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IN 86-106
Supplement 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, DC 20555

February 13, 1987

IE INFORMATION NOTICE NO. 86-106, SUPPLEMENT 1: FEEDWATER LINE BREAK

Addressees:

All nuclear power reactor facilities holding an operating license or a construction permit.

Purpose:

This supplement to Information Notice (IN) 86-106 is intended to provide addressees with additional information about a potentially generic problem which resulted in thinning of secondary system piping at both units of an operating nuclear power station, catastrophic failure of a main feedwater suction pipe, and injuries and fatalities of workers in the vicinity of the pipe. Recipients are expected to review this information for applicability to their facilities and consider actions, if appropriate, to preclude the occurrence of similar problems at their facilities. However, suggestions contained in this information notice do not constitute NRC requirements; therefore, no specific action or written response is required.

Discussion:

IN 86-106 was issued on December 16, 1986 in response to a feedwater line break at Surry Power Station Unit 2. That notice provided information regarding the feedwater line break. NRC regional offices are collecting information about the condition of piping in other plants.

In addition to the failure of the suction line to feedwater pump "A," the licensee (Virginia Electric and Power Company,) found that the check valve in the discharge line for the pump had failed. One of two hinge pins had apparently been missing for some time, and the disc/seat assembly was dislodged from the valve body. Dislocation of the disc/seat assembly had resulted from failure of two clamp assemblies which hold the disc/seat assembly in the valve body. Failure of the clamping assemblies appears to be the result of erosion/corrosion. Loss of one hinge pin probably would not prevent the valve from performing its function. Dislocation of the disc/seat assembly did not contribute to failure of the suction line but may have contributed to the volume of water released.

On January 14, 1987, the licensee submitted a detailed account of the circumstances surrounding the Surry 2 feedwater piping failure of December 9, 1986.* On February 10, 1987 the licensee shared results of their determinations thru meetings with industry representatives. The licensee's conclusion is that thinning of the feedwater pipe wall was caused by erosion/corrosion. On January 15, 1987, the NRC staff met with technical experts from several engineering disciplines--piping design, metallurgy, nondestructive testing, 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 2 and the means to predict and reduce the effects of erosion/corrosion in piping systems.

The technical panel concluded that the Surry pipe break failure mechanism was erosion/corrosion. Erosion/corrosion is flow-assisted corrosion. Corrosive action is initiated by erosion of protective metal oxide. The role of those parameters which could have potentially contributed to erosion/corrosion in the feedwater piping system are summarized below:

o Piping Design

The configuration of the piping where the break occurred at Surry 2 is believed to have played a major role in establishing conditions which promoted erosion/corrosion. The pipe failure occurred on the outer radius of a 90-degree, (long radius), 18-inch diameter elbow which was connected downstream of a flow-splitting tee in the 24-inch diameter condensate header. The break initiated in the carbon steel elbow material (A234 Grade WPB) -- not in either weld. The average bulk flow velocity of the water was calculated to be 17 ft/sec in the 18-inch branch line. The elbow-tee configuration has been identified as an undesirable design arrangement which is believed to have caused direct flow impingement on the inside of the elbow and to have established secondary flow paths in the elbow causing even higher, turbulent flow velocities.

The use of a 45-degree lateral fitting rather than a tee would have reduced the direct flow impingement effects and reduced the local flow turbulence in the elbow. The piping design stresses in the elbow were low and believed not to have contributed to pipe wall degradation.

o Fluid Dynamics

Oxide dissolution is believed to play a key role in the mechanism of erosion/corrosion wear and is highly interactive with flow velocity. An increase in flow velocity generally tends to increase the erosion/corrosion rate in carbon steel piping although the effect is more pronounced in two-phase flow conditions. Experimental tests have further

*Virginia Electric and Power Company, "Surry Unit 2 Reactor Trip and Feedwater Pipe Failure Report," Revision 0, January 14, 1987.

established that local flow velocities in an elbow can be two-to-three times higher than bulk flow velocities.

Pipe wall measurements performed at both Surry Units have shown that piping erosion/corrosion effects are most severe at locations where local flow velocities are high (e.g., downstream of restricting orifices, flow-control valves, reducers, and in elbows and tees).

Based on the system operating temperature and pressure at the time of the pipe failure (374°F/367 psi, 50°F subcooled), the conditions for cavitation to exist in the elbow was not likely. However, cavitation-erosion cannot completely be excluded as a contributory factor under different operating modes such as single-pump operation.

The temperature of the feedwater at the Surry 2 carbon steel pipe elbow that failed is nominally 374°F. The temperature effects of erosion/corrosion on carbon steel are greatest in the 250-340°F range. Below 250°F and above 340°F, erosion/corrosion wear rates decrease rapidly.

- Piping Material

Carbon steel can be vulnerable to erosion/corrosion when certain unfavorable conditions are present. However, by increasing the alloy content (e.g., chromium, molybdenum, copper), its resistance to erosion/corrosion can be increased significantly. Field experience has shown that the use of 2¼ Cr-1 Mo steel improves piping resistance to erosion/corrosion by a factor of four. Chemical analyses of the failed pipe elbow from Surry 2 have disclosed unusually low amounts of these elements, particularly chromium (less than 0.02 percent).

Austenitic stainless steel has been proven to be highly resistant to erosion/corrosion under normally expected flow conditions.

