Issue 89: Stiff Pipe Clamps (Rev. 2)

DESCRIPTION

Historical Background

This issue was identified[1] following a staff evaluation of allegations that improper consideration of "stiff" pipe clamps in Class 1 piping systems could result in unsafe plant operation. IE Information Notice No. 83-80[2] was issued to alert OLs and CPs of this concern. In the staff's evaluation, it was found that piping designers often assumed that the clamp effects on piping systems were negligible and did not warrant any explicit consideration. This assumption was acceptable for most clamp applications. However, for some applications, certain piping system conditions coupled with specific stiff pipe clamp design requirements could result in interaction effects that should be evaluated in order to determine the significance of pipe stresses induced.

Safety Significance

Stiff pipe clamps were installed because of requirements for piping systems to withstand dynamic loads such as SRV discharges to suppression pools, LOCA-induced loads, and seismic loadings. A preloading of pipe clamp U-bolts or straps (which imposes a constant compressive load on the piping) is necessary to prevent stiff pipe clamps from lifting off piping under dynamic loading conditions. Since clamp-induced stresses are generally not significant with conventional pipe clamps, the pipe stresses induced by stiff pipe clamps generally were also not considered. Therefore, it was believed that further analyses of these stresses on piping systems were necessary before determining whether the stresses were significant.[3]

In addition to the large preloading of the clamps, four other new design features were identified by the staff as requiring additional analyses because of their difference from conventional pipe clamps. These were: (1) use of high-strength or non-ASME approved materials; (2) local surface contact on the pipe; (3) uncommonly thick and/ or wide design of clamp; and (4) clamp applications to piping components other than straight pipe, such as pipe elbows.

If neglect of the additional stress from stiff pipe clamps results in overestimating the pressure-retaining capabilities of piping systems, the probability of pipe breaks caused by dynamic loads may be higher than previously estimated. This increased probability could potentially result in an increased CDF that could lead to PRAs understating the public risk. This issue affected those operating and future plants that installed stiff pipe clamps.

Possible Solution

A possible solution could have the following elements:

(1) Evaluation of the local pipe stresses induced by stiff pipe clamps under all loading conditions;

(2) If the evaluation in (1) above indicated that clamp-induced pipe stresses were unacceptable, hardware modifications should be considered;

(3) As recommended[4] by the staff, NRC could submit a request to ASME to revise Section III of the

[1] Memorandum for D. Eisenhut et al. from R. Vollmer, "Evaluation of Allegations Regarding Class 1 Piping Design Deficiencies (TAC #49242)," September 1, 1983. [8309210477]
[2] IE Information Notice 83-80, "Use of Specialized "Stiff" Pipe Clamps," November 23, 1983. [ML082840454]
[3] Memorandum for D. Eisenhut et al. from R. Vollmer, "Evaluation of Allegations Regarding Class 1 Piping Design Deficiencies (TAC #49242)," September 1, 1983. [8309210477]
[4] Memorandum for D. Eisenhut et al. from R. Vollmer, "Evaluation of Allegations Regarding Class 1 Piping Design Deficiencies (TAC #49242)," September 1, 1983. [8309210477]

Code to include procedures for: (1) categorizing pipe stresses resulting from clamp-induced loads; and (2) evaluating those clamp applications where the ASME Code stress indices and flexibility factors do not apply;

(4) As recommended[5] by the staff, a technical assistance program could be initiated to experimentally and analytically evaluate the interactions between piping and pipe clamps. The goal of this program would be to develop a simplified method to facilitate staff evaluations of clamp-induced pipe stresses.

PRIORITY DETERMINATION

Assumptions

It was assumed[6] that the issue affected La Salle 1 and 2, Quad Cities 1 and 2, Dresden 2 and 3, and all plants whose operation or construction began in September 1983 or later. Thus, there were 44 operating plants affected by this issue: 27 PWRs and 17 BWRs, with average remaining lives of 33.4 and 28.9 years,

respectively. These 44 plants included a few that were under construction at the time of the staff's evaluation.[7]

It was also assumed[8] that none of the 44 plants had upgraded their stiff pipe clamps as a result of IE

Information Notice No. 83-80[9] and all 44 plants had stiff pipe clamps that required some degree of hardware modification.

