VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

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W. L. STEWART
VICE PRESIDENT
NUCLEAR OPERATIONS

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555

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Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
NORTH ANNA POWER STATION UNITS 1 AND 2
RESPONSE TO IE BULLETIN 87-01

The information requested by the NRC Bulletin No. 87-01 "Thinning of Pipe Walls in Nuclear Power Plants" is attached for both Surry and North Anna Power Stations. (Attachment 1 and 2, respectively).

Should you have any questions regarding this information, please contact us.

Very truly yours,

W L Stewart

W. L. Stewart

Attachment

cc: U. S. Nuclear Regulatory Commission
Region II
101 Marietta Street, N. W.
Suite 2900
Atlanta, Georgia 30323

Mr. W. E. Holland
NRC Senior Resident Inspector
Surry Power Station

Mr. J. L. Caldwell
NRC Senior Resident Inspector
North Anna Power Station

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RESPONSE TO IEB 87-01
THINNING OF PIPE WALLS IN NUCLEAR POWER PLANTS
SURRY POWER STATION

Actions Requested

Provide the following information concerning the programs for monitoring the wall thickness of pipes in condensate, feedwater, steam and connected high-energy piping systems, including all safety related and non-safety related piping systems fabricated of carbon steel:

NRC Item 1

Identify the codes and standards to which the piping was designed and fabricated.

Response

The Surry piping systems of interest were designed to:

Surry Piping Specification - NUS-20
ANSI B31.1.0 - 1967 Edition
ASME Section IX - Welding Qualification
American Welding Society Specifications
Pipe Fabricators Institute

NRC Item 2

Describe the scope and extent of your programs for ensuring that pipe wall thicknesses are not reduced below the minimum allowable thickness. Include in the description the criteria that you have established for:

a) Selecting points at which to make thickness measurements

Response

Selection of Inspection Locations

In order to determine the extent of erosion/corrosion (E/C) in the secondary side and auxiliary piping systems, an initial inspection program was developed to recommend ultrasonic (UT) and visual inspection locations. Technicon Enterprises, Inc. (the consultant that prepared EPRI Report NP-3944 - "Erosion/ Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines") was contracted to recommend the initial inspection locations.

Technicon recommended the initial inspection locations based on water chemistry, pipe material, temperature, velocity and pipe geometry. Systems selected were those steam or water systems which met all of the following conditions: controlled low oxygen levels, constructed from carbon steel materials, and operating temperatures greater than 195°F. This temperature limit was selected primarily for personnel safety considerations.

Systems having austenitic stainless steel piping are not considered to be subject to E/C attack and therefore, no inspection locations in these systems were selected by Technicon. No chromium-molybdenum piping systems were specified originally for the Surry Power Station. Carbon steel piping is assumed to have an insignificant amount of chromium and therefore, no effect in retarding erosion/corrosion.

The operating pH levels for the Surry water chemistry is controlled below the 9.3-9.5 pH level. Above this level, erosion/corrosion is reduced. Therefore, there were no exemptions from consideration, due to pH levels, since all were assumed to be in the pH range susceptible to erosion/corrosion.

A listing of the piping systems that were selected for inspection is given in Table 2a.1. Table 2a.2 shows a listing of piping systems eliminated from the inspection program and the reason for the elimination. These tables were generated as a result of a review of the system design data, e.g., flow diagrams, system descriptions and piping specifications.

During the development of the future Inspection Program, the NUMARC guidelines on single phase erosion/corrosion will be applied to systems presently excluded from the Inspection Program.

TABLE 2a.1

Piping Systems Inspected for E/C

Condensate

Feedwater

Main Steam Moisture Separator & H.P. Heater Drains

Steam Generator Blowdown

Flash Evaporator

L. P. Heater Drains

Auxiliary Steam

1st & 2nd Pt. Extraction Steam

3rd & 4th Pt. Extraction Steam

5th & 6th Pt. Extraction Steam

*Auxiliary Feed

*Charging

*These systems were not within the scope of recommended inspections, but were added to the scope of the Unit 1 inspections in order to validate the stainless steel material exclusion criteria and to verify integrity of the safety related auxiliary feed system. Since no evidence of E/C was found in the Unit 1 auxiliary feed or charging systems, the scope of the Unit 2 inspections did not include these systems.

TABLE 2a.2
Piping Systems Eliminated From The Inspection Program

SYSTEM	Reason For Elimination: HIGH O_2	LOW TEMP	NOT CARBON STEEL	NOT H_2O
Fire Protection	X	X		
Domestic Water	X	X		
Fuel Oil				X
Waste Oil				X
Circ. Water	X	X		
Service Water	X	X		
Vacuum Priming	X	X		
Chilled Water	X	X		
Water Treatment	X	X		
Compressed Air				X
Primary Grade Water		X	X	
Turbine Lube Oil				X
Gland Seal				X
Electro-Hydraulic Control				X
Bearing Cooling Water	X	X		
Secondary Sampling			X	
Reactor Coolant			X	
Residual Heat Removal			X	
*Chem. & Volume Control			X	
Boron Recovery			X	
Liquid Waste		X	X	
Decontamination			X	
Gaseous Waste			X	X
Radiation Monitoring				X
Spent Fuel Pit	X	X	X	
Reactor Cavity Purification	X	X	X	
Component Cooling	X	X		
Safety Injection		X	X	
Containment Spray		X	X	
Recirculation Spray		X	X	
Primary Sampling			X	
Containment Vacuum				X
Primary Vents & Drains			X	
Neutron Shield Cooling		X	X	
Condensate Polishing		X		
**Auxiliary Feed		X		

*This system was added to the scope of the recommended inspections for Unit 1 in order to validate the stainless steel material exclusion criteria.

