ENCLOSURE III

RESPONSES TO PLANT SPECIFIC QUESTIONS ON DEPRESSURIZATION AND DECAY HEAT REMOVAL
(QUESTIONS 6a, 6b, 12, 13a, 13c and 13d)

SAN ONOFRE NUCLEAR GENERATING STATION
UNITS 2 AND 3

JUNE 1983

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SAN ONOFRE NUCLEAR GENERATING STATION

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EXECUTIVE SUMMARY

RESPONSES TO PLANT SPECIFIC QUESTIONS ON DEPRESSURIZATION AND DECAY HEAT REMOVAL

SAN ONOFRE UNITS 2 AND 3

The NRC staff has requested information on the capability of Combustion Engineering plants without PORVs for rapid depressurization and decay heat removal. Because of the broad range of concerns and the substantial effort required to prepare responses to the fourteen NRC questions, SCE and other affected utilities have developed responses to these questions under the sponsorship of the Combustion Engineering Owners Group (CEOG). Responses to questions 6a, 6b, 12, 13a, 13c, and 13d, because of their plant specific nature were addressed separate from the CEOG effort by SCE. This report addresses these plant specific questions and the following is a summary of these responses.

Question 6a - Describe the proposed low pressure system to supplement the Auxilary Feedwater System and its use, including water supplies (and their capacity), flow paths, pumps, power supplies to components, control equipment and procedures.

Response Summary

The proposed configuration involves use of the condensate pumps in conjunction with depressurization of the steam generators via an Atmospheric Dump Valve This line up requires only a minimal change in the normal feed and condensate line up. Basically, the condensate system is lined up to directly feed a steam generator with the main feed pumps bypassed and isolated.

The alignment of the condensate pumps to the steam generator can be completed form the control room with the exception of opening the two main feed pump bypass valves which can be accomplished by local manual operator action. All other operations, including control of steam generator pressure and water level, are completed following existing SONGS 2 and 3 procedures.

Question 6b - Describe the water chemistry interface requirements for the proposed low pressure system in order to assure its use will not cause unacceptable steam generator integrity degradation or heat transfer capability.

Response Summary

Sufficient condensate grade make up is available and in the unlikely event this becomes depleted, a large quantity of service grade water may be used to fill the steam generators. This is relatively benign water and as such, the potential for steam generator integrity degradation or loss of heat transfer capability are not expected to be causes for concern during the time frame required to reach shutdown cooling entry conditions. Thus, there are no water chemistry interface requirements for this configuration.

Question 12 - If the results of the risk analysis (Question 11) yield appreciable gain in safety, what could be the cost of installing PORVs?

Response Summary

The results of the risk analysis yeilded a negligible safety impact due to the addition of PORVs, however, a cost estimate was completed taking into account the costs associated with engineering design, installation of the PORV piping and instumentation, and operational analysis of an installed PORV system. The total cost to complete this modification to both SONGS Units 2 and 3 is estimated to be approximately $4.6 million (labor and materials). In addition, replacement power costs will be at least $2 million per plant and may be as high as $35 million per plant.

Question 13 (a,c, & d) - One of the main reasons CE has concluded that PORVs are not needed for emergency decay heat removal is that alternative water sources could be made available to the steam generators for decay heat removal purposes. An inherent assumption in this approach is that steam generator integrity will be maintained throughout the life of the plant. One method of assuring combined steam generator integrity is by inservice inspection and plugging of tubes excessively degraded. Please discuss the following:

a. What is the minimum allowable wall thinning that could exist in the steam generator tubes without plugging?

c. Given a steam generator with the maximum allowed tube thinning and degradation, confirm that those tubes will maintain their integrity by demonstrating they have been analyzed and shown to

remain intact for all design basis loadings used for the steam generator design including seismic loads.

d. Describe the analytical and experimental justification for establishing a minimum accpetable steam generator tube wall thickness for the CE System 80 steam generators in accordance with guidelines in Regulatory Guide 1.121. "Bases for Plugging Degraded PWR Steam Generator Tubes". The justification should include the analyses to calculate the hydraulically induced loading on the steam generator and the thermal response of its tubes and shell to an assumed LOCA, MSLB and an FWLB.

<u>Response Summary</u>

The CEFLASH computer code was used to analyze the response of the SONGS 2 and 3 steam generators to all design basis loads. The results of this analysis showed:

