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POWER
SYSTEMS

STN 50-470F

December 5, 1984
LD-84-070

Darrell G. Eisenhut, Director
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: CESSAR Amendment 10

Dear Mr. Eisenhut:

As a result of startup testing conducted at Palo Verde on the first System 80™ plant, C-E has identified changes to CESSAR. These proposed changes are described in the attachment and are provided for NRC Staff review.

These changes are currently in the FSAR change process and will be added to CESSAR in Amendment 10. If you have any questions or comments concerning these changes, please feel free to call me or Mr. T. J. Collier of my staff at (203) 285-5215.

Very truly yours,

COMBUSTION ENGINEERING, INC.

A. E. Scherer
Director
Nuclear Licensing

AES:las
Attach.
cc: P. Moriette

E003

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SUMMARY OF CHANGES

Chapter 5: Reactor Coolant System and Connected Systems

Section 5.2.2.10 and Figure 5.2-2 are changed to reflect a lower maximum ΔT across a steam generator. This change is made to allow additional operational flexibility and limits the maximum ΔT at which a Reactor Coolant Pump can be started to 100°F. Additionally, clarification is added to more accurately reflect the Shutdown Cooling System relief valves used in construction.

Figure 5.2-1 is modified to credit the typical difference in height between the pressurizer and the shutdown cooling system. This change was also made to provide operational flexibility.

Section 5.4.2.4.1 is changed to correct the Section numbers referenced. This change is considered editorial in nature.

Section 5.4.10.3 is revised to indicate that pressurization rate testing is not performed during Hot Functional Testing. Pressure control setpoints are determined analytically and checked during Power Ascension Testing.

Chapter 6: Engineered Safety Features

Tables 6.3.3.3-1 and 6.3.3.3-2, and Figure 6.3.3.2-5L, are modified to ease Low Pressure Safety Injection flow requirements. These flow changes were found to be sufficient to preserve the present ECCS performance results. Comparison of the revised figure with the figure currently in CESSAR demonstrates the insignificance of this change on the worst case postulated break.

Appendix 6B: Iodine Removal System

Section 7.16.4 is revised to remove unwarranted restrictions on the transfer of hydrazine and to clarify the qualifications of the arrangement used to transfer hydrazine to the Spray Chemical Additional Tank.

Chapter 7: Instrumentation and Controls

Section 7.1.2.10 is revised to clarify conformance to IEEE 384-1974 as augmented by Regulatory Guide 1.75 (Rev. 0, 2/74). It shows that the commitment to perform specific analyses have been completed.

Chapter 9: Auxiliary Systems

Tables 9.2-1 and 9.3-1, and Section 9.3.4.1.3.2, are updated to reflect C-E's latest guidance on chemistry controls.

Chapter 10: Steam and Power Conversion System

Tables 10.3.4-1 and 10.3.4-2, and Section 10.3.4, are updated to reflect C-E's latest guidance on chemistry controls.

Chapter 14: Initial Test Program

Section 14.2.12.2.5 (page 14.2-59) is revised to correct an editorial error. The letdown system valves tested are the control valves not the isolation valves.

Chapter 16: Technical Specifications

Specifications 3.4.1.3 and 3.4.1.4.1 and their bases are modified to reflect the reduced steam generator ΔT described under Chapter 5 above.

Appendix A

The Regulatory Guide 1.68.2, Revision 1 position statement is revised to reflect compliance with the intent of that guide. This change was effected in Amendment 6 to CESSAR dated November 20, 1981, but was not reflected in Appendix A.

5.2.2.10.1.1 Credit for Operator Action

No credit is taken for operator action for 10 minutes after the operator is made aware that a transient is in progress.

5.2.2.10.1.2 Single Failure

In the LTOP mode, each SCS relief valve is designed to protect the reactor vessel given a single failure in addition to a failure that initiated the pressure transient. The event initiating the pressure transient is considered to result from either an operator error or equipment malfunction. The SCS relief valve system is independent of a loss of offsite power. Each SCS relief valve is a self actuating spring-loaded liquid relief valve which does not require control circuitry. The valve opens when the RCS pressure exceeds its setpoint.

The redundant SCS suction line trains between the RCS and SCS relief valves meet the single failure criteria as described in paragraph 5.4.7.1.2 and table 5.4.7-3. No single failure of an isolation valve or its associated interlock will prevent one relief valve from performing its intended function.

5.2.2.10.1.3 Testability

Periodic testing of the SCS isolation valves is defined in the Technical Specifications, paragraph 16.3/4.5.2.

5.2.2.10.1.4 Seismic Design and IEEE 270 Criteria

The SCS suction line relief valves, isolation valves, associated interlocks, and instrumentation are designed to Seismic Category I requirements as discussed in subsections 3.2.1, paragraph 5.4.7.2.5 and table 3.2-1. The interlocks and instrumentation associated with the SCS suction isolation valves satisfy the appropriate portions of IEEE 279 criteria as discussed in paragraphs 5.4.7.2.5, 7.6.2.1.1 and 7.6.2.2.1.

5.2.2.10.2 Design and Analysis

In demonstrating that the SCS relief valves meet the criteria listed in paragraph 5.2.2.10.1, the following additional information is provided.

5.2.2.10.2.1 Limiting Transients

Transients during the low temperature operating mode are more severe when the RCS is operated in the water-solid condition. Addition of mass or energy to an isolated water-solid system produces increased ~~in~~ system pressure. The severity of the pressure transients depends upon the rate and total quantity of mass or energy addition. The choice of the limiting LTOP transients was based on evaluations of potential transients for System 80 plants. The most limiting transients initiated by a single operator error or equipment failure are:

a) An inadvertent safety injection actuation (mass input).
b) A reactor coolant pump start when a positive steam generator to reactor vessel ΔT exists (energy input).

The transients were determined as most limiting by conservative analyses which maximize mass and energy additions to the RCS. In addition, the RCS is assumed to be in a water-solid condition at the time of the transient; such a condition has been noticed to exist infrequently during plant operation since the operator is instructed to avoid water-solid conditions whenever possible.

Figure 5.2-1 shows the result of the inadvertent safety injection actuation transient analysis when the RCS is in the LTOP mode. The mass addition due to the simultaneous operation of two HPSI and three charging pumps was considered, along with the simultaneous addition of energy from decay heat and the pressurizer heaters.

Figures 5.2-2 shows the result of the transient analysis of a reactor coolant pump start when a steam generator to reactor vessel Δ T of ~~150°F~~ 100°F exists. This Δ T is ~~considered greater than any that can possible occur in the system~~ the maximum allowed by technical specification during the LTOP mode. In addition to considering the energy addition to the RCS from the steam generator secondary side, energy addition from decay heat, the reactor coolant pump and all pressurizer heaters were also included. In this analysis the steam generators were assumed to be filled to the zero power, normal water level. For conservatism, the secondary water, both around and above the U-tubes, was assumed to be thermally mixed in order to maximize the energy input to the primary side. This assumption is conservative since as a result of the temperature distribution within the steam generator during the transient, the water inventory above the tubes is practically isolated thermally from the heat transfer region. Therefore the heat transfer rate, and thus the primary side pressure, is not sensitive to the secondary side water level as long as the tubes are covered.

On the basis of experience, the ΔT value of ~~150°F~~ 100°F used in the analysis is much larger than any ΔT that might be expected during plant operation. This maximum allowable ΔT of ~~150°F~~ 100°F will prevent pressurizer pressure from exceeding the minimum P-T limit ~~(approximately 540 psia)~~ allowed for the lowest system temperature during the LTOP mode of operation. (See Technical Specification Figure 3.4-2). During RCS cooldown using the shutdown cooling system, coolant circulating with the reactor coolant pumps serves to cool the steam generator to keep the temperature difference between the reactor vessel and the steam generator minimal. Procedures will direct the operator to maintain the ΔT below approximately 20°F.

LTOP transients have not been analyzed for the simultaneous startup of more than one reactor coolant pump (RCP). Such operation is procedurally precluded since the operator starts only one RCP at a time and a second RCP is not started until system pressure is stabilized. Additionally, there is an LTOP transient alarm that should indicate that a pressure transient is occurring. Accordingly, the second RCP would not be started.

Technical Specification section ~~16.3/4.1.3~~ 16.3/4.4.1.3 requires that the operator not start an RCP if the ΔT exceeds ~~150°F~~ 100°F. However, as mentioned above, administrative procedures will ensure that the ΔT is maintained below approximately 20°F.

The results of the analyses provided in Figures 5.2-1 and 5.2-2 show that the use of either SCS relief valve will provide sufficient pressure relief capacity to mitigate the most limiting LTOP events identified above.

