Docket File

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

July 10, 1992

Docket Nos. 50-272
and 50-311

LICENSEE: Public Service Electric and Gas Company

FACILITY: Salem Nuclear Generating Station, Units 1 and 2

SUBJECT: SUMMARY OF MEETING WITH PUBLIC SERVICE ELECTRIC AND GAS COMPANY (PSE&G) ON JULY 1, 1992, TO DISCUSS RESOLUTION OF THE OPEN EROSION/CORROSION ISSUES THAT WERE IDENTIFIED IN THE JUNE 25, 1992 MEETING

On July 1, 1992, PSE&G met with the NRC staff to provide information relative to open issues concerning the erosion/corrosion (E/C) program that had been identified in a meeting held on June 25, 1992.

Background: On June 25, 1992, a meeting was held with PSE&G to discuss their E/C program and the results of the implementation of that program at Salem 1 and 2. At the conclusion of that meeting, the following issues were identified as being open and additional information was required for complete resolution:

1. The bases for re-rating the design pressure of the portion of the feedwater system that is unisolable from the steam generator;

2. Detailed calculation of minimum wall thickness and the application of the 1.2 factor for maximum allowable stress, including assumptions and the bases for the assumptions;

3. Details of calculations of E/C rates; and

4. The assurance that the corrosion pattern in the feedwater piping is not in the form of a sine curve.

In addition, PSE&G was requested to provide information concerning the sizes of the areas exhibiting E/C and the results of the steam generator expander examinations and the corrective action to be taken.

Summary:

1. Re-rating of the portion of the feedwater system piping that is unisolable from the steam generators:

This piping was originally designed for the same pressure rating as the main feedwater system. The 1967 edition of ANSI/ASME B31-1, which is the design code of record for Salem, does not have any guidance for determining design pressures for piping connected to a pressure vessel.

DF01

However, the 1980 edition does, so PSE&G used those guidelines. Based on the application of those guidelines, the design pressure, as detailed in Enclosure 1, was determined to be 1335 psig. The staff agreed that this design was reasonable and had no further questions.

2. Detailed calculation of minimum wall thickness and the application of the 1.2 factor for maximum allowable stress:

   The calculation of minimum wall thickness uses the equations given in B31-1 (the code). Two factors that are used in this calculation are the design pressure and the allowable stress as given in code stress tables. In addition, the code allows the allowable stresses to be increased by a factor of 1.2 for pressure transients that occur for less that 1% of the time. The maximum pressure in the feedwater system is the added shutoff heads of the condensate pumps and the main feedwater pumps (1870 psig). PSE&G had reviewed the original design specifications for the feedwater system and found that 1870 psig was used as the maximum working pressure and that because this represented the maximum pressure transient, the allowable stress was multiplied by 1.2. Using these factors, the minimum wall thickness was calculated to be 0.717 inches for 14-inch main feedwater piping.

   A more typical way of determining the minimum wall thickness would be to determine the design pressure, which would be near the normal pressure (which in this case is about 1195 psig) and was calculated by PSE&G to be 1420 psig. The wall thickness would be determined and then the stresses calculated for the maximum pressure condition. Because the minimum wall thickness, as calculated using the higher pressure and higher stresses (by the 1.2 factor), enveloped the stresses using a derived design pressure, the staff agreed that this was a reasonable approach. PSE&G again reiterated their position that if the projected wall thickness was below the minimum wall thickness, the piping/component would be replaced. The details of PSE&G's calculations are given in Enclosure 1.

3. Details of calculations of E/C rates:

   In calculating the E/C rates, PSE&G used a method of averaging around the minimum point as measured by ultrasonic testing (UT). The method incorporated the results of inspections from three outages, if available. A method was also developed if the area had been inspected less than three times. In addition, an E/C rate was calculated that was based on the nominal wall thickness. The maximum rate that was calculated was used to project the wall thickness that would remain at the end of the operating cycle. The staff agreed that the E/C rates and projections were conservative. The details of PSE&G's E/C rate calculations are given in Enclosure 1.

