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Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants

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ABSTRACT

This report describes the research performed to assess the effects of age-related degradation of buried piping at nuclear power plants (NPPs). The evaluation of buried piping was conducted in order to develop analytical methods and degradation acceptance criteria (DAC) that can be used to assess the condition of degraded buried piping. The research focused on a risk-informed approach to evaluate the most common aging effects in buried piping consisting of general wall thinning and localized loss of material/pitting. The effects of degradation over time were included in the methodology developed to assess buried piping.

To achieve the goals of this research effort, fragility modeling procedures for degraded buried piping have been developed and the effect of degradation on fragility and plant risk has been determined. The measure used for plant risk was based on the change in core damage frequency (ΔCDF) due to internal events during full power operation. The analytical approach provides the technical basis for evaluating the structural adequacy of degraded buried piping and for developing guidelines for assessing the effect of degraded conditions on plant risk.

The results of this research demonstrate that, for a buried pipe meeting the conditions of the DAC, a pipe thickness loss less than approximately 45% of the original nominal pipe wall thickness, identified at the time of inspection, is not expected to have an immediate significant effect on plant risk. The effects of degradation over time were considered in developing the DAC in a manner that provides the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. The types of buried piping systems, configurations, materials, applicable pipe loads (e.g., pressure, surcharge, live load, etc.) and other conditions that must be satisfied to use the DAC have been developed and presented in this report. The results obtained are based on the service conditions that buried piping is designed for (e.g., pressure induced stresses less than ¼ of the minimum ultimate strength of the material and relatively low temperatures) and recognizing that seismic induced stresses in buried piping are self-limiting since deformations or strains are limited by seismic motion of the surrounding media. In addition, the DAC were developed from probabilistic risk assessments which accounted for the contribution to risk of the postulated degradation of buried piping systems at NPPs. It should be noted that even if a degraded buried pipe meets the DAC, it is expected that the licensee will evaluate the conditions that led to the degradation and may need to repair the degraded pipe based on the evaluation findings, the level of degradation, and the plant's current licensing basis.

The methodology and degradation acceptance criteria (DAC) developed in this report are intended to provide guidance to the NRC staff for making an assessment in a timely manner whether degraded conditions, identified at a plant site, potentially have an immediate significant effect on plant risk. This knowledge is important in order to provide input that can help determine whether immediate repairs are warranted, or whether the appropriate investigation, inspection, aging management, or other actions can be determined in the normal course of evaluating the condition. The methodology and DAC can not be used by the industry as a design tool to justify existing degraded conditions; licensees are still required to meet their commitments regarding their current licensing basis.

FOREWORD

This report documents a risk-informed assessment of degraded buried piping systems in nuclear power plants. This study is part of a research program initiated by the U.S. Nuclear Regulatory Commission (NRC) and carried out by the Brookhaven National Laboratory, to assess the effect of age-related degradation on structures and passive components in nuclear power plants.

This study included all buried piping systems within the scope of the Maintenance Rule and the License Renewal Rule, as set forth in Title 10, Section 50.65 and Part 54, of the *Code of Federal Regulations* (10 CFR 50.65 and 10 CFR Part 54), respectively. As such, the study evaluated the most common aging effects observed in buried piping, namely general wall thinning and localized loss of material/pitting. Toward that end, the researchers performed three major tasks to develop (1) a methodology to assess pipe fragility (the failure probability of buried piping as a result of various input loads), (2) a time-dependent methodology to assess the effect of degraded buried piping on plant risk, and (3) degradation acceptance criteria (DAC) for buried piping.

The methodologies developed in this study can be used to derive risk insights concerning the impact of wall thinning in buried piping. However, appropriate use of these methodologies requires a justifiable estimate of the pipe wall degradation rate. Consequently, this report discusses degradation rates and provides representative values. Nonetheless, users of these methodologies should present acceptable justification that the degradation rate used in a given assessment is appropriate for the particular piping evaluated.

Moreover, risk-informed decision-making requires additional risk insights concerning the impact of wall thinning in buried piping on large early release frequency (LERF). Although this report does not directly address LERF, it does provide a method to assess the risk-significance related to core damage frequency (CDF). Users can extend that method to evaluate the risk-significance related to LERF.

In addition, it is important to note that when a degraded condition is identified in a given pipe, it is often not immediately known whether that pipe complies with the licensing basis or whether it has a significant effect on plant risk, and it may take time for the licensee to evaluate the degraded condition. In such instances, the methodologies presented in this report provide tools to help the NRC staff make a quick, independent assessment to determine whether the identified degradation has the potential for an immediate, significant effect on plant risk. Nonetheless, licensees cannot and shall not use the methodologies discussed in this report to justify exemptions to current regulations or to request changes to a plant's licensing basis.

Charles J. Miller for

Carl J. Paperiello, Director
Office of Nuclear Regulatory Research
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EXECUTIVE SUMMARY

As U.S. nuclear power plants (NPPs) continue to operate, aging of plant structures, systems, and components is becoming an important area that needs to be understood in order to maintain and continue the safe operation of the plants. To address issues related to degradation, the NRC sponsored a number of studies in the past, many of which focused on active components. Age-related degradation of active components can usually be managed by monitoring their performance parameters such as pressure, temperature, or electrical signal. Age-related degradation of structures and passive components, however, in most cases cannot be managed in a similar way. Therefore, the NRC sponsored studies to assess the effects of age-related degradation on structures and passive components.

One of these studies, reported in NUREG/CR-6679, included a scoping study of all structures and passive components found at U.S. NPPs. The purpose of this scoping study was to identify which structures and passive components warrant more detailed assessment in subsequent phases of the research study. Five structures and passive components were identified in the scoping study: concrete members, buried piping, steel tanks, anchorages, and masonry walls. The evaluation of age-related degradation of concrete members was completed and reported in NUREG/CR-6715. The assessment of buried piping followed and is presented in this report.

The purpose of the study described in this report was to develop analytical methods and risk-informed degradation acceptance criteria that could be used to assess the risk significance of degraded conditions of buried piping at NPPs. The methodology developed for this study relied on performing fragility analyses of buried piping at various levels of degradation and then evaluating the effect of the buried piping degradation on plant risk.

Section 1 of the report discusses the background of aging degradation of structures and passive components found in NPPs and presents the objective of the research study. Then this section explains the scope of the study by describing the types of buried piping systems, aging effects, loadings, and material types included. This section also outlines the major steps in the development of the analytical approach and the degradation acceptance criteria (DAC) for degraded buried piping.

Section 2 specifically identifies the buried piping systems found at NPPs and the common material and design parameters applicable to buried piping. Much of this information was based on a survey of buried piping reported in a Welding Research Council Bulletin, submittals of license renewal applications, and referenced documents developed by the Electric Power Research Institute. Section 2 also discusses the codes and analysis methods that are available and that have been used in the nuclear industry. More detailed descriptions including the equations used to analyze and design buried piping is presented later in Section 5.

Section 3 discusses the various aging mechanisms and resulting aging effects that may develop in buried piping. Aging mechanisms such as general corrosion, pitting corrosion, crevice corrosion, galvanic corrosion, selective leaching, microbiologically influenced corrosion, fouling/biofouling, erosion, and cavitation are described. These aging mechanisms primarily result into two types of aging effects, general wall thinning and localized loss of material/pitting. This section also describes the operating experience of buried piping by reviewing NRC generic correspondences, information reported in license renewal applications, and other documents.

Section 4 addresses inspection methods that are used to examine the conditions of buried piping. These methods include visual inspection, use of cameras, ultrasonic test (UT) devices, electromagnetic test devices, pipeline pigs, and cathodic protection systems. Some of these methods require access to the interior and/or exterior of the buried pipe, while others can be performed by remote means. This section of the report also discusses the current regulatory requirements and technical guidance that exist in the nuclear industry related to buried piping. The regulatory requirements and technical guidance documents described include 10 CFR 50.65 - Maintenance Rule, NRC Inspection Procedures, 10 CFR Part 54 - License Renewal Rule, and associated documents such as the Standard Review Plan and the Generic Aging Lessons Learned (GALL) report. In addition to the above, industry programs related to aging management, such as NUMARC 93-01 and NEI 95-10 are described.

Section 5 describes the fragility evaluation performed for degraded buried piping. It begins by assessing the governing load(s) for use in the risk-informed study. The loads that were reviewed and addressed in this study consist of internal pressure, soil surcharge (dead load), groundwater, surface loads, temperature, soil movement, and seismic loads. A methodology for calculating buried piping fragility was developed and applied to a range of steel buried piping with varying sizes (diameters). Fragility curves were developed for wall thinning based on pipe stress equations assuming uniform wall thinning. Then a statistical evaluation of available test data on pressure tests of degraded pipes, removed from service and which exhibit localized loss of material and pitting, was performed. The fragility data for the aging effects were developed for varying levels of degradation which were utilized later in Section 7 to develop degradation acceptance criteria (DAC).

Section 6 contains the risk evaluation of degraded buried piping systems. To estimate the effect of buried piping degradation on plant risk, five nuclear plant sites having buried piping systems were selected for this study. In order to develop the DAC, a quantitative measure of “acceptable risk” was needed. Section 6 defines what can be considered as acceptable risk for use in this evaluation. This was done based on the recommendations presented in the NRC Regulatory Guide 1.174, Revision 1, entitled, “An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes To The Licensing Basis.” The acceptance guidelines in the regulatory guide led to the selection of an acceptable change in core damage frequency (ΔCDF) corresponding to what is considered to be “very small changes” as defined in the Regulatory Guide. In this study, this small change in core damage frequency (ΔCDF) constitutes what is considered to be the risk acceptance criteria.

To develop risk-informed acceptance criteria corresponding to different levels of observed degradation of the buried piping, the impact of this degradation on plant risk as a function of time must be calculated. Section 6 describes the time-dependent methodologies developed for assessing the risk significance of a system with degraded buried piping at an NPP. The methodologies provide two main outcomes: 1) the increase in projected risk as a function of time due to degraded buried piping, and 2) the maximum number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk, given that the degraded pipe has not failed at the time of inspection. Some parameters required by these methodologies were obtained by executing the SAPHIRE computer code with the Standardized Plant Analysis Risk (SPAR) version 3 models of the five selected plants. A SPAR model is a level-1 probabilistic risk assessment (PRA) model of internal events during full-power operation.

Section 7 describes how the methodology developed in Section 6 was used to develop the DAC for buried piping. This methodology utilized the set of equations developed in Section 6 to determine the acceptable pipe wall loss corresponding to the risk acceptance criteria. In order to utilize these equations to determine the number of years required for the buried pipe to reach risk significance, an appropriate degradation rate was needed. Since the degradation rate is a function of many variables (i.e., a function of various plant and piping system conditions), the DAC were determined for a range of expected degradation rates that would occur at NPPs. The DAC were prepared in tabular form as a function of degradation rate, pipe size, and observed wall loss at the time of inspection. Tables containing the DAC provide the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. This section of the report also provides the guidance for the use of the DAC, including the acceptable range of conditions permitting its use, and recommendations if the DAC cannot be satisfied.

The final DAC is presented in Table 7.5 and detailed guidance for its use is provided in Section 7.3. This table and Section 7.3 can be used by NRC staff to determine the risk significance of a degraded buried piping condition that may be identified at an NPP. Examples for the application of the DAC to specific pipe degradation conditions, and guidance for selection of appropriate degradation rates are presented in Section 7.3.

Section 8 summarizes the conclusions of the research effort regarding the evaluation of degraded buried piping at NPPs and provides recommendations for expanding the applicability of the DAC and updating some of the plant information used in the study. Conclusions are described for the: current understanding of buried piping degradation, detection of age-related degradation and condition assessment, fragility evaluation, risk assessment, and degradation acceptance criteria. The results demonstrate that for a buried pipe meeting the conditions of the DAC, a pipe thickness loss less than about 45% of the original nominal pipe wall thickness,[*] at the time of inspection, is not expected to have an immediate significant effect on plant risk. The types of buried piping systems, configurations, materials, and other conditions that must be satisfied to use the DAC have been developed and presented in this report. The results obtained are based on the service conditions that buried piping is designed for (e.g., pressure induced stresses less than ¼ of the minimum ultimate strength of the material and relatively low temperatures) and recognizing that seismic induced stresses in buried piping are self-limiting since deformations or strains are limited by seismic motion of the surrounding media. In addition, the DAC were developed from a probabilistic risk assessment which accounted for the contribution to risk of the postulated degradation of buried piping systems at NPPs. It should be noted that even if a degraded buried pipe meets the DAC, it is expected that the licensee will evaluate the conditions that led to the degradation and may need to repair the degraded pipe based on the evaluation findings, the level of degradation, and the plant's licensing commitments.

If buried pipe degradation is identified at an NPP, it may not be evident whether the pipe still complies with the plant licensing commitments or whether the degradation potentially has an immediate significant effect on plant risk. Normally, the licensee performs an evaluation of the degraded condition which may include further inspections, testing, calculation/design review, and other actions to determine the severity of the condition, risk implications, and whether an immediate repair is needed. Since these steps may take time, often beyond a week, the methodology and DAC developed in this report provides guidance to the NRC staff for making an assessment in a timely manner whether the degraded condition potentially has an immediate significant effect on plant risk. This knowledge is important in order to provide input that can help determine whether immediate repairs are warranted, or whether the appropriate investigation, inspection, aging management, or other actions can be determined in the normal

[*] Nominal pipe wall thickness is the thickness of the pipe wall specified by ASME B36.10M-2004 without consideration for manufacturing tolerance.

course of evaluating the condition. The methodology and DAC can not be used by the industry to justify existing degraded conditions; licensees are still required to meet their commitments regarding the plant's current licensing basis.

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The authors extend their appreciation to Mr. Gary Vine, Electric Power Research Institute, Inc. (EPRI) representative in Washington, DC, for assisting the staff in obtaining a number of EPRI reports related to buried piping. These reports contain valuable information about industry experience, material and design information, data on degradation, condition monitoring and historical performance for various buried piping systems. Information from these documents were extremely helpful in ensuring that the research described in this report covers, to the extent possible, the range of buried piping configurations, materials, aging mechanisms and effects, and current inspection techniques at U.S. nuclear power plants.

1 INTRODUCTION

1.1 Background

The majority of U.S. nuclear power plants have been in operation for over twenty years. Many of these plants are approaching 30 years of operation and are submitting license renewal applications to the NRC to extend their operating licenses from 40 to 60 years. As U.S. nuclear power plants continue to operate it becomes essential to assess the effects of age-related degradation of their plant structures, systems, and components.

The importance of aging has been recognized and has led to a number of regulatory requirements such as the Maintenance Rule (10 CFR 50.65), which identifies requirements for monitoring the effectiveness of maintenance at nuclear power plants (NPPs). Another regulation is the License Renewal Rule (10 CFR Part 54) which requires that license renewal applicants demonstrate that the effects of aging will be managed so that the intended function(s) of structures, systems, and components will be maintained consistent with the current licensing basis through the period of extended operation.

Aging is a concern because past studies and inspections have identified instances of aging degradation and this trend may increase if not properly understood and managed. Although research on aging has been ongoing for some time, there is a lack of knowledge of how degradation could affect the structural response and resistance of structures and passive components to various design loads. The degree to which aging can affect the performance of structures and passive components is also important because there is a lack of reliable inspection techniques and limited accessibility for some structures and passive components such as buried piping.

To address age-related issues, the NRC has funded a number of studies in the past, many of which related to active components and particular key safety-related passive components (e.g., reactor pressure vessel, steam generators, containments). Age-related degradation of active components can usually be managed by monitoring their performance parameters such as pressure, temperature, or electrical signal. Most age-related degradation of structures and passive components, however, cannot be managed in a similar way. Therefore, the NRC has sponsored studies to assess the effects of age-related degradation on structures and passive components.

One of these studies, reported in NUREG/CR-6679, included a scoping study of all structures and passive components found at U.S. NPPs. The purpose of this scoping study was to identify which structures and passive components warrant more detailed assessment in subsequent phases of the research study. Five structures and passive components were identified in the scoping study: concrete members, buried piping, steel tanks, anchorages, and masonry walls.

The detailed assessment for age-related degradation of concrete members was completed and described in NUREG/CR-6715. The assessment for age-related degradation of buried piping followed and is presented in this report.

1.2 Objective

The objective of the research program described in this report is to develop analytical methods and risk-informed degradation acceptance criteria (DAC) for assessing degraded buried piping at NPPs. To achieve this objective, fragility modeling procedures for degraded buried piping have been developed and the effect of degradation on fragility and overall plant risk has been determined. The analytical approach provides the technical basis for evaluating degraded buried piping at NPPs and for developing guidelines for assessing the effect of degraded conditions on plant risk.

The DAC are not intended to be used by the industry as a design tool to justify existing degraded conditions. Licensees are still required to meet their commitments regarding their current licensing basis. The DAC are intended to provide guidance to the NRC staff for making an assessment in a timely manner whether degraded conditions, identified at a plant site, potentially have an immediate significant effect on plant risk. This knowledge is important in order to provide input that can help determine whether immediate repairs are warranted, or whether the appropriate investigation, inspection, aging management, or other actions can be determined in the normal course of evaluating the condition. If the degraded condition exceeds the criteria then immediate repair would be needed unless otherwise justified. If the degradation condition is less than the criteria, then it is expected that the licensee will still evaluate the conditions that led to the degradation and may need to repair the degraded pipe based on the evaluation findings, the level of degradation, and the plant's current licensing basis.

1.3 Scope

The scope of this research study consists of all buried piping systems within the scope of the Maintenance Rule 10 CFR 50.65 and the NRC License Renewal Rule 10 CFR Part 54. This includes buried piping that are: safety-related, or non-safety related but a failure could affect other safety-related components, or that meet several other criteria defined within the scope of the maintenance rule and license renewal rule.

All currently available information was utilized to identify what buried piping systems exist at NPPs. Potential aging effects for buried pipes were reviewed and those determined to be the most predominant types of aging effects were evaluated for their effect on plant risk. Design basis loadings applicable to buried piping systems were identified and those that were determined to be significant or major contributors to plant risk were evaluated in detail. Materials used for buried piping were also identified and those that were most common were studied.

1.4 Approach

If the failure of a buried pipe is found at a NPP, then it is clear that the pipe will need to be repaired. However, if an inspection reveals that a buried pipe has not failed, but it has degraded, the regulatory question that arises is: "does the pipe have to be repaired immediately, or is it acceptable for the plant to continue operation?" This question can be answered by determining whether the degradation poses a significant risk to the plant at this time or some time in the future.

The approach that was implemented to achieve the objective described above is summarized below.

<u>Buried piping degradation phenomena</u>

Identify buried piping aging mechanisms and aging effects, buried piping systems found at NPPs, operating experience, most predominant aging effects, inspection/detection methods, and aging management programs for buried piping. This effort is described in Sections 2 through 4.

Fragility evaluation of degraded buried piping

Evaluate the effects of various levels of degradation on the structural performance of buried piping. This requires determining the types of load(s) that can significantly affect the structural adequacy of buried piping, identifying statistical data for the important parameter(s), and developing fragility curves for undegraded and degraded conditions. This evaluation is presented in Section 5.

Risk evaluation of degraded buried piping

Develop a quantitative definition of risk significance based on available nuclear regulatory requirements, guides, and industry standards. A methodology is developed that estimates the effect of reductions in fragility on plant risk. The probabilistic risk assessment (PRA) models of selected NPPs are evaluated to obtain the required parameters for the methodology. The methodology includes consideration of degradation over time so that the number of years required for the buried pipe to reach risk significance could be calculated. This methodology is described in Section 6.

Degradation acceptance criteria

Use the methodology described above to develop the degradation acceptance criteria (DAC) for buried piping. This can be achieved by utilizing the formulations developed in Section 6 to calculate the acceptable pipe wall loss corresponding to the risk significance criteria. Then, the number of years to reach this pipe wall loss can be determined given a degradation rate, pipe size, and pipe wall thickness at the time of inspection. The results are compiled in a simplified form to create the DAC, and any conditions that must be satisfied in order to use the DAC are also developed.

2 BURIED PIPIING SYSTEMS AT NUCLEAR POWER PLANTS

2.1 Types of Buried Piping Systems

One useful source for identifying the types of buried piping that exist at NPPs is the Welding Research Council Bulletin 446. This bulletin describes the practices followed in the design and repair of buried pipe in the power, process, pipeline, and waterworks industries. Part III of the bulletin identifies information on buried piping systems obtained from surveys of various industries including the nuclear power industry. A list of buried piping systems and associated design information provided by the bulletin is presented in Table 2.1 of this report.

Although this list does not represent a complete description of all types of buried piping systems found at NPPs, it does provide information for the most common types of buried piping found at NPPs and important material and design information which will be discussed further in Sections 2.2 and 2.3.

Another useful source for identifying buried piping found at NPPs is contained in the license renewal applications (LRAs) submitted by utilities to the NRC for approval of extending the operating licenses of their plants from 40 to 60 years. Twelve LRAs have been reviewed for descriptions of the buried piping systems at the plants. A summary of the available information for buried piping at these twelve plants is presented in Table 2.2. General plant information for these 12 NPPs is presented in Table 6.1.

Table 2.2 presents the types of buried piping systems used at NPPs. This table also presents the material of the piping, diameter/thickness, interior and exterior coating, and some additional information. Table 2.2 provides a separate tabulation for each of the twelve plants in alphabetical order. While this table provides a more complete listing of the types of buried piping systems at NPPs, detailed design information was not contained within the LRAs. This table is very useful to compile a list of the most predominant types of buried piping that are found at NPPs and the piping material.

Table 2.2 also presents for each plant some additional information about aging management programs and operating experience that was discussed in the LRAs. This information will be discussed further in Sections 3 and 4 of this report.

It is evident from Table 2.2 that some piping systems such as the service water system and diesel fuel oil system have buried piping at many plants while other systems such as the recirculation spray system or standby gas system have buried piping at very few plants. Table 2.3 shows the distribution of the types of systems containing buried piping at the twelve plants for which the LRA was reviewed. For the twelve plants, the buried piping systems that are most common to NPPs in decreasing order are: service water, diesel fuel oil, fire protection, emergency feedwater, condenser circulating water, condensate, containment spray, standby gas treatment, and safety injection systems. The remaining buried piping systems listed in Table 2.3 appear only once at a given NPP.

2.2 Material and Design Parameters

Buried piping found at NPPs are constructed from carbon steel, ductile iron, cast iron, stainless steel, galvanized steel, low-alloy steel, copper-nickel, Yoloy, fiberglass, concrete, and cement-lined steel pipe. Yoloy steel is high strength low-alloy steel with enhanced corrosion resistance (ASTM A-714). Because of its significant weight, concrete pipe is generally used for large diameter lines such as the water intake piping from sources of cooling water (e.g., lakes, rivers, and reservoirs). These large diameter lines are directly accessible for visual inspection and typically are examined periodically by plant personnel.

Identification of buried piping material and design parameters is difficult to obtain for NPPs from publicly available sources. Table 2.4 summarizes the type of material utilized for each buried piping system obtained from the WRC Bulletin 446 and the twelve LRAs reviewed. Blank entries indicate that information was not available. This table shows that buried piping used in the service water, diesel fuel oil, and emergency feedwater systems primarily utilize carbon steel material. Buried piping used in the fire protection systems primarily utilize cast iron, ductile iron, and carbon steel material. For the remaining systems there was insufficient data to draw any general conclusions.

Pipe diameter and schedule for buried piping depend on the system. Based on the information obtained from the WRC Bulletin, which is presented in Table 2.1, service water buried piping diameters typically range from 10.2 to 76.2 cm (4 to 30 in.). The pipe schedule is likely to be standard weight considering the relatively low pressures in the piping. Diesel fuel oil buried piping is generally small diameter pipe, 7.62 cm (3 in.) or less based on the two plants surveyed. Standard weight is utilized for 6.35 cm (2 ½ in.) or more pipe diameter and schedule 80 pipe is used for 5.08 cm (2 in.) or less. Buried piping used in the emergency feedwater system may be 30.5 or 35.6 cm (12 or 14 in.) based on the two plants surveyed. Data for the remaining systems shown in Table 2.1 are not sufficient to make general conclusions.

Design pressures for all the buried piping shown in Table 2.1 are considered relatively low, ranging from atmospheric or static head to 1.03 MPa (150 psig). Some lines shown in Table 2.4 have higher pressures; however, most of these lines are very unique for buried piping. Design temperatures for all buried piping shown in Table 2.1 are also relatively low, ranging from ambient to 60°C (140°F). Some lines shown in Table 2.4 would also have higher temperatures but as stated before, these lines are very unique for buried piping.

Another important parameter for the design of buried piping is the depth of the buried piping below grade. Table 2.1 indicates that buried piping is generally placed 0.914 to 3.05 m (3 to 10 ft) below grade. Piping such as the diesel fuel oil storage might be enclosed in secondary pipe. Because this type of piping is so unique, the evaluation described in this report will not include piping enclosed within a secondary pipe.

The length of buried piping can vary greatly depending on the particular plant and system. Based on EPRI Report 1006994 (2002), buried piping at five plants reviewed in the report range in total length from 2,768 to 25,163 m (9,080 to 82,555 ft). These lines contain changes in elevation and many elbows, and have limited access at several stations. For service water buried piping, the results of a survey (EPRI Survey 95-110, “Inspecting Inaccessible Service Water Piping,”) were presented in EPRI Report GC-108827 (1998). This survey showed that buried service water piping ranged in size from 40.6 to 107 cm (16 to 42 in.), had uninterrupted total lengths of 30.5 to 1,524 m (100 to 5,000 ft), with as few as 2 elbows to a maximum of 50 elbows. Internal linings of piping included coal tar enamel, plastic, and concrete lined; however, most had no internal lining. Access to piping typically was by inspection ports, valves, blind or open flanges, or a spool piece.

2.3 Analysis and Design of Buried Piping

Buried piping was generally designed to ASME Section III or ASME B31.1 Codes. The design of buried piping was often augmented by additional design requirements based on industry practice. Some analysis procedures were based on other industry codes such as AWWA M-11 or architect/engineer in-house developed procedures.

Typically, the material and diameter of the pipe is selected to satisfy flow requirements. Then, the minimum thickness of the pipe is determined based on internal pressure. The applicable code or standard defines the wall thickness equation to use to calculate the minimum required thickness.

As an example, for steel piping in accordance with ASME B31.1 – Power Piping:

$$t_m = \frac{PD_o}{2(SE + Py)} + A \qquad (2.1)$$

where

- t_m = minimum required wall thickness due to pressure alone
- P = internal design pressure
- D_o = pipe outside diameter
- S = maximum allowable stress in material at design temperature
- E = joint efficiency factor
- y = temperature dependent coefficient which varies from 0.4 at 482°C (900°F) to 0.7 above 677°C (1250° F)
- A = additional thickness required for items such as corrosion, erosion and mechanical strength where necessary

For seamless buried pipe at low temperature, E = 1.0 and y = 0.4. After the minimum required wall thickness (t_m) is calculated, as shown above, the minimum pipe wall thickness is increased to account for manufacturing tolerance.

Additional loads that buried piping at NPPs are typically designed for include: earth/soil, surface loads, groundwater, thermal expansion, and seismic. Other loads that are not as common but might be considered are: surface impact loads, fluid transients, and soil subsidence.

Good descriptions of the design and analyses of buried piping are provided in a number of references such as Buried Pipe Design (Moser, 2001), American Lifelines Alliance Report (2001), and WRC Bulletins 425 and 446 (Antaki, 1997 and 1999). Buried Pipe Design (Moser, 2001) describes how to design gravity flow pipes and pressure pipes for rigid and flexible buried piping. It explains how to analyze buried piping for internal and external loads for various metallic and non-metallic pipes in accordance with applicable codes and standards. WRC Bulletin 446 (Antaki, 1999) describes the practices followed for the design and repair of buried piping in the power, process, pipeline and waterworks industries. The design section reviews buried pipe design requirements of several codes such as ASME B31.1 for Power, B31.3 for Process, B31.4 for Oil Pipelines, B31.8 for Gas Pipelines, and AWWA for Waterworks. Specific equations are provided in accordance with these codes for design of buried piping for internal pressure, soil loads, surface loads, soil subsidence, temperature, water hammer, and seismic. WRC Bulletin 425 (Antaki, 1997) has more detailed information regarding analysis methods for buried piping. More recently, the American Lifelines Alliance Report (2001) has been developed which provides a very complete description with some examples for the design of buried piping for various loads. This document represents a consensus of practicing engineers and academics.

For seismic analysis of buried piping, NUREG-0800, SRP Section 3.9.2 states that the following items should be considered: (1) the inertial effects due to an earthquake upon buried piping systems, (2) the effects of the static resistance of the surrounding soil on piping deformations or displacements, differential movements of piping anchors, bent geometry and curvature changes, etc., and (3) when applicable, the effects due to local soil settlements, soil arching, etc. Section 3.7.2 of NUREG-0800 provides guidance for Category I buried piping, conduits, tunnels, and auxiliary systems, indicating that in addition to the above three items, the seismic analysis should also consider (1) relative deformations imposed by seismic waves traveling through the surrounding soil or by differential deformations between the soil and anchor points, and (2) lateral earth pressures and groundwater effects acting on the structures. For guidance on the load combinations, system operating transients, and stress limits, NUREG-0800, Section 3.9.3 provides information that would be applicable to mechanical components including buried piping.

For detailed guidance on seismic analysis of buried piping, the ASCE Report (1983) "Seismic Response of Buried Pipes and Structural Components" presents a description of a methodology for the seismic analysis and design of buried piping and structures at NPPs. This document discusses routing considerations, investigation of soil conditions along the route, and determination of earthquake loads. Because of the complexity of performing a 3-dimensional dynamic analysis of the piping/structure and surrounding soil, a simplified approach is considered. This approach, which is based on expressions derived by Newmark (1967) and expanded by Yeh (1977), calculates the instantaneous axial strain and bending strains of the buried pipe/structure due to compression, shear, and surface waves. These equations are applicable to long straight pipe sections. For bends, expressions developed by Shah and Chu (1974) and Goodling (1978 and 1980) are described. The ASCE report also provides an example for the seismic analysis of a buried steel pipe. An important observation made by the report is that "seismic effects on buried structures are self-limited since deformations or strains are limited by seismic motions of the surrounding media." Therefore, seismic stresses should be considered in a similar fashion as thermal stress which would classify them as secondary stresses not primary stresses.

A more recent ASCE Standard, ASCE 4-98 (2000), describes the seismic analysis of safety-related nuclear structures which includes a section on "special structures" such as buried piping and conduits. The section on buried pipes and conduit provides equations/criteria for calculating stresses and strains for straight sections of buried pipe; pipe near anchor points, sharp bends, or intersections; and effects of anchor point movements. The equations for axial strain and maximum curvature for long straight sections of pipe are based on the ASCE Report (1983) described above. For forces on bends, intersections, and anchor points, an expression is provided for calculating an upper bound for the axial force and guidance is provided for the analysis of bending moments and shears by treating the structure as a beam on an elastic foundation subjected to an applied axial force. The commentary section of the ASCE 4-98 (2000) states that although shear strains are theoretically also developed in a straight buried structure by traveling wave effects, these shear strains are relieved and converted into curvature strains by very small amounts of local relative lateral displacement between the buried structure and the surrounding soil. Therefore the ASCE standard concludes that "except under abnormal circumstances of very strong and stiff soil (such as might exist with permafrost or frozen ground) immediately surrounding the buried structure, shear strains are negligible and can be ignored."

Another useful document, which describes how to apply the Code (ASME B31.1) rules to restrained buried piping, is Appendix VII of ASME B31.1 (1998). This Appendix, which is nonmandatory, acknowledges that experience over the years has demonstrated that the Code rules may have been conservatively applied to the design and analysis of buried piping systems. The Appendix states that because buried piping stresses are secondary in nature, and since the piping is continuously supported and restrained, higher total stresses may be permitted as follows:

$$S_C \leq S_A + S_h \tag{2.2}$$

where

S_A is allowable expansion stress range

S_h is the basic material allowable stress at maximum operating temperature

Although the Appendix does not address earthquake loadings, it does provide guidance on how to develop a computer model of buried piping for evaluation of various loads that buried piping is subjected to. This includes calculation of element lengths and lateral soil springs based on the modulus of subgrade reaction.

Further discussions on the analysis of buried piping for internal pressure, soil, surface, temperature, and seismic loadings are presented in Section 5 of this report. Section 5 evaluates the contribution of each of the loadings to the total stress expected in buried piping and the risk significance associated for these loads, in an effort to identify the governing loads for consideration in the probability-based fragility analysis.

Table 2.1 Buried Piping Systems at Nuclear Power Plants – WRC Bulletin 446 Survey

System	Material	Diameter*/ Thickness (in.)	Layout	Joint Type	Depth	Coating Ext./Int.	Pressure	Temp	Comments
Emergency Service Water (7 plants)	CS (SA106 Gr. B)	6, 10, 20, 24, 30/	Note 1	Butt-welded, Dresser couplings near bends	3 to 10 ft. below grade	Unknown/ None	Inlet: 125 psig Dischge: atmo-spheric	Inlet: Ambient; Dischge: 140°F	ASME III design; loads: seismic soil strains, thermal expansion, wt. Of overburden, live loads; analysis method: AE procedure, AWWA M-11, Goodling (1983).
Emergency Feedwater (2 plants)	CS (SA106 Gr. B)	12, 14/	Note 2	Butt-welded	3 to 10 ft. below grade	Unknown/ Unknown	125 psig	Ambient	ASME III design; loads: seismic soil strains, wt. Of overburden, live loads; AE analysis procedure based on AWWA M-11.
Condenser Cooling Water	DI	10/	Note 3	Bell and spigot	3 ft below grade	Unknown/ Cement	Static head	140°F	ASME B31.1 design; loads: restrained thermal expansion, wt. Of overburden, live loads; analysis method: Goodling (1983).
Emergency Diesel Fuel Oil	CS (SA106 Gr. B)	3/	Note 2	Butt-welded	3 to 10 ft. below grade	Unknown/ Unknown	125 psig	Ambient	ASME III design; loads: seismic soil strains, wt. Of overburden, live loads; AE analysis procedure based on AWWA M-11.
Fire Protection	Yoloy	12/	Note 4		3 to 10 ft. below grade	Unknown/ Cement	Static head	Ambient	ASME III design; loads: seismic soil strains, restrained thermal expansion, wt. Of overburden, live loads; analysis method: Iqbal and Goodling (1973).
Auxiliary Salt Water	CS (SA106 Gr. B)	4 to 24/ Standard weight pipe and fittings	Note 5	Flanged or Dresser couplings	Buried in trenches with bedding, side & top envelope	Three layer coating, cathodic protection/ 1/8” lining	111 psig (design)	138°F (design)	ASME B31.7-1969 Addendum and provisions of ASME B31.1b-1973; loads: dead, surcharge, soil pressure, live, pressure, thermal, seismic, tsunami (additional detailed information on loads, combinations, and allowables provided).
Diesel Fuel Oil Storage	CS (SA106 Gr. B or A)	/ Sch 80 (≤2 in.), Std wt (>2 ½in.)	Note 6	Butt-welded or flanged	Enclosed in secondary pipe	Devguard 238/ Pickled & passivated	150 psig (design)	120°F (design)	ASME B31.7-1969 w/1970 Addendum and provisions of ASME B31.1b-1973; Title 23, Div 3, Chap 16 California Code; loads: same as above ground pipe due to enclosure in secondary pipe.

1 in. = 2.54 cm; 1 ft = 30.5 cm; 1 psi = 6.89 kPa; °C = (°F – 32)/1.8

Notes:

1. Yard piping, several long runs > 15.2 to 30.5 m (50 to 100 ft), with 45° and 90° bends.
2. Yard piping, long runs > 30.5 m (100 ft), with 45° and 90° bends.
3. Cooling water discharge from condenser. Yard piping, long straight run to large diameter header.
4. Yard piping, long straight run to large diameter header.
5. Several thousand feet of piping, with elbows, flanged joints, and Dresser couplings connecting the intake structure with turbine building. Concrete thrust blocks with ASTM A615 Grade 60 reinforcing steel are provided at all changes in direction.
6. About 30.5 m (100 ft) of piping, with elbows, flanged joints, and expansion joints connecting the underground diesel fuel oil storage tanks to the turbine building transfer vaults.

Acronyms:
CS - Carbon steel
DI - Ductile iron
NPS - Nominal pipe size[*]

[*] Diameter (nominal pipe size) corresponds to a standardized outside diameter (O.D.) as defined in ASME B36.10M-2004. For nominal pipe sizes 14 inches and above, the actual O.D. is equal to the nominal pipe size. For nominal pipe sizes 12 in. and smaller, the actual O.D. is greater than the nominal pipe size, (e.g., 2 inch nominal pipe actually corresponds to 2.375 in. O.D.).

Table 2.2 Buried Piping Systems at Nuclear Power Plants
Based on Twelve LRAs Reviewed

Arkansas Nuclear One – Unit 1

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Service Water	CS		External Coating/	Note 1
Fuel Oil	CS		External coating/	Note 1

Notes:

1. Buried pipe inspections will be performed to ensure that loss of material due to external surface corrosion of buried piping is adequately managed. When underground piping is uncovered during plant maintenance or modification activities, visual inspections of protective coatings will be performed. Sampling of underground pipe would become warranted if observations of defective protective coatings or losses of material on external pipe surfaces were seen during inspections.

Calvert Cliffs Nuclear Power Plant Units 1 & 2

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Auxiliary Feedwater	CS		Wrapping, coating, cathodic protection/Unknown	Note 1
Diesel Fuel Oil	CS		Wrapping, coating, cathodic protection/Unknown	Notes 2, 3
Saltwater	CS, CI		Wrapping, enamel coating, cathodic protection/Lining	Note 4

Notes:

1. Under a new Auxiliary Feedwater (AFW) buried pipe inspection program, representative samples of buried piping will be selected for visual inspection to ensure that the pipe wrappings/coatings are adequately protecting the pipe from the external environment. Any evidence of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting will initiate corrective actions.
2. In 1996, portions of four buried pipelines were inspected. It was discovered that the pipe wrap (trade name, “TRUE COAT”, an extruded polyvinyl coating covered with a black tape) was slightly damaged during construction, but the piping was in pristine condition after 20 years of operation.

3. Under a new Diesel Fuel Oil (DFO) buried pipe inspection program, variations in environmental conditions (including cathodic protection) will be considered to select representative samples of buried piping for inspection to ensure that the pipe coating/wrapping and cathodic protection system are adequately protecting the pipe from external aging degradation mechanisms.
4. The existing plant preventive maintenance (PM) program requires periodic inspections of internal linings. A new age-related degradation inspection program covering components not inspected under the PM program will require inspections of representative samples of susceptible areas for signs of internal liner degradation and corrosion.

Catawba Nuclear Power Station, Units 1 & 2

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Condenser Circulating Water	CS		Coal tar epoxy/ Internal coating	Notes 1, 2
Diesel Generator Fuel Oil	SS		Coal tar epoxy/ Internal coating	
Fire Protection	CS, DI		Coal tar epoxy/ Internal coating	
Nuclear Service Water	CS		Coal tar epoxy/ Internal coating	Note 3
Standby Shutdown Diesel	SS, CS		Coal tar epoxy/ Internal coating	

Notes:

1. Condenser Circulating Water System Internal Coating Inspection Program is used to provide symptomatic evidence of the condition of all buried piping external surfaces. Visual inspections of intake and discharge piping for internal coating degradation performed every five years. Externally generated through-wall pits will be revealed through observance of blistering, peeling, or missing internal coatings as well as signs of corrosion of underlying pipe and inleakage of soil or groundwater.
2. Original interior coating was not properly applied and is failing. As a result, the Condenser Circulating Water System is scheduled to be entered every outage for blasting and recoating and/or walkdown of areas not recoated. These inspections have not identified any through-wall pits originating from pipe exterior.
3. During the 2000 outage, the Nuclear Service Water System piping was cleaned to remove fouling buildup. Internal inspection revealed a row of through-wall pits. Excavation and examination of external coating revealed that the coating had been cut during construction allowing the underground environment to contact pipe surface. Except for the cut, the external coating was in good shape. Other instances of externally generated through-wall leaks of buried components have been identified and attributed to construction-related damage.