It was assumed that 20 future plants (10 PWRs and 10 BWRs) would be affected by this issue. The Oconee 3 and Grand Gulf 1 PRAs were used as the representative PWR and BWR, respectively.

Frequency Estimate

The risk associated with pipe breaks resulting from the use of stiff pipe clamps can be divided into the following two types: Type 1 seismic-induced pipe breaks, resulting in LOCA and/or reactor transients; and Type 2 pipe breaks in Class 1 piping, resulting from dynamic loads following LOCAs and transients.

Type 1 Pipe Break: The source of quantitative risk information was a study[10] performed to identify risk-sensitive components in nuclear power plants during and after a seismic event. This study used PRA methodology to expand risk-sensitivity analyses by accounting for seismicity and component fragility data taken from existing nuclear power plant PRAs. To estimate the risk reduction achievable, the adjusted case assumed upgrades to various piping systems such that there would be an increase by a factor of 5 in the median peak ground acceleration (the level of peak ground acceleration at which a component has a 50% probability of failure) for these piping systems. The reduction in CDF due to this piping upgrade was 8% (0.08) for PWRs and 6% (0.06) for BWRs.

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[5] Memorandum for D. Eisenhut et al. from R. Vollmer, "Evaluation of Allegations Regarding Class 1 Piping Design Deficiencies (TAC #49242)," September 1, 1983. [8309210477]
[6] Memorandum for D. Eisenhut et al. from R. Vollmer, "Evaluation of Allegations Regarding Class 1 Piping Design Deficiencies (TAC #49242)," September 1, 1983. [8309210477]
[7] Memorandum for D. Eisenhut et al. from R. Vollmer, "Evaluation of Allegations Regarding Class 1 Piping Design Deficiencies (TAC #49242)," September 1, 1983. [8309210477]
[8] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.
[9] IE Information Notice 83-80, "Use of Specialized "Stiff" Pipe Clamps," November 23, 1983. [ML082840454]
[10] NUREG/CR-3357, "Identification of Seismically Risk Sensitive Systems and Components in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1983.

It was estimated that, for the base case, the affected annual CDF from seismic events was approximately 5.2×10^{-6}/RY for PWRs and 9.1×10^{-5}/RY for BWRs. The change in piping system reliability that could result from the

possible solution would be less than the factor of 5 that was used in NUREG/CR-3357[11] since pipe clamps are only one of the piping system components whose failure contribute to piping system failure probability; others are components such as welds, elbows, branch connections, and snubbers. Therefore, a factor needed to be developed to model the portion of the piping system reliability improvement that would result from improvements to pipe clamps. This factor was assumed to be the fractional difference between the upper and median bending

moment capacity of a reference pipe segment. Using the results from NUREG/CR-2405,[12] this factor was estimated[13] to be 0.145.

For operating plants, to calculate the reduction in CDF that could result from implementation of the possible solution, the product of the following three factors was calculated: piping component contribution; base case; and effects of pipe clamp improvement.

PWRs: CDF Reduction = $(0.08)(5.2 \times 10^{-6}/RY)(0.145) = 6.0 \times 10^{-8}/RY$

BWRs: CDF Reduction = $(0.06)(9.I \times 10^{-5}/RY)(0.145) = 7.9 \times 10^{-7}/RY$

For future plants, the CDF reduction was assumed to be the same as that for operating plants.

Type 2 Pipe Break: The Oconee 3 and Grand Gulf 1 PRAs were reviewed[14] to identify those cut sets containing a hardware failure in an ECCS. For each element so identified, the largest hardware failure probability (typically associated with a valve or pump) was identified and its percentage contribution to the element's total failure probability was calculated. These percentage contributions were calculated for all the identified elements at Grand Gulf 1 and Oconee 3. These were averaged to yield values of 6.1% for Grand Gulf 1 and 6% for Oconee

3. These values were assumed to represent the failure contribution to the CDF resulting from Class 1 pipe breaks arising from dynamic loads induced following LOCAs and transients, and were used as a surrogate measure in estimating the risk contribution from Type 2 pipe breaks.

