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Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

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ABSTRACT

Erosion/corrosion in single-phase piping systems was not clearly recognized as a potential safety issue before the pipe rupture incident at the Surry Power Station in December 1986. This incident reminded the nuclear industry and the regulators that neither the U.S. Nuclear Regulatory Commission (NRC) nor Section XI of the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* require utilities to monitor erosion/corrosion in the secondary systems of nuclear power plants. This report provides a brief review of the erosion/corrosion phenomenon and its major occurrences in nuclear power plants. In addition, efforts by the NRC, the industry, and the ASME Section XI Committee to address this issue are described. Finally, results of the survey and plant audits conducted by the NRC to assess the extent of erosion/corrosion-induced piping degradation and the status of program implementation regarding erosion/corrosion monitoring are discussed. This report will support a staff recommendation for an additional regulatory requirement concerning erosion/corrosion monitoring.

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ABBREVIATIONS

ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASNT	American Society of Nondestructive Testing
ASTM	American Society for Testing of Material
AVT	all-volatile treatment
BNL	Brookhaven National Laboratory
BOP	balance of plant
Btu	British thermal unit
BWR	boiling-water reactor
CFR	*Code of Federal Regulations*
CRT	cathode-ray tube
EPRI	Electric Power Research Institute
FAC	flow-assisted corrosion
GTAW	gas tungsten arc weld
HTGR	high temperature gas reactor
IN	information notice
INPO	Institute of Nuclear Power Operations
ISI	inservice inspection
LER	licensee event report
MSR	moisture separator reheater
MWe	megawatt electric
NDE	nondestructive examination
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NUMARC	Nuclear Utility Management and Resource Council
PORV	power-operated atmospheric relief valve
ppb	parts per billion
psig	pounds per square-inch gauge
PWR	pressurized-water reactor
RCS	reactor coolant system
RFO	refueling outage
RG	regulatory guide
RT	radiographic testing
RWCU	reactor water cleanup
SER	significant event report
SMAW	shielded metal arc weld
SRP	Standard Review Plan
USAS	United States of America Standards
UT	ultrasonic testing

1 INTRODUCTION

Erosion/corrosion, or flow-assisted corrosion (FAC), is a form of material degradation that can affect metallic materials that are normally resistant to corrosion because they are protected by an oxide film that forms on the surface. However, turbulent and fast-flowing water or wet steam wears away the protective film and leads to continued dissolution of the underlying metal. Erosion/corrosion, or FAC, is clearly different from erosion that is caused by mechanical processes such as abrasion (caused by particles in water), impingement (caused by water droplets in steam), and cavitation (caused by collapsing gas bubbles).

Erosion/corrosion can occur in both single-phase and two-phase carbon steel systems. It is basically a material transport process. Carbon steel piping that has been affected by erosion/corrosion under single-phase conditions shows evidence of uniform wall thinning similar to that caused by general corrosion. In the case of two-phase flow, the damaged surface has the appearance of "tiger striping."

Substantial research has been performed to establish the main factors that control erosion/corrosion. Those factors that control the erosion/corrosion of carbon steel in water are discussed below.

Alloy Composition

Alloy composition significantly affects the resistance of carbon steel to erosion/corrosion. By increasing the alloy content (e.g., chromium, molybdenum, copper), the resistance of carbon steel to erosion/corrosion improves significantly. Field experience has shown that carbon steel piping with a chromium content of 0.02 percent has little or no resistance to erosion/corrosion in the secondary system of pressurized-water reactors (PWRs) while using 2-1/4 percent chromium, 1 percent molybdenum (2-1/4 Cr-1 Mo) steel improves piping resistance to erosion/corrosion by a factor of 4. Furthermore, austenitic stainless steels are practically immune to erosion/corrosion attack.

Water Chemistry

Chemistry parameters affecting erosion/corrosion are oxygen concentration and pH. The erosion/corrosion wear rate of carbon steel increases significantly in the pH range of 7 to 9. The rate drops sharply at pH levels above 9.2. Highly dissolved oxygen in water reduces the rate of erosion/ corrosion by keeping the steel surface passive. It has been reported (Huijbregts, 1984) that iron release rates from carbon steel in pure water (neutral pH) decreased by up to 2 orders of magnitude for the temperature range of 38 to 204 °C with increasing oxygen concentration from 1 to 200 parts per billion (ppb). The precise oxygen level required to prevent erosion/corrosion depends on other factors such as pH level and the presence of contaminants. However, operating experience indicates that little erosion/corrosion has occurred in the condensate-feedwater system of boiling- water reactors (BWRs) where the dissolved oxygen level is recommended to be around 30 ppb.

Temperature

Erosion/corrosion-induced piping degradation has been reported (Bignold, 1980) in single-phase carbon steel systems within the temperature range of 80 to 230 °C, whereas for two-phase lines the temperatures ranges from 140 to 260 °C. The temperature at which maximum erosion/corrosion occurs changes depending on water chemistry; however, it is about 130 to 150 °C under single-phase conditions.

Piping Design and Hydrodynamic Conditions

Piping configuration and flow rate also strongly affect erosion/corrosion rates because geometry and flow rate control the mass-transfer rate of oxide dissolutive products. Laboratory results have confirmed that the mass-transfer coefficient is the controlling parameter. Unfortunately, local mass-transfer coefficients are dependent on local geometrical discontinuities (such as a backing ring for welding) and, at this time, they can only be derived empirically or by estimation. Eliminating the local geometrical discontinuities is an important step toward reducing erosion/corrosion damage.

2 MAJOR INCIDENTS OF PIPE WALL THINNING AND RUPTURE IN FEEDWATER SYSTEMS

2.1 Erosion and Rupture of Heater Drain Piping

The Trojan Nuclear Power Plant is a 1080 megawatt electric (MWe) pressurized-water reactor (PWR) designed by Westinghouse. It is located 32 miles north of Portland, Oregon, and is operated by Portland General Electric.

On the evening of March 9, 1985, the Trojan reactor was operating at 100 percent power. Average coolant temperature was 585°F and reactor coolant system (RCS) pressure was 2235 psig. At 9:50 p.m., a reactor trip occurred from automatic actuation of the reactor protection system following a main turbine trip. The turbine trip was caused by a spurious main turbine bearing high-vibration signal. The reactor protection system and plant safety systems functioned as designed during the transient. Following the turbine trip, the resulting automatic main feedwater isolation produced a pressure pulse to approximately 875 psig in the heater drain and feedwater systems, as expected. However, the pressure surge caused an eroded section of the 14-inch-diameter heater drain pump discharge piping to rupture, resulting in the release of a steam-water mixture of approximately 350°F into the 45-foot (ground-level) elevation of the turbine building. In addition to the fire suppression (deluge) system actuation by heat sensors in the turbine building and damaged secondary plant equipment, one member of the plant operating staff received first and second degree burns on 50 percent of his body from the high temperature fluid.

Because of the ruptured piping and steam and water buildup in the turbine building, condenser vacuum was lost approximately 4 minutes after the reactor trip. Loss of vacuum rendered the steam dump system inoperable, so the steam line power-operated atmospheric relief valves (PORVs) were used to control steam pressure and plant temperature. Makeup water for the steam generators was supplied from the condensate storage tank using the auxiliary feedwater system. The plant was maintained in hot standby until 3:50 a.m. on March 10, 1985, when a forced cooldown, using PORVs and auxiliary feedwater, was initiated. The plant entered hot shutdown at 10:20 a.m. and the residual heat removal system was placed in service 1 hour later.

The ruptured section of the carbon steel heater drain system piping (American Society for Testing Material [ASTM] A-106 Grade B) had been severely damaged by erosion/corrosion. Because the feedwater flow out of a normally open 14-inch manual globe valve was directed against the pipe wall, the pipe wall at the rupture location had eroded from a nominal thickness of 0.375 inch to a thickness of approximately 0.098 inch. The system flow rate at this location was 20 to 24 feet per second at normal operating conditions of approximately 450 psig and 350°F. Apparently, the pipe had been installed as a modification in about 1977 to aid in maintaining heater drain tank levels during plant startup, but was not intended to carry full flow during normal full-power operation. However, as the result of operational problems, the pipe did become the normal flow path. Subsequent inspections showed that the only other section of piping where significant erosion/corrosion had occurred was at a 10-to-14-inch expander section downstream of a 10-inch control valve. Although minimum wall thickness was still met at that location, repairs were made during the 1985 outage. The damaged section pipe was replaced, and power operation resumed on March 15, 1985.

2.2 Feedwater Line Rupture

The Haddam Neck Nuclear Power Plant is a 569 MWe PWR designed by Westinghouse. It is located 13 miles east of Meriden, Connecticut, and is operated by Connecticut Yankee Atomic Power.

On March 16, 1985, with Haddam Neck operating at 100 percent power, the operators in the control room heard a "pop" from the turbine building at 8:05 p.m. Security and health physics personnel notified the control room of a steam leak in the northeast, lower-level area of the turbine building. The control room operator notified the shift supervisor who was making a tour for plant status. The main control board indications appeared normal.

The shift supervisor and secondary side control operator investigated the steam leak. Steam and water appeared to be coming from the area of the 1B feedwater heater normal level control valve. Steam was blowing toward the steam generator feed pumps. The shift supervisor ordered a manual trip of the reactor and turbine because of the possibility of grounding the steam generator feed pump motor(s) and/or heater drain pump motor(s). In addition, the exact location of the pipe rupture had not been determined.

The reactor and turbine were manually tripped. Steam generators 1 and 3 were noted as having lower secondary side levels than steam generators 2 and 4. The steam generator low levels were attributed to the tripping of reactor coolant pumps 1 and 3 during the event, which caused shrinkage following idling of the loop. These pumps are required to trip by design during four-loop operation following a reactor scram. These pumps were restarted by 8:30 p.m.

After manually tripping the reactor, the A steam generator feed pump was shut down. The A and B auxiliary steam generator feed pumps were started to ensure availability in the event that both feed trains required isolation.

Condenser vacuum was lost because of air leaking through the turbine seals. The gland steam supply had previously been isolated for reasons unrelated to this event. The high-pressure steam dump was lost when the condenser vacuum reached 20 inches mercury. This was recognized after the primary side control operator noted an increase in average primary coolant temperature. In response to the increase in primary temperature, the secondary side control operator manually opened the atmospheric steam dump at about 8:15 p.m. Primary side temperature and pressure were controlled by the atmospheric steam dump until restart.

Automatic initiation of auxiliary feedwater flow occurred at 8:13 p.m. as a result of the low level in steam generators 2 and 4, 44 percent and 45 percent wide-range level, respectively. The levels of steam generators 2 and 4 remained below 45 percent for 20 seconds. The levels were low because of increased boil-off, which was caused by loops 1 and 3 being idled when their reactor coolant pumps were tripped. After the reactor was tripped, the pipe rupture was located. The pipe had ruptured downstream of the 1B feedwater heater normal level control valve, which is a Masoneilan Camflex valve. The actual rupture was approximately 1/2 inch by 2-1/4 inches.

The pipe rupture occurred because the flow exiting the 1B feedwater heater normal level control valve impinged directly on the pipe surface and severely eroded the pipe in that area. The eroded section of pipe was replaced. In addition, the corresponding pipe on the A feedwater train was checked for erosion. The licensee already had a program for monitoring pipe elbows for erosion in the main steam and condensate and feedwater systems. The licensee plans to include sections of pipe adjacent to flow control valve configurations, similar to the pipe that ruptured, in the plant's reliability engineering program for monitoring erosion of secondary system pipe elbows.

2.3 Catastrophic Rupture of Feedwater Line

The Surry Nuclear Power Station,.located on the James River approximately 12 miles from Newport News, Virginia, is operated by the Virginia Power Company.

On Tuesday, December 9, 1986, at 2:20 p.m., both units at the Surry Power Station were operating at full power when the 18-inch suction line to the main feedwater pump A for Unit 2 failed catastrophically.

Units 1 and 2 are identical. In each unit, feedwater flows from a 24-inch header to two 18-inch suction lines that each supply one of two main feedwater pumps. At maximum load under normal conditions, feedwater flow through each pump is 5 million pounds per hour. Feedwater temperature, pressure, and enthalpy are 370°F, 450 psig, and 346 Btu/lb, respectively. During these conditions the fluid is in the single-phase liquid-only regime.

The event was initiated by the main steam isolation valve on steam generator C failing closed. Because of the increased pressure in steam generator C that collapsed the voids in the water, the reactor tripped on low-low level in that steam generator. A 2-by-4-foot section of the wall of the suction line to the main feedwater pump A was blown out and came to rest in an overhead cable tray. The break was located in an elbow in the 18-inch line about 1 foot from the 24-inch header. The lateral reactive force generated by scraping feedwater completely severed the suction line. The free end whipped and came to rest against the discharge line for the other pump.

Steam flashing from the break and condensing in control cabinets and in open conduit piping apparently caused the fire suppression system to actuate, resulting in release of halon and carbon dioxide in the emergency switchgear room and in various cable tunnels and vaults and in the cable spreading room.

Investigation of the accident and examination of data by the licensee, NRC, and others led to the conclusion that failure of the piping was caused by erosion/corrosion of the carbon steel pipe wall. Although erosion/corrosion pipe failures have occurred in other carbon steel systems, particularly in small-diameter piping in two-phase systems and in water systems containing suspended solids, there have been few previously reported failures in large-diameter systems containing high-purity water. Consistent with general industry practice, the licensee did not have in place an inspection program for examining the thickness of the walls of feedwater and condensate piping.