**This system was added to the scope of the recommended inspections for Unit 1 in order to verify integrity of the safety related Auxiliary Feed system.

The following carbon steel piping subsystems were reviewed and also excluded from the recommended scope of inspection for the listed reasons:

Piping Subsystem	Reason for Inspection Exclusion
Main Steam	
-SHP line to atmosphere thru FE-MS100	Infrequent use
-Safety and reliefs	Infrequent use
-Decay heat release	Infrequent use
-Main steam dumps	Infrequent use
-Turbine stops to cylinder heating	MS superheated condition downstream of CV
-1 1/2" SRE line from reheater to crossunder (warm up line)	Infrequent use
Misc. Drains Secondary Plant	
-Equipment condensate drains (excluding traps)	Infrequent use
Boron Recovery	
-VA system	Not steam or water
Sampling System	
-Steam generator blowdown	Fluid downstream of coolers is less than 150°F. Carbon steel upstream of coolers is part of Blowdown System inspection program
Extraction Steam	
-1 1/2" and 2" S1ED thru S4ED	Infrequent use
Condensate	
-Feedwater heater relief lines	Infrequent use
Auxiliary Steam	
-8"-SA-13-301	Infrequent use
-4"-SA-8-301	Infrequent use
-3"-SA-3-301	Infrequent use
-4"-SA-29,30-301	Infrequent use
-ACA & AJA lines	Less than 100°F and at atm. or vac. press.
Steam Trap Lines	Not considered a major operational or safety hazard; to be considered by the ongoing Inspection Program

Piping Subsystem	Reason for Inspection Exclusion
Auxiliary Steam	
-Piping downstream of Control Valves	Low pressure and not considered a major operational or safety hazard; to be considered by the Ongoing Inspection Program
-Heating steam piping	Same as above

In order to validate the stainless steel material exclusions, inspections were done on the Unit 1 charging systems. Inspections were also done on the Unit 1 auxiliary feedwater system to prove the integrity of its piping. Since no evidence of E/C was found in the Unit 1 auxiliary feed or charging system; inspections were not done on these systems in Unit 2.

Points were selected within each system in Table 2a.1 based on velocity and geometry with the overriding parameter being geometry since the velocities and temperature are relatively constant within each line segment. Line segments in the condensate and feedwater systems have different temperatures in different locations and inspection points were selected based on geometry and temperature in these systems. Since there was no previous examination data on single phase liquid flow lines at Surry, a sampling of inspection points was taken for those areas of each system that were representative of system temperatures and velocities expected to have significant E/C wear.

Wet steam system inspection points were selected based on the Keller's equation methods presented in EPRI Report NP-3944 entitled "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines". This report relates E/C wear rates to temperature, fluid velocity, moisture content and individual components using Keller's equation. Geometry was a separate consideration for compound component configuration, since Keller's equation does not relate the effect of compound geometry to E/C wear rate. The application of such configurations is left to judgement, with separation between flow disturbances being the criteria for severity and ultimate selection. A minimum of ten pipe diameters is recommended between flow discontinuities. Keller's equation also does not include any influence from changes in water chemistry.

Since no known methods existed for selection of E/C locations in single phase flow during the development of the progam, Technicon developed a rating scheme to identify potentially high E/C wear in single phase flow components as follows:

A. Temperatures are considered constant within systems unless mass flow additions or energy changes cause significant temperature changes. Any such temperature change was factored into selection of data points. E/C ratings for various temperature ranges in single phase flow were assigned the following values:

Temperature (°F)	Rating
265-320	5
245-265 & 320-350	4
230-245 & 350-380	3
210-230 & 380-410	2
195-210 & 410-440	1
< 195 & > 440	0

NOTE: Lines which operate at or near (5°F) saturation should have the above rating value increased by 3.

B. Velocity effects are compounded by system geometry and in general, flow disturbances caused by other irregularities in the pipe wall. E/C ratings for velocities were assigned the following values:

Velocity Feet per second (FPS)	Rating
25-30	5
20-25	4
15-20	3
10-15	2
5-10	1
< 5	0

C. Piping system geometry was reviewed on a line segment basis considering temperature and velocity, and points were selected for inspection. Consideration was given to high potential E/C areas typical of components such as: Tee's, close coupled fittings, elbows, reducers, pipe downstream of control valves, orifices, check valves, instrument taps, pipe I.D., weld contours and backing rings. The characteristics of these components in conjunction with fluid velocity create significant flow disturbances. These flow disturbances create even higher local velocities and alter flow patterns thus increasing the degradation rate in these local areas.

E/C ratings for various geometries and flow disturbances were assigned the following values:

Geometry & Flow Disturbances	**Rating**
Control valve, tee (splitting), 180° bend	10
Check valves, globe valves, tees (branch), flow orifices, components separated 3D < d < 10D	8
90° bends, elbows, reducing elbows	6
Butterfly valves, instrument taps, reducers	4
Gate valves, welds in straight pipe	2
Straight pipe	0

NOTE: For close coupled geometry (0 < d < 3 D) combine components by adding rating values.
D = pipe diameter
d = distance between components

A summation of the numerical values assigned to each category provides a relative comparison of the various factors effecting E/C and when placed in numerical order provides a priority for inspection point selection.
The results of the inspections that have been conducted will be used to refine the E/C rating model presented above.

Technicon also recommended that visual inspections be done on the turbine crossunder piping and on any piping components that were adjacent to any components that were removed or serviced for various reasons.