5.2.2.10.2.2 Provision for Overpressure Protection

During heatup, RCS pressure is maintained below the maximum pressure for SCS operation until RCS cold leg temperature exceeds the applicable P-T operating curve temperature corresponding to 2500 lb/in.^{2}a (see Figure 3.4-2 in the Technical Specifications). If SI-651 and 653 or SI-652 and 654 SCS suction isolation valves are open and RCS pressure exceeds the maximum pressure for SCS operation, an alarm will notify the operator that a pressurization transient is occurring during low temperature conditions. Either SCS relief valve will terminate inadvertent pressure transients occurring during RCS temperature below the applicable P-T operating curve temperature corresponding to 2500 lb/in.^{2}a. Above the maximum LTOP temperature, overpressure protection is provided by the pressurizer safety valves when the SCS relief valve is isolated from the RCS.

During cooldown whenever RCS cold leg temperature is below the applicable temperature for LTOP, the SCS relief valves provide the necessary protection. If the SCS is not aligned to the RCS before cold leg temperature is decreased to the maximum temperature requiring LTOP, an alarm will notify the operator to open the SCS suction isolation valves (SI-651, 652, 653, 654). The maximum temperature requiring LTOP is based upon the evaluation of the applicable P-T curves. However, the SCS can not be aligned to the RCS until the pressure is below the maximum pressure allowing SCS operation (see paragraph 5.4.7.2.3, item a.2).

These LTOP conditions are within the SCS operating range. Technical Specification section 16.3/4.4.8.3 requires the SCS suction line isolation valves to be open when operating in the LTOP mode. Also, this Technical Specification ensures that appropriate action is taken if one or more SCS relief valves are out of service during the LTOP mode of operation.

Either SCS relief valve will provide sufficient relief capacity to prevent any pressure transient from exceeding the isolation interlock setpoint (See figures 5.2-1 and 5.2-2).

5.2.2.10.2.3 Equipment Parameters

The SCS relief valves are spring-loaded ~~(bellows)~~ liquid relief valves with sufficient capacity to mitigate the most limiting overpressurization event. Pertinent valve parameters are as follows:

Parameter

Nominal Setpoint 450 lb/in.^{2} absolute
Accumulation 10%
Capacity 4000 (@ 10% acc) gal/min

Since each SCS relief valve is a self actuating spring-loaded liquid relief valve, control circuitry is not required. The valve will open when RCS pressure exceeds its setpoint.

The SCS relief valves are sized, based on an inadvertent safety injection actuation signal (SIAS) with full pressurizer heaters operating from a water-solid condition. The SIAS assumes simultaneous operation of two HPSI pumps and three charging pumps with letdown isolated. The resulting flow capacity requirement for water is 4000 gpm. The analysis in Section 5.2.2.10.2.1 assumed that either SCS relief valve relieved water at this rate. The design relief capacity of each of two SCS relief valves (shown in P&ID Figure 6.3.2-1B) as supplied by the valve manufacturer ~~is 5180 gpm. This design relief capacity exceeds~~ the minimum required relief capacity of 4000 gpm ~~with~~ sufficient margin in relieving capacity for even the worst transient. The SCS relief valves are Safety Class 2, designed to Section III of the ASME Code.

5.2.2.10.2.4 Administrative Controls

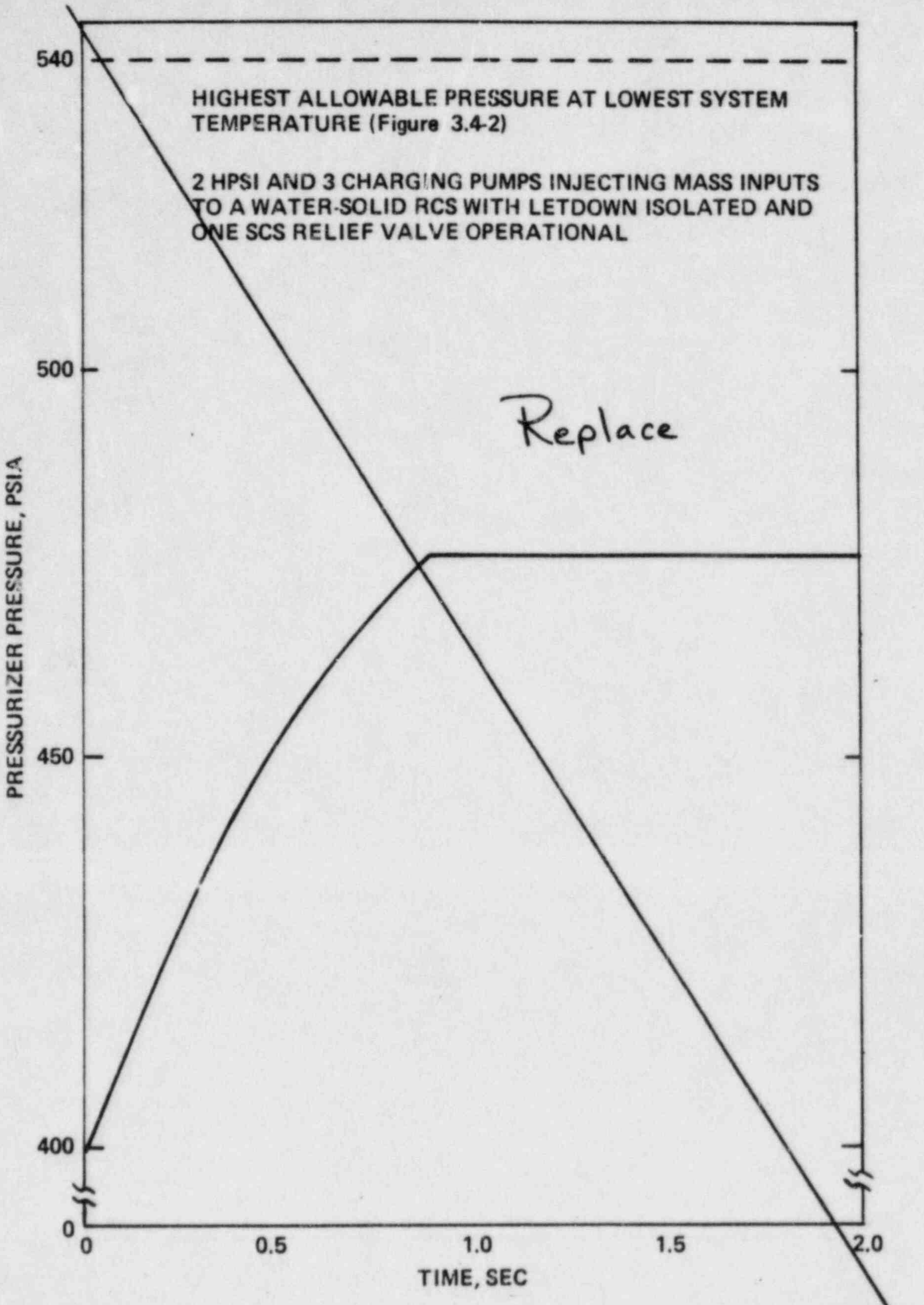
Administrative controls necessary to implement the LTOP provisions are limited to those controls that open the SCS isolation valves. Before entering the low temperature region for which overpressure protection is necessary, RCS pressure is decreased to below the maximum pressure required for SCS operation. Once the SCS is aligned, no further specific administrative procedural controls are needed to ensure proper overpressure protection. The SCS will remain aligned whenever the RCS is at low temperatures and the reactor vessel head is secured. As designated in Table 7.5-2, indication of SCS isolation valve position is provided.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specification