2.4 Severe Pipe Wall Thinning of Feedwater Lines

During the June 1987 outage at the Trojan Nuclear Power Plant, it was discovered that at least two areas of the straight sections of the main feedwater piping system experienced wall thinning to an extent that the pipe wall thickness would have reached the minimum thickness required by the design code (American National Standard Institute (ANSI) Standard B31.7, "Nuclear Power Piping") during the next refueling cycle. These areas are in safety-related portions of the American Society of Mechanical Engineers' *Boiler and Pressure Vessel Code* (ASME Code), Section III, Class 2 piping inside containment.

The pipe wall had thinned in both horizontal and vertical runs that were at least seven pipe diameters downstream of elbows or other devices that can cause flow disturbance. Criteria developed by the Electric Power Research Institute (EPRI Users Manual NSAC-112, "CHEC" [Chexal-Horowitz Erosion-Corrosion], June 1987) would not have required the pipe wall in these straight sections to be examined.

In addition, the licensee discovered approximately 30 additional areas of the main feedwater piping system where the pipe wall had thinned so that the thickness of the pipe wall was either less than the minimum thickness required by the design code or would have eroded to the minimum required thickness during the next operating cycle. Of these areas, 10 were in the safety-related portions of the system, while the rest were in non-safety-related portions. All of these 30 additional areas were in regions that the EPRI criteria would have indicated as needing examination.

Pipe wall thinning of the condensate and feedwater system was discovered when the piping inspection program at Trojan was expanded to include single-phase piping, including all safety-related high-energy carbon steel piping inside containment.

Results of the licensee's failure analysis and the staff's independent verification indicate that erosion/corrosion coupled with cavitation caused by severe flow conditions at the pump discharge elbows are the primary mechanism that caused pipe wall thinning of the feedwater line at Trojan.

2.5 Accelerated Pipe Wall Thinning

During the September 1988 outage at the Surry Nuclear Power Station, the licensee discovered that pipe wall thinning had occurred more rapidly than expected. On the suction side of one of the main feedwater pumps, an elbow that was installed during the 1987 refueling outage lost 20 percent of its 0.500-inch wall in 1.2 years. In addition, wall thinning is continuing in safety-related main feedwater piping and in other non-safety-related condensate piping.

On the basis of partial inspection results, the licensee indicated that the broad area thinning rate for the replacement piping, installed during the last refueling outage, is roughly 60 mils/year. The maximum localized thinning rate is 90 mils/year. These rates were higher than the 20-to-30 mils/year rate estimated previously. The estimated rate of 20 to 30 mils/year was based on a single measurement and an assumption that wall thinning had been progressing linearly since initial full-power operation was achieved. This new rate of wall thinning, which is based on a second data point, indicates that significant wall thinning may have coincided with a reduction in feedwater dissolved-oxygen concentration following replacement of the steam generator. The lower rate of wall thinning associated with a higher feedwater dissolved-oxygen concentration is consistent with the low rates of erosion/corrosion reported in NRC Information Notice (IN) 88-17, "Summary of Response to NRC Bulletin 87-01, 'Thinning of Pipe Walls in Nuclear Power Plants,' " for boiling-water reactors (BWRs), which typically operate at a feedwater dissolved-oxygen concentration of approximately 30 ppb. The licensee is continuing its failure analysis to determine the cause(s) of the increase in the estimated pipe wall-thinning rate.

2.6 Other Incidents of Pipe Wall Thinning

In addition to the major incidents of pipe wall thinning and rupture of feedwater piping systems, numerous piping degradation resulting from erosion- or erosion/corrosion-induced wall thinning has occurred in the secondary systems of many operating nuclear power plants. A brief summary of these events are described below.

Plant	Year	Description	Reference
Oconee 3	1976	Extraction line pinhole leak	NRC IN 82–22
	1980	Replace erosion/corrosion thinned elbow	NRC IN 82–22
Browns Ferry 1	1982	Failure of 8-inch discharge line on the MSR drain pump	INPO Significant Event Report (SER) 41–82
Oconee 2	1983	Failure of a 3- to 10-inch expander down stream of a reheater drain tank	INPO SER 23–85
Calvert Cliffs 1	1984	Rupture of a 16-inch elbow in a branch line from a cold reheat steam line	INPO LER 88–84
Haddam Neck	1985	Pipe rupture downstream of a feedwater heater	INPO Licensee Event Report (LER) 305–85006
Kewaunee	1985	Rupture of a 2-inch excess steam vent line from a MSR	INPO LER 305–85017
Hatch 2	1986	Rupture of a 20- to 16-inch reducer in an extraction steam line	INPO LER 366–86010
Ginna	1986	Failure of a 6-inch elbow of a moisture separator reheater drain line	INPO LER 244–86004

3 CODES, STANDARDS, AND REGULATORY REQUIREMENTS OF CARBON STEEL PIPING

The requirements for the construction and inservice inspection of safety-related systems differ from those of systems that are not safety related because safety-related systems are relied on to provide the capability to prevent or mitigate the consequences of accidents, remove heat from the reactor, and maintain it in a safe shutdown condition. The construction requirements of safety-related systems differ from non-safety-related systems in the areas of materials inspection and nondestructive examination of piping system weldments, overpressure protection, and quality assurance, including third-party inspection. For the main steam and feedwater system, the principal difference between the design of the safety-related and non-safety-related components is that the safety-related systems are required to meet seismic criteria and requirements for design quality assurance that complies with Appendix B to Title 10 of the *Code of Federal Regulations* Part 50 (10 CFR 50). Safety-related portions of these lines also are required to receive inservice inspection and testing under 10 CFR 50.55a(q), which invokes Section XI of the ASME Code. Non-safety-related systems are not required by any standard or regulatory requirement to receive inservice inspection. Design codes/standards for typical BWR and PWR systems are listed in Tables 3.1 and 3.2, respectively.

Table 3.1 Design codes standards for typical BWR piping systems (high-energy systems)

System	Code/Standard*
Nuclear boiler	ASME Sec. III, ANSI B31.1
Reactor recirculating	ASME Sec. III, ANSI B31.1
Control rod drive hydraulic	ASME Sec. III, ANSI B31.1
Standby liquid control	ASME Sec. III, ANSI B31.1
Residual heat removal	ASME Sec. III, ANSI B31.1
Low-pressure core spray	ASME Sec. III, ANSI B31.1
High-pressure core spray	ASME Sec. III, ANSI B31.1
Reactor core isolation cooling	ASME Sec. III, ANSI B31.
Reactor water cleanup (RWCU)	ASME Sec. III, ANSI B31.1
Filter/demineralyzer RWCU	ASME Sec. III, ANSI B31.1**
Main and reheat steam	ASME Sec. III, ANSI B31.1
Auxiliary steam	ASME Sec. III, ANSI B31.1
Condensate	ANSI B31.1
Feedwater	ASME Sec. III, ANSI B31.1
Heater vents and drains	ANSI B31.1
Main and reactor feed pump turbine seal	ANSI B31.1
Moisture separator-reheater	ANSI B31.1
Extraction steam	ANSI B31.1

* The safety-related portion of the piping is designed to ASME Code Section III. The non-safety-related portion of the piping is ANSI Standard B31.1.

** Piping is designed to ANSI Standard B31.1 and fabricated to ASME Code Section III.

Table 3.2 Design codes/standards for typical PWR piping systems

System	Code/Standard*
Main steam	ASME Code Section III, Class 2 ANSI Standard B31.1
Extraction steam	ANSI Standard B31.1
Auxiliary feedwater	ASME Code Section III, Class 2, ANSI Standard B31.1
Main feedwater (outside containment)	ANSI Standard B31.1
Main feedwater	ASME Code Section III, Class 2
Steam generator blowdown	ANSI Standard B31.1
Heater drains	ANSI Standard B31.1

The term non-nuclear is not well defined, but as used by many and in the response below it describes piping not constructed to Section III of the ASME Code. Power plants built before the adoption of Section III of the ASME Code were constructed to other standards such as American National Standards Institute (ANSI)/ASME Standard B31.1, "Power Piping."

The condensate and feedwater systems of PWRs provide feedwater at the required temperature, pressure, and flow rate to the secondary side of the steam generators. Condensate is pumped from the main condenser hotwell by the condensate pumps, passes through the low-pressure feedwater heaters to the feedwater pumps, and then is pumped through the high-pressure feedwater heaters to the secondary side of the steam generators. That portion of the condensate and feedwater system located within the turbine building and the portion of the feedwater lines between turbine building up to the containment isolation valves located outside the reactor containment building are not classified as safety related. The portion of the feedwater system from the containment isolation valves located outside the reactor containment building up to and including the secondary side of the steam generators are within the nuclear portion of the power plant and are classified as safety related.

An auxiliary feedwater system is connected to the main feedwater system and normally operates during startup, hot standby, and shutdown to provide feedwater to the steam generators. This system also functions as an emergency system for the removal of heat from the primary system when the main feedwater system is not available and for emergency conditions including small loss-of-coolant accidents. The entire auxiliary feedwater system is classified as a safety-related system.

Regulatory guidance with regard to the auxiliary feedwater system, the main feedwater system, main condensers, and condensate system is provided in the following sections of the Standard Review Plan (SRP), NUREG-0800, Revision 2 (July 1981).

SRP Section	Title
10.4.1	Main Condensers
10.4.7	Condensate and Feedwater System
10.4.9	Auxiliary Feedwater System

The following regulatory guides also provide guidance with regard to quality group classification (applicable codes and standards), seismic design requirements, and quality assurance requirements for components of nuclear power plants.

Regulatory Guide	Title
1.26, Revision 3 (February 1976)	Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants
1.29, Revision 3 (September 1978)	Seismic Design Classification

The construction codes and standards applicable to the auxiliary feedwater system and the safety-related portion of the main feedwater system at Surry Units 1 and 2 are as follows:

- Portions of main feedwater piping—ANSI Standard B31.1-1967 supplemented by ASME Code Case N-7. Auxiliary feedwater piping—ANSI Standard B31.1-1967
- Pumps—such as auxiliary feedwater pumps—manufacturer's standards
- Valves—manufacturer's standards and ANSI Standard B31.1-1967 and related standards such as Standard B16.5

The construction codes and standards applicable to the non-safety-related portions of the condensate and feedwater system at Surry Units 1 and 2 are as follows:

- Condensate and feedwater piping—ANSI Standard B31.1-1967, "Power Piping Code"
- Pressure vessels such as feedwater heaters—ASME Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels"
- Pumps, such as condensate and feedwater pumps, and steam turbines—manufacturer's standards
- Valves—manufacturer's standards and ANSI Standard B31.1-1967 and related standards such as ANSI Standard B16.5

Section XI of the ASME Code, "Rules for Inservice Inspection of Nuclear Power Plant Components," is used by the licensee to provide guidance during plant operation on inservice inspection of components and inservice testing of pumps and valves that are safety related because Surry was constructed before the development of ASME Code Section III, which is applicable to safety-related systems today.

Section XI of the ASME Code currently does not contain a requirement to explicitly measure wall thickness to detect thinning. Weldments are inspected by nondestructive examinations to determine if indications are within allowable limits.

Classification of the Piping System

Regulatory Guide (RG) 1.26, SRP Section 3.2.2, and 10 CFR 50.55 provide the staff's criteria for classifying the main steam line and the feedwater line from the reactor up to and including the outermost isolation valve as Quality Group A (ASME Code Section III, Class 1). RG 1.26 also classifies the main steam line up to but not including the turbine stop valve and bypass valves as Quality Group B (ASME Code Section III, Class 2) (see Table A.1, SRP Section 3.2.2). Alternatively, for BWRs containing a shutoff valve (in addition to the two containment isolation valves) in the main steam line and in the main feedwater line, Quality Group B standards should be applied to those portions of the steam and feedwater systems extending from the outer most containment isolation valve up to and including the shutoff valve (see SRP Section 3.2.2). Weldments in Quality Groups A and B are subject to periodic inservice inspection in accordance with Section XI of the ASME Code per 10 CFR 50.55(a)(g).

4 INDUSTRY EFFORT TO ADDRESS THE EROSION/CORROSION ISSUE

Shortly after the December 1986 accident at the Surry Nuclear Power Station, the nuclear industry took the initiative to address the single-phase erosion/corrosion issue by ensuring that initial inspections would be conducted at all U.S. domestic power plants.

In March 1987 the Nuclear Utility Management and Resource Council (NUMARC) established a working group on erosion/corrosion; that group developed a recommended industry program (Appendix A) to address the issue. The program identifies potential evidence of a single-phase erosion/corrosion problem and provides guidelines for utilities to follow. In general, the recommended NUMARC guidelines are threefold: (1) to conduct appropriate analysis and a limited but thorough baseline inspection program, (2) to determine the extent of thinning, if any, and to repair/replace components as necessary, and (3) to perform followup inspections (to confirm or quantify thinning) and longer term corrective actions (i.e., adjust chemistry, operating parameters, or others) as appropriate. The NUMARC program specifies an initial inspection requirement of 15 fittings, with maximum reliance for their selection based on engineering judgment and a computer code (such as the CHEC code developed by EPRI). This program is developed to optimize nondestructive examination (NDE) resources needed for inspection.

Before the Surry accident, EPRI research programs had helped the industry by identifying two-phase erosion/corrosion as a flow-accelerated corrosion process that leads to wall thinning (metal loss) of carbon steel components exposed to flowing wet steam. An inspection guideline (Kastner et al, 1988) was issued to help utilities in developing their erosion/corrosion monitoring program for the two-phase lines. The guideline was developed to meet utilities needs to address the erosion/corrosion problem and is based on combining the results of the root-cause research work and the firsthand site inspection with practical experience. A methodology for developing a plant-specific, cost-effective, and reliable inspection program was provided, which included rating and prioritizing systems and subsystems and identifying components most susceptible to severe erosion/corrosion degradation.