Edwin I. Hatch Nuclear Power Plant Units 1 & 2

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Residual Heat Removal Service Water	CS	18 in. (portion)/	Enamel coated, coal tar fiber wrapped/	
High Pressure Coolant Injection			Enamel coated, coal tar fiber wrapped/	
Reactor Core Isolation Cooling			Enamel coated, coal tar fiber wrapped/	
Plant Service Water	CS	30 in. (portion)/	Enamel coated, coal tar fiber wrapped/	Note 1
Standby Gas Treatment			Enamel coated, coal tar fiber wrapped/	
Diesel Fuel Oil Supply	CS		Enamel coated, coal tar fiber wrapped/	
Fire Protection				Leaking piping, deterioration of coatings within fire water storage tank and fouling of lines due to corrosion product buildup have been reported

1 in. = 2.54 cm

Notes:

1. Long runs > 30.5 m (100 ft), with 45° and 90° bends.

McGuire Nuclear Station, Units 1 & 2

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Condenser Circulating Water	CS		Coal tar epoxy/ Internal coating	Notes 1, 2
Diesel Generator Fuel Oil	SS		Coal tar epoxy/ Internal coating	
Fire Protection	GS, DI		Coal tar epoxy/ Internal coating	

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Nuclear Service Water	CS		Coal tar epoxy/ Internal coating	
Standby Shutdown Diesel	SS, CS		Coal tar epoxy/ Internal coating	

Notes:

1. Condenser Circulating Water System Internal Coating Inspection Program is used to provide symptomatic evidence of the condition of all buried piping external surfaces. Visual inspections of intake and discharge piping for internal coating degradation performed every five years. Externally generated through-wall pits will be revealed through observance of blistering, peeling, or missing internal coatings as well as signs of corrosion of underlying pipe and inleakage of soil or groundwater.
2. Two leaks occurred to date. One was a crack in a weld resulting from waterhammer events. The other was a pinhole that was larger on the outside than the inside, indicating that corrosion initiated on external pipe surface. Pinhole was repaired with a steel pipe plug.

North Anna Power Station, Units 1 & 2

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Quench Spray (Containment Spray)	SS		External coating/	
Emergency Diesel Generator	CS, LS		External coating/	
Fire Protection	CI		External coating/	Maintenance activities have not identified any significant external degradation to date
Recirculation Spray	SS		External coating/	
Residual Heat Removal	SS		External coating/	
Safety Injection	SS		External coating/	
Service Water	CS, LS		External coating/	Maintenance activities have not identified any significant external degradation to date

Oconee Nuclear Station 1, 2, & 3

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Condenser Circulating Water	CS, SS		External coating/	A small hole in branch line pipe observed in 1992. Root cause: galvanic or pitting corrosion at a pinhole coatings void. A 2.54 cm (1 in.) diameter hole discovered in 3.35 m (11 ft) diameter piping in 1997. Root cause: local galvanic cell created by a void in exterior coating.
High Pressure Service Water			External coating/	
Service Water (Keowee)			External coating/	Note 1
Standby Shutdown Facility Diesel Generator Fuel Oil			External coating/	
Turbine Generator Cooling Water (Keowee)			External coating/	Note 1

Notes:

1. The onsite emergency power source for Oconee is the Keowee Hydroelectric Station, which is located at the Keowee dam on Lake Keowee.

Peach Bottom Atomic Power Station Units 2 & 3

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Standby Gas Treatment	CS			Note 1
High Pressure Service Water	CS			Notes 1, 2
Emergency Service Water	CS			Notes 1, 2
Fire Protection	CI (lined)			Notes 1, 3
Emergency Cooling Water	CS			Notes 1, 2
Emergency Diesel Generator	CS			Note 1, 4

Notes:

1. The Outdoor, Buried and Submerged Component Inspection Activities program provides for management of loss of material and cracking of external surfaces of components subject to outdoor, buried, and raw water external environments. This program includes visual inspection of buried commodities whenever they are uncovered during excavation. Component inspections include inspection of external surfaces for the presence of pitting, corrosion, and other abnormalities.
2. The ISI program provides for monitoring of pressure boundary integrity for outdoor and buried components through pressure tests, flow tests, and inspections.
3. The Fire Protection Activities program provides for inspection, monitoring, and performance testing of fire protection systems and components to detect aging effects prior to loss of intended function. Degradation due to corrosion buildup, biofouling, and silting are detected by performance testing based on NFPA 24 standards. The program includes continuous monitoring of system pressure to detect leakage of buried fire main piping and valves, and periodic flow test to detect blockage and component degradation in buried fire main piping and valves.
4. The Lubricating and Fuel Oil Quality Testing Activities Program manages loss of material and cracking in components that contain fuel oil. Testing of fuel oil for the presence of corrosion particles or water provides a means for detecting loss of material for fuel oil storage tanks and underground fuel oil piping.

St. Lucie Units 1 & 2

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Fire Protection	CI			
Intake Cooling Water	CS, SS			Note 1
Auxiliary Feedwater	SS			
Condensate	SS			Note 2

Notes:

1. The Intake Cooling Water system Inspection Program addresses internal inspection of the Intake Cooling Water piping to identify and manage loss of material on the external surface of buried piping.
2. A one-time visual inspection will be performed to determine the extent of the loss of material due to pitting and microbiologically influenced corrosion on the external surfaces of the buried piping that connects the St. Lucie Unit 1 and Unit 2 condensate storage tanks. The results of this inspection will be evaluated to determine the need for additional inspections.

Surry Power Station, Units 1 & 2

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Condensate			External coating/	
Containment Spray	SS		External coating/	
Emergency Diesel Generator	CS, LS		External coating/	
Feedwater	CS, LS		External coating/	
Fire Protection	CI		External coating/	Maintenance activities have not identified any significant external degradation to date
Safety Injection	SS		External coating/	
Security	CS, LS		External coating/	
Service Water	CS, LS, CN, SS, FG		External coating/	

Turkey Point Units 3 & 4

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Intake Cooling Water	CI			
Fire Protection	CI, CS			
Standby Steam Generator Feedwater System	SS			

Virgil C. Summer Nuclear Station Unit 1

System	Material	Diameter/ Thickness	Coating Ext./Int.	Comments
Diesel Generator Services	CS		External coating, wrapping/	Notes 1,2
Emergency Feedwater	CS		External coating, wrapping/	Note 1
Fire Service	DI		External coating, wrapping/	Note 1
Service Water	CS		External coating, wrapping/	Note 1

Notes:

1. The Buried Piping and Tanks Inspection program is a new inspection activity that will manage loss of material due to crevice, galvanic, general, pitting, and microbiologically influenced corrosion (MIC) on the external surfaces of components exposed to an underground environment. Under this program, the condition of coatings and wrappings will be determined by visual inspection whenever buried components are excavated for maintenance or for other reasons. If coatings or wrappings are damaged or removed as part of the maintenance activity, the underlying metal will be visually inspected for degradation.
2. During an evaluation, the Cathodic Protection System was found to provide inadequate protection to the diesel generator fuel oil storage tanks and associated underground piping. As a result, an ultrasonic examination of the fuel oil storage tanks and associated piping was performed. The tank inspection indicated a very slow (or negligible) rate of wall thinning. Approximately 10.7 m (35 ft) of fuel oil piping was inspected and found to be in good condition with no corrosion identified.

General Notes For Entire Table:

Materials:

CS – Carbon Steel
LS - Low-alloy Steel
SS – Stainless Steel
GS – Galvanized Steel
CI – Cast Iron
FG – Fiberglass
CN – Copper-Nickel
DI – Ductile Iron
Yoloy – high strength low alloy steel with enhanced corrosion resistance (ASTM A-714)

Information presented in this table was obtained from the License Renewal Applications for each plant submitted to the US NRC, and is available at the NRC web site or through the NRC Public Document Room.

Table 2.3 Nuclear Power Plant Systems with Buried Piping

System	Source of Information[1,2]	Number of Plants[1] (From: WRC 446)	Number of Plants[1] (From: LRAs)
Service Water [3]	w(8),a,cc,c,h(2),m,n, o(2),sl,vs,s,t,p	8	15
Diesel Fuel Oil[4]	w(2),a,cc,c(2),h,m(2) ,n,o,vs,s,p	2	12
Fire Protection[5]	w,c,h,m,n,sl,vs,s,t,p	1	9
Emergency Feedwater [6]	w(2),cc,sl,vs,s,t	2	5
Condenser Circulating Water [7]	w,c,m,o	1	3
Condensate	sl,s	-	2
Containment Spray[8]	n,s	-	2
Standby Gas Treatment	h,p	-	2
Safety Injection	n,s	-	2
High Pressure Coolant Injection	h	-	1
Reactor Core Isolation Cooling	h	-	1
Recirculation Spray	n	-	1
Residual Heat Removal	n	-	1
Turbine Generator Cooling Water	o	-	1
Security	s	-	1
Emergency Cooling Water	p	-	1

Notes:

1. Identification of systems that include buried piping obtained from WRC Bulletin 446 survey and from information provided in License Renewal Applications (LRAs). Plants included in WRC survey were not specifically identified.
2. See legend below for plant identification.
3. Includes Service Water, Emergency Service Water, Auxiliary Salt Water, Saltwater, Nuclear Service Water, Residual Heat Removal Service Water, Plant Service Water, High Pressure Service Water, Intake Cooling Water.
4. Includes Diesel Fuel Oil, Emergency Diesel Fuel Oil, Diesel Fuel Oil Storage, Fuel Oil, Diesel Generator Fuel Oil, Standby Shutdown Diesel, Diesel Fuel Oil Supply, Emergency Diesel Generator, Diesel Generator Services, Standby Shutdown Facility Diesel Fuel Oil.
5. Includes Fire Protection and Fire Service.
6. Includes Emergency Feedwater, Auxiliary Feedwater, Feedwater, Standby Steam Generator Feedwater.
7. Includes Condenser Circulating Water and Condenser Cooling Water.
8. Includes Containment Spray and Quench Spray.

Legend:

w – WRC Bulletin 446 survey
a – Arkansas Nuclear One – Unit 1
cc – Calvert Cliffs 1 & 2
c – Catawba 1 & 2
h – Edwin I. Hatch 1 & 2
m – McGuire 1 & 2
n – North Anna 1 & 2
o – Oconee 1, 2, & 3
p – Peach Bottom 2 & 3
sl – St. Lucie 1 & 2
vs – V. C. Summer 1
s – Surry 1 & 2
t – Turkey Point 3 & 4

Table 2.4 Buried Piping Material and Design Parameters

System	Source of Information	Material [1,2]	Nominal Diameter/Thickness (in.)
Service Water [3]	WRC Bulletin 446	CS (SA-106 Gr. B) [8]	4, 6, 10, 20, 24, 30 / Standard weight[9]
	Twelve LRAs	CS[10], LS[2], SS[2], CI[2], CN, FG,	
Diesel Fuel Oil[4]	WRC Bulletin 446	CS (SA-106 Gr. B) [2]	≤2 / Sch 80 [10] ≥2 ½ / Std wt. [10] 3 /
	Twelve LRAs	CS[9], SS[2], LS[2]	
Fire Protection[5]	WRC Bulletin 446	Yoloy [1]	12 /
	Twelve LRAs	CI[5], DI[3], CS[2], GS	
Emergency Feedwater [6]	WRC Bulletin 446	CS (SA-106 Gr. B) [2]	12, 14 /
	Twelve LRAs	CS[2], SS[2], LS	
Condenser Circulating Water [7]	WRC Bulletin 446	DI	10 /
	Twelve LRAs	CS[3], SS	
Condensate	Twelve LRAs	SS	
Containment Spray[8]	Twelve LRAs	SS[2]	
Standby Gas Treatment	Twelve LRAs	CS	
Safety Injection	Twelve LRAs	SS[2]	
High Pressure Coolant Injection	Twelve LRAs		
Reactor Core Isolation Cooling	Twelve LRAs		
Recirculation Spray	Twelve LRAs	SS	
Residual Heat Removal	Twelve LRAs	SS	
Turbine Generator Cooling Water	Twelve LRAs		
Security	Twelve LRAs	CS, LS	
Emergency Cooling Water	Twelve LRAs	CS	

1 in. = 2.54 cm

Notes:

1. Values in square brackets denote number of plants which identified having the material; without brackets denote only one plant.
2. See legend below for pipe material definition.

3. Includes Service Water, Emergency Service Water, Auxiliary Salt Water, Saltwater, Nuclear Service Water, Residual Heat Removal Service Water, Plant Service Water, High Pressure Service Water, Intake Cooling Water.
4. Includes Diesel Fuel Oil, Emergency Diesel Fuel Oil, Diesel Fuel Oil Storage, Fuel Oil, Diesel Generator Fuel Oil, Standby Shutdown Diesel, Diesel Fuel Oil Supply, Emergency Diesel Generator, Diesel Generator Services, Standby Shutdown Facility Diesel Fuel Oil.
5. Includes Fire Protection and Fire Service.
6. Includes Emergency Feedwater, Auxiliary Feedwater, Feedwater, Standby Steam Generator Feedwater.
7. Includes Condenser Circulating Water and Condenser Cooling Water.
8. Includes Containment Spray and Quench Spray.
9. Auxiliary Salt Water system 4 to 24 in. / standard weight.
10. Diesel Fuel Oil Storage

Materials:

CS – Carbon Steel
LS - Low-alloy Steel
SS – Stainless Steel
GS – Galvanized Steel
CI – Cast Iron
FG – Fiberglass
CN – Copper-Nickel
DI – Ductile Iron
Yoloy – high strength low alloy steel with enhanced corrosion resistance (ASTM A-714)

3 AGING MECHANISMS AND CONSEQUENTIAL DEGRADATION EFFECTS

3.1 Potential Aging Mechanisms and Effects

Age-related degradation of buried piping is of interest in the nuclear power industry because of safety concerns and economic considerations. Instances of pipe degradation have been identified at NPPs and research has been expended on understanding what causes aging degradation of buried piping.

Degradation of buried piping can occur within the pipe and/or external to the pipe. Different types of degradation can occur in all types of pipe materials (metals, plastics, or concrete). Degradation may develop due to environmental conditions alone or may be initiated due to poor design, installation, or maintenance.

There are a number of sources for identification of the aging mechanisms, or causes of degradation, and the aging effects resulting from the aging mechanism. A list of the most important aging mechanisms applicable to buried commodities, which would include buried piping, (Esselman et al., 1997) is presented in Table 3.1. This list encompasses most aging mechanisms that could potentially occur; however, some of the aging mechanisms would not generally apply to buried piping at NPPs. As an example, aging mechanisms related to polymer pipe would not be a concern because polymer pipe is rarely used for buried pipe at NPPs. Freeze-thaw of buried pipe would also not be a concern in general because this aging mechanism would only be potentially significant for concrete pipe in cold climates where the frost line would be deep and in such locations, good design practices at NPPs would preclude this from occurring by placing the buried piping below the frost line.

A listing of aging mechanisms and aging effects for structures and passive components is also presented in NUREG-1801 Generic Aging Lessons Learned (GALL) Report. The aging mechanisms and aging effects from the GALL Report, related to buried piping, is presented in Table 3.2. The GALL Report was developed by the NRC to document the staff's basis for determining which generic existing programs are adequate to address aging and which programs need to be augmented for license renewal of NPPs. More discussion on the GALL Report is provided later in Section 4.2 of this report.

The aging mechanisms and aging effects presented in Table 3.2 were not intended to be a complete listing of every possible degradation phenomena, but rather a listing of the degradations that are expected to occur at NPPs. The applicant (licensee) would still be expected to review his plant design, operating experience, and industry wide experience to include any additional aging effects that could potentially occur at the plant.

A review of the various aging mechanisms from Table 3.2 for steel piping shows that the list of aging mechanisms is consistent with the list presented in Table 3.1. The only aging effect identified in Table 3.2 is loss of material which is intended to capture all forms of loss of material such as general wall thinning and localized pitting or holes through the pipe wall.

A compilation of the aging mechanisms and corresponding aging effects from the above sources and other reference material is provided in Table 3.3. This table also presents for each aging mechanism/effect, the pipe material that may be susceptible to the aging effect/mechanism, the manifestation, and some additional information related to the degradation.

3.1.1 Aging Mechanisms

The primary aging mechanisms that directly affect buried metallic/steel piping are described below. Aging mechanisms affecting polymer piping are not discussed because polymer buried piping are rarely used at NPPs. Aging mechanisms of concrete pipe are also not discussed because buried concrete pipe is primarily used at NPPs for large diameter lines due to their significant weight. These large diameter lines provide the ability for personnel to gain access and perform periodic inspections. Therefore, the focus of this research study is limited to buried metallic pipe. Information for aging mechanisms and effects of concrete pipe would be similar to those already described for concrete members in NUREG/CR-6715.

<u>General Corrosion</u>

General corrosion is a degradation of the pipe surface that results in loss of material over a region without appreciable localized attack. Corrosion is caused by a direct current that flows from a metal such as a buried pipe to an electrolyte such as the soil material. Corrosion occurs at the location where the current exits the pipeline to enter the soil. Corrosion depends on the electrical resistance and potential of the electric circuit that is developed. Corrosion varies with the moisture content of the soil. If the soil is dry, very little corrosion is expected to occur, while in soils with higher moisture content, the resistivity drops and higher rates of corrosion would occur.

Corrosion is also a function of the level of oxygen in the soil. Where oxygen is more plentiful, the rate of corrosion is initially high and then is slowed by the corrosion products that remain adhered to the pipe surface. Corrosion products however cannot be relied upon to prevent corrosion because they do not adhere tightly to the pipe, may be thin, and may not exist throughout the pipe.

General corrosion rates vary depending on many design and environmental parameters. A discussion of general corrosion rates in steel pipe is provided in Section 3.4

Because of the poor corrosion resistance of carbon steel pipes, they are often lined or coated on the inside with bonded polymeric coatings, cement-mortar, or elastomers. On the outside, buried pipes are usually protected by coal tar epoxy coatings and wrappings. Buried piping is also protected at many plants by a cathodic protection system which is described in Section 4.1 of this report.

<u>Pitting Corrosion</u>

Pitting corrosion is a localized form of corrosion that forms cavities or holes in the material. Pitting corrosion occurs when chemical attack breaks through the passive film that protects the metal surface. Once a pit penetrates the passive film, an electrochemical (galvanic) reaction develops. The metal in the pit becomes anodic while the surface outside the pit is cathodic. The exposed surface outside the pit is cathodically protected and can lead to a large cathode to anode ratio which can accelerate the anodic reaction in the pit. The reaction in the pit leads to a reduction in the pH and an increase in the chloride ion concentration. The acidic chloride environment is aggressive to most metals and thereby propagates the pit growth. It is possible for most of a pipe section to show little corrosion while some deep pits may develop.

Crevice Corrosion

Crevice corrosion is a localized corrosion that may occur in small areas of stagnant solutions in crevices, joints, and contacts between metals and metals or metals and nonmetals. Examples of crevice geometries include flanges, gaskets, threaded joints, disbonded protective linings/coatings, fasteners, lap joints, and surface deposits. As in pitting corrosion, the metallic material in the stagnant crevice region develops a more anodic property compared to the exposed bulk surface adjacent to the crevice.

As described in EPRI Report TR-102410 (1993), negative ions such as chlorides and sulfates migrate to the crevice region creating metal chlorides, which results in an increased level of acidity (low pH) in the crevice. When the level of chloride ion and pH reaches a critical threshold, crevice corrosion is initiated. The level of chloride ion and pH depends on the pipe material. As an example, for Type 316 stainless steel, a chloride level of 142,000 parts per million and a pH of 1.65 can lead to initiation of crevice corrosion. Other factors that promote crevice corrosion are small gap dimensions and increasing depth of corrosion.

Galvanic Corrosion

Galvanic corrosion refers to corrosion that occurs when two dissimilar metals are coupled in a corrosive electrolyte such as soil containing moisture. When a galvanic couple forms, one of the metals become the anode and corrodes faster than it would by itself, while the other becomes the cathode and corrodes slower that it would alone. The driving force for the corrosion is the potential difference between the different materials. The less-noble metal will become the anode of the corrosion cell and will corrode at a faster rate. An example of this is a copper water line that may be run to steel pipes or tanks.

Selective Leaching

Selective leaching, also known as dealloying, is the removal (leaching) of one element from an alloy by the corrosion. The more active element in the galvanic series is dissolved away leaving the more noble one. The most common examples of selective leaching are cast iron graphitization and dezincification. Graphitization is the process by which cast iron pipe corrodes. As the iron matrix is leached away, a brittle sponge-like structure of graphite remains. The cast iron retains its appearance and shape but it becomes weaker structurally. Under dezincification, zinc is removed from brass alloys leaving a porous copper structure.

Microbiologically Influenced Corrosion

Microbiologically influenced corrosion, known as MIC, is corrosion caused by the presence and/or activities of microorganisms in biofilms on the surface of the pipe. Microorganisms have been observed in a variety of environments that include seawater, natural freshwater (lakes, rivers, wells), soils, and sediment. The microbiological organisms include bacteria, fungi, and algae. They have been known to tolerate a wide range of temperatures, pH values, oxygen concentrations, and extreme hydrostatic pressure. These microorganisms can influence corrosion by effects such as the destruction of the protective surface films, creating corrosive deposits, and/or altering anodic and cathodic reactions depending on the environment and organism(s) involved. MIC affects most alloys such as steel (including stainless and galvanized), ductile iron, and copper. It is more common to find MIC inside buried piping; however, it may also occur on the outside of the pipe. Bacterial corrosion can occur outside buried pipe, generally in moist soils, such as clays, and it thrives in locations where there is a lot of organic matter.

Fouling/Biofouling

Fouling is the deposition of material that may impair or degrade a pipeline and can reduce or block fluid flow. The fouling may be due to build-up of silting or corrosion products, or due to macro-organisms (biofouling). Corrosion causes fouling by creating mounds from the corrosion byproducts which are much larger than the metal material that is lost. Biofouling refers to the growth of marine organisms in submerged surfaces that impair the flow or degrade the pipeline. Biofouling can be caused by organisms such as plant sea mosses, barnacles and mollusks (oysters and mussels). These are a concern for raw water systems such as the service water system that use open waters, estuaries, and rivers containing macro-organisms. Biofouling is usually most widespread in warm conditions and in low velocity seawater. Marine organisms attach themselves to some metals and alloys more readily than others. Steels, titanium, and aluminum will foul more easily. Copper-based alloys, such as copper-nickel, are more resistant to biofouling.

Erosion

Erosion is the removal of material on a pipe surface due to the fluid motion. Erosion is accelerated when abrasive material such as solid particles is suspended in the fluid and/or high velocity flow is present. Erosion can also be detrimental when conditions exist that create turbulence, flow restrictions, obstructions, and abrupt changes in flow direction. These often occur in bends, tees, pump impellers, and valves. Carbon steels and copper alloys are generally more susceptible to erosion while stainless steel and nickel-based allows are less affected by erosion.

Cavitation

Cavitation occurs when a fluid’s operational pressure drops below its vapor pressure creating a negative pressure (vacuum). This condition causes gas pockets and bubbles to form and then collapse. Cavitation can occur at locations such as the suction of a pump, the discharge of a valve or regulator, and geometry-affected pipe locations (e.g., elbows and expansions). Loss of material due to cavitation is normally eliminated by design which avoids large pressure drops and reducing hydrodynamic pressure gradients.

3.1.2 Aging Effects

The major aging effects for buried metallic piping is loss of material and loss or reduction of flow in the pipe. Most of the aging mechanisms shown in Tables 3.1 through 3.3 lead to loss of material and only fouling/biofouling result in the loss or reduction of flow. Reduction in flow due to fouling/biofouling can be addressed by monitoring system performance parameters such as system flow and pressure, periodic examination of equipment fed by the system, and other means (see Section 3.2 Operating experience). Therefore, the study presented in this report was based on the aging effect of loss of material.

Loss of material is grouped into two types: general thinning over a region of the pipe wall surface and localized loss of material/pitting which can develop pits or holes in the pipe surface. If undetected, general wall thinning can lead to sudden failure of the buried piping. Pitting is harder to detect and is more difficult to design against than general wall thinning. In addition to localized loss of thickness, pits can be harmful by inducing stress risers that could initiate stress corrosion cracking and fatigue. However, fatigue is not usually a concern for buried piping at NPPs because of the low number of load cycles that the piping experiences over its lifetime.

3.2 Operating Experience

Buried piping degradation has occurred at some NPPs and it is a concern that needs to be addressed on an ongoing basis. The operating experience of buried piping has generally been good; however, there have been some systems that have had greater instances of degradation than others.

<u>NRC Generic Correspondences</u>

A number of NRC Generic Correspondences related to degradation of the service water system have been issued. In some cases, it is not clear whether the degradation occurrences described in the generic correspondences were in the buried portions of the piping system; however, if these occurred above ground, it would also be a concern for the buried piping regions.

On April 10, 1981, the NRC issued IE Bulletin 81-03 to request holders of operating licenses and holders of construction permits at NPPs to submit information relating to flow blockage of cooling water to safety system components by Asiatic clams and mussel. Asiatic clams were identified in the service water system for containment cooling units at Arkansas Nuclear One, Unit 2. Following this discovery, inspection of other equipment cooled by service water in both plant units revealed some fouling or plugging due to buildup of silt, corrosion products, and debris (mostly clam shell pieces). During an outage, clams and shells were found to have accumulated to depths of 0.914 to 1.37 m (3 to 4 ½ ft) in certain areas of the intake bays for Unit 2.

NRC Information Notice (IN) 81-21, issued on July 21, 1981, identified that situations not explicitly discussed in IE Bulletin 81-03 may occur and result in a loss of direct access to the ultimate heat sink. The situations identified are: debris from shell fish other than Asiatic clams and mussels may cause flow blockage, flow blockage can cause high pressure drops that lead to certain problems in heat exchangers, and change in operation (e.g., long outages with no flow through seawater systems) appears to permit buildup of mussels where previous inspections showed no appreciable problem.

IN 85-24 was issued on March 26, 1985 to alert NPPs that a potentially significant problem pertaining to the selection and application of protective coatings for safety-related piping exists. The issue arose in the spray pond piping system in 1982 at Palo Verde Nuclear Generating Station Unit 1 where delamination and peeling of the interior epoxy lining in three 61.0 cm (24 in.) diameter elbows occurred. Indications were that this was caused by improper application of the epoxy coating. This IN also identified at the same plant, degradation of the epoxy coating in train A of the spray pond piping leading to the diesel generators which resulted in complete blockage of the generator governor oil coolers. The epoxy coating degradation included severe blistering, moisture entrapment between layers of the coating, delamination, peeling, and widespread rusting.

IN 85-30 was issued on April 19, 1985 to alert NPPs of significant corrosion pitting due to MIC identified in stainless steel piping sections of a service water system after an extended plant outage. This degradation was identified on January 26, 1984, at the H. B. Robinson Unit 2 plant which was shut down and remained shut down throughout the year to replace the lower assemblies of the steam generator and perform other maintenance work. On November 19, 1984, minor pinhole leaks were found in the heat affected zones of circumferential welds joining 15.2 cm (6 in.) diameter, schedule 10, 304 stainless steel piping that provides service water to the four containment chilling units. Visual inspection of the entire system revealed minor leakage at 32 welds inside and 22 welds outside containment. Further radiographic examination indicated that localized corrosion pitting occurred on the inside surface at many other weld joint locations.

In 1987, the Office for Analysis and Evaluation of Operational Data (AEOD) in the NRC initiated a study and evaluation of the failures and degradations in service water systems at NPPs. The results of the study, which covered the period between 1980 to early 1987, were published in NUREG-1275. The results indicate that of the 980 operational events involving the service water system, 276 were deemed to have potential generic safety significance. Of these generic significant events, 58 percent involved system fouling, followed by 17 percent due to personnel and procedural errors, 10 percent due to seismic deficiencies, 6 percent due to single failures and other design deficiencies, 4 percent due to flooding, and 4 percent due to significant equipment failures. The fouling mechanisms included corrosion and erosion (27 percent), biofouling (10 percent), foreign material and debris intrusion (10 percent), sediment deposition (9 percent), and pipe coating failure and calcium carbonate deposition (1 percent). The study identified several actions as potential NRC requirements.

NRC Generic Letter 89-13 was issued on July 18, 1989 to request each licensee and applicant to inform the NRC whether it has established programs to implement the recommendations of the Generic Letter or that it has pursued an equally effective alternative course of action. This request was instituted because as described in the Generic Letter, the staff has been studying the problems associated with service water cooling systems for a number of years. Based on the degradation occurrences reported in IE Bulletin 81-03, IN 81-21, Generic Issue 51 (“Proposed Requirements for Improving Reliability of Open Cycle Service Water Systems), and the AEOD Case Study, the staff issued Generic Letter 89-13 to address the various forms of degradations in the service water systems. The recommended actions identified in the Generic Letter to be taken by the licensees include various surveillance programs; control techniques; test programs; frequent maintenance; inspection programs; confirmation of system performance in accordance with the licensing basis for the plant; and confirmation that the maintenance practices, operating and emergency procedures, and training are adequate. A supplement to the Generic Letter 89-13 was issued by the NRC on April 4, 1990 which contains the questions and answers read into the transcripts during several workshops the NRC conducted in 1989.

Other NRC Information Notices related to degradation of piping systems that contain buried piping are IN 88-37 “Flow Blockage of Cooling Water to Safety System Components,” June 14, 1988, IN 90-39 “Recent Problems with Service Water Systems,” June 1, 1990, IN 94-79 “Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping,” November 23, 1994, and IN 86-96 “Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems,” November 20, 1986.

Operating Experience Reported in License Renewal Applications

Another source of operating experience at NPPs is contained in the License Renewal Applications (LRAs) recently submitted for twelve plants. These LRAs have been reviewed for descriptions of operating experience for buried piping. A short description of the operating experience that was reported for buried piping systems at each plant is presented in Table 2.2 under the “Comment” column. It should be noted that some of the LRAs did not provide specific or complete operating experience for the buried piping and so there probably would be some additional cases of degraded buried piping.

From Table 2.2, the following degradation occurrences in buried piping have been reported in the LRAs:

SYSTEM	PLANT	DEGRADATION
Service Water	Catawba	Fouling, through-wall pits
Diesel Fuel Oil	Calvert Cliffs	Pipe wrap damage
Fire Protection	Hatch	Coating deterioration, fouling of lines due to corrosion
Condenser Circulating Water	Catawba, McGuire	Interior coating failure, crack in weld, pinhole

It should be noted that a few of the LRAs indicate that some of the degradations were initially caused by improper application of coatings, construction methods, or in one instance waterhammer load.

Although this listing of degradations is not extensive, it indicates that the primary manifestations of degradation are deterioration of the interior or exterior coating, through-wall pits or holes, and fouling.

Operating Experience Presented in EPRI Reports

Operating experience with buried piping is also described in EPRI reports. Much of the information is presented in the form of case histories contained in various EPRI reports such as EPRI TR-103403 (1993), TR-102174 (1993), TR-101541 (1993), 1006994 (2002), and a technical report prepared for EPRI by G. J. Licina (1988). Descriptions of the degradations are primarily contained in papers presented at EPRI sponsored workshops, reported in proceedings and compendium type documents, and were obtained from surveys. Many of the case histories describe degradation of piping in the service water system, where problems in buried piping have been identified. As reported, the primary cause of degradation in service water systems is corrosion and fouling. The type of corrosion and fouling mechanisms vary significantly depending on the plant location, pipe material, external and internal environmental conditions, operation of the system, and maintenance procedures. Various forms of corrosion are present in most service water systems and pipe materials. These include general corrosion, MIC, crevice corrosion, galvanic corrosion, erosion, pitting, fouling, and soil related corrosion. As a result, EPRI has and is continuing to sponsor numerous studies to address service water system degradation.

NUREG-1522

In June 1995, the NRC published NUREG-1522 which describes the condition of structures and civil engineering features at operating nuclear power plants. The NUREG contains descriptions of age-related degradation, which were obtained from many different sources. The most significant information came from site visits at six older NPPs licensed before 1977. The report indicated that there was internal coating degradation of buried piping at three of the six plants visited. Remedial action was taken by the licensees after the degradation resulted in inadequate flow conditions or unacceptable water quality.

3.3 Important Aging Effects for Use in this Study

Although there are numerous aging mechanisms possible for buried piping, the analysis described in this report is based on the aging effect or manifestation of the degradation, not what causes the degradation. This approach is taken because to achieve the objective of developing degradation acceptance criteria (DAC), the degradation criteria will need to be developed in terms of observable levels of degradation which normally correspond to aging effects such as loss of material in the pipe wall. Based on Table 3.3, the primary aging effects that are caused by almost all aging mechanisms are thinning of the pipe wall over a region and localized loss of material/pitting in the pipe wall. The remaining aging effect of loss/reduction in flow is not addressed because this aging effect can be monitored by measuring performance parameters of the system such as flow rates, pressure, and sampling of the fluid.

Degradation to the internal or external coatings as reported in Table 2.2 for some plants is not considered because the coating is a protective material whose deterioration can lead to wall thinning or pitting of the pipe wall at some time in the future, only if no action is taken. As long as degradation of the steel pipe has not occurred, degradation of the coating does not affect overall plant risk. The purpose of this study is to develop DAC on degraded buried piping and not acceptance criteria on the coating material. It is expected that any degradation identified with the interior or exterior coating of buried piping will be repaired unless otherwise justified.

3.4 Degradation Rates For Corrosion and Localized Loss of Material/Pitting

The rate of degradation of steel buried piping is a function of environmental variables, metallurgical variables, and hydrodynamic variables. Environmental variables that can affect the degradation rates occur on the exterior surface of the buried pipe and inside surface of the pipe. For the external surface of the pipe, the rate of degradation is a function of parameters such as aggressive chemicals, oxygen, pH level, and stray currents that may exist in the soil material and groundwater (if present). The rate of degradation on the interior pipe surface is a function of fluid parameters such as fluid velocity, temperature, aggressive chemicals, pH level, dissolved oxygen, and biological elements. Metallurgical variables consist of the chemical composition of various elements in the pipe material such as the weight percentage of chromium, molybdenum, and copper in the steel, which may affect the degradation rate. Hydrodynamic variables such as fluid velocity, piping configuration, and roughness of the pipe inner surface also affect the degradation rate.

Other variables that may affect the degradation rate are: time, type of corrosion/degradation, and whether the piping is pressurized. Depending on the conditions and time period of interest, the degradation rate may not be constant with respect to time. The two types of aging effects which are evaluated in this study (general wall thinning and localized loss of material/pitting) may have some effect on the degradation rate of the buried pipe. In addition, the degradation rate is also expected to be affected by piping that is normally operating and thus “continuously” subject to internal pressure, and by piping that is normally in standby and thus is not subject to internal pressure at all times.

Based on the above discussion, it is evident that predicting an accurate degradation rate for buried piping systems is difficult to achieve, and beyond the scope of this research program.

Therefore, a literature search was performed to determine what are typical degradation rates for buried piping systems that might be appropriate for use in nuclear power plants. Based on EPRI Report TR-103403 (1993), general corrosion rates vary from 1 to >10 mils/year (1 mil per year = 0.0254 mm per year (0.001 in. per year)) for carbon steel and low alloy steels in fresh water at temperatures of 1.67°C to 40.6°C (35°F to 105°F). Assuming 3 mils/year and a 40 year life, this results in a loss of thickness equal to approximately 0.318 cm (1/8 in.), which should have been considered as corrosion allowance in the original design of buried pipe. Corrosion rates of stainless steels, nickel based alloys, and copper alloys have much lower corrosion rates, often less than 1 mil per year. These materials would be used in buried piping subjected to more aggressive environments such as seawater or brackish waters, or where safety concerns require more corrosion-resistant material.

Since there wasn't much more information that could be identified specifically for buried piping, data on degradation rates for above ground piping systems were also searched. Degradation occurrences reported in NRC Information Notices were identified and reviewed. Information Notices that provided quantitative data on degradation rates are IN 2001-09; IN 86-106, Supplement 3; IN 87-36; IN 91-18; and IN 92-35. A review of these Information Notices indicates that the degradation rates for the reported occurrences generally went as high as 60 mils per year, with one case for localized thinning at 90 mils per year. It should be noted that most of these cases occurred in high energy lines such as feedwater systems and it could be argued that their degradation rates are more severe than what would be expected in buried piping systems operating at lower pressures, temperatures, and fluid velocities. On the other hand, these above ground piping systems are not subjected to the external environment that buried piping may be exposed to. Often this external environment in buried piping is mitigated by means of external coatings on the pipe or sometimes by the use of cathodic protection systems. The information provide by these Information Notices do give a measure of perhaps the upper bound of what might be expected in buried piping systems.

Based on the above discussion, it appears that a reasonable range of degradation rates for buried piping would be between 1 and 100 mils per year. This information is only provided as guidance on typical values that have been reported. The selection of an appropriate degradation rate is the responsibility of the individual performing the assessment, based on the conditions that exist for a particular buried piping system.