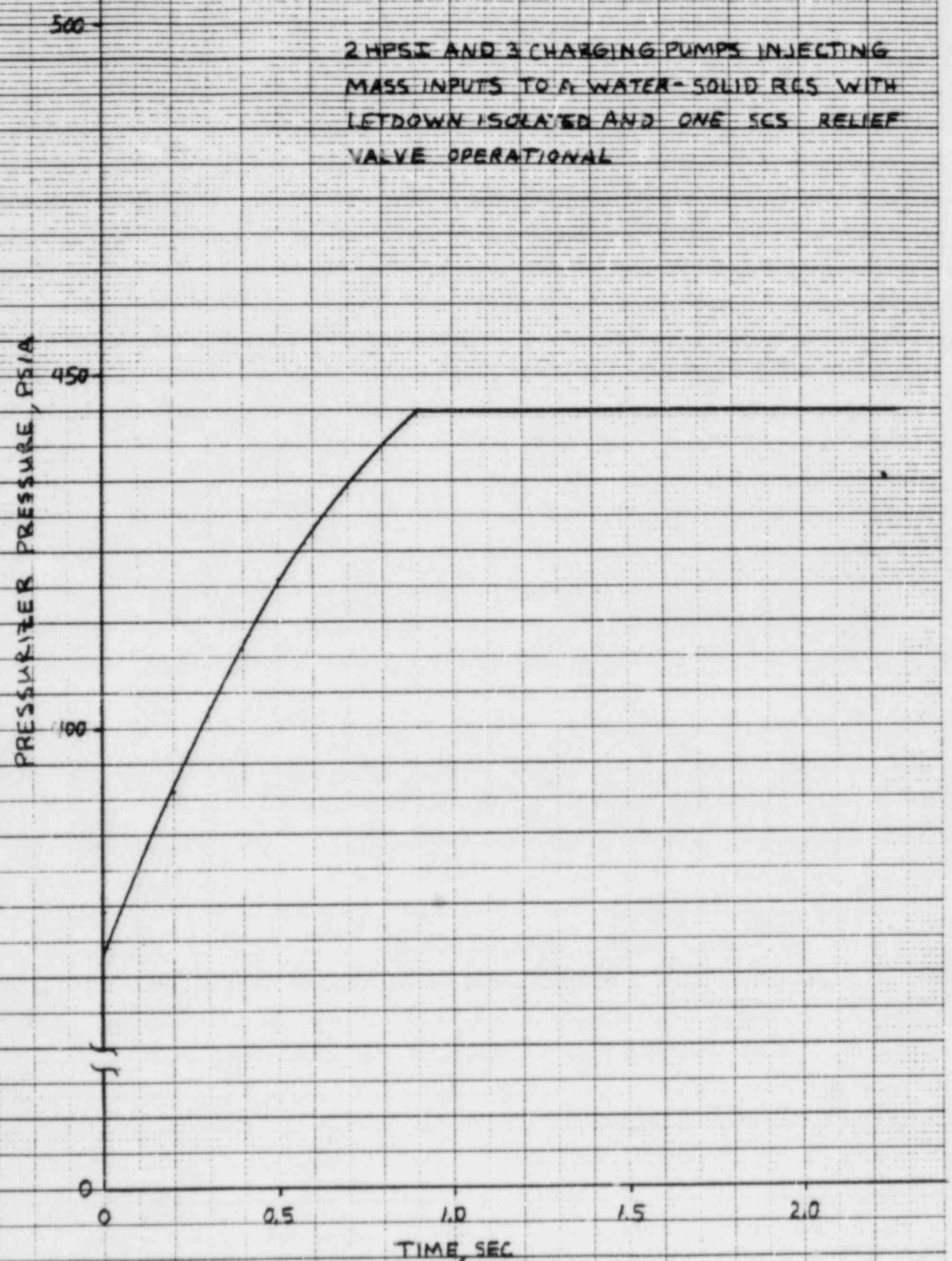
A list of specifications for the principal ferritic materials, austenitic stainless steels, bolting and weld materials, which are part of the reactor coolant pressure boundary is given in Table 5.2-2.

Studies have shown that the irradiation induced mechanical property changes of SA-533B materials can depend significantly upon the amount of residual elements present in the compositions, namely; copper, phosphorous, and vanadium. It has also been found that residual sulfur affects the initial toughness of SA-533B materials. Specific controls are placed on the residual chemistry of reactor vessel plates and the as-depositied welds used to join these plates to limit the maximum predicted increase in the reference temperature (RT_{NDT}, which is discussed in Section 5.3.1.6) and to limit the extent of the reactor vessel beltline. The beltline is defined by Appendix G of 10CFR50.