A number of the Technicon primary inspection points were selected at the outset of the initial inspection effort based primarily on piping geometry. This effort was completed, at the request of the station, to direct the inspections that were already underway into the more critical areas of the plant. Subsequent evaluation of system operation and calculation of line velocities shows that some of these primary points could have been eliminated. Inspection results confirmed this to be the case.

The total number of inspection points for Unit 2 was less than the total for Unit 1. This reduced inspection scope for Unit 2 was a result of knowledge gained from the Unit 1 inspections, which were completed first. For piping systems exhibiting essentially no E/C wall loss in the Unit 1 inspections (for example the auxiliary feed and charging systems), the number of inspection points was reduced in the Unit 2 scope. However, piping systems shown to have E/C wall loss by the Unit 1 inspections were subjected to essentially the same number of inspection points in the Unit 2 inspection scope.

The primary inspection point selection procedure for the ongoing Inspection Program will use a model similar to that presented in this report combined with updates and refinements resulting from the inspections conducted and the guidelines presented in the recent NUMARC proposal on erosion/corrosion.

NRC Item 2.b

Determining how frequently to make thickness measurements and,

NRC Item 2.d

Making replacement/repair decisions.

Response

Since the criteria for determining the frequency of pipe wall thickness measurements and for the replacement/repair decisions are based on the measured and predicted E/C, the response to these two aspects of our program are closely related. A combined response to NRC Items 2b and 2d follows:

The pipe wall thickness acceptance criteria uses measured wall thicknesses using UT methods to develop an E/C wear rate, which is used to predict when the pipe wall thickness would approach its code minimum wall. The acceptance criteria provides guidance on determining if a piping component needs to be replaced or repaired immediately, is projected for replacement at some future time in its operating life, or should be monitored by inspection during its operating life.

The general formulation for the pipe wall thickness acceptance criteria is as follows:

$T_a - nW_r \geq Tm$, where

T_a = as found UT wall thickness measurement, in.

n = projected remaining operating time in years

W_r = calculated yearly wear rate

T_m = calculated code minimum required wall thickness, in.

W_r is calculated as follows:

$$W_r = \frac{T_N - T_a}{y}, \text{ where}$$

T_N = maximum nominal wall thickness (nominal wall + manufacturing tolerance)

y = actual operating time in years
(hours critical converted to years)

If the lowest actual measured component wall thickness minus the maximum wear expected in a remaining time period of operation is greater than or equal to the code (minimum required wall thickness) then the component meets the acceptance criteria.

Substituting the W_r definition into the general formulation equation and solving for T_a yields a more useful form of the acceptance criteria as follows:

$$T_a \geq T_N - \frac{y}{y+n} (T_N - T_m)$$

defining T_{acc} the acceptance criteria thickness as:

$$T_{acc} = T_N - \frac{y}{y+n} (T_N - T_m)$$

gives $T_a \geq T_{acc}$ as the acceptance criteria formula.

Note that $T_N - T_m$ is the total wear allowance of the component.

The wall thickness criteria equation can be used to put the piping components into various acceptance categories, by comparing the as found wall thickness, T_a, to the acceptance criteria, T_{acc}.

Piping components which fall into Acceptance Category E (Place the Component in Station's Ongoing Inspection Program) in Table 2b.1 will have an estimated remaining wear life calculated based on the wear rate defined above. This will allow a determination of the frequency at which thickness measurements will be taken under the Station's Ongoing Inspection Program.

The acceptance criteria formula developed herein was formulated using a linear wear rate based on actual wall thickness UT measurements of the various piping components. The acceptance criteria formula is considered conservative based on the following factors in its formulation:

1. Pipe and fittings were assumed to have been installed with a maximum nominal wall thickness, which was defined as nominal wall plus maximum manufacturer's tolerance for pipe. Therefore, calculated wear rates are conservative. (For pipe and fittings that had wall thickness less than $Tacc/_{n=t1}$, but had wall thickness greater than T_m, an evaluation was done using T_N = nominal thickness to calculate the wear rate, if the UT data suggested the component was supplied at or below nominal wall thickness. The evaluation also determined the time for the component to reach T_m with considerations given to pre-outage inspections.)

2. For wear rate calculations, the time of operation was assumed to be the time of critical operation of each unit. This does not include any noncritical operation time or any unit lay-up time. This fact adds conservatism to the calculated wear rates as E/C or other mechanisms could have occurred during the times that were not considered for wear rate calculations.

3. The value for n, number of years of operation remaining for a component with its calculated wear rate, was chosen as the time to reach a future refueling outage plus an additional 1/2 year or 1 year depending on the acceptance category.

The above factors of conservatism in the acceptance criteria formula justify its use as a very conservative criteria for replacement or inspection of components in the secondary and auxiliary system piping.

The basis of comparison for acceptance or rejection of a component is the calculated code minimum required wall thickness for the component. The code minimum wall is determined with the assumption that the pipe wall is at uniform minimum wall thickness over the entire pipe circumference. However, wall thinning resulting from E/C generally occurs in localized areas and, therefore, the measured minimum wall thickness usually does not extend around the entire circumference of the pipe. Because a component can withstand the pressure used in the code minimum wall calculation with local wall thicknesses lower than code minimum wall, an additional factor of conservatism exists in the criteria.

The UT inspection procedures being used have a high confidence level of locating components experiencing general area wall thinning that could result in catastrophic failure of the component. The possibility of a small failure (pin hole leak or small blowout) in a component due to other corrosion mechanisms exists because of the inspection grid layouts. This possibility is considered very unlikely because the inspection procedures call for expanded inspections if thicknesses near minimum wall are measured.