Table 3.1 Degradation Mechanisms of Buried Commodities (Esselman et al., 1997)

Corrosion Attack of Metals Uniform Corrosion Pitting Crevice Corrosion Intergranular Corrosion Environmentally Induced Corrosion (including Stress Corrosion Cracking) Microbiologically Influenced Corrosion Galvanic Corrosion Selective Leaching/Dealloying
Polymer Degradation Chemical Attack Thermal Decomposition Mechanically Induced Damage
Concrete Degradation Leaching Abrasion Freeze-Thaw Chemical Attack Cracking Reinforcement Corrosion
Mechanical Failure from Imposed Loading Differential Settlement Freeze-Thaw and Frost Heave Heavy Ground-Surface Loading Fatigue Imposed Anchor Displacement Fatigue Tree Root Encroachment Ground Water Erosion Rotating Equipment Soil Arching
Failure of Degradation Protection Protective Coating Degradation Cathodic Protection Failure Protective Conduit or Encasement Failure

Table 3.2 NUREG-1801 GENERIC AGING LESSONS LEARNED (GALL) REPORT, APRIL 2001
INFORMATION CONTAINED IN GALL RELATED TO BURIED PIPING

GALL: VII Auxiliary Systems, C1 Open-Cycle Cooling Water System (Service Water System), C1.1 Piping

Item	Structure and/or Component	Material	Environment	Aging Effect/Mechanism	Aging Management Program (AMP)	Further Evaluation
C1.1-a C1.1.1	Piping Piping and fittings (with or without internal lining or coating)	Carbon steel (for fresh water only), aluminum-bronze, brass, copper-nickel, stainless steel	Raw, untreated salt water or fresh water	Loss of material/ General (only for carbon steel without lining/coating or with degraded lining/coating), selective leaching (only for aluminum-bronze, brass, and copper-nickel), pitting, crevice, galvanic, microbiologically influenced corrosion and biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System" and Chapter XI.M33, "Selective Leaching of Materials"	No
C1.1-b C1.1.2	Piping Underground piping and fittings (external surface, with or without organic coating or wrapping)	Carbon Steel	Soil	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M28, "Buried Piping and Tanks Surveillance," or Chapter XI.M34, "Buried Piping and Tanks Inspection"	No Yes, detection of aging effects and operating experience are to be further evaluated
C1.1-c C1.1.2	Piping Underground piping and fittings (external surface, with or without organic coating or wrapping)	Cast Iron	Soil	Loss of material/ selective leaching and general corrosion	Chapter XI.M33, "Selective Leaching of Materials"	No

GALL: VII Auxiliary Systems, G. Fire Protection

Item	Structure and/or Component	Material	Environment	Aging Effect/Mechanism	Aging Management Program (AMP)	Further Evaluation
G.6-b G.6.2	Water-based fire protection system Filter, fire hydrant, mulsifier, pump casing, sprinkler, strainer, and valve bodies (including containment isolation valves)	Carbon steel, cast iron, bronze, copper, stainless steel	Raw water	Loss of material/ General, galvanic, pitting, crevice, microbiologically influenced corrosion and biofouling	Chapter XI.M27, “Fire Water System”	No

GALL: VII Auxiliary Systems, H1 Diesel Fuel Oil System

Item	Structure and/or Component	Material	Environment	Aging Effect/Mechanism	Aging Management Program (AMP)	Further Evaluation
H1.1-a H1.1.1	Piping Aboveground piping and fittings	Carbon steel	Outdoor ambient conditions	Loss of material/ General, pitting, and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
H1.1-b H1.1.2	Piping Underground piping and fittings	Carbon steel	Soil and ground-water	Loss of material/ General, galvanic, pitting, crevice and microbiologically influenced corrosion	Chapter XI.M28, “Buried Piping and Tanks Surveillance,” or Chapter XI.M34, “Buried Piping and Tanks Inspection”	No Yes detection of aging effects and operating experience are to be further evaluated

GALL: VIII Steam and Power Conversion System, E. Condensate System,

Item	Structure and/or Component	Material	Environment	Aging Effect/Mechanism	Aging Management Program (AMP)	Further Evaluation
E.5-d E.5.1	Condensate storage Tank (buried, external surface)	Carbon steel	Soil and ground water	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M28, "Buried Piping and Tanks Surveillance," or Chapter XI.M34, "Buried Piping and Tanks Inspection"	No Yes detection of aging effects and operating experience are to be further evaluated

GALL: VIII Steam and Power Conversion System, G. Auxiliary Feedwater System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/Mechanism	Aging Management Program (AMP)	Further Evaluation
G.1-c G.1.1 G.1.2	Auxiliary feedwater piping Piping and fittings (aboveground) Piping and fittings (buried)	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
G.1-d G.1.1 G.1.2	Auxiliary feedwater piping Piping and fittings (aboveground) Piping and fittings (buried)	Carbon steel	Untreated water from backup water supply	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion, and biofouling	A plant-specific aging management program is to be evaluated.	Yes, plant specific

G.1-e G.1.2	Auxiliary feedwater piping Piping and fittings (buried) external surface	Carbon steel	Soil and groundwater	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M28, “Buried Piping and Tanks Surveillance,” or Chapter XI.M34, “Buried Piping and Tanks Inspection”	No Yes, detection of aging effects and operating experience are to be further evaluated

Table 3.3 Buried Piping Aging Mechanisms and Aging Effects

Aging Mechanisms	Aging Effects	Material Type	Manifestation	COMMENTS
General corrosion	Loss of material	cs, ci	Thinning of pipe over a region	
Pitting corrosion	Loss of material	cs, ss	Localized pits/holes in pipe wall	
Crevice corrosion	Loss of material	cs, ss, cu, ni	Localized loss of material in regions of contact between metals or metals and nonmetals	Generally requires stagnant or low flow
Galvanic corrosion	Loss of material	cs, ci [1]		[1] Can develop in metals that are further apart in the "Galvanic Series." The lower noble metal will corrode.
Selective leaching	Loss of material	ci		
Microbiologically influenced corrosion (MIC)	Loss of material, & loss/reduction in flow	cs, ss, concrete[2]	Can be internal & external cs – blockage which can reduce flow, pitting ss – pitting through wall generally at welds	Conditions that promote aging effect are stagnant or operation with low or intermittent flow. Use of once-through systems using water from lakes, cooling ponds, or water sources with high organic material. [2] Concrete pipe is primarily used for large diameter lines which are/should be periodically inspected
Biofouling	Loss of material, & loss/reduction in flow	cs, ss		
Fouling	Loss of material, & loss/reduction in flow	cs, ci, ss		
Erosion	Loss of material	Various	Loss of material primarily at elbows and bends	Primarily a concern for higher fluid velocity and suspended particles.
Cavitation	Loss of material	Various	Thinning of pipe	Not common because aging mechanism is normally designed out from piping system.

<u>Legend</u>

Material: cs is carbon steel (including low alloy steel), ss is stainless steel, ci is cast iron, cu is copper, ni is nickel-based alloys

4 DETECTION OF AGE-RELATED DEGRADATION AND CONDITION ASSESSMENT

4.1 Inspection Methods

Inspection methods for the degradation of buried piping can be based on visual, non-destructive, or destructive methods. Since degradation mechanisms can cause aging effects on the interior and/or exterior of buried piping systems, information about the condition of the inside and outside surface of buried piping is important. Large diameter lines such as portions of the service water system usually can be examined by manual visual inspection provided there is access to the line. Smaller diameter lines however, are not easily accessible and require other techniques which have been improved significantly over recent years. The methods that can be used to inspect the condition of buried piping are described below. The use of a particular method depends on the size of the line, access to the interior or exterior surface, pipe material, aging effect of interest, and cost.

Visual Inspection

This is the most common form of inspection of the condition of the interior or exterior buried piping. For interior examination of large diameter lines, inspections are usually performed during plant outages where a trained individual (inspector) enters the pipeline to examine the condition of the pipe surfaces, coatings (if applicable), welds, and mechanical joints. If the water in the line is not drained, inspections can still be performed using trained divers. The inspector can identify any fouling of the pipe, loss of wall thickness, degradation of coating, and identify the extent of any other degradation. Loss of wall thickness can be identified using a pit gauge to measure pit depth, ultrasonic test (UT) meter to measure general loss of material, and tape measure to record the area of the corroded region. Inspection for coating degradation would include examination for cracking, blistering, debonding, peeling, erosion, and general loss of coating material. During the inspection the inspector can collect any built-up material due to fouling or corrosion by-products for subsequent analysis. In addition, the inspector can insert and remove coupons which can be evaluated for degradation of the pipe material.

Sometimes, an indication of the condition of the interior surface for buried piping can be determined by examining accessible entry points where the buried piping rises above the ground surface or enters into buildings. This may not be reliable though if conditions of the buried piping section are different than the accessible portions of pipe above ground or within the buildings. This may be due, as an example, to stagnant water in the buried piping section which may not exist in the other regions being examined.

Visual inspections from inside the pipe cannot identify degradation on the outside surface of the pipe unless corrosion or pitting penetrates the thickness of the pipe. Therefore, to obtain complete knowledge of the condition of a buried pipe, examination of the inside and outside surface is recommended. The same visual inspection methods described above can be used to examine the exterior surface of the pipe; however, excavation would be needed to gain access to the exterior pipe surface.

Cameras

Cameras can be used for visual inspection of buried pipes. These cameras provide visual type information without the need for direct personnel inspection or excavation to gain access to buried pipe. These cameras are useful for smaller diameter lines where direct visual inspection by personnel is not possible. Presently, these cameras are tethered and may be difficult to operate in tees, bends, vertical segments, and have a limited range in terms of length of operation in the buried pipe.

<u>Ultrasonic Test (UT)</u>

The UT method is used to measure wall thickness in pipe. The UT method is based on the pulse echo principle in which a short ultrasonic pulse is generated in the transducer head and transferred into the body to be measured. The pulse travels through the pipe wall and then reflects from the back of the pipe wall or surface of a discontinuity and is returned to the transducer. The transmission time of the pulse from when it enters the pipe wall to when it returns is recorded with UT equipment. Multiplication of this transmission time by the speed of sound in the pipe material provides the thickness of the pipe wall. This method can be used to accurately identify degradation of buried pipe which results in wall thinning. Some of the UT equipment are hand held devices and can be used in submerged conditions.

Because UT is a slow process and is not practical to examine long lengths of buried pipe or large surface areas, it is usually used to perform inspections in areas of concern and as a “spot check” for sample locations. Areas of concern for which UT would be utilized include regions where a leak is observed, at welded joints, and areas where loss of material is noted.

A technique called guided wave ultrasonic scanning method can be used to inspect buried pipe over long runs from a single set-up point. The method requires that access to the pipe at one point be made (on the order of 61.0 cm (24 in.) along the pipe) and the scan can be made in each direction to distances of about 27.4 m (90 ft). It works for pipe sizes in the range of 2.54 to 91.4 cm (1 to 36 in.) in diameter or more.

<u>Electromagnetic Test</u>

Electromagnetic test methods use an electric current or magnetic field to detect discontinuities or variations in materials. The electric current can be applied directly or by a magnetic field which is a more common approach. This method is often called “eddy current testing. The frequency used, conductivity, and magnetic permeability of the material determine the depth of penetration of the eddy currents in the component. The method can only be used on conducting materials.

A low frequency electromagnetic technique is available for detecting and quantifying degradation on the inside, outside, and within the pipe wall in a single scan. According to a manufacturer of such test equipment (TesTex, Inc.), the device is hand held, can inspect through coatings, and can test at a rate of 4.57 to 6.10 m (15 to 20 ft) per minute over a width of approximately 7.62 to 10.2 cm (3 to 4 in.). It can detect pitting, wall thinning, and cracking. The separation between the sensors and the pipe surface can be as much as 0.953 cm (0.375 in.). The unit which is primarily used to examine pipe from the outside surface, can inspect ferrous and stainless steel pipe material and can operate while the piping is in-service or out of service. This equipment has already been utilized at NPPs for detection of MIC in service water systems and fire protection piping (it is not clear whether it was used for above ground or buried piping). There are some limitations regarding depth of penetration for measurements, distances separating device to the pipe (which may require cleaning or surface preparation), and accuracy (level of defect detection). Therefore, once locations of degradation are identified using this technique, it is recommended to follow-up with UT examination to obtain more accurate readings of the affected areas.

Pipeline Pigs (In-Line Inspection)

Pipeline “pigs” are devices that are inserted into pipelines to perform maintenance or inspection functions. Pipeline pigs for cleaning or emptying pipelines have been used for many years in numerous pipeline industries. Depending on the need, different pigs are used to clean the pipeline, dewater the pipeline, sweep out air pockets, check pipe inner diameter, or remove condensate in pipelines. In addition to these maintenance operations, “smart pigs” have been developed which can detect and determine the extent of degradation in pipelines. These smart pigs are computerized, self-contained devices that are propelled forward by the liquid flowing through the pipe and record the condition as they move along. Smart pigs can be fitted with corrosion tools such as magnetic field or ultra-sound to detect changes in pipe wall thicknesses, crack detection tools utilizing ultrasound to detect cracks, and geometry tools to identify deviations in a pipeline internal diameter or locations of dents in the pipe. A major advantage with the smart pigs is that they allow remote inspection capability where excavation or access by direct visual examination is either too costly or not possible.

Based on EPRI Report GC-109054 (1997), smart pigs are about 2.44 m (8 ft) long and can travel inside the pipe at the flow rate of the fluid, typically 4.02 to 14.5 km/hr (2.5 to 9 mph) or about 1.22 to 3.96 m/s (4 to 13 ft/s). The location of the pig is tracked by 3 to 4 odometer wheels which identify the distance the pig travels along the pipe with respect to a reference location such as a circumferential weld. They are able to negotiate pipe bends and elbows while they record data using electronic probes or transducers. Smart pigs can be untethered operating on batteries for several days. They contain 1 to 4 computers which store the data recorded from magnetic flux leakage (MFL) and ultrasonic (UT) thickness measurements. MFL sensitivity to pipe wall thinning is about 10% with an 80% confidence level, while UT sensitivity for a 2.54 cm (1 in.) diameter pit is approximately 0.203 cm (0.08 in.) deep in 1.27 cm (1/2 in.) thick pipe wall thickness. Additional technical information is available in the referenced EPRI report.

More detailed description and guidance on the use of NDE methods for smart in-line inspection devices (pigs) are presented in EPRI Report GC-108827 (1998). Since straight sections of buried pipe at NPPs are relatively short and contain a number of elbows or bends, the report suggests that tethered, self-propelled vehicles provide the best option for examination of buried pipe in the nuclear industry. The EPRI report describes the use of magnetic flux leakage, ultrasonic immersion, remote field eddy current, and low frequency eddy current methods with the in-line inspection devices. Guidance on the applicability of these methods to conditions such as types of aging effects, pipe sizes, and lining within a pipe is provided in the report. In addition, the availability and capability of these devices to examine buried piping is discussed.

Cathodic Protection System

Although a cathodic protection system is not an inspection method, it can provide some information which would indicate whether buried piping is adequately protected against corrosion or in the case of abnormal electrical readings, degradation problems may be developing. Many buried piping systems are cathodically protected. Cathodic protection is a technique which connects a metal of higher potential (anode) to the buried metallic piping. This creates an electrochemical cell that causes the lower potential pipe to become a cathode thereby protecting it from corrosion. In Galvanic cathodic protection systems, anodes are used which have a natural potential more reactive than that of the structure being protected. In impressed current systems an external power source to impress a current on the buried piping is used. Impressed current cathodic systems have many advantages but they must be monitored regularly (as often as monthly or bimonthly). It is this monitoring that provides an indication of the effectiveness of the cathodic protection system and readings of the current or voltage that are out of range is a sign of some breakdown in the protective system or an indication that degradation may be developing.

<u>Other Methods</u>

There are other methods that have been developed using different technologies or variations of the technologies described above. These include remote field eddy current, magnetic flux leakage, and infrared thermography. Test methods for priestesses concrete pipe include acoustic emission, impact-echo, hammer testing, and remote field eddy current. Although NDE methods for concrete pipe are not as well developed, concrete pipe is used primarily for large diameter lines which would likely permit direct visual inspection.

4.2 Regulatory Requirements and Technical Guidance

There are a number of regulatory requirements (e.g., 10 CFR 50, Appendix A, General Design Criteria) that apply to buried piping systems, but many of these requirements relate to initial plant design and pressure/functional testing. NRC generic correspondences such as Generic Letters and Information Notices have been issued on degradation of buried piping. These have been described in Section 3.2 of this report. Other regulatory requirements or technical documents that relate to degradation of buried piping are discussed below.

<u>10 CFR 50.65 – Maintenance Rule</u>

On July 10, 1991, the NRC published 10 CFR 50.65 entitled, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” referred to as the Maintenance Rule. The purpose of the regulation, which went into effect on July 10, 1996, is to monitor the effectiveness of maintenance activities for safety significant plant equipment in order to minimize the likelihood of failures and abnormal events caused by the lack of effective maintenance. The final rule requires that licensees monitor the performance or conditions of structures, systems, and components (SSCs) against licensee-established goals in a manner sufficient to provide reasonable assurance that the SSCs will be capable of performing their intended functions. Such monitoring needs to be established commensurate with safety and, where practical, take into account industry operating experience. For buried piping that meets the scope definition in paragraph 10 CFR 50.65 (b) of the Maintenance Rule, the licensee would be required to monitor the performance or condition of the piping.

Several other NRC documents related to the Maintenance Rule contain additional technical information and guidance: “Statements of Consideration for 10 CFR 50.65,” Regulatory Guide 1.160, Rev. 2, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and several NRC inspection procedures.

<u>NRC Inspection Procedures</u>

NRC Inspection Procedure 62706, “Maintenance Rule,” provides instructions to the staff for verifying implementation of 10 CFR 50.65. It specifies the inspection requirements, inspection guidance, and referenced material that provide additional guidance on acceptable methods to implement the requirements of the Maintenance Rule.

NRC Inspection Procedure 62002, “Inspection of Structures, Passive Components, and Civil Features at Nuclear Power Plants,” provides guidance to the staff to (1) evaluate by visual examination and/or review of licensee documentation the condition of structures, passive components, and civil engineering features and (2) verify implementation of 10 CFR 50.65. The inspection procedure lists buried piping, pipe supports, and equipment anchorages as one of ten groups of SSCs that would be included for review under the Maintenance Rule. Specific guidance is provided in paragraph 03.01(e) of the Inspection Procedure for buried piping. It indicates that the documentation of the licensee's maintenance program, including preventive maintenance for buried piping, is reviewed. Seismic Category I buried piping should be able to perform its functions under vibratory loads resulting from seismic events. The cathodic protection system (if present) should be functional and the inspector should review the licensee's documentation and surveillance to ensure that the system is protecting all elements served by the cathodic protection system. Licensees should include acceptance criteria for corrosion of piping, pipe supports, and anchorages. Buried piping maintenance programs should include visual examinations when piping is accessible.

<u>10 CFR Part 54 – License Renewal Rule</u>

The requirements for obtaining the renewal of a nuclear power plant operating license for up to an additional 20 years are presented in 10 CFR Part 54 – License Renewal Rule. Under this rule, the applicants are required to identify all SSCs that are within the scope of the rule. A screening review is then required to identify those SSCs that are "passive and long-lived" structures and components. For the passive, long-lived structures and components, the applicant must demonstrate that the effects of aging will be managed so that the intended function(s) will be maintained consistent with the current licensing basis through the period of extended operation. Depending on the system, NPPs have buried piping that fall within the scope of the License Renewal Rule.

In July 2001, the NRC published the "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR) (NUREG-1800). The SRP-LR was prepared to provide guidance for staff reviewers in performing safety reviews of applications to renew licenses of NPPs in accordance with 10 CFR Part 54. The SRP-LR in many cases references the "Generic Aging Lessons Learned " (GALL) report. The GALL report (NUREG-1801) presents an evaluation of existing generic programs to document the conditions under which these programs are considered adequate to mange identified aging effects without change and the conditions under which existing programs should be augmented. The GALL report includes tables for various passive structures and components within the scope of the License Renewal Rule. The tables list for each structure or component the material type, environment, aging effect/mechanism, aging management program, and whether further evaluation is needed. The information obtained from the GALL report for buried piping is presented in Table 3.2 and is discussed in Section 3.1 of this report.

The GALL report also contains evaluations of acceptable aging management programs for the various structures and components within the scope of the License Renewal Rule. Aging management programs evaluated in GALL include Buried Piping and Tanks Surveillance, Buried Piping and Tanks Inspection, Open-Cycle Cooling Water System, Selective Leaching of Materials, Fire Water System, Water Chemistry and a related One-Time Inspection Program. In some cases a plant-specific program would be required. The GALL evaluates the aging management programs using 10 attributes consisting of the scope of program, preventive actions, parameters monitored/inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

4.3 Industry Programs to Manage Aging

As a result of the concern with degradation to SSCs, the nuclear industry has various programs that manage aging. These programs have been instituted for a number of reasons including NRC regulatory requirements; state and local codes; cost considerations for replacement, repair, and down time; environmental concerns; and increased safety. The programs include preventive maintenance and corrective maintenance, maintenance procedures, inspection and examination procedures, testing programs, and coating programs. That is why for many licensees who are applying for license renewal, they are able to take advantage of existing programs that manage aging rather than developing and committing to new programs.

A major driving force to expand and improve these programs to manage aging was the Maintenance Rule and License Renewal Rule which were discussed earlier. To support NPPs in developing acceptable maintenance and aging programs to address the Maintenance Rule and the License Renewal Rule, the industry developed guidance documents, NUMARC 93-01 (1996) and NEI 95-10 (1996).

<u>NUMARC 93-01</u>

NUMARC 93-01 (1996), "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was issued in April 1996. This document describes an acceptable approach for individual NPPs to implement the requirements of the Maintenance Rule and to build on the progress, programs, and facilities already established to improve maintenance. The guideline provides an approach for identifying the SSCs within the scope of the Maintenance Rule. It then describes the approach for developing plant-specific risk and performance criteria/goals, and monitoring the SSCs against the criteria. If performance criteria are not being met, then goals are established to make the necessary improvements in performance. For buried piping within the Maintenance Rule, it is expected that either existing plant-specific programs are relied upon or new plant-specific programs have been developed.

<u>NEI 95-10</u>

NEI 95-10 (1996), "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," was issued in March 1996. This document provides an acceptable approach that licensees can follow for implementation of the License Renewal Rule. The guideline describes methods for identifying the scope, identifying the intended functions, identifying the structures and components subject to aging management review, assuring that aging effects are managed, application of inspections for license renewal, identifying and evaluating time-limited aging analyses, and describing a format and content of a license renewal application. In Appendix B of the guideline, a table is presented which includes under the category "non-class I piping components," underground piping and identifies it as a passive component.

<u>Industry Life Cycle Management Programs</u>

In an effort to manage aging degradation, improve equipment reliability, and reduce obsolescence of important structures, systems, and components (SSCs), the industry is developing Life Cycle Management" (LCM) processes. To assist the nuclear industry in this endeavor, the Electric Power Research Institute (EPRI) is researching and preparing LCM Sourcebooks for selected systems and components. As indicated in EPRI Overview Report 1003058 (2001), the objective of the LCM sourcebook effort is to provide plant system engineers with generic information, data, and guidance which can be utilized to develop long-term reliability plans for SSCs.

One of two prototype sourcebooks already prepared covers the passive SSC of buried piping (EPRI Report 1006616, 2002). This LCM sourcebook covers buried large-diameter piping, which is defined as buried piping 50.8 cm (20 in.) and larger that are within the condenser circulating water system (CCW), essential service water system (ESW), and the non-essential service water system (NESW). The buried piping sourcebook describes operating experience and performance history, guidance for plant-specific condition and performance assessment, aging mechanisms, alternative LCM plans, determination of failure rates, guidance for economic modeling, and information sources and references. This document also includes a technical evaluation of a hypothetical case to illustrate the process of performing an LCM evaluation and also some summaries of buried piping aging management programs from specific NPPs.

5 FRAGILITY EVALUATION OF DEGRADED BURIED PIPING SYSTEMS

In this section, the fragility of buried piping is determined for undegraded and degraded pipe. Fragility is the cumulative probability of failure, in this case for the pipe, for a given value of input load. The governing loads acting on buried pipe are identified and then the applicable equations are used to perform the fragility analysis. The results of the fragility analysis developed in this section are later combined with the risk assessment analysis from Section 6 to develop degradation acceptance criteria. The description of how the fragility results and risk assessment results were used to develop degradation acceptance criteria is presented in Section 7.

In this section of the report, the units of measure are first given in English units followed by SI (metric) units in parenthesis because many of the equations and parameters are derived based on English units.

5.1 Governing Load(s) for Risk-Informed Study

The loads that buried piping systems are generally designed for consist of internal fluid pressure, soil surcharge (dead weight of soil above the pipe), groundwater, surface loads (permanent loads or live loads such as cars, trucks, etc.), seismic, and thermal expansion. Other loads that are not common but might be considered are surface impact loads, fluid transients, buoyancy, and soil/building settlement.

5.1.1 Internal Pressure Loads

These loads are due to the internal pressure of fluid (water) inside the buried pipe. Design of buried piping typically begins with sizing the required pipe diameter and thickness based on the internal pressure. After selecting the desired pipe material and diameter to meet certain flow requirements, the designer calculates the minimum required pipe thickness needed to withstand the design pressures at the design temperatures. The equations used to calculate the minimum required wall thickness depend on the code or standard applicable to the intended use. More discussion about the specific equations used to calculate the required minimum wall thickness is presented in Section 5.2.

5.1.2 Soil Surcharge (Dead Load)

As discussed in Section 1.2 of WRC Bulletin 446 (Antaki, 1999), soil loads are an important consideration for rigid pipes and non-ductile pipes such as concrete or cast iron. Soil loads are also important for pipes with large D/t (diameter to thickness) ratios. Many of the equations that have been developed for calculating earth loads on buried pipe are often based on the Marston load theory (discussed in Moser, 2001).

A. <u>Vertical Soil Load on Pipe</u>

<u>Rigid Pipe</u>

For rigid pipe buried in a trench, the maximum vertical soil pressure at the top of the pipe is carried primarily by the pipe. The resultant load on the pipe can be calculated by the following equation [WRC Bulletins 425 and 446 (Antaki, 1997 and 1999), Moser, 2001; and ASCE Manuals and Reports of Engineering Practice No. 77/WEF Manual of Practice FD-20)]:

$$V = \frac{\gamma B_d^{\,2}[1 - e^{-2K\mu'(H/B_d)}]}{2K\mu'} \tag{5.1}$$

which can be rewritten as:

$$V = C_d \gamma B_d^{\,2} \tag{5.2}$$

where

$$C_d = \frac{[1 - e^{-2K\mu'(H/B_d)}]}{2K\mu'} \tag{5.3}$$

where

V = soil load per unit length of pipe (force/length)

P_v = soil pressure load on pipe (force/length^2) = V / D

D = outside diameter of pipe

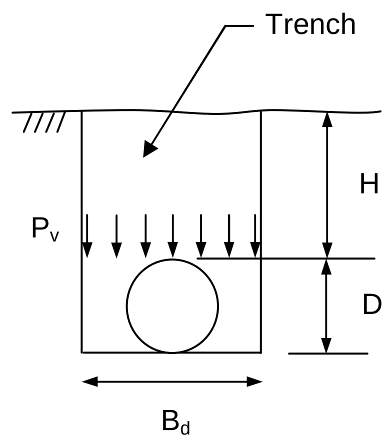
γ = total unit weight of soil (weight density)

B_d = width of trench

K = Rankine's ratio (for active pressure)

$$K = \frac{1 - \sin\phi}{1 + \sin\phi},$$

where ϕ = friction angle in soil



$\mu' = \tan\phi'$ = coefficient of friction between the backfill material and sides of trench

H = height of fill above the pipe

As explained by Moser (2001), for very rigid pipe (clay, concrete, heavy walled cast iron, etc.) the fill material at the side of the pipe is more compressible than the pipe and therefore, the pipe may carry a very large portion of the load V.

<u>Flexible Pipe</u>

For flexible pipe, where the pipe stiffness is close to the soil stiffness, the pipe and side fill support the surcharge load. Therefore, the load on a flexible pipe can be substantially less than on a rigid pipe. The maximum resultant load for flexible pipe is expressed as [WRC Bulletins 425 and 446 (Antaki, 1997 and 1999), and Moser (2001)]:

$$V = C_d \gamma D B_d \tag{5.4}$$

where

V = soil load per unit length of pipe (force/length)

P_v = soil pressure load on pipe (force/length^2) = V / D

C_d and the other parameters are as defined above

Steel Pipe

For soil loads on buried steel buried pipe the American Lifelines Alliance (2001) considers steel pipe to be flexible and recommends that the pressure loading due to the soil above the pipe be based on a prism of soil with a width equal to the pipe diameter and a height equal to the depth of fill over the pipe. This leads to the equation for soil pressure on the pipe as:

$$V = \gamma HD \tag{5.5}$$

where

V = soil load per unit length of pipe (force/length)
P_v = soil pressure load on pipe (force/length^2) = V / D
γ and H are as defined above

For steel pipe, the rigid pipe equations lead to an overprediction of pipe loads while the flexible pipe equations are considered minimum loads. The prism load approach for steel pipe results in loads that are in-between the loads calculated using the rigid and flexible pipe equations. Over a long period of time actual pipe loads may approach the prism load, and therefore the prism load approach is recommended as a basis for design (Moser 2001).

Example

To gain an understanding of the significance of surcharge soil loads on buried pipe, consider the following example:

Pipe size = 24 in. (61.0 cm)
Pipe schedule = standard thickness = 0.375 in. (0.953 cm)
Wet sand unit weight = 130 lb/ft^3 (2,083 kg/m^3) (considered as an upper bound value)
Trench Depth = 7 ft (2.13 m) to top of pipe
Trench width = 56 in. (142 cm)

For sand,

K = 0.33 and μ' = 0.50 (based on Table 2.1 presented in Moser, 2001)
H/B_d = (7 x12) / 56 = 1.5
Using equation (5.3), C_d = 1.18

Maximum soil pressure load on pipe:

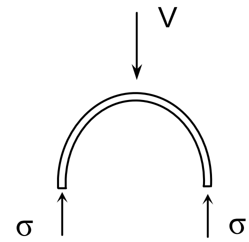
For rigid pipe, using equation (5.2), V	= 278 lb/in (4,965 kg/m)
(Considering the diameter)	= 11.6 psi (80.0 kPa) pressure
For flexible pipe, using equation (5.4), V	= 119 lb/in (2,125 kg/m)
(Considering the diameter)	= 4.97 psi (34.3 kPa) pressure
For steel pipe, using equation (5.5), V	= 152 lb/in (2,714 kg/m)
(Considering the diameter)	= 6.32 psi (43.6 kPa) pressure

Thus, for the steel pipe using the soil prism method, the soil pressure of 6.32 psi (43.6 kPa) acting on top of the pipe is in between the values for the flexible pipe and the rigid pipe.

B. Side Wall Compressive Stress in Pipe

To determine the compressive stress that develops at each side of the pipe, the following equation can be used:

$$\sigma = \frac{V}{2t} \qquad (5.6)$$



where t = thickness of the pipe

Example

Using the results from the previous example, this leads to the following sidewall stress:

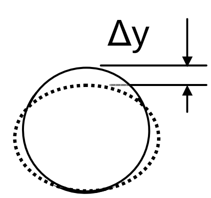
For rigid pipe, σ = 371 psi (2.56 MPa)
For flexible pipe, σ = 159 psi (1.10 MPa)
For steel pipe, σ = 203 psi (1.40 MPa)

Therefore, even for the worst case of a very rigid pipe relative to the soil, the maximum compressive stress in the side wall is only 371 psi (2.56 MPa).

C. Maximum Through-Wall Bending Stress

The through-wall bending stress in the buried pipe developed under the surcharge load can be calculated using an approach presented in the American Lifelines Alliance Report (2001). This approach, which is based on the modified Iowa deflection formula, calculates the ovality (amount of pipe vertical deflection with respect to the pipe diameter).

$$\frac{\Delta y}{D} = \frac{D_l K_b P_v}{\left[\frac{(EI)_{eq}}{R^3} + 0.061E'\right]} \qquad (5.7)$$



Ovality of Pipe

where
D = pipe outside diameter
Δy = vertical deflection of pipe
D_l = deflection lag factor (~1.0 to 1.5)
K_b = bedding constant (~0.1)
P_v = Vertical pressure on pipe due to soil load
R = pipe radius
$(EI)_{eq}$ = equivalent pipe wall stiffness per inch of pipe length (which includes any pipe lining and/or coating if applicable)
E' = modulus of soil reaction of pipe bedding (soil beneath the pipe)

$I = \frac{t^3}{12}$ (per unit length of pipe), where t = pipe wall thickness

Recommendations for some of the above parameters are provided (Moser, 2001) as follows:

The deflection lag factor accounts for the continued deflection of the pipe over time after installation of the pipe. Deflections over 40 years could increase as much as 30% and so a design value of 1.5 for D_l is recommended. The Iowa deflection formula for ovality however, is based on the Marston load approach. Therefore, if the prism load is used for design rather than the Marston load, the deflection lag factor should be reduced to 1.0 because the long-term load on the pipe will not exceed the prism load.

The modulus of elastic reaction (E') represents the stiffness of the soil surrounding the pipe. Average modulus of soil reaction values are available based on test data. Values of E' can vary from 0 for poorly graded and poorly compacted soil up to 3,000 psi (20.7 MPa) for coarse grained soil that is well compacted (Moser, 2001).

The stress in the pipe is calculated by substituting the ovality calculated above into the following equation (American Lifelines Alliance Report, 2001) for through-wall stress:

$$\sigma_{bw} = 4E\left(\frac{\Delta y}{D}\right)\left(\frac{t}{D}\right) \tag{5.8}$$

where σ_{bw} = through-wall bending stress

Example

Using the same example as before 24 in. (61.0 cm), standard schedule pipe, 7 ft (2.13 m) soil cover), the maximum through-wall bending stress is calculated using the soil pressure previously calculated for steel pipe and the following parameters:

P_v = 6.32 psi (43.6 kPa)
D_l = 1.0 (since the prism load is used not the Marston load)
E' = assume 1,000 psi (6.89 MPa) for moderate compaction of bedding and well-graded soil, based on Moser (2001), Table 3.4.
$I = \frac{(0.375)^3}{12}$ = 0.00439 in^4 per inch of pipe length (0.0720 cm^4 per centimeter of pipe)
K_b = 0.1
Using equation (5.7) leads to $\frac{\Delta y}{D} = .00469$
Using equation (5.8) leads to $\sigma_{bw} =$ 8.51 ksi (58.7 MPa)

This stress is considered to be low, well below the yield stress and only about 14% of the ultimate stress value for a typical buried carbon steel pipe.

5.1.3 Groundwater

If the water table is above the buried pipe, then the effect of the water on the soil surcharge can be evaluated using the following equation (American Lifelines Alliance, 2001):

$$P_v = \gamma_w h_w + R_w \gamma_d H \tag{5.9}$$

where

P_v = earth dead load pressure on the pipe (force/length^2)
γ_d = dry unit weight of fill (weight density)
H = height of fill above the pipe
h_w = height of water above pipe
γ_w = unit weight of water (weight density)
R_w = water buoyancy factor = 1- 0.33(h_w/H)

Note: For the range of buried steel pipe sizes of interest in this study, up to about 42 inches (107 cm), the upward buoyancy force on a worst-case empty pipe is less than the downward loads of pipe weight and saturated soil weight. The 42 inch (107 cm) maximum pipe size is selected as an upper bound because it covers most buried pipe sizes at NPPs, is normally commercially available in varying schedules, and larger diameters would probably violate the D/t requirements developed in Section 5.1.5 of this report.

Example

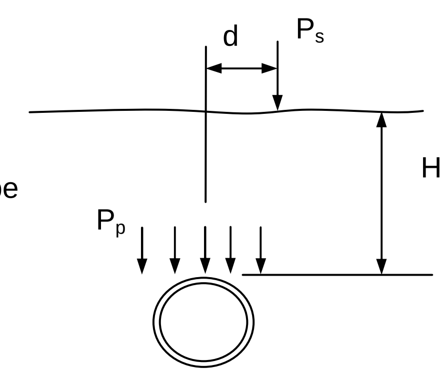
Use the same example as before for dead load and conservatively assume that the water table is at the ground surface and that γ_d (dry unit weight of fill) is equal to 120 lb/ft^3 (1,922 kg/m^3). The soil and groundwater load on the pipe calculated using equation (5.9) is 6.94 psi (47.8 kPa), which is only 9.8% higher than the 6.32 psi (43.6 kPa) soil pressure previously calculated.

5.1.4 Surface Loads

Surface loads could include dead loads such as buildings, tanks, etc., and/or live loads (temporary loads) such as equipment, vehicles, and railways. For this study, it will be assumed that there are no buildings or other large uniform dead loads on the surface. Instead, the evaluation will consider the more likely case of a live load due to a large truck which imposes a concentrated load at the surface. An equation for calculating stress in a semi-infinite elastic medium due to concentrated loads applied at the surface was developed by Boussinesq. The solutions assume that the soil is an elastic, homogeneous, and isotropic material which often is not the case. However, when properly applied, the Boussinesq solutions have been shown to give reasonable results for soils based on actual tests (Moser, 2001).

Based on the Boussinesq solution, the pressure P_p decreases as the square of the soil cover H and is given by American Lifelines Alliance (2001) as:

$$P_p = \frac{3P_s}{2\pi H^2\left[1+\left(\frac{d}{H}\right)^2\right]^{2.5}} \qquad (5.10)$$



where

P_p = pressure transmitted to the pipe wall
P_s = concentrated load at the surface, above the pipe
H = depth of soil cover above pipe
d = offset distance from pipe to line of application of surface load

For severe surface loads such as truck traffic, an AASHTO H20 truck loading will be considered. The H20 truck loading corresponds to a 32,000 lb (142 kN) load under one axle. For each side of the axle a wheel loading of 16,000 lb (71.2 kN) concentrated load over a small area is evaluated and the resulting pressure loading on a pipe has been tabulated. The pressure loading on the pipe as a function of the soil cover, for the H20 truck loading (which is independent of pipe size) is presented below. The values for pressure include an impact factor of 1.5 to account for bumps or irregularities in the road. The tabulated values are obtained from the American Lifelines Alliance (2001).

Live Load Pressure (P_p) Transferred to Pipe Due to H20 Truck Loading
American Lifelines Alliance (2001)

Height of cover (ft)	1	2	3	4	5	6	7	8	10
Live load P_p (lb/in^2)	12.5	5.56	4.17	2.78	1.74	1.39	1.22	0.69	Negligible

1 ft = 0.3048 m; 1 lb/in^2 = 6.89 kPa

This table shows that the live load pressure due to a truck load diminishes very rapidly with increasing depth of the pipe. At ten feet (3.05 m) the pressure is considered negligible. As reported in the American Lifelines Alliance Report (2001), an impact factor of 1.0 would be applicable to highways for depths over 3 feet (0.914 m). This would mean that the pressure load on the pipe for a 3 feet (0.914 m) cover (minimum value considered for this study) would be 4.17 psi x 1.0/1.5 = 2.78 psi (19.2 kPa). At 7 ft (2.13 m) the soil pressure in the pipe would be 0.813 psi (5.61 kPa) (very small)

5.1.5 Combined Loading for Vertical External Soil Pressure Loads

A. Buckling Evaluation

As a check on the potential for buckling of the pipe under the soil surcharge dead load, groundwater, and surface live load, the following equation can be used to calculate what is referred to as ring buckling (American Lifelines Alliance, 2001):

$$P_B = \frac{1}{FS}\sqrt{32 R_W B' E' \frac{(EI)_{eq}}{D^3}} \tag{5.11}$$

where

P_B = allowable vertical soil pressure on pipe to preclude ring buckling
FS = factor of safety; 2.5 for H/D $\geq$ 2 and 3.0 for H/D $\leq$ 2
H = depth of soil cover above pipe
D = diameter of pipe
R_w = water buoyancy factor = 1-0.33(h_w/H), 0 < h_w < H
h_w = height of water surface above top of pipe
B' = empirical coefficient of elastic support (dimensionless)
Given in AWWA Manual 11 as

$$B' = \frac{1}{1 + 4e^{(-0.065H/D)}}$$

E' = modulus of soil reaction (see Section 5.1.2 of this report for more information)
$(EI)_{eq}$ = equivalent stiffness considering bare pipe, lining, and coating (if applicable)
E = modulus of elasticity of material
I = moment of inertia of material = $t^3/12$

Example

Using the same example as before; a 24 in. (61.0 cm) diameter, standard schedule pipe, with a depth of soil cover equal to 7 ft (2.13 m), water table conservatively assumed at the ground surface, and a modulus of soil reaction E' of 1,000 psi (6.89 MPa), the critical buckling soil pressure load ($P_{critical}$) is calculated as follows:

$$B' = \frac{1}{1 + 4e^{(-0.065(7x12/24))}} = 0.239$$

$$R_w = 1 - 0.33\ (7/7) = 0.67$$

$$P_{critical} = \sqrt{32(0.67)(0.239)(1000)\frac{(29x10^6)(0.00439)}{24^3}} = 217 \text{ psi } (1.50 \text{ MPa})$$

This is compared to the total applied soil pressure load for dead load (6.94 psi (47.8 kPa) with groundwater included) plus live load (1.22 x (1.0/1.5) = 0.813 psi (5.61 kPa)), which is equal to 7.75 psi (53.4 kPa). The total applied soil pressure load of 7.75 psi (53.4 kPa) is well below the 217 psi (1.50 MPa) critical soil pressure load that would cause ring buckling in the pipe.

For comparison, using a 3 ft (0.914 m) cover, $P_{critical}$ results in a critical soil pressure of 207 psi (1.43 MPa), which is only slightly lower than the 217 psi (1.50 MPa) calculated above. Thus, it is very unlikely that the steel pipe would buckle for the range of parameters being studied in this research effort.