4. Assurance that corrosion is not occurring in the form of a sine pattern:

   PSE&G stated that, based on discussions with other utilities and parties knowledgeable in the field of E/C, they did not identify a mechanism that would produce a sine pattern. To assure that the minimum is identified, the grid is extended two pipe diameters when a decreasing trend is noted at the grid boundary. To be considered satisfactory, the pipe wall must be 75 mils above the calculated minimum wall thickness. The staff found this to be acceptable.

5. The areas of E/C are given in Enclosure 2. The size of the areas that are exhibiting E/C are generally small (less than 10 square inches).

6. Results of the steam generator expander examinations.

   In Salem 1, cracking of three of the four expanders had been found. The decision had been made by PSE&G to replace all four expanders prior to restart.

   In Salem 2, an indication in one expander was noted, but it was determined by UT not to be a crack. No other indications were found in Salem 2.

   PSE&G is looking into the reasons Salem 1 experienced cracking and Salem 2 did not. The major area of investigation is the operation of the Auxiliary Feedwater System.

At the conclusion of the meeting, the staff had no further questions concerning the application of the design code, the corrective actions being taken and the basis for the calculation of minimum wall and E/C rates. Enclosure 3 is a list of attendees at the meeting.

/S/
Stephen M. Pindale, Acting Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Handout of Erosion/Corrosion Issues
2. Areas of Erosion/Corrosion
3. Meeting Attendees

cc w/enclosures:
See next page

DISTRIBUTION:

Docket File	JCalvo	RLobel, EDO	MHartzman	ACRS (10)
NRC & Local PDRs	CMiller	CHsu, 9715	JFair	EWenzinger, R-I
PDI-2 Reading	JStone	JMedoff	SPindale	JWhite, R-I
TMurley/FMiraglia	MO'Brien	DESmith	RMcBrearty	
JPartlow	OGC	BLeFave	RHermann	
SVarga	EJordan	KParczewski	DGamberoni	

OFFICE	PDI-2/LA	PDI-2/PM	PDI-2/D		
NAME	MO'BRIEN	SPINDALE:tlc	CMILLER		
DATE	7/9/92	7/10/92	7/10/92	/ /	/ /

OFFICIAL RECORD COPY FILENAME: A:\METSUM.71

4. Assurance that corrosion is not occurring in the form of a sine pattern:

   PSE&G stated that, based on discussions with other utilities and parties knowledgeable in the field of E/C, they did not identify a mechanism that would produce a sine pattern. To assure that the minimum is identified, the grid is extended two pipe diameters when a decreasing trend is noted at the grid boundary. To be considered satisfactory, the pipe wall must be 75 mils above the calculated minimum wall thickness. The staff found this to be acceptable.

5. The areas of E/C are given in Enclosure 2. The size of the areas that are exhibiting E/C are generally small (less than 10 square inches).

6. Results of the steam generator expander examinations.

   In Salem 1, cracking of three of the four expanders had been found. The decision had been made by PSE&G to replace all four expanders prior to restart.

   In Salem 2, an indication in one expander was noted, but it was determined by UT not to be a crack. No other indications were found in Salem 2.

   PSE&G is looking into the reasons Salem 1 experienced cracking and Salem 2 did not. The major area of investigation is the operation of the Auxiliary Feedwater System.

At the conclusion of the meeting, the staff had no further questions concerning the application of the design code, the corrective actions being taken and the basis for the calculation of minimum wall and E/C rates. Enclosure 3 is a list of attendees at the meeting.

Stephen M. Pindale, Acting Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Handout of Erosion/Corrosion Issues
2. Areas of Erosion/Corrosion
3. Meeting Attendees

cc w/enclosures:
See next page

cc:

Mark J. Wetterhahn, Esquire
Winston & Strawn
1400 L Street NW
Washington, DC 20005-3502

Richard Fryling, Jr., Esquire
Law Department - Tower 5E
80 Park Place
Newark, NJ 07101

Mr. Calvin A. Vondra
General Manager - Salem Operations
Salem Generating Station
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. S. LaBruna
Vice President - Nuclear Operations
Nuclear Department
P.O. Box 236
Hancocks Bridge, New Jersey 08038

