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ISSUE 139: THINNING OF CARBON STEEL PIPING IN LWRs (REV. 1)

DESCRIPTION

Historical Background

This issue was raised[1089] as a result of a pipe rupture in the main feedwater (MFW) system at the Surry Unit 2 nuclear power plant on December 9, 1986. The MFW pipe rupture followed a reactor trip from full power shortly after the unit returned to operation on December 8, 1986, following a scheduled refueling outage. The staff presented briefings on the incident to the Commission on February 25, 1987, and to the ACRS at its 322nd Meeting on February 5, 1987.

The Surry pipe rupture was in the 18-inch "A" MFW pump suction line immediately downstream of a compound 90 elbow and T-section connecting the 18-inch pipe to the 24-inch condensate header. The rupture was a catastrophic, 360 circumferential break. A piece of the ruptured pipe (approximately 4 feet by 2 feet in size) was blown some distance from the break point. The piping still attached to the pump suction rotated away from the break point and came to rest against a portion of the "B" MFW pump discharge piping. No significant damage to the "B" MFW pump was noted.

The failed 18-inch suction line was fabricated from ASTM A-106 Grade B carbon steel and ASTM A-234 Grade WPB carbon steel wrought fittings with a nominal wall thickness of 0.5 inches. Visual inspections of the inside surface of the elbow revealed a dimpled surface and general pipe wall thinness as small as 0.05 inches. Ultrasonic thickness measurements indicated the wall-thinning to be a gradual change over most of the elbow fitting. The licensee concluded that the pipe ruptured because of the thinned wall and that the thinning was a result of erosion/corrosion.

On January 15, 1987, the Honorable Edward Markey (U.S. House of Representatives) requested the GAO to assess NRC actions following the Surry event and several other technical problems at nuclear power plants. The GAO assessment[1090] of actions taken related to the Surry event and similar piping deteriorations detected at other LWRs was issued in March 1988. The major GAO conclusions and recommendations are provided in the conclusion of this analysis.

A similar pipe rupture occurred at the Trojan plant following a reactor/turbine trip on March 9, 1985 (See LER 85002, Docket No. 5000344). The pipe rupture at the Trojan plant was in the 14-inch heater drain pump discharge line immediately downstream of a globe valve leading to the condensate header and MFW suction side. The piping was the same ASTM A-106 Grade B material with a required minimum wall thickness of 0.375 inches. The wall thickness in the region of the rupture was thinned to approximately 0.1 inches and the cause was attributed to wall-thinning by erosion/corrosion.

In both events, the fluid medium was single-phase, subcooled water at nominally 350F and 450 psi. Water velocities were in the range of 20 to 40 fps and the flow in the ruptured locations was subject to turbulence induced by piping and fitting configurations, with pressure increases resulting from automatic MFW isolation.

Historically, erosion/corrosion in nuclear and fossil plants has occurred primarily in wet steam (two-phase) lines and has not been reported in dry steam lines (EPRI NP-5410).[1092] The erosion/corrosion in single-phase (water) systems was not expected and differs in the mechanisms contributing to the process, being a complex phenomenon dependent on many variables such as alloy content, temperature, Ph, and flow velocities and perturbations caused by piping and fitting configurations.

Following the Surry event, the staff issued a series of Information Notices informing the industry of the Surry pipe rupture. On July 9, 1987, the staff issued NRC Bulletin No. 87-01[1093] requesting licensees to submit information concerning their programs for monitoring the thickness of pipe walls in high-energy, single- and two-phase, carbon steel piping systems.

Staff review of the licensees' responses to Bulletin 87-01[1093] were reported in SECY-88-50[1094] and Information Notice No. 88-17.[1095] A staff report on the status of the industry erosion/corrosion program was provided in SECY-88-50A.[1096] For two-phase, high-energy, carbon steel piping systems, responses indicated that licensees had programs at all plants for

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inspecting pipe wall-thinning. However, because the guidelines were not required to be implemented, the scope and extent of the programs varied significantly from plant to plant.