B. Pipe Stress

Example

Using the same example as before; the total dead load and live load, including the effect of the water table at ground surface is 7.75 psi (53.4 kPa). Following the same approach as before for soil surcharge loads:

Pipe sidewall compressive stress -

From equation (5.6), σ = V/2t =7.75 psi x 24 in/(2x.375) = 248 psi (1.71 MPa) (negligible)

Pipe through-wall bending stress -

From equations (5.7) and (5.8) σ = 10.4 ksi (71.7 MPa) (considered to be low)

Note that the above calculation was for the 7 ft (2.13 m) soil cover case. If the 3 ft (0.914 m) (proposed minimum soil cover for this study discussed in Section 5.1.4) was used, the contribution from dead load would drop off faster than the increase in the live load, and so the 7 ft (2.13 m) case is more conservative.

Effect of Varying D/t and Soil Modulus

To see whether the relatively low stress for combined external loadings applies to other configurations, consider the variation in stress due to other pipe diameters and schedules. This can be done by using the same example as before and solving for the maximum through-wall bending stress for varying D/t ratios for pipe. The effect of varying D/t is shown for soil modulus of 2,000, 1,000, and 500 psi (13.8, 6.89, and 3.45 MPa).

Maximum Through-Wall Bending Stress

Diameter to thickness ratio (D/t)		20	40	60	80	100	120	140
Max. through-wall bending stress (ksi)	E' = 2000 psi	1.77	5.30	7.08	7.03	6.36	5.62	4.98
	E' = 1000 psi	1.81	6.19	9.96	11.4	11.2	10.4	9.44
	E' = 500 psi	1.84	6.76	12.5	16.5	18.0	18.0	17.1

1 psi = 0.00689 MPa; 1 ksi = 6.89 MPa

The above tabulation indicates that for E' = 1000 psi (6.89 MPa), with higher D/t ratios there is an increase in through-wall bending stress to a maximum of 11.4 ksi (78.6 MPa) and then for D/t ratios above 80, the bending stress decreases. For E' = 500 psi, (3.45 MPa) the bending stress rises to a maximum of 18.0 ksi (124 MPa) at D/t of 100 to 120 and then decreases for higher D/t ratios.

Effect of Varying Soil Cover Depth

The amount of soil cover to the top of the buried pipe can also affect the level of stress in the pipe. Therefore, it is suggested to limit the depth of soil cover to an amount that would not develop significant stresses in the pipe. For this study it is recommended to limit the maximum pipe bending stress from combined external soil loadings (surcharge, groundwater, and surface live load) to 15 ksi (103 MPa) (25% of the minimum ultimate strength of A 106 Gr. B pipe). Using the modulus of soil reaction equal to 1,000 psi (6.89 MPa) (well graded and moderate compaction), this leads to the following acceptable soil cover depth for use in this study:

Acceptable Soil Cover

Diameter to thickness ratio (D/t)	20	30	40	50	60	70	80
Acceptable soil cover for this study (ft)	64	30	18	14	11	10	10

1 ft = 0.3048 m

The above table was prepared for the range of pipe sizes and schedules considered in this research effort. A D/t limit of 80 was utilized because most buried piping at NPPs have D/t ratios less than or equal to 80. The maximum pipe size identified at NPPs from Tables 2.1 and 2.2 is 30 in. (76.2 cm). For 30 in. (76.2 cm) pipe, having standard schedule wall thickness (t = 0.375 in. (0.953 cm)), the D/t ratio equals 80. Smaller diameter standard schedule pipes will have lower D/t ratios.

Effect of Wall Thinning

The sensitivity for reduction in wall thickness due to aging effects was evaluated for its effect on the pipe through-wall bending stress. Using the same 24 in. (61.0 cm), t = 0.375 in. (0.953 cm) pipe example as before, but varying the wall thickness, the stress increase due to reductions in pipe wall thickness is shown below:

Stress Variation as a Function of Wall Loss

Reduction in Wall Thickness (%)	0	10	20	30	40	50	60	70
Ovality (Δy /D as %)	0.58	0.68	0.78	0.90	1.0	1.1	1.2	1.2
Max. through-wall bending stress (ksi)	10.4	11.0	11.4	11.4	11.0	10.0	8.55	6.69

1 ksi = 6.89 MPa

The above results indicate that a reduction in wall thickness increases the ovality somewhat; however, the bending stress slightly increases and then falls for reductions in wall thickness beyond 30%. It is interesting to note that with reductions in wall thickness beyond 30%, the bending stress actually gets smaller. Although this may be unexpected, it can be understood by examining the equations for ovality and stress. This behavior occurs because as the pipe wall reductions get very large, the pipe becomes more flexible and its contribution to carrying the soil pressure load is much smaller than that of the adjacent soil surrounding the pipe. The equation for calculating stress though is linearly proportional to the pipe thickness so the stress continues to drop off as the pipe thickness is reduced.

The results shown above are very important because they demonstrate that the stresses due to vertical external soil loads (surcharge (dead load), groundwater, and live load) are low and are not significantly affected by wall thinning. This is evident because of the following:

- For the configurations and parameters discussed, the stress in the pipe is considered low (10.4 ksi (71.7 MPa) for the example studied with 7 ft (2.13 m) soil cover depth and will be kept below 25% of the ultimate strength of the pipe for all bounding cases).

- Most significantly, the tabulation for the effects of wall thinning demonstrate that up to 30% wall thinning there is very little effect on the through-wall bending stress and beyond 30%, the stresses actually begin to reduce.

Based on these findings, the vertical external soil loads due to surcharge (dead load), groundwater, and live load were not explicitly included in the fragility analysis. However, the stresses due to these loads were considered in developing the degradation acceptance criteria which is described in Section 7.2.

5.1.6 Temperature

Differential temperature in buried piping causes an unrestrained pipe to expand in accordance with the following equations:

$$\varepsilon = \alpha(T_2 - T_1) \tag{5.12}$$

$$\Delta L = \varepsilon L \tag{5.13}$$

where

ε	= longitudinal strain in pipe
α	= coefficient of thermal expansion of the pipe
T_2	= maximum operating temperature
T_1	= installation temperature
ΔL	= total change in length of a straight pipe segment
L	= length of pipe segment

If a pipe is not restrained then there would be no stresses induced by the change in temperature. However, in buried piping pipe/soil friction and bends at each end of a straight pipe section can act to restrain the expansion of the pipe. If a very conservative assumption is made that the pipe/soil friction or the bends at the end of straight pipe section fully restrain the pipe, then the maximum stress in the pipe is calculated by:

$$\sigma = E\alpha\alpha(_2 - T_1) \tag{5.14}$$

where

σ	= compressive stress
E	= modulus of elasticity of pipe

<u>Example</u>

Use the same buried pipe example as before and assume a maximum operating temperature equal to 150°F (65.6°C) (Table 2.1 suggests maximum temperature of 140°F (60.0°C). For ambient temperature/installation temperature assume 70°F (21.1°C).

$$\sigma = (29 \text{ x } 10^6 \text{ psi}) \text{ x } (6.345\text{x}10^{-6} \text{in/in °F}) \text{ x } (150\text{°F} - 70\text{°F})/1000 = 14.7 \text{ ksi } (101 \text{ MPa})$$

This stress is considered very conservative because the soil/pipe friction would only develop for very long straight sections. For pipe segments with bends, this stress is also very conservative because the soil at the bends is not infinitely stiff and thus any slight compression in the soil would relieve this thermal induced compressive stress.

Effect of wall thinning:

Based on equation (5.14) it is evident that the pipe stress is independent of the pipe thickness. Therefore, wall thinning that may arise from aging effects does not increase the pipe stress. For purposes of this study, temperature effects will not be included in the fragility analysis based on the following:

- For the configurations and parameters discussed, the maximum stress in the pipe is low (14.7 ksi (101 MPa)) compared to the ultimate strength of carbon steel pipe (~60 ksi (414 MPa)).
- The maximum calculated stress was based on the very conservative assumption of fully restrained pipe segment. This would require very long pipe segments which are aligned in a straight line.
- Thermally induced stresses are secondary type stresses that are self-limiting.
- Most significantly, the effects of wall thinning have no effect on the longitudinal stress in the pipe.
- The temperature effects of concern act longitudinally in the pipe; whereas, the pressure induced stresses used in the fragility analysis act circumferentially.

5.1.7 Soil Movement

Soil movement can occur due to differential soil settlement, soil settlement between building and surrounding soil, and seismic induced soil movement. Buried piping at NPPs is typically routed in well-graded soil with adequate compaction which will preclude soil settlements. If a particular site may be susceptible to soil movement, then this would have been addressed during the design and construction stage of the plant. Settlement causing relative displacements between building structures and buried piping is also assumed to have been adequately addressed in the design and construction stage. If soil settlement could occur at a plant, then settlement of building structures and civil engineering features would have already materialized since most NPPs have already been in operation for more than 20 years. Furthermore, stresses due to relative displacement are considered as secondary type stresses which are self-limiting (i.e., do not continue to grow). Therefore, for the purpose of this study, soil movement will not be included in the fragility analysis. If soil movement has occurred or exists at a plant, then any buried piping degradation will need to be addressed on a case-by-case basis.

5.1.8 Seismic

Seismic loading is comprised of two effects; wave passage and seismic anchor movements. Concerns also exist with the adequacy of the supporting soil with respect to ground failure (liquefaction, landsliding, lateral spreading, and settlements).

A. Wave Passage Effects

Wave passage effects for axial and bending strains in straight sections of buried pipe away from anchor points, sharp bends, or intersections are as follows (ASCE 4-98):

$$\text{aximum axial strain} \, (\varepsilon_a)_{max} = \frac{\nu_{max}}{\alpha_\varepsilon c} \qquad (5.15)$$

where

v_{max} = maximum ground velocity

α_ε = coefficient equal to 2.0 for shear waves and 1.0 for compressional and Rayleigh waves

c = apparent wave velocity

For straight sections remote from anchor points, sharp bends, or intersections, the maximum axial force calculated from equation (5.15) may be reduced because of slippage between the pipe surface and the surrounding soil. In this case the maximum force can be calculated by (ASCE 4-98):

$$(\varepsilon_a)_{max} = \frac{f_{max}\lambda_w}{4E_{sct}A_p} \tag{5.16}$$

where

f_{max} = maximum friction force per unit length between the pipe and surrounding soil

λ_w = apparent wavelength of the dominant seismic wave associated with peak ground velocity

E_{sct} = secant modulus of elasticity associated with an axial strain for the buried pipe

A_p = net cross-sectional area of the pipe

Maximum Curvature (Bending) $$\varphi_{max} = \frac{a_{max}}{(\alpha_k c)^2} \tag{5.17}$$

where

a_{max} = maximum ground acceleration

α_k = 1.6 for compressional waves and 1.0 for shear and Rayleigh waves

c = apparent wave velocity

Forces on buried pipe bends, intersections, and anchor points can be calculated using (ASCE 4-98):

Maximum axial force $$F_a = E_{sct}A_p(\varepsilon_a)_{max} \qquad \text{(5.1-18)}$$

where $(\varepsilon_a)_{max}$ = the smaller of (5.15) and (5.16)

Bending moments and shears according to ASCE 4-98 shall be determined from an analysis which treats the buried pipe as a beam on an elastic foundation subjected to the applied axial load F_a, that was calculated considering elbow flexibility and lower-bound friction force values in the longitudinal leg.

<u>Observations Made in This Study</u>

In assessing the seismic wave passage effects, several observations are noted as follows:

The American Lifelines Alliance (2001) only considers axial strain induced in buried pipe due to wave propagation. It states that “Flexural strains due to ground curvature are neglected since they are small for typical pipeline diameters.”

Analytical studies performed in this research effort have determined that the calculated strains (and corresponding stresses) due to wave propagation are not significantly affected by reductions in pipe wall thickness.

The maximum stresses due to pressure, soil surcharge, groundwater, and surface loads, occur in the hoop (circumferential) direction of the pipe. Seismic induced stresses primarily develop longitudinal stresses (due to flexure of the pipe), and therefore, are not additive to the other loadings. The longitudinal stresses due to pressure, which would be additive to seismic, are only one-half the hoop stresses. Also, when considering seismic induced stresses as secondary type stresses, the pipe would not rupture when the ultimate stress (strength) of the pipe is reached because of the large ductility available in carbon steel and stainless steel pipe material.

ASCE Report (1983) states that “It is important to emphasize that seismic effects on buried structures are self-limited since deformations or strains are limited by seismic motions of the surrounding media.” Therefore, seismic stresses should be considered in a similar fashion as thermal stresses which would classify them as secondary stresses not primary stresses.

ASCE 4-98, commentary section, indicates that shear strains can develop in a straight buried pipe by traveling wave effects; however, due to very small relative lateral deformation between the buried pipe and the surrounding soil, these shear strains are relieved and converted into curvature strains. Therefore, shear strains are “considered negligible and can be ignored” unless abnormal circumstances of very strong and stiff soil (e.g., frozen ground) exists immediately surrounding the pipe.

In a report on seismic design of oil and gas pipeline systems, the ASCE Report (1984) discusses the capability of modern buried pipelines fabricated from ductile steel pipe with full penetration butt welds at joints. The report states that “Such pipelines possess good inherent ductility. There does not appear to be any case of a buried petroleum transmission pipeline ever having ruptured from the effects of ground shaking.” The report indicates that ruptures or severe distortions of buried piping are usually caused by relative displacements associated with fault movements, landslides, liquefaction, loss of support, or differential motion at abrupt interfaces with buildings, tanks, or rock.

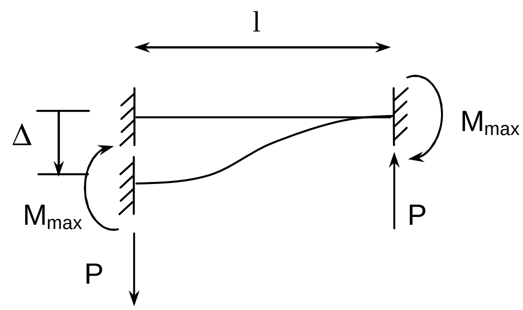
Based on the above discussion, it is concluded that seismic wave passage effects do not need to be considered in the fragility analysis used to develop risk-informed degradation acceptance criteria.

B. <u>Seismic Anchor Movements</u>

In addition to the strain and forces imposed on buried piping, the seismic event can cause strains and forces due to the relative displacement between anchor points such as buildings and the adjacent soil. The strains/forces generated in the pipe due to seismic anchor movements (SAMs) are also considered to be self-limiting and are secondary type stresses. Furthermore, it is assumed for this research effort that sufficient flexibility was initially designed into the buried piping system (flexible transition into building structures). Therefore, the only question remaining is whether reductions in pipe wall thickness have a detrimental effect on the pipe when SAMs are imposed.

The effect of SAMs for buried pipe attachments to a building structure can be approximated by looking at two cases as follows:

1. Sidesway of a beam fixed at both ends subjected to an imposed lateral displacement.



$$\Delta = \frac{Pl^3}{12EI} \tag{5.19}$$

and

$$M_{max} = \frac{Pl}{2} \tag{5.20}$$

Solving equation (5.19) for P and substituting it into equation (5.20), and then calculating the maximum bending stress leads to the following equation:

$$\sigma = \frac{M_{max}c}{I} = \frac{6E\Delta c}{l^2} \tag{5.21}$$

where

c = distance from the neutral axis of a pipe to the outside surface
I = moment of inertia of pipe

From this equation it is evident that the maximum bending stress in a pipe due to sidesway anchor movement is independent of the thickness of the pipe. Therefore, a reduction in thickness due to wall thinning will not increase the bending stress of the pipe.

2. Axial elongation or compression of a beam.

$$F = K\Delta \tag{5.22}$$

$$K = \frac{AE}{l} \tag{5.23}$$

Substituting K from equation (5.23) into equation (5.22), and then calculating the maximum axial stress leads to the following equation:

$$\sigma = \frac{F}{A} = E\frac{\Delta}{l} \tag{5.24}$$

where A = cross-sectional area of pipe

From this equation it is evident that the axial stress in a pipe due to anchor movement along the pipe axis is also independent of the thickness of the pipe. Therefore, a reduction in thickness due to wall thinning will not increase the axial stress of the pipe.

Based on the above discussion and the solutions for sidesway and axial elongation or compression of a buried pipe, it can be concluded that seismic anchor movements do not need to be considered in this study effort for developing risk-informed degradation acceptance criteria.

C. Soil Adequacy

As noted earlier another concern with earthquakes is that they may cause failure of the soil to provide sufficient support to buried piping as well as other plant structures. This may be caused by liquefaction, landsliding, lateral spreading, and settlements. NPPs are normally sited at locations that have good soil conditions and are not placed at or near fault locations. Buried piping at NPPs is typically routed in well-graded soil with adequate compaction which will preclude soil settlements. If a particular site may be susceptible to soil movement under a seismic event, then this would have been addressed during the design and construction stage of the plant. Therefore, it is assumed that competent soil conditions have been ensured during the design stage of licensing plants and that soil adequacy does not have to be considered in the fragility analysis used to develop risk-informed degradation acceptance criteria.

5.2 Methodology for Developing Buried Piping Fragility

For the purpose of this study, pipe failure is defined as a catastrophic pipe rupture which results in the total loss of a buried piping system's capability to perform its intended function. In Section 5.1, it was shown that stresses due to soil loads including surcharge (dead load), groundwater and live load are low and are not significantly affected by wall thinning. Thermal and seismic loads produce secondary stresses which are self-limiting in nature and are also not significantly affected by reductions in wall thickness. On the other hand, stresses due to internal pressure are primary stresses which are directly affected by loss of material due to age-related degradation mechanisms. The hoop stress due to internal pressure is inversely proportional to the wall thickness. Therefore, as the pipe degrades, the safety factor for pressure design decreases, thereby increasing the probability of a pipe rupture failure in the buried pipe. The following sections describe the methodology for developing buried piping fragility curves for internal pressure loading. Stresses due to other loads were also considered and incorporated into the degradation acceptance criteria as discussed in Section 7.1.

5.2.1 Buried Piping Internal Pressure Design Requirements

Both the ASME B31.1 Power Piping Code and the ASME Boiler and Pressure Vessel Code, Section III, NC/ND-3600, provide minimum wall thickness requirements for pressure design of piping components. The intent of the requirements is to limit the maximum primary membrane stress in the pipe to an allowable stress value equal to ¼ of the minimum ultimate tensile strength of the material. ASME B31.1 specifies that the minimum wall thickness for design pressures and for temperatures not exceeding those for the various materials specified in its allowable stress tables, including allowances for mechanical strength, shall not be less than that determined by Equations (5.25) or (5.26) below:

$$t_m = \frac{PD_o}{2(SE + Py)} + A \tag{5.25}$$

$$t_m = \frac{Pd + 2SEA + 2yPA}{2(SE + Py - P)} \tag{5.26}$$

where

t_m = minimum required wall thickness
P = internal design pressure
D_o = outside diameter of pipe
d = inside diameter of pipe
SE = maximum allowable stress due to internal pressure and weld joint efficiency
A = additional thickness required for items such as corrosion or erosion
y = 0.4 for temperatures less than 900°F (482°C) and D_o/t_m ratio greater than 6

The additional thickness, A, is to compensate for material removed in threading or grooving, to provide for corrosion and/or erosion, or to provide for mechanical strength where necessary. After the minimum wall thickness t_m is determined by equation (5.25) or (5.26), the minimum pipe wall thickness shall be increased by an amount sufficient to provide the manufacturing tolerance allowed in the applicable pipe specification or required by the process. The next heavier commercial wall thickness shall then be selected from standard thickness schedules or from manufacturers' schedules. The design pressure shall not exceed the value calculated by Equations (5.27) or (5.28) as follows:

$$P = \frac{2SE(t_m - A)}{D_o - 2y(t_m - A)} \tag{5.27}$$

$$P = \frac{2SE(t_m - A)}{d - 2y(t_m - A) + 2t_m} \tag{5.28}$$

The above equations apply to straight pipe under internal pressure. The Code does not require minimum thickness analysis for other piping components. Standard fittings that are purchased and used in accordance with specified ANSI standards are considered acceptable because their pressure-temperature ratings are based on burst tests, thereby assuring that the fitting will withstand the design pressure. For nonstandard fittings, the code provides design rules. For pipe bends, the wall thickness after bending must satisfy the minimum thickness requirement for straight pipe. For fabricated branch connections, reinforcement requirements are provided to assure that the area of metal removed from the branch connection is replaced in close proximity to the area removed. The use of standard fittings and application of design rules provides a conservative pressure design basis for components other than straight pipe and reasonable assurance that these components are as strong or stronger than the straight pipe in the system. Therefore in the assessment of the probability of pressure failure, it is reasonable to assume that the straight pipe is the weak link in the buried piping system.

For piping designed to the ASME Boiler and Pressure Vessel Code, Section III, NC/ND-3600, the pressure design requirements are essentially the same. They provide the same minimum wall thickness equations, allow the use of standard ANSI fittings without analysis, and provide design rules for nonstandard fittings. The most significant difference is that the allowable materials and allowable stresses are those given in the tables of the ASME Boiler and Pressure Vessel Code, Section II, Appendix D. For the steel materials commonly used in buried piping systems, however, the stress allowables are the same as the ASME B31.1 stress allowables.

5.2.2 Development of Fragility Curves for Uniform Wall Thinning

A series of fragility curves were developed for pipe failure under internal pressure loading. These curves were generated for undegraded pipes and for degraded pipes with varying degrees of uniform wall loss. The methodology and assumptions applied in the development of these curves are described below.

A review of the WRC Bulletin 446 survey results summarized in Table 2.1 of this report indicates that SA-106 Grade B carbon steel pipe is widely used in buried piping systems. This piping material is used in various critical nuclear plant systems including service water, diesel fuel oil, and emergency feedwater systems. Typical pipe diameters cover a wide range from less than 2 inches (5.08 cm) NPS (nominal pipe size*) for diesel fuel systems up to 30 inches (76.2 cm) NPS for service water systems. The systems are typically low temperature (ambient to 140°F (60°C)) and low pressure (up to 150 psig (1.03 MPa)). On this basis, an SA-106 Grade B carbon steel buried piping system within this range of dimensional and operational parameters was selected as a representative buried piping system.

In the development of the fragility curves for degraded piping, it was assumed that general corrosion results in wall thinning that is uniformly distributed around the circumference and length of the pipe. Although it is highly unlikely that wall thinning will be uniform, this assumption should provide conservative probability of failure estimates for the buried piping systems. This assumption greatly simplified the analytical effort. More refined analyses, such as finite element analyses, could have been performed to consider effects of local thinning, but at the onset, this was judged not to be required because of the anticipated large margins to failure. Sensitivity studies and evaluations of burst test data of degraded piping presented in later sections of this report support the conservatism of this approach.

The strength of the pipe is dependent on its tensile properties and its dimensional properties. The maximum hoop stress, S_h, due to internal pressure in a thin-walled pipe is calculated in accordance with the following equation:

$$S_h = \frac{PD}{2t} \tag{5.29}$$

where

S_h = hoop stress
P = internal pressure
D = average diameter
t = wall thickness

* Nominal pipe size (or nominal pipe diameter) corresponds to a standardized outside diameter (O.D.) as defined in ASME B36.10M-2004. For nominal pipe sizes 14 inches and above, the actual O.D. is equal to the nominal pipe size. For nominal pipe sizes 12 in. and smaller, the actual O.D. is greater than the nominal pipe size, (e.g., 2 inch nominal pipe actually corresponds to 2.375 in. O.D.).

For this study, it was assumed that pipe failure (rupture) occurs when the hoop stress due to internal pressure reaches the ultimate tensile strength, S_u, of the material. The failure pressure, P_f, may be defined as follows:

$$P_f = \frac{2tS_u}{D} \qquad (5.30)$$

From the probabilistic standpoint, the tensile strength, pipe diameter and pipe thickness may be considered random variables to determine the probability of failure of the system as a function of internal pressure. The ASME SA-106 material specification provides tensile strength requirements and permissible variations in diameter and wall thickness. For SA-106 Grade B, the minimum tensile strength is 60 ksi (414 MPa). Although the specification does not provide an average or upper bound value, it is well known that material certification tests typically show average strength values of 20 percent or more compared to minimum required strength values. The minimum wall thickness at any point shall be no less than 12.5 percent below the specified nominal wall thickness*. No maximum wall thickness is defined. Allowable variations in outside diameter are dependent on the nominal diameter and range from ±1/64 inch (0.397 mm) for pipe diameters up to 1 ½ inch (3.81 cm) NPS, up to -3/16 inch to +1/32 inch (-4.76 mm to +0.794 mm) for pipe diameters greater than 34 inch (86.4 cm) NPS. The variations in diameter are very small and would have an insignificant impact (<1%) on pipe stress for a given pressure. Therefore, for the probabilistic evaluation, this variation was not considered and pipe diameter was treated as a constant. Variations in wall thickness were explicitly investigated in order to develop different fragility curves for undegraded pipes and for degraded pipes with varying percentages of wall loss. Fragility curves for undegraded pipes were conservatively based on the minimum wall thickness allowed by the material specification. For degraded pipes, the fragility curves were based on the nominal thickness minus a percentage wall loss due to degradation. The material tensile strength was treated as a random variable with a lower bound value equal to the minimum required value of 60 ksi (414 MPa), a mean value equal to the minimum plus 20 percent (72 ksi (496 MPa)), and an upper bound value equal to the minimum plus 40 percent (84 ksi (579 MPa)). The value of the tensile strength was assumed to have a normal distribution centered about the mean with lower and upper bound values corresponding to the 5th and 95th percentile values, respectively. A normal (or Gaussian) distribution is defined by the following probability density function:

$$f(x;\mu(\sigma) = \frac{1}{\sigma\sqrt{2\pi}}\exp\left[-\frac{(x-\mu)^2}{2\sigma^2}\right] \qquad (5.31)$$

where

x = random variable
μ = mean
σ = standard deviation

The cumulative normal distribution, which gives the probability of a randomly selected value from a normal distribution with parameters μ and σ being less than x, is given by the following equation:

---

* Nominal pipe wall thickness is the thickness of the pipe wall specified by ASME B36.10M-2004 without consideration for manufacturing tolerance. Hereinafter, this term will also be referred to as simply: wall thickness.

$$F(x;\mu;\sigma) = \int_{-\infty}^{x} \frac{1}{\sigma\sqrt{2\pi}} \exp\left[-\frac{(z-\mu)^2}{2\sigma^2}\right] dz \tag{5.32}$$

From a table of standard cumulative normal distribution (Hahn and Shapiro, 1967), the 5th and 95th percentile values for a normal distribution correspond to the mean ± 1.645 times the standard deviation ($\mu \pm 1.645\sigma$). Therefore, for the SA-106 Grade B pipe material with a mean tensile strength μ = 72 ksi (496 MPa) and 5th percentile and 95th percentile tensile strength equal to μ ± 12 ksi (82.7 MPa), the tensile strength standard deviation σ equals 12/1.645 = 7.3 ksi (50.3 MPa). By applying these values of mean and standard deviation in Equations 5.31 and 5.32, the probability density function and the cumulative distribution function for the tensile strength were calculated and are plotted in Figures 5.1 and 5.2.

The probability density function shows the anticipated distribution of tensile strength for any randomly selected sample of SA-106 Grade B carbon steel pipe. The cumulative distribution function curve represents the probability that the tensile strength of a randomly selected pipe sample is less than or equal to a specific value. For example, the figure indicates that the probability that the tensile strength is lower than its mean value of 72 ksi (496 MPa) is 50 percent, as expected. Similarly, the probability that the tensile strength is below its lower bound value of 60 ksi (414 MPa) is 5 percent, and the probability that it is below its upper bound value of 84 ksi (579 MPa) is 95 percent.

A fragility curve is the cumulative distribution function of the probability of failure for a given value of input load. For this case, it was assumed that failure occurs when the hoop stress in the pipe is equal to the tensile strength of the pipe material. Therefore the cumulative distribution function curve also represents the fragility curve for a pipe with probability of failure plotted as a function of the hoop stress. Figure 5.3 presents the fragility curve for the SA-106 carbon steel pipe in terms of hoop stress. In order to identify the probability values at the low end, the probability of failure was plotted on a semi-logarithmic scale. For SA-106 Grade B carbon steel piping, this curve gives the probability of failure at any given level of applied stress. For example, if the hoop stress in the pipe is 30 ksi (207 MPa), the probability of failure is less than 10^{-8}. At a stress level of 90 ksi (621 MPa), the probability of failure is 1.0. For a stress level of 45 ksi (310 MPa), the probability of failure is 10^{-4}.

The probability of failure curve may also be presented as a function of internal pressure. As an example, a 30 in. (76.2 cm) standard weight pipe with outer diameter of 30 in. (76.2 cm) and wall thickness of 0.375 in. (0.953 cm) was considered as a representative large buried pipe. For the undegraded case, a minimum wall thickness of 12.5 percent below nominal (0.328 in. (0.833 cm)) was used. By applying Equation 5.30, the mean, lower bound and upper bound failure pressures were calculated as follows:

Mean P_f = 2(.328)(72000)/(30 - .328) = 1592 psi (11.0 MPa)

Lower Bound P_f = 2(.328)(60000)/(30 - .328) = 1327 psi (9.15 MPa)

Upper Bound P_f = 2(.328)(84000)/(30 - .328) = 1857 psi (12.8 MPa)

The standard deviation = (1857 – 1592)/1.645 = 161 psi (1.11 MPa)

The fragility curve for this case was calculated by using the above values in Equation 5.32. In order to generate fragility curves for a degraded pipe, the calculations were repeated for the same size pipe subjected to uniform wall thinning with wall losses of 25%, 50%, and 75% of nominal wall thickness. When degradation is considered (reduction in wall thickness), the average pipe diameter needed for use in equation (5.30) is calculated assuming the inside diameter of the undegraded pipe is held constant and the outside diameter and thickness of the pipe is reduced due to the degradation. However, it should be noted that the assumption of whether the reduction in wall thickness occurs on the inside or outside of the pipe has a negligible effect on equation (5.30) and the final results. The mean and standard deviation for the failure pressures of the undegraded and degraded pipe are summarized below.

Condition	Wall Thickness (in.)	Failure Pressure (psi)	
		Mean	Std. Deviation
Undegraded (Min. Wall)	0.328	1592	161
25% wall loss	0.281	1367	139
50% wall loss	0.188	914	93
75% wall loss	0.094	459	47

1 in. = 2.54 cm; 1 psi = 0.00689 MPa

The fragility curves for the undegraded and the degraded cases are shown in Figure 5.4a. The same curves are plotted on a semi-logarithmic scale in Figure 5.4b in order to identify the lower values of probability of failure. These fragility curves can be used to determine the probability of failure for a degraded or undegraded 30 in. (76.2 cm) standard weight pipe at any internal pressure. For example, Figure 5.4b shows that with in internal pressure of 1000 psi (6.89 MPa), the probability of failure of an undegraded pipe with minimum allowable wall thickness is 1.0E-04. If the pipe has degraded and lost 25% of its nominal wall thickness, the probability of failure increases to 4.0E-03. With a 50% wall loss, the probability is 0.8. With a 75% wall loss, the probability is 1.0.

As discussed in Section 5.2.1, the design pressure in a pipe is prescribed by Code rules. For piping designed to either ASME B31.1 or ASME Section III, Class 2 or 3, the requirements are identical. For a given design pressure, the minimum wall thickness is determined by the smaller value from Equations (5.25) or (5.26). The design pressure shall not exceed the value calculated by Equations (5.27) or (5.28). For pipe designed to the requirements of either Code, the specified maximum allowable stress for pressure design of SA-106 Grade B pipe is 15 ksi (103 MPa). In practice, the Code equations would be used to determine the minimum wall thickness. An additional thickness, A, to account for erosion/corrosion, threading and grooving, and other factors would be included. The minimum thickness would then be increased by the manufacturing tolerance, and finally, the next heavier standard wall thickness would be selected. For the purpose of determining a conservative maximum pressure value for use in this study, it was assumed that the 30 in. (76.2 cm) standard weight pipe was designed exactly to the minimum required wall thickness requirement with no additional thickness, A, and with actual wall thickness equal to the minimum allowed by the SA-106 Grade B material specification. The maximum value for the design pressure was then calculated from Equation (5.27) as follows:

$$P = [(2)(15000)(.328)]/[30-(2)(.4)(.328)] = 330 \text{ psi } (2.28 \text{ MPa})$$

Figure 5.4b shows that for a 30 in. (76.2 cm) standard weight degraded pipe with 75% wall loss subjected to an internal pressure equal to its maximum allowable design pressure of 330 psi

(2.28 MPa), the probability of failure is about 3.0E-03. If the pipe has wall loss of 50% or less, the probability of failure is less than 1.0E-08.

If it is conservatively assumed that the internal pressure in a pipe is equal to its maximum allowable design pressure, the probability of failure may be plotted as a function of wall loss in the pipe. For the 30 in. (76.2 cm) standard wall pipe, this is shown in Figure 5.5. This curve may be used to determine the probability of failure due to internal pressure loading for a 30 in. (76.2 cm) standard wall SA-106 Grade B carbon steel degraded pipe with uniform wall thinning at any percentage wall loss.

The methodology described above may be applied to develop fragility curves and probability of failure versus wall loss curves for other pipe sizes. In Section 5.3, the methodology was applied to develop a series of additional curves for pipes ranging in size from 2 to 42 in. (5.08 to 107 cm) in diameter. This methodology may be extended to other ductile steel piping materials if the following conditions are met: (1) the piping is designed in accordance with either the ASME B31.1 or Section III, NC/ND-3600 Code rules, (2) the material property distributions are consistent with the distributions used in this study, and (3) the anticipated failure mode can be characterized as a ductile pipe rupture failure which occurs when the pipe hoop stress reaches the ultimate tensile stress of the material.

5.2.3 Fragility Curves for Localized Thinning/Pitting

The fragility curves developed by analysis in Section 5.2.2 were based on the assumption that the aging effects due to corrosion may be conservatively characterized as uniform wall thinning around the entire circumference and length of a buried pipe. In general, however, the effects of corrosion are more likely to be localized. An alternate approach for the development of fragility curves was investigated based on a review of test results from samples of corroded pipes that were removed from service and pressure tested to failure.

ASME B31G-1991, "Manual for Determining the Remaining Strength of Corroded Pipelines, A Supplement to ASME B31 Code for Pressure Piping," provides guidelines to assist pipeline operators in making decisions on whether a corroded region of a buried pipe may safely remain in service or whether it needs to be repaired or replaced. The manual provides a procedure as well as formulas, charts and tables to evaluate corroded piping on the basis of the maximum depth and length of the corroded area. The manual states that the procedure is applicable to all pipelines within the scope of the ASME B31 Code for Pressure Piping. However, it specifies the following limitations on the applicability of the procedure:

(a) The manual is limited to corrosion on weldable pipeline steels categorized as carbon steels or high strength low alloy steels. Typical of these materials are those described in ASTM A-53, A-106, and A-381, and API 5L.

(b) The manual applies only to defects in the body of line pipe which have relatively smooth contours and cause low stress concentration (e.g., electrolytic or galvanic corrosion, loss of wall thickness due to erosion).

(c) The procedure should not be used to evaluate the remaining strength of corroded girth or longitudinal welds or adjacent heat affected zones, defects caused by mechanical damage, such as gouges and grooves, or defects introduced during pipe manufacture.

(d) The criteria for corroded pipe to remain in service presented in the manual are based only upon the ability of the pipe to maintain structural integrity under internal pressure. It should not be the sole criterion when the pipe is subject to significant secondary stresses (e.g., bending), particularly if the corrosion has a significant transverse component.

(e) The intent of the procedure is to determine whether a degraded pipe has sufficient strength to remain in service. It is not intended to predict when leaks or rupture failures will occur.

The procedure and acceptance criteria prescribed in the manual were developed under a research effort conducted by the American Gas Association. The overall objective of the program was to examine the fracture initiation behavior of various sizes of corrosion defects by determining the relationship between the size of a defect and the level of internal pressure that would cause a leak or rupture. The guidelines and acceptance criteria contained in the manual were developed and validated based on an extensive series of pressure tests which utilized both laboratory pipe specimens with machined defects and actual full-size corroded pipe specimens. Several hundred full-scale tests were conducted on all types of defects to establish general defect behavior. Mathematical expressions to calculate the pressure strength of corroded pipes were developed on the basis of these tests. The mathematical expressions were semi-empirical but were founded on well-established principles of fracture mechanics. During 1970 and 1971, 47 pressure tests were conducted on several pipe sizes to evaluate the effectiveness of the mathematical expressions in determining the strength of corroded areas. Actual field specimens of pipes that had sustained corrosion damage were removed from service and were tested to failure either in-place or in a large, full-scale test cell. The diameters of the pipes tested ranged from 16 in. through 30 in. (40.6 cm through 76.2 cm) and wall thicknesses ranged from 0.312 in. to 0.375 in. (0.792 cm to 0.953 cm). The yield strengths of the pipe materials ranged from 25,000 psi to 52,000 psi (172 MPa to 359 MPa). These final test results validated the acceptance curve presented in the manual.

From the information available in the ANSI B31G manual, it was not clear whether the loss of material in the degraded pipes, used for the pressure tests, occurred on the inside surface of the pipe, outside surface, or both. This is not expected to have any significant effect on the results of this study.

The results of the final 47 pressure tests of actual corroded pipes presented in ANSI B31G were evaluated in our study to determine whether fragility curves for localized thinning/pitting corrosion could be developed from this test data. However, due to the small size of the test sample, it was concluded that the level of confidence in fragility curves developed from a statistical evaluation of this data would be limited. Instead, a statistical evaluation of this test data was performed to provide a comparison to the fragility curves developed by analysis. This comparison was made to determine whether the fragility results obtained using the analytical approach developed in Section 5.2.2 bound the test data, and therefore can also be conservatively used for localized loss of material or pitting. In B31G, the test results were presented on a plot of corrosion depth/wall thickness ratio versus corrosion length. Each data point on the plot represented one full-size pressure test on a corroded pipe. Since the tests involved different pipe sizes and materials, the failure pressure stress for each test was reported as a percentage of the specified minimum yield stress of the material (based on nominal pipe dimensions). For the statistical evaluation, the test data was divided into three sample sets based on varying corrosion depths. The ranges of ratios of maximum corrosion depth to nominal pipe wall thickness for the three sample sets were 40% to 60%, 60% to 80%, and 80% to 100%. For the purpose of this evaluation, it was conservatively assumed that the failure pressure was independent of the length of the corrosion defect. The mean and standard deviation of the failure pressure data within each sample set were calculated and the results are summarized in the table below:

Range of Corrosion Depth (% wall thickness)	Number Of Data Points in Sample Set	Failure Stress (% Min.Yield)	
		Mean	Std. Dev.
80% - 100%	6	132.3	49.7
60% - 80%	28	128.4	21.9
40% - 60%	11	142.4	26.2

For comparison against the fragility curves generated by analysis, these results were applied to the representative pipe analyzed in Section 5.2.2 using dimensional and material properties of a 30 in. (76.2 cm) standard wall SA-106 Grade B carbon steel pipe. The values of the mean and standard deviation of the failure stresses for each range were calculated using the specified minimum yield stress of 35 ksi (241 MPa). The corresponding failure pressure mean and standard deviation for each range were determined by solving Equation (5.29) for pressure. The probability density function and cumulative distribution function curves were then generated for each range of corrosion depth. For the comparison of analysis to test results, the probability density function and cumulative distribution function (fragility) curves were regenerated for 40%, 60% and 80% uniform wall loss for the 30 in. (76.2 cm) pipe using the analytical methodology described in Section 5.2.2. A comparison of analysis versus test results for the failure pressure mean and standard deviation is summarized in the table below. Comparisons of analysis versus test probability density function curves for the three ranges of degradation are shown in Figures 5.6a through 5.6c. Comparisons of fragility curves for the three ranges are presented in Figures 5.7a through 5.7c.