The same factor of 0.145 used above for a Type 1 pipe break was used to represent the portion of piping system reliability improvement that could result from improvements to pipe clamps. Based on the non-seismic total CDF

reported in NUREG/CR-3357[15] (6×10^{-5}/RY for PWRs and 2.9×10^{-5}/RY for BWRs), the changes in CDF resulting from implementation of the possible solution were:

PWRs: Reduction in CDF = $(0.060)(6.0 \times 10^{-5}/RY)(0.145) = 5.2 \times 10^{-7}/RY$

BWRs: Reduction in CDF = $(0.061)(2.9 \times 10^{-5}/RY)(0.145) = 2.6 \times 10^{-7}/RY$

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[11] NUREG/CR-3357, "Identification of Seismically Risk Sensitive Systems and Components in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1983.
[12] NUREG/CR-2405, "Subsystem Fragility"Seismic Safety Margins Research Program (Phase 1)," U.S. Nuclear Regulatory Commission, February 1982.
[13] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.
[14] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.
[15] NUREG/CR-3357, "Identification of Seismically Risk Sensitive Systems and Components in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1983.

Therefore, for operating plants, the total possible reduction in CDF, considering both Type 1 and Type 2 pipe breaks, was 5.8×10^{-7}/RY and 1.1×10^{-6}/RY for PWRs and BWRs, respectively. This reduction in CDF will be realized only if hardware modifications are made to the stiff pipe clamps.

For future plants, the CDF reduction was assumed to be the same as that for operating plants.

Consequence Estimate

Type 1 Pipe Break: The reduction in CDF, combined with the offsite consequences of the appropriate release categories[16] resulted in a potential public risk reduction of 0.3 man-rem/RY for PWRs and 2.1 man-rem/RY for BWRs. These values were used for all affected operating and future plants.

Type 2 Pipe Break: The reduction in CDF, combined with the offsite consequences of the appropriate release categories,[17] resulted in a potential public risk reduction of 0.6 man-rem/RY for PWRs and 1.4 man-rem/RY for BWRs. These values were used for all affected operating and future plants.

Assuming the 44 operating plants (27 PWRs and 17 BWRs) will need some degree of hardware improvements, the potential public risk reduction over their remaining lives was estimated to be:

[(0.3 + 0.6)(27)(33.4) + (2.1 + 1.4)(17)(28.9)] man-rem = 2,500 man-rem.

Assuming that there will be 20 future plants (10 PWRs and 10 BWRs) affected by this issue, the potential public risk reduction over their 40-year life would be:

[(0.3 + 0.6)(10)(40) + (2.1 + 1.4)(10)(40)] man-rem = 1,760 man-rem.

Cost Estimate

Industry Cost: Implementing the possible solution at each of the 44 operating plants would be done in two parts: (1) perform a piping analysis to assess the effects of pipe clamp to piping interaction; and (2) modify the stiff pipe clamps that produce significant pipe clamp to piping interaction.

A total of 28 man-weeks were assumed for the pipe clamp and piping analyses. At a cost of $2,270/man-week, this resulted in a cost of $63,560/plant and a total of $2.8M for all 44 affected plants.

For the 44 plants that require some degree of hardware modifications, the cost per plant was based on the estimate[18] of the cost of hangers for 1000 feet of 8-inch pipe; at $21/foot, this cost was $21,000/plant.

Installation labor costs were estimated[19] based on $44/man-hour burdened labor rates. Based on an estimate[20] of 4.6 man-hours per linear foot, a total of 4600 man-hours/plant would be required. Applying a 10.08 adjustment factor for labor productivity effects for work in radiation zones and congested areas, manageability, and access/ handling difficulties, labor costs were estimated to be $2.04M/plant. Summing

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[16] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.
[17] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.
[18] NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986, (Rev. 1) February 1989, (Rev. 2) February 1992.
[19] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.
[20] NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986, (Rev. 1) February 1989, (Rev. 2) February 1992.

over all plants yielded $0.92M for hardware and $89.8M for labor, for a total of $90.72M for 44 plants.