For single-phase piping systems such as in the feedwater/condensate lines, a limited number of inspections were conducted following the Surry event. Based on the Bulletin[1093] responses up to the time this issue was evaluated in November 1988, 23 out of a total of 110 units had not established an inspection program for the single-phase lines. Of these units, 17 were operating plants and 6 were under construction.

The staff review[1091] showed that wall-thinning in the feedwater/condensate systems was more prevalent in PWRs than in BWRs. The review indicated that licensees of 27 PWRs and 6 BWRs identified various degrees of wall-thinning in feedwater piping and fittings. The pipe wall-thinning problem was widespread for single- and two-phase, high-energy, carbon steel piping systems in PWR and BWR plants. Since the problem was more prevalent in PWRs, this analysis focused on PWR plants. However, due to the nature of the problem, the resolution indicated that the issue related to all LWRs.

Safety Significance

There were no requirements for the industry to have an inspection program for monitoring and examining the ASME minimum wall thickness for carbon steel piping. Therefore, even though a pipe break is a design basis event for which plants are designed, the potential frequency of such breaks was higher than previously anticipated. Lacking inspection requirements to provide assurance of the defense-in-depth against catastrophic pipe ruptures in the secondary power conversion systems (and specially the feedwater/condensate systems), plants may not have adequate assurance that they meet the design basis life.

The higher pipe rupture frequencies could also introduce additional challenges to safe plant shutdown from potential systems interactions of the high-energy steam/water releases that may damage, or affect, other systems (see "Systems Interactions from Pipe Ruptures" below). Thus, risks from design basis pipe ruptures that did not account for erosion/corrosion wall-thinning in the secondary piping systems may be greater than previously evaluated.

Possible Solution

The staff was continuing its review of pipe wall-thinning and was expected to assess the results obtained from inspections to be performed during the 1988 Spring refueling outages.[1094,1096] This assessment included visiting up to ten plants to review their inspection methods and results. The staff anticipated that its review would be completed by December 1988 and could, if necessary, provide the basis for new requirements[1094,1096] in single- and two-phase carbon steel piping systems.

A possible solution for the single-phase piping systems, which unlike the two-phase systems that have existing monitoring programs, might include inspections to be conducted at each refueling outage. However, for the long term solution, the staff planned to continue working with NUMARC and EPRI to arrive at an implementation program and schedule for the resolution of pipe wall-thinning in both single- and two-phase carbon steel piping systems.

PRIORITY DETERMINATION

Pipe ruptures from erosion/corrosion-induced wall-thinning of carbon steel piping had not been reported prevalent in dry-steam lines[1092] such as the main steam lines. Two-phase piping lines, such as the turbine crossover/under piping and steam extraction lines, had experienced erosion/corrosion wall-thinning and ruptures even though licensees had monitoring and inspection methods (though not required) in place to various degrees for some time. This indicated that improvements were needed in the existing inspection programs to provide timely detection of the piping degradations.

Single-phase carbon steel piping runs, which were not believed to be susceptible to erosion/corrosion wall-thinning, were not in general (prior to the Surry event) monitored or inspected for potential wall-thinning. The single-phase systems in the secondary power conversion systems which had been found to be susceptible to wall-thinning were the feedwater/condensate systems and the high pressure feedwater heater drain pump discharge piping lines. These single-phase

lines transport water at a nominal temperature of 350^0F and water velocities ranging from 20 to 40 fps. Both of these conditions tend to exacerbate the erosion/corrosion phenomenon in carbon steel piping systems carrying single-phase fluid (water).

AFW piping lines that typically draw water at lower temperatures from the condensate storage tank, and do not experience continuous flow during power production, had not been reported to be susceptible to erosion/corrosion wall-thinning. Because it was difficult to determine the effectiveness of the two-phase piping systems inspections, lacking information on previous repairs and replacements resulting from the inspections, the two-phase rupture frequency was assumed equivalent to the single-phase carbon steel piping rupture frequency estimated below. Without existing inspections, the two-phase piping systems would be expected to have a higher rupture frequency.