ANALYSIS			TEST		
% Uniform Wall Loss	Failure Pressure (psi)		% Local Wall Loss	Failure Pressure (psi)	
	Mean	Std. Dev.		Mean	Std. Dev.
40%	1096	111	40 – 60%	1261	232
60%	732	74	60 – 80%	1137	194
80%	367	37	80 – 100%	1172	441

1 psi = 0.00689 MPa

The table comparison clearly demonstrates the conservatism of the analysis based on the uniform wall thinning assumption in predicting the mean failure pressure. However, the standard deviations for the test data are much larger than the standard deviations from the analysis. This is believed to be primarily due to the small sample sizes of the test data and is not likely to be representative of the entire population. It is noted that the 80 – 100% wall loss sample set includes only six points and has the largest standard deviation. On the other hand, the 60 – 80% wall loss sample set includes 28 points and has the smallest standard deviation.

The comparison of probability density functions shown in Figures 5.6a through 5.6c demonstrates the overall conservatism of analysis versus test results. The large test data curve spreads (especially for the 80 – 100% wall loss test sample set) illustrate the effect of the large standard deviations of the test data. The comparison of fragility curves shown in Figures 5.7a through 5.7c shows that the analysis curves generally predict higher probability of failure at any given pressure. Due to the large standard deviations, the test fragility curves have a wider spread and in some cases exceed the analysis curves at the low-pressure end. This, however, is believed to be a reflection of the uncertainty in assuming that the statistical distribution of the small sample set applies to the entire population. If more test data were available, the curves would be defined with a higher degree of confidence and the spread of the test curves would most likely be reduced.

In conclusion, although the above comparison is not statistically rigorous due to the small test data sample sizes, it provides a reasonable level of confidence that the fragility curves developed by analysis assuming uniform wall thinning also predict conservative estimates of the probability of failure of a degraded pipe that exhibits localized or pitting corrosion.

5.2.4 Fragility Curve Sensitivity Studies

In Section 5.2.2, the development of the fragility curves for buried piping with uniform wall thickness reduction treated the tensile strength as a random variable with a normal distribution centered about the mean with lower bound (LB) and upper bound (UB) values corresponding to the 5^{th} and 95^{th} percentile values, respectively. The material specification for SA-106 Grade B carbon steel pipe material specifies a minimum tensile strength of 60 ksi (414 MPa) which was assumed to be the LB value. Based on typical material certification test results, it was assumed that the mean tensile strength value was 20 percent higher than the minimum value (72 ksi (496 MPa)). The UB value was assumed to be 40 percent higher than the minimum (84 ksi (579 MPa)). This information and the assumption that pipe failure occurs when the pipe stress due to internal pressure reaches the material tensile strength provided the basis for defining the probability density function and the probability of failure (fragility) curves.

The above assumptions on material strength distribution were based on typical anticipated material property distributions. In order to provide a quantitative measure of the sensitivity of variations in the tensile strength distribution on the results, a sensitivity study was also carried out. Additional material property combinations were analyzed to determine the effect of different tensile strength distributions both in terms of mean value and variations from the mean. Probabilities of failure were recalculated using lower mean strength (10 percent above minimum) and different values of lower and upper bound percentiles (1% and 99%). The following three additional cases were analyzed and compared to the baseline case:

Case No.	LB T.S.	Mean T.S.	UB T.S.	LB Percentile	UB Percentile
1 (baseline)	60 ksi	72 ksi (120%)	84 ksi (140%)	5%	95%
2	60 ksi	72 ksi (120%)	84 ksi (140%)	1%	99%
3	60 ksi	66 ksi (110%)	72 ksi (120%)	5%	95%
4	60 ksi	66 ksi (110%)	72 ksi (120%)	1%	99%

1 ksi = 6.89 MPa

The same procedures that were used for the first case were applied to develop the probability density functions and probability of failure curves for the three additional cases. The mean values for each case are listed above. The standard deviations were calculated as follows:

<u>Case 2:</u>

From a table of standard cumulative normal distribution, the 1st and 99th percentile values correspond to the mean $\pm$ 2.33 standard deviations ($\mu \pm 2.33\sigma$):

$$\mu = 72 \text{ ksi (496 MPa)}, \quad \sigma = (72\text{-}60)/2.33 = 5.15 \text{ ksi (35.5 MPa)}$$

<u>Case 3:</u>

The 5th and 95th percentile values correspond to the mean $\pm$ 1.645 standard deviations ($\mu \pm 1.645\sigma$):

$$\mu = 66 \text{ ksi (455 MPa)}, \quad \sigma = (66\text{-}60)/1.645 = 3.65 \text{ ksi (25.2 MPa)}$$

<u>Case 4:</u>

$$\mu = 66 \text{ ksi (455 MPa)}, \quad \sigma = (66\text{-}60)/2.33 = 2.58 \text{ ksi (17.8 MPa)}$$

The probability density functions for the four cases were calculated in accordance with Equation (5.31) and were plotted in Figure 5.8. A comparison of the curves illustrates that the baseline case has the widest distribution. Case 2 which has the same mean value but a smaller standard deviation shows a narrower distribution as expected. Cases 3 and 4 both have a lower mean value and lower standard deviations. Both curves show narrower distributions than the baseline case as anticipated. As a result of the widest distribution of the baseline case, the probabilities of failure at the low stress levels are expected to be higher. This was demonstrated using the 30 in. (76.2 cm) representative pipe as an example and is discussed below.

Using the methodology developed in Section 5.2.2, fragility curves for a 30 in. (76.2 cm) standard wall pipe were calculated as probability of failure versus internal pressure for the revised material strength distributions of Cases 2 though 4. A comparison of the probability of failure versus internal pressure curves for the four cases with different levels of wall loss is shown in Figures 5.9a though 5.9c. For the 50% wall loss case, Figure 5.9a shows that the baseline case (Case 1) predicts the highest probability of failure for internal pressures of up to

750 psi (5.17 MPa). At the design pressure of 330 psi (2.27 MPa) (also shown in this figure), the probability of failure is less than 10^{-8} for all cases. Figure 5.9b shows that with 75% wall loss, the baseline case predicts the highest probability of failure at the pressures up to 380 psi (2.62 MPa). At the design pressure of 330 psi (2.27 MPa), the probability of failure for the baseline case is 3 x 10^{-3} which is higher than the other cases. At 80% wall loss, Figure 5.9c shows that the baseline case predicts highest probability of failure for internal pressure up to 305 psi (2.10 MPa). At the design pressure of 330 psi (2.27 MPa), Cases 3 and 4 predict higher probabilities of failure.

In conclusion, this sensitivity study investigated the effects of variations in the distribution of the tensile strength of a typical piping material. The results demonstrated that the distribution used in the baseline case provides conservative probabilities of failure for piping subjected to its allowable design pressures with wall losses of up to 75% of the wall thickness.

5.3 Fragility Curves for Undegraded and Degraded Buried Piping

Using the methodology described in Section 5.2.2, a series of fragility curves were developed for buried piping systems with an anticipated range of dimensional parameters. The WRC Bulletin 446 survey reported buried pipe systems with pipe diameters varying from less than 2 in. (5.08 cm) to as large as 30 in. (76.2 cm). Based on the results of a survey (EPRI Survey 95-110, “Inspecting Inaccessible Service Water Piping,”) summarized in EPRI Report GC-108827 (1998), buried service water piping ranged in size from 16 to 42 in. (40.6 to 107 cm). Therefore, fragility curves were developed for the representative standard weight (ST) piping dimensions shown below. For 42 in. (107 cm) standard weight pipe, the D/t ratio exceeds the limit of 80. Therefore, a thickness of 0.562 in. (1.43 cm) which meets this limit was used for this study.

NPS/Schedule (Wt)	Outer Diameter (in.)	Wall Thickness (in.)
2 inch Sch 40 (ST)	2.375	0.154
4 inch Sch 40 (ST)	4.5	0.237
8 inch Sch 40 (ST)	8.625	0.322
16 inch Sch 30 (ST)	16.0	0.375
24 inch Sch 20 (ST)	24.0	0.375
30 inch (ST)	30.0	0.375
42 inch (0.562 wall)	42.0	0.562

1 in. = 2.54 cm

Following the procedure described in Section 5.2.2, for each pipe size, the design pressure and the mean and standard deviation of the failure pressure were calculated for an undegraded pipe with minimum allowable wall thickness and for a degraded pipe with 25%, 50% and 75% wall loss. These results as well as the ratios of mean failure pressure to design pressure are summarized below:

Pipe Diameter (NPS)	Condition	Design Pressure (psi)	Mean Failure Pressure (psi)	Ratio of Mean Failure/Design Pressure
2 inch	Undegraded (Min Wall)	1790	8662	4.84
	25% Wall Loss		7489	4.18
	50% Wall Loss		5080	2.84
	75% Wall Loss		2586	1.44
4 inch	Undegraded (Min Wall)	1440	6957	4.83
	25% Wall Loss		6004	4.17
	50% Wall Loss		4059	2.82
	75% Wall Loss		2059	1.43
8 inch	Undegraded (Min Wall)	1010	4863	4.81
	25% Wall Loss		4188	4.15
	50% Wall Loss		2820	2.79
	75% Wall Loss		1424	1.41
16 inch	Undegraded (Min Wall)	630	3015	4.79
	25% Wall Loss		2592	4.11
	50% Wall Loss		1738	2.76
	75% Wall Loss		874	1.39
24 inch	Undegraded (Min Wall)	420	1996	4.75
	25% Wall Loss		1714	4.08
	50% Wall Loss		1147	2.73
	75% Wall Loss		576	1.37
30 inch	Undegraded (Min Wall)	330	1592	4.82
	25% Wall Loss		1367	4.14
	50% Wall Loss		914	2.77
	75% Wall Loss		459	1.39
42 inch	Undegraded (Min Wall)	360	1706	4.74
	25% Wall Loss		1465	4.07
	50% Wall Loss		980	2.72
	75% Wall Loss		492	1.37

1 psi = 0.00689 MPa

The above results show that both the design pressures and mean failure pressures decrease with increasing pipe sizes. This is consistent with the increase in D/t ratios with increasing diameter for standard weight pipes. However, for the same wall thinning condition, the ratio of mean failure pressure to design pressure, which may be considered the mean design margin, remains fairly constant for all the pipe sizes. This indicates that the design margins are relatively independent of pipe diameter.

The procedure described in Section 5.2.2 was used to generate fragility curves as a function of internal pressure for each pipe size considered. These are shown in Figures 5.10a through 5.10f using linear scales and in Figures 5.11a through 5.11f using semi-logarithmic scales. Assuming that the internal pressure equals the design pressure, plots of probability of failure versus percent wall loss were generated for each size pipe. These are shown in Figures 5.12a through 5.12f.

The probability of failure versus percent wall loss plots for all pipe sizes were summarized on a single graph which is shown in Figure 5.13. This figure demonstrates that for pipes operating at their design pressure, the probability of failure of a degraded pipe does not vary significantly with pipe diameter.

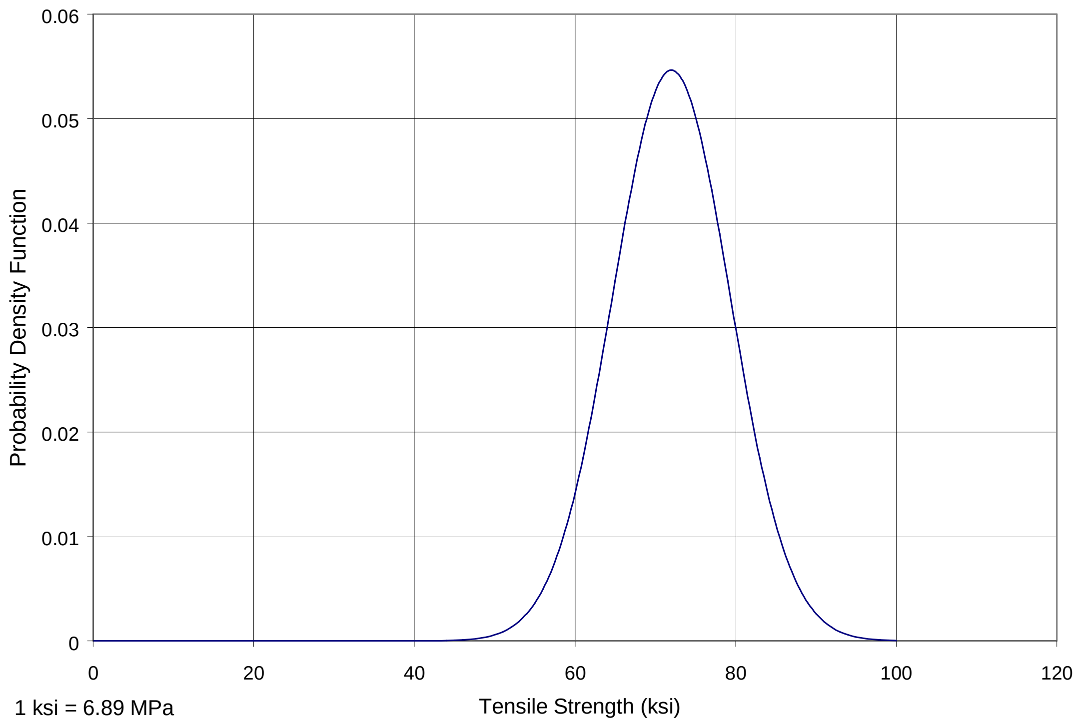


Figure 5.1 Probability Density Function for SA-106 Grade B Tensile Strength

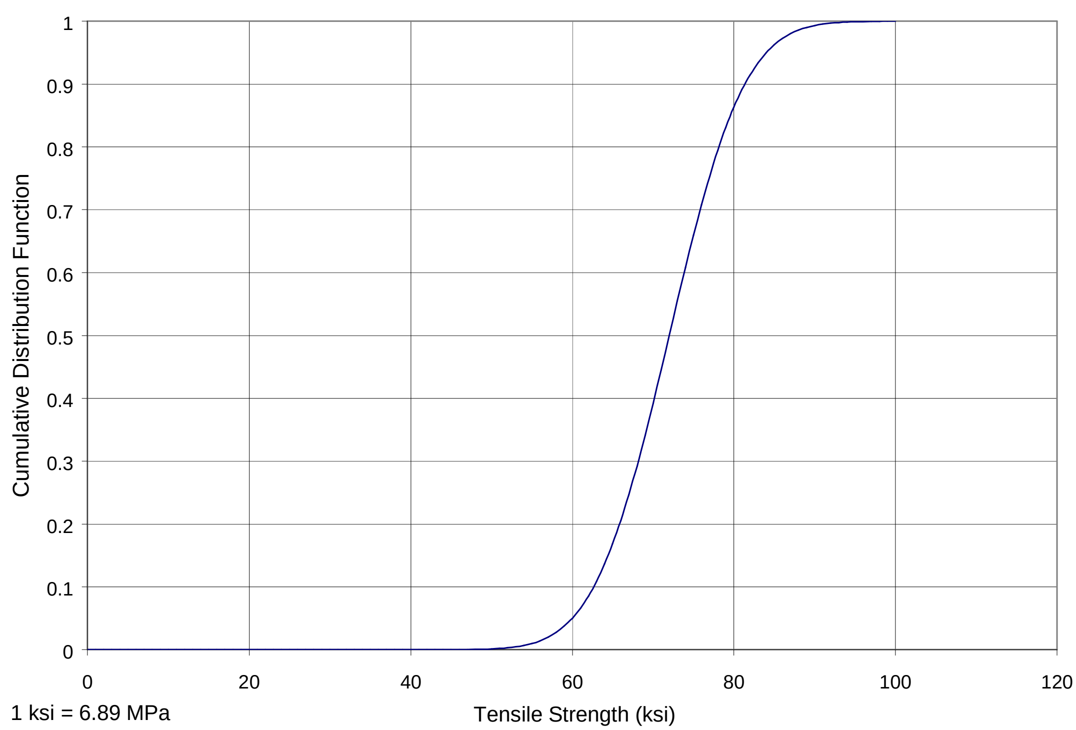


Figure 5.2 Cumulative Distribution Function for SA-106 Grade B Tensile Strength

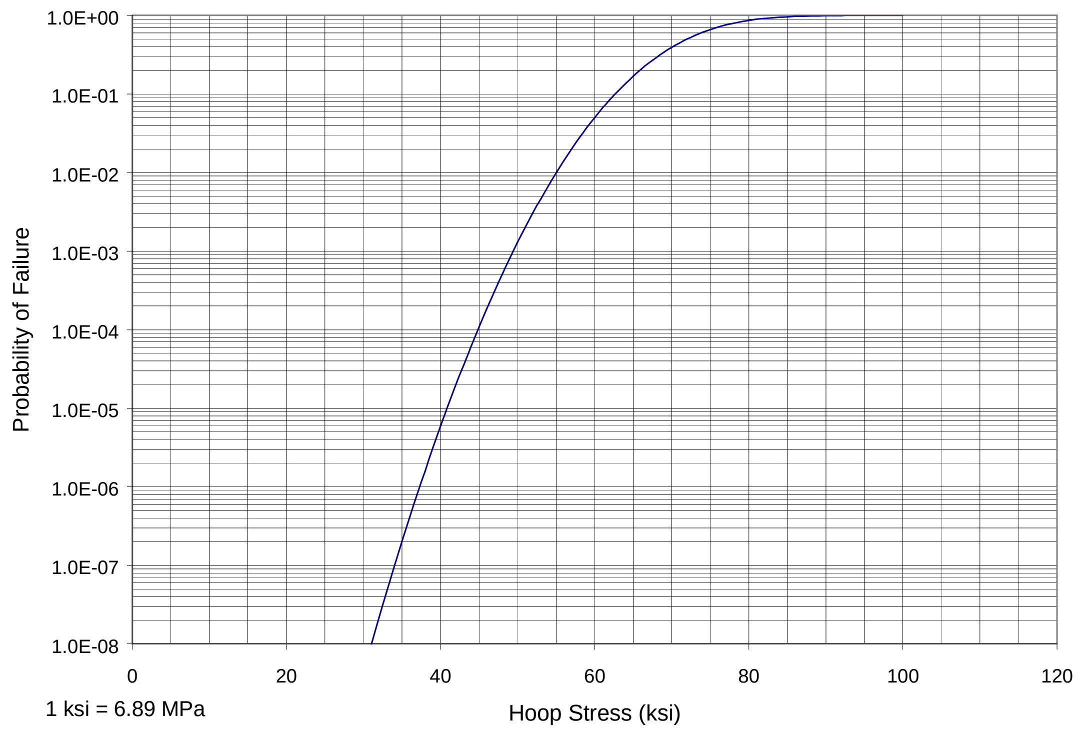


Figure 5.3 Fragility Curve for SA-106 Carbon Steel Pipe as a Function of Hoop Stress

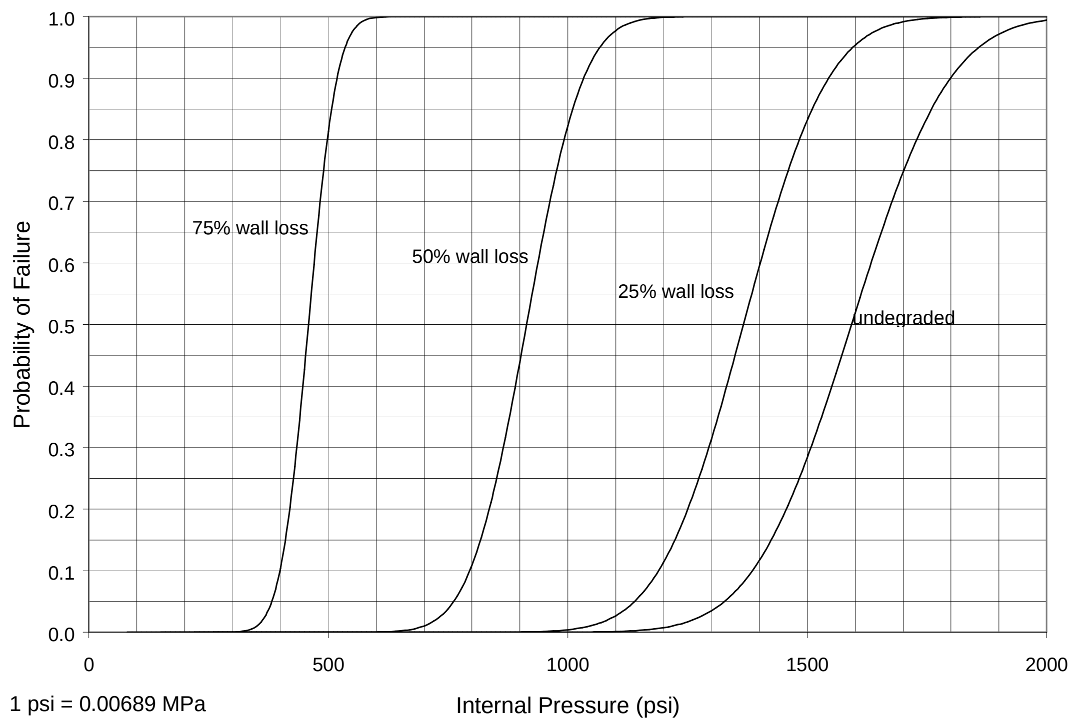
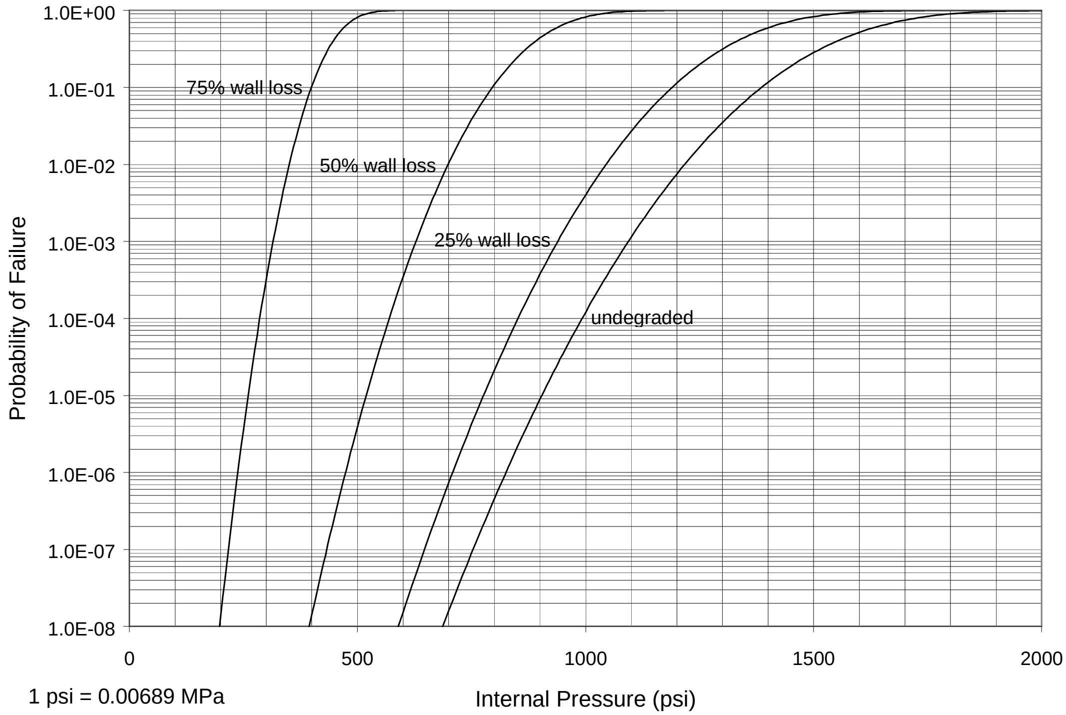


Figure 5.4a Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss



1 psi = 0.00689 MPa

Figure 5.4b Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss

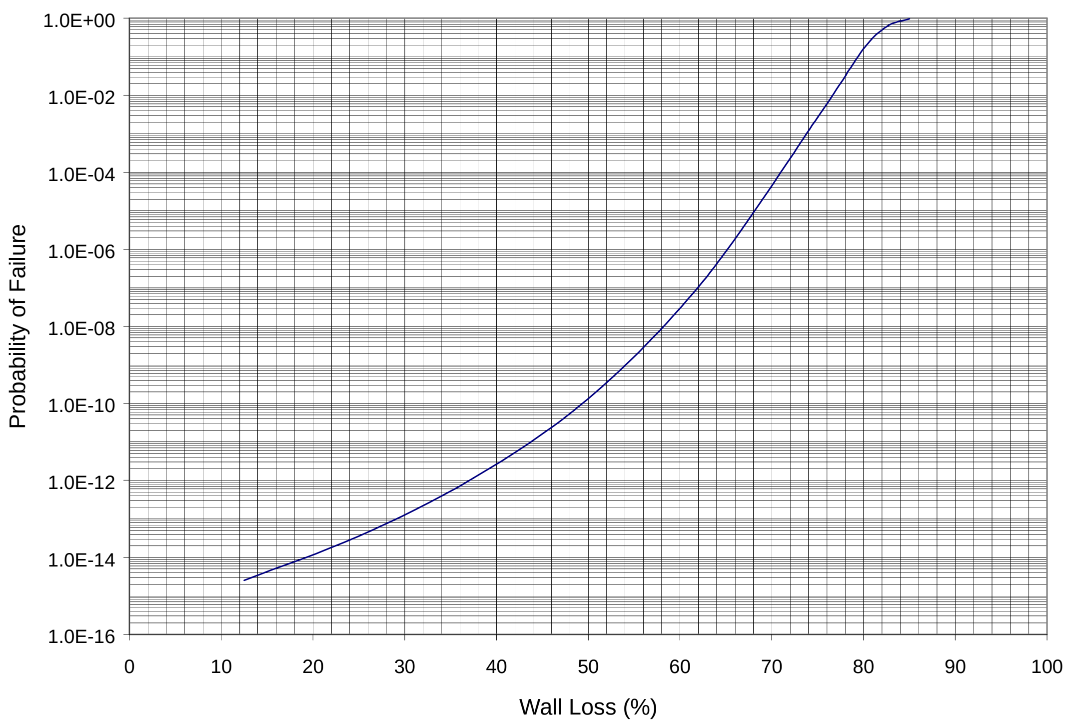


Figure 5.5 Probability of Failure for a 30 in. (76.2 cm) Standard Wall SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss

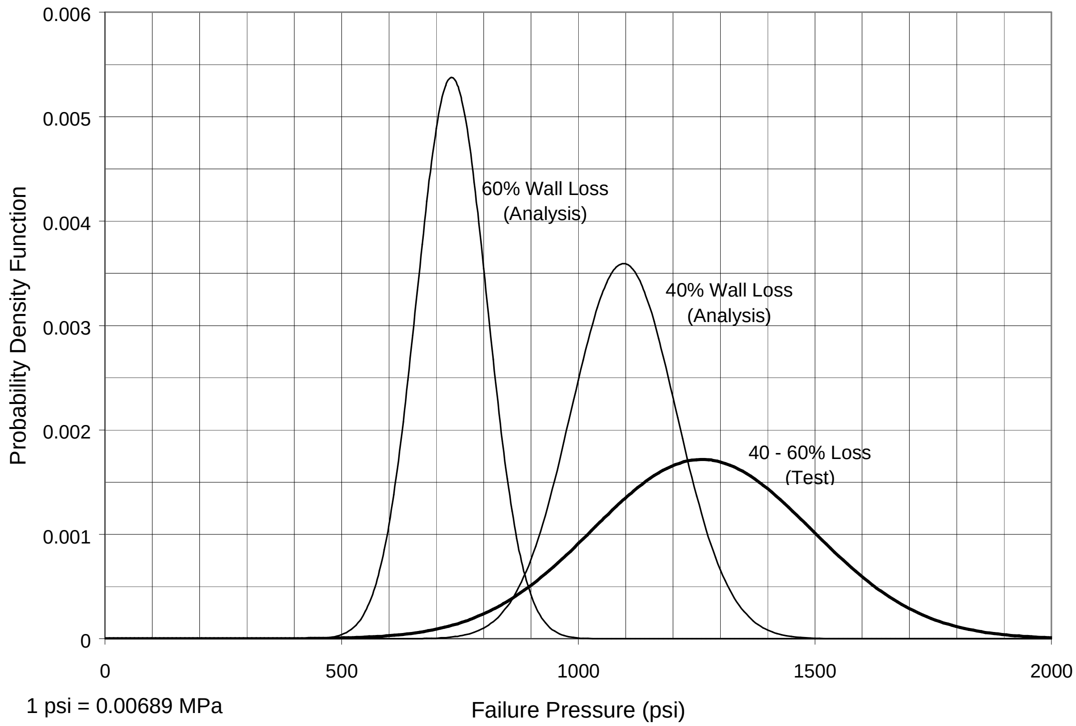


Figure 5.6a Probability Density Function for Failure Pressure of a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe – Analysis vs. Test Comparison (40 – 60% Wall Loss)

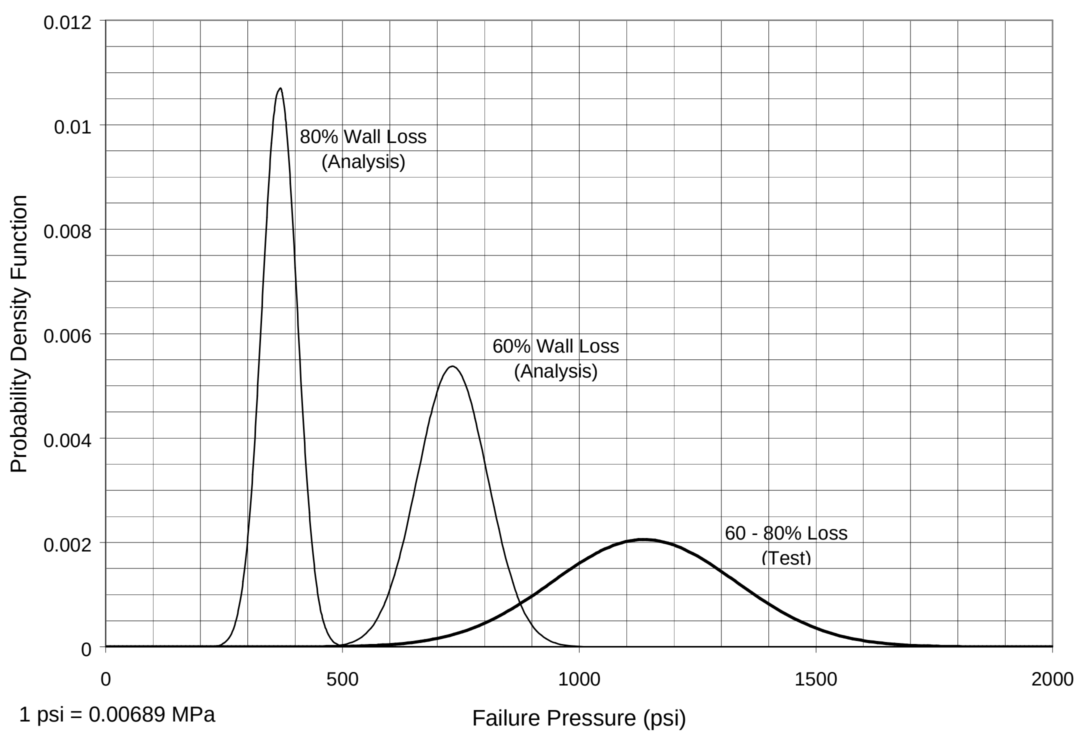


Figure 5.6b Probability Density Function for Failure Pressure of a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe – Analysis vs. Test Comparison (60 – 80% Wall Loss)

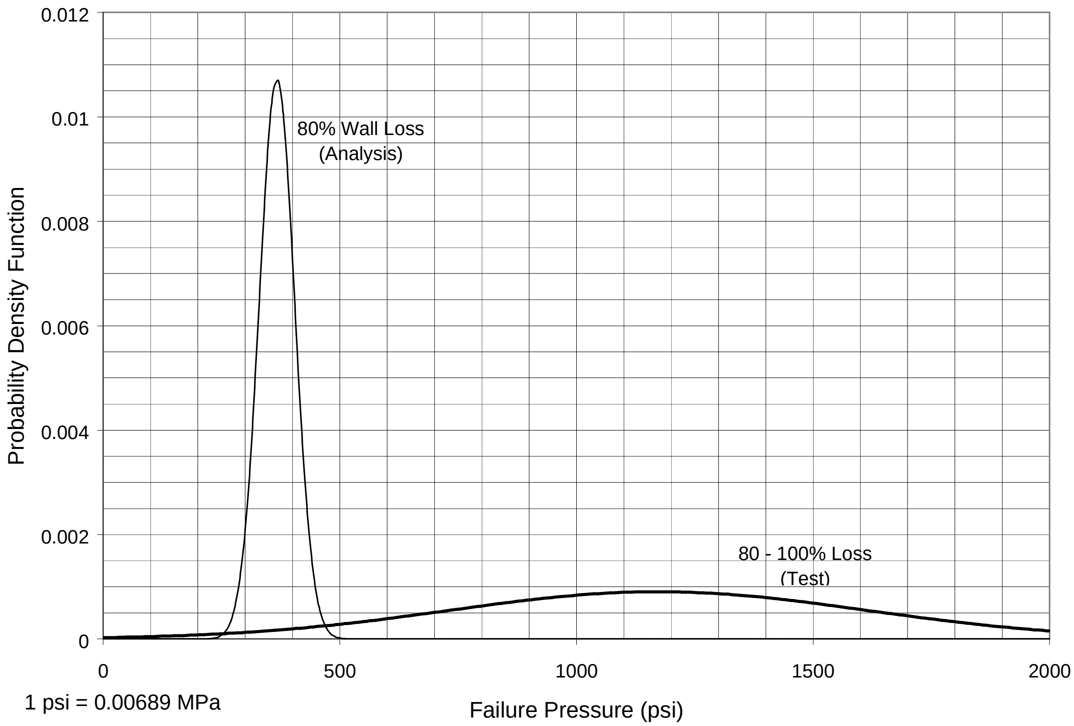


Figure 5.6c Probability Density Function for Failure Pressure of a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe – Analysis vs. Test Comparison (80 – 100% Wall Loss)

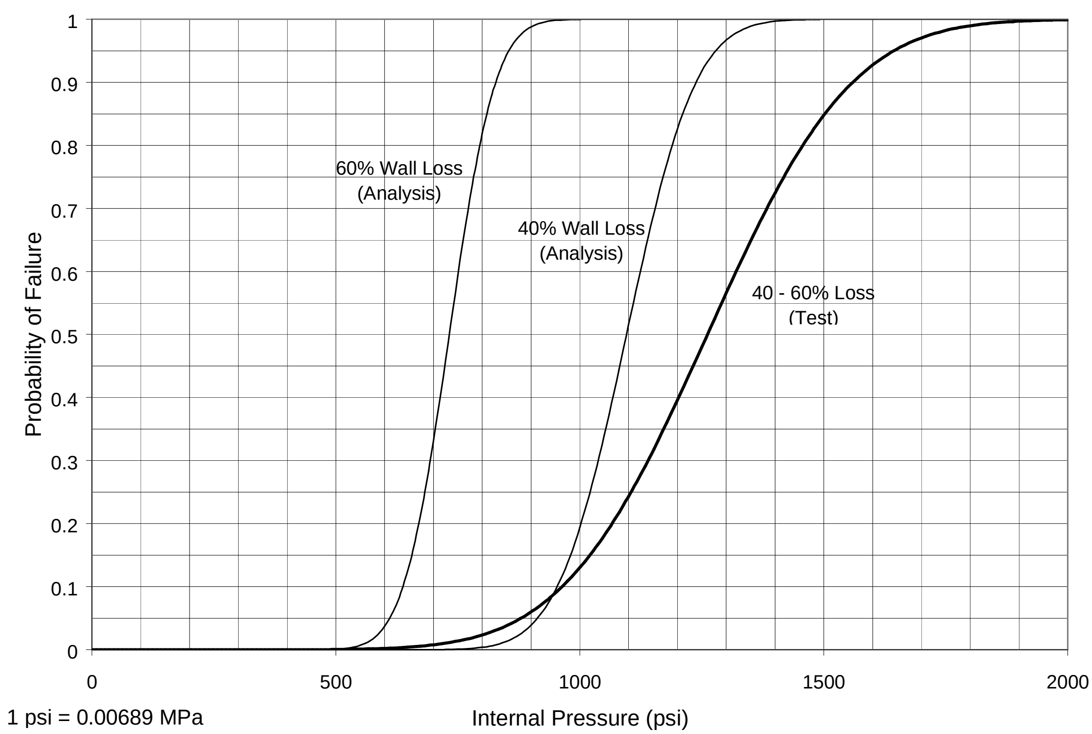


Figure 5.7a Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe as a Function of Internal Pressure – Analysis vs. Test Comparison (40 – 60% Wall Loss)

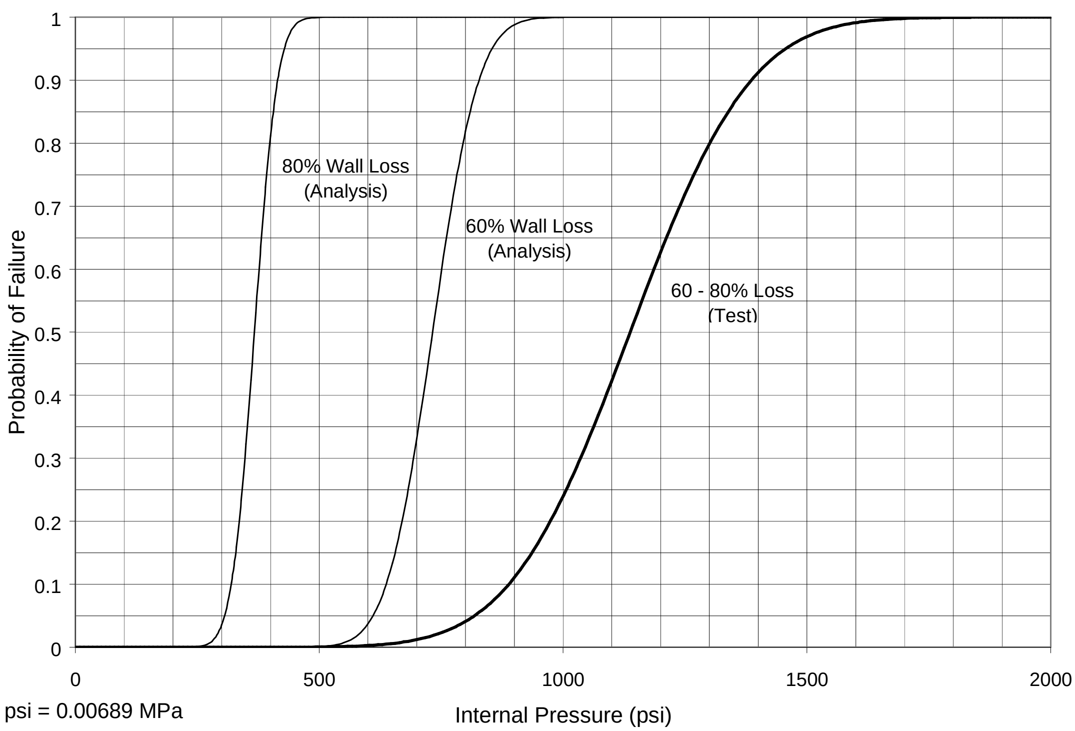


Figure 5.7b Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe as a Function of Internal Pressure – Analysis vs. Test Comparison (60 – 80% Wall Loss)