The validity of the acceptance criteria will be confirmed during the ongoing inspection program by:

1. Visual inspections of the removed components.
2. Periodic UT inspections of components in key locations in the secondary system piping to substantiate wear rates.

TABLE 2b.1

PIPING COMPONENT WALL THICKNESS ACCEPTANCE CATEGORIES

Acceptance Category	Criteria	Remarks
A. Immediate replacement of Component	$Ta \le Tm$ or $Ta \le 0.100$	Replace or repair
B. Engineering Evaluation of Component	$Tm < Ta < Tacc/_{n=t_1}$	t_1 = time to next outage + 1/2 year. As a result of the engineering evaluation each component in this category must be put in Category A or Category C.
C. Potential Next Outage Replacement of Component	$Tacc/_{n=t_1} < Ta < Tacc/_{n=t_2}$	t_2 = time to next 2 outages + 1/2 year. Component will be inspected at the next outage to verify the wear rate in order to confirm the need for replacement.
D. Each outage Inspection of Component	$Tacc/_{n=t_2} < Ta < Tacc/_{n=t_3}$	t_3 = time to next 3 outages + 1 year. If no wear is determined by reinspection during the next 3 outages put the component into Category E.
E. Place Component in Station's On-going Inspection Program	$Ta \ge Tacc/_{n=t_3}$	The Station's On-going Inspection Program is in the process of being developed.

NRC Item 2.c

Selecting the methods used to make thickness measurements

Response

Description of NDE Procedures

Determination of whether or not a piping component had been subject to E/C and whether or not it was adequate for continued service was made by determining the remaining component wall thickness of selected inspection locations. Wall thickness readings were obtained in accordance with Surry Power Station Administrative Procedure, SUADM-M-33 entitled "Secondary Piping Inspections"; NDE Procedure, NDE-UT-4, entitled "Ultrasonic Thickness Measurements"; Supplement No. 1 to SUADM-M-33 entitled "Criteria for Progressive Field Wall Thickness Examinations by UT"; and Supplement No. 2 to SUADM-M-33 entitled "Criteria for 100% Field Wall Thickness Examination by UT". In addition, the "Program to Demonstrate Efficacy of Field Wall Thickness Determinations Per Procedure SUADM-M-33 was implemented to demonstrate that the limited areas being inspected on the various piping components were representative of the condition of the bulk of the component.

NRC Item 3

For liquid-phase systems, state specifically whether the following factors have been considered in establishing your criteria for selecting points at which to monitor piping thickness (item 2a).

a) Piping material (e.g. chromium content)
b) Piping configuration (e.g. fittings less than 10 diameters apart)
c) pH of water in the system (e.g. pH less than 10)
d) System temperature (e.g between 190°F and 500°F)
e) Fluid bulk velocity (e.g. greater that 19 ft/s)
f) Oxygen content in the system (e.g. oxygen content less than 50 ppb)

Response

All of these factors have been considered in the point selection criteria for the thickness monitoring programs at Surry. These items were discussed in the response to item 2.

NRC Item 4

Chronologically list and summarize the results of all inspections that have been performed, which were specifically conducted for the purpose of identifying pipe wall thinning, whether or not pipe wall thinning was discovered, and any other inspections where pipe wall thinning was discovered even though that was not the purpose of the inspection.

a) Briefly describe the inspection program and indicate whether it was specifically intended to measure wall thickness or whether wall thickness measurements were an incidental determination.

Response

Surry Power Station implemented two phase inspections in 1984. Following is a chronological summary of the inspections.

1984 - 1985	Inspected approximately 28 components on the Moisture Separator drains on Unit 2.
1985	Inspected approximately 20 components on the extraction steam piping on Unit 2.
1986	Inspected steam crossunder piping on Unit 1.
1986	Inspected approximately 78 components on the extraction steam piping on Unit 1.
1986	Inspected approximately 34 components on the Moisture Separator drain to condenser piping on Unit 1.
1986	Inspected approximately 14 components in piping from the evaporator condenser to the flash evaporator on Unit 1.
1986	Inspected approximately 22 components on piping from the 5th point FW heater drains piping on Unit 1.

Replacements as a result of these inspections were made as required.

For 1987 inspection results see response to item 4c.

NRC Item 4b

Describe what piping was examined and how (e.g. describe the inspection instrument(s), test method, reference thickness, locations examined, means for locating measurement point(s) in subsequent inspections.

Response

This item was addressed in responses to items 2a, b, c, and d. Subsequent inspections will be conducted in accordance with the response to item 5.

NRC Item 4c

Report thickness measurement results and note those that were identified as unacceptable and why.

NRC Item 4d

Describe actions already taken or planned for piping that has been found to have non-conforming wall thickness. If you have performed a failure analysis include the results of that analysis. Indicate whether the actions involve repair or replacement, including any change of materials.

Response

1987 Inspection Results

Table 4c.1 shows that approximately 21% of the combined Unit 1 and Unit 2 components inspected were categorized for Immediate Replacement, but less than half of these (approximately 7% of the components inspected) were found to be below code minimum wall thickness. The other Immediate Replacement category components were placed in the category for construction convenience or because the acceptance criteria indicated that the component could potentially lose enough wall to be near code minimum wall at the next refueling outage.

Table 4c.1 shows that less than 3% of the combined Unit 1 and Unit 2 components inspected were categorized for Potential Replacement at Next Refueling Outage and that approximately 9% of the components were categorized for Inspection at Next Refueling Outage with approximately 5% of the components added to this category for additional monitoring.