Mr. Thomas P. Johnson, Senior Resident Inspector
Salem Generating Station
U.S. Nuclear Regulatory Commission
Drawer I
Hancocks Bridge, NJ 08038

Dr. Jill Lipoti, Asst. Director
Radiation Protection Programs
NJ Department of Environmental Protection
CN 415
Trenton, NJ 08625-0415

Maryland People's Counsel
American Building, 9th Floor
231 East Baltimore Street
Baltimore, Maryland 21202

Mr. J. T. Robb, Director
Joint Owners Affairs
Philadelphia Electric Company
955 Chesterbrook Blvd., 51A-13
Wayne, PA 19087

Richard Hartung
Electric Service Evaluation
Board of Regulatory Commissioners
2 Gateway Center, Tenth Floor
Newark, NJ 07102

Regional Administrator, Region I
U. S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Lower Alloways Creek Township
c/o Mary O. Henderson, Clerk
Municipal Building, P.O. Box 157
Hancocks Bridge, NJ 08038

Mr. Frank X. Thomson, Jr., Manager
Licensing and Regulation
Nuclear Department
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. David Wersan
Assistant Consumer Advocate
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Mr. J. A. Isabella
MGR. - Generation Department
Atlantic Electric Company
P.O. Box 1500
1199 Black Horse Pike
Pleasantville, NJ 08232

Carl D. Schaefer
External Operations - Nuclear
Delmarva Power & Light Company
P.O. Box 231
Wilmington, DE 19899

Public Service Commission of Maryland
Engineering Division
ATTN: Chief Engineer
231 E. Baltimore Street
Baltimore, MD 21202-3486

Mr. Steven E. Miltenberger
Vice President and Chief Nuclear Officer
Public Service Electric & Gas Company
Post Office Box 236
Hancocks Bridge, New Jersey 08038

ENCLOSURE 1

PSE&G/NRC MEETING

DISCUSSION OF EROSION/CORROSION ISSUES
AGENDA

JULY 1, 1992

- DISCUSSION OF FEEDWATER SYSTEM DESIGN PRESSURE
- DISCUSSION OF APPLICATION OF 1.2 STRESS ALLOWABLE FACTOR
- EROSION/CORROSION RATE CALCULATION
- DISCUSION OF SINE PATTERN EROSION/CORROSION
- ADDITIONAL INFORMATION
  - CHARACTERIZATION OF EROSION/CORROSION AREAS
  - UPDATE ON STEAM GENERATOR EXPANDER EXAMINATIONS

DETERMINATION OF DESIGN PRESSURE
FEEDWATER PIPE - S/G TO FIRST VALVE
SALEM NUCLEAR GENERATING STATION

REF: ANSI/ASME B31.1 - 1980

122.1.3

FEEDWATER DESIGN PRESSURE = S/G MAX. ALLOWABLE WORKING PRESSURE (MAWP)

+ (LESSER OF 25% MAWP OR 225 psi)

+ STATIC ELEVATION PRESSURE

S/G DESIGN P = 1085 psig. 25% (1085) = 271.25

STATIC EL. HEAD = 23.4

225

1333.4 = 1335

FOR INFORMATION:

- HIGHEST SAFETY VA. SET AT 1125 psi. + 3% = 1158.75
- S/G MAX OVERPRESSURE 1085 (1.1) = 1193.5

[illegible]

June 30, 1992

STEAM GENERATOR FEEDWATER
MINIMUM WALL THICKNESS DESIGN BASIS

BACKGROUND

1. From the piping specification (S-C-MPOO-MGS-0001), the normal working service pressure is 1195 psig.

2. From the piping specification (S-C-MPOO-MGS-0001), the maximum working service pressure is 1870 psig.

3. From the UFSAR, Revision 6, Table 10-4.1, the main feedpump shut-off head is 1893 psig (when the condensate pump impeller was modified, the shut-off head was increased from 1870 psig to 1893 psig).