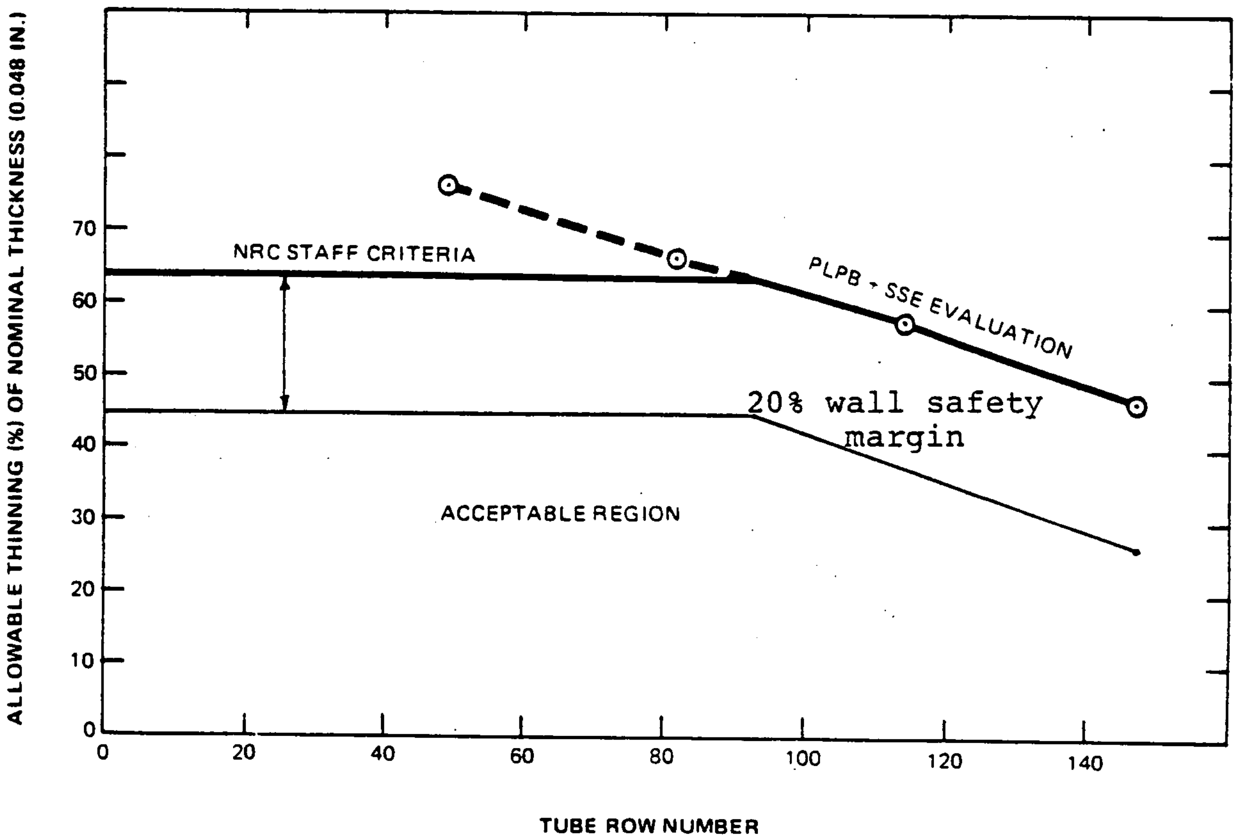
a. Tubes with detected acceptable defects will not be stressed during the full range of normal reactor operation beyond the elastic range of tube material.

b. The factor of safety against failure by bursting under normal operating conditions is not less than three at any tube location where defects have been detected.

c. Crack-type defects that could lead to tube rupture either during normal operation or under postulated accident conditions are not acceptable.

When evaluating against the above criteria for San Onofre steam generator geometry and operating conditions, an allowable tube thinning as shown in the upper curve of Figure 1 is permissable. However, the technical specification is conservatively set at a 20% lower tube wall thinning value.

In summary, the design basis can be met for a design base earthquake in conjunction with either a primary loop pipe break (PLPB) or a main steam line break (MSLB), with appreciable tube wall thinning. The actual allowable thinning being related to tube row can be as high as 64% wall penetration for rows 1-91 and decreasing linearly to 47% wall penetration at row 147. If it is determined during surveillance testing that tube wall thinning may approach 20% of the value shown in Figure 1 during the next operating cycle, the tubes will be removed from service by plugging to ensure that the thinning criteria will not be violated.



SAN ONOFRE
NUCLEAR GENERATING STATION
Units 2 & 3

TUBE WALL THINNING
ACCEPTANCE CRITERIA

RESPONSES TO PLANT SPECIFIC QUESTIONS ON DEPRESSURIZATION AND DECAY HEAT REMOVAL

SAN ONOFRE UNITS 2 AND 3

The NRC staff has requested information on the capability of Combustion Engineering plants without PORVs for rapid depressurization and decay heat removal(1). Because of the broad range of concerns and the substantial effort required to prepare responses to the fourteen NRC questions, SCE and other affected utilities have developed responses to these questions under the sponsorship of the Combustion Engineering Owners Group (CEOG). Responses to questions 6a, 6b, 12, 13a, 13c, and 13d, because of their plant specific nature were addressed separate from the CEOG effort by SCE. This report addresses these plant specific questions and the following is a summary of these responses. Combustion Engineering Reports CEN-239 and Supplement 1 to CEN-239 in conjunction with the responses contained herein constitute a complete response to the NRC Questions.

Question 6a

Describe the proposed low pressure system to supplement the AFWS and its use, including water supplies (and their capacity), flow paths, pumps, power supplies to components, control equipment and procedures.

1) Letter R. L. Tedesco, Assistant Director of Licensing, NRC, to Mr. R. Dietch, Vice President, Southern California Edison Company, "Depressurization and Decay Heat Removal for San Onofre 2 and 3", March 27, 1982.

Response to Question 6a

In the unlikely event of a loss of the safety grade three train AFWS at SONGS 2 & 3, there are several sources of low pressure water available for use as makeup to the steam generators (see Figure 1). The preferred source would be the condensate system of the affected unit. The four condensate pumps are relatively high head (500-600 PSIG) and can use water from multiple sources (e.g., hotwell, condensate storage tanks, demineralizer make up) and through use of the feed pump bypass line, deliver make-up directly to each steam generator. Each condensate pump has a capacity of 7750 GPM. The normal condensate make-up sources (hotwell and condensate storage tanks) contain 746,600 gallons. If additional make up is required, there are several alternate means to refill the condensate storage tanks. Make up grade water is available from the condensate system of the companion unit through the condensate cross tie line and from the onsite demineralizer system. As a back up to these sources, service grade water is available from the fire protection system of Units 2 & 3 as well as Unit 1. The fire protection reserve for Units 2 & 3 is 750,000 gallons and Unit 1 has a 3 million gallon reservoir.* This means that there is over 5 million gallons of on-site condensate make up water for the SONGS 2 & 3 steam generators to supplement the AFWS. There is also a virtually unlimited supply of potable water available from the domestic water system (Tri-Cities Municipal Water District).

If for some reason the four condensate pumps in the affected unit are unavailable, the condensate transfer pump may be used to deliver make up to the steam generators. The condensate transfer pump is rated at 1000 GPM at 65 PSI. The same water sources previously described for the condensate pump are available for

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* The Unit 1 reservoir is included for completness purposes only. There is an adequate supply of on-site make up water without requiring use of the Unit 1 reservoir.

the condensate transfer pump. In this case both the condensate and feedpumps are bypassed. The condensate transfer pump can take a suction from the condensate storage tank and deliver make up directly to the steam generators.