As stated above, this analysis focused on evaluating the carbon steel wall-thinning pipe ruptures in single-phase piping systems and the wall-thinning ruptures in two-phase piping systems of PWR power conversion systems. Based on existing inspection results, BWRs appeared to have a similar problem, but to a lesser degree. Therefore, this analysis bounded the issue for all LWRs.

Recovery of Power Conversion Systems

The power conversion systems feed into one another through various piping configurations, including straight lines or headers and various valving or fitting arrangements. Therefore, a rupture in either the single- or two-phase piping systems could disable the PWR power conversion systems to various degrees. Thus, the probability of recovering the power conversion systems was uncertain. Therefore, it was conservatively estimated that the probability of non-recovery of the power conversion systems (PCSNR) was 0.5, given a rupture in the secondary systems.

Carbon Steel Pipe Rupture Frequency

The data on erosion/corrosion-induced wall-thinning resulting in ruptures of carbon steel piping carrying single-phase fluid was limited to the Surry and Trojan events described earlier. This limited data was used to estimate upper and lower bounds of the subject pipe rupture frequency.

For the upper bound estimate, the plant-specific experiences of Surry and Trojan were used. At the Trojan plant, the pipe rupture occurred after approximately 9 years of operation. At the Surry plant, the pipe rupture occurred after approximately 14 years of operation. This data yielded an upper bound rupture frequency of 9×10^{-2}/RY. For the lower bound estimate, the two pipe ruptures were ratioed over the total number of PWR reactor-years of operation (approximately 600 RY). This yielded a lower bound estimate of 3.3×10^{-3}/RY.

The rupture frequency was approximated by a log normal distribution with an error factor of five and the upper and lower bounds were assumed as two symmetrically located percentiles (0.05 to 0.95) of a log normal distribution. The calculated mean rupture frequency was 3×10^{-2}/RY. As stated earlier, it was assumed that the rupture frequency of 3×10^{-2}/RY was applicable to the secondary side carbon steel piping systems identified herein.

Most of the pipe ruptures that might occur in the non-safety-related portions of the secondary systems are likely to be outside of containment because most (90%) of the secondary side piping is located outside containment. Pipe ruptures in the safety-related portion of the MFW piping inside containment can result in the secondary side of the affected steam generator blowing down to the containment atmosphere. For these lower frequency ruptures, $(0.1)(3 \times 10^{-2}) = 3 \times 10^{-3}$/RY, isolation of AFW to the affected steam generator will reduce the chance of containment overpressurization from continued long-term steaming due to decay heat from the reactor core. Automatic AFW isolation is necessary to ensure that the containment design pressure will not be exceeded. This event, like other ruptures that may occur in the PWR power conversion systems, was treated as a total loss of main feedwater. This sequence was bounded by the TMLU rupture event sequence described below. However, pipe ruptures inside containment are less likely and will not likely induce the negative systems interaction problems that can result from pipe ruptures outside containment.

Systems Interactions from Pipe Ruptures

Communication Systems Failures: During the MFW pipe rupture at the Surry plant,

the Cardox and Halon fire suppression systems were actuated by steam/water intrusion into their control panels. The security repeater which was located approximately five feet from a Cardox discharge nozzle failed and was later found to be covered with a thick layer of ice. As a result, security communications were temporarily limited to the non-repeater hand-held radios. Therefore, actuation of the Surry fire protection system (FPS) resulted in loss of a train of the communication systems.

Given that loss of one train of plant communications occurred in one of the two pipe rupture events, the probability that failure of this train of communication can occur as a result of pipe ruptures in the secondary systems outside containment was estimated to be 0.5.