A total of 8 man-hours/RY were estimated for the inspection of the replacement pipe clamps at those plants requiring hardware madifications. For the 27 PWRs and 17 BWRs with average remaining lives of 33.4 and 28.9 years, respectively, and at a cost of $2,270/man-week, the total cost was $0.63M. Thus, the total industry backfit cost was $(2.8 + 90.72 + 0.63)M or $94.15M.

For the 20 future plants, the effect of stiff pipe clamps on piping can be evaluated and taken care of in the design and analysis stage, if required, and no backfit hardware modification will be necessary. Assuming that the cost/ plant is also $63,560 to perform a piping analysis during the design and analysis stage to assess the effects of pipe clamp to piping interaction, the total cost for these plants will be $1.3M. Assuming a total of 8 man-hours/ RY would also be required for inspection of stiff pipe clamps, the total industry operating and maintenance cost was estimated to be $[(20)(40)(8)(2270)/40]M or $0.4M. Therefore, the total industry cost for implementing the possible solution was $(1.3 + 0.4)M or $1.7M.

NRC Cost: NRC implementation of the possible solution at the 44 operating plants could be quite extensive. NRC would develop proposed procedures categorizing pipe stresses resulting from clamp-induced loads and procedures for evaluating those clamp applications where the ASME Code stress indices and flexibility factors are not applicable. Developing these procedures, a complicated problem, was estimated to require approximately 2 man-years of labor to develop, review, and approve. At $100,000/man-year, this cost would be $0.2M.

Implementation of the possible solution also included establishing a program to acquire experimental data to verify analytical techniques and results. The test equipment was estimated at $250,000 and preparation of test procedures, QA activities, and analysis of test results were estimated to require 1 man-year of labor at a cost of $100,000/year. Thus, the total cost of the program was $0.35M.

A generic letter directed to potentially affected plants would be required and this was estimated[21] to take 6 man- weeks. At a cost of $2,270/man-week, this cost was $0.01M. Review of licensee submittals in response to the generic letter was assumed to require 5 man-weeks/plant. At $2,270/man-week, the total cost for 44 plants was $0.5M.

The cost for reviewing operations and maintenance of the possible solution was estimated to be 0.5 man-day/RY. At $2,270/man-week, this cost will be $227/RY. Multiplying $227/RY by 44 plants over their average remaining lives resulted in a total operations and maintenance cost of $0.32M. Thus, the total NRC backfit cost was $(0.2 + 0.35 + 0.01 + 0.5 + 0.32)M or $1.38M.

Assuming the cost to develop procedures categorizing pipe stresses resulting from clamp-induced loads and procedures for evaluating those clamp applications was $0.2M, the cost for a program to acquire experimental data was $0.35M. Assuming also that the cost to update relevant Regulatory Guides and SRP[22] Sections was $0.5M and the cost to review operations and maintenance was $227/RY, for 20 plants with a 40-year plant life, the total cost was $0.2M. Therefore, the total NRC front-fit cost was $(0.2 + 0.35 + 0.5 + 0.2)M or $1.25M.

Total Cost: For the 44 operating plants, the total industry and NRC cost associated with the possible solution was $(94.15 + 1.38)M or $95.53M. For the 20 future plants, the total industry and NRC cost associated with the possible solution was $(1.7 + 1.25)M or $2.95M.

Value/Impact Assessment

Using the above estimates of total public risk reduction and implementation costs, separate value/impact scores were developed for the 44 operating plants and the 20 future plants.

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[21] NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986, (Rev. 1) February 1989, (Rev. 2) February 1992.

[22] NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Ed.) November 1975, (2nd Ed.) March 1980, (3rd Ed.) July 1981.