The Appendix to Question 6a's response contains a detailed procedure guideline for setting up the condensate system to use the above sources of water and pumps. Table 1 lists the available sources and quantity of water including pump power supplies, power requirements and flow rates.

In summary, the AFWS at SONGS 2 & 3 can be supplemented by the condensate system for steam generator make up in the following ways:

1) The condensate system remains in its normal power operation valve lineup (i.e., condensate pumps lined up to the hotwell and the hotwells being supplied with water from the condensate storage tank as required to maintain hotwell level). The main feed pump discharge valves are shut and the main feed pump bypass valves are open.

2) Same pump and valve line up as 1 above ,but if required, the condensate storage tank can be replenished from the following sources: onsite demineralizer, companion unit condensate system, fire protection system for Units 2 and 3 or Unit 1, and domestic service water via the fire protection system.

3) If the affected units condensate pumps are unavailable, the condensate transfer pump can be used to fill the steam generator. The pre-startup steam generator fill procedure can be used in this instance. The condensate transfer pump is lined up to the condensate storage tank, the condensate and main feed pump discharge valves

are closed, and the steam generator fill valve downstream of the condensate pump discharge valves is opened. The same alternate sources of condensate make up to the condensate storage tanks as used in 2 above can also be used if required.

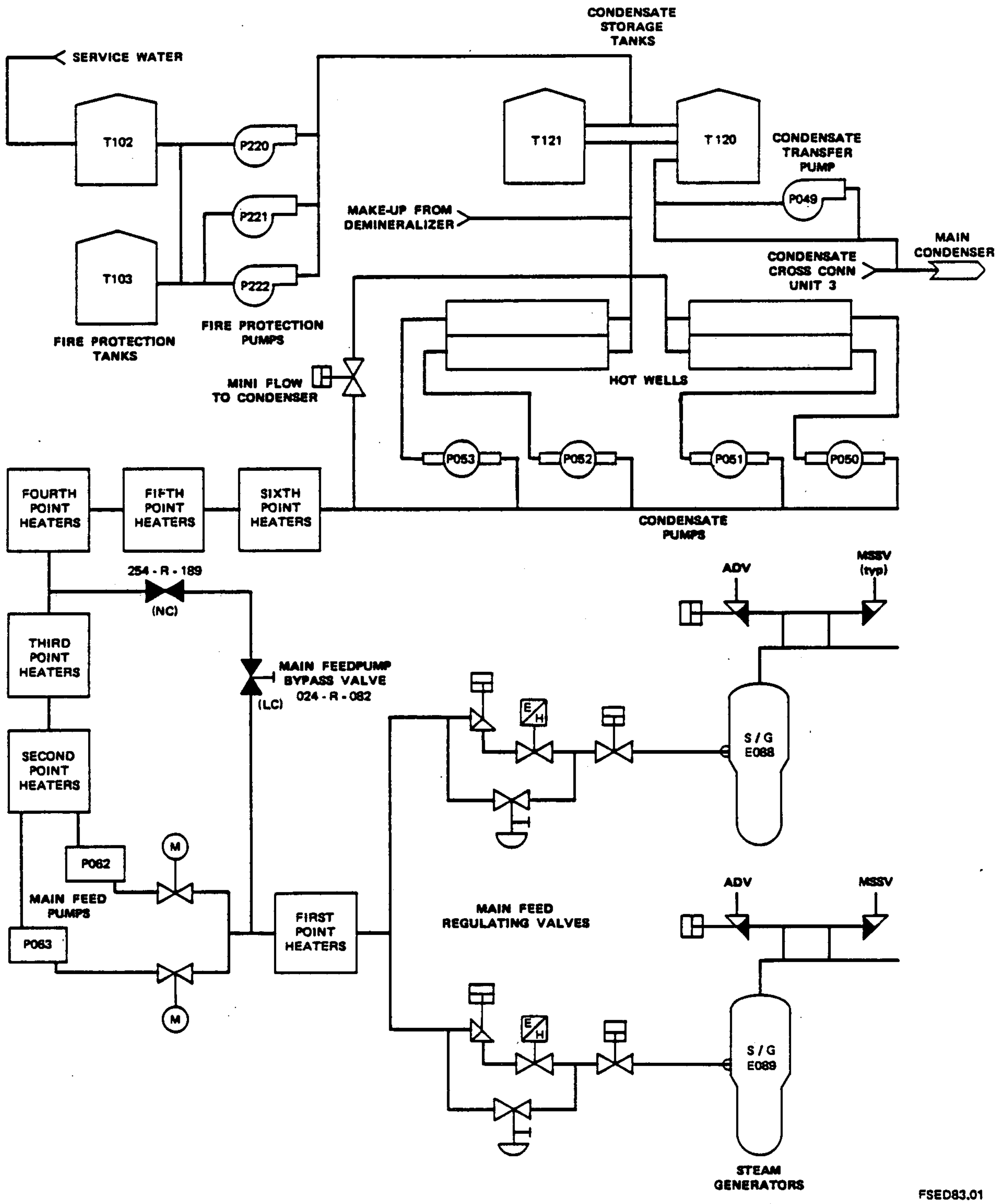

Figure 1

SIMPLIFIED SCHEMATIC OF SONGS 2 AND 3
ALTERNATE SECONDARY HEAT REMOVAL CONFIGURATION

TABLE 1

SOURCES OF WATER AND PUMP CAPABILITIES TO SUPPLEMENT SONGS 2&3 AFWS

SYSTEM	WATER SOURCE	QUANTITY (GAL)	PUMP	POWER SUPPLY	RATING (HP)	FLOW RATE (GPM)	HEAD (PSI)
Condensate (Units 2 or 3)	T-120*	500,000	P-049	2BF	60	1000	65
	T-121	150,000					
	Hotwell	96,600	P-050	2A07	3000	7750	500-600
			P-051	"	"	"	"
			P-052	"	"	"	"
			P-053	"	"	"	"
Fire Protection (Units 2 & 3)	T-102	375,000	P-221	2B14	200	1500	125
	T-103	375,000	P-222	2B12	200	1500	125
			P-220	Diesel		2500	125
Fire Protection (Unit 1)	Reservoir	3,000,000	G11	480 V Switch-gear #1	125	1000	275
			G11S	480 V Switch-gear #2	125	1000	275

* Make up to condensate storage tanks is available from the domestic water system (Tri-Cities Municipal Water District) through the demineralizer or fire service water systems. This is virtually an unlimited source. Water can also be trucked in from one of the 14 other Edison sites.