Resulting Component Replacement:

As a result of the inspection, 47 components from Unit 1 and 60 components from Unit 2 were placed in the Immediate Replacement category. These components (except for the four Unit 2 components to be replaced in the Fall, 1987 snubber outage) were replaced before the Units return to service. These components, being in verified E/C wear locations, will be in the highest priority category for the Ongoing Inspection Program that is being developed for the Secondary and Auxiliary Systems. All new components being used to replace existing components will be baseline UT inspected in accordance with Supplement 3 to SUADM-M-33, ADM-89.13.

The four Unit 2 components are 3E-12"-S1E-101-301 (1st point heater extraction steam line), 3R-6"-WHPD-104-301 (LP heater drain pump discharge line), 2E-14"-SIE-104-301 (1st point heater extraction steam line) and 4E-20"-S2E-103-301 (2nd point heater extraction steam line). These lines were evaluated and were found to have enough remaining wear life for operation until the next refueling outage. These components, however, fell into the Immediate Replacement category because of the six month wear life conservatism in the acceptance criteria. These components all have at least 0.050 inches more wall thickness than their code minimum wall. Therefore, these four components will be inspected during the Fall, 1987 snubber outage to confirm wear rate and to decide if replacement is needed.

The use of a chromium - molybdenum steel material in place of carbon steel and the reconfiguring of the components in order to lower the turbulence of the flow were factors that were considered prior to replacing the components that were placed into the "Immediate Replacement" category.

A. The use of chrome-moly steel for replacement components was ruled out for two reasons:

1) The effects on E/C of placing a chrome-moly component adjacent to existing carbon steel components is not fully understood and needs further research.

2) The long lead time for delivery of chrome-moly components, such as elbows and tees, would delay the units startup. Therefore, all Immediate Replacement components were replaced with in-kind materials. However, potential use of chrome-moly material for replacement of carbon steel components experiencing E/C will be considered in a future Engineering study for possible piping system redesigns to reduce E/C.

B. Only one section of piping having components in the Immediate Replacement category was considered practical for reconfiguration. This was a reconfiguration of the branch of the 18" feed pump suction line from its 24" header (components 6T and 1E of both lines 18"-WCPD-33-301 and -133-301). This was the section of piping in Unit 2 that ruptured causing the December 9, 1986 accident. The 18" feed pump suction line was reconfigured from an 18" 90° branch off of the 24" header which immediately butted to a 90° elbow to a 45° lateral off of the 24" header and a 45° elbow. This reconfiguration will produce much less turbulence than the original design and should dramatically reduce the E/C wear rate, which was estimated to be approximately 0.038 inches/year for Unit 1 and 0.046 inches/year for Unit 2. The components in this reconfiguration will be carefully monitored by inspection to determine the long term effect of the reconfiguration on the E/C of the components.

Stress calculations were performed on this section of reconfigured piping which showed that the piping reconfiguration was an acceptable design.

The Unit 2 steam generator "A" and "B" feedwater lines, 14"-WFPD-117-601 and 14"-WFDP-113-601 respectively, were found to have localized wall thinning in the spool pieces between the loop seal and the reducer to the inlet nozzle of the steam generators. As discussed in detail in our letters of March 4, 1987 (Serial No. 87-108) and April 16, 1987 (Serial No. 87-108A), the reduced wall measurements were presumed to be due to a combination of piping anomalies associated with installation of nonconcentric pipe and the lack of baseline data for the as-installed pipe as well as erosion/corrosion. Following evaluation, the wall thicknesses of both spool pieces (A and B) were restored using a weld build-up process rather than attempting to replace the piping sections. Due to the uncertainty in the projected E/C wear rate, the spool pieces will be inspected and reevaluated during the Fall, 1987 outage. In addition, the spool pieces have been placed into the "Potential Replacement" category.

TABLE 4c.1
Component Inspection Program Summary - 1987

	Unit 1	Unit 2
Components Inspected	506**	317**
Components Designated for Immediate Replacement	73=(30 below code+17 below criteria*+26 for construction convenience)	89=(31 below code+29 below criteria***+29 for construction convenience)
Components Designated for Potential Replacement at Next Refueling Outage	8=(8 below criteria)	14=(14 below criteria)
Components Designated for Inspection at Next Refueling Outage	95=(55 below criteria +37 additional monitoring)	22=(21 below criteria + 1 additional monitoring)

*Includes 6 components from the Potential Replacement at the Next Refueling Outage category and 2 components from the Outage inspection category that were downgraded to the Immediate Replacement Category as a result of the 100% inspections.

**Total does not include sections of straight pipe that were inspected and does include 14 Unit 2 Flash Evaporator piping components inspected after Unit 2 start-up.

***Includes 4 components that may be replaced during the Fall 1987 snubber outage and 4 components from the Potential Replacement at the Next Refueling Outage category downgraded as a result of 100% inspections.

NOTE: For Unit 1 inspections, 68 of 73 Immediate Replacement components, 6 of 8 Potential Replacement at Next Refueling Outage components and 46 of 95 Inspections at Next Refueling Outage components were from the feedwater and condensate systems. For Unit 2 inspections to date, 77 of 88 Immediate Replacement Components, 13 of 14 Potential Replacement at Next Refueling Outage Components, and 19 of 22 Inspection at Next Outage components were from the feedwater and condensate systems.

NRC Item 5

Describe any plans either for revising the present or for developing new or additional programs for monitoring pipe wall thickness.

Response

Long-Term Secondary Inspection Program

Virginia Power is in the process of developing a Long Term Secondary System Inspection Program for our nuclear units. This program will contain criteria and methodology for selection, inspection, and acceptance. It will also contain historical inspection data for each unit, trending information for wear rate development, and information required for future inspections.