(1) **Operating Plants**: Based on a risk reduction of 2,500 man-rem and a cost of $95.53M for 44 plants, the

$$S = \frac{2{,}500\ \text{man} - \text{rem}}{\$95.53\text{M}}$$

$$= 26\ \text{man} - \text{rem} / \$\text{M}$$

value/impact score was given by:

(2) **Future Plants**: Based on a public risk reduction of 1,760 man-rem and a cost of $2.95M for 20 plants, the value/impact score was given by:

$$S = \frac{1{,}760\ \text{man} - \text{rem}}{\$2.95\text{M}}$$

$$= 597\ \text{man} - \text{rem} / \$\text{M}$$

Other Considerations

(1) Extensive work in radiation zones will be required at the 44 operating plants that need pipe clamp replacements and hardware changes. Using data from NUREG/CR-4627,[23] it was estimated that 46,000 man- hours/plant would be required. This work is in containment with an assumed radiation dose rate of 0.025 rem/hr.[24] The total occupational dose is (44 plants)(O.025 rem/hr)(4.6 x 10^4 man-hours/plant) or 51,000 man-rem.

(2) The occupational dose reduction due to accident avoidance was calculated from the reduction in CDF multiplied by the assumed accident dose of 19,860 man-rem.[25] The possible solution reduces the CDF in 44 plants which have an occupational dose rate reduction of 1.6 x 10^{-2} man-rem/RY: (19,860 man-rem x 5.8 x 10^{-7}/ RY) for PWRs and (19,860 man-rem x 1.1 x 10^{-6}/RY) for BWRs. With the 27 PWRs having an average remaining life of 33.4 years and 17 BWRs having an average remaining life of 28.9 years, this resulted in a best estimate total occupational dose reduction due to accident avoidance of 22 man-rem.

(3) The accident avoidance cost savings for PWRs were estimated to be the CDF (5.8 x 10^{-7}/RY) multiplied by the estimated cost of a core-melt accident ($1,650M) multiplied by the estimated remaining life of 33.4 years. The accident avoidance cost savings for BWRs were estimated to be the CDF (1.1 x 10^{-6}/RY) multiplied by the estimated cost of a core-melt accident ($1,650M) multiplied by the estimated remaining life of 28.9 years. This resulted in a total cost of $1.75M.

CONCLUSION

Based on the value/impact assessment and total reduction in public risk, the backfit actions described above were not justified for the 44 operating plants considered. In addition, the accident avoidance cost savings and occupational dose reduction due to accident avoidance were not significant when compared

[23] NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986, (Rev. 1) February 1989, (Rev. 2) February 1992.

[24] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.

[25] NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986, (Supplement 5) July 1996.

to the cost and doses used in the value/impact score. However, the occupational dose increase is higher (51,000 man-rem) than the best estimate public risk reduction (2,500 man-rem). This occupational dose increase supported a LOW priority ranking (See Appendix C) for this group of plants, because the high occupational dose increase indicated that more dose would be taken modifying the stiff pipe clamps than the total estimated benefit realized from the solution. In an RES evaluation,[26] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

For future plants, the value/impact consideration was more favorable since the effect of stiff pipe clamps on piping could be evaluated in the design and analysis stage. Furthermore, the occupational dosage for front- fitting future plants would be limited to operation and maintenance and should be minimal. Thus, this issue had a medium priority ranking (See Appendix C) for future plants only. RES recommended that a possible update of relevant Regulatory Guides and SRP[27] Sections be contemplated to ensure that interface design procedures are used by CPs to control the flow of design information from the support design group (which has the responsibility for the design of stiff clamps) to the pipe stress analysis group.[28] Items 3 and 4 delineated in the Possible Solution should also be considered for future plants.

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[26] Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994. [9406170365]
[27] NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Ed.) November 1975, (2nd Ed.) March 1980, (3rd Ed.) July 1981.
[28] Memorandum for T. Murley from E. Beckjord, "Recommendations Regarding Revision of Standard Review Plan Sections Related to 'Stiff Pipe Clamps,'" August 12, 1992. [9312220199]