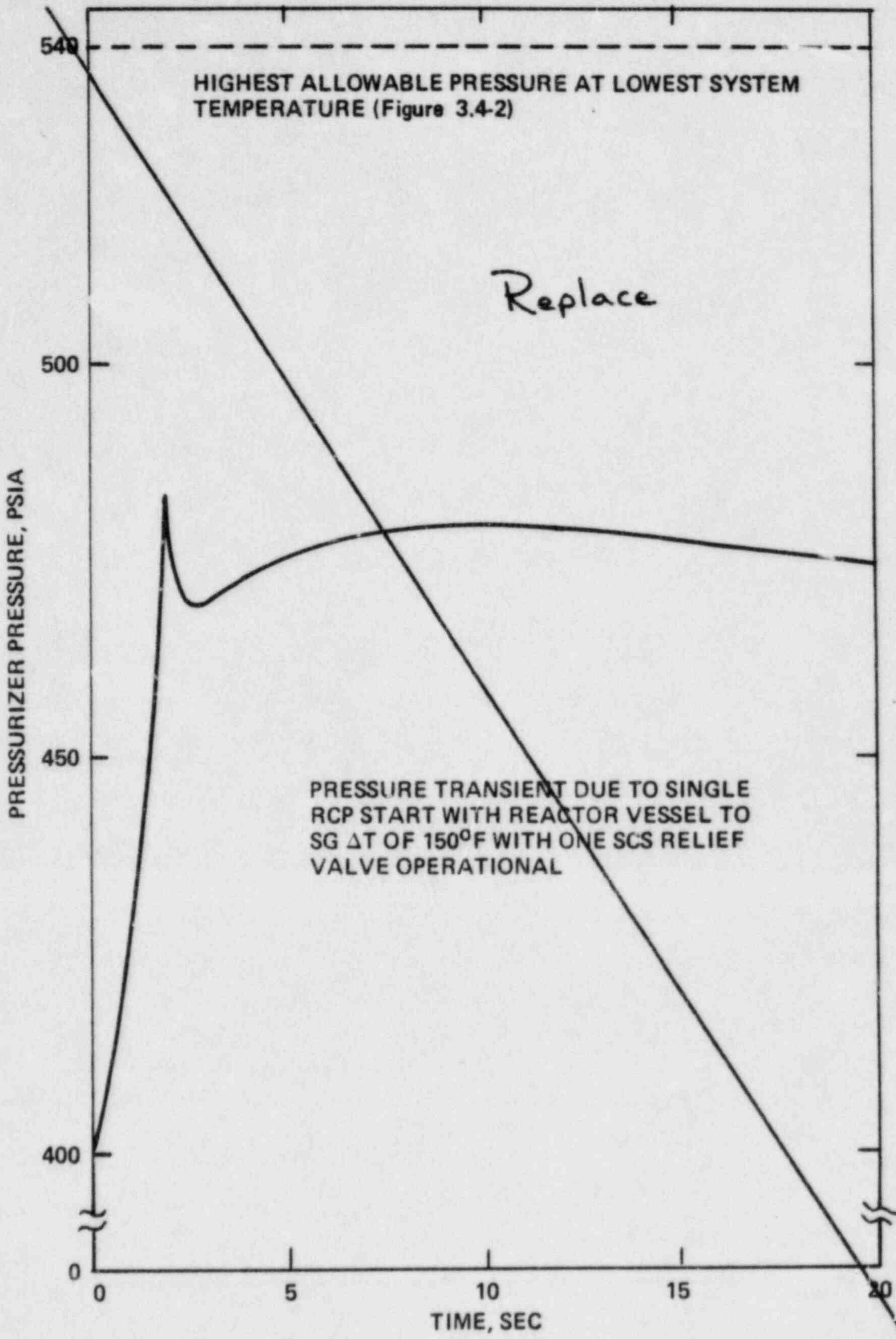


Amendment No. 6
November 20, 1981

C - E SYSTEM 80	PRESSURIZER PRESSURE DURING INADVERTENT SAFETY INJECTION ACTUATION	Figure 5.2-1

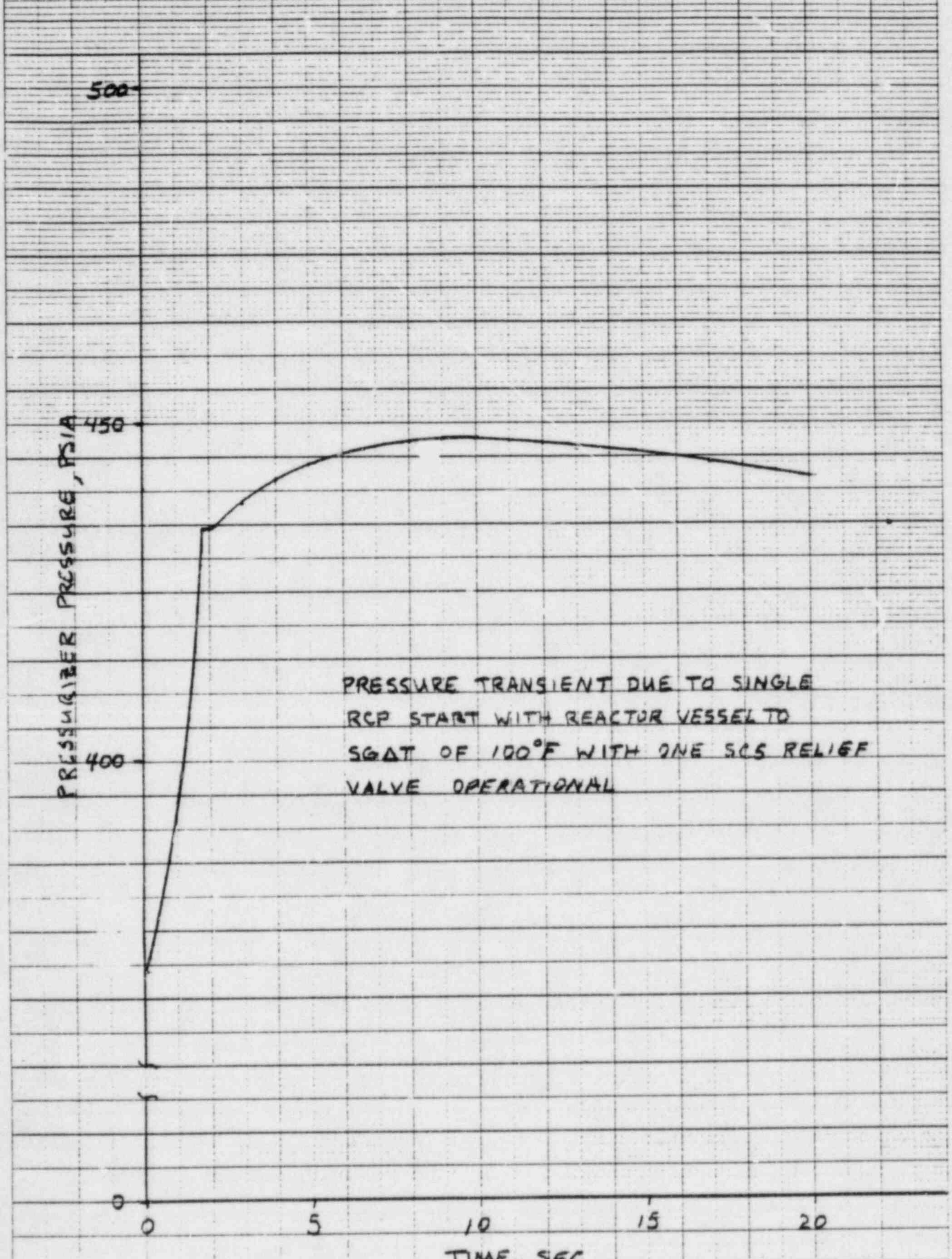


PRESSURIZER PRESSURE FIGURE 5.2-1
DURING INADVERTENT SAFETY INJECTION ACTUATION



Amendment No. 6
November 20, 1981

C - E SYSTEM 80	PRESSURIZER PRESSURE DURING RCP START WITH RCS ΔT	Figure 5.2-2



PRESSURIZER PRESSURE DURING RCP START WITH RCS ΔT

FIGURE 5.2-2

designed for either tensile or buckling loads. An effort has been made to avoid the use of thin plates which may collapse when subjected to differential pressure.

5.4.2.4 Steam Generator Materials

The pressure boundary materials used in the construction of the steam generator are listed in Table 5.2-2. These materials are in accordance with the ASME Boiler and Pressure Vessel Code, Section III. Code cases used in the fabrication of the steam generator are discussed in Section 5.2.1.

The Class 1 components of the steam generator will meet the fracture toughness requirements of the ASME code. An additional discussion of fracture toughness testing is included in Section 5.2.3.

Discussion of the techniques used to maintain cleanliness during final assembly and shipment are discussed in Section 5.2.3. Onsite cleaning and cleanliness control for the steam generator is discussed in the Applicant's SAR.

5.4.2.4.1 Steam Generator Tubes

The method of fastening tubes to the tube sheet conforms with the requirements of Section III and IX of the ASME Code. Tube expansion into the tube sheet is total with no voids or crevices occurring along the length of the tube in the tube sheet.

Localized corrosion of tubing material has led to steam generator tube leakage in some operating reactor plants. Examination of tube defects that have resulted in leakage has shown that two mechanisms are primarily responsible. These localized corrosion mechanisms are referred to as (1) stress assisted caustic cracking, and (2) wastage or beavering. Both of these types of corrosion have been related to steam generators that have operated on phosphate chemistry. The caustic stress corrosion type of failure is precluded by controlling bulk water chemistry to the specification limits shown in Section 10.3.4. Removal of solids from the secondary side of the steam generator is discussed in Section 10.4.8.

Localized wastage or beavering has been eliminated by removing phosphates from the chemistry control program.

Volatile chemistry (discussed in Section 10.3.4) has been successfully used in all C-E steam generators that have gone into operation since 1972.

5.4.2.5 Tests and Inspections

Prior to, during and after fabrication of the steam generator, nondestructive tests based upon Section III of the ASME Code are performed.

level, resulting in a transient pressure below normal operating pressure. To minimize the extent of this transient, the backup heaters are energized, contributing more heat to the water. Backup heaters are deenergized in the event of concurrent high-level error and high-pressurizer pressure signals. A low-low pressurizer water level signal deenergizes all heaters before they are uncovered to prevent heater damage. The pressure control program is shown in Figure 5.4.10-5.

5.4.10.3 Evaluation

It is demonstrated by analysis in accordance with requirements for ASME Code, Section III, Class 1 vessels that the pressurizer is adequate for all normal operating and transient conditions expected during the life of the facility. Following completion of fabrication, the pressurizer is subjected to the required ASME Code, Section III hydrostatic test and post-hydrostatic test non-destructive testing.

During hot functional testing, the transient performance of the pressurizer is checked by determining its normal heat losses and maximum ~~pressurization and~~ depressurization rate~~s~~. This information is used in setting the pressure controllers.

Further assurance of the structural integrity of the pressurizer during plant life will be obtained from the inservice inspections performed in accordance with ASME Code, Section XI, and described in Section 5.2.

Overpressure protection of the Reactor Coolant System is provided by four ASME Code spring-loaded safety valves. Refer to Section 5.4.12 and 5.4.13.

5.4.10.4 Tests and Inspections

Prior to and during fabrication of the pressurizer, non-destructive testing is performed in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code. Table 5.4.10-2 summarizes the pressurizer inspection program, which also includes tests not required by the Code. Refer to Section 5.2.1 for inservice inspections of the pressurizer.

TABLE 6.3.3.3-1

SAFETY INJECTION PUMPS MINIMUM DELIVERED FLOW TO RCS

(Assuming One Emergency Generator Failed)

RCS Pressure (psig)	Flow Rate Per Injection Point*, (gpm) A_1	A_2	B_1	B_2
1775.0	0	0	0	0
1650.0	50.0	50.0	50.0	50.0
1440.0	100.0	100.0	100.0	100.0
1270.0	125.0	125.0	125.0	125.0
1095.0	150.0	150.0	150.0	150.0
865.0	175.0	175.0	175.0	175.0
605.0	200.0	200.0	200.0	200.0
310.0	225.0	225.0	225.0	225.0
200.0	234.0	234.0	234.0	234.0
130.0 ~~150.0~~	581.0 ~~1118.0~~	581.0 ~~1118.0~~	240.0 ~~238.0~~	240.0 ~~238.0~~
100.0	1282.0 ~~1743.0~~	1282.0 ~~1743.0~~	243.0	243.0
50.0	1884.0 ~~2166.0~~	1884.0 ~~2166.0~~	246.0	246.0
0	2357.0 ~~2500.0~~	2357.0 ~~2500.0~~	250.0	250.0

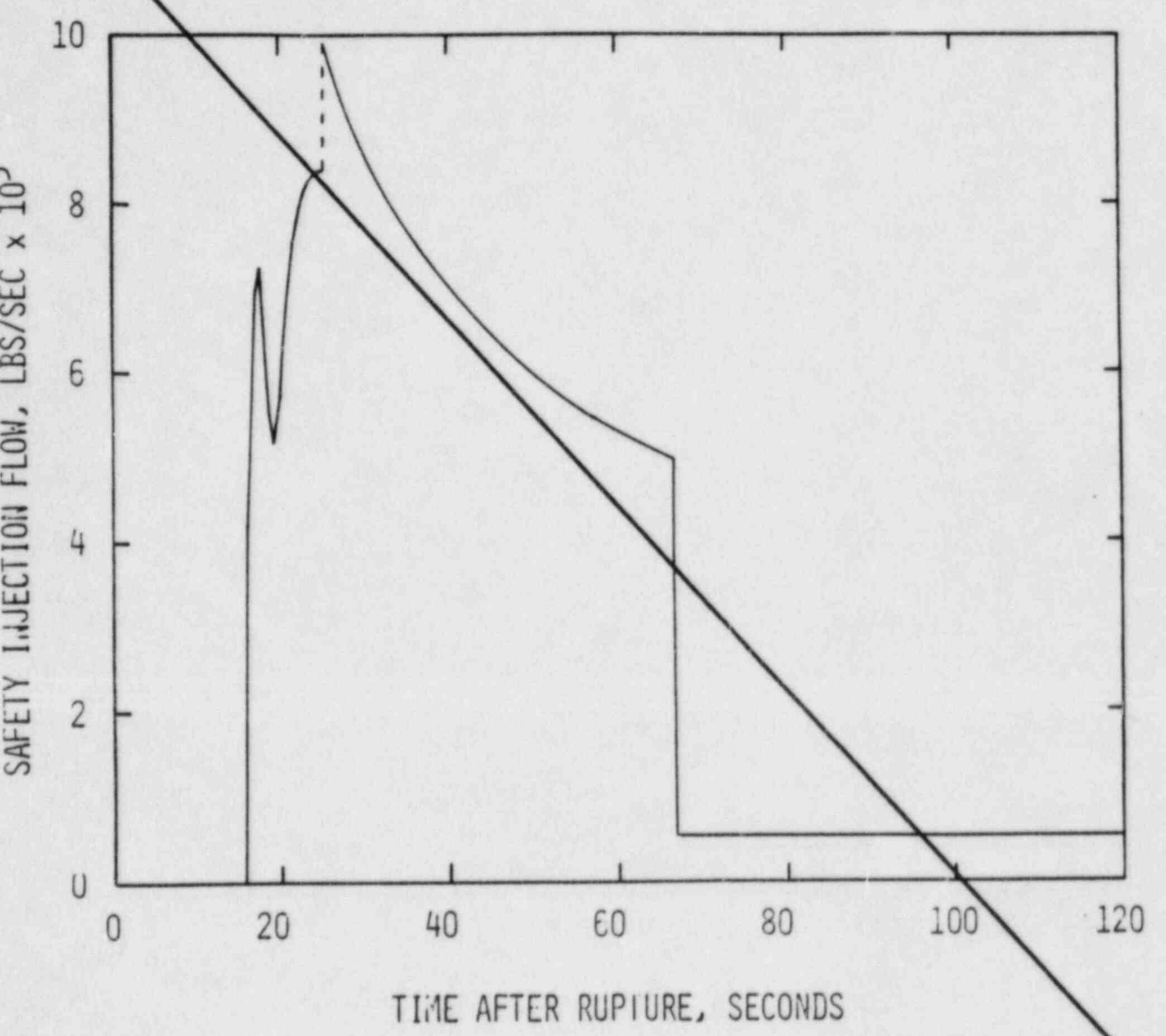
* Injection Point A1 is assumed to be attached to the broken pump discharge leg.