To estimate the probability of loss of the backup hand-held communication radios, the following were assumed: probability of battery failure = 0.1; probability of operator error in not replacing the batteries = 0.1; and probability that other units are not readily available = 0.1. The probability of loss of both communication systems, given a pipe rupture in the secondary systems outside containment, was estimated to be 5×10^{-4}.

To estimate the impact of the loss of plant communication systems, it was assumed that loss of communications would increase operator errors in the four event sequences affected by the pipe rupture. Based on an examination of the fault trees[54] for the four sequences, and adjusting the operator errors to account for loss of communications, the percentage increase in core-melt frequency for each sequence was estimated as follows:

Loss of Communications

Sequence	% Increase In Sequence Core-Melt Frequency
TMQH	7
TMKU	negligible
TML(PCSNR)U	7
TMQD	2

Actuation of FPS: Within minutes of the MFW pipe rupture at Surry, 62 sprinkler heads opened in the immediate area of the rupture. As a result of the sprinkler water and the feedwater discharge, the Cardox and Halon suppression systems control panels were affected by intrusion of steam/water. The intrusion caused the time limit, battery charger, and the dual zone modules to short. Thus, the manual remote actuation circuit located in the control room was affected.

In Issue 57, the effects of actuation of the FPS actuation and the potential increases to core-melt frequency were estimated; the sequence evaluated was the TMLU sequence and the safety system evaluated was the AFW system. Because one of the two pipe rupture events (Surry and Trojan) affected the FPS manual remote control, the estimates in Issue 57 were adjusted by assigning a probability of 0.5 to failure of the FPS manual control. With this adjustment, the increase in unavailability of the AFW system, given actuation of the FPS water deluge system, was estimated to be 2×10^{-5}. Assuming typical AFW unavailability of 5×10^{-5} (discussed later), the combined AFW unavailability, given actuation of the FPS, was 7×10^{-5}.

Using the same 2×10^{-5} increased unavailability for other safety systems in the event sequences of this issue, no significant effect was found because the other safety systems were less sensitive to the 2×10^{-5} estimate. This conclusion was consistent with the Issue 57 assessment.

Electric Door Lock Failures: At the time of the Surry pipe rupture event, water and steam saturated a security card-reader located approximately 50 feet from the break point. As a result, key-cards would not open plant doors. The control room doors were opened to provide access to the control room and security personnel were assigned to the control room to provide the access security. One operator was temporarily trapped in a stairway due to the card-reader failure. At the time of this evaluation, the Surry plant was considering installing electric override switches to remedy this problem.

In Issue 81, the impact of the electric lock (card-reader) failure at Surry was evaluated. The results from Issue 81 indicated that failure of electric locks, without override protection, may contribute approximately 2% to core-melt accidents from pipe ruptures outside containment.

Frequency Estimate

To estimate the core-melt frequency from ruptures in PWR secondary systems, an example PRA[54] was used together with additional information provided in NUREG/CR-2800.[64] The pertinent accident sequences were then adjusted to account for pipe ruptures in the secondary side of PWR plants. The accident sequences used in this analysis were TMQD, TMKU, TMQH, and TML(PCSNR)L where:

- TM - a loss of power conversion system (PCS) transient caused by other than loss-of-offsite power. For this analysis, TM corresponds to the secondary system pipe rupture frequency (3×10^{-2}/RY) resulting in loss of the main feedwater system (M = 1);
- Q - the pressurizer safety/relief valve demanded opens (0.01) and any pressurizer safety/relief valve fails to re-close (0.05);
- D - failure to provide sufficient ECCS injection (10^{-3});
- K - failure of the RPS (2.6×10^{-5});
- H - failure of the ECCS recirculation system (7×10^{-3});
- PCSNR - failure to recover the PCS (0.5, as discussed earlier);
- U - failure of the operator to start high pressure injection, or feed-and-bleed is initiated, but is unsuccessful. For this analysis, U = 0.2 was assumed;
- L - failure of the AFW system. For 3-train AFW system plants, a typical AFW unavailability was 1.8×10^{-5} /demand. For 2-train AFW system plants, the goal of Issue 124 was to upgrade the AFW systems to 10^{-4}/demand. Therefore, a typical value of 5×10^{-5}/demand was used in this analysis.