Virginia Power has been directly involved in the NUMARC working group on erosion/corrosion. We intend to apply the NUMARC inspection guidelines for single phase erosion/corrosion into our Long Term Secondary System Inspection Program.

RESPONSE TO IEB 87-01
THINNING OF PIPE WALLS IN NUCLEAR POWER PLANTS
NORTH ANNA POWER STATION

Actions Requested

Provide the following information concerning the programs for monitoring the wall thickness of pipes in condensate, feedwater, steam and connected high-energy piping systems, including all safety related and non-safety related piping systems fabricated of carbon steel:

NRC Item 1

Identify the codes and standards to which the piping was designed and fabricated.

Response

The North Anna piping systems of interest were designed to:

North Anna Design Specification NAS-290
North Anna Installation Specification NAS-1009
ANSI B31.1.0 - 1967 Edition
ANSI B31.7 - 1969 Edition with Addenda through 1970
ASME IX Welding Qualifications
American Welding Society Specifications

NRC Item 2

Describe the scope and extent of your programs for ensuring that pipe wall thickness are not reduced below the minimum allowable thickness. Include in the description the criteria that you have established for:

a) Selecting points at which to make thickness measurements

Response

Selection of Inspection Locations

To determine the extent of erosion/corrosion (E/C), each of the piping systems in the plant was reviewed to determine if it was susceptible to erosion/corrosion damage. In this regard, consideration was given to the following factors which are known to contribute significantly to erosion/corrosion either jointly or individually and a technical decision was made whether or not to include a particular system in the erosion/corrosion program at this time.

- o System Fluid: Piping carrying fluids other than water and wet steam are excluded from the erosion/corrosion program.

- o System Material: Historical data show that stainless steel material is virtually immune to erosion/corrosion damage and Cr-Mo materials are not susceptible to rates of erosion corrosion detrimental to the station. To validate this material exclusion criteria, poor geometry areas in a stainless steel piping system were inspected at the Surry Station. No evidence of erosion/corrosion was found in the stainless steel piping. For the erosion/corrosion program at North Anna, stainless steel materials are excluded. Carbon steel piping components were assumed to have insignificant chromium content for retarding erosion/corrosion.

- o Fluid Temperature: 195°F was selected as the system operating temperature below which personnel safety is not a major consideration. Additionally, test data shows that below this temperature the rate of erosion/corrosion is significantly reduced. Fluid systems operating at less than 195°F are being excluded from the erosion/corrosion program at this time.

- o Oxygen Levels: This factor, although not used as a sole justification for excluding piping from the erosion/corrosion program, was used with the other factors discussed above as additional justification for excluding particular systems. Research work show that the rate of erosion/corrosion can be significantly reduced by raising the fluid oxygen levels.

- pH Levels: The operating pH levels for the North Anna water chemistry is below the 9.3 -9.5 pH level. Above this level, the erosion/corrosion is reduced. Therefore, no inspection locations were exempted due to operating pH levels. That is, all were assumed to be in the pH range susceptible to erosion/corrosion.

In addition, certain carbon steel water and wet steam systems are being excluded from the program at this time because the operating pressures are less than atmospheric, they are used infrequently, and/or the system is not considered to be a major operational or personnel safety hazard.

Table 2a.1 provides a complete list of the North Anna Unit 1 and 2 piping systems and the technical justification for either including or excluding the piping from the erosion/corrosion program at this time.

Subsequent to the implementation of this program, the NUMARC guidelines on single phase erosion/corrosion will be applied to systems presently excluded from the inspection program.

TABLE 2a.1

PIPING SYSTEMS EVALUATED FOR INCLUSION

IN THE NORTH ANNA UNIT 1 EROSION/CORROSION INSPECTION PROGRAM

System	Included (Y or N)	Reason for Elimination: High O_2	Low Temp	Not C/S	Not H_2O	Notes
Instrument Compressed Air	N				X	
Containment Purge & Air Conditioning	N		X		X	
Radiation Monitoring	N		X		X	
Vacuum Priming	N		X		X	
Service Compressed Air	N		X		X	
Building Drains	N		X			
Bearing Lube Oil Water	N		X			
Boron Recovery	N			X		(1)
Component Cooling	N		X			
Component Cooling Chilled Water	N		X			(2)
Chemical Feed	N		X		X	
Chemical and Volume Control	N			X		(1), (3)
Containment Vacuum	N				X	
Emergency Diesel Air Start	N				X	
Containment Atmosphere Cleanup	N		X	X	X	
Compressed Dry Air Bottle System	N				X	
Leakage Monitoring	N		X	X	X	
Liquid Waste	N		X	X		(1)
Neutron Shield Tank Cooling Loops	N		X			
Fuel Pool Cooling	N		X	X		
Fuel Oil	N		X		X	
Fire Protection	N	X	X			
Primary Plant Gas Supply	N		X		X	
Gaseous Waste	N		X	X	X	
Decontamination	N		X	X		
Lube Oil	N		X		X	
Primary Grade Water	N		X			
Quench Spray	N		X	X		
Reactor Coolant	N			X		
Resident Heat Removal	N			X		
Refueling Purification	N		X	X		
Recirculation Spray	N		X	X		
Radioactive Waste	N		X	X		
Auxiliary Steam	Y					