TABLE 6.3.3.3-2

GENERAL SYSTEM PARAMETER AND INITIAL CONDITIONS
SMALL BREAK ECCS PERFORMANCE ANALYSIS

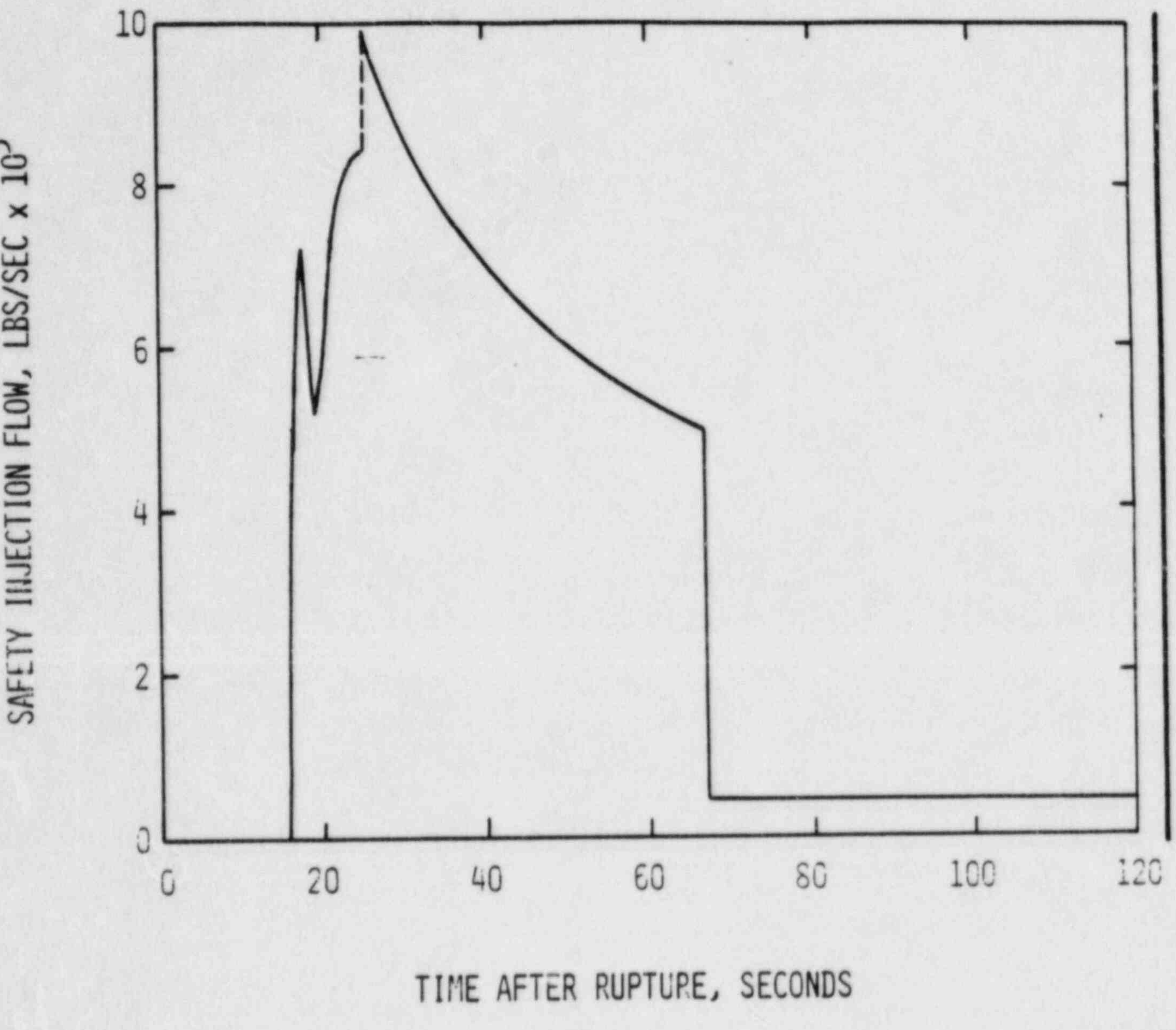
Quantity	Value	Units
Reactor Power Level (102% of Nominal)	3876	MWt
Average Linear Heat Rate (102% of Nominal)	5.6	kw/ft
Peak Linear Heat Rate	15.0	kw/ft
Gap Conductance at Peak Linear Heat Rate	1497	btu/hr-ft^2-°F
Fuel Centerline Temperature at Peak Linear Heat Rate	3681	°F
Fuel Average Temperature at Peak Linear Heat Rate	2319	°F
Hot Rod Gas Pressure	1187	psia
Moderator Temperature Coefficient at Initial Density	0.0	[illegible]/°F
System Flow Rate (Total)	164.0×10^6	lbs/hr
Core Flow Rate	159.1×10^6	lbs/hr
Initial System Pressure	2250	psia
Core Inlet Temperature	565	°F
Core Outlet Temperature	623	°F
Low Pressurizer Pressure Scram Setpoint	1600	psia
Safety Injection Actuation Signal Setpoint	1600	psia
Safety Injection Tank Pressure	608	psia
High Pressure Safety Injection Pump Shutoff Head	1775	psig
Low Pressure Safety Injection Pump Shutoff Head	142. ~~200~~	psig

Replace with following Figure



~~Amendment No. 4~~
~~July 16, 1981~~

C-E SYSTEM 80	1.0 x DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG SAFETY INJECTION FLOW INTO INTACT DISCHARGE LEG	Figure 6.3.3.2-5L



C-E SYSTEM 80

1.0 x DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG
SAFETY INJECTION FLOW INTO INTACT DISCHARGE LEG

Figure 6.3.3.2-5L

7.16.4.2 Provisions shall be made to preclude the introduction of air into the SCST ~~or shipping containers~~ during fill operations.

INSERT (A)

7.16.4.3 ~~If a pump is used to transfer hydrazine to the SCST, all of the metal components of the pump should be type 304 or 347 stainless steel. Seals should be the mechanical type and should be constructed according to the pump supplier's recommendations for hydrazine service.~~

7.16.5 FIRE PROTECTION

A fire protection system shall be provided to protect the Iodine Removal System and shall include, as a minimum, the following features:

a. Facilities for fire detection and alarming.

b. Facilities or methods to minimize the probability of fire and its associated effects.

c. Facilities for fire extinguishment.

d. Methods of fire prevention such as use of fire resistant and non-combustible materials whenever practical, and minimizing exposure of combustible materials to fire hazards.

e. Assurance that fire protection systems do not adversely affect the functional and structural integrity of safety related structures, systems, and components.

f. Care should be exercised to ensure fire protection systems are designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety related structures, systems, and components.

7.17 ENVIRONMENTAL

See Section 7.7 and CESSAR Section 3.11 for environmental interfaces.

7.18 MECHANICAL INTERACTION

7.18.1 IRS components shall be properly supported such that pipe stresses and support reactions are within allowable limits, as defined in CESSAR Section 3.9.2. CE provides the Applicant the loads at the supports/structures interface locations for components that CE supplies, under normal, upset, emergency, faulted, and test conditions, as described in CESSAR Section 3.8.5.

7.18.2 IRS piping and fittings shall be Seismic Category I.

INSERT (A)

7.16.4.3 All transfer lines and pump components in contact with the hydrazine solution should be clean and hydrazine compatable as recommended by the chemical manufacturers.