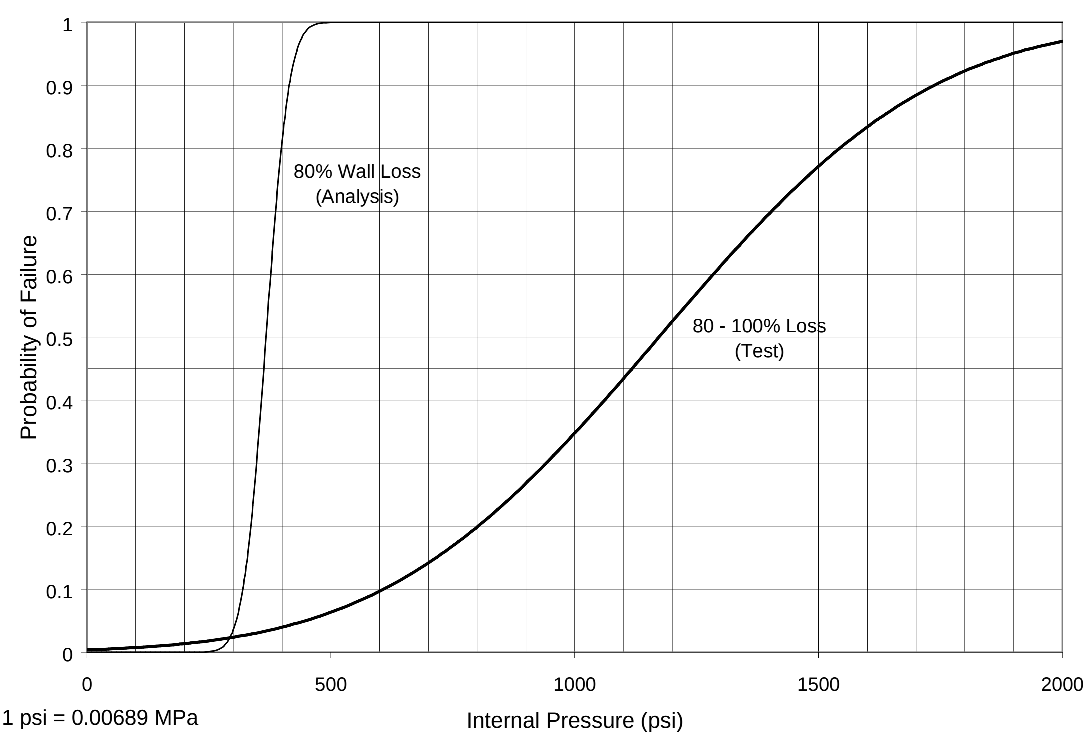


Figure 5.7c Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe as a Function of Internal Pressure – Analysis vs. Test Comparison (80 – 100% Wall Loss)

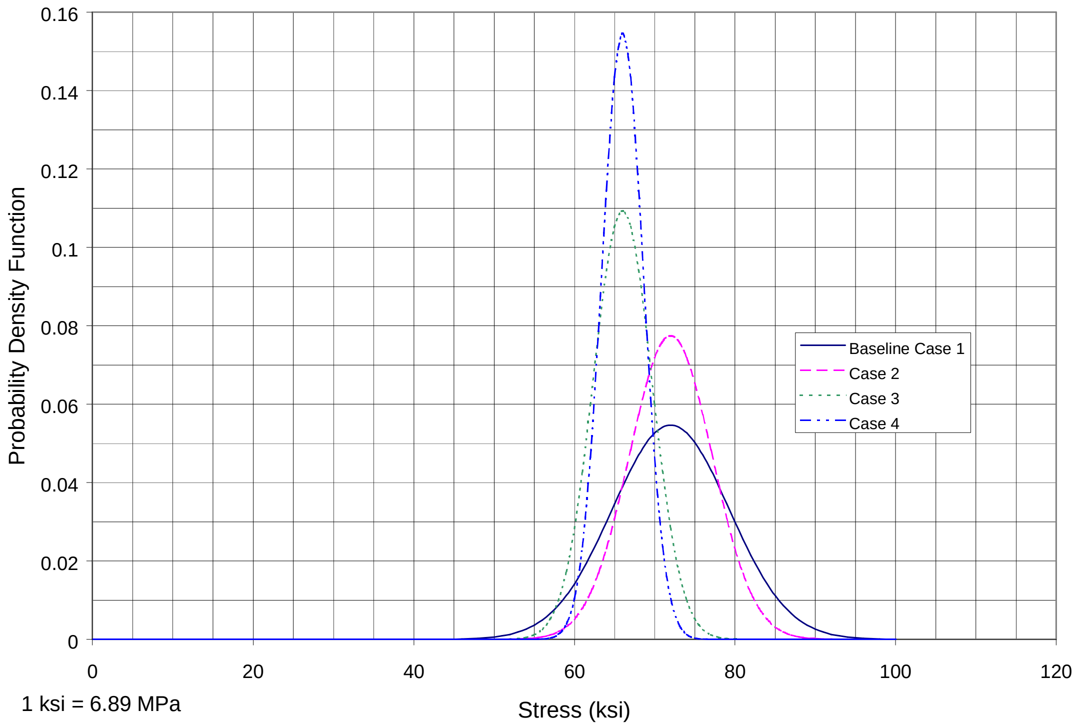


Figure 5.8 Probability Density Function for SA-106 Gr. B Pipe Tensile Strength Sensitivity Study Cases 1 through 4

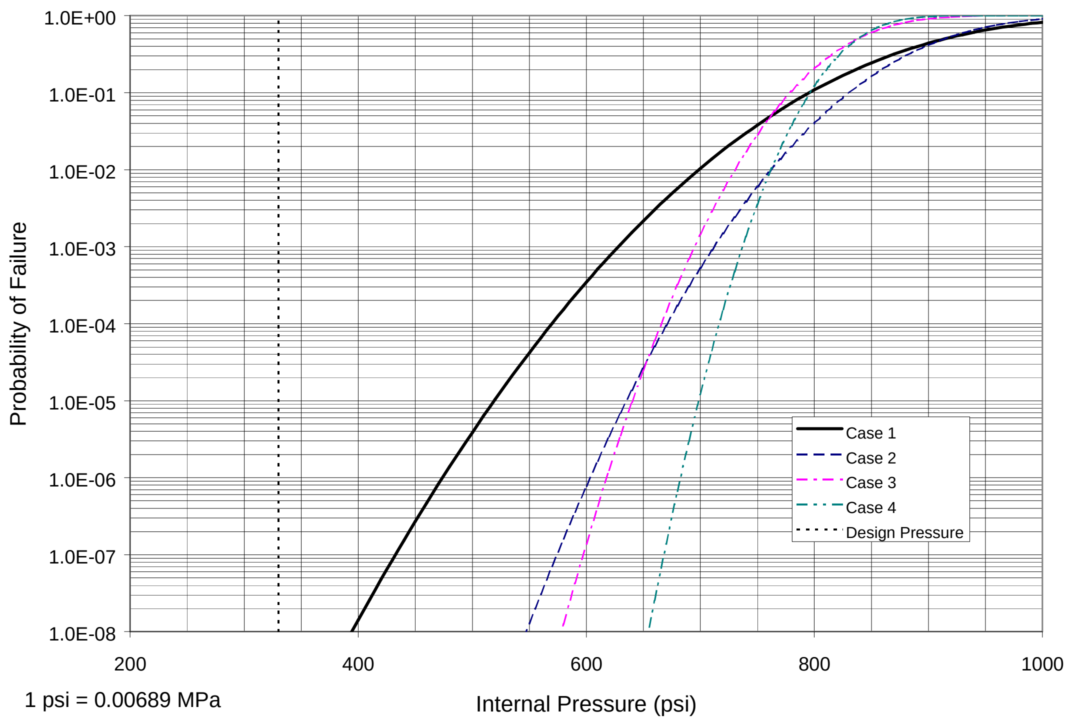


Figure 5.9a Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe with 50% Wall Loss Sensitivity Study Cases 1 through 4

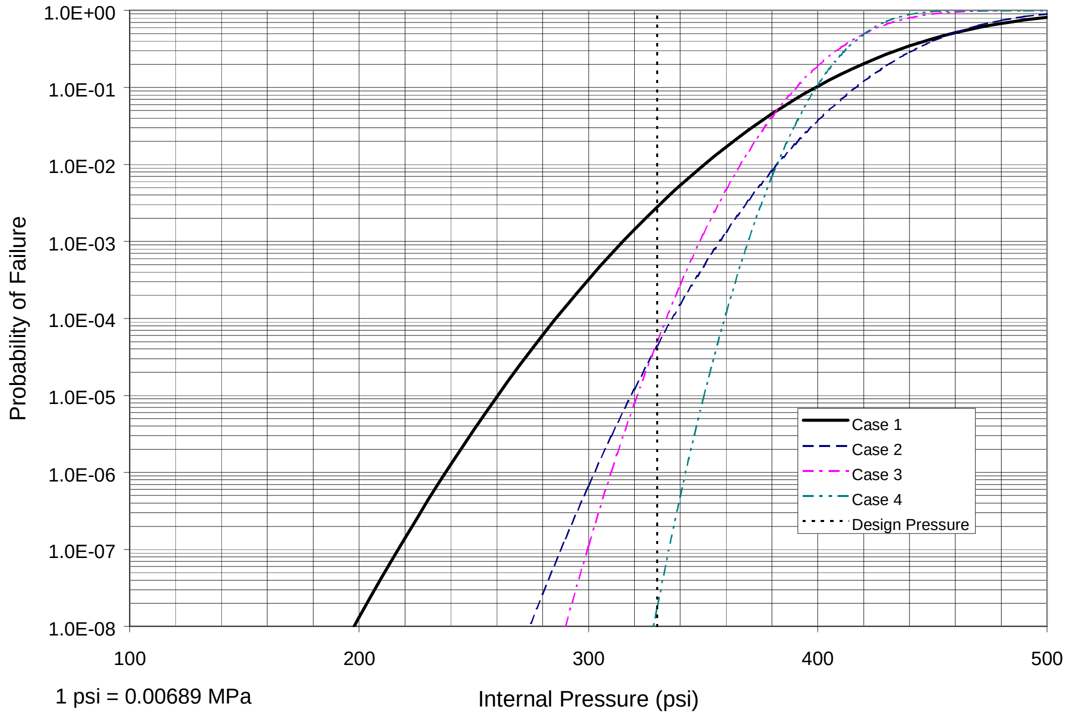


Figure 5.9b Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe with 75% Wall Loss Sensitivity Study Cases 1 through 4

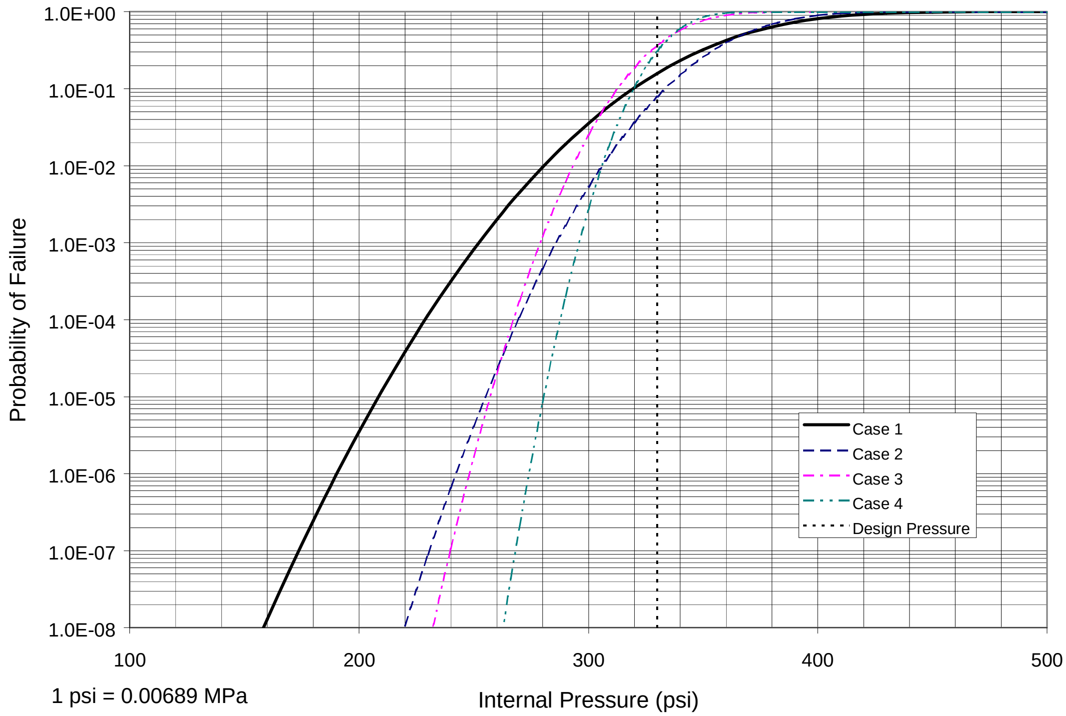


Figure 5.9c Fragility Curves for a 30 in. (76.2 cm) Standard Wall SA-106 Gr. B Pipe with 80% Wall Loss Sensitivity Study Cases 1 through 4

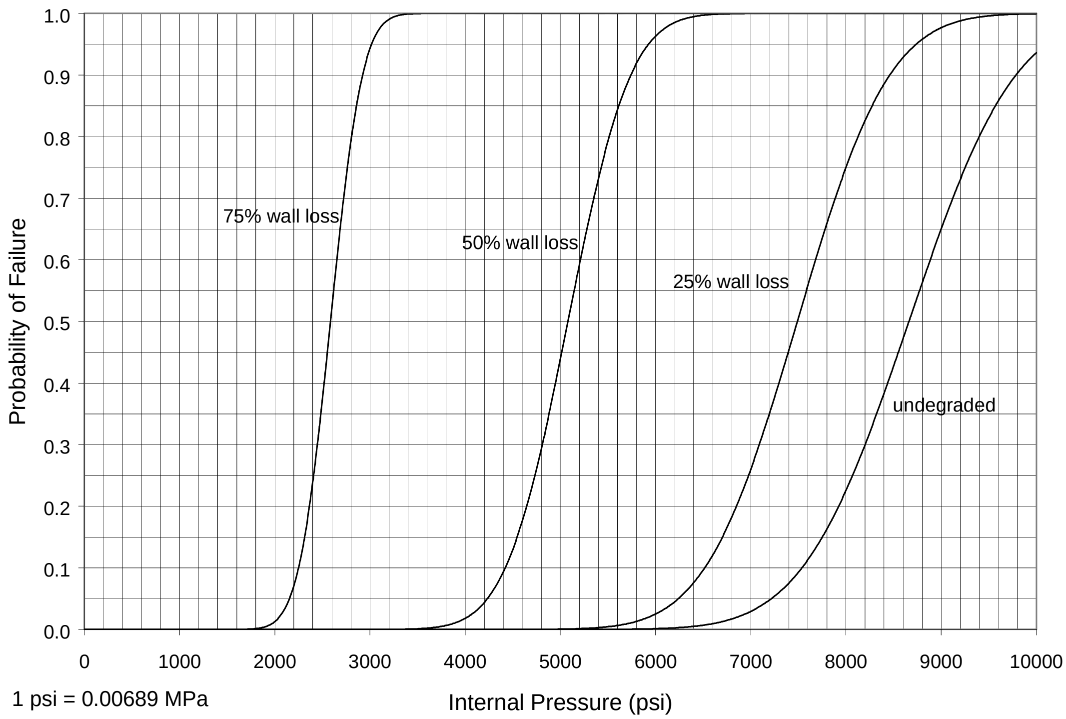


Figure 5.10a Fragility Curves for a 2 in. (5.08 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure with Varying Levels of Wall Loss

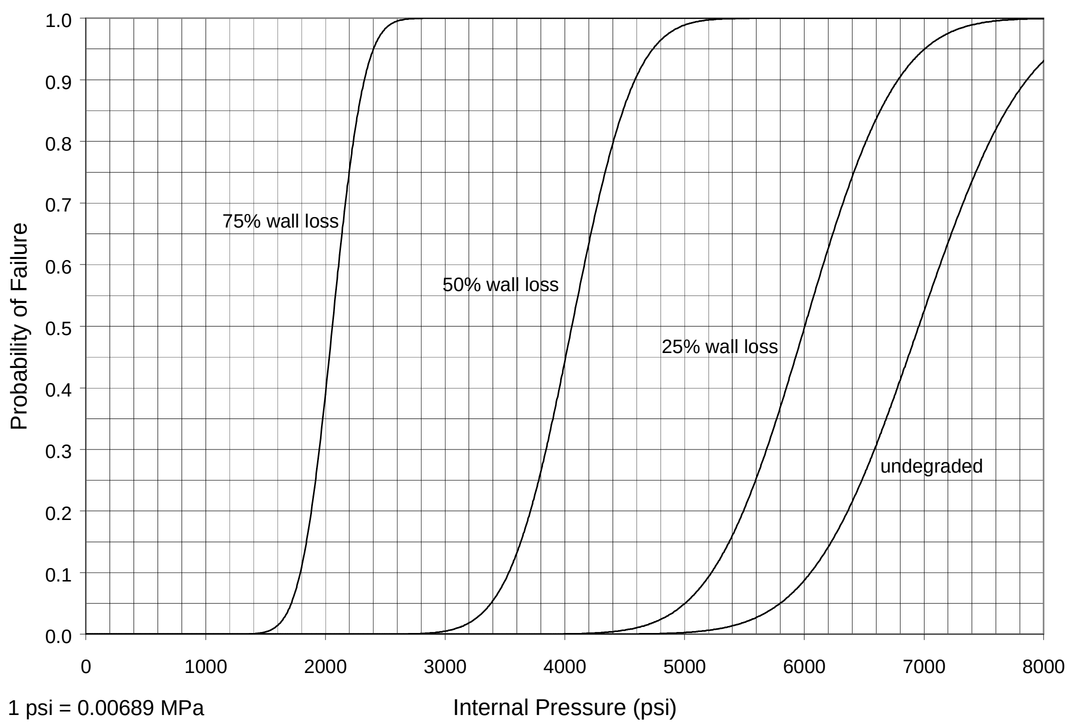


Figure 5.10b Fragility Curves for a 4 in. (10.2 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure with Varying Levels of Wall Loss

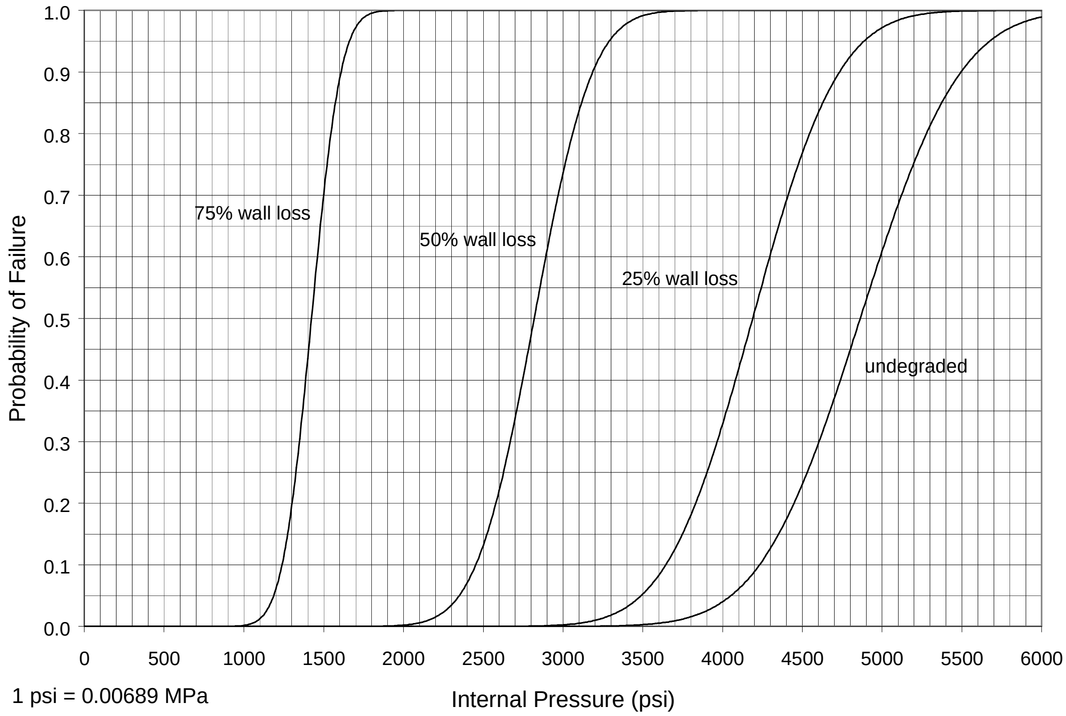


Figure 5.10c Fragility Curves for an 8 in. (20.3 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure with Varying Levels of Wall Loss

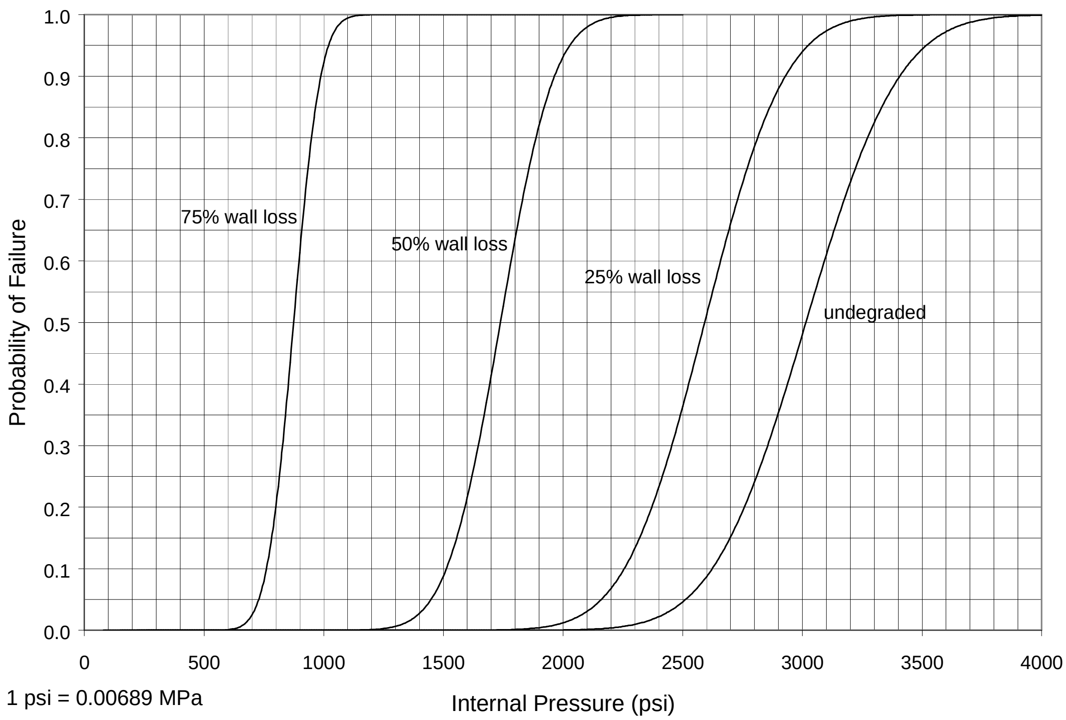


Figure 5.10d Fragility Curves for a 16 in. (40.6 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure with Varying Levels of Wall Loss

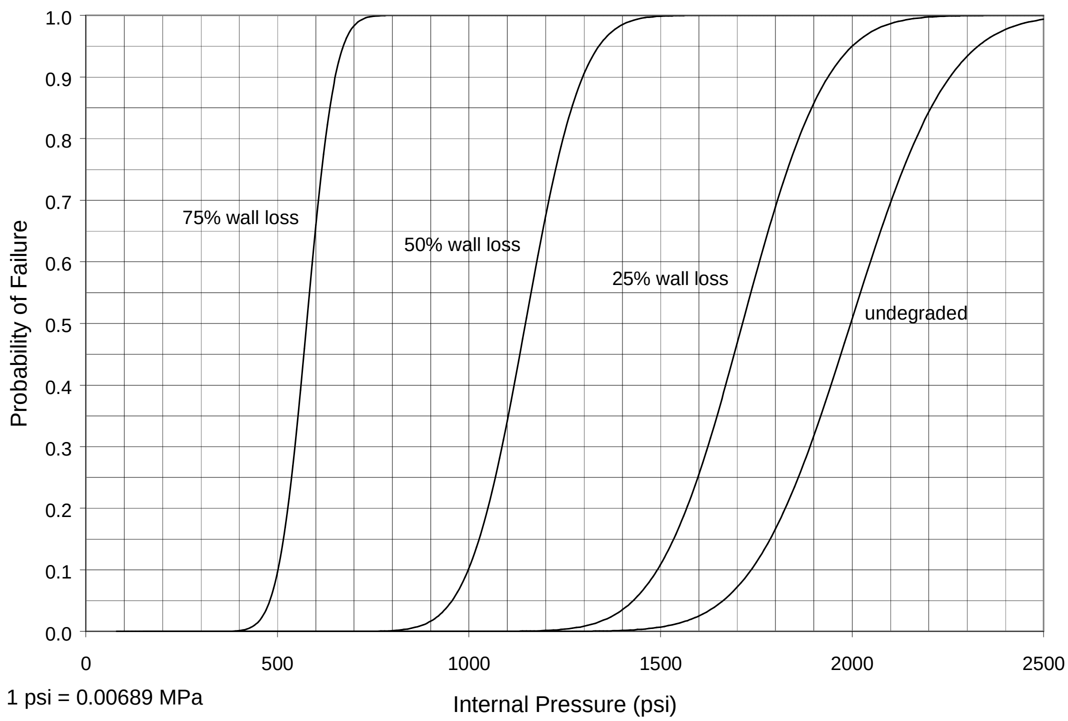


Figure 5.10e Fragility Curves for a 24 in. (61.0 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure with Varying Levels of Wall Loss

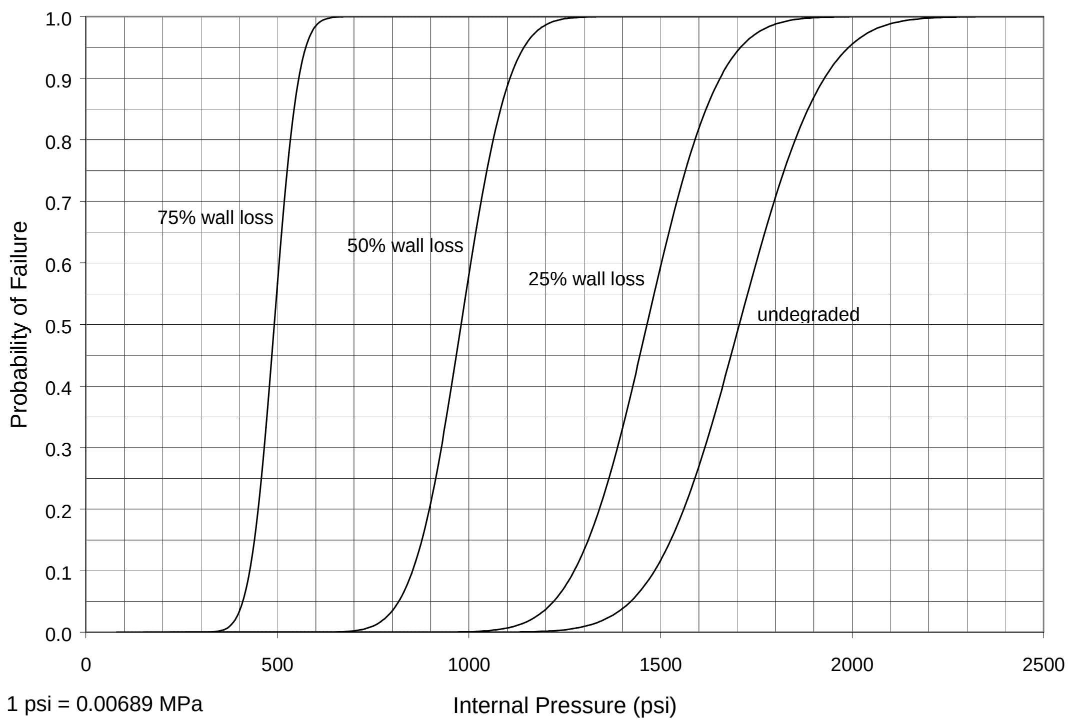


Figure 5.10f Fragility Curves for a 42 in. (107 cm) Diameter x .562 in. (1.43 cm) Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure with Varying Levels of Wall Loss

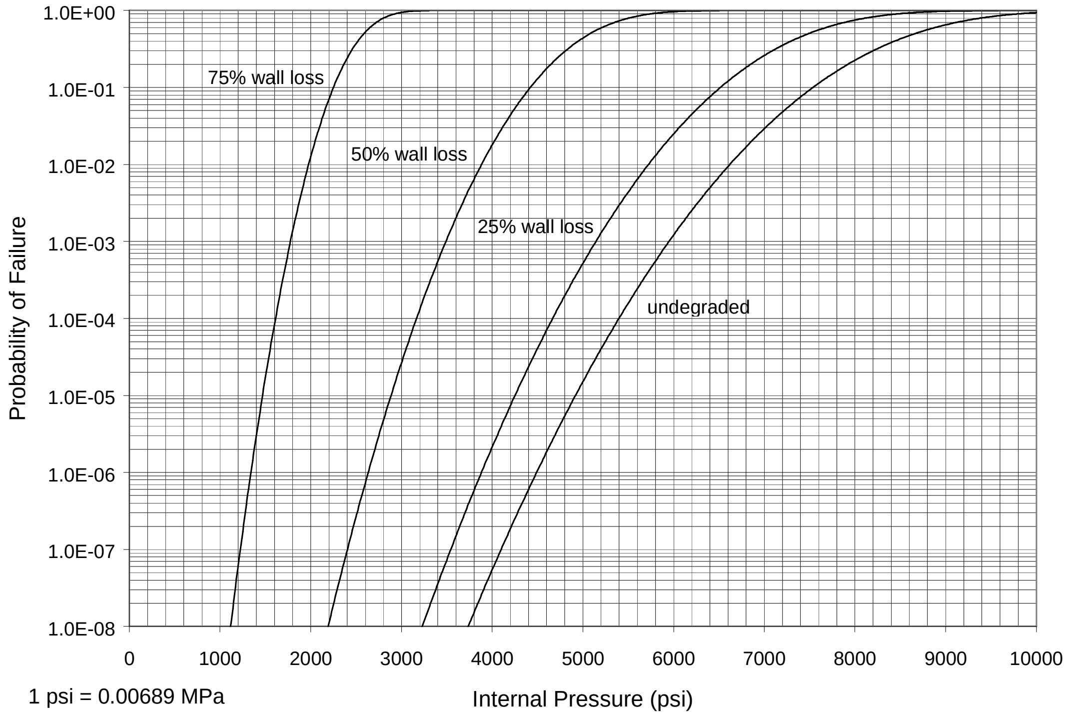


Figure 5.11a Fragility Curves for a 2 in. (5.08 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss

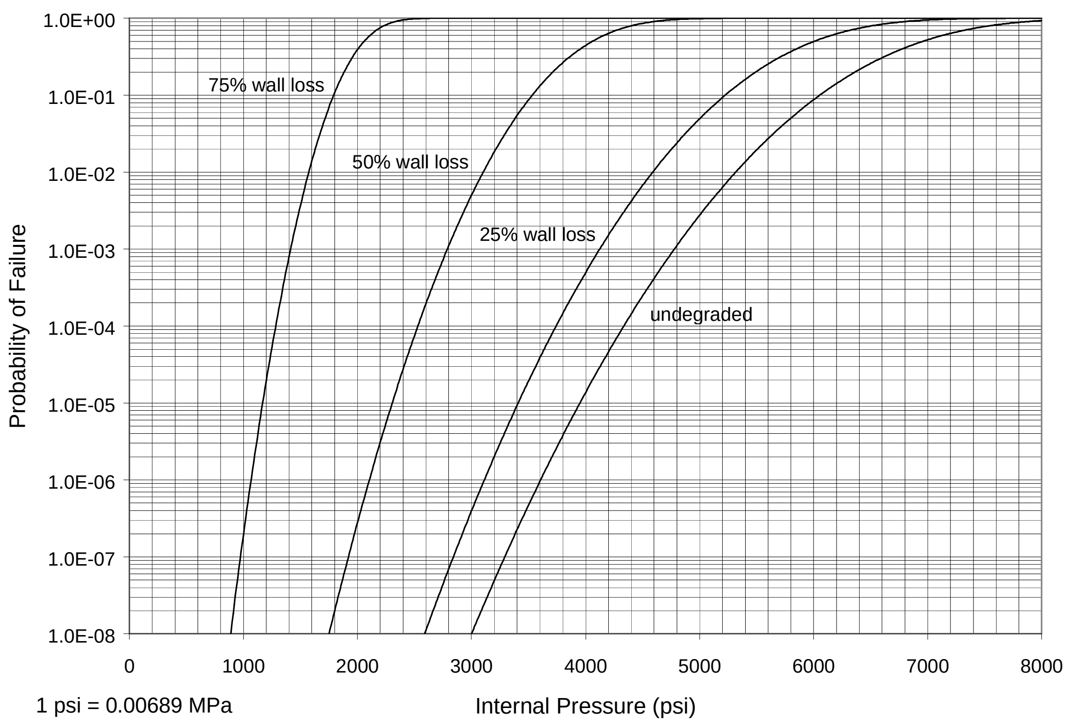


Figure 5.11b Fragility Curves for a 4 in. (10.2 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss

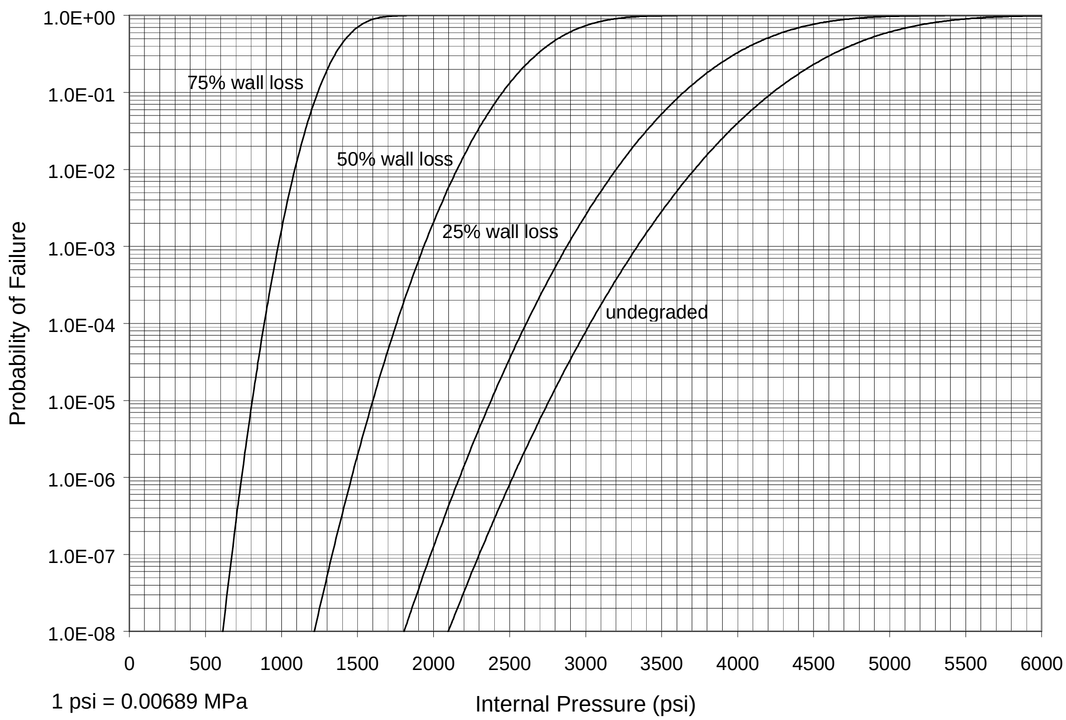


Figure 5.11c Fragility Curves for an 8 in. (20.3 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss

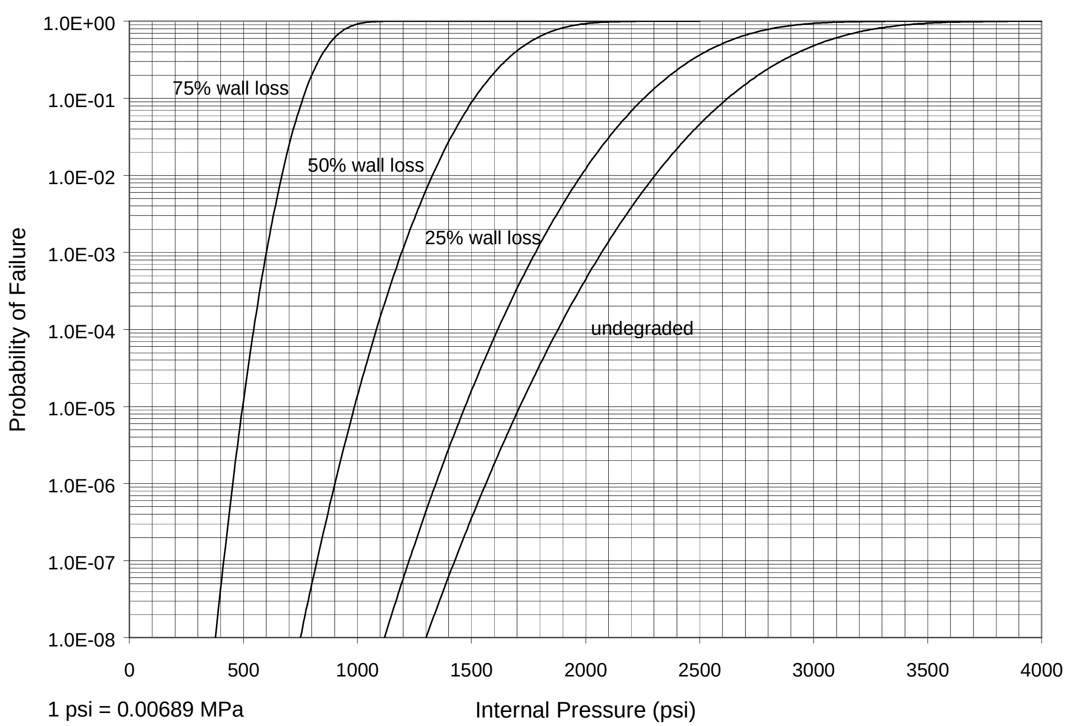


Figure 5.11d Fragility Curves for a 16 in. (40.6 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss

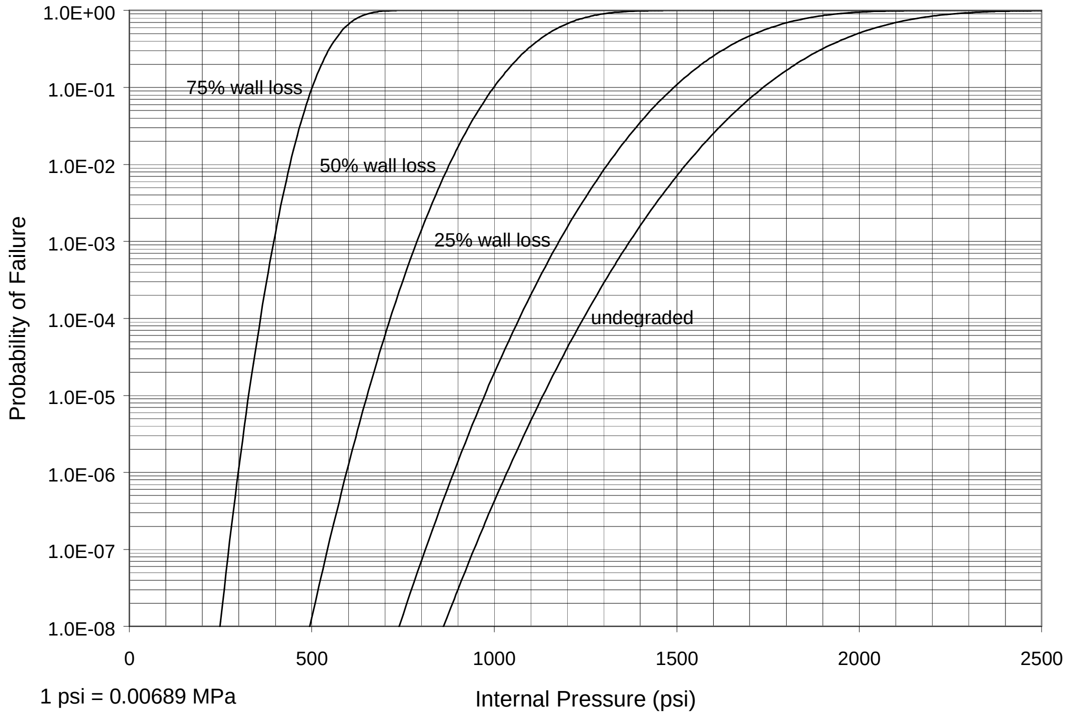


Figure 5.11e Fragility Curves for a 24 in. (61.0 cm) Standard Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss

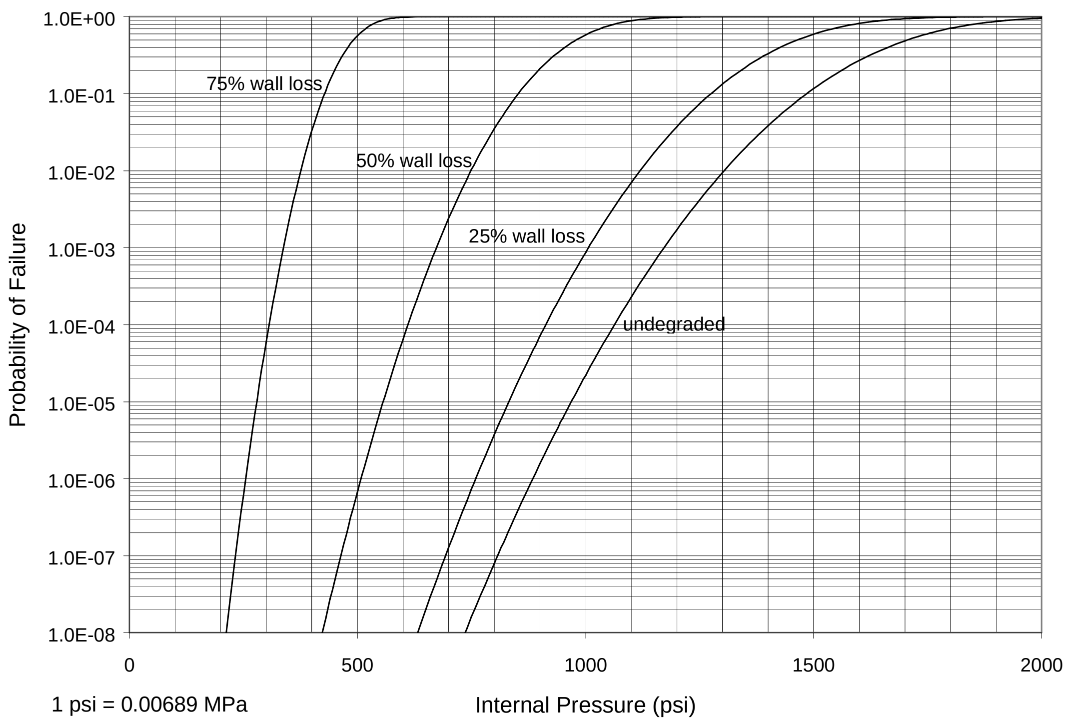


Figure 5.11f Fragility Curves for a 42 in. (107 cm) Diameter x .562 in. (1.43 cm) Wall SA-106 Carbon Steel Pipe as a Function of Internal Pressure With Varying Levels of Wall Loss

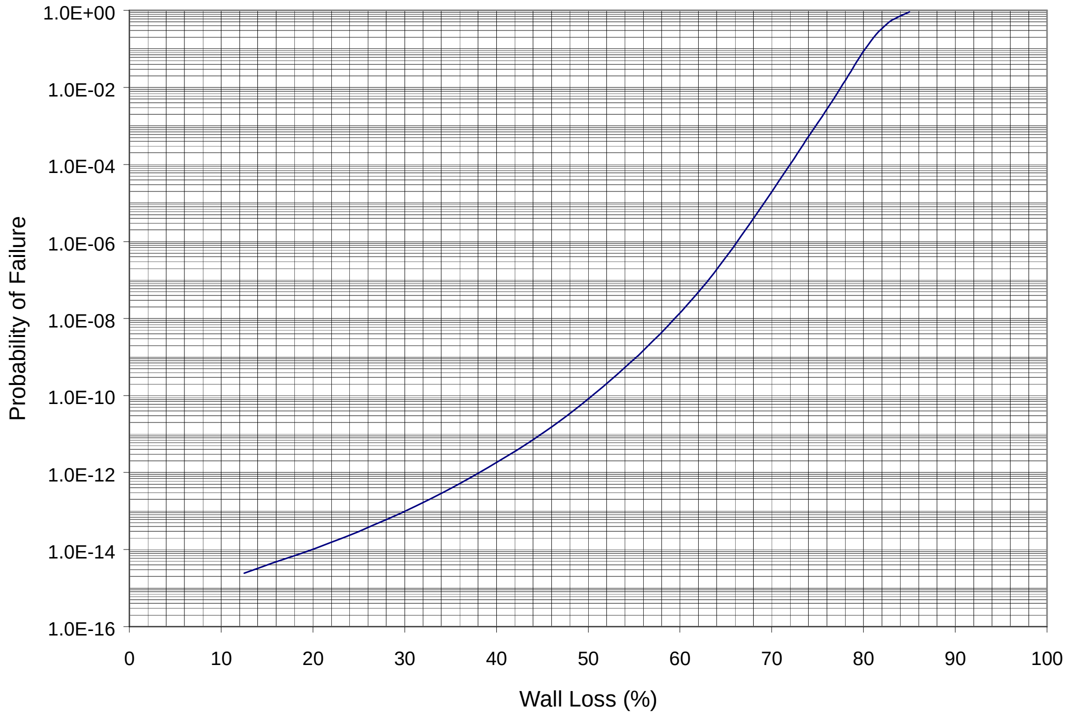


Figure 5.12a Probability of Failure for a 2 in. (5.08 cm) Standard Wall SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss

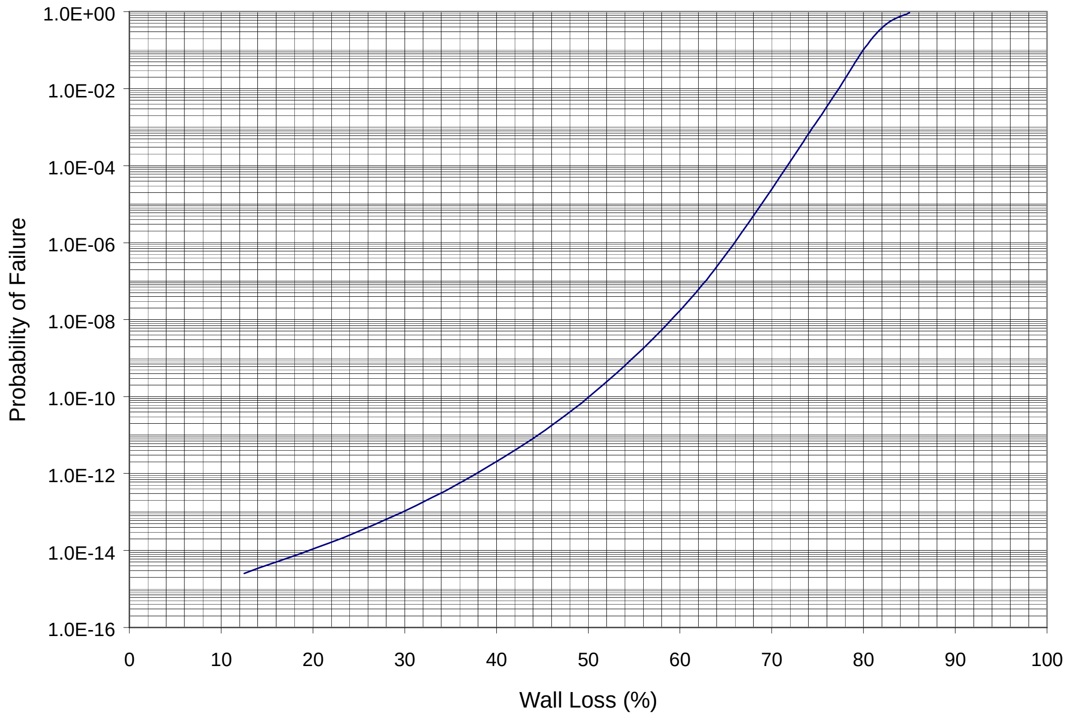


Figure 5.12b Probability of Failure for a 4 in. (10.2 cm) Standard Wall SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss

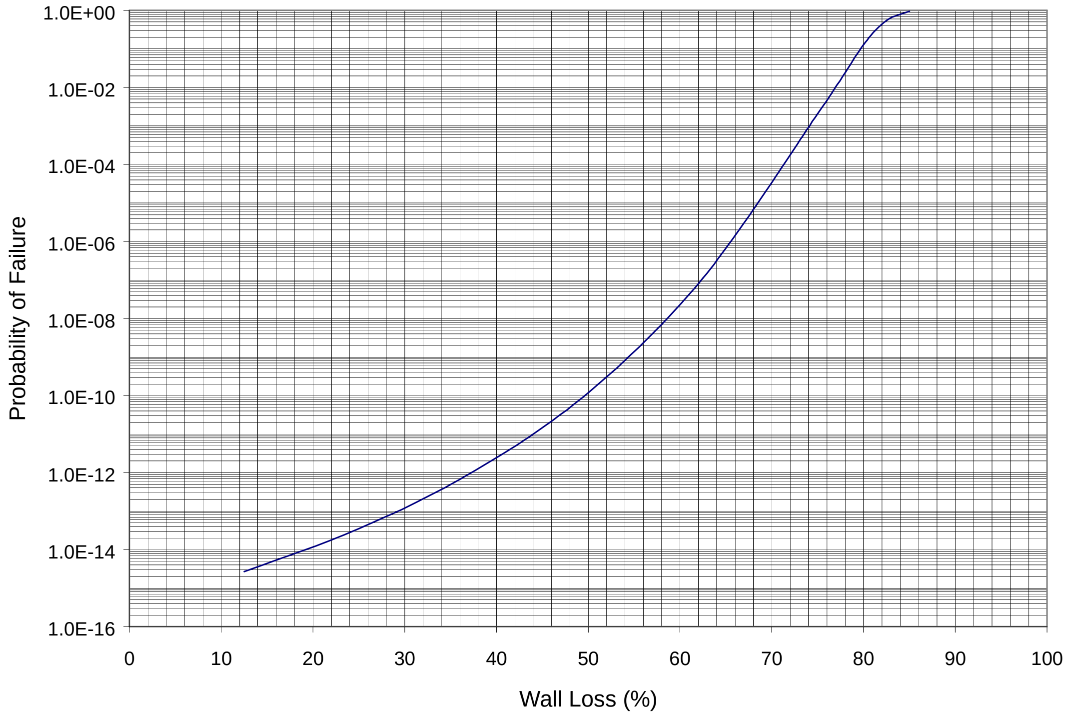


Figure 5.12c Probability of Failure for an 8 in. (20.3 cm) Standard Wall SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss

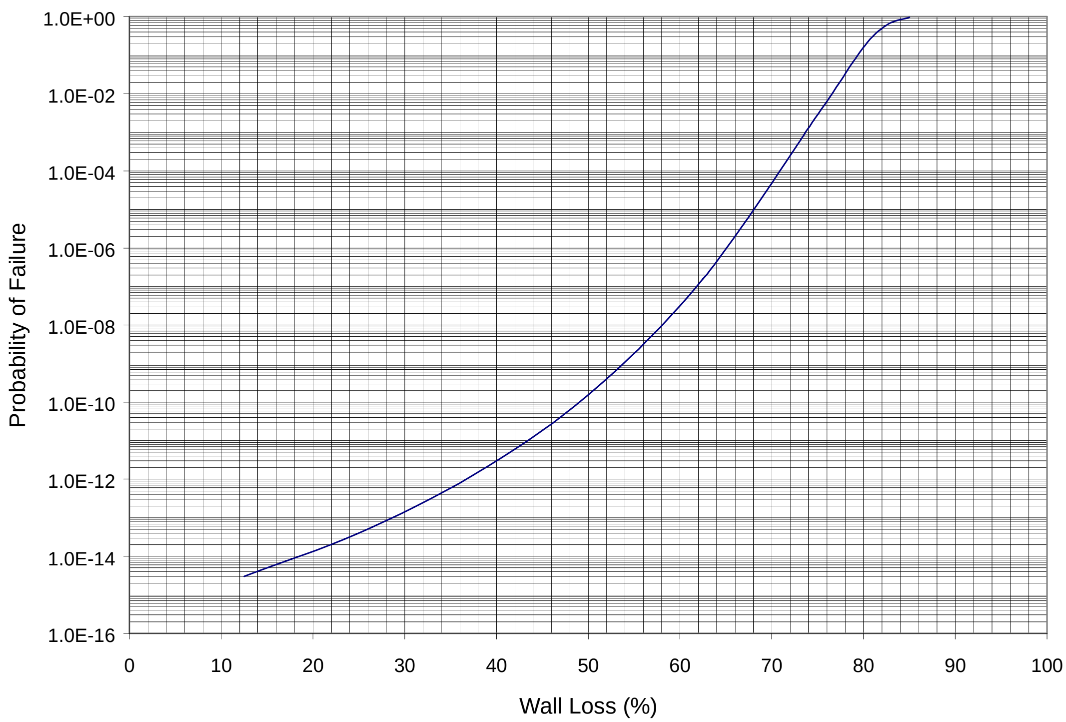


Figure 5.12d Probability of Failure for a 16 in. (40.6 cm) Standard Wall SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss

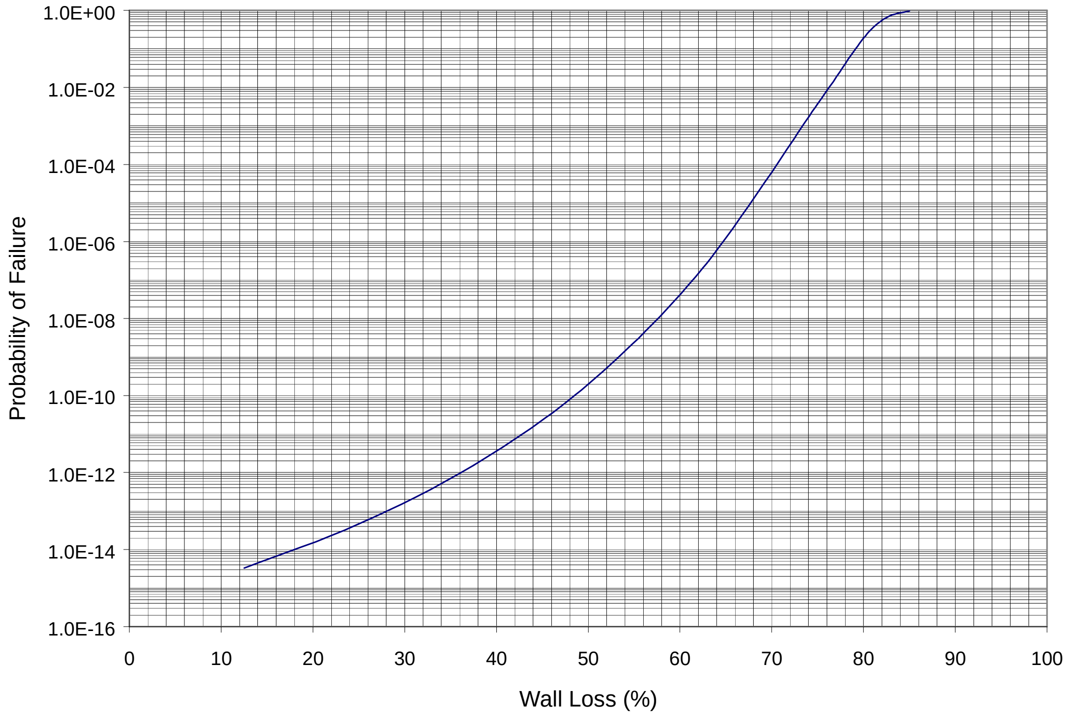


Figure 5.12e Probability of Failure for a 24 in. (61.0 cm) Standard Wall SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss

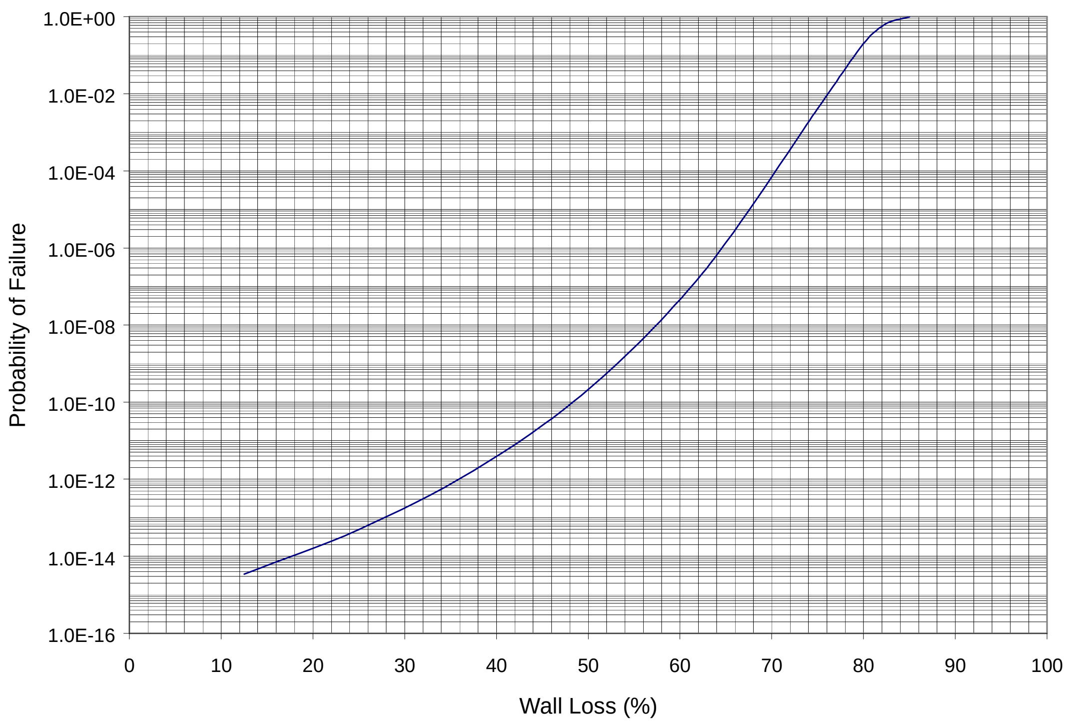


Figure 5.12f Probability of Failure for a 42 in. (107 cm) Diameter x .562 in. (1.43 cm) Wall SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss

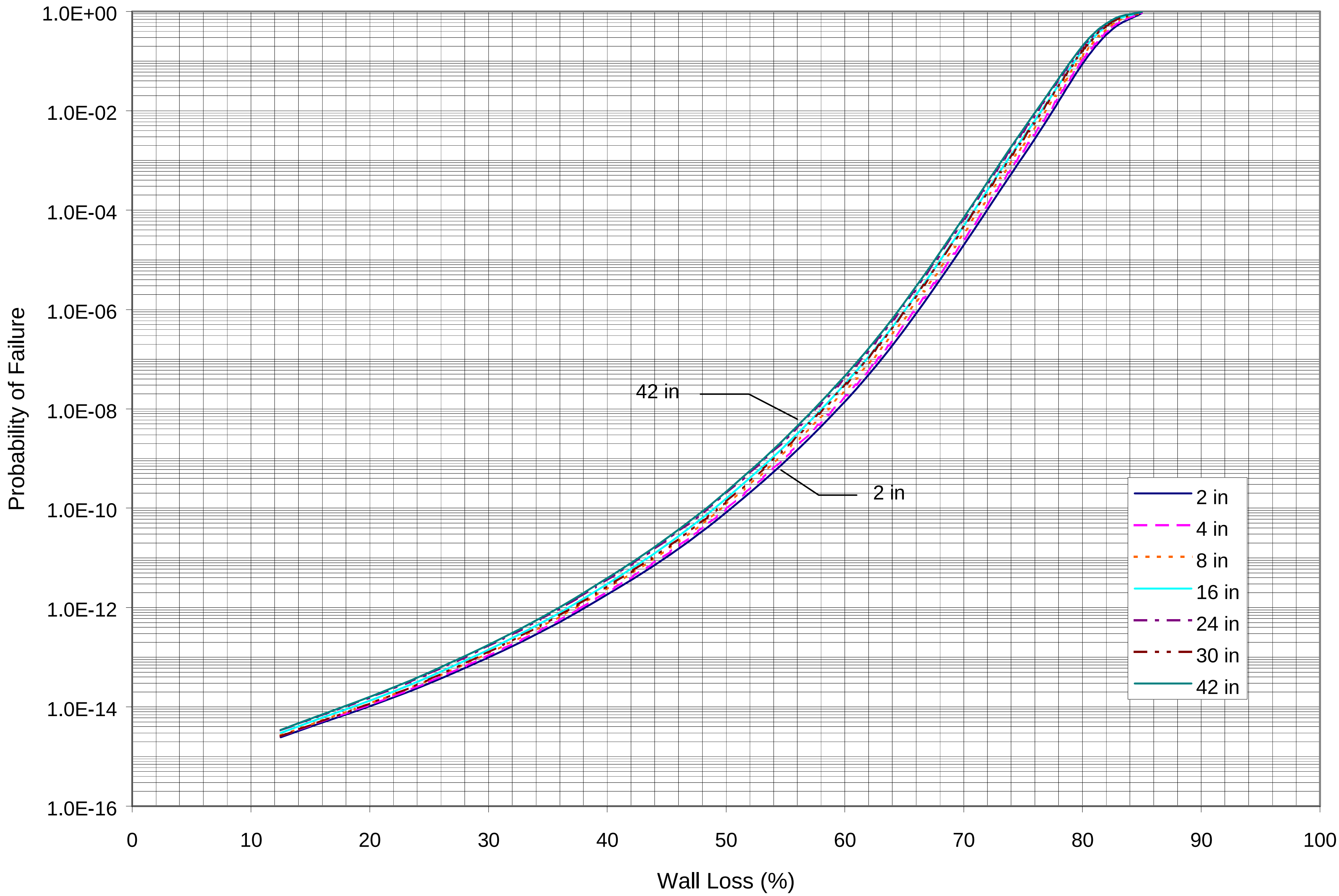


Figure 5.13 Probability of Failure for SA-106 Carbon Steel Pipe Under Design Pressure vs. Wall Loss – All Sizes

6 RISK EVALUATION OF DEGRADED BURIED PIPING SYSTEMS

Buried piping systems at a nuclear power plant (NPP) can degrade, as described in the previous sections. Such deterioration potentially could impair the operation of the system that contains the buried piping, and thus impact the overall risk of an NPP.

Currently, buried piping is not systematically inspected. Accordingly, a failure of a buried pipe is "discovered" because the failure is self-revealing[1], or a failure or degradation of a buried pipe is "discovered" because of another event, such as excavation that is performed for unrelated items. If the "discovery" indicates that the pipe has failed, then a repair[2] has to be completed to return it to normal condition. If the "discovery" indicates that the pipe has not failed, but it has degraded, the regulatory question that arises is: "does the pipe have to be repaired immediately, or is it acceptable for the plant to continue operating?[3]" In essence, the methods and criteria described in this report provide guidance to the NRC staff to assist them in answering this question.

These methods assess the increase in projected risk as a function of time from the time of inspection to answer the question in the previous paragraph. In this way, they estimate the number of years before the plant risk becomes unacceptable. The expression "projected risk" means that the risk is evaluated at some time after the time of inspection.

The increase in projected risk is assessed from the time of inspection because it is known that the pipe has not failed at this time, and the objective of the evaluation is to assess whether continued operation of the pipe (plant) from this time leads to "unacceptable" risk. Figure 6.1 depicts relevant events as a function of time from the start of life of a buried pipe.

To estimate the effect of buried piping degradation on plant risk, five nuclear plant sites having buried piping systems were selected. Section 6.1 describes the process used to select the five nuclear plant sites with buried piping systems. Each site may have one or more NPPs; to simplify the discussion, this report refers to one site simply as an NPP or a plant.

To develop degradation acceptance criteria, which is one of the stated goals of this research, a quantitative measure of "acceptable risk" is needed. Section 6.2 defines what is considered to be acceptable risk, the conditions for which it is applicable in this study, and the quantitative risk acceptance criteria.

The evaluation of the risk associated with degrading buried piping depends on the type of system that contains this piping. Section 6.3 discusses some top-level considerations for developing methods for estimating this risk, including a classification of the plant's systems for the purpose of assessing this risk. Section 6.3 concludes that all the systems with buried piping of the five nuclear plants selected fall into two categories:

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[1] A failure of a buried pipe is self-revealing, for example, when a system that is normally operating fails in such a way that the failure becomes visible to plant personnel.
[2] In this section the term "repair" is used in a very broad sense, including replacement. In other words, when a "repair" is carried out, it is considered that the pipe is returned to a condition that meets the plant's current licensing basis.
[3] If the buried pipe is degraded but not failed, the licensee is still expected to evaluate the degraded condition to determine if any corrective action needs to be taken depending on the evaluation findings and the level of degradation. Although future inspections are an option, there is no requirement to do so.

1) A system is normally operating and its failure causes an initiating event (IE), and
2) A system is not subjected to internal pressure at all times and its failure does not cause an IE.

The methods for estimating the risk associated with degrading buried piping presented in Sections 6.5 and 6.6 use the conditional probability that the pipe will fail by M years after the time of inspection, given that it has not failed at the time of inspection. Section 6.4 presents a derivation of this probability.

Sections 6.5 and 6.6 derive the methods for estimating the risk associated with degrading buried piping for a system that is normally operating and its failure causes an Initiating Event, and for a system that is normally in standby and its failure does not cause an Initiating Event, respectively. These methods are applied to the selected plants to obtain results that will be used in Section 7 to calculate degradation acceptance criteria.

6.1 Selection of Plants

To evaluate the risk of degraded buried piping, five NPPs were selected for analysis from among twelve License Renewal Applications (LRAs) submitted to the NRC. The choice was made from these twelve plants because their LRAs were the only reliable sources of information that specifically listed what buried piping systems exist at their plant.

Table 2.2 lists the buried piping systems for each of the twelve LRA plants; these data are summarized in Table 2.3. Table 6.1 reformats this information in terms of the number of buried piping systems for each plant. This table also provides plant information consisting of the reactor type, NSSS supplier, type of containment, architect/engineer, and location in the United States. All of these data were used to select the five plants for the risk evaluation.

The first criterion was to choose plants with the greatest number of buried piping systems to get the most information about such systems. These plants were Surry, North Anna, and Hatch, all having seven or more buried piping systems. Then, for the remaining plants having five buried piping systems, it was desirable to select two more plants that would offer the best variation on the remaining parameters shown in Table 6.1. Peach Bottom was dropped because it is a GE BWR, Steel Mark I containment, designed by Bechtel, which is the same plant information for the Hatch plant (already selected). McGuire and Catawba have the same plant parameters and so only one of them was needed; the former was selected. Oconee was included because it has a Babcock & Wilcox designed PWR, a prestressed concrete containment, and it was constructed by Duke and Bechtel; all of these parameters differ from the other plants.

Accordingly, the risk evaluation encompassed the following five plants:

- Surry
- Hatch
- North Anna
- McGuire
- Oconee.

The information given in Table 2.3 shows that these five plants are a good selection because they cover practically all systems having buried piping, as reported in the LRAs. In addition, they contain both “frontline” and “support” systems having buried piping.

6.2 Defining Acceptable Risk

Current trends in the regulatory environment and industry are to incorporate risk-informed decisionmaking in order to make more productive uses of available resources by applying them to those activities that can have the greatest improvement on safety of NPPs while maintaining costs at reasonable levels. To assist the industry in using information from risk assessments, the NRC has issued Regulatory Guide 1.174, Revision 1, entitled “An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes To The Licensing Basis.”

Regulatory Guide 1.174, Revision 1 (RG 1.174), provides recommendations developed by the staff for using risk information in support of licensee-initiated licensing basis (LB) changes that require review and approval by the NRC. The document describes an approach that is acceptable to the NRC for analyzing proposed changes to the LB of a plant and for assessing the impact that such changes may have on the risk associated with the plant.

Another document that relates to probabilistic risk assessments is the NRC Standard Review Plan NUREG-0800, Chapter 19 Rev. 1 (2002), which is entitled, “Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decisionmaking: General Guidance.” The standard review plan was issued to provide guidance to the NRC staff for performing evaluations of licensees' requests for changes to the LB that utilize risk insights.

The RG 1.174 and the Standard Review Plan both indicate that the licensees' submittals are expected to use an integrated process that combines risk insights from a PRA, together with insights from traditional engineering analyses, supported by performance monitoring and feedback. The quality of the PRA needed to support this process should be commensurate with the roles the risk insights play in the final decisionmaking.

The research described in this report is intended to be used as a guideline for determining the potential risk significance of a specific degraded condition. Therefore, RG 1.174 is being used to provide a quantitative measure of what can be considered as “significant risk” and is not being used to justify a change in the licensing basis at the plant where the degradation has occurred.

In developing the approach described in RG 1.174, the NRC has decided that only small increases in risk would be permitted, and then only when it is reasonably assured, among other things, that sufficient defense in depth and sufficient safety margins are maintained. This approach is followed because of the inherent uncertainties and the need to account for safety issues that may arise related to design, construction, and operation of NPPs.

As described above, a quantitative measure of acceptable risk was needed for this study in order to develop quantitative acceptance criteria for degraded buried piping. The quantitative guidelines of acceptable risk contained in RG 1.174 were adapted to develop these criteria. Subsection 6.2.1 discusses the quantitative guidelines of acceptable risk in RG 1.174, and Subsection 6.2.2 develops the quantitative risk acceptance criteria for degraded buried piping.

6.2.1 Quantitative guidelines of acceptable risk in RG 1.174

Subsection 2.2.4 of RG 1.174 presents quantitative measures of risk. Acceptance guidelines for changes in Core Damage Frequency (CDF) are presented in Figure 3 of the Guide. The guidelines in Figure 3 are broken down into three regions: I, II, and III. Once the baseline CDF of a particular plant is developed (or already known from past assessments), the ΔCDF resulting from the proposed change in the LB is used to determine the acceptance region. A change that falls in Region I is a significant change for which the Guide states “no changes allowed.” Region II is considered a “small change” which requires the licensee to “track cumulative impacts.” Region III corresponds to “very small changes” which permit “more flexibility with respect to baseline CDF” and also requires the licensee to “track cumulative impacts.”

The acceptance guidelines described in RG 1.174 were used to define acceptable risk for evaluating degraded buried piping in order to determine the level of degradation that should be considered to potentially have a significant effect on plant risk. To be conservative and to account for some of the uncertainties described elsewhere in the report, the definition of acceptable risk will be if the ΔCDF due to degradation falls in Region III as described earlier.

From Figure 3 of RG 1.174, the upper boundary of Region III has a ΔCDF of 10^{-6} per year and the maximum baseline CDF for this Region ends at somewhat less than 10^{-3} per year. Since the maximum baseline CDF shown for Region III is not represented with a well-defined boundary, a value of 5×10^{-4} per year was selected as an upper bound value for the baseline CDF. Based on these observations, the acceptable ΔCDF selected for this study is 1×10^{-6} per year and the maximum baseline CDF selected is 5×10^{-4} per year. These criteria were selected as a definition of acceptable risk and were applied to all plants for this study.

The acceptance guidelines of RG 1.174 also specify that these guidelines are intended for comparison with a full-scope (including internal events, external events, full power, and shutdown) assessment of the change in risk metric. As described later in Sections 6.5 and 6.6 of this report, the methods for assessing the risk associated with buried piping used parameters obtained from evaluating the SPAR version 3 models that are full-power level-1 probabilistic risk assessment (PRA) models for internal events. The evaluation of level-1 PRAs of internal events during full power operation is considered acceptable because RG 1.174 states that it is recognized that many PRAs are not full scope and PRA information of less than full scope may be acceptable. The approach described in this report utilizes the latest available PRA models that are currently accessible for use in this research study. Also, the soil above buried piping would protect the pipe from external events of high winds, flooding, fire, lightning, snow and ice, and a light aircraft crash (the external event of earthquakes is addressed separately in Section 5.1 of this report). In addition, the conservatisms included in the fragility analysis approach provide added margins to account for the uncertainties and assumptions made.

It is acknowledged that RG 1.174 indicates that in addition to the acceptance guideline for CDF (Figure 3 of RG 1.174), the acceptance guideline for Large Early Release Frequency (LERF) (Figure 4 of RG 1.174) should also be used. This however was not possible for this study because only level 1 PRA models were available for performing the risk assessments. In addition, RG 1.174 is really intended to be used by licensees to evaluate proposed changes to a plant’s licensing basis. The results presented in this report are intended to be used as a guideline for determining the potential risk significance of a specific degraded condition. RG 1.174 in the context of this study is being used to provide a quantitative measure of what can be considered as “significant risk” and is not being used to justify a change in the licensing basis at the plant where the degradation has occurred. To address the concern regarding the need to consider the acceptance guideline for LERF, those buried piping systems whose main function is to mitigate events other than level 1 internal events (e.g., LERF and fire) have been identified and excluded from the degradation acceptance criteria. These buried piping systems should be considered on a case-by-case basis. From the list of buried piping systems shown in Table 2.3, three systems that should be considered on a case-by-case basis are the standby gas treatment, containment spray, and recirculation spray systems.

On the other hand, the methods presented in this section can be applied to assess the risk related to CDF and LERF provided that models for evaluating these parameters are available. In particular, one possibility for obtaining a simplified evaluation of LERF (or of Large Early Release Probability (LERP)) is to use the approach of NUREG/CR-6595, Rev. 1 (Pratt et al., 2004). An evaluation of LERP using this approach can be combined with the methods described in this section for evaluating the contribution to risk related to LERF.

6.2.2 Quantitative risk acceptance criteria for degraded buried piping

If a buried pipe is subjected to some type of degradation mechanism(s), it will degrade as a function of time. As discussed earlier, the objective of the risk evaluation is to assess whether continued operation of the pipe (plant) from the time of inspection leads to unacceptable risk. The increase in projected risk is assessed from the time of inspection because it is known that the pipe has not failed at this time. Accordingly, the risk is evaluated M years after this time; see Figure 6.1. In this study, the measure of risk due to the pipe's degradation is the increase in the core damage probability (ΔCDP) over these M years.

First, an acceptable ΔCDP over M years of operation after the time of an inspection can be expressed as

$$\Delta CDP_{Acceptable} = \Delta CDF_{Acceptable} \times M \qquad (6.1)$$

where $\Delta CDP_{Acceptable}$ is the acceptable increase in the core damage probability over M years from the time of inspection, and

$\Delta CDF_{Acceptable}$ is an acceptable increase in core damage frequency.

As discussed in Subsection 6.2.1, according to the guidelines in RG 1.174, an acceptable ΔCDF is 1E-6/year, so (6.1) becomes

$$\Delta CDP_{Acceptable} = (1E\text{-}6/year) \times M \qquad (6.2)$$

where M is in units of years.

Accordingly, from a plant risk point of view, a system with buried piping that is degrading could be allowed to continue operating after the time of an inspection as long as

$$\Delta CDP < \Delta CDP_{Acceptable} \qquad (6.3)$$

where $\Delta CDP_{Acceptable}$ is calculated using equation (6.2).

ΔCDP is the increase in the core damage probability over M years after the time of inspection due to degradation of the buried piping.

Substituting equation (6.2) into equation (6.3),

$$\Delta CDP < (1E\text{-}6/year) \times M \qquad (6.4)$$

Equation (6.4) and the condition that the maximum baseline CDF of a plant is 5×10^{-4} per year or less, discussed in Subsection 6.2.1, are the quantitative risk acceptance criteria. These criteria are used in this study to assess the acceptability of the degradation of the buried piping over M years of operation after the time of an inspection. Calculating the ΔCDP to be used in equation (6.4) depends on the type of system being evaluated. Sections 6.5 and 6.6 derive the methods for estimating the risk associated with degrading buried piping for a system that is normally operating and its failure causes an Initiating Event, and for a system that is normally in standby and its failure does not cause an Initiating Event, respectively.

In this report, a statement such as plant risk falls below the risk acceptance criteria means that the ΔCDP associated with a degrading buried pipe is less than 1E-6/year * M, as shown by equation (6.4).

Section 6.3 discusses some top-level considerations for developing methods for estimating the risk associated with degrading buried piping, including a classification of the plant's systems for the purpose of assessing this risk.

6.3 Considerations for Developing Methods for Estimating the Risk of Buried Piping

Buried piping subjected to degradation mechanisms will eventually fail if no repair or other actions are taken. The time elapsed from the time the piping is installed to the time it fails depends on the rate of its degradation. If this rate is slow, it would take a long time for buried piping to fail; on the other hand, if this rate is fast, then the piping will fail sooner.

One of the main objectives of this research program is to develop risk-informed acceptance criteria corresponding to different levels of observed degradation of buried piping. For example, assume that an inspection of buried piping after 5 years of operation reveals that it has not failed, but has a 20% wall loss. Then, is it acceptable that this piping remains in operation given this level of degradation, or does it have to be replaced? To respond, the rate of degradation of this piping must be considered. As discussed above, if this rate is slow, then the impact of degraded piping on the plant risk would likely fall below the risk acceptance criteria derived in Subsection 6.2.2 by the end of M years, after the time of inspection. Even if the impact of the degraded condition on plant risk falls below the risk acceptance criteria, the licensee is still expected to evaluate the degraded condition to determine what, if any, corrective action needs to be taken. However, if the pipe is degrading rapidly, then its impact on the plant risk would likely exceed the risk acceptance criteria by the end of these M years, and accordingly, the piping has to be repaired as soon as possible. The terms such as "slow" or "rapid" are used to illustrate the impact of the rate of degradation on the plant risk, and are not defined specifically. The results presented in Table 7.3 were carried out for a range of rates of degradation, and these results demonstrate this impact. Rates of degradation for buried piping are discussed in Sections 3.4, 7.2.1, and 7.3.1.

Therefore, to develop risk-informed acceptance criteria corresponding to different levels of observed degradation of the buried piping, the impact of this degradation on plant risk as a function of time must be calculated. Sections 6.4 through 6.6 derive the methods for estimating this risk.

To develop the methods for assessing the impact of degrading buried piping on plant risk, the following considerations were made:

1. At the top level, there are two technical aspects for evaluating the contribution of degraded buried piping to ΔCDP. One is determining this contribution to ΔCDP as a function of time, and the other is assessing it as a function of space. The first is the subject of this section. In simple terms, the second one is assessing a degradation rate (and a ΔCDP) as a function of the pipe's length because different segments of the pipe may degrade at different rates. Since spatial dependency is not considered, it is assumed that the rate of degradation is constant throughout the pipe. This is considered acceptable if the maximum degradation rate along the pipe is used for the assessment.

2. The approach described in this report applies to steady-state stresses, and not to transient ones. Generally, buried piping is not subjected to transient loads, and if it is, then the piping would need to be evaluated on a case-by-case basis.