APPENDIX TO QUESTION 6a RESPONSE: EMERGENCY GUIDELINE FOR ALTERNATE SECONDARY HEAT REMOVAL

In the unlikely event of a loss of both main and auxilary feedwater at SONGS Units 2 or 3, there exists an alternate means to remove decay heat from the core using the steam generators. This alternate method involves only a minimal change in the normal main feed valve lineup in conjunction with depressurization of a steam generator by means of the atmospheric dump valve (ADV). Basically, the condensate system is lined up to directly feed a steam generator with the main feed pumps bypassed and isolated. Since the condensate pumps are lower head than the main feed pumps, the steam generator must be depressurized to below the 500 psig shutoff head of the condensate pump.

The alignment of the condensate pumps to the steam generator can be completed from the control room with the exception of opening the two main feed pump bypass valves which can be accomplished by local manual operator action. All other operations, including control of steam generator pressure and water level, are completed following existing SONGS 2 and 3 procedures. Refer to Figure 1 for a schematic of the alternate secondary heat removal configuration.

The following is a detailed outline of the steps that may be followed for a loss of main and auxilary feedwater.

1. Verify that offsite power is available to the condensate pump motors.

2. Manually open the main feed pump bypass valves 254-R-189 and 024-A-082. The latter valve is normally locked shut and requires a key.

3. From the control room, close the main feed pump discharge valves.

4. Ensure that sufficient make-up is available in the hotwell to run a condensate pump using existing condensate system procedures.

5. Establish a flow path to the steam generator by opening the following valves from the control room: main feed isolation valve, and either the main feed bypass regulating valve or the main feed regulating valve and associated block valve.

6. Reduce steam generator pressure to below the shutoff head of the condensate pump (500 psig) by opening an ADV.

7. Start a condensate pump for which suction, discharge path and power is available.

8. Control steam generator level by throttling either the main feed regulating valve or the bypass valve (whichever is being used for a flow path).

9. Continue to monitor steam generator level, hotwell level and steam generator pressure. Repeat applicable portions of this guideline to maintain system parameters within limits. If the CSTs become depleted, make-up is available from the demineralizer, companion unit condensate system or, as a last resort, site fire protection system water. These alternate sources of water can be obtained following existing SONGS 2 and 3 procedures.

10. Continue to feed the steam generator in this manner following prescribed cooldown rates until shutdown cooling entry conditions are achieved. At this point follow the shutdown cooling procedure to complete plant shutdown.

Question 6b

Describe the water chemistry interface requirements for the proposed low pressure system in order to assure its use will not cause unacceptable steam generator integrity degradation or heat transfer capability.

Response to Question 6b

The potential risk of short term steam generator degradation must be addressed if alternate sources of secondary cooling water are to be considered a viable method for decay heat removal. Of the alternate sources of water discussed in the previous response to NRC question 6A, the limiting worst case water chemistry (to be utilized after all secondary condensate makeup is expended) is taken directly from the fire protection system without water treatment. The description of this water source is service grade water (or "potable water") which is a stored reserve for fire protection.

The potential risks of utilizing the alternate cooling water sources can lead to acceleration of existing corrosion mechanisms or include additional degradation mechanisms not associated with normal operation. The following discussion describes the potential hazards and estimates the rate of degradation from the use of the limiting water chemistry (service grade water) during the decay heat removal operations. This approach allows conservatism since the normal condensate makeup can provide approximately 746,600 gallons of secondary grade coolant prior to utilizing the service grade water.

The precise conditions of core decay heat removal rate may vary with time, however, it is reasonable to assume that the secondary side of the steam generator will be maintained at approximately 400 F maximum at normal operating pressure and at a much lower heat flux of approximately 1% of full power. During initial start of decay heat removal the temperature, pressure, and decay heat rate may be at much higher levels.

DISCUSSION

The ultimate source of the service grade water comes from the Tri City Water District through the Metropolitan Water District of San Clemente, California. The following typical water quality report was taken in November 1982.

	Milligrams Per Liter
Silicon, Si	9.4
Calcium, Ca	38.0
Sodium, Na	58.0
Carbonate, Co_3	-
Bicarbonate, HCO_3	93.0
Sulfate, SO_4	194.0
Chloride, Cl	62.0
Nitrate, NO_4	1.8
Flouride, Fl	1.9
TDS (Total Dissolved Solids)	347.0
Hardness	157.0
Alkalinity	76.0
Free CO_2	0.8
Boron	0.13
pH	8.27
Turbidity	0.07 NTU (Nephelometric Turbitity Units)
Temperature	16.3°C

From a corrosion standpoint, the above water chemistry represents the rather benign "tap" water analysis showing low concentrations of those key elements associated with accelerated corrosion, namely chlorides and sulfur. The influence of the above water chemistry on the steam generator shell and tubes are compared and analyzed to test results of similar materials and environments.

The secondary shell and head, made of low alloy steel or carbon steel (ASME SA-533, Grade A, Class 1 and ASME SA-508, Grade 70), have higher expected corrosion rates than the heat transfer surfaces of the inconel tubes.

It has been shown that when chloride concentration and oxygen concentration are increased in aqueous environments, the corrosion rates also increase(1). In addition, when corrosion rates are controlled by dissolved oxygen, the corrosion rate for a given oxygen concentration has a linear relationship to temperature. Tests indicate that the corrosion rate of similar carbon steels may triple for a temperature increase from room temperature to 320°F.

Within a range of about pH 4 to 10, the corrosion rate is independent of pH(1). This observation suggests pH is not a variable of interest within the specification limits for the service water.