System	Included (Y or N)	Reason for Elimination: High O_2	Low Temp	Not C/S	Not H_2O	Notes
High Pressure Steam Atmospheric Discharge	N					(4)
Decay Heat Release	N					(4)
Gland Steam	N					(8)
Main Steam	Y					(8)
Cold and Hot Reheat Steam	Y					
Auxiliary Boilers	N					(5)
Safety Injection	N		X	X		
Sampling Systems	N		X	X		(1), (6)
Extraction Steam	Y					
MSR and High Pressure Heater Drains and Vents	Y					
Low Pressure Heater Drains and Vents	Y					
Feedwater	Y					
Bearing Cooling Water	N		X			
Condenser Tube Cleaning	N	X	X			
Condensate Make-up Water	N		X			
Condensate	Y					
Domestic Water	N		X			
Circulating Water	N	X	X			
Primary Grade Make-up Water	N		X	X		
Flash Evaporator	Y					
Filtered Water	N		X			
Steam Generator Blowdown	Y					
Service Water	N		X			
Chemical Feed and Water Supply	N		X			
Auxiliary Feedwater	N		X			
Plant Steam Trap Drains and SLPD	N					(7)
Plant Vents, Drains and Safety/Relief Stacks	N					(4)
Low Pressure Steam	N					(4)

NOTES:

1. Carbon steel portions of this systems are low temperature.
2. Discharge line from air ejectors operates at 200°F and -13psig. Due to the low operating pressure this piping is being excluded from the erosion/corrosion program at this time.
3. Heating coil for the boric acid batching tank is being excluded form this erosion/corrosion program at this time due to it infrequent use.
4. This piping is being excluded from this program at this time due to its infrequent use.

5. Auxiliary boilers and the associated heating steam piping are in service intermittently and not considered a major operational or safety hazard. This piping will be included as part of the long term replacement/ inspection program.
6. Main steam sampling lines are excluded from the program at this time due to their infrequent use.
7. Steam trap drain piping is not considered a major operational or safety hazard. This piping will be considered as part of the long term replacement/inspection program.
8. Upstream of the regulating valve is main and auxiliary steam system piping; downstream is superheated steam conditions. SGLV, SGSH, and SGSV operate at 0 psig/100°F.

A detailed technical evaluation was completed on each piping system identified in Table 2a.1 that was included in the erosion/corrosion program. This evaluation applied the single phase piping and two phase piping inspection point selection criteria, and included a review of previous outage examination results.

The resulting number of points identified for inspection this outage are as follows:

TABLE 2a.2 NDE INSPECTION PLAN (1)

***NORTH ANNA UNIT 1**

System	Total Points(2)
Extraction & Auxiliary Steam	57
Flash Evaporator	9
Steam Generator Blowdown	6
Condensate	16
Feedwater	98
H.P. Heater & MSR Drains/Vents	30
L.P. Heater Drains/Vents	9
	225

*North Anna Unit 2 Inspections will begin in late August 1987.

NOTES:

1. (a) Main Steam - no inspections
   (b) Crossunder - VT all accessible piping and UT 3 areas
   (c) Crossover - VT all accessible piping
2. For the purpose of conducting the inspections it is convenient to divide a particular area into 2 or more inspection points. For example, an elbow and adjoining reducer would be identified as 1 area comprised of 2 inspection points.

Single Phase Piping - Inspection Point Selection Criteria

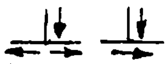
Piping geometry and fluid temperature and velocity are the primary factors used to identify potential problem areas within the single phase systems. Research work identified the "relative" susceptibility of a system to erosion/corrosion damage based on fluid velocity and temperature, assuming similar piping geometries exist. The erosion/corrosion program at North Anna used this information as a tool in selecting inspection areas. Each system was divided into subsystems based primarily on velocity and temperature and plotted on a graph that related this information to erosion/corrosion wear rate. The effect of piping geometry on erosion/corrosion was evaluated by applying the factors described in Table 2a.3. These factors were developed based on the documented evidence of the effect of geometry on two phase erosion/corrosion and applying the knowledge of Surry piping inspection results.

The combined effect of velocity, temperature, and geometry was then evaluated by multiplying the velocity/temperature factor (V/T Factor) with the geometry from Table 2a.3. Individual components within a subsystem were rated by applying this approach.

Inspection points were selected that are representative of the higher rated components. In certain areas lower rated components were also identified for inspection. The results of these inspections should provide additional data for further correlation of erosion/corrosion as a function of geometry and fluid velocity and temperature.

TABLE 2a.3

GEOMETRICAL EROSION/CORROSION FACTORS (2) (3) (4)

	V/T Factor
Control Valve, pressure breakdown orifice, downstream turning vanes (pump outlets)	12
Tee (Splitting ), Globe valves	10
Tee (), check valve, reducing and SR elbow	8
Elbows 90° (LR)	6
Butterfly valves, instrument taps, reducers, tees () 90°bends (1), FE	4
Gate valves, welds in straight pipe, reservoir upstream	2
Straight pipe	0

NOTES:

(1) Bends get special consideration where minimal margins exist between code wall and minimum manufactured wall thickness.

(2) When distance to upstream components is < 3d, add the upstream components geometry. Second upstream component is not considered.

(3) When distance to upstream component is > 3d but < 10d add 1/2 the upstream components geometry. Second upstream component is not considered.

(4) 45° lateral is rated at 1/2 90° tee, same for the elbows.

Two Phase Piping Inspection Point Selection Criteria

Wet steam system inspection points were selected based on applying methods presented in EPRI Report NP-3944 entitled "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines". This EPRI report relates erosion/corrosion wear rates to piping system material, geometry, and fluid velocity, temperature, and percent moisture, by applying Keller's equation. Keller's equation does not relate the effect of compound component configurations to erosion/corrosion wear rates. The evaluation of such configurations is left to judgement, with separation between flow disturbances being the criteria for severity and ultimate selection.