The Surry accident focused attention on the potential deterioration of carbon steel piping because of erosion/corrosion damage in a single-phase secondary coolant system. To assist utilities in identifying areas of carbon steel piping that might be undergoing erosion/corrosion damage under single-phase conditions, NUMARC and EPRI developed a recommended inspection plan to monitor pipe wall-thinning problems. The major elements of this plan consist of (1) where to look for locations that are susceptible to erosion/corrosion attack, (2) how to look for these potentially vulnerable locations, (3) when to look for them, and (d) what are the repair/replacement criteria. The NUMARC program is designed to provide the industry with a predictive capability with regard to the pipe wall-thinning rate as a function of operating time for a given component and to provide a cost-benefit analysis with regard to repair/replacement options. The staff reviewed NUMARC's program on erosion/corrosion in single-phase lines in June 1987 and found it to be acceptable (Appendix A).

On March 17, 1988, NUMARC representatives provided a briefing on industry efforts to implement a program to address erosion/corrosion. On the basis of NUMARC data, 112 of 113 plants have committed to implement an erosion/corrosion program for single-phase piping by October 1988. Subsequent to the meeting, the remaining plant, a new BWR, had an unplanned shutdown and conducted an examination of single-phase piping. As of early 1988, 54 plants had completed inspections. Components were replaced in 19 of these plants as a result of single-phase erosion/corrosion. Only one BWR replaced components, demonstrating that the problem is more extensive for PWRs. For the 19 plants replacing components, 10 replaced more than five components and 9 replaced fewer than five components.

Although the staff accepted the NUMARC working group's program, it indicated that assurances are needed that all plants have systematically addressed the issue of two-phase erosion/corrosion and have procedurally implemented long-term programs for single-phase and two-phase piping systems. To address these concerns, NUMARC is supporting EPRI in the development of a computer-based program for two-phase erosion/corrosion. This program is similar to the single-phase program.

5 NRC EFFORTS TO ADDRESS THE EROSION/CORROSION ISSUE

5.1 Issuing Information Notices

Shortly after the catastrophic failure of the main feedwater pipe at the Surry Nuclear Power Station in December 1986, the NRC dispatched an investigation team to determine the cause of the incident and its generic implication. The team determined that the failure was caused by wall thinning because of erosion/ corrosion. On December 16, 1986, the NRC issued Information Notice 86-106 "Feedwater Line Break," to all nuclear power plant licensees describing the event and its generic implication so that utilities could review the problem for applicability to their facilities. Subsequently, extensive investigations at Surry revealed that erosion/corrosion also had occurred in the other piping systems and locations. Repairs were made by replacing the piping. During the investigation, the NRC issued supplemental information notices to all nuclear power plant licensees on February 13 and March 18, 1987. Those notices provided the information developed through the investigation, including potentially generic system interaction problems that were caused by release of large quantities of feedwater.

After the Trojan incident, the NRC issued another Information Notice 87-36 on August 4, 1987, to alert licensees to a potentially generic problem pertaining to significant unexpected erosion that resulted in pipe wall thinning in the safety-related portions of feedwater lines. In addition, the staff established a task force on July 9, 1987. The task force is made up of staff from different offices of the NRC as well as consultants, many of whom were involved in the resolution of the Surry feedwater line break incident. This interdisciplinary team has the needed technical expertise to investigate the Trojan pipe wall-thinning event and to address general issues related to erosion/corrosion and pipe wall thinning.

On July 22, 1987, the task force visited the Trojan plant to review the event and to evaluate the licensee's corrective actions and other related activities. The task force attended briefings, interviewed licensee staff, and made visual examinations of selected piping sections and components removed from the feedwater lines. In addition, the task force selected piping samples to independently verify the licensee's analysis.

The task force completed its preliminary review of the Trojan event on August 13, 1987, and determined that the damage mechanism at Trojan was similar to that of the Surry accident. Although the licensee has provided reasonable assurance for safe operation of the feedwater systems through the end of the 1988 operating cycle, the task force will review the results of the licensee's final failure analysis and those from the independent verification to determine the long-term operability of the Trojan feedwater systems.

By letter dated June 22, 1988, the licensee provided results of its failure analysis regarding pipe wall thinning of the feedwater and condensate system at the Trojan plant. The staff determined that the piping material was consistent with design specification, the damage mechanism was identified, and corrective actions are adequate to provide reasonable assurance for continued operation of the feedwater piping system at Trojan, including seismic Category 1 piping.

5.2 Organizing Technical Panel Discussion

On January 15, 1987, the staff invited experts from several engineering disciplines (piping design, metallurgy, nondestructive examination, water chemistry, corrosion, and fluid mechanics) to participate in a technical panel discussion on the parameters believed to have had an important role in the pipe break at Surry and on the means to predict and mitigate the effects of erosion/corrosion in piping systems. The cause of the Surry failure, which occurred in the feedwater piping near the suction side of one of the feedwater pumps, has been identified as pipe thinning from erosion/corrosion; however, at least one panel member believes that cavitation erosion cannot be completely excluded. The actual failure of the thinned pipe wall resulted from a system pressure transient, not a classical water hammer event.

The complex interactions of the individual variables that affect the erosion/corrosion phenomenon and influence the rate at which it proceeds, have not been thoroughly established by available research activity in this country or abroad. The panel discussion elaborated on the role of those parameters that could have potentially contributed to erosion/corrosion in the feedwater piping system. The panel made several observations and recommendations, which are summarized as below.

Observations

- The phenomena associated with pipe wear as a result of erosion, erosion/ corrosion, or cavitation have not been recognized as significant problems by piping designers. Consequently, designers do little to accommodate piping wear resulting from these phenomena in their design.

- The NRC initiative on omitting the dynamic effects of postulated pipe ruptures, whenever technically justified, should not be affected by the Surry failure.

- The amount of erosion/corrosion damage and the rate at which it proceeds is a complex phenomenon depending on a number of variables.
- In the case of Surry and other U.S. plants, the three most important variables influencing the erosion/corrosion process are material, local fluid velocity/turbulence, and water chemistry/pH.
- Although erosion/corrosion is not a new or unknown phenomenon, it has received relatively little study in the United States because incidence of recorded failures has been low and the relationship of the variables influencing the processing is complex.

Recommendations

- The panel believes that adjustments to pH or oxygen content, from levels now in use to protect steam generators, should not be made without a thorough study of the possible global effects of such changes on the entire system.
- The panel believes that the factors influencing the rate at which the erosion/corrosion phenomenon proceeds in single-phase systems cannot be ranked because the available current quantitative data are insufficient.
- Data resulting from baseline wall thickness measurements taken as a result of recommendation 2 should be correlated with flow velocity, turbulence, water chemistry, temperature, actual material chemical composition, and installed original wall thickness, to the extent that such data are available.
- ASME should consider the need for providing appropriate guidance to system designers on the subject of erosion and erosion/corrosion in its conventional pressure piping and nuclear piping codes and standards.

5.3 Requesting ASME to Address the Erosion/Corrosion Issue

As mentioned above, following the Surry feedwater line rupture, there was a technical meeting held at the request of the staff to consider the generic implications of this failure. One of the recommendations made by participants of the meeting was that ASME should consider the need for providing appropriate guidance to system designers on pressure piping and nuclear piping codes and standards.

To implement the above recommendation, the staff requested that the ASME Section XI Committee consider this subject during its meeting of March 19, 1987. After the Trojan event in June 1988, the staff sent a second request to the ASME Section XI Committee asking that the issue concerning erosion/corrosion-induced pipe wall thinning be addressed.

In response to the NRC requests, the ASME Section XI Committee established a special working group on pipe wall thinning in April 1988 and started to assess the need of a possible monitoring requirement. The current status concerning the progress made on this issue is summarized below.

With regard to balance-of-plant (BOP) piping, the Committee believes the historic approach used by many utilities is appropriate; namely that utilities develop their own nondestructive examination (NDE) program to determine if there is a problem with BOP piping. With regard to safety-related piping such as Class 1 and 2 piping systems, the Committee agrees with the staff recommendation; thus, the Section XI special working group on pipe wall thinning is developing requirements and procedures to detect and prevent pipe wall thinning resulting from erosion/corrosion in nuclear power plants. It is expected that the final version, standard code language, will be an equitable balance between the existing ASME Section XI requirements for Class 1 and 2 piping and the added requirements resulting from examinations for wall thinning. Currently, Class 1 examinations are predominantly volumetric while Class 2 examinations are a mixture of volumetric, surface, and visual. In systems such as the feedwater line, 7.59 percent of the welds are required to be examined volumetrically. The special working group is reviewing this requirement to see if the percentage can be lowered, provided that the welds with highest stress intensity factors are examined.

Codifying pipe wall-thinning examinations is not an easy task. Because of the nature of the damage mechanism, several interactive parameters, such as temperature, alloy composition, pH and dissolved oxygen content of the water, and piping geometry are all important considerations in selecting the inspection points. Furthermore, the damage may occur at a variety of locations with different morphology, making examination even more difficult.

5.4 Issuing NRC Bulletins

An informal NRC staff survey, conducted during the first week of February 1987, demonstrated (1) that the wall-thinning problem is widespread in two-phase lines at nuclear power plants and (2) that most licensees either did not have a monitoring program for pipe wall thinning or had an inadequate program.

Main feedwater systems, as well as other power conversion systems, are important to safe operation. Failures of active components in these systems, such as valves or pumps, or of passive components, such as piping, can result in undesirable challenges to plant safety systems required for safe shutdown and accident mitigation. Failure of high-energy piping, such as feedwater system piping, can result in complex challenges to the operating staff and the plant because of potential systems interactions of high-energy steam and water with other systems, such as electrical distribution, fire protection, and security systems. All licensees have either explicitly or implicitly committed to maintain the functional capability of high-energy piping systems that are a part of the licensing basis for the facility. An important part of this commitment is that piping will be maintained within allowable thickness values.

As a result of the survey findings, NRC Bulletin 87-01 was issued on July 9, 1987. This bulletin required all licensees to provide information to the NRC on their erosion/corrosion experience and monitoring programs for single-phase and two-phase high-energy carbon steel piping systems. Specifically, the licensees were requested to provide the following information:

- Identify the codes or standards to which the piping was designed and fabricated.
- Describe the scope and extent of programs for ensuring that pipe wall thicknesses are not reduced below the minimum allowable thickness. Include in the description the criteria established for:
  - selecting points at which to make thickness measurements
  - determining how frequently to make thickness measurements
  - selecting the methods used to make thickness measurements
  - making replacement/repair decisions
- For liquid-phase systems, state specifically whether the following factors have been considered in establishing criteria for selecting points at which to monitor piping thickness (second item under 2 above):
  - piping material (e.g., chromium content)
  - piping configuration (e.g., fittings less than 10 pipe diameters apart)
  - pH of water in the system (e.g., pH less than 10)
  - system temperature (e.g., between 190 and 500°F)
  - fluid bulk velocity (e.g., greater than 10 ft/s)
  - oxygen content in the system (e.g., oxygen content less than 50 ppb)
- Chronologically list and summarize the results of all inspections that have been performed, 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 purpose of that inspection.
  - 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.
  - Describe what piping was examined and how (e.g., describe the inspection instrument(s), test method, reference thickness, locations examined, and means for locating measurement point(s) in subsequent inspections).
- Describe plans for revising existing pipe wall-thinning monitoring procedures or developing new or additional inspection programs.

All licensees responded to the bulletin and the staff completed its review of the responses in December 1987. Furthermore, at the end of September 1988, the staff completed inspection of 10 plants to assess the licensees' efforts toward implementing their erosion/corrosion monitoring program. The purpose of this report is to summarize the results of the staff review of the licensees' responses to the bulletin and the inspection results of the 10 plants. On the basis of these results and the efforts of NUMARC and the ASME Section XI (Inservice Inspection) Committee in terms of addressing the pipe wall-thinning issue, recommendations will be made with respect to the need of regulatory requirements for pipe wall-thinning monitoring.

6 SUMMARY OF LICENSEE'S RESPONSES TO NRC BULLETIN 87-01

6.1 Design and Fabrication Code or Standard

The staff review of licensee responses to the bulletin showed that for domestic nuclear power plants the secondary system piping and components are all made of carbon steel. The material specification for straight runs of piping is American Society for Testing Material (ASTM) A-106 Grade B steel, and the specification for elbows is ASTM A-234 Grade WPB carbon steel.

The review indicated that before the ASME Code Section III rules for piping, pumps, and valves were revised in 1971, the secondary coolant systems in nuclear power plants were designed and fabricated in accordance with the ANSI requirements of ANSI Standard B31.1, which includes 57 of all licensed units. After 1971, safety-related portions of the secondary coolant systems were designed and fabricated in accordance with ASME Code Section III rules while non-safety-related portions of the secondary coolant systems continued to be designed and fabricated in accordance with ANSI Standard B31.1, which includes 43 percent of all licensed units.

6.2 Pipe Wall-Thinning Monitoring Program

For two-phase, high-energy, carbon steel piping systems, the responses to the bulletin indicated that programs exist at all plants for inspecting pipe wall thinning. Inspection locations are generally established in accordance with the 1985 guidelines described in the Electric Power Research Institute (EPRI) document NP-3944, "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines." However, because implementation of these guidelines is not required, the scope and the extent of the program vary significantly from plant to plant.