Compositions of iron or steel within the usual commercial limits of carbon or low alloy steels have little practical effect on the corrosion rate of these steels in fresh water environments. Pitting and general corrosion rates for three steels in four

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(1) Corrosion and Corrosion Control, H. H. Uhlig, John Wiley and Sons, New York, 1967.

different aqueous environments were tested in the unpolluted Gatineau River water of Canada and the water of the Monongahela, Allegheny, and Mississippi Rivers(2). The maximum corrosion rate for any of the steels in the Gatineau River water was approximately 0.005 inches per year (ipy), and was 0.007 ipy in the Monongahela River (polluted with ferric sulfate from coal mining drainage). The corrosion rates were somewhat lower in the Allegheny and Mississippi Rivers. Based on the above discussion, the corrosion rates quoted for natural river water environments can be used as a conservative guide to corrosion from service grade water when adjusted for temperature effects. Therefore, the expected corrosion rates of 0.005 to 0.007 ipy may accelerate 3 fold to 0.015 to 0.021 ipy in the higher temperature environments during decay heat removal. Model boiler coupon tests(3) indicate the corrosion rate to be significantly lower. The model boiler tests were carried out with AISI 1018 plain carbon steel coupons using faulted water chemistry composed of acidified river water (with higher chloride level than the subject service grade water). The maximum penetration was 0.014 ipy.

The heat transfer surfaces in the SONGS 2 and 3 steam generators are made up of highly corrosion resistant Inconel 600 tubes (NiCrFe ASME SB-163). The design of the tubes incorporates a general corrosion allowance that should provide for reliable operation over the plant design life under normal conditions. However, experience with these tubes has shown that long term degradation occurs which is basically attributable to; 1) phosphate water treatment, 2) concentration build up over time, of aggressive species in crevices and crud build ups, and 3) secon

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(2) C. P. Larrabe, Corrosion, Volume 9, page 259, 1953.

(3) "Model Boiler Test Results," EPRI Contract RP-623-4, Combustion Engineering Report CE NSPD-196.

dary water chemistry transients. For SONGS 2 and 3, the bulk secondary water chemistry is controlled by an all volatile treatment which should preclude many of the long term service problems with the inconel tubes experienced in phosphate treated plants. In the case of emergency short term use of the transient water chemistries described above, the inconel tube surfaces should not exhibit increased degradation from denting, because rapid concentration build up of corrosion products, a precursor to denting, is a somewhat longer time dependent phenomena, requiring bulk boiling to occur. In addition, the service grade water is neither highly caustic, which could lead to caustic stress corrosion cracking (SCC) or intergranular attack (IGA), nor is it highly acidic which could cause acidic stress corrosion cracking and also does not contain an appreciable amount of Cu or other metal ions which has been known to accelerate pitting of inconel.

Fouling of the heat transfer surfaces should not present a problem in the relatively short time required to get to shutdown cooling entry conditions. Tests [3], and service experience [4] have shown no significant performance degradation exhibited from biological fouling for operating periods on the order of 1 year. In addition, service grade water should contain less microbiology than the river or seawater used in the referenced test programs.

CONCLUSION

General and pitting corrosion rates of steam generator surfaces are not expected to be a limiting short term phenomen since the worst case service grade water chemistry is relatively benign.

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(4) Pipe, D. H., et. al., "Studies in Biological Induced Corrosion of Heat Exchanger Systems at Savannah River Plant," Corrosion 82, March 1982.

The maximum expected rate of corrosion for the carbon and low alloy steel surfaces is on the order of 0.015 to 0.021 ipy. For the Inconel 600 tubes, any appreciable change of corrosion rate is not expected. This implies that there is reasonable assurance that steam generator degradation, i.e., primary to secondary penetration will not occur in the time frame required to reach shutdown cooling entry conditions.

Question 12

If the results of the risk analysis (Question 11) yield appreciable gain in safety, what could be the cost in- stalling PORVs?

Response to Question 12

The risk analysis indicate that installation of PORVs has a negligible safety impact, but a cost estimate was completed to ascertain the expected installation costs.

The PORVs could be used as a backup depressurization and decay heat removal system to be operated manually in the event that multiple failures preclude use of safety grade systems (e.g., auxiliary feedwater, auxiliary spray systems). The PORVs, if required, could be installed on an existing spare pressurizer nozzel and connected to the existing pressurizer quench tank. Figure 1 is a schematic of the design used for the SONGS 2 and 3 PORV cost estimate.

This design is similar to existing PORV systems in operating plants. There are no existing requirements for PORV systems designed for decay heat removal purposes, but it is felt that the assumed design is sufficient for cost estimating purposes.

In estimating the total cost of installing the PORVs, several factors must be considered: e.g., engineering design; installation (including potential replacement power costs); re-analysis of ECCS response, core thermal margins, plant transient response; changes to technical specifications; changes to operating procedures; and procurement costs.

The SONGS 2 and 3 PORV cost estimate was prepared using the following bases and assumptions:

1) It is a safety grade (i.e., electrical class 1E) and seismic category 1 system.

2) It will not be single failure proof (both trains are required for successful operation).

3) The PORV and block valves are both normally closed. They will be opened electrically by manual operator action when required.

4) The PORVs are sized for feed and bleed purposes only (i.e., the valves are not designed to mitigate ATWS or PTS events).

5) Minimal interference exists for installing required piping between the pressurizer and quench tank.

6) A qualified PORV exists and no additional valve testing is required.

7) An existing pressurizer nozzle will be available for PORV connection.

8) Essential power is available for the system (i.e., spare circuit breaker and existing cable trays can be used for cable routing).

9) Space is available in the control room to mount the PORV switches in existing panels.

10) Containment penetrations are available for routing of cables.

For the purpose of estimating the total cost of PORV installation all the potential cost factors were put into three categories: 1) Engineering Design, 2) Installation, and 3) Operational Analysis. The latter category includes thermal hydraulic response and changes to operating procedures and technical specifications. Table 1 contains a summary of the estimated costs for each of these categories. Cost estimates for specific

tasks were obtained from experience on similar projects (e.g., installation costs were from site personnel experienced in electrical and piping installation). The total estimated cost to install PORVs at SONGS 2 and 3 is approximately 4.6 million dollars excluding replacement power costs.