4. From the piping specification (S-C-MPOO-MGS-0001), the maximum working service temperature is 470F.

5. From the UFSAR, Revision 6, section 3.9.2, piping equivalent to ASME Code Classes 2 & 3 was designed to B31.1, extended in a manner paralleling later versions of the ASME Code. The following limits were used:

Design Category	Loading Combination	Stress Limit
Normal	Normal Pressure & Weight and External Loadings	$P_C < S_h$ $P_L < S_h$
Upset	Maximum (short time) Pressure & Weight and External Loadings and OBE	$P_C < 1.2S_h$ $P_L < 1.2S_h$
Faulted	Maximum (short time) Pressure & Weight and External Loadings and SSE	$P_C < 1.2S_h$ $P_L < 1.8S_h$

where P_C is the circumferential stress and P_L is the longitudinal stress.

6. From B31.1, 1967 Edition, paragraph 102.3.2.(a), "The calculated stress due to internal pressure shall not exceed the allowable stress values given in the Allowable Stress Tables, except as permitted in Paragraph 102.2.4."

7. From B31.1, 1967 Edition, paragraph 102.3.3.(a), "The sum of the longitudinal stresses produced by internal pressure, live and dead loads and those produced by occasional loads such as the temporary supporting of extra weight may exceed the allowable stress values given in the Allowable Stress Tables by the amounts and durations of time given in Paragraph 102.2.4."

8. From B31.1, 1967 Edition, paragraph 102.2.4, "It is recognized that variations in pressure and temperature inevitably occur, and therefore the piping system shall be considered safe for occasional operation at higher than the design pressure or temperature. Either pressure or temperature, or both, may exceed the design values if the stress in the pipe wall calculated by the formulas using the maximum expected pressure during the variation does not exceed the S-value allowable for the maximum expected temperature during the variation by more than the following allowances for the periods of duration indicated:

   (1) Up to 15 percent increase above the S-value during 10 percent of the operating period.
   (2) Up to 20 percent increase above the S-value during 1 percent of the operating period."

9. The original pipe wall sizing calculations for the SGF piping used allowable stresses for A106 Gr. B & C material of 18,000 psi and 21,000 psi. These values are 20 percent greater than the Allowable Stress table values of 15,000 psi and 17,500 psi.

10. The original pipe wall sizing calculations for the SGF piping used a pressure of 1870 psig.

CONCLUSIONS

1. The original calculations (and UFSAR) are based on the maximum expected pressure and 120% of the allowable stress.

2. The maximum expected pressure is the main feedpump shut-off head.

3. The maximum expected pressure is assumed to occur less than 1% of the operating time.

4. A specific "design pressure" was not defined. All calculations are based on the normal pressure and maximum pressure.

5. If a "design pressure" were to be defined, it would likely be about 1420 psig. This value is based on the maximum normal pressure of 1195 psig plus a safety margin of 225 psig (using a similar approach to what the 1980 B31.1 Code recommends for piping inside the last isolation valve).

6. If the minimum wall thickness calculations were performed using 1420 psig and 100% of the allowable stress and 1870 psig and 120% of the allowable stress, the 1870 psig/120% S_h case would be limiting (for example, for 14" pipe):

$$t_{1870} = \frac{1870 \cdot 14}{2(1.2 \cdot 17500 + 1870 \cdot 0.4)} = 0.717$$

$$t_{1420} = \frac{1420 \cdot 14}{2(17500 + 1420 \cdot 0.4)} = 0.550$$

7. In addition, when determining the minimum wall thickness, the longitudinal stress equations in B31.1 are also evaluated to verify that the longitudinal stress limits are satisfied.

June 30, 1992

CALCULATION METHODOLOGY FOR EROSION RATES AND THICKNESS PREDICTIONS

The method used to calculate the predicted minimum wall thickness at the next refueling outage is based on the UT inspection results from previous outages and is described below.

1. Review the inspection results for the previous three refueling outages. For each outage, identify the location of the minimum wall thickness, both the circumferential and axial locations. If inspection results are available for only two outages, use those results. If results are available for only one outage, go to step 7.

   If the location of minimum thickness varies significantly (e.g., at both ends of a reducer or elbow), then there are two areas of erosion and the following calculations should be completed for each area.