Table 3.139-1 includes the sequences with and without the effects of systems interactions from pipe ruptures in the secondary systems outside of containment.

Examination of the results indicate that collectively the systems interactions may increase the core-melt frequency from pipe ruptures in the secondary systems outside containment by approximately 20% (9×10^{-8}/RY). The total core-melt frequency, with the systems interactions (SI) effects included, was estimated to be 5×10^{-7}/RY.

TABLE 3.139-1

Sequence	Without (SI)	Communications (SI)	FPS (SI)	Locked Doors (SI)	TOTAL
TMQD	1.50×10^{-8}	3.00×10^{-10}	neg.	3.0×10^{-10}	1.56×10^{-8}
TMKU	1.50×10^{-7}	neg.	neg.	3.0×10^{-9}	1.53×10^{-7}
TMQH	1.05×10^{-7}	7.40×10^{-9}	neg.	2.1×10^{-9}	1.15×10^{-7}
TMLU	1.50×10^{-7}	1.05×10^{-8}	6×10^{-8}	3.0×10^{-9}	2.24×10^{-7}
SUM	4.20×10^{-7}	1.80×10^{-8}	6×10^{-8}	8.4×10^{-9}	5.00×10^{-7}

Consequence Estimate

The core-melt sequences under consideration involve no large breaks initially in the reactor coolant system pressure boundary. The reactor is likely to be at high pressure until the core melts through the lower vessel head with a steady *discharge of steam and gases through the PORV(s). These are conditions that may produce significant H_2 generation and* combustion.

For these sequences, a 3% probability of containment failure due to H_2 burn and a 1% probability of containment isolation failure were used. If the containment does not fail by H_2 burn or isolation failure, it was assumed to fail by basemat melt-through.

The conditional releases for these containment failure modes had a weighted average core-melt release of 1.7×10^5 man-rem. The calculated releases were based on a core inventory typical of a 1120 MWe plant, a uniform population density of 340 persons per square mile from an exclusion area of one-half mile out to a 50-mile radius from the plant, no evacuation of people, no injestion pathways, and meteorology typical of a midwest site.

The annual public risk from secondary side piping ruptures due to wall-thinning was the product of the core-melt frequency (5×10^{-7}/RY) and the weighted average

release (1.7×10^{-5} man-rem). Therefore, the public risk was 8.5×10^{-2} man-rem /RY. Assuming a remaining plant life of 30 years, the cumulative public risk was 3 man-rem/reactor.

Cost Estimate

Industry Cost: A possible solution for early detection of wall-thinning in carbon steel piping in the secondary systems was to implement and conduct inspection programs for these systems during each refueling outage. A report was prepared by EPRI[1092] to provide guidance to the industry for conducting NDE of ferritic piping systems for wall-thinning caused by erosion/corrosion in nuclear and fossil power plants. The EPRI report contained the results of investigations of various NDE methods that may be applicable to the detection of erosion/corrosion effects. EPRI reported that virtually all plants used manual ultrasonic thickness measurements. Four utilities had performed automated ultrasonic thickness measurements from the outside surface of the piping. One EPRI source reported that an automated examination would cost approximately $50,000 and take one week, whereas a manual team of two operators could perform the examination in one afternoon. Therefore, the cost of the manual inspection was estimated to be $10,000 per outage.

The difference noted by EPRI was that the manual team would acquire data on a 4-inch grid pattern and the automated system could acquire data continuously over the entire surface. Additional setup time was also required for the automated system. Therefore, the above $10,000 cost for the manual inspection could have been overestimated.