In early June 1987, NUMARC, in conjunction with EPRI, developed guidelines for inspection and repair of single-phase piping. These guidelines utilize a computer code that identifies and prioritizes inspection locations on the basis of plant-specific factors such as fluid velocity, piping geometry, system temperature, and water chemistry. Areas that are subjected to flow disturbances, such as elbows, branch connections, and piping and fittings downstream of control valves or flow orifices, are preferentially selected locations for inspection. By letter dated June 12, 1987, the NRC staff informed NUMARC that, with minor comments, these guidelines were acceptable.

Responses to the bulletin indicated that limited inspections of the single-phase feedwater and condensate system were conducted in the majority of plants after the Surry Unit 2 incident. Most licensees developed their wall-thinning monitoring programs for single-phase piping because of the events at the Surry and Trojan plants. Some plants apparently developed programs after NRC Bulletin 87-01 was issued. Out of a total of 110 units, 23 units still have not established an inspection program for monitoring wall thinning in single-phase lines. Of these units, 17 are operating and 6 are under construction.

6.3 Frequency and Method of Inspection

The inspection frequency for pipe wall-thickness measurements and replacement or repair decisions is based on a combination of predicted and measured erosion/corrosion rates. In general, the pipe wall-thickness acceptance criteria use measured wall thicknesses and an erosion/corrosion damage rate to predict when the pipe wall thickness will approach its code-allowable minimum wall thickness. The acceptance criteria provide guidance for determining if a piping component must be replaced or repaired immediately or for projecting when a piping component should be replaced at some future time.

The primary method of inspection reported was ultrasonic testing (UT), supplemented by visual examination and, in a few cases, by radiography. Pipe wall-thickness measurements were either made by or verified by Level II or Level III inspectors certified to the American Society of Nondestructive Testing (ASNT) TC-1A Standard. The NRC staff considers this to be an adequate inspection technique.

6.4 Affected Systems and Components

The staff's review of licensees' responses to NRC Bulletin 87-01 showed that wall thinning in the feedwater and condensate system is more prevalent in pressurized-water reactors (PWRs) than boiling-water reactors (BWRs). As shown in Table 6.1, 26 PWRs and 6 BWRs have identified various degrees of wall thinning in feedwater piping and fittings.

The systems and components reported as experiencing pipe wall thinning are listed below.

Single-Phase Line	Two-Phase Line
main feedwater lines, straight runs, fittings	main steam line
main feedwater recirculation to condenser, straight runs, fittings	turbine crossover piping
feedwater pump suction line, straight runs, fittings	turbine crossunder piping
feedwater pump discharge line, straight runs, fittings	extraction steam lines
condensate booster pump recirculation line fittings	moisture separation reheater
steam generator letdown lines, straight runs, fittings	feedwater heater drain piping

Wall-thinning problems in single-phase piping occurred primarily in the feedwater and condensate system; the problems in two-phase piping, although varied in extent, have been reported in a variety of systems in virtually all operating plants. Although inspection of single-phase lines is not scheduled until the next refueling outage for a number of plants, the available data from plants already inspected indicate a widespread problem.

The staff's review further indicated that the recirculation-to-condenser line (minimum-flow line) in the feedwater and condensate system has experienced pipe wall-thinning degradation most frequently. The line is used to protect the pump during low-power operation and is isolated by a minimum-flow valve during high-power operation. Specific information regarding a minimum-flow line degradation incident at the LaSalle County Station is provided in the bulletin to alert licensees about this problem.

Table 6.1 Plants experiencing wall thinning in the feedwater condensate system

Plant/Unit	Type of Reactor	Initial Criticality Date	Degraded Components, Fittings, or Straight Runs
Dresden 2	BWR	January 1970	elbows
Duane Arnold	BWR	March 1974	elbows, reducers, straight runs
Pilgrim 1	BWR	June 1972	elbows
Oyster Creek 1	BWR	May 1969	elbows
River Bend 1	BWR	October 1985	recirculation line
Perry 1	BWR	June 1986	straight runs
Arkansas 1	PWR	August 1974	elbows, drain pump discharge piping
Arkansas 2	PWR	December 1978	undefined
Calvert Cliffs 1	PWR	October 1974	elbows, reducers, straight runs
Calvert Cliffs 2	PWR	November 1976	elbows, reducers, straight runs
Callaway 1	PWR	October 1984	recirculation line elbows
Diablo Canyon 1	PWR	April 1984	elbows, straight runs
Diablo Canyon 2	PWR	March 1978	elbows
Ft. Calhoun 1	PWR	August 1973	elbows, straight runs
Haddam Neck	PWR	July 1967	recirculation line
Harris 1	PWR	October 1986	recirculation line
Millstone 2	PWR	October 1975	elbows, heater vent piping
North Anna 1	PWR	April 1978	elbows, straight runs
North Anna 2	PWR	June 1980	elbows, straight runs
Robinson 2	PWR	September 1970	recirculation lines
San Onofre 1	PWR	June 1967	reducers, heater drain piping
San Onofre 2	PWR	July 1982	heater drain piping
San Onofre 3	PWR	August 1983	heater drain piping
Salem 1	PWR	December 1976	recirculation line
Salem 2	PWR	August 1980	recirculation line
Surry 1	PWR	July 1972	fittings
Surry 2	PWR	March 1973	fittings
Sequoyah 1	PWR	July 1980	elbows, straight run
Sequoyah 2	PWR	November 1981	elbows
Trojan	PWR	December 1975	elbows, reducers, straight runs
Turkey Point 3	PWR	October 1972	feedwater pump suction line fittings
Fort St. Vrain	HTGR*	January 1974	straight run in emergency feedwater line
Rancho Seco 1	PWR	September 1974	straight runs downstream of main feedwater (MFW) loop isolation valve or MFW pump miniflow valve

*high-temperature gas reactor

7 ONSITE INSPECTION

7.1 Inspection Criteria

Ten plants were selected for inspection as part of the overall staff actions to address the pipe wall-thinning issue. The NRC inspection team included consultants from the Brookhaven National Laboratory (BNL). The staff assessed how licensees are implementing their erosion/corrosion monitoring program to ensure that proper techniques were used by qualified personnel for pipe wall-thickness measurements and to ensure that adequate guidance was provided for corrective actions and other activities regarding repair and replacement of degrading piping and components. Through selective examination of each licensee's program for monitoring pipe wall thinning, the procedures and administrative controls defining the activities to be accomplished were verified for consistency with the licensee's program commitment. The staff's criteria to evaluate the licensees' erosion/corrosion monitoring programs and their implementation are briefly described below.

Review of Licensee's Erosion/Corrosion Monitoring Program

- The licensee has developed an erosion/corrosion monitoring program.
- The licensee's program has well-defined criteria for
  - selecting inspection points
  - determining inspection frequency
  - defining method of inspection
  - making replacement/repair decisions
- The licensee's program meets the intent of NUMARC guidelines.
- The licensee's program includes
  - high-energy single-phase lines, including long-term inspection
  - two-phase lines, including guidelines and computer codes
  - large moderate-energy single-phase piping systems
- The licensee has established a plant-specific history of pipe wall thinning, including failure analysis and damage mechanism.
- The licensee has a well-developed training program and personnel conducting NDE examinations have been properly certified.

Review of Licensee's Implementation of Erosion/Corrosion Monitoring Program

- Inspection procedures and guidelines
  - are properly reviewed and approved before their implementation
  - cover periodic monitoring of high-energy safety-related and non-safety-related carbon steel
  - provide for qualification or certification of personnel and equipment
  - are consistent with commitments
- The equipment used to perform NDE has been calibrated against known standards for types of metals and range of thickness to be measured.
- Pipe wall thickness is being measured in accordance with established instructions and results are being appropriately documented.
- Qualified personnel are evaluating pipe wall measurements to determine the need for corrective action and the frequency of continued periodic monitoring.
- A schedule has been established to repair and continually monitor piping that has shown evidence of wall thinning.
- Administrative controls are in place and management support is evident.
- The licensee's commitments in response to NRC Bulletin 87–01 are being met.

7.2 Summary of Inspection Results

7.2.1 Erosion/Corrosion Monitoring Program

Most licensees in the 10-plant inspection developed their initial erosion/corrosion monitoring program for two-phase lines in 1982 after the 24-inch pipe rupture (extraction steam line) at the Oconee Unit 2 plant. A few of them later expanded their program to include high-energy single-phase piping after the failure of a heater drain discharge pipe at the Trojan Plant in 1985. After the feedwater line rupture at Surry Unit 2 in 1986, a majority of licensees again expanded their program to include large moderate-energy single-phase piping systems.

Most licensees established their own erosion/corrosion multidisciplinary task force in early 1987 shortly after the

Surry incident to address the issue of pipe wall thinning. The task force's objectives were to

- develop a predictive method to select inspection locations on the basis of pipe configurations, materials, velocities, and water chemistry
- inspect each unit using various NDE methods at points established by system modeling
- develop a baseline from the information gathered during inspections and use it for trending purpose
- expand the overall program to include the utility's fossil units

The task force also established an action plan to inspect piping of 1 inch and larger with a system temperature greater than 100°C. In general, piping over 8 inches in diameter was given priority. This action plan covers main steam, extraction steam, heater drains, condensate, feedwater, and reheat systems.

The locations for inspection were selected on the basis of NUMARC guidelines or calculated flow rates, piping geometries, and past experience. The EPRI "CHEC" computer code was used in most cases to determine the most susceptible areas to erosion/corrosion damage. However, most licensees indicated that the results were more consistent when the selections were made on the basis of operating conditions and engineering judgment rather than on the basis of the computer code alone.

For small bore piping systems, some licensees are using a through-insulation radiography technique for detecting wall thinning. When wall thinning was identified by radiography, insulation was removed and actual depth of wall thinning was determined by ultrasonic (manual) measurement. In actual practice, however, some licensees have chosen to replace all piping 8 inches in diameter and less rather than measuring the actual thickness if erosion/corrosion thinning is detected.

7.2.2 Corrective Actions and Repair/Replacement Criteria

All licensees in the 10-plant inspection either implictly or explicitly have adopted an acceptance criteria for making repair/replacement decisions consistent with the NUMARC guidelines for erosion/corrosion in single-phase lines.

In general, the licensees have been replacing all piping that shows a significant amount of wall thinning. Most replacement piping has been made of the same carbon steel (ASTM A-106 Grade B and ASTM A-234 Grade WPB) or the ASME SA equivalents. However, depending on availability, in some cases 2-1/4 Cr-1 Mo steel (SA 335 Grade P22), or other low-alloy steel was used for replacement piping.

In some instances, licensees have chosen to weld overlay a thinned area of piping so that it exceeds the minimum wall thickness requirements of the piping system. In cases where a pipe is repaired by weld overlay, the pipe wall thickness is monitored closely to ensure the pipe integrity, otherwise the overlay will only stay in place until the next outage at which time it will be replaced with pipe of the same specification or of a more resistant low-alloy steel.

All replacement pipe welds were welded without backing rings. The root passes for these replacement welds generally were made by the gas tungsten arc weld (GTAW) testing method while the subsequent passes were made with the shielded metal arc weld (SMAW) testing techniques.

7.2.3 Inspector Qualification and Training Program

Majority of the licensees in the 10-plant inspection used outside contractors to perform the ultrasonic testing inspection of the secondary piping systems. Only a few licensees used their own NDE personnel for the pipe wall-thickness measurements. However, in both cases, the inspectors who conducted the erosion/corrosion examination were certified to the ASNT TC-1A Standard.

7.2.4 Overall Program Assessment

The 10 licensees in the inspection have developed and have in place an erosion/corrosion monitoring program that meets the intent of the NUMARC guidelines for erosion/corrosion monitoring in single-phase lines. In addition, all licensees have completed their initial inspection on the feedwater and condensate system. Although these inspections were carried out by qualified and certified NDE inspectors, none of these licensees have formalized their procedures and administrative controls to implement their erosion/corrosion monitoring programs.

7.3 Plant-Specific Inspection Findings

Plant 1 (PWR), Inspection Date: May 24-27, 1988

The initial program for erosion/corrosion was instituted in 1982 after the 24-inch pipe rupture of an extraction steam line at Oconee Unit 2. This program was expanded in 1985 after the heater drain discharge pipe failure at the Trojan plant. A third expansion of the program was made after the Surry incident in 1986. This modification was made to include large moderate energy piping systems with single-phase flow conditions. The program has since evolved to include small-diameter high- and moderate-energy piping systems as well as the condensate system piping.

The following systems of both units were examined for wall thinning:

- feedwater and condensate system
- heater-drain pump discharge piping
- extraction steam piping
- turbine crossunder piping
- small piping downsteam of steam trap

To date, pipe wall thinning has been discovered in the heater-drain discharge piping, the feedwater and condensate piping, and downstream of steam traps on lines coming off the main steam lines of Unit 1. Only a small amount of wall thinning was discovered in the piping of the feedwater and condensate system. Failure analyses of damaged piping or components were conducted routinely by the licensee. The inspection team reviewed a typical investigation report during the visit; it appeared to have been done in a thorough and professional manner.

Ultrasonic testing (UT) and radiographic testing (RT) were used for wall-thickness measurements. The licensee contracts with outside vendors to do UT inspection as well as the RT work. The inspection team reviewed NDE certifications of vendor personnel who have conducted the wall-thickness measurements and found their qualifications satisfactory.