2. Determine the circumferential location of the minimum wall thickness for each set of inspection data.

3. Determine the axial location of the minimum wall thickness for each set of inspection data.

4. For each set of inspection data, calculate an average wall thickness in the area of the minimum thickness. The average minimum is calculated using each of the measurement points in the grid area bounded by the range of the measured minimum thicknesses plus one grid location in each direction. For example, if the following grid was used for UT measurements:

T_{11}	T_{12}	T_{13}	T_{14}	T_{15}	T_{16}
T_{21}	T_{22}	T_{23}	T_{24}	T_{25}	T_{26}
T_{31}	T_{32}	T_{33}	T_{34}	T_{35}	T_{36}
T_{41}	T_{42}	T_{43}	T_{44}	T_{45}	T_{46}
T_{51}	T_{52}	T_{53}	T_{54}	T_{55}	T_{56}
T_{61}	T_{62}	T_{63}	T_{64}	T_{65}	T_{66}

   and the minimum wall thickness was at location T_{33} during the last inspections, location T_{45} two inspections ago and location T_{53} three inspections ago, the area used to calculate the average thickness would be all points in the area bounded by T_{22}, T_{26}, T_{66}, and T_{62}.

The calculated averages are labeled:

t_1	average thickness three outages ago
t_2	average thickness two outages ago
t_3	average previous outage

In addition, a fourth thickness is defined equal to the nominal wall thickness:

t_0	nominal wall thickness

If data is available for only two previous outages, the average thickness t_1 can not be calculated and is neglected.

5. The predicted erosion-corrosion rate is selected as the maximum of the four rates calculated using thicknesses t_0 to t_3 and the plant operating durations between the measurements:

$$r_p = \mathrm{MAX}(r_{12}, r_{23}, r_{13}, r_{03})$$

$$r_{12} = \frac{t_1 - t_2}{d_{12}}$$

$$r_{23} = \frac{t_2 - t_3}{d_{23}}$$

$$r_{13} = \frac{t_1 - t_3}{d_{13}}$$

$$r_{03} = \frac{t_0 - t_3}{d_{03}}$$

where:

d_{12}	is the plant operating duration between measurements 1 and 2
d_{23}	is the plant operating duration between measurements 2 and 3
d_{13}	is the plant operating duration between measurements 1 and 3
d_{03}	is the plant operating duration until measurement 3

If data is available for only two outages, d_{12} and d_{13} can not be calculated, so the predicted erosion rate is taken equal to the greater of the rates d_{23} and d_{03}.

6. The predicted minimum wall thickness at the next outage is calculated using the minimum wall thickness measured at any inspection, t_{min}, the predicted erosion rate, r_p, and the time until the next outage, d_p.

$$t_p = t_{min} - r_p d_p$$

7. If data is available for only one outage, extrapolation using measured erosion rates can not be performed. In these cases, an estimated erosion rate over the plant life is used. The wall thickness at the beginning of plant life is assumed to be the greater of the pipe nominal wall thickness or the maximum measured wall thickness (from the inspection results). This value is identified as t_0.

   t_0 is the thickness at beginning of life

   For fittings such as tees, reducers, etc., where additional material reinforcement was added during original fabrication, engineering judgement should be used to estimate a local maximum thickness instead of simply selecting the maximum measured value. Whenever a judgement is made, the rationale for selecting t_0 should be documented in the calculation.

8. The measured minimum wall thickness is identified as t_1.

   t_1 is the minimum measured wall thickness

9. The erosion rate is calculated using the time the plant has operated.

$$r_p = \frac{t_0 - t_1}{d_{01}}$$

   where:

   d_{01} is the operating time at the time of the measurement

10. The predicted minimum wall thickness at the next outage is calculated using the minimum wall thickness, t_1, the predicted erosion rate, r_p, and the predicted operating time until the next outage, d_p.