1.75, "Physical Independence of Electric Systems". A discussion of the physical independence is provided below which describes the compliance with Section 4.6 of IEEE 279-1971 and General Design Criteria 3 and 21. General Design Criterion 17 is discussed in the Applicant's Safety Analysis Report.

The PPS cabinet is divided into four bays which are separated by mechanical and thermal barriers. Each bay contains one of the four redundant channels of the RPS and ESFAS. This provides the separation and independence necessary to meet the requirements of Section 4.6 of IEEE 279-1971.

INSERT

~~Tests or analyses will be performed to demonstrate that no single credible event in one PPS bay can propagate the fault created to any other bay. The tests or analyses will be completed about two months prior to the fabrication of the equipment for installation in the first Applicant's facility and will be submitted for review prior to installation.~~

The ESFAS Auxiliary Relay Cabinets provide separation and independence for the selective two-out-of-four actuation logics and actuation relays of the two redundant ESF Systems' Trains. Each train's logic and relays are contained in a separate cabinet with all of the train A actuation circuits in one cabinet and all of the train B actuation circuits in the other cabinet. There are mechanical and thermal barriers within the cabinets to protect different portions of the selective two-out-of-four logic from spurious actuation. The two cabinets are physically separated from each other.

The RTSS consists of four RTSG. Each RTSG and its associated switches, contacts, relays, etc. is contained in a separate cabinet. Each cabinet is physically separated from the other cabinets. This method of construction ensures that a single credible failure in one RTSG cannot cause malfunction or failure in another cabinet.

The separation and independence of the power supplies for each of the above systems is discussed in Chapter 8.0. The interface requirements appear in Section 7.1.3 while the implementation will appear in the Applicant's Safety Analysis Report. Protection system analog signals, sent to the Plant Monitoring System (PMS), are isolated from the protection system. Digital signals are also isolated for the associated signals coming from the protection system.

All of these isolation techniques ensure that no credible failures on the output side of the isolation device will effect the PPS side and that the independence of the PPS is not jeopardized. The test results reports on the isolation devices (within CESSAR Licensing scope) will be submitted for review prior to installation of the devices in the first Applicant's facility.

7.1.2.11 Conformance to IEEE 387-1972

Conformance to IEEE 387-1972 , "IEEE Trial-Use Standard: Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations", as criteria in the design of these systems is discussed in the Applicant's Safety Analysis Report.

CESSAR 7.1.2.10

Replace paragraph 3 with the following paragraph.

Separation of redundant Class 1E circuits within the PPS cabinet is accomplished through 6 inch separation or barriers or conduit. However, in the formation of the logic matrices (AB, AC, BC, AD, BD, CD), initiation circuits, and actuation circuits, 6 inch separation is not maintained, nor can barriers or conduit be utilized. An analysis has been performed to show that the separation achieved is acceptable. Tests and analyses have also been completed to demonstrate that no single credible event in one PPS bay can prevent the circuitry in any other bay from performing its safety function.

TABLE 9.2-1

~~PRIMARY AND SECONDARY~~

MAKEUP WATER SYSTEM DEMINERALIZER EFFLUENT LIMITS

pH*	6.0 to 8.0
Conductivity	Less than ~~2~~ 0.2 μmhos
Chloride	Less than ~~0.15~~ 0.005 ppm Cl
Fluoride	Less than ~~0.10~~ 0.005 ppm F
~~Suspended Solids~~	~~Less than 0.5 ppm~~
~~Gaseous**~~	~~Non-Deaerated/Deaerated~~
Silica ~~(SiO_2)***~~ (SiO_2)	Less than 0.01 ppm
Sodium	Less than 0.003 ppm

* If water contains CO_2, the pH specification may be lowered to 5.8 to compensate for CO_2 absorption.

~~** Deaeration gives conservatism to makeup water system design but it is not considered necessary.~~

~~*** Pertains to secondary makeup water only.~~

time when exposed to normal reactor coolant chemistry conditions, approaching low steady state values within approximately 200 days. The high pH condition produced by high ammonia concentration (to 50 ppm) minimizes corrosion product release and assists in the rapid development of the passive oxide film. Most of the film is established within 7 days at hot, high pH conditions.

To aid in maintaining the pH during this passivation period, lithium in the form of lithium hydroxide, is added to the coolant and maintained within a 1-2 ppm lithium-7 range.

At power, oxygen concentration is limited by maintaining excess dissolved hydrogen gas in the coolant. The excess hydrogen forces the water decomposition/synthesis reaction in the reactor core to water rather than hydrogen and oxygen. Oxygen in the makeup water is removed in the same way.

In order to minimize the effect of crud deposition on the reactor core heat transfer surfaces, lithium-7 hydroxide additions to the reactor coolant are made. The lithium-7 hydroxide produces pH conditions within the reactor coolant at operating temperature which reduces the corrosion product solubility and, hence, the dissolved crud inventory in the circulating reactor coolant. The elevated pH promotes conditions within the coolant for selective deposition of corrosion products on cooler surfaces (SG) rather than hotter surfaces (core). An additional advantage is the formation of a more stable and tenacious passive oxide layer on out-of-core system surfaces. The lithium concentration is maintained within a ~~0.2-1.0~~ 1.0-2.0 ppm lithium-7 range during operation. ~~Late in core life, when boron concentration is low, maintaining lithium at the high end of this band could lead to the formation of lithium metaborates. For this reason, when the deborating ion exchanger is placed on line for boron control (30 ppm boron) the lithium concentration is decreased and maintained within 0.2-0.5 ppm lithium. Lithium is not controlled (i.e., there is no minimum concentration) during refueling operations.~~

9.3.4.1.3.3 Reactivity Control. Boron concentration is normally controlled by feed and bleed. To change concentration, the makeup system supplies either reactor makeup water or boric acid to the Volume Control Tank, and the letdown stream is diverted to the holdup tanks via the preholdup ion exchanger and the gas stripper. Toward the end of a fuel cycle, with low boric acid concentration in the coolant, feed and bleed becomes inefficient, and the deborating ion exchanger is used to reduce the RCS boron concentration. The ion exchanger contains an anion resin initially in the hydroxyl form, which is converted to a borate form as boron is removed from the reactor coolant.

9.3.4.2 System Description

9.3.4.2.1 System

The normal reactor coolant flow path through the CVCS is indicated by the heavy lines on the Piping and Instrumentation Diagrams, Figures 9.3-1 through 9.3-4.

TABLE NO. 9.3-1

(Sheet 1 of 2)

OPERATING LIMITS

1.0 REACTOR COOLANT MAKEUP WATER

Analysis	Normal	~~Abnormal~~
Chloride (Cl)	<0.15 ppm	~~< .15 ppm~~
~~Silica (SiO_2)~~	~~<0.01 ppm~~	~~< .02 ppm~~
~~Conductivity~~	~~<1.0 μmhos/cm~~	~~< 2 μmhos/cm~~
pH	6.0 - 8.0 (1)	-
Fluoride (F) ~~(2)~~	<0.1 ppm	~~<0.1 ppm~~
Suspended Solids	<0.5 ppm	-

2.0 PRIMARY WATER

Analysis	Pre Core Hot Functionals ~~(3)~~ (2)	Initial Core Load and ~~Initial~~ Criticality	~~Power~~ Operation
pH (77°)	9.0 - 10.4	4.5 - 10.2 ~~(4)~~	4.5 - 10.2 ~~(4)~~
Conductivity	~~(5)~~ (3)	~~(5)~~ (3)	~~(5)~~ (3)
Hydrazine	30 - 50 ppm (4)	30 - 50 ppm (4)	1.5 × Oxygen ppm (5) (max. 20 ppm)
Ammonia	<50 ppm	<50 ppm	<0.5 ppm
Dissolved Gas	---	---	(6)
Lithium	1-2 ppm	1.0 - 2.0 ~~0.2 - 1.0~~ ppm ~~(7)~~	1.0 - 2.0 ~~0.2 - 1.0~~ ppm ~~(8)~~
Hydrogen	---	--- (7)	25 ~~10~~ - 50 cc (STP)/kg (H_2O) (8)
Oxygen	≤0.1 ppm	≤0.1 ppm ~~(9)~~ (10)	≤0.1 ppm (10)
Suspended Solids	<0.5 ppm, 2 ppm max. (9)	<0.5 ppm, 2 ppm max. (9)	<0.5 ppm, 2 ppm max. (9)
Chloride	≤0.15 ppm	≤0.15 ppm	≤0.15 ppm
Fluoride	≤0.1 ppm	≤0.1 ppm	≤0.1 ppm
Boron	---	≤Refueling Concentration	~~<4400 ppm~~ ≤ Refueling Concentration

TABLE 9.3-1 (Cont'd) (Sheet 2 of 2)

Notes for Table No. 9.3-1

(1) May be as low as 5.8 if proven due to CO_2 absorption.