An additional cost associated with the inspections was the removal and disposal of asbestos insulation and re-insulation. These costs were reported to range from $300,000 to $750,000 per outage. In some plants, asbestos insulation was programatically being removed due to strict state and local guidelines associated with health hazards to workers from asbestos.

Approximately half (44) of the 92 plants contacted in the EPRI survey had asbestos insulation. Thirty-two of the forty-four had at least partially replaced asbestos with other insulation, or were planning to remove the asbestos, and the remaining twelve plants were undecided.

Based on the above, any NRC requirement to conduct NDE inspections at each refueling outage could provide an additional incentive for the 12 plants (13% of all plants) to remove and replace the asbestos insulation with other types of insulation. Therefore, on an average, the industry costs to remove and dispose of the asbestos insulation to facilitate NDE inspections was estimated to be a one-time cost of (0.13)($750,000 + $300,000)/2 = $68,000/plant. However, the argument could be made that the cost of asbestos removal could be driven by the state and local requirements, and not by NRC inspection requirements.

Assuming a remaining plant life of 30 years and a typical time between refueling outages of 1.5 years, the cumulative *number of inspections that may be conducted during each refueling outage for each plant was 20. The annual cost over 30* years was (20)($10,000)/30 = $6,700/plant. The present value of the NDE annual costs over 30 years, considering a 5% discount rate, was approximately $100,000/plant. The combined one-time costs for asbestos insulation removal and disposal and the sent value NDE cost over 30 years is $168,000/plant.

NRC Cost: It was estimated that one man-year of effort may be needed to reach a staff position on this issue and an additional man-year of effort to develop a Regulatory Guide or SRP Section. Assuming $100,000/man-year, the NRC costs were

estimated to be $200,000. When distributed over approximately 100 plants, this cost was $2,000/plant.

Total Cost: The combined industry and NRC cost for the possible solution was estimated to be $170,000/plant.

Value/Impact Assessment

Based on the estimated risk reduction of 3 man-rem/reactor and implementation costs of $170,000/plant for the possible solution (NDE examinations at each plant refueling outage), the value/impact score was given by:

$$S = \frac{3\,\text{man}-\text{rem}}{\$0.17\text{M}}$$

$$= 17.6\,\text{man}-\text{rem}/\$\text{M}$$

Other Considerations

Accident Avoidance Cost: The present value of onsite property damage conditional on a core-melt for a remaining plant life of 30 years, assuming a 5% discount rate, was $20 billion. For a core-melt frequency of 5×10^{-7}/RY attributed to pipe ruptures in the secondary systems, the accident avoidance cost by eliminating or significantly reducing the probability of pipe ruptures was $10,000/plant.

Industry Rupture Avoidance Cost: The rupture avoidance costs are the plant costs estimated to result from a pipe rupture in the secondary systems, assuming the plant responds as designed and no core-melt from potential equipment failures ensues. For a pipe rupture frequency of 3×10^{-2}/RY, the chance of a pipe rupture in the secondary side can approach unity over the life of a plant.

To estimate the costs of plant repairs after a forced outage from a pipe rupture in the secondary system, historical plant operational data indicates that a best estimate repair cost from forced outages for a typical nuclear power plant is approximately $1,000/hour.[1082] The Trojan plant outage time following a pipe rupture in the secondary system was 6 days, whereas the Surry plant outage time lasted approximately 90 days. Based on the above, the plant repair costs from these two events was estimated to range from $140,000 to $2M. The replacement power costs resulting from the forced outages of 6 days for the Trojan plant and 90 days for the Surry plant were $3M and $45M, respectively; the cost of replacement power was estimated at $500,000/day.

It was assumed that the above cost estimates reflected lower and upper bound costs that could be represented by a log normal distribution with an error factor of 4. The combined repair costs and replacement power costs, adapted to a log normal distribution, yielded an estimated value of $17M as the mean plant costs resulting from a pipe rupture in the secondary systems.