The licensee is replacing all piping that shows a significant amount of wall thinning. As of the last refueling outage before the NRC inspection, all replacement piping was of the 2-1/4 percent chromium, 1 percent molybdenum variety of steel (SA 335, Grade P22). In some instances, the licensee may opt to weld overlay to a thinned area of piping so that it exceeds the minimum wall thickness requirements of the piping system. In such cases, the repaired piping will stay in place only until the next outage at which time it will be replaced with SA 335, Grade P22 material. In addition, all replacement pipe welds were done without the use of backing rings. The staff determined that this new welding procedure will reduce significantly the propensity of erosion/corrosion-induced pipe wall thinning.

The staff found the licensee's erosion/corrosion monitoring program meets the intent of NUMARC guidelines. The licensee's program is above industry standards. Specifically, replacing carbon steel pipe with chromium-molybdenum steels without backing rings in welds is a positive step towards reducing the pipe wall thinning problem.

All of the appropriate controls appear to be in place at this site. The only potential problem with the program is the lack of formalization with implementing procedures. The utility is currently using a series of memoranda to document the practices to be used. As of this date, the current time frame for an overall implementing procedure to be written and approved is the summer of 1989.

Plant No. 2 (PWR) - Inspection Date: June 7-8, 1988

The licensee's program of erosion/corrosion monitoring was initiated in the spring of 1985, with early detection of two-phase (wet steam) line degradation being the primary concern. During the fall of 1985, the licensee began its inspection of steam piping in accordance with the guidelines given in EPRI Report NP-3944. After the 1986 Surry pipe rupture event, the licensee organized a multidisciplinary task force to expand the original pipe wall-thinning monitoring program and to develop an action plan for implementing the NUMARC recommendations for monitoring erosion/corrosion in single-phase lines. In addition, the licensee also established a program of accelerated monitoring of heat drains and vents.

To date, the licensee has replaced pipe in various areas of the plant for two-phase erosion/corrosion but has not experienced any incidents of single-phase erosion/corrosion. A section of piping downstream from a throttle valve (entering the steam generator blowdown flash tank) was replaced recently with stainless steel pipe. In another case, a main feedwater pump elbow (90° minimum flow line) was replaced with a P-11 elbow, which was found leaking after only 6 months in service. The licensee is monitoring this elbow by frequent inspections and will conduct a failure analysis after replacement at the next refueling outage.

The licensee has looked at all but one of the potential areas of erosion/corrosion. It is currently evaluating the feasibility of inspecting the auxiliary feedwater system and the main steam drain lines. In addition, the licensee plans to inspect the safety-related portion of the feedwater system as well as the blowdown and essential service water systems at the next refueling outage.

The staff found that the licensee normally uses UT techniques for its inspection and it has very elaborate and precise procedures for the layout of inspection grids for UT. When UT did not provide meaningful results, the licensee's practice was to use RT. Only Level II inspectors certified to ASNT Standard TC-1A, are used in the pipe wall-thinning inspection program. Records review and personnel interviews indicated that the licensee has established an adequate qualification and training program for its NDE inspectors.

The licensee's program is above the industry standards. There was excellent assignment of responsibilities and concise, explicit procedures approved and issued for conducting pipe wall-thickness measurement, and there was evidence of good management support and well-defined organizational responsibilities. However, because of intrinsic difficulties with UT inspections through weld overlays, the licensee should prepare UT standards to be used for various thin-wall/overlayed conditions.

Plant No. 3 (BWR) - Inspection Date: July 6–8, 1988

The licensee's initial interest in the erosion/corrosion phenomenon developed in 1978 when a small crack was discovered in a feedwater discharge pipe downstream of a reactor feedwater pump. Subsequent UT showed that wall thinning had occurred on all three feedwater pumps, and three feedwater pipe reducers were replaced. In late 1978, a 6-inch pipe downstream of a reheater drain tank flow control valve was inspected and wall thinning was detected. During 1983 and 1984, a total of 40 locations in various parts of the main steam, extraction steam, and feedwater piping systems were inspected. As a result of this inspection, three feedwater expansion elbows, 14 x 16 inches, were replaced. Although a total of 46 locations were identified for inspection in 1986, only five main steam line drains were inspected and replaced because of schedular priorities. During the 1987 outage, 43 locations were inspected; six components were found to require reinspection within the next three outages. The staff found that, to date, the licensee has not inspected the safety-related portion of the feedwater lines. However, the licensee indicated that this will be done during the next refueling outage.

The licensee primarily uses UT techniques in monitoring pipe wall thinning. The licensee's inspections were conducted by its own NDE personnel and those of its contractors. The NRC inspection team reviewed the licensee's qualification and training program for the NDE personnel responsible for conducting pipe wall-thinning examination. The results showed that only inspectors (Level II and III) certified by ASNT Standard TC–1A were used on the inspections.

To date, the licensee has replaced all degraded components with original carbon steel replacements. However, the licensee is making a concerted effort to locate and procure chromium-molybdenum materials for future outage replacements. Although there is no written procedures that preclude the use of backing rings in replacement situations, the welding supervisor could recall no instances where eroded/corroded pipe or components were replaced using backing rings.

The licensee also took initiative to develop its own computer program for selecting inspection locations. The NRC inspection team found that the licensee's computer program was developed by basing the Keller equations with modifications as well as considering the parameters recommended in the NUMARC guidelines for monitoring erosion/corrosion in single-phase lines.

The staff finds that the licensee has a multidiscipline approach to address the pipe wall-thinning problem. The program, involving various engineering and quality assurance groups, is found to meet the intent of the NUMARC guidelines. The staff recommended that the licensee should examine the safety-related portion of the feedwater lines for potential erosion/corrosion problems as soon as possible and should formalize its implementation procedures and administrative controls to ensure that its pipe wall-thinning inspection program will be conducted just like any other inservice inspection (ISI) program.

Plant No. 4 (PWR) - Inspection Date: July 12–14, 1988

The erosion/corrosion monitoring program initially evolved in 1978 as an informal single-point-per-component production plant maintenance monitoring program. The second phase started during the Unit 2 refueling outage in 1984. Crossunder and extraction steam piping was selected for inspection; the results showed an active erosion/corrosion mechanism in the system. The inspection program then was expanded for two-phase piping. Heater drain tank pump discharge piping and feedwater pump discharge piping were added in 1985 as the result of INPO SER 23–85. A sample of large bore cooling water piping was added in 1985 after a leak was experienced near a cooling water pump discharge piping weld. The licensee's current program covers turbine crossunder piping, high-pressure extraction piping, feedwater pump discharge piping, and cooling water piping. The licensee has found areas of pipe wall thinning.

The licensee has replaced two sections of piping as a result of the thickness survey program. However, in both cases the licensee determined that the piping removal was necessary because of lamination and not because of erosion/corrosion-induced wall thinning. No piping samples or written failure analysis reports were available for review.

The inspections were performed by using various forms of NDE such as UT, RT, and visual examination. However, UT remains the primary inspection method. Radiography has been attempted with limited results. A procedure would have to be developed to qualify the use of RT to determine actual wall thickness of damaged pipe sections. Inspection areas were selected by reviewing results from computer code, the findings of an independent survey by an outside vendor, and the requests of the Plant Extensions Group. Forty-five areas were scheduled for inspection. Single- and two-phase systems greater than 4-inch diameter with a design temperature over 200 °F are presently included in the inspection scope.

Outside contractors were used to conduct UT inspections. All inspectors were certified in accordance with ASNT Standard TC–1A requirements. In addition, data interpretation and evaluation were done by ASNT-certified Level II or Level III inspectors. However, specialized training is required for personnel using Ultra Image III UT equipment. The NRC inspection team also reviewed the licensee's training program and certification records of selected NDE personnel and found them satisfactory.

The licensee's corrective actions and repair/replacement criteria for pipe wall thinning is based on the NUMARC guidelines for single-phase lines. The responsible plant system engineer evaluated the inspection results and determined if a repair/replacement was required. Replacement piping materials are currently planned as like kind replacement (i.e., carbon steel A–106 Grade B replacing the original carbon steel A–106 Grade B material).

The staff finds that the licensee's erosion/corrosion monitoring program meets the intent of the NUMARC guidelines and is above the industry standards. Specifically, the licensee took initiative to evaluate the advantages of selecting inspection locations on the basis of using the computer code or on the basis of operating experience and engineering judgment alone. The licensee concluded that the benefit gained by use of the computer code does not justify the resources and efforts spent on providing data input for the computer code. Similar conclusions by other licensees also were reported to the staff. The appropriate controls appear to be adequate to meet program requirements. However, a potential problem with the program is the lack of formalization of the program implementing procedures and the level of responsibilities assigned to the plant systems engineer. Approval of procedures currently in a draft/review status and a shift of material repair/replacement responsibilities to the Materials & Special Processes Group should go far to provide formal program implementation.

Plant No. 5 (PWR) - Inspection Date: July 26–28, 1988

The licensee initiated its original erosion/corrosion monitoring program in 1983/1984 outage. However, the program was confined to two-phase lines only. The main steam reheat crossunder piping was inspected and numerous components were either repaired by weld buildup or replaced with new components of the same specification.

After the Surry incident in December 1986, the licensee inspected 70 fittings from systems, such as the condensate bypass, condensate and feedwater, and the heater drain pump discharge recirculation, of one unit. Three locations were found to be below the minimum wall thickness of the piping material specification; these were all replaced. During the 1987 inspection, 88 fittings in the secondary systems of the second unit were inspected. Of the 30 locations identified with a wall thickness below the acceptance criteria, 3 locations were repaired by weld overlay, 13 locations were replaced, and 14 locations were evaluated to be adequate for continued service. To date, the licensee has not identified any cases of single-phase erosion/corrosion. During the inspection, no failure analysis reports were available for the NRC inspection team to review.

The licensee's erosion/corrosion monitoring program is governed by three memoranda instead of a formalized well-integrated master inspection program plan. These memoranda establish a 2-inch grid pattern for UT measurements. To date, no permanent reference points have been marked on the pipes, only point stick grids have been drawn. The licensee's selection of inspection locations was primarily on the basis of engineering judgment and operating experience. Use of the EPRI CHEC computer code for inspection point selection was not encouraging.

The licensee uses qualified (ASNT Standard TC–1A, Level II) personnel to perform UT inspection. Certification records and training program for NDE personnel were reviewed and found satisfactory.

The staff finds the utility's program meets the NUMARC guidelines for inspection of erosion/corrosion in single-phase lines. However, the lack of coherent corporate (formalized) program and associated implementing procedures is a potential problem area.

Plant No. 6 (BWR) - Inspection Date: August 9–11, 1988

An erosion/corrosion inspection program at both units was started in 1982 in response to industry reports of wall-thinning problems occurring in the cross-around steam piping. The extraction steam piping was examined (both units) in 1985 and heater drain piping was examined at Unit 2 in 1986. In the fall of 1987, the licensee performed a baseline inspection at Unit 1. A similar inspection was performed at Unit 2 in the spring of 1988. There were instances of erosion/corrosion problems in single-phase lines at both units although more so at Unit 2.

The licensee used three contractors during the fall 1987 inspection to determine which areas of the plant were the most likely candidates for wall thinning. A total of 36 single-phase locations were chosen from the feedwater, condensate, condensate booster, and heater drains. In addition, 21 two-phase locations were chosen, as well as four additional elbows, in response to leaks found in the reactor feed pump minimum flow lines of another licensee's plant. Of the 61 locations inspected, 11 had UT grid reduction performed; these all were found to be acceptable after engineering evaluation.

During the spring 1988 outage, a pipe wall-thinning inspection was performed at Unit 2. Of the 46 locations (20 single-phase and 26 two-phase) inspected, 41 were found to be acceptable (either on initial inspection or after engineering evaluation); in 2 locations nozzles were repaired; and in 3 locations, 6-inch diameter pipes were replaced. UT methods were used in these inspections. So far, no radiography has been used for pipe wall-thinning inspection. Outside contractors were used for these inspections and all evaluation of data was performed by ASNT-certified Level II or Level III inspectors. The NRC inspection team reviewed certification documentation and the inspector training program and found them to be adequate.

No repairs or replacements were necessary following the Unit 1 inspection. Three 6-inch pipe replacements were necessary following the Unit 2 inspection. The damaged P–1 material (carbon steel) was replaced with P–5 (5 percent chronium) material making the line entirely P–5. The inspection team reviewed the work package for the replacement work, welder performance qualification records, the NDE inspector's certification records, and the training program; all were found to be satisfactory.

The staff finds the licensee's overall erosion/corrosion program meets the intent of the NUMARC guidelines for single-phase lines. All appropriate controls for an effective pipe wall-thinning program were in place at both units under one program manager. The ability of the licensee to draw from experience at its other sites is a definite advantage. However, overall administrative procedures for pipe wall thinning need to be written. Currently, there is not a procedure available to control this program. The utility stated that such a procedure would be written and in effect before the June 1989 outages.

Plant No. 7 (PWR) - Inspection Date: August 30–31, 1988

The licensee's erosion/corrosion experience dates back to the extraction steam pipe inspections at Unit 1 in 1978. In 1980, 70 fittings of the extraction steam lines were again inspected at Unit 1 without instance of pipe wall thinning. A similar inspection was conducted at Units 2 and 3 in 1985. Seventy-six locations in each unit were examined and all locations were found to be above minimal wall thickness. A 1986 inspection of Unit 1 steam extraction piping disclosed an elbow with a wall-thinning problem. Eight other elbows also were examined and they were found to be satisfactory. In addition, 12 main steam (tees and elbows) and 5 feedwater elbows were examined on Unit 1 in 1986. All fittings were within the manufacturer's tolerance for wall thickness.