$$t_p = t_1 - r_p d_p$$

UNIT 1

11 COMPONENTS

LOCATION	COMPONENT	COMMENTS
1S-SGF-52-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-SGF-37-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-SGF-22-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-SGF-4-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-HD-260-L1	6 Elbow	Slight erosion, must review past history.
1S-FWR-P2-P1	6 Pipe	Thinning in counterbore area (P22 material).
1S-FWR-10-B1	6 Pipe Bend	Thinning in extrados appears attributable to bending. Intrados proportionately thicker in bending area than extrodos. In straight areas of pipe, pipe wall thickness is more uniform.
1S-FWR-P10-P1	6 Pipe	Thinning in counterbore area (P22 material).
1S-SGF-71-L1	20 Elbow	Slight erosion in downstream pipe, must review past history.
1S-SGF-5L-P1	14 Pipe	Slight erosion, must review past history.
1S-C216-L1		General thinning thru-out entire fitting. Counterbore area encroaching upon t_m. Could have been received in thin condition since identical other train elbow and two (2) Unit 2 24-inch elbows are about 0.250" above t_m thru-out elbow.

11 Components are all above Code t_m using 1.20 S_H criteria per 1967 B31.1 para 102.2.4

UNIT 2

COMPONENTS

LOCATION	COMPONENT	COMMENTS
2-SGF-113-R1	24 X 18 Reducer	Replace due to localized thinning below Code tm in counter bore area. Appears dut to initial eccentric fit up. Some erosion occurring.
2-SGF-113-R2	24 X 18 Reducer	"DITTO" Above.
2-SGF-113-T1B	24 Tee	Lowest reading 0.105" > t_m in counterbore area of connecting pipe. No E/C occurring in tee.
2-SGF-112-L1	24 Elbow	Lowest reading 0.159" > t_m in counterbore area of connecting pipe. No E/C occurring in tee.
2-SGF-113-T2B	18 X 14 Tee	Lowest reading 0.148" > t_m in counterbore area of connecting pipe. No E/C occurring in tee.
2-SGF-19-L1	14 Elbow	Lowest reading 0.015" > t_m in counterbore area of connecting pipe. Appears due to initial eccentric fit up. Some slight erosion occurring downstream.
2-SGF-34-L1	14 Elbow	Lowest reading 0.049" > t_m in counterbore area of connecting pipe. Appears due to initial eccentric fit up. Some slight erosion occurring downstream.
2-SGF-33-L2	14 Elbow	Lowest reading 0.031" > t_m in downstream pipe area. Some erosion occurring.
2-SGF-108-L1	24 Elbow	Lowest reading 0.047" > t_m in counterbore area Some erosion appears to be occurring in extrados.
2-SGF-49A-E1	16 X 14 Reducer	Lowest reading 0.093" > t_m in counterbore area of connecting 14" pipe. No apparent erosion occurring.
2-SGF-47-L2	14 Elbow	Lowest reading 0.059" > t_m in counterbore area of upstream pipe. No apparent erosion occurring.
2-SGF-48-L1	14 Elbow	Lowest reading 0.061" > t_m in counterbore area of upstream pipe. No apparent erosion occurring.
2S-HD-554-L1	8 Elbow	Lowest reading 0.043" > t_m in downstream pipe. Some slight erosion occurring.
2-SGF-81-T2B	20 X 18 Tee	Lowest reading 0.154" > t_m in counterbore area of 18" tee branch to pipe. No apparent erosion occurring.

12 of 14 components are all above t_m using 1.20 S_H criteria per 1967 B31.1 para 102.2.4; 2 of 14 being replaced are below Code t_m only in counterbore area. All SGF components t_m derived using 1893 PSI although some SGF fittings fall within present P-MAX of 1335 PSI.

UNIT 1

11 COMPONENTS

LOCATION	COMPONENT	COMMENTS
1S-SGF-52-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-SGF-37-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-SGF-22-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-SGF-4-E1	12 X 14 Reducer	Thinning in counterbore area.
1S-HD-260-L1	6 Elbow	Slight erosion, must review past history.
1S-FWR-P2-P1	6 Pipe	Thinning in counterbore area (P22 material).
1S-FWR-10-B1	6 Pipe Bend	Thinning in extrados appears attributable to bending. Intrados proportionately thicker in bending area than extrodos. In straight areas of pipe, pipe wall thickness is more uniform.
1S-FWR-P10-P1	6 Pipe	Thinning in counterbore area (P22 material).
1S-SGF-71-L1	20 Elbow	Slight erosion in downstream pipe, must review past history.
1S-SGF-5L-P1	14 Pipe	Slight erosion, must review past history.
1S-C216-L1		General thinning thru-out entire fitting. Counterbore area encroaching upon t_m. Could have been received in thin condition since identical other train elbow and two (2) Unit 2 24-inch elbows are about 0.250" above t_m thru-out elbow.