Engineering design of the PORV system involves analysis to determine the optimum size of the PORV taking into account HPSI flow and required heat rejection rate for the system. Other design cost considerations include piping and support analysis to ensure the system can withstand required operational, seismic and high energy line break loads; physical and electrical design of the system hardware; drafting associated with electrical and mechanical components; and preparation of required documentation such as; procurement specification, system design description, and final design report. The total estimated engineering design cost is $775,000 for one unit. The basic PORV design will be identical for both units, but due to differences in physical layout of cable runs and piping, there will be additional engineering costs associated with the second unit. The estimated engineering design cost for the second unit is approximately $500,000.

The installation costs associated with the PORV system include procurement of the required hardware, receiving inspection of the components (e.g., valves, piping, sensors, supports), labor costs to install the electrical and mechanical components, quality control inspections of the finished product, and pre-operational testing (e.g., flushing, hydro, vibration and system component operational tests). The total estimated installation costs are $1,515,000 per plant. The minimum elapsed time required to complete the installation of the PORV system is estimated to be approximately six weeks. This includes tapping into the primary system at the pressurizer spare nozzle piping and the line leading to the quench tank, welding the piping and valves in place, installing and setting all required system supports (e.g.,

snubbers, restraints), quality control inspections on all components, and system testing.

The installation estimate does not include potential replacement power costs. If the system is installed during an outage scheduled specifically for this design change, replacement power costs could be as high as $35 million dollars per unit (i.e., approxmiately $800,000 per day per plant). If completed during a scheduled outage, the replacement power costs would be based on the additional time needed to perform all the required tasks beyond the originally scheduled outage length. Assuming that all hardware work could be completed "off the critical path," it is expected that at least two to three days would be required for system testing after all other work in the plant had been completed. Thus replacement power costs are estimated to be a minimum of $2 million dollars and could conceivably be as high as $35 million per unit for the initial installation.

Operational costs associated with the PORV system include preparation of documentation to update the FSAR, plant procedures (e.g., surveillance, testing, maintenance) and technical specifications. Operator training in use of the PORV system will also be required. Additional plant specific analysis must be performed to determine the response of the emergency make-up systems and evaluate the capability of the PORV to perform its intended function (rapid depressurization and decay heat removal). In addition, the effects of potential negative safety impacts such as inadvertent actuation and operator errors during test and maintenance must be evaluated. The estimated cost to perform these tasks, including computer charges, is estimated to be $290,000.

Thus the total costs for both plants is estimated to be $4.6 million, exclusive of replacement power costs.

Other costs that must be considered, at least in a qualitative manner, are the increase in plant unavailability due to maintenance and testing of the PORVs and the increased man REM exposure to personnel due to installation and maintenance activities. In addition, there will be administrative costs associated with the system. Lastly, as with any engineering cost estimate, even when a contingency has been included in the estimate, the final cost can be substantially higher due to design complications which become apparent during design, installation or testing of the system.

In summary, the potential cost factors associated with implementing a PORV system at SONGS 2 and 3 consists of engineering design, installation and operational analysis. The total cost to complete this modification to <u>both</u> SONGS Units 2 and 3 is estimated to be approximately $4.6 million (labor and materials). In addition, replacement power costs will be at least two million dollars per plant and may be as high as $35 million per plant.

This cost estimate is based on the design shown in Figure 1 and is in 1983 dollars. The estimates are for costs associated with engineering design and services, procurement of hardware, and installation labor. It does not address factors such as the cost of money (i.e., finance charges), or costs associated with postponing other projects to complete the PORV installation.