In the 1986 inspection of Unit 2, 93 areas on the steam extraction piping were examined; this included the 76 locations previously examined in the 1985 baseline inspections. No significant wall thinning was observed.

The Unit 3 feedwater and condensate piping was examined in the 1986/1987 timeframe as a result of the Surry incident. Thirty-six locations were examined and six reducers replaced. Two reducers were replaced with Type 304 stainless steel and four reducers with a 2-1/4 percent chromium, 1 percent molybdenum alloy.

Sixty-nine locations of the Unit 2 feedwater and condensate system piping also were examined in the 1986/1987 timeframe. This included 10 locations recommended by computer code. The steam extraction piping for Unit 3 was re-examined in 1987. Although some evidence of wall thinning was observed, all of the locations exceeded the minimum design requirements for wall thickness. Also in 1987, 102 locations of the Unit 1 feedwater and condensate system piping were examined; 3 areas were found to have readings below manufacturer's tolerance but no areas exceeded the replacement limit. In a 1988 inspection at Unit 3, 98 locations were inspected. Two expanders were replaced with chromium-molybdendum material because of significant wall thinning and two other fittings were replaced with chromium-molybdendum fittings because of experience gained at Unit 2.

UT is the normal method of inspection for erosion/corrosion pipe wall thinning. Both A-scan (CRT display) and ultra image equipment were used during examination. Grid patterns were applied by "paint stick" to facilitate examinations.

Although the licensee has implemented the EPRI "CHEC" computer program for determination of the most susceptible areas for pipe wall thinning, no significant wall thinning had occurred at these chosen locations. In contrast, erosion/corrosion-induced wall thinning had occurred at various other locations, predominantly at expanders downstream of control valves. To date, there has been no instance of significant erosion/corrosion in safety-related feedwater lines.

The licensee used outside contractors for the baseline inspections at all three units. The NRC inspection team reviewed the licensee's qualification program and certification documents of selected NDE personnel. In addition, certification and calibration documentation for test equipment and test blocks were reviewed. The results were all satisfactory. However, the licensee has no training or retraining program for the NDE personnel.

Concerning repair/replacement criteria, the licensee attempts to replace the original carbon steel components with more corrosion-resistant materials (e.g., stainless steel or chromium-molybdenum alloys). In addition, backing rings have not been used in welding or repairs at the site since the construction phase was completed.

The staff finds that the licensee's erosion/corrosion monitoring program meets the intent of the NUMARC guidelines and is above industry standards. The replacement of carbon steel piping with more corrosion-resistant materials is a definite step toward mitigating pipe wall thinning caused by erosion/corrosion. Review and root cause evaluations are done by a company metallurgist, which also is a positive attribute of the licensee's program. These two items plus the utility's large inspection population definitely show that appropriate controls are in place at the site. The only area lacking completeness in the program is absence of an overall administrative procedure that would delineate the responsibilities of the various groups involved with the pipe wall-thinning monitoring program.

Plant No. 8 (PWR) - Inspection Date: August 24–25, 1988

The licensee performed its first pipe wall-thinning inspection in 1981 on the extraction steam lines. Thirteen elbows and one "tee" connection were examined. Three elbows were replaced and one elbow was repaired and eventually replaced. In 1982, 56 elbows from the extraction steam lines and 4 elbows from the main steam line were examined. Six elbows were repaired and three elbows were replaced because of wall thinning. In 1984, 39 elbows and 2 drains of the extraction lines were examined; 10 elbows were replaced and 2 locations on the 5th-point extraction drain lines were temporarily patched. Sixty-nine elbows were examined in 1985. The systems covered extraction drain lines, the high-pressure turbine skim tank vent, feedwater heater steam vents, and heater drains. Pipe wall thinning occurred in all systems with eight elbows replaced and one repaired. The 1987 inspection encompassed: 149 elbows, 9 tees, 14 drain locations, 10 vent locations, and 2 pipe-to-nozzle connections. The systems inspected included feedwater lines and many other two-phase lines. This inspection required 55 elbows to be replaced and 1 vent location plus the entire second-point vent to be replaced. To date, formal failure analyses were not performed on damaged components. However, during the plant audit, significantly thinned sections from small bore drain lines, the heater drain system, and the high-pressure moisture preseparator drain system were shown to the NRC inspection team. Visual examination of these components by the NRC team confirmed the licensee's proposed erosion/corrosion failure mechanism.

The licensee uses UT techniques to determine pipe wall thinning, where feasible, and supplements this by visual examination. During the next refueling outage, the licensee plans to inspect 283 locations (e.g., pipe, fitting, elbow, and tee). Inspections were done by outside contractors and only ASNT-certified, Level II inspectors were used. The NRC inspection team reviewed certification documents of inspectors and calibration records for equipment and instruments used for wall-thickness measurements and found them to be satisfactory.

The licensee is replacing components that show a significant amount of wall thinning. Although some replacements have been "in kind" (carbon steel for carbon steel), the licensee is attempting to replace eroded/corroded components with P-22 materials (2-1/4 Cr-1 Mo).

The staff finds that the licensee's current program meets the intent of NUMARC guidelines for erosion/corrosion monitoring in single-phase lines. The licensee has an aggressive program of component inspection with good management.

Although a great many inspections have been performed for erosion/corrosion pipe wall thinning, the repairs have been performed with a minimum of procedures. The utility tends to assign a cognizant engineer to a project, who in turn "runs the show" for his/her area of responsibility. Previous record keeping (pre-1987 outage) shows a somewhat haphazard approach to documenting erosion/corrosion inspections. A more formalized program with appropriate procedures would tend to firm up and fill out an otherwise good program.

Plant No. 9 (BWR) - Inspection Date: September 6–9, 1988

The licensee began its development of a erosion/corrosion monitoring program in 1985 as a result of NRC IE Information Notice 82–22, INPO SER 41–82, and INPO Significant Operating Experience Report 82–11. These documents address erosion and erosion/corrosion of steam piping at several nuclear power plants. Phase II of the licensee's program evolved as action response to NRC Bulletin 87–01. Thirty additional components were selected for inspection bringing the total number of components to thirty-eight. These components will be inspected at every reactor refueling outage (RFO) with expansion of the erosion/corrosion monitoring program determined on the basis of field inspection results.

In June 1987, an 18-inch condenser drain leak was investigated. The condenser was in service since 1982. Steam erosion was determined to be the cause of the leak. The line was repaired using a P11 ASME SA–335 insert. Impingement of water droplets was determined to be the root cause of the material degradation. However, no formal failure analysis has been reported.

To date the licensee has used digital ultrasonic thickness measurement equipment (D-meter) and visual examination for pipe wall-thinning inspection. Automated ultrasonic equipment has not been used because of the short operating time of Unit 1. The next scheduled inspection will be performed at RFO 3, March 1989.

The staff finds that the licensee's erosion/corrosion monitoring program meets the NUMARC guidelines. The appropriate engineering and plant operational controls are in place and provide adequate instruction, response, and corrective actions when required. The inspection program engineering commitments are good and provide operational restraints when program requirements are exceeded. However, administrative/management interface for the erosion/corrosion program does not appear to be clearly defined either by procedures or organizational flow charts. The licensee is in the process of incorporating the erosion/corrosion inspection program requirements into a plant specification or procedure, which would provide the administrative/management organizational interface that the program is currently weak in.

Plant No. 10 (PWR) - Inspection Date: September 28–29, 1988

The licensee did its first pipe wall-thinning inspection in 1983. Two-phase lines at 36 locations were inspected, which resulted in replacement of only one reducer. In 1985, the licensee inspected another 21 locations on two-phase lines and no significant wall thinning was discovered. In 1987, 69 locations on single-phase lines were examined. Four locations showed wall-thickness discrepancies. Two components are currently being redesigned, another one was replaced, and the fourth one was found acceptable to the next refueling outage. The licensee has not completed any failure analysis on the degraded components.

Currently, selection of inspection points and sample expansion are based on criteria from the NUMARC guidelines and the Bechtel Power Corporation "WATHEK" computer code. Prioritization of sampling for single-phase systems is determined using onsite erosion/corrosion events, industry experience, and consideration of factors that affect the rate of erosion/corrosion.

The licensee uses outside contractors for all NDE-related activities. The contractors' personnel are qualified in accordance with ASNT Standard TC-1A. All evaluation of data is performed by ASNT-certified Level II or Level III inspectors. The licensee reviews and approves all contractor procedures and personnel qualifications. However, the licensee currently does not have in-house procedures or equipment to perform NDE examinations or verify the contractors' results.

The licensee generally will replace all piping that shows a significant amount of wall thinning. Repair/replacement to date has been with carbon steel and 2-1/4 Cr-1 Mo materials. The licensee is reviewing design changes and the use of stainless steel piping materials for future repair/replacement. All nonconforming inspections for safety-related and non-safety-related systems are documented on nonconformance reports and transmitted to the Nuclear Engineering Department for resolution.

The staff finds that the licensee's erosion/corrosion monitoring program meets the intent of NUMARC guidelines. However, inspections have shown that there is a definite need to improve record keeping (reproducibility of wall-thickness inspection data). Appropriate implementing procedures and positive program commitments also would fill out an otherwise good erosion/corrosion program.

8 CONCLUSION

As this review has shown, erosion/corrosion is a complex phenomenon and its rate can be affected by factors such as piping material, geometry and hydrodynamic conditions, and operating conditions of the secondary systems such as temperature, pH, and dissolved oxygen content. The problem is widespread for both single-phase and two-phase high-energy carbon steel piping systems. Although the Surry incident was the first time for such a catastrophic failure occurring in a nuclear power plant, it was no worse than previous failures in large steam turbine reheat lines or in feedwater lines. The failure mechanism was different to some extent because the Surry incident was caused by erosion/corrosion-induced pipe rupture whereas the wet steam pipe failures were caused by a cavitational type of erosion damage.

Many nuclear utilities initiated inspection programs to monitor erosion/ corrosion on their own initiative shortly after the Surry incident. However, the extent of the inspection programs varied until NUMARC and EPRI developed uniform guidelines for inspection, repair, and replacement of piping and components degraded by erosion/corrosion attack. These guidelines were endorsed by the NRC in June 1987, and they form the basis for most erosion/corrosion monitoring programs developed by utilities. In addition, as requested by the NRC, the ASME Section XI Committee is developing a new requirement for pipe wall-thinning inspection. The new requirement will cover both Class 1 and 2 piping of the safety-related portion of the feedwater lines.

Recent utility reports to NUMARC have indicated that inspections using the new guidelines or their equivalent were completed at all 113 plants at the end of October 1988. Results of the 10 plant audits completed by the NRC indicate that all licensees have conducted initial erosion/corrosion monitoring inspections and the programs meet the intent of the NUMARC guidelines for erosion/corrosion monitoring in single-phase lines. A few of the 10 licensees are in the process of formalizing procedures or administrative controls to implement their long-term programs; however, all licensees have not committed to these procedures or controls for a long-term program. In many instances, licensees had not specified record keeping during previous inspections to allow for the future reproducibility and trending. There also were instances where work was done by outside contractors using the contractor's guidelines rather than the licensee's guidelines, which may lead to inconsistency.

Therefore, in the absence of formalized procedures and administrative controls, there is not adequate assurance that licensees will continue to meet their licensing basis by maintaining the structural integrity of high-energy carbon steel piping systems. In addition, codifying pipe wall-thinning examinations is not an easy task. Past experience shows that it will take several years before the final code requirements regarding pipe wall-thinning inspection are formalized and implemented. Consequently, the staff recommends, as an interim step to ASME imposing its code requirements, that the NRC (through a generic letter) require licensees to formalize their procedures and administrative controls to ensure that the NUMARC program or another equally effective program is implemented so that the integrity of all high-energy piping systems is maintained.

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NUMARC TECHNICAL SUBCOMITTEE
WORKING GROUP ON PIPING EROSION/CORROSION
SUMMARY REPORT

June 11, 1987

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EXECUTIVE SUMMARY

The need exists to establish industry initiatives to identify potential evidence of single phase erosion/corrosion and thus help ensure personnel safety and minimize unnecessary plant challenges resulting from potential further failures. It is paramount that timely and appropriate action be taken.

Schedules for completion of these industry efforts should be aggressive for those units where the potential exists indicative of unacceptable wall thinning. For other units where no indication exists, analysis and inspections are necessary but may be performed on a schedule commensurate with normal refueling cycles.

Simply stated, the recommendations of the NUMARC Working Group are threefold. They are 1) conduct appropriate analysis and a limited but thorough baseline inspection program, 2) determine the extent of thinning, if any, and repair/replace components as necessary, and 3) perform follow-up inspections to confirm or quantify thinning and take longer term corrective actions (i.e., adjust chemistry, operating parameters, or others), as appropriate.

To assist in accomplishing these efforts, the Working Group consistent with their stated mission is providing guidance to industry in the following areas.

SAMPLE SELECTION

° Initial sample - 10 most susceptible locations and 5 additional locations

SAMPLE EXPANSION

° For each component below acceptance guidelines, the inspection shall be expanded to similar fittings/components based on engineering judgement and appropriately documented.

INSPECTION

° Technique selected by the inspecting utility using recommendations provided

ACCEPTANCE

° T_{nom} - Wear > code allowable min. wall at end of next refueling cycle or expected operating cycle (+ 10% margin of that time)

COMMITMENTS

° Analyze within 3 months
° If analysis shows unacceptable conditions, perform inspection on initial sample selection within 6 months.
° All others perform analysis and inspections within next refueling cycle or 18 operating months.