- Water Chemistry

Water chemistry is believed to have been another important factor in causing the pipe wall thinning at Surry 2. The erosion/corrosion wear rate of carbon steel is greatest when the pH levels are between 7 and 9 or below pH 5. Erosion/corrosion rates drop sharply at pH levels above 9.2. The Surry 2 pH levels were reported to have been maintained between pH 8.8 and 9.2, however, local values could vary significantly.*

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*It also has been noted that during the initial years of operation, ineffective control of water chemistry and condenser in-leakage may have contributed to the degraded feedwater piping in Surry 2, especially at locations of high flow velocity. Subsequent to 1981, condensate polishing units have been used at Surry 2 to remove impurities from the condensate.

A preliminary finding by the Surry 2 licensee that extremely low oxygen content in its secondary side water contributed to the recent pipe break has been questioned. Although it is known that oxygen content of about 100 parts per billion (ppb) is beneficial for neutral water (pH of 7.0) because this improves repassivation of carbon and low alloy steels, many fossil plants and foreign nuclear plants have operated at extremely low oxygen content with no evidence of piping erosion/corrosion in the feedwater piping. At Surry 2, the oxygen content has been maintained at 4 ppb to minimize steam generator tube degradation.

Predictive measures to detect erosion/corrosion in piping systems also have been identified and these measures are summarized below. Erosion/corrosion failures in two-phase systems and erosion in single-phase systems containing suspended solids were noted to be much more prevalent than erosion/corrosion in condensate and feedwater systems. Consequently, these single phase and two-phase systems have received more attention in operation and maintenance. Many utilities have programs to control and reduce damage in two-phase systems such as steam extraction lines and turbine wet steam piping and in single-phase systems containing suspended solids such as service water piping. Except for concerns with suspended solids, erosion in service water systems would not likely result in a catastrophic failure because of the low operating temperature and pressure.

Currently, Section XI of the ASME Boiler and Pressure Vessel Code does not require any inservice inspections specifically for measuring pipe wall thickness. Although not required to do so, many utilities had elected to perform wall thickness measurements routinely in piping systems where erosion/corrosion caused by wet steam or raw water impurities had been found to result in severe pipe wall degradation. The use of the zero-degree ultrasonic beam technique is generally utilized for measuring pipe wall thickness. Although Section XI does not require measurement of wall thickness, a volumetric examination for indication of flaws is required in Code Class 1 and 2 piping systems, but examination is limited to the weld area and heat-affected zone using 45 and 60 degree shear wave techniques. There are no inservice volumetric requirements for ASME Code Class 3 piping, nor any inservice inspection requirements for ANSI B31.1 piping systems.

The effectiveness of ultrasonic measurements in piping is enhanced by predictive methods that can locate potential areas of maximum wear. The Department of Mechanical Engineering of MIT (Cambridge, MA) has been developing a computer program to predict location and extent of wear in two-phase piping systems. The program is reported to also be applicable to single-phase piping systems. The NRC staff has not performed any substantial review of this computer program.

In other studies, as reported in EPRI Report NP-3944, "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines," April 1985, the influence of the flow path configuration for various fittings has been established and expressed as a range of empirical values from 0.04 (least harmful flow occurring in straight pipe) to 1.0 (most harmful flow occurring in flow-splitting tees) to be used for calculating erosion/corrosion wear in two-phase (wet steam) piping systems. The Surry-2 elbow-tee configuration albeit not in a two-phase system would have been predicted as an arrangement potentially susceptible to severe erosion/corrosion wear based on the high empirical value of the elbow-tee configuration.

Additional information pertaining to erosion/corrosion in wet steam piping can be found in IE Information Notice No. 82-22, "Failure in Turbine Exhaust Lines," dated July 9, 1982. Other erosion/corrosion events pertaining specifically to the feedwater systems (including emergency and auxiliary feed) have occurred in feed pump minimum flow lines, J-tubes in steam generator feedwater rings, and emergency feedwater supply to a helium circulator.

No specific action or written response is required by this information notice. If you have any questions about this matter, please contact the Regional Administrator of the appropriate NRC regional office or this office.

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Attachment: List of Recently Issued IE Information Notices

Attachment 1
IN 86-106 Sup. 1
February 13, 1987

LIST OF RECENTLY ISSUED IE INFORMATION NOTICES

Information Notice No.	Subject	Date of Issue	Issued to
87-12	Potential Problems With Metal Clad Circuit Breakers, General Electric Type AKF-2-25	2/13/87	All power reactor facilities holding an OL or CP
87-11	Enclosure of Vital Equipment Within Designated Vital Areas	2/13/87	All power reactor facilities holding an OL or CP
87-10	Potential for Water Hammer During Restart of Residual Heat Removal Pumps	2/11/87	All BWR facilities holding an OL or CP
87-09	Emergency Diesel Generator Room Cooling Design Deficiency	2/5/87	All power reactor facilities holding an OL or CP
87-08	Degraded Motor Leads in Limitorque CD Motor Operators	2/4/87	All power reactor facilities holding an OL or CP
87-07	Quality Control of Onsite Dewatering/Solidification Operations by Outside Contractors	2/3/87	All power reactor facilities holding an OL or CP
87-06	Loss of Suction to Low-Pressure Service Water System Pumps Resulting From Loss of Siphon	1/30/87	All power reactor facilities holding an OL or CP
87-05	Miswiring in a Westinghouse Rod Control System	2/2/87	All Westinghouse power reactor facilities holding an OL or CP
87-04	Diesel Generator Fails Test Because of Degraded Fuel	1/16/87	All power reactor facilities holding an OL or CP
87-03	Segregation of Hazardous	1/15/87	All NRC licensees

OL = Operating License
CP = Construction Permit