTS*	
1	OVF001HW	OVF002HW
2	OFL000HW	
3	ECA040H	
4	ECA021H	
5	OPM002HW	OVF001HW
6	OPM001HW	OVF002HW

* Event names:

OVF001HW	Flow Diverted Through Relief Valve F003A
OVF002HW	Flow Diverted Through Relief Valve F003B
OFL000HW	Plugged Suction Lines From Tank
OPM001HW	SLCS Pump A (C001A) Fails to Operate
OPM002HW	SLCS Pump B (C001B) Fails to Operate
ECA021H	AC Power Cable 21 Failure
ECA040H	AC Power Cable 40 Failure

10.4 System Design Response

The SLCS system components identified in top cutsets of the total plant fault tree would normally be considered for redesign or for risk focused maintenance, as noted above. However, for this example the seven events identified by the system fault tree are the areas most significant to system failure to carry out its function.

Two of the events in Table 2 result from flow of SLCS fluid being diverted through relief valves back to pump suction rather than into the RPV. Since gate and check valve failures (which could result in relief valve operation) are accounted for by separate events, these relief valve failures of concern can be considered to be valve body failures or inadvertent opening of the relief valves. Plugging of the suction lines from the storage tank could result from some contamination of the tank fluid or collection of foreign matter in the tank. The pump failures to start upon demand could result from electrical or mechanical problems at the pumps or their control circuits.

Two AC electrical system failures that contribute to SLCS system failure are identified in Table 2. No further details of electrical system failures or maintenance are included here. That leaves the five components noted above for special attention with regard to reducing the risk of system failure.

a. Redesign

If the system reliability is already adequate to meet its goals, redesign will not be necessary. Redesign considerations, if required, will include trying to identify more reliable relief valves, more reliable pumps, and suction lines less likely to plug. The latter might be achieved by using larger diameter pipes, inlet strainers, or multiple suction lines. Pump and valve reliability might be enhanced by specific design changes or by providing greater redundancy of equipment. Any such redesign would have to be evaluated by balancing the increase in reliability achieved against the added complication to plant equipment and layout.

b. Failure Mode Identification

If redesign is not necessary, or after redesign has been completed, the appropriate reliability focused maintenance should be identified for the three SLCS component types identified by the fault tree and discussed above. This begins with determining the likely failure modes that will lead to loss of function. Examples of the types of failure modes that could impact reliability of these identified components are shown in Table 3. The table is not a complete listing of important failure modes, but is intended to indicate the types of failures that would be considered.

c. Recommended Maintenance

For each identified failure mode the appropriate maintenance tasks will be identified to assure that the failure mode will be (a) avoided, (b) rendered insignificant, or (c) kept to an acceptably low probability. The type of maintenance and the frequency of doing maintenance are both important aspects of assuring that the equipment failure rate will be no greater than that assumed for the PRA. Examples of maintenance activities and frequencies are shown in Table 3 for each identified failure mode.

TABLE 3. EXAMPLES OF SLCS FAILURE MODES & RISK FOCUSED MAINTENANCE

COMPONENT	FAILURE MODE/CAUSE	RECOMMENDED MAINTENANCE	FREQUENCY
Relief valve	Body leakage	Visual inspection	24 months
	Spurious opening, spring failure	Inspect closure spring for breaks; measure spring constant; replace spring.	10 years
	Spurious opening, spring fastener failure	Visual inspection of spring fastener; replace if necessary.	10 years
	Spurious opening, failure of valve stem or disk	Visual and penetrant inspection of stem and disk, ultrasonic inspection of stem; replace if necessary.	10 years
Pump	Fails to start, electrical problems	Functional test of pump with suction from test tank, no flow from storage tank.	6 months
	Fails to run, mechanical problems	Measure pump vibration during pump operation in functional test.	6 months
		Disassemble/inspect pump for corrosion, wear. Refurbish as necessary.	5 years
Suction Lines	Lines plugged by sediment	Sample storage tank water for sediment; clean tank as necessary	6 months
	Lines plugged by precipitated boron compounds	Sample storage tank water for degree of saturation of boron compounds. Increase tank temperature as necessary.	1 month

11. GLOSSARY OF TERMS

CDF	The core damage frequency as calculated by the PRA.
D-RAP	Design Reliability Assurance Program performed by the plant designer to assure that the plant will be operated and maintained in such a way that the reliability assumptions of the PRA apply throughout plant life.
GE-NE	GE Nuclear Energy, ABWR plant designer.
Owner/ Operator	The utility or other organization that owns and operates the ABWR following construction.
PRA	Probabilistic risk assessment performed to identify and quantify the risk associated with the ABWR.
RAP	Reliability Assurance Program performed by the owner/operator to assure that the plant operates safely, consistent with the PRA.
Risk-critical	Those SSCs which are identified as contributing significantly to the CDF and/or to the risk to the public.
SSCs	Structures, systems and components identified as being important to the plant operation and safety.

12. REFERENCES

(1) E. V. Lofgren, et. al., "A Process for Risk-Focused Maintenance", SAIC, NUREG/CR-5695, March 1991

Enclosure 2

NRC/GE MEETING ON RELIABILITY ASSURANCE PROGRAM

JANUARY 14, 1992

Name	Organization	Mail Stop
Chet Poslusny	NRR/DAR/PDST	11-H-03
Jeffry Sharkey	NRR/DLPQ/LPEB	10-A-19
Cindi Carpenter	NRR/DLPZ/LPEB	10-A-19
Tim Polich	NRR/DLPQ/LPEB	10-A-19
Adel El-Bassioni	NRR/DREP/PRAB	10-E-09
Jerry Wilson	NRR/DAR/PDST	11-H-03
Nick Saltos	NRR/DREP/PRAB	10-E-04
Cal Tang	GE-NE	
Charlie Larson	GE-NE	
Adrian Heymer	NUMARC	

DISTRIBUTION:

Docket File	NRC PDR	PDST R/F	TMurley/FMiraglia
DCrutchfield	WTravers	RPierson	JNWilson
CPoslusny	VMcCree	RNease	PShea
JMoore, 15B18	EJordan, MNBB3701	TBoyce	RHasselberg
THiltz	TKenyon	MMalloy	TWambach
ACRS (10)	LShao, NL007	RBosnak, NL007	JOBrien, NL271A
BSheron, RES	BHardin, NLS169	JMurphy, NLS007	RVanHouten, SECY
ZRosztoczy,NLS169	JHWilson	RCorreia, 10A19	JMSharkey, 10A19
CCarpenter, 10A19	TPolich, 10A19	[illegible]Bassioni,10E9	NSaltos, 10E4
GGrant, EDO			