PROGRAM FOLLOWUP

° General inspection results through "Nuclear Network"
° INPO include programmatic review in plant evaluations

SECTION 1

BACKGROUND

Many nuclear utilities initiated various inspections and investigations of erosion/corrosion phenomena in piping containing single phase, high energy fluid subsequent to the Surry incident in December 1986. These activities were initiated since this was the first incident of this kind for a nuclear utility. The need existed for the nuclear industry to establish initiatives to identify evidence of single phase erosion/corrosion and thus help ensure personnel safety and minimize unnecessary plant challenges resulting from potential further failures. It was paramount that timely and appropriate action be taken.

Although some action has already been taken, further action is required. Hence, analysis and limited but thorough baseline inspection program is necessary. Schedules for completion of these industry efforts should be aggressive for those units where the potential exists indicative of unacceptable wall thinning. For other units where no indication exists, analysis and inspections are necessary but may be performed on a schedule commensurate with normal refueling cycles.

To assist in performing the above analysis and inspection tasks, the NUMARC Working Group, consistent with their stated mission (Appendix A), is providing guidance to industry in the following areas:

- ° Selection process, including analytical methods, for inspection points
- ° Inspection methods and techniques including related acceptance criteria
- ° Possible remedy options for near term
- ° Nature and extent of future inspections

SECTION 2

GUIDANCE

SAMPLE SELECTION AND EXPANSION

Introduction

A large amount of information exists regarding this subject and was discussed in detail at the EPRI Workshop on Erosion/Corrosion April 14, 15 and at various industry briefings. The purpose here is to provide summary information and direction for the ensuing industry efforts to determine the scope of the concern and appropriate actions to be taken.

The following are summary recommendations and will be discussed below:

° The initial sample size should be, as a minimum, the 10 "most susceptible locations" and 5 additional locations based on unique operating conditions or special considerations.

° A structured approach should be employed to increase sampling size upon indication of unacceptable thinning.

Sample Selection

The following guidance should be used to determine the locations to be investigated:

1) Determine population of piping products listed in Table 1 which are contained in the portions of piping systems listed in Table 2 (page 2-7).

2) The piping subsystems may be grouped into examination categories that have similar characteristics.

3) Based upon EPRI methodology (reference summary provided below) or engineering judgement/analysis, determine which piping products/locations are most susceptible to erosion/corrosion by considering the effect of the parameters listed in Table 3. List these in descending order of severity (likelihood of erosion/corrosion to exist). Unusual operating conditions (e.g. extended recirc line flow or others) which are different from normal operating conditions should be considered in generating the list.

4) Choose the 10 most susceptible, at a minimum, of piping product/locations from the list generated in Step 3 above. This will conservatively bias the sample. In addition, 5 piping product/locations should be selected at random.

EPRI Model Summary

The erosion-corrosion damage process is fundamentally flow assisted corrosion. It is observed only when specific combinations of piping material composition, water chemistry, and hydrodynamic conditions co-exist.The EPRI empirical model was developed by correlating a large amount of experimental erosion-corrosion rates, both from laboratory and plant data, with the pertinent measurable system parameters. The result is a series of factors which when multiplied together yield the predicted erosion-corrosion rate. As some of the factors are interrelated, the model is not linear. The model formulation is comprised of 6 factors incorporating various plant variables affecting each factor. As can be seen, the following system and component variables must be identified to use the model:

° The piping material alloy content.

° The water chemistry variables of operating temperature, pH, oxygen concentration and the water treatment used.

° The hydrodynamic variables of pipe diameter, component geometry (fitting type and configuration) and flow rate.

A personal computer based program, CHEC (Chexal-Horowitz-Erosion-Corrosion), was developed for prediction of erosion-corrosion in single-phase piping systems using specific plant data. The program was developed by EPRI as part of its ongoing research effort on erosion-corrosion in both nuclear and fossil power plants. Use of the program will be detailed in technical report NSAC-112 (The EPRI Computer Program for Erosion/Corrosion User Manual). For a given plant or unit, the program will:

1. Rank components in the piping system in order of susceptibility to erosion-corrosion.

2. Choose most susceptible locations for inspection based on several criteria.

3. Use wall thickness inspection data to develop a plant specific model to predict time to reach minimum required wall thickness.

The computer program is a user friendly, interactive program in simple language with multiple data files included in the program to provide input on nominal wall thickness, geometry factors, and other important factors needed to supplement computations. It represents the most complete data base available on single phase erosion/corrosion. Specific plant inspection data is combined with the empirical model to refine useage of the program to the specific unit or plant.

Sample Expansion:

For each piping product (component) found that has a wall thickness which is below code minimum requirements or expected within the next refueling cycle or expected operating cycle (+10% margin of that time) to be below code minimum requirements and which is known to be caused by erosion/corrosion, the inspection shall be expanded to additional susceptible components in the examination category based on engineering judgement (Reference "Acceptance Guidelines" pg. 2-5). The additional samples shall be taken from similar or like components in the examination category (i.e. sister train or similar arrangement) or components in proximity to the area of concern. The inspection of additional samples by this criteria is also required for piping product/component determined to be unacceptable in any additional test lot. When the EPRI model is used, additional samples may be taken from the next "tier" of susceptible components.

INSPECTION AND ACCEPTANCE

Introduction

EPRI Document 1570-2 (Nondestructive Examination of Ferritic Piping for Erosion/Corrosion) provided a compilation of various methods that may be employed in performing inspections to detect erosion/corrosion. Most methods used within the industry to determine pipe/component wall thickness are well developed, provide repeatable and accurate results, and are governed by standard practices. Upon component inspection, decisions must be made regarding determination of thinning and resulting potential replacement or continued monitoring. Acceptance guidelines at this stage are not well defined and consistently applied.

The following summary recommendations are provided:

- UT or RT may be utilized for the initial round of inspections with personnel qualified in accordance with SNT-TC-1A. NDE procedures should be reviewed by qualified Level III.
- Utilize current industry experience gained in performance of inspections.
- Establish benchmark or zero wear point at T_{nom}, 100% wear at $t_{code\ min}$.

Inspection Guidelines

If UT methods are utilized, the following guidance is provided.

1. Grids - The area of interest is laid out in a grid and thickness readings are recorded for the points where the grid lines cross. Grid lines may be close together (1") or far apart (6"). One method that is particularly effective in giving both thorough coverage of an area and a sufficient number of data points is the use of the large grid (greater than 2") where the entire area of interest is scanned. (Reference attached sketches, Appendix B). The first step would be to collect data at the grid line intersection points. The second step would be to scan the entire area of interest and record the location and thickness for any point that is more than 20% below the average of the four adjacent grid intersection readings. (Reference attached sketches, Appendix B).

2. Partial Grids - These are primarily used for elbows but may be similarly applied to other components. There are five areas of interest for this type of scan. The first two would be segments centered on the intrados and the extrados. The remaining three would be bands running circumferentially around the elbow at each pipe weld and one midway between the welds (Reference attached sketches, Appendix B). Areas of interest would be marked with a grid and readings would be taken similar to the method described above.

3. Quick Scan - This type of scan may be used as a preliminary inspection or scoping work where a large amount of pipe is being evaluated for further examination. The key element in this type of inspection is setting the A-scan of the ultrasonic scope such that a small change in pipe thickness

will make a large change in the sweep position of the first back wall reflection. The inspection sequence would begin by placing couplant on the area to be scanned. The technician would then place the transducer on the pipe and moving it a specified distance clockwise then counterclockwise around the circumference of the pipe. At the end of each circumferential scan, the technician would index the transducer axially by a specified distance and perform another circumferential scan. this process would continue until the area to be quick scanned was complete. During the scanning the technician would watch for change in the sweep position of the A-scan presentation of the scope to see if there were any significant changes on the pipe wall thickness.

4. Automatic Scanning - This provides an excellent scan coverage as well as thorough record keeping for the inspection parameters, but this method is more time consuming than conventional methods.

5. Marking - Components should be appropriately marked (i.e. with high temp. paints, low stress stamps, etc.) for reference for future inspections.

If RT methods are utilized, refer to EPRI Document 1570-2 and related references.

Acceptance Guidelines

The NDE results should be used to calculate the approximate erosion/corrosion rate and the number of cycles remaining before the component reaches minimum wall thickness. If the calculations indicate that an area will reach code minimum allowable wall thickness within 1 refueling cycle or expected operating cycle (+10% margin of that time), the questionable component must be repaired or replaced unless the results of an engineering analysis show that there is an acceptable safety margin for continued operation beyond that point.

1. Erosion/Corrosion (E/C) Rate Calculation:
(For each piping product/location)

E/C Rate = $(t_{nom} - t_{measured})/\text{Time}$

T_{nom} = Nominal wall thickness*

$T_{measured}$ = Actual wall thickness from the in-plant inspections (min value).

Time = Operating time, hours critical

* The actual nominal wall thickness may be significantly different than the value listed in the manufacturer's specification. If the wall loss is localized it is often possible to determine a more realistic nominal wall thickness value through actual measurement on areas of the component that are not showing signs of wall loss.

Determined or measured nominal wall thickness should not be used unless it is equal to or greater than the manufacturer's specified, or as supplied, nominal wall thickness.

2. Engineering Evaluation:

Each utility should choose its own method for engineering evaluation within Code requirements.

3. Subsequent Inspection:

Each utility should perform future inspections based on the results of the initial inspections. Timing of the inspections would be based on predicted wear rates utilizing initial inspection data and related acceptance guidelines.

TABLE 1
SUGGESTED FITTINGS

- Closely Coupled Fittings or Configurations
- Entrant Tee, Combining Tee, Splitting Tee
- 90° Elbow
- Reducer/Expander
- Straight Section of Pipe Downstream of:
    - Reducer
    - Flow Control/Throttling Valve
    - Restricting Orifices
    - Multiple Thermowells, etc.

TABLE 2
SUGGESTED PIPING LOCATIONS

- Feedwater Suction
- Feedwater Discharge
- Heater Drain Pump Discharge
- Condensate from FW Heater
- HPCI (BWR)

TABLE 3
KEY PARAMETERS

- C.S. piping & components - major parameter, chromium content
- pH
- O_2 content
- Fluid temperature
- Local/Bulk flow rate
- Piping product geometry factor
- Joint configurations (backing rings, etc.)

NOTE: Information extracted from EPRI Workshop Information (April 14-15) and EPRI Report NP-3944.

SECTION 3

COMMITMENTS

INSPECTION SCHEDULES

In order to provide sufficient information to further assess the extent of the concern regarding single-phase erosion/corrosion and to gather this information in a controlled and timely fashion, the following schedules are proposed:

1. All units should conduct an analysis in accordance with EPRI method within 3 months of release of the EPRI model or provide other acceptable evaluation methods.

2. Where analysis and current operating parameters/conditions are indicative of unacceptable wall thinning, they should perform inspections within 6 months after release of the EPRI model.

3. For units where programs have previously performed inspections based on other methodology, they must ensure the most susceptible locations identified by the analysis performed in accordance with 1. above are inspected in accordance with 2. above or 4. below as applicable.

4. All other units should perform inspections at their most susceptible locations as a minimum at the next refueling outage or within 18 operating months, whichever is sooner after release of the EPRI model.

5. Future inspections will be based on the results of the first inspection and inspections continued accordingly.

INSPECTION AND PROGRAM FOLLOWUP

General inspection results for each nuclear unit will be provided by "Nuclear Network" entries by the utility. Program followup will be provided through ongoing INPO plant evaluations beginning in June 1987.

APPENDIX A

NUMARC TECHNICAL SUBCOMMITTEE WORKING GROUP ON PIPING EROSION/CORROSION

(SPECIFIC OBJECTIVES)

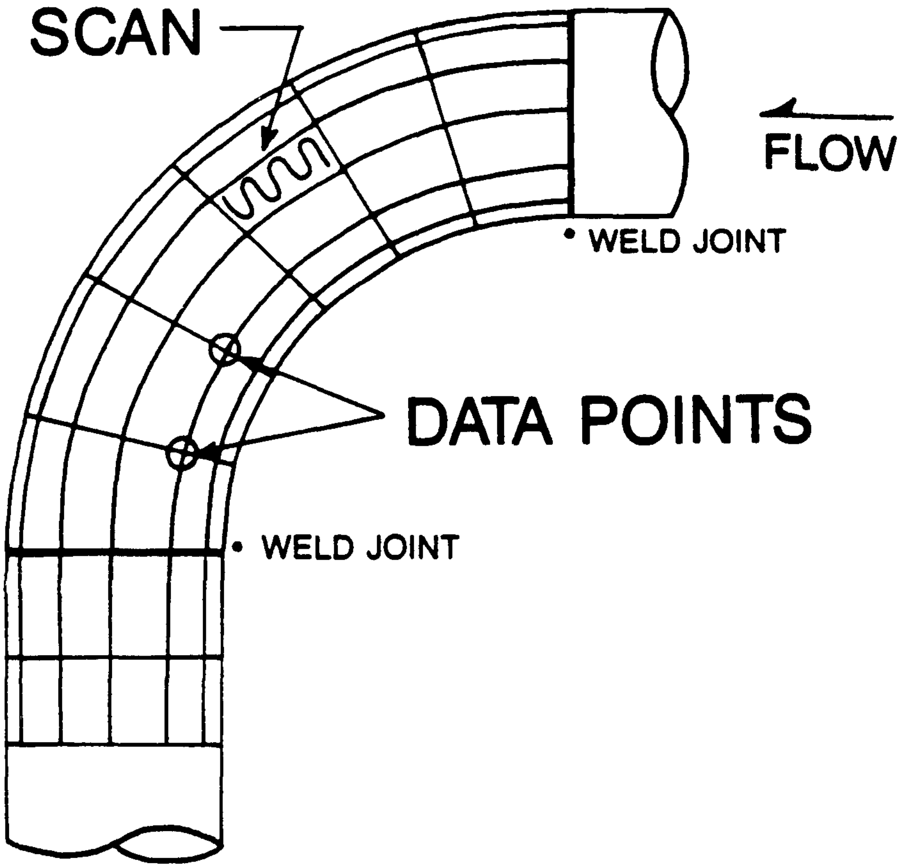
MISSION Review current industry activity regarding inspection plans for piping containing single phase, high energy fluid that is susceptible to erosion/corrosion phenomena.