~~(2) Fluoride limit applicable to water intended for primary makeup.~~

(2) ~~(3)~~ Special hot conditioning limits:

Temperature >350°F for 7-10 days

~~(4) During core load and refueling, pH may be as low as 3.8 due to high boron concentration.~~

(3) ~~(5)~~ Consistent with additive concentration.

INSERT (A)

(6) Prior to a depressurization shutdown, reduce total gas to <10cc(STP)/kg (H_2O) to limit the possibility for explosive mixtures.

INSERT (B)

~~(7) If the purification ion exchanger is being saturated with ^{7}Li on line, maintain 1-2 ppm ^{7}Li until saturation is reached (indicated by ^{7}Li breakthrough), then revert to the 0.2-1 ppm range. This range must be in force prior to criticality. The lithium range does not apply during core loading.~~

~~(8) Near end of life, when the deborating ion exchanger is placed in service (~30 ppmB) the lithium limit is 0.2-0.5 ppm.~~

~~(9) Not applicable during core load.~~

INSERT (A)

(4) Hydrazine is maintained at 30-50 ppm any time the RCS is less than 150°F.

(5) Prior to exceeding 150°F during heatup or below 400°F during cooldown.

INSERT (B)

(7) During the transition from post-core to operating, hydrogen should be maintained in the 15 to 25 cc(STP)/kg(H₂ range to minimize degassing requirements in case the reactor plant must be shutdown and depressurized.

(8) Hydrogen should be <5 cc(STP)/kg (H_2O) before securing the reactor coolant pumps.

(9) The abnormal condition of 0.5 to 2.0 ppm is permitted for up to 14 hours to allow for crud burst conditions.

(10) Not applicable during core load.

Secondary water chemistry is based on the zero solids treatment method. This method employs the use of volatile additives to maintain system pH and to scavenge dissolved oxygen present in the feedwater.

A neutralizing amine is added to establish and maintain alkaline conditions in the feedtrain. Neutralizing amines which can be used for pH control are ammoniz, morpholine, and cyclohexylamine. Ammonia should be used in plants employing condensate polishing to avoid resin fouling. Although the amines are volatile and will not concentrate in the steam generator, they will reach an equilibrium level which will establish an alkaline condition in the steam generator.

Hydrazine is added to scavenge dissolved oxygen present in the feedwater. Hydrazine also tends to promote the formation of a protective oxide layer on metal surfaces by keeping these layers in a reduced chemical state.

Both the pH agent and hydrazine can be injected continuously at the discharge headers of the condensate pumps or condensate demineralizer, if installed. These chemicals are added as necessary for chemistry control, and can also be added to the upper steam generator feed line when necessary.

Operating chemistry limits for ~~feedwater and~~ secondary steam generator water and feedwater and condensate ~~water~~ are give in Tables 10.3.4-1 and 10.3.4-2.

The limits stated are divided into two groups; normal and abnormal. The limits provide high quality chemistry control and yet permit operating flexibility. The normal chemistry conditions can be maintained by any plant operating with little or no condenser leakage. The abnormal steam generator limits are suggested to permit operations with minor system fault conditions until the affected component can be isolated and/or repaired.

The following procedures are recommended to the applicant:

~~If the continuous monitors on the steam generator blowdown sample lines detect more than four μmhos/cm specific conductivity, the steam generator water should be immediately sampled and analyzed for chloride concentration:~~

~~A. If chloride concentration is within baseline* values, operations may continue. The generators should be sampled for chlorides at least once per eight hour shift while conductivity exceeds four μmhos/cm.~~

~~B. If chloride concentration is in excess of baseline* values or approaching 0.1 ppm, a condenser leak is indicated and leak isolation procedures should be instituted.~~

~~*Baseline values are defined as the chloride concentration which exists in the steam generator water at steady state operating conditions without condenser leakage. A typical baseline chloride concentration is expected to be approximately 20 ppb.~~

INSERT (A)

INSERT (A)

When the normal range is exceeded, immediate investigation of the problem should be initiated, sampling frequency increased to the abnormal level (at least twice per 8 hour shift) and blowdown increased to one (1) percent of the main steaming rate. The problem should be corrected and the parameter(s) returned to the normal range within one week. If this cannot be done, and the parameter has a listed abnormal range, power should be reduced to 25% as if the abnormal range had been exceeded.

When the abnormal range is exceeded, power should be reduced to the lowest value (maximum of 25%) consistent with automatic operation of the feed system. Continued plant operation is then possible while corrective action is taken. Power reduction should be initiated within four hours of exceeding the abnormal range. The problem should be corrected and the parameter(s) returned to the normal range within one hundred (100) hours. If this cannot be done, the unit should be shutdown.

~~If any of the normal operating specifications in Table 10.3.4-1 are exceeded, immediate investigation of the problem should be initiated, sampling frequency increased to the abnormal level (at least twice per eight hour shift) and blowdown increased to one percent of the main steaming rate. If condenser leakage is indicated, leak isolation procedures should be instituted. Upon verification of a condenser leak, with steam generator chloride in excess of 0.1 ppm, a plant power reduction should be initiated immediately and should be reduced to 25% within four hours. Power should not exceed 25% until chloride concentration is within the normal specifications.~~

~~In the event condenser leakage causes any operating specifications in Table 10.3.4-1 to equal or exceed abnormal limits, a shutdown should be completed within four hours.~~ Draining or flushing of the steam generators will be necessary to reduce the impurity concentration.

10.3.4.2 Corrosion Control Effectiveness

Alkaline conditions in the feedtrain and the steam generator reduce general corrosion at elevated temperatures and tend to decrease the release of soluble corrosion products from metal surfaces. These conditions promote the formation of a protective metal oxide film and thus reduce the corrosion products released into the steam generator.

Hydrazine also promotes the formation of a metal oxide film by the reduction of ferric oxide to magnetite. Ferric oxide may be loosened from the metal surfaces and be transported by the feedwater. Magnetite, however, provides an adherent protective layer on carbon steel surfaces. Hydrazine also promotes the formation of protective metal oxide layers on copper surfaces.

The removal of oxygen from the secondary waters is also essential in reducing corrosion. Oxygen dissolved in water causes general corrosion that can result in pitting of ferrous metals, particularly carbon steel. Oxygen is removed from the steam cycle condensate in the main condenser deaerating section. Additional oxygen protection is obtained by chemical injection of hydrazine into the condensate stream. Maintaining a residual level of hydrazine in the feedwater ensures that any dissolved oxygen not removed by the main condenser is scavenged before it can enter the steam generator.

The presence of free hydroxide (OH^-) can cause rapid corrosion (caustic stress corrosion) if it is allowed to concentrate in a local area. Free hydroxide is avoided by maintaining proper pH control, and by minimizing impurity ingress in the steam generator.

TABLE 10.3.4-1

OPERATING CHEMISTRY LIMITS FOR SECONDARY STEAM GENERATOR WATER

Variable	Normal Specifications (1)	Abnormal Limits ~~(2)~~
pH (mixed system) (2)	8.5 ~~8.2~~ - 9.2	~~7.5 - 8.2~~
(copper free)	9.0 - 9.6	~~>9.2 - 9.3~~
Cation ~~Specific~~ Conductivity (3)	< 0.8 ~~7~~ µmhos/cm ~~(3)~~	0.8-2.0 ~~7 - 15~~ µmhos/cm
~~Suspended Solids~~	~~< 1.0 ppm~~	~~1 - 10 ppm~~
Silica	< 300 ppb ~~< 1.0 ppm~~	~~1 - 10 ppm~~
Chloride	< 20 ppb ~~< 0.1 ppm~~	20 - 100 ppb
Sodium (4)	< 20 ppb	20 - 100 ppb
Sulfate	< 15 ppb	15 - 100 ppb

NOTES:

(1) Normal specifications are those which should be maintained by continuous steam generator blowdown during proper operation of secondary systems.

~~(2) Abnormal limits indicate a fault condition exists and plant shutdown should be commenced if abnormal limits are exceeded for 4 hours.~~

~~(3) Specific conductivity alarm set point: 4 µmhos/cm.~~

(2) Mixed system is any secondary system containing copper alloy components.

(3) If the immediate shutdown limit of 7.0 µmhos/cm is exceeded the unit should be shutdown within four hours.

(4) If the immediate shutdown limit of 500 ppb is exceeded the unit should be shutdown within four hours.