NRC Item 2b

Determining how frequently to make thickness measurements and,

NRC Item 2d

Making repair replacement/repair decisions

Response

The response to items 2.b and 2.d have been combined. The North Anna program for determining the frequency of measurements and replacement/repair decisions is identical to the Surry program. Therefore, refer to the response to items 2.b and 2.d in Attachment 1 (Surry Responses).

NRC Item 2c

Selecting the methods used to make thickness measurements.

Response

Description of NDE Procedures

Component inspections were conducted in accordance with North Anna Station Administration Procedures ISI-ADM-8.0 "Secondary Single Phase Piping Examinations" and ISI-ADM-8.1 "Secondary Two Phase Piping Examinations". Components in the feedwater, condensate and heater drains systems were inspected using the Single Phase procedure. Components in the extraction steam, evaporator, blowdown, and heater vent systems were inspected using the Two Phase procedure.

Each procedure addresses the area of component to be inspected, inspection grid pattern, method of marking, and the sequence in which the thickness readings are to be taken.

The results of these inspections when combined with the NUMARC guidelines will provide the basis for the long term erosion/corrosion inspection program for North Anna Unit #1. When the condition of the piping systems relative to erosion/corrosion is established and documented, the inspection program will:

- o Identify when and what component inspections are required each outage.
- o Provide for altering the scope of the inspected systems as more experience in predicting E/C behavior is gathered.
- o Allow for updating inspected component status changes due to replacements or configuration changes.

NRC Item 3

For liquid-phase systems, state specifically whether the following factors have been considered in establishing your criteria for selecting points at which to monitor piping thickness (item 2a).

a) Piping material (e.g. chromium content)
b) Piping configuration (e.g. fittings less than 10 diameters apart)
c) pH of water in the system (e.g. pH less than 10)
d) System temperature (e.g. between 190°F and 500°F)
e) Fluid bulk velocity (e.g. greater than 19 ft/s)
f) Oxygen content in the system (e.g. oxygen content less than 50 ppb)

Response

The criteria for selecting points for inspection is discussed in the response to Item 2. The factors identified above are considered in our selection criteria.

NRC Item 4

Chronologically list and summarize the results of all inspections that have been performed, which were specifically conducted for the purpose of identifying pipe wall thinning, whether or not pipe wall thinning was discovered, and any other inspections where pipe wall thinning was discovered even though that was not the purpose of the inspection.

a) Briefly describe the inspection program and indicate whether it was specifically intended to measure wall thickness or whether wall thickness measurements were an incidental determination.

Response

North Anna Power Station implemented two phase inspections/replacements in 1984. Following is a chronological summary of these inspections and replacements:

1984 - Replaced approximately 12 components on extraction steam piping on Unit 2.

1985 - Inspected approximately 20 components on extraction steam piping and H.P. Heater drains. Replaced approximately 5 components on Unit 1.

1986 - Inspected approximately 37 components on extraction steam piping, inspected steam crossover and crossunder piping on Unit 2.

For 1987 inspection results see response to item 4c.

NRC Item 4b

Describe what piping was examined and how (e.g. describe the inspection instrument(s), test method, reference thickness, locations examined, means for locating measurement point(s) in subsequent inspections.

Response

This item was addressed in responses to items 2a, b, c, and d. Subsequent inspections will be conducted in accordance with the response to item 5.

NRC Item 4c

Report thickness measurement results and note those that were identified as unacceptable and why.

Response

North Anna Unit 1 Inspection Results - 1987

Below is a summary of the inspection results by system. A through D correspond to the recommended disposition categories described below. The number of components that fell into each category is as indicated.

A - replace immediately
B - reinspect next refueling outage, potential replacement
C - reinspect next refueling outage
D - reinspect after X refueling outages
X is typically selected to be approximately one half of the components calculated remaining life. For example, if the calculated remaining life is 3 refueling outages, reinspection will be required during the second refueling outage.

NAPS TABLE 4c.1

System	A	B	C	D
Extraction Steam	9	10	13	23
Auxiliary Steam	-	-	-	2
Flash Evaporator	-	2	1	6
Steam Generator Blowdown	-	-	-	6
Condensate	-	1	1	14
Feedwater	16	21	25	36
Moisture Separator & H.P. Heater Drains & Vents	2	1	1	24
Low Pressure Heater Drains & Vents	-	-	-	11
TOTAL	*27	35	41	122

The total number of components inspected during the implementation of this program was 225.

*Some components rejected because of conservative acceptance criteria did not exhibit evidence of erosion/corrosion.

NRC Item 4d

Describe actions already taken or planned for piping that has been found to have non conforming wall thickness. If you have performed a failure analysis, include the results of that analysis. Indicate whether the actions involve repair or replacement, including any change of materials.

Response

North Anna Unit 1

Components identified in the response to Item 4c, Category A, Table 4c.1, were replaced during the 1987 outage. Also, some components in Category B, Table 4c.1, were replaced for construction convenience. On a case by case basis, changes in material and wall thickness were considered, and documented on Station Engineering Work Requests (EWRs). When required, an analysis was performed to evaluate changes in stress values created by the new components. When available, chrom-moly replacement components were used on the extraction steam system.

NRC Item 5

Describe any plans either for revising the present or for developing new or additional programs for monitoring pipe wall thickness.

Response

Long-Term Secondary Inspection Program

Virginia Power is in the process of developing a Long Term Secondary System Inspection Program for our nuclear units. This program will contain criteria and methodology for selection, inspection, and acceptance. It will also contain historical inspection data for each unit, trending information for wear rate development and information required for future inspections.

Virginia Power has been directly involved in the NUMARC working group on erosion/corrosion. We intend to apply the NUMARC inspection guidelines for single phase erosion into our Long Term Secondary System Inspection Program.