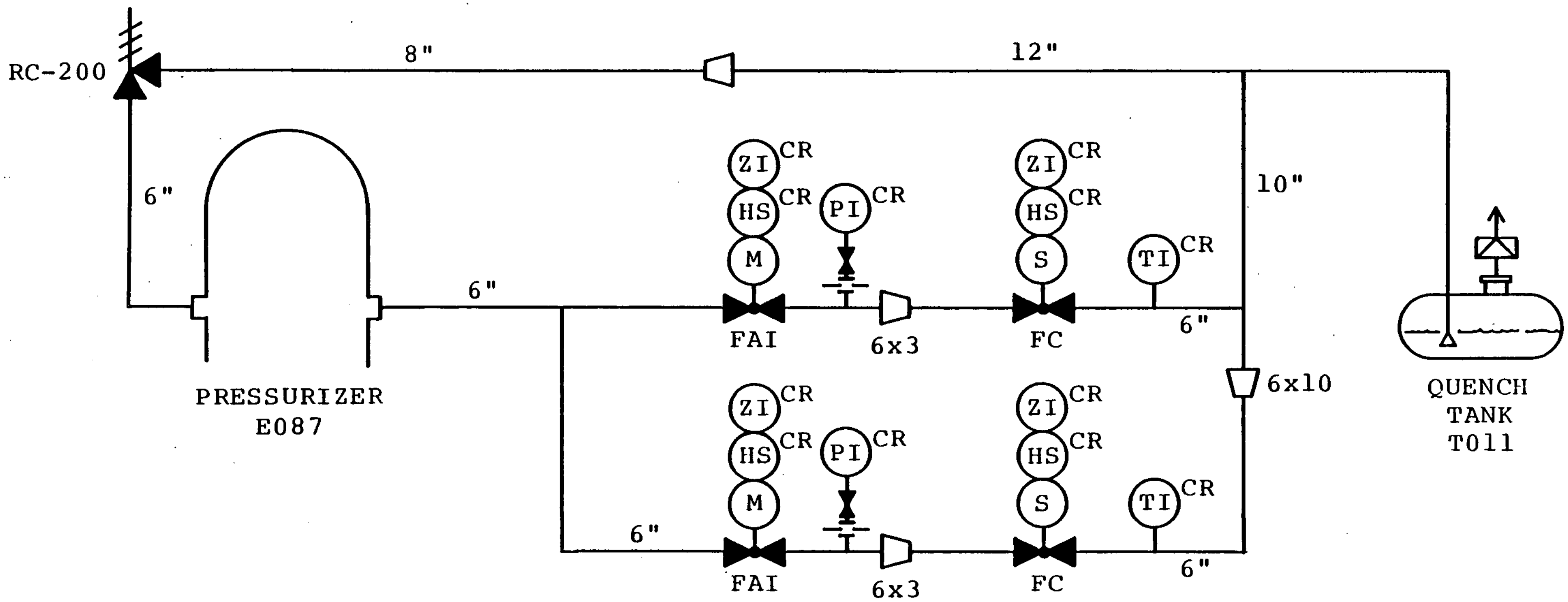


Figure 1

CONCEPTUAL SONGS 2 AND 3 PORV SYSTEM

FSDA83.02

TABLE 1

COST SUMMARY FOR
SONGS 2 AND 3 PORV INSTALLATION

TASK	LABOR COST	DIRECT COST(1)	SUB TOTAL
Engineering Design			
Unit 2	654,000	121,000	775,000
Unit 3	420,000	80,000	500,000(2)
Installation			
Unit 2	1,240,000	275,000	1,515,000
Unit 3	1,240,000	275,000	1,515,000
Operational Analysis			
Unit 2	225,000	65,000	290,000
Unit 3	-	-	-
		Total	$4,600,000(3)

1) Includes computer and hardware costs.

2) While Units 2 and 3 are similar in design, the physical layout of the plants with respect to piping and cable runs are different enough that much of the engineering design will be duplicated for each plant.

3) Excluding replacement power costs.

Question 13 (a,c, & d)

One of the main reasons CE has concluded that PORVs are not needed for emergency decay heat removal is that alternative water sources could be made available to the steam generators for decay heat removal purposes. An inherent assumption in this approach is that steam generator integrity will be maintained throughout the life of the plant. One method of assuring combined steam generator integrity is by inservice inspection and plugging of tubes excessively degraded. Please discuss the following:

a. What is the minimum allowable wall thinning that could exist in the steam generator tubes without plugging?

c. Given a steam generator with the maximum allowed tube thinning and degradation, confirm that those tubes will maintain their integrity by demonstrating they have been analyzed and shown to remain intact for all design basis loadings used for the steam generator design including seismic loads.

d. Describe the analytical and experimental justification for establishing a minimum accpetable steam generator tube wall thickness for the CE System 80 steam generators in accordance with guidelines in Regulatory Guide 1.121. "Bases for Plugging Degraded PWR Steam Generator Tubes". The justification should include the analyses to calculate the hydraulically induced loading on the steam generator and the thermal response of its tubes and shell to an assumed LOCA, MSLB and an FWLB.

Response to Questions 13a, 13c, & 13d

SONGS 2 and 3 steam generator tube integrity is assured through maintenance of proper water chemistry and an engineering design which minimizes the potential for excessive stresses leading to tube failures. The minimum allowable tube thinning has been determined through analysis of the stresses induced by design

basis loads and then calculating the wall thicknesses required to sustain these loads.

Tube Wall Thinning

The extent of tube-wall thinning that can be tolerated in the San Onofre steam generators without exceeding the allowable faulted condition stress limits is determined by dynamic structural analysis.

The purpose of this analysis is to determine the structural adequacy of the steam generator internals when the unit is subjected to a hypothetical large pipe break accident. Analyses are performed for both the combined primary loop pipe break (PLPB) plus design base earthquake (DBE) and the main steam line break (MSLB) plus DBE. A summary of the methods and codes used in the analyses are described below.

Primary Loop Pipe Break and Design Base Earthquake

The CEFLASH computer code is used to perform the hydraulic dynamic analysis of the primary loop during a PLPB event. The computer model is constructed in such a manner that response to variations of critical parameters can readily be determined. Among the parameters studied are pipe break opening time, break location, break opening area, and power level.

Dynamic structural response to the steam generator due to the impulsive loading associated with the escaping fluid during the PLPB event is determined. This loading is calculated using the STRUDL computer code. Displacement histories at various elevations in the steam generator are computed for guillotine breaks at the reactor vessel nozzle, steam generator hot leg nozzle and steam generator cold leg nozzle.

The rarefaction wave, associated with primary fluid rushing out of the tubes during a hypothesized PLPB event, loads individual tubes as though they were frames being loaded in-plane. Since the tube geometrics and support arrangement vary from one tube row to another, it is necessary to evaluate four tube/tube support geometries for the dynamic loadings from the CEFLASH results. Each load case represents a "family" of the tube rows (i.e., those with one, three, five and seven effective vertical support grids). Using the results of these evaluations, it is possible to develop stresses as a function of the tube row. Tube stresses are calculated for the impulsive PLPB loading by imposing the displacment histories on the single tube row model. Stresses caused by the DBE and pressure are also calculated.

Tube stresses resulting from these four loadings are superimposed in a conservative manner (combined in an absolute summation basis) and compared to appropriate allowables. Assuming that margins exist between the allowable stresses and the calculated stresses, the permissible amount of tube wall thinning or degradation is then calculated.

Main Steam Line Break and Design Base Earthquake

The CEFLASH computer code is used to perform the hydraulic dynamic analysis of the secondary loop during a postulated MSLB accident. The effects of cross-flow through the tube bundle and across the steam separator deck are of primary concern during MSLB. Similar parametric studies to those performed for the LOCA analysis are conducted for MSLB.

Displacement histories due to the impulsive loading of the secondary fluid escaping from the broken pipe are calculated for various elevations in the unit. This analysis is again accomplished with the use of the STRUDL computer code.

The stresses in tubes resulting from cross-flow through the tube bundle depend on how individual tubes interact with one another. To determine these stresses a lumped parameter model of the entire bundle is constructed with elements simulating the vertical strips and appropriate boundary conditions representing other tube supports. Tube stresses are then calculated for the loads from the CEFLASH results by employing the ANSYS computer code.