Review and evaluate current technical information from EPRI and others regarding inspection criteria, extent of inspections, and scheduling of inspections. Identify parameters affecting erosion/corrosion in nuclear power plant piping and their relative importance. Provide screening criteria, inspection and acceptance guidelines, and possible remedy options for near term concerns.

Determine whether an industry-wide program to monitor pipe wall thinning is technically justified. Consolidate and coordinate industry positions and plans to ensure any potential generic concerns are addressed. Formulate actions and provide required industry liaison with NRC.

APPENDIX B

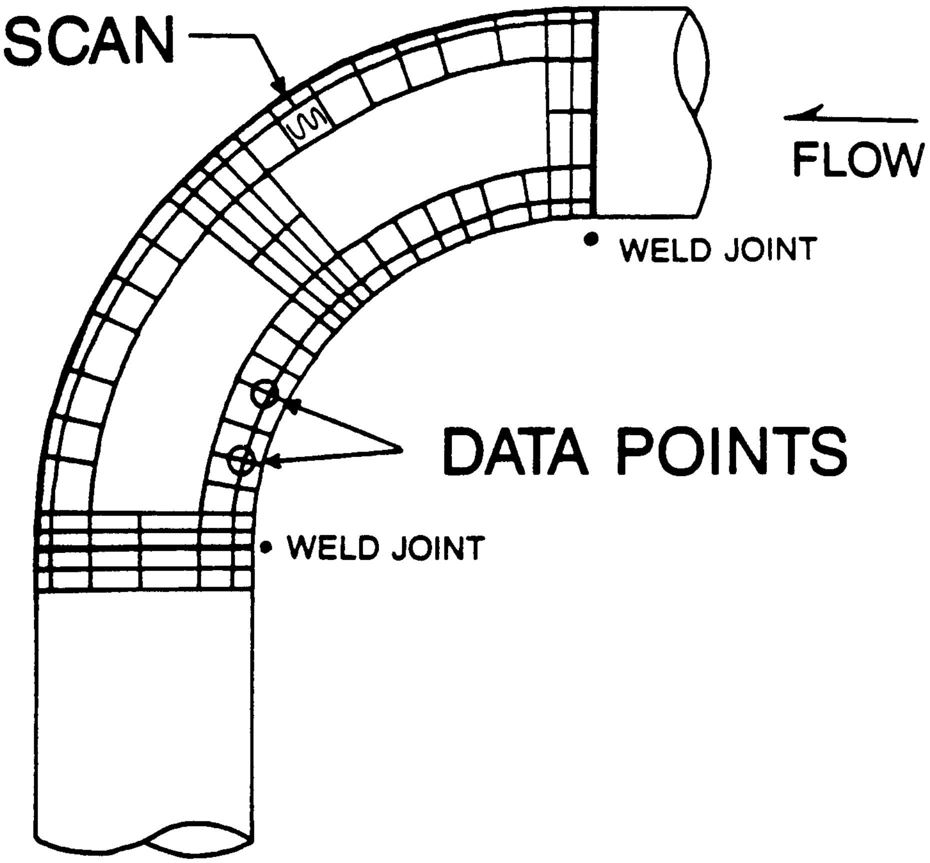
GRID LAYOUT SKETCHES



Grid-Type Inspection*

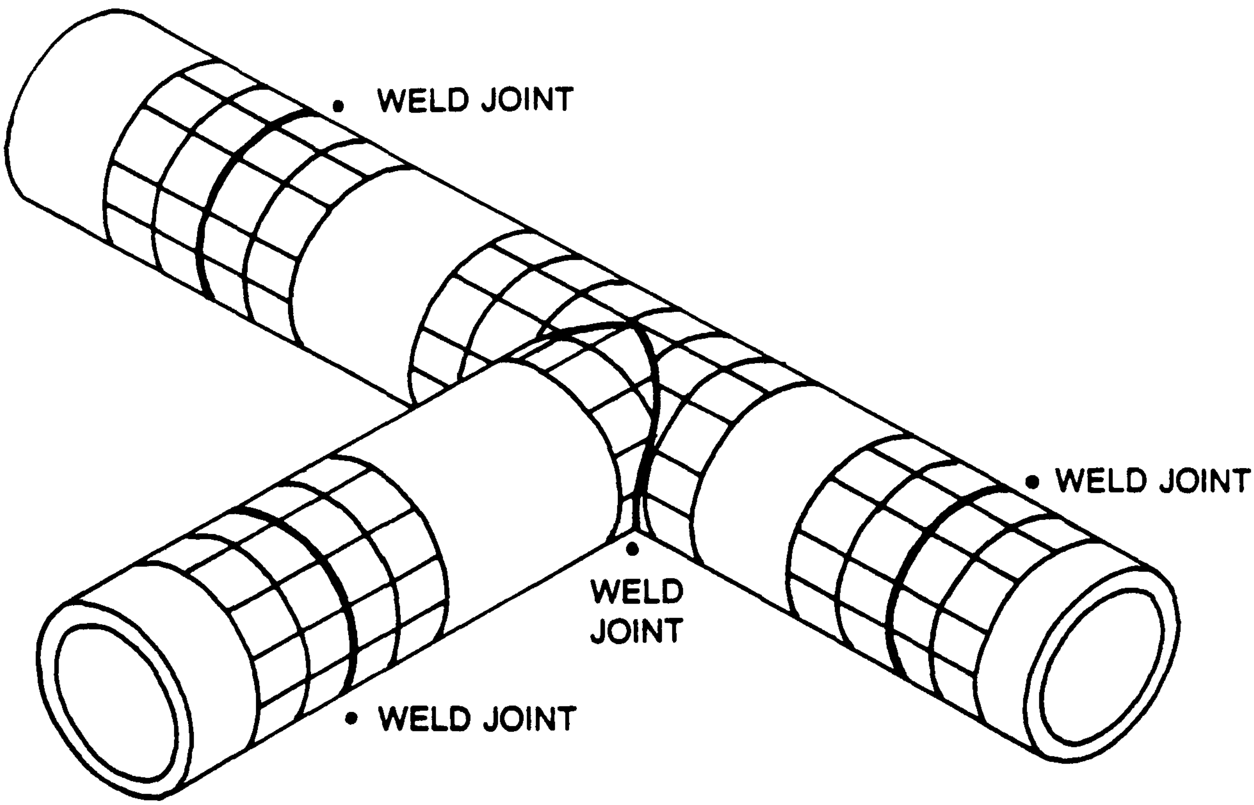
NOTE: SIMILAR PHILOSOPHY SHOULD BE APPLIED TO OTHER COMPONENTS (i.e. REDUCER / EXPANDER, TEE, etc.)

* SEE SECTION 2, PAGE 4



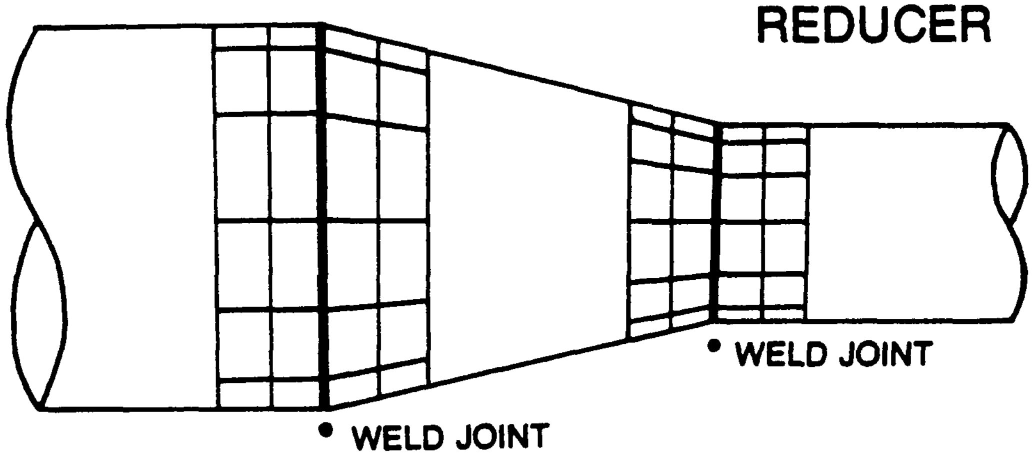
Example Of A Partial Grid Inspection Of An Elbow*

*** SEE SECTION 2, PAGE 4**



TEE

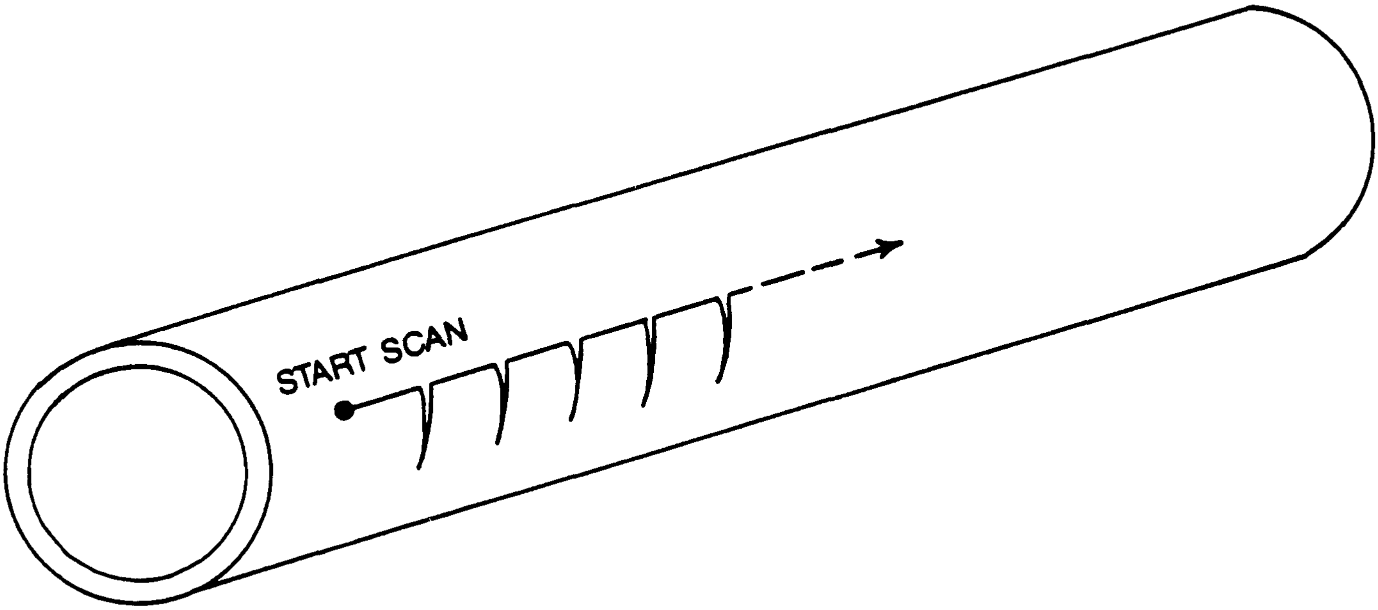
REDUCER



Other Applications Of The Partial Grid Method*

* SEE SECTION 2, PAGE 4

NOTE: SIMILAR PHILOSOPHY SHOULD BE APPLIED TO OTHER COMPONENTS (i.e. REDUCER / EXPANDER, TEE, etc.)



Quick-Scan Inspection*

* SEE SECTION 2, PAGE 4

NRC FORM 335 (2-84) NRCM 1102, 3201, 3202

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BIBLIOGRAPHIC DATA SHEET

SEE INSTRUCTIONS ON THE REVERSE

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12 SUPPLEMENTARY NOTES

13 ABSTRACT (200 words or less)

Erosion/corrosion in single-phase piping systems was not clearly recognized as a potential safety issue before the pipe rupture incident at the Surry Power Station in December 1986. This incident reminded the nuclear industry and the regulators that neither the U.S. Nuclear Regulatory Commission (NRC) nor the American Society of Mechanical Engineers (ASME) Section XI Boiler and Pressure Vessel Code require utilities to monitor erosion/corrosion in the secondary systems of nuclear power plants. This report provides a brief review of the erosion/corrosion phenomenon and its major occurrences in nuclear power plants. In addition, efforts by the NRC, the industry, and the ASME Section XI Committee to address this issue are described. Finally, results of the survey and plant audits conducted by the NRC to assess the extent of erosion/corrosion-induced piping degradation and the status of program implementation regarding erosion/corrosion monitoring are discussed. This report will support a staff recommendation for an additional regulatory requirement concerning erosion/corrosion monitoring.

14 DOCUMENT ANALYSIS – a. KEYWORDS/DESCRIPTORS

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Flow-Assisted Corrosion
Ultrasonic Testing

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