The $10,000/plant accident (core-melt) avoidance costs were small compared to the estimated rupture avoidance costs of

$17M/plant. The low core-melt frequency of 5×10^{-7}/RY drove down the accident avoidance costs. However, based on the estimated pipe rupture frequency of 3×10^{-2}/RY, the chance of a pipe rupture in the secondary systems over the life of a plant approaches unity. Thus, the rupture avoidance costs dominated the combined accident and rupture avoidance costs.

When the implementation cost ($170,000/plant) is offset by the accident and rupture avoidance costs (a $17M/plant cost savings), the denominator of S becomes negative. The negative denominator of approximately $17M/plant indicates a substantial potential cost savings (industry incentive) by avoiding piping ruptures in the secondary systems.

Occupational Safety: Erosion/corrosion-induced ruptures in high energy carbon steel piping lines described in this analysis resulted in injury and fatalities to plant personnel and contractor employees working in the area of the ruptures. At the time of the Surry pipe rupture, 8 contractor employees were working in the area of the pipe rupture; 6 of these individuals were hospitilized for treatment of severe burns and 2 were treated at a clinic and released. Four of the severely burned individuals died and the other two were in serious to critical condition. One of the two remained in serious condition for more than a month after the accident. Following the pipe rupture at the Trojan plant, one member of the plant operating staff received first and second degree burns and was treated at a local hospital over a three-week period.

CONCLUSION

The estimated core-melt frequency of 5×10^{-7}/RY and the potential risk reduction of 3 man-rem/reactor indicated that pipe ruptures in the PWR secondary systems from erosion/corrosion-induced wall-thinning is of low safety significance to the public. Since inspection results indicated that erosion/corrosion wall-thinning of carbon steel piping is less prevalent in BWR plants, the above PWR risk estimates should be bounding. Therefore, as a generic safety issue, this issue would have been given a low priority ranking. However, the erosion/corrosion-induced wall-thinning of carbon steel piping in secondary systems was not expected to be a significant cause of pipe ruptures. Pipe ruptures were more generalized as limiting faults: postulated, but not expected to occur. Thus, knowledge and an understanding of this phenomena was limited. This analysis indicated that, without adequate defensive methods or measures, pipe rupture induced by wall-thinning can be expected within the lifetime of a plant: an infrequent event with a higher frequency than the limiting fault (postulated) pipe ruptures.

The GAO concluded that the Surry accident initiated a new era of understanding regarding erosion/corrosion at nuclear power plants and demonstrated that unchecked erosion/corrosion can lead to a fatal accident. The GAO also concluded that NRC needed a mechanism to ensure that utilities periodically assess the integrity of piping systems to reduce the risk of future injury to plant personnel or damage to equipment caused by erosion/corrosion. The GAO recommended that NRC require utilities to:

(1) inspect all nuclear plants to develop data regarding the extent that erosion/corrosion existed in piping systems, including straight sections of pipe;

(2) replace piping that did not meet the industry's minimum allowable thickness standards; and

(3) periodically monitor piping systems and use the data developed during these inspections to monitor the spread of erosion/corrosion in the plants.

Based on the potential low public risk, the NRC need (References 1090, 1094, 1096) to establish a new position or requirement on the previously unexpected phenomena, and a significant industry cost incentive to address and resolve the issue, this issue was classified as a Regulatory Impact issue by RES consistent with the ongoing levels of staff and industry actions described in SECY-88-50[1094] and SECY-88-50A.[1096] However, NRR considered the issue to be resolved based on: (1) guidelines on erosion/corrosion in single-phase piping, as developed by NUMARC and found acceptable by the staff; (2) participation in a timely way by all 113 operating LWR plants; (3) acceptable analytical procedures for the evaluation and selection of piping to be inspected; (4) replacement of components as needed; and (5) a long-term as well as a short-term program for continuing evaluation and inspection of both single-phase and two-phase piping.[1132]