As was the case for the Primary Loop Pipe Break loading, tube stresses are calculated for MSLB dynamic response by imposing the displacement histories from the STRUDL results on the ANSYS model. Stresses caused by the DBE loading and pressure are also calculated.

Summary of Results

The results from the Main Steam Line Break and Design Base Earthquake analysis were very favorable. The maximum stress of 22.4 ksi occurred at tube row 25 due to the fact that it is the stiffest tube row encountering a vertical tube support grid assembly. This result was noncontrolling for any tube row.

The results from the Primary Loop Pipe Break and Design Base Earthquake analysis were favorable. The maximum stresses for each "family" of tube rows are tabulated below:

Tube Row Evaluated	"Family" Includes Rows	No. of Vertical Support Grids	Combined Stress Intensity-ksi
49	25 - 49	1	17.2
82	50 - 82	3	23.7
114	83 - 114	5	29.9
147	115 - 147	7	38.2

As the horizontal tube spans become longer (i.e., higher number rows with larger radius of curvature), the loads and hence stresses, become greater in spite of the increased number of tube supports. These results were found to be controlling with regard to allowable tube thinning for tube rows 92 through 147. Figure 1 shows the curve for acceptable tube wall degration using absolute NRC criteria in addition to a curve utilizing a 20% safety factor to account for flaw detectability and degradation between inspections.

In addition to the above analyses, the following criteria must be met in determining allowable tube thinning:

A. Tubes with detected acceptable defects will not be stressed during the full range of normal reactor operation beyond the elastic range of tube material.

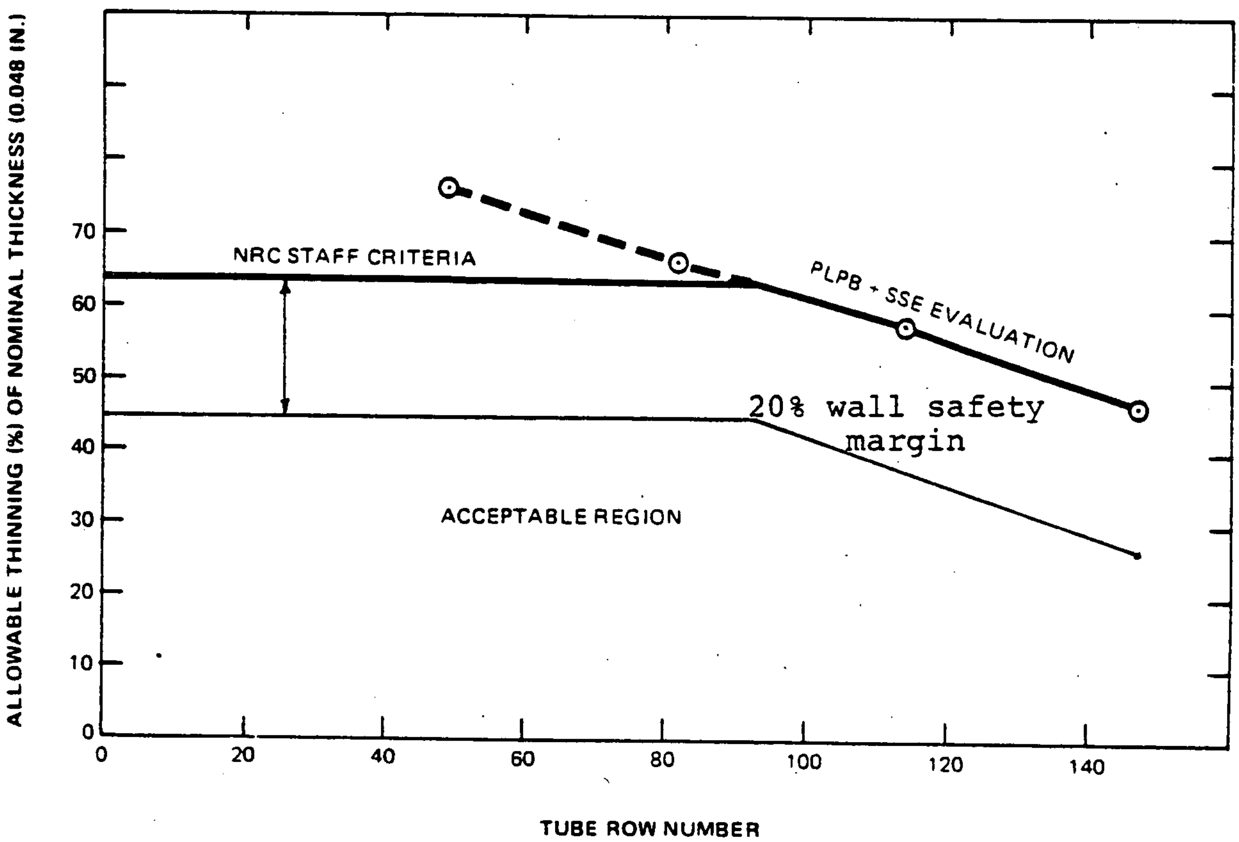
B. The factor of safety against failure by bursting under normal operating conditions is not less than three at any tube location where defects have been detected.

C. Crack-type defects that could lead to tube rupture either during normal operation or under postulated accident conditions are not acceptable.

When evaluating against the above criteria for San Onofre steam generator geometry and operating conditions, an allowable tube thinning as shown in the upper curve of Figure 1 is permissable. However, the technical specification is conservatively set at 20% lower tube wall thinning value.

In summary, the design basis can be met for a DBE in conjunction with either a PLPB or MSLB, with appreciable tube wall thinning. The actual allowable thinning being related to tube row can be as high as 64% wall penetration for rows 1-91 and decreasing

linearly to 47% wall penetration at row 147. As an additional safety factor, if it is determined during surveillance testing tube wall thinning may approach 20% of the value shown in Figure 1 prior to the next operation cycle, the tubes will be removed from service by plugging.



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