TABLE 10.3.4-2

OPERATING CHEMISTRY LIMITS FOR FEEDWATER AND CONDENSATE

Variable	Normal(1) Specifications	~~Abnormal(2) Limits~~
pH		
a. Mixed ~~Feedwater~~ system ~~containing copper-alloy components~~	8.8 - 9.2	
b. Copper-free ~~feedwater~~ system	9.3 - 9.6 ~~9.2 - 9.6~~	
Conductivity (Intensified cation) (Feedwater)	< 0.2 ~~0.5~~ µmhos/cm	~~0.5 - 1.5 µmhos/cm~~
Hydrazine (Feedwater)	10 - 50 ppb	
Dissolved Oxygen		
(Feed)	< 3 ~~5~~ ppb (2)	~~5 - 10 ppb~~
(Condensate)	< 10 ppb	~~10 ppb~~
Sodium (3)	< 3 ~~1~~ ppb	~~1 - 10 ppb~~
Copper (Feedwater)	~~(3)~~ <2 ppb (4)	~~(3)~~
Iron (Feedwater)	< 20 ~~10~~ ppb	~~10 - 30 ppb~~
~~Ammonia~~		
~~(with copper)~~	~~< 1.0 ppm~~	
~~(without copper)~~	~~< 2.0 ppm~~	
~~Silica~~	~~< 10 ppb~~	
pH Control Additive	(5)	

NOTES:

(1) Normal specifications are those which should be maintained during proper operation of secondary systems.

~~(2) Abnormal limits indicate a fault conditions exists and plant shutdown should be commenced if abnormal limits are exceeded for 4 hours.~~

~~(3) Eliminate copper ingress to the steam generators where practical.~~

(2) The condensate abnormal limit is 10-30ppb but the requirement for immediate shutdown does not apply even if the problem is not corrected within 100 hrs.

(3) For the condensate, sodium is monitored at each condenser hot well.

(4) Analysis not required for copper free systems.

(5) Limit is dependent upon pH.

2.0 PREREQUISITES

2.1 Pressurizer pressure and level control system instrumentation has been calibrated.

2.2 Support systems required for the operation of the pressurizer pressure and level control systems are operational.

2.3 Test equipment is available and calibrated.

3.0 TEST METHOD

3.1 Simulate a decreasing pressurizer pressure and observe heater response and alarm and interlock setpoints.

3.2 Simulate an increasing pressurizer pressure and observe heater and spray valve response and alarm and interlock setpoints.

3.3 Simulate a low level error in the pressurizer and observe proper charging pump response and alarm and interlock setpoints.

3.4 Simulate a high level error in the pressurizer and observe proper charging pump response and alarm and interlock setpoints.

3.5 Simulate a low pressurizer level and observe operation of the letdown ~~isolation~~ CONTROL valves.

3.6 Simulate a low-low pressurizer level and observe heater response and alarm and interlock setpoints.

4.0 DATA REQUIRED

4.1 Response of pressurizer heaters to simulated pressure and level signals.

4.2 Response of spray valves to simulated pressurizer pressure.

4.3 Response of charging pumps to simulated pressurizer level.

4.4 Response of letdown CONTROL valves to simulated pressurizer level.

4.5 Response of letdown ~~isolation~~ CONTROL valves to simulated low pressurizer level.

4.6 Values of parameters at which alarms and interlocks occur.

LIMITING CONDITION FOR OPERATION

3.4.1.3 At least two of the loop(s)/train(s) listed below shall be OPERABLE and at least one Reactor Coolant and/or shutdown cooling loop shall be in operation.*

a. Reactor Coolant Loop #A and its associated steam generator and at least one associated Reactor Coolant pump,**

b. Reactor Coolant Loop #B and its associated steam generator and at least one associated Reactor Coolant pump,**

c. Shutdown Cooling Train #1,

d. Shutdown Cooling Train #2.

APPLICABILITY: MODE 4 ($T_{Cold} \leq 350°F$)

ACTION:

a. With less than the above required Reactor Coolant and/or shutdown cooling loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible; if the remaining OPERABLE loop is a shutdown cooling loop, be in COLD SHUTDOWN within 24 hours.

b. With no Reactor Coolant or shutdown cooling loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required coolant loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.3.1 The required Reactor Coolant pump(s), if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

* All Reactor Coolant pumps and shutdown cooling pumps may be de-energized for up to 1 hour provided (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

** A Reactor Coolant pump shall not be started with one or more of the Reactor Coolant System cold leg temperatures less than or equal to (a) (***)°F during cooldown or (b) (***)°F during heatup unless the secondary water temperature of each steam generator is less than ~~150°F~~ 100°F above each of the Reactor Coolant System cold leg temperatures.

*** See Applicant's SAR.

COLD SHUTDOWN - LOOPS FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.1 At least one shutdown cooling loop shall be OPERABLE and in operation*, and either:

a. One additional shutdown cooling loop shall be OPERABLE#, or

b. The secondary side water level of at least two steam generators shall be greater than 25% on the wide range level indicator.

APPLICABILITY: MODE 5 with Reactor Coolant loops filled##.

ACTION:

a. With less than the above required loops OPERABLE or with less than the required steam generator level, immediately initiate corrective action to return the required loops to OPERABLE status or to restore the required level as soon as possible.

b. With no shutdown cooling loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required shutdown cooling loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4.1.1 The secondary side water level of at least two steam generators when required shall be determined to be within limits at least once per 12 hours.

4.4.1.4.1.2 At least one shutdown cooling loop shall be determined to be in operation and circulating reactor coolant at a flowrate greater than or equal to 4000 gpm at least once per 12 hours.

\# One shutdown cooling loop may be inoperable for up to 2 hours for surveillance testing provided the other shutdown cooling loop is OPERABLE and in operation.

\## A reactor Coolant pump shall not be started with one or more of the Reactor Coolant System cold leg temperatures less than or equal to (**)°F during cooldown or (**)°F during heatup unless the secondary water temperature (saturation temperature corresponding to the steam generator pressure) of each steam generator is less than 100°F above each of the Reactor Coolant System cold leg temperatures.

* The shutdown cooling pump may be de-energized for up to 1 hour provided 1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

** See Applicant's SAR.

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with both reactor coolant loops and associated reactor coolant pumps in operation, and maintain DNBR above 1.22 during all normal operations and anticipated transients. In MODES 1 and 2 with one reactor coolant loop not in operation, this specification requires that the plant be in at least HOT STANDBY within 1 hour.

In MODE 3, a single reactor coolant loop provides sufficient heat removal capability for removing decay heat; however, single failure considerations require that two loops be OPERABLE.

In MODE 4, and in MODE 5 with reactor coolant loops filled, a single reactor coolant loop or shutdown cooling loop provides sufficient heat removal capability for removing decay heat; but single failure considerations required that at least two loops (either shutdown cooling or RCS) be OPERABLE. Thus, if the reactor coolant loops are not OPERABLE, this specification requires that two shutdown cooling loops be OPERABLE.

In MODE 5 with reactor coolant loops not filled, a single shutdown cooling loop provides sufficient heat removal capability for removing decay heat; but single failure considerations, and the unavailability of the steam generators as a heat removing component, require that at least two shutdown cooling loops be OPERABLE.

The operation of one Reactor Coolant Pump or one shutdown cooling pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. A flowrate of at least 4000 gpm will circulate one equivalent reactor coolant system volume of 12,097 cubic feet in approximately 23 minutes. The reactivity change rate associated with boron reductions will, therefore, be within the capability of operator recognition and control.

The restrictions on starting a Reactor Coolant Pump during MODES 4 and 5 with one or more RCS cold leg less than or equal to * °F during cooldown or * °F during heatup are provided to prevent RCS pressure transients, caused by energy additions from the secondary system, which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by restricting starting of the RCPs to when the secondary water temperature of each steam generator is less than ~~150°F~~ 100°F above each of the RCS cold leg temperatures.

* See Applicant's SAR.

The limitations imposed on the pressurizer heatup and cooldown rates and spray water temperature differential are provided to assure that the pressurizer is operated within the design criteria assumed for the fatigue analysis performed in accordance with the ASME Code requirements.

The OPERABILITY of two shutdown cooling suction line relief valves, one located in each shutdown cooling suction line, while maintaining the limitations imposed on the RCS heatup and cooldown rates, ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to * °F during cooldown or * °F during heatup. Either one of the two SCS suction line relief valves provide adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either (1) the start of an idle RCP with the secondary water temperature of the steam generator less than or equal to 150°F above the RCS cold leg temperatures or (2) the inadvertent safety injection actuation with two HPSI pumps injecting into a water solid RCS with full charging capacity and with letdown isolated. These events are the most limiting energy and mass addition transients, respectively, when the RCS is at low temperatures.

100°F

3/4.4.9 STRUCTURAL INTEGRITY

The inspection programs for the safety-related ASME Code Class 1, 2 and 3 components ensure that the structural integrity of these components will be maintained at an acceptable level throughout the life of the plant. To the ble, the inspection program for these components is in compliance with Section XI of the ASME Boiler and Pressure Vessel Code.

* See Applicant's SAR.

Regulatory Guide 1.68.2, Revision 1
INITIAL STARTUP TEST PROGRAM TO DEMONSTRATE REMOTE
SHUTDOWN CAPABILITY FOR WATER-COOLED NUCLEAR POWER PLANTS

SUMMARY

Regulatory Guide 1.68.2, Rev. 1 describes an initial startup test program acceptable to the NRC staff for demonstrating hot standby capability and the potential for cold shutdown from outside the control room.

POSITION

The CESSAR initial startup test program fully meets the intent of Regulatory Guide 1.68.2.