11 Components are all above Code t_m using 1.20 S_H criteria per 1967 B31.1 para 102.2.4

ENCLOSURE 2

UNIT 2
COMPONENTS

LOCATION	COMPONENT	COMMENTS
2-SGF-113-R1	24 X 18 Reducer	Replace due to localized thinning below Code tm in counter bore area. Appears dut to initial eccentric fit up. Some erosion occurring.
2-SGF-113-R2	24 X 18 Reducer	"DITTO" Above.
2-SGF-113-T1B	24 Tee	Lowest reading 0.105" > t_m in counterbore area of connecting pipe. No E/C occurring in tee.
2-SGF-112-L1	24 Elbow	Lowest reading 0.159" > t_m in counterbore area of connecting pipe. No E/C occurring in tee.
2-SGF-113-T2B	18 X 14 Tee	Lowest reading 0.148" > t_m in counterbore area of connecting pipe. No E/C occurring in tee.
2-SGF-19-L1	14 Elbow	Lowest reading 0.015" > t_m in counterbore area of connecting pipe. Appears due to initial eccentric fit up. Some slight erosion occurring downstream.
2-SGF-34-L1	14 Elbow	Lowest reading 0.049" > t_m in counterbore area of connecting pipe. Appears due to initial eccentric fit up. Some slight erosion occurring downstream.
2-SGF-33-L2	14 Elbow	Lowest reading 0.031" > t_m in downstream pipe area. Some erosion occurring.
2-SGF-108-L1	24 Elbow	Lowest reading 0.047" > t_m in counterbore area Some erosion appears to be occurring in extrados.
2-SGF-49A-E1	16 X 14 Reducer	Lowest reading 0.093" > t_m in counterbore area of connecting 14" pipe. No apparent erosion occurring.
2-SGF-47-L2	14 Elbow	Lowest reading 0.059" > t_m in counterbore area of upstream pipe. No apparent erosion occurring.
2-SGF-48-L1	14 Elbow	Lowest reading 0.061" > t_m in counterbore area of upstream pipe. No apparent erosion occurring.
2S-HD-554-L1	8 Elbow	Lowest reading 0.043" > t_m in downstream pipe. Some slight erosion occurring.
2-SGF-81-T2B	20 X 18 Tee	Lowest reading 0.154" > t_m in counterbore area of 18" tee branch to pipe. No apparent erosion occurring.

12 of 14 components are all above t_m using 1.20 S_H criteria per 1967 B31.1 para 102.2.4; 2 of 14 being replaced are below Code t_m only in counterbore area. All SGF components t_m derived using 1893 PSI although some SGF fittings fall within present P-MAX of 1335 PSI.

MEETING ATTENDEES

EROSION/CORROSION IN FEEDWATER SYSTEM

SALEM NUCLEAR GENERATING STATION, UNITS 1 & 2

July 1, 1992

NAME	ORGANIZATION
Jim Partlow	NRR/AD
Jim Stone	NRR/PDI-2
Richard Lobel	NRC/EDO
Chuck Hsu	AEOD/ROAB
Jim Medoff	NRR/EMCB
Charlie Miller	NRR/PDI-2
Mel Gray	PSE&G-Licensing
Bob Coward	MPR Associates
Frank Thomson	PSE&G-Licensing
Tim Taylor	PSE&G
D. E. Smith	NRR/DET/EMCB
Bill LeFave	NRR/DST/SPLB
Kris Parczewski	NRR/DET/EMCB
Mark Hartzman	NRR/DET EMEB
John Fair	NRR/DET/EMEB
S. Pindale	NRC/R-I/Res. Inspector
Ron Haupt	Pressure Piping Engineering Associates
Robert McBrearty	NRC/R-I/Reactor Engineer
Robert Hermann	NRR/DET/EMCB
David Gamberoni	NRR/DOEA