3. As mentioned at the beginning of this section, if an inspection reveals that a buried pipe has not failed, but it has degraded, the regulatory question that arises is: "does the pipe have to be repaired immediately, or is it acceptable for the plant to continue operation?" To answer this question it is noted that since at the time of the inspection the pipe has not failed, the probability of failure of the pipe at any time before and at the time of inspection is zero. Accordingly, the risk associated with the degrading pipe for any time before the time of inspection evaluated at the time of inspection is zero. Thus, the risk should be controlled from the time of inspection, and the approach to control the risk is that the estimated increase in projected risk from this time over a period of M years is acceptably small. Therefore, evaluating the increase in projected risk associated with the degrading pipe from the time of inspection is the relevant measure of risk to assess the acceptability of continued operation of the buried pipe. The methods developed in this section account for the fact that the buried pipe is degraded at the time of inspection, even though the pipe may still meet the conditions of the current licensing basis. If the pipe does not meet the current licensing basis, the licensee is required to take appropriate action (e.g., repair or replacement) to bring the pipe back into compliance.

4. The methods developed in this section use the level-1 probabilistic risk assessment (PRA) of internal events during full-power operation of each selected plant. Accordingly, the increase in core damage probability (ΔCDP) is the resulting measure of risk. Therefore, for this study, the measure of the impact of degraded buried piping on the risk of an NPP is the ΔCDP due to internal events during full-power operation. Accordingly, the evaluations in this section do not include the impact of degraded buried piping for other modes of operation, other levels of PRA, and other challenges (such as external events). The impact on plant risk of degrading buried piping systems that fall into these categories should be reviewed in light of the discussion presented in Section 6.2.1.

The contribution of degraded buried piping to the risk of an NPP typically is not quantified in conventional Probabilistic Risk Assessments (PRAs). Hence, this contribution is not included in the risk due to internal events quantified in a conventional PRA, or in Individual Plant Examination (IPE) submittals.

For the purpose of evaluating the contribution to ΔCDP of the failure of a system with buried piping, the systems in an NPP can be classified into one of two main categories:

1. the system's failure causes an initiating event, or

2. the system's failure does not cause an initiating event, but is required to mitigate an initiating event.

An initiating event (IE) is an occurrence that causes a reactor trip. The second category can be subdivided into the following subcategories:

2.1 The buried pipe is subjected to internal pressure at all times. After the pipe fails, it may be replaced (or repaired) subsequent to the shutdown of the plant or while the plant is operating. Thus, two cases are identified as follows:

2.1.a Replacement (or repair) is done when the plant is shut down immediately after the pipe breaks.

2.1.b Replacement (or repair) is done while the plant is operating.

2.2 The buried pipe is not subjected to internal pressure at all times. The pipe will not fail when not subjected to internal pressure. However, the pipe may fail after a true demand (initiating event) or after a test demand (demand while the system is being tested), since the pipe is under pressure in these circumstances.

The contribution from potential failures after test demands to the ΔCDP comes from the pipe failing on a test demand, the plant continuing to operate while the pipe is being repaired, and a true demand occurring while the pipe is being repaired. It is considered that this contribution is negligible because the likelihood of the plant continuing to operate, and a true demand occurring before the repair of the pipe is completed, is expected to be small.

The contributions to the ΔCDP from potential failures after true and test demands should in principle be added. However, since the contribution from potential failures after test demands is considered negligible, only the contribution to the ΔCDP from true demands is considered in this study. Accordingly, one case is identified as follows:

2.2.a The pipe is not subjected to internal pressure at all times and its failure does not cause an IE. Only the contribution to the ΔCDP from potential failures after true demands is considered.

Hence, the first step in evaluating the contribution to ΔCDP from a system with buried piping is to define the category that the system falls into. Figure 6.2 presents a roadmap that can be used to select the method to be used for each category. The discussion in the rest of this section provides the basis and details for using each method.

The buried piping systems of the five nuclear plants selected were reviewed to identify the category that each of their systems falls into. The review indicated that all the systems of these five plants fall into two categories:

<u>Category 1</u>: The system to which the buried pipe belongs is normally operating, and its failure causes an IE. An example for McGuire 1 and 2 is the Service Water (SW) system.

<u>Category 2.2.a</u>: The system to which the buried pipe belongs is not subjected to internal pressure at all times, and its failure does not cause an IE. An example for North Anna 1 and 2 is the Residual Heat Removal (RHR) system.

Therefore, for the five plants, methods were developed to assess the contribution to ΔCDP from a system belonging to each of these two categories; they are described in Sections 6.5 and 6.6. Since systems (with buried piping) belonging to other plants may fall into one of the other categories (other than Category 1 and Category 2.2.a), these other categories are discussed next.

Category 2.1.a. The piping system is normally operating, so it is subjected to internal pressure at all times. The plant is shut down immediately when the pipe breaks and replacement (or repair) is done while the plant is shut down. For this case, the risk during power operation, is negligible, since the likelihood of an initiating event occurring during the process of shutting down is very small. One might have to consider that the shutdown process could, for example, cause a loss of offsite power event, but the likelihood that a controlled shutdown would challenge the grid stability is small. Thus, the risk due to pipe degradation for this case is neglected.

Category 2.1.b. The piping system is normally operating, so it is subjected to internal pressure at all times. After the pipe fails, it may be replaced (or repaired) while the plant is operating. The contribution to the ΔCDP comes from the possibility of an initiating event occurring during the time the pipe is being repaired and is unavailable. This contribution to the ΔCDP would have to be evaluated on a case-by-case basis.

The methods for estimating the risk associated with degrading buried piping presented in Sections 6.5 and 6.6 use the conditional probability that the pipe will fail by M years after the time of inspection, given that the pipe has not failed at the time of inspection. Section 6.4 presents a derivation of this probability, and an approach to evaluate it.

6.4 Derivation of the Conditional Probability of Failure of a Buried Pipe

If a buried pipe is subjected to some type of degradation mechanism(s), it will degrade as a function of time. Since it is known that the pipe has not failed at the time of inspection, it is necessary to estimate the (conditional) probability that the pipe will fail by M years after the time of inspection, given that it has not failed at the time of inspection.

Starting with the general expression from probability theory for the conditional probability of two events A and B:

$$P(A/B) = \frac{P(B/A)P(A)}{P(B)} \tag{6.5}$$

where P(A / B) is the probability of A given B has already occurred.

Let

A = pipe failed by time t

B = pipe not failed by time t_0

t_0 is the time of inspection (after the start of life of the buried pipe). The time t is any time after the time of inspection, so $t > t_0$. To simplify the discussion that follows, the time of inspection, t_0, is set to zero. Accordingly, $t > 0$; see figure 6.1.

Then, if F(t) is the cumulative failure distribution of the time-to-failure of the pipe,

$$P(A) = P(\text{pipe failed by time t}) = F(t) \tag{6.6}$$

$$P(B) = P(\text{pipe not failed by time = 0}) = 1 - F(0) \tag{6.7}$$

To derive P(B / A) = P(pipe not failed by time = 0 / pipe failed by time t), it is noted that

$$P(\text{pipe failed by time = 0 / pipe failed by time t}) = F(0) / F(t) \tag{6.8}$$

$$P(\text{pipe not failed by time = 0 / pipe failed by time t}) = 1 - [F(0) / F(t)] \tag{6.9}$$

Hence,

$$P(B / A) = P(\text{pipe not failed by time = 0 / pipe failed by time t}) = 1 - [F(0) / F(t)] \tag{6.10}$$

Inserting (6.6), (6.7), and (6.10) into (6.5):

$$CP(t) = \frac{F(t) - F(0)}{1 - F(0)} \tag{6.11}$$

where CP(t) is the conditional probability that the pipe failed by time t, given it has not failed at time = 0.

For a plant that has operated M years after the time of inspection, the conditional probability that the pipe failed by the end of the Mth year, given it has not failed at the time of inspection (t = 0) is then given by:

$$CP(M) = \frac{F(M) - F(0)}{1 - F(0)} \tag{6.12}$$

A derivation of the cumulative failure distribution of the time-to-failure of a buried pipe, F(t), and an approach to estimate the terms F(0) and F(M) in equation (6.12) are presented next.

The cumulative failure distribution of the time-to-failure of a buried pipe, F(t), is defined in terms of the fragility curves presented in Section 5. A fragility curve is the cumulative distribution function of the probability of failure for a given value of input load, given by

$$F(t) = P(\text{strength} \leq \text{load}) \tag{6.13}$$

For this study, it was assumed that failure occurs when the hoop stress in the pipe is greater or equal to the tensile strength of the pipe material. Accordingly,

$$F(t) = P[\text{pipe's tensile strength} \leq PD(t)/2w(t)] \tag{6.14}$$

where

P = pipe's internal pressure
D(t) = time-dependent pipe's average diameter
w(t) = time-dependent pipe's wall thickness

Section 5 calculates the time-dependent average pipe diameter, D(t), assuming that the inside diameter of the undegraded pipe is constant and the outside diameter of the pipe is reduced due to the degradation. Section 5 indicates that the assumption of whether the reduction in wall thickness occurs on the inside or outside of the pipe has a negligible effect on the final results.

Section 5 also assumes that the pipe's internal pressure equals the maximum design pressure. Accordingly, for a given pipe size, the maximum design pressure is a constant. In addition, the time-dependent pipe's average diameter, D(t), is a function of the time-dependent pipe's wall thickness, w(t). Therefore, equation (6.14) shows that a fragility curve (the cumulative distribution function of the probability of failure) is a function of w(t), which can be written as F(w(t)). For this reason, the fragility curves can be derived and presented as a function of the pipe's wall thickness; this is the approach used in Section 5. Figure 5.13 presents these fragility curves for several pipe sizes[1].

The terms F(0) and F(M) in equation (6.12) are obtained as follows. F(0) is the value of a fragility curve at the wall thickness equal to the observed wall thickness at the time of inspection, w(0). In other words, F(0) is given by the fragility curves presented in Section 5 as F(w(0)). F(0) represents the probability of failure of the pipe given knowledge of the wall thickness at the time of inspection, but, of course, not given the knowledge that the pipe is not in a failed condition at the time of inspection.

F(M) is the value of a fragility curve at the wall thickness equal to the estimated wall thickness when the plant has operated for M years after the time of inspection, w(M). Hence, to obtain F(w(M)), it is necessary to estimate the wall thickness by this time, w(M). This thickness can be assessed using the thickness observed at the time of inspection (t = 0) and the rate of degradation for the piping. This rate may be considered to be constant, r, or a function of time, r(t). In the general case in which the rate of degradation is a function of time, the pipe's wall thickness after M years of operation from the time of inspection is given by

$$w(M) = w(0) - \sum_{i=1}^{M} r(i) \qquad (6.15)$$

where r(i) is the rate of degradation (per year) during year i, and the summation is carried out in intervals of one year.

The wall's thickness by the end of the Mth year can then be calculated using w(M) from equation (6.15), and the probability that the buried pipe failed by this time, F(w(M)), can be obtained from the corresponding fragility curve.

Sections 6.5 and 6.6 describe methods to assess the contribution to ΔCDP from a system having buried piping and belonging to Category 1 (normally operating, and its failure causes an

[1] The fragility curves in Figure 5.13 are actually presented as a function of the percentage of wall loss. This percentage obviously can be derived from the pipe's original wall thickness and the remaining wall thickness, w(t).

IE) and to Category 2.2.a (normally in standby, its failure does not cause an IE, and the system fails after a true demand), respectively. The methods estimate the contribution to ΔCDP due to degrading buried piping, and are applicable to those cases where an inspection shows that a pipe has not failed, but has degraded.

6.5 A System is Normally Operating and its Failure Causes an Initiating Event

Since the system is normally operating, the piping is subjected to internal pressure. The failure of the system causes an initiating event. A typical example of this kind of system in a pressurized water reactor (PWR) is the component cooling water (CCW) that supplies cooling, directly or indirectly, to the motor and seals of the reactor coolant pumps. Accordingly, if the CCW is lost (failed), the initiating event "loss of CCW" occurs, and the mitigating systems that it supports also would be unavailable, unless the CCW is recovered or another recovery action is completed.

A method was developed to estimate the contribution to ΔCDP due to degraded buried piping for a system in Category 1. In other words, the system is normally operating, the piping is subjected to internal pressure, and the failure of the system causes an initiating event. If the pipe was inspected at time $t = 0$ and has not failed at this time, but is considered to be subjected to degradation mechanisms, then it can be expected to continue degrading over the following years.

The increase in core damage probability (ΔCDP) over M years of operation after the time of the inspection due to the degradation of the buried piping can be expressed as:

$$\Delta CDP = CP(M) \times CCDP \tag{6.16}$$

where

CP(M) = conditional probability of failure of the system (piping) between the time of an inspection ($t = 0$) and the end of year M, given that the system has not failed at the time of the inspection. It is given by equation (6.12).

CCDP is the conditional CDP given the loss of the system has occurred. In the example of the CCW, this is the probability that core damage will occur given the loss of the CCW.

Equation (6.16) can be solved for different values of M, the number of years from the time of inspection to some future time, to obtain the ΔCDP over this interval.

Assessing the contribution to ΔCDP for those systems in Category 1 (Section 6.5) and Category 2.2.a (Section 6.6) requires calculating the following parameters: the conditional CDP given the loss of the system (CCDP), the CDF given that a buried pipe fails, and the CDF given that a buried pipe does not fail. The following considerations apply to these evaluations:

1. They were made using the Standardized Plant Analysis Risk (SPAR) models version 3.xx that were available at the beginning of March 2004 for the selected NPPs. Version 3.xx corresponds to SPAR model versions 3.01 and 3.02 depending upon the particular plant being evaluated. These models are full-power, level-1 PRA models for internal events. They have some basic capabilities that previous versions did not have, such as more support systems and an expanded number of event trees.

2. The calculations using the SPAR models were carried out with the SAPHIRE computer code version 7. The cutoff value for all evaluations was 8.8E-12/year (1.0E-15/hour). It was used in documenting the SPAR models and is considered adequate for the evaluations.

3. Since detailed information about the layout of a buried piping system was unavailable, it was assumed that when the piping failed the complete system was unavailable.

4. The following systems were not evaluated because they were not included in the SPAR 3.xx model of their corresponding plant: Fire Protection of McGuire 1 and 2, Fire Protection of North Anna 1 and 2, Fire Protection and Containment Spray of Surry 1 & 2, and Standby Gas Treatment of Hatch 1 & 2. It appears that the reason that these systems are not included in the SPAR 3.xx models of these plants is that they are mainly used for events other than level-1 internal events, such as fire events or level-2 events.

5. It is not known whether the Service Water and the Turbine Generator Cooling Water of the Keowee's hydro units of the Oconee nuclear plant are normally operating (with internal pressure), or if they are kept in standby. On the other hand, these systems are unique to Oconee's hydro units, so the findings are not expected to be applicable to any other nuclear plant. For this reason, they were not evaluated at this time.

The CCDPs for the systems in Category 1 were evaluated using the SPAR 3.xx model of the selected NPPs. Table 6.2 presents the results of these evaluations.

Equation (6.16) shows that the larger the CCDP, the larger is the contribution to ΔCDP. Hence, for the five plants selected in this study, using the system with the largest CCDP value leads to a maximum ΔCDP. From Table 6.2, the largest value of the CCDP is 3.4E-2, which corresponds to the Service Water System of McGuire. A generic evaluation of the contribution to ΔCDP over M years of operation after the time of inspection can be obtained by substituting this value for CCDP in equation (6.16), which leads to:

$$\Delta CDP = (3.4E\text{-}2) \times CP(M) \tag{6.17}$$

Therefore, a generic calculation of the ΔCDP over M years of operation after the time of inspection, for Category 1 type systems belonging to the five plants, can be carried out using equations (6.17) and (6.12).

Equations (6.4), (6.17), and (6.12) can be solved in an incremental way for different values of M until the risk acceptance criterion, i.e., equation (6.4), is satisfied. Subsection 7.1.1 describes this process for the systems in Category 1. In this way, these equations are used to assess whether it is acceptable for a plant to operate for M years after the time of inspection. The results presented in Section 7 for the systems in this Category were obtained by solving these equations.

Equation (6.12) is solved by using a degradation rate appropriate to this Category of system where the pipe is subjected to internal pressure.

Equation (6.17) was developed to carry out a generic evaluation because it uses the largest CCDP of all Category 1 piping systems from the 5 plants selected in this study.

6.6 A System is Normally in Standby and its Failure Does Not Cause an Initiating Event

This section describes a method to estimate the contribution to ΔCDP due to degrading buried piping for a system in Category 2.2.a. In other words, the system is normally in standby, and the failure of the system does not cause an initiating event during power operation. A typical example is the Residual Heat Removal (RHR) system.

If a buried pipe was inspected at time $t = 0$ and has not failed at this time, but is considered to be subjected to degradation mechanisms, then it can be expected to continue to degrade over the following years. If the plant is operated M years after the time of inspection, then the method developed below determines the increase in projected risk over this period by calculating the ΔCDP that results from operating this plant during the M years.

The piping is not subjected to internal pressure during power operation, but only on a system demand, which may be either a *test demand* or a *true system demand*. If the pipe fails on a *test demand*, then the contribution to ΔCDP comes from the possibility of an initiating event requiring the system's operation while the pipe is being repaired, provided the plant is not shut down to repair the system. The contribution to ΔCDP of the pipe failures discovered during *true system demands* depends on the frequency of both true system demands and test demands. This is because if the pipe fails on a *true demand,* the system fails, and if the pipe fails on a test demand, the system will be unavailable while the pipe is being repaired, as long as the plant keeps operating during this repair.

A review of the specific systems to be evaluated (for the five NPPs selected) indicated that if any of them fails during operation after a test, then the plant will not continue to operate, i.e., it will be shut down. Hence, the ΔCDP for these systems is due to failures after "true" demands.

To derive an expression for calculating the change in CDP (ΔCDP), let λ_i be the initiating event frequency for initiating events of type i. For the pipe to fail on a true system demand of type i, in the interval (t, t+dt), a true system demand of type i must occur (with probability $\lambda_i\,dt$); the pipe must not have failed before t (represented by the reliability of the pipe, R(t)), and the pipe must fail on the true system demand at time t (probability CP(t)). Then, the probability that the pipe fails in the interval (t, t+dt) given initiating event i is given by $\lambda_i\,CP(t)\,R(t)\,dt$.

To obtain the contribution of pipe failures on true system demands to the core damage probability (ΔCDP), this expression ($\lambda_i\,CP(t)\,R(t)\,dt$) is multiplied by [P(CD / IE_i and pipe fails) – P(CD / IE_i and pipe does not fail)], summed over all initiating events, and then integrated from the time of the inspection (time = 0) to the end of M years (time = M), as follows:

$$\Delta CDP = \int_{t=0}^{t=M} \sum_i \lambda_i [P(CD/IE_i \text{ and pipe fails}) - P(CD/IE_i \text{ and pipe does not fail})] CP(t) R(t)\,dt \qquad (6.18)$$

where P(CD / IE_i and pipe fails) is the probability of core damage given that the initiating event i occurred, and the pipe failed. P(CD / IE_i and pipe does not fail) is defined similarly.

The contribution of pipe failures on true system demands to the core damage probability (ΔCDP) is obtained by summing all initiating events in equation (6.18):

$$\Delta CDP = \int_{t=0}^{t=M} CP(t)R(t)[CDF(\text{given pipe fails}) - CDF(\text{given pipe does not fail})]dt \qquad (6.19)$$

To calculate the probability the pipe has not failed before time t (the reliability R(t) in equation (6.19)), it is noted that the pipe can fail from either true system demands or test demands. Denote the frequency of total demands by λ_{total},

$$\lambda_{total} = \sum_i \lambda_i + \lambda_{test} \qquad (6.20)$$

where λ_{test} is the test frequency. The reliability decreases in time because of pipe failures that occur according to:

$$\frac{dR(t)}{dt} = -\lambda_{total} CP(t)R(t) \qquad (6.21)$$

The solution of differential equation (6.21) is:

$$R(t) = \exp\left[-\lambda_{total} \int_{t=0}^{t=M} CP(t)dt\right] \qquad (6.22)$$

The degradation acceptance criteria presented in Section 7 indicates that a buried pipe should not be allowed to continue operating if the degradation at the time of inspection is more than approximately 45% of the original nominal pipe wall thickness. The fragility curves in Figure 5.13 show that a buried pipe of any size with a 45% wall loss has a probability of failure of less than 1E-10, and a pipe with a percentage wall loss less than 45% has a smaller probability of failure. The range of wall loss of 45% or less is named in this study the "range of wall loss of interest" because a buried pipe with a degradation of about 45% or more of wall loss would not be allowed to continue operating.

CP(t) in equation (6.22) is given by equation (6.11). CP(t) is about 1E-10 or less for the range of wall loss of interest. Since CP(t) is very small for the range of wall loss of interest, equation (6.22) shows that R(t) is very close to 1. In addition, the terms CDF(given pipe fails) and CDF(given pipe does not fail) in equation (6.19) are considered constant over time. According to these considerations, equation (6.19) becomes

$$\Delta CDP = [CDF(\text{given pipe fails}) - CDF(\text{given pipe does not fail})] \int_{t=0}^{t=M} CP(t)dt \qquad (6.23)$$

The solution of equation (6.23) can be approximated by numerically solving the integral in increments of 1 year, as follows:

$$\Delta CDP = [CDF(\text{given pipe fails}) - CDF(\text{given pipe does not fail})] \sum_{i=1}^{M} CP(i) \qquad (6.24)$$

where CP(i) is the conditional probability of pipe failure between the time of inspection and the end of year i. CP(i) is given by equation (6.11).

Since R(t) was approximated to 1, the effect of test demands on reducing the contribution of pipe failures to the core damage probability has conservatively been omitted. This conservatism is considered negligible.

Equation (6.24) can then be solved for different values of M, the number of years from the time of inspection to some future time, to obtain the ΔCDP over this interval.

Equation (6.24) shows that the larger the difference in the expression

[CDF(given pipe fails) - CDF(given pipe does not fail)],

the larger the contribution to ΔCDP. A generic evaluation of the ΔCDP after M years of operation can be obtained by using the largest difference [CDF(given pipe fails) - CDF(given pipe does not fail)] from the systems of this type belonging to the five plants. Values for the CDF(given pipe fails) and CDF(given pipe does not fail) were evaluated using the SPAR 3.xx model of the selected NPPs, according to the considerations described in Section 6.5. Table 6.3 provides the results of these evaluations. From this table, the largest difference [CDF(given pipe fails) - CDF(given pipe does not fail)] is 8.5E-3 / year, corresponding to Surry's Emergency Feedwater. A generic evaluation of the contribution to ΔCDP can be obtained using this value in equation (6.24) as follows:

$$\Delta \mathrm{CDP} = (8.5\mathrm{E}\text{-}3 \text{ / year}) \sum_{i=1}^{M} \mathrm{CP}(i) \qquad (6.25)$$

Therefore, a generic calculation of the ΔCDP over M years of operation after the time of inspection, for the systems of this type belonging to the five plants, can be carried out using equations (6.25) and (6.11).

Equations (6.4), (6.25), and (6.11) can be solved in an incremental way for different values of M until the risk acceptance criterion, i.e., equation (6.4), is satisfied. Subsection 7.1.2 describes this process for the systems in Category 2.2.a. In this way, these equations are used to assess whether it is acceptable for a plant to operate for M years after the time of inspection. The results presented in Section 7 for the systems in this Category were obtained by solving these equations.

Equation (6.11) is solved by using a degradation rate appropriate to this type of system where the pipe may not be under pressure, and there is no flow in the pipe.

Equation (6.25) yields a generic evaluation because it uses the largest difference of the expression

[CDF(given pipe fails) - CDF(given pipe does not fail)]

among all of the systems of this type from the five plants selected in this study.

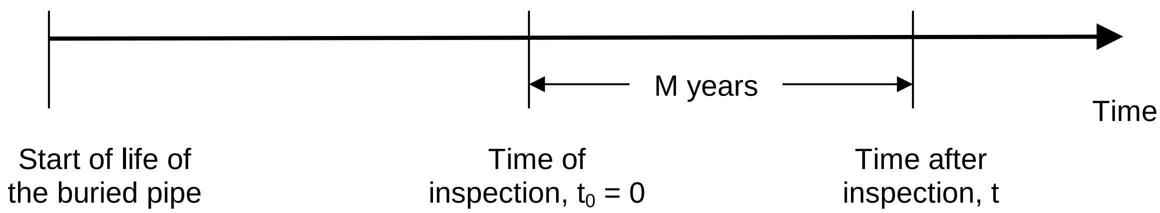


Figure 6.1 Relevant Events From the Start of Life of a Buried Pipe

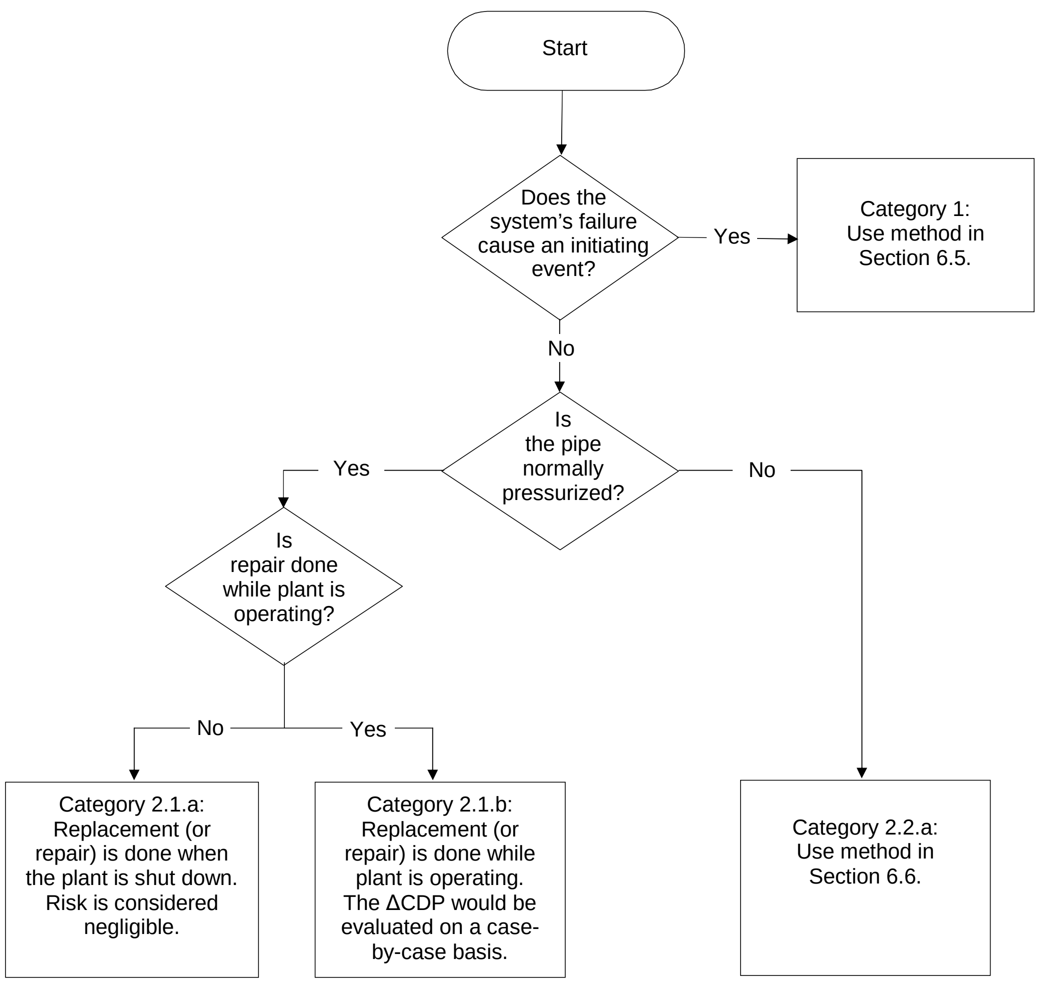


Figure 6.2 Roadmap For Selection of the Method to be Used For Each Type of System

Table 6.1 Buried Piping Systems and Descriptions of Twelve NPPs That Submitted Their License Renewal Application

Plant	Number of Buried Piping Systems	Reactor Type	NSSS	Containment	Architect/ Engineer	Location
Surry 1 & 2	8	PWR	W	Reinf. Conc.	S&W	Virginia
Edwin I. Hatch 1& 2	7	BWR	GE	Steel MK I	Bechtel	Georgia
North Anna 1 & 2	7	PWR	W	Reinf. Conc.	S&W	Virginia
Peach Bottom 2 & 3	5	BWR	GE	Steel MK I	Bechtel	Pennsylvania
McGuire 1 & 2	5	PWR	W	Steel (Ice Cond.)	Duke	N. Carolina
Catawba 1 & 2	5	PWR	W	Steel (Ice Cond.)	Duke	S. Carolina
Oconee 1, 2, & 3	5	PWR	B&W	Prestr. Conc.	D&B	S. Carolina
St. Lucie 1 & 2	4	PWR	CE	Steel	Ebasco	Florida
V. C. Summer	4	PWR	W	Prestr. Conc.	Gilbert	S. Carolina
Calvert Cliffs 1 & 2	3	PWR	CE	Prestr. Conc.	Bechtel	Maryland
Turkey Point 3 & 4	3	PWR	W	Prestr. Conc.	Bechtel	Florida
Arkansas Nuclear One 1	2	PWR	B&W	Prestr. Conc.	Bechtel	Arkansas

GE = General Electric; W = Westinghouse; B&W = Babcock & Wilcox; CE = Combustion Engineering
S&W = Stone & Webster; D&B = Duke & Bechtel

Table 6.2 Conditional Core Damage Probabilities
Used in the Methodology for Category 1 Buried Piping Systems

Plant	System	CCDP
McGuire 1 and 2		
	Service Water (SW)	3.4E-2
	Condenser Circulating Water(2)	6.4E-6
North Anna 1 and 2		
	Service Water	1.6E-2
Oconee 1, 2, and 3		
	Condenser Circulating Water(3)	2.7E-3
	High Pressure Service Water(3)	6.1E-4
Surry 1 & 2		
	Service Water (1)	3.3E-3
	Condensate(2)	3.2E-6
Hatch 1 & 2		
	Service Water (SW)	7.9E-3

Notes:

1. According to Surry's Individual Plant Examination (IPE), Service Water provides cooling to the control room and relay room air conditioning unit chiller condensers. The emergency switchgear room cooling is dependent upon these chillers. Hence, loss of Service Water causes a loss of chilled water. This loss is not modeled in the SPAR 3.xx model, so the notebook for the Significance Determination Process (SDP) of Surry (Azarm, 2003) was used to estimate this CCDP. This is a unique utilization of an SDP notebook.

2. Loss of this system was considered to cause a transient with loss of main feedwater.

3. "Loss of Condenser Circulating Water" and "Loss of High Pressure Service Water" are not included as initiating events in Oconee's SPAR 3.xx model or in Oconee's SDP notebook. It was assumed that either of these losses causes a "Loss of Low Pressure Service Water."

Table 6.3 Conditional Core Damage Frequencies
Used in the Methodology for Category 2.2.a Buried Piping Systems

Plant	System	CDF [given pipe fails] (per year)	CDF [given pipe does not fail] (per year)
McGuire 1 and 2			
	Diesel Fuel Oil(1)	9.2E-4	1.1E-5
North Anna 1 and 2			
	Diesel Fuel Oil(1)	6.4E-3	2.2E-5
	Safety Injection(2, 4)	1.6E-3	
	Recirculation Spray(2)	1.2E-4	
	RHR (2)	2.9E-5	
	Containment Spray(2)	2.7E-5	
Oconee 1, 2, and 3			
	SSF DG Fuel Oil(3)	1.4E-5	1.2E-5
Surry 1 & 2			
	Emergency Feedwater	8.5E-3	1.4E-5
	Diesel Fuel Oil(1)	4.4E-3	
	Safety Injection(4)	1.3E-3	
Hatch 1 & 2			
	Diesel Fuel Oil(1)	2.9E-3	4.3E-5
	HPCI(6)	1.3E-4	
	RCIC(7)	9.0E-5	
	Fire Protection(5)	4.3E-5	

Notes:

1. Failure of Diesel Fuel Oil was assumed to cause the unrecoverable loss of all emergency diesel generators (EDGs).

2. After the failure of the Containment Spray, Recirculation Spray, RHR, and Safety Injection systems, their pumps were considered to be unavailable.

3. The failure of the Standby Shutdown Facility's (SSF's) Diesel Generator Fuel Oil was considered to cause the unavailability of the SSF Diesel Generator.

4. For the failure of Safety Injection, all high- and low-head safety injection (HHSI and LHSI) pumps were considered to be lost.

5. For failure of Fire Protection at Hatch, the firewater injection was considered not available.

6. The failure of the High-Pressure Coolant Injection (HPCI) was modeled as the loss of the HPCI pump.

7. The failure of the Reactor Core Isolation Cooling (RCIC) was modeled as the loss of the RCIC pump.

7 DEGRADATION ACCEPTANCE CRITERIA

The risk-informed degradation acceptance criteria (DAC) were developed by identifying the level of degradation of a buried pipe that would potentially have a significant effect on plant risk. The approach used to develop the DAC is based on the fragility curves calculated in Section 5.3, definition of acceptable risk presented in Section 6.2, and the methodology for estimating the risk associated with degrading buried pipe described in Sections 6.3 through 6.6. The DAC developed below consider the effects of degradation after the time of inspection and the impact that corrosion allowance, if provided for in the original design, may have on the final results.

7.1 Calculation of Acceptable Wall Loss

Sections 7.1.1 and 7.1.2 describe the methodology used to develop the acceptable wall loss for generalized pipe wall degradation which may occur on the outside or inside surface of a buried pipe. The applicability of these results to localized loss of material/pitting is discussed separately in Section 7.1.3.

For any pipe size and thickness, fragility curves can be developed as described in Section 5.3. The fragility curves for nominal pipe sizes[*] 2 through 42 in. (5.08 through 107 cm) were calculated and presented in Figure 5.13. The fragility curves provide the probability of failure versus percentage wall loss for SA-106 carbon steel pipe under design pressure loading. Standard schedule pipe was utilized for all pipe sizes except 107 cm (42 in.) pipe, which used a pipe thickness of 1.43 cm (0.562 in.) as explained in Section 5.3.

As described in Section 6.3, each buried piping system in the five selected plants used in this study can be categorized as either a system that is normally operating and whose failure causes an initiating event (Category 1), or a system that is normally in standby and whose failure does not cause an initiating event (Category 2.2.a). The DAC were developed separately for Category 1 and Category 2.2.a buried piping systems as described below in Sections 7.1.1 and 7.1.2. The evaluation approach for buried piping of systems that might fall into other categories are discussed in Section 6.3.

7.1.1 Category 1 Buried Piping System

For a buried piping system that is normally operating and whose failure causes an initiating event, the methodology described in Section 6.5 was utilized to determine the maximum permissible wall loss. As shown in Section 6.5, the following equation can be used to calculate the increase in core damage probability (ΔCDP) for a Category 1 buried piping system:

$$\Delta CDP = (3.4E\text{-}2) \times CP(M) \tag{7.1}$$

As discussed in Section 6.5, the value of 3.4E-2 corresponds to the envelope of the conditional core damage probability (CCDP) for all buried piping systems from the five plants. CP(M) is the conditional probability of failure of the piping by year M after the time of inspection and is given by:

[*] Nominal pipe size corresponds to a standardized outside diameter (O.D.) as defined in ASME B36.10M-2004. For nominal pipe sizes 14 inches and above, the actual O.D. is equal to the nominal pipe size. For nominal pipe sizes 12 in. and smaller, the actual O.D. is greater than the nominal pipe size, (e.g., 2 inch nominal pipe actually corresponds to 2.375 in. O.D.).

$$CP(M) = \frac{F(M) - F(0)}{1 - F(0)} \qquad (7.2)$$

M is the number of years after the time of inspection and F(M) is the cumulative failure distribution of the time-to-failure of the pipe at time M (i.e., fragility value from the fragility curves). In this equation, F(0) represents the fragility of the pipe at time = 0 (time of inspection).

A spreadsheet calculation was performed using these equations to create a table which solves for ΔCDP progressively year by year, for a given degradation rate and for various observed wall loss percentages at the time of inspection. Table 7.1 presents a sample table created for a 40.6 cm (16 in.) diameter pipe which is degrading at a rate of 0.254 mm/year (0.01 in./year). These tables were also calculated at other degradation rates of 0.0254 and 2.54 mm/year (0.001 and 0.100 in./year) to cover the maximum expected range of degradation rates (see Section 3.4). Table 7.1 shows the calculation of the various parameters needed to solve equations (7.1) and (7.2). The parameters used in Table 7.1 are explained in the footnotes to the table.

For a given degradation rate, the ΔCDP can be solved for increasing values of time (the number of years of operation after the time of inspection). As described in Section 6.2.2, the criterion for assessing the acceptability of risk significance is that the ΔCDP of the system is less than or equal to the acceptable increase in core damage probability identified as $\Delta CDP_{Acceptable}$ (hereinafter, referred to as ΔCDP_A). At each year, the plant's calculated ΔCDP can be compared to the ΔCDP_A. When the plant's calculated ΔCDP reaches ΔCDP_A, that defines the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. This becomes the degradation acceptance criterion in terms of risk.

Using Table 7.1 as an example, for an observed wall loss at the time of inspection equal to 60%, the ΔCDP reaches ΔCDP_A (see shaded boxes) between years 4 and 5. This corresponds to an estimated percentage wall loss (EPWL) equal to 71.5%. The EPWL entries in the table were calculated using the observed wall loss at the time of inspection and adding the additional increment of wall loss (each year) caused by the degradation rate. Considering the range of percent wall losses after the time of inspection of 10% through 70% (Table 7.1 shows a partial tabulation of 10, 20, 50, & 60%), the acceptable EPWL varies between 71.5% and 73.5%. The evaluation considered EPWL up to 70% because at 70% or higher, the number of years to reach risk significance is less than one, which means that the buried pipe needs to be repaired immediately. Since the variation in EPWL from 71.5% to 73.5% is relatively small, the minimum acceptable EPWL value within each pipe size (71.5% in this case) was utilized to obtain the acceptable percentage wall loss. Additional calculations were also performed at degradation rates of 0.0254 and 2.54 mm/year (0.001 and 0.100 inches/year). For this example, the 2.54 mm/year (0.100 in./year) degradation rate resulted in a slightly lower value of 69.2% (compared to the 71.5%). Since the differences in the acceptable percentage wall loss corresponding to varying degradation rates were small, the minimum values for acceptable percentage wall losses were utilized for the degradation acceptance criteria. The resulting acceptable percentage wall loss as a function of pipe size (enveloped across varying observed wall loss percentages and across varying degradation rates), is tabulated below. Using the minimum value of percentage wall loss in the enveloping process provides some additional level of conservatism.

Acceptable Percentage Wall Loss
For Category 1 Buried Piping Systems
(Considering Pressure Loading)

Nominal Pipe Size cm / in.	Acceptable % Wall Loss
5.08 / 2	70.3
10.2 / 4	70.4
20.3 / 8	69.6
40.6 / 16	69.2
61.0 / 24	68.7
76.2 / 30	68.1
107 / 42	69.2

Since the acceptable percentage wall loss was initially determined based on pressure loads alone, an adjustment was made to account for other loads such as soil surcharge load, groundwater, and surface live loads. For each pipe size, the acceptable percentage wall loss listed above was reduced by an amount needed to accommodate these other loads. To do this, an "acceptable risk-based stress level" in the pipe corresponding to the acceptable percentage wall loss was developed. The acceptable risk-based stress level in the pipe ($\sigma_{\text{acceptable risk}}$) is given by:

$$\sigma_{\text{acceptable risk}} = \frac{PD_{\text{acceptable}}}{2t_{\text{acceptable}}} \tag{7.3}$$

where

P = design pressure
$t_{\text{acceptable}}$ = thickness at the acceptable % wall loss based on pressure alone (obtained from the above table
$D_{\text{acceptable}}$ = average diameter at the acceptable % wall loss based on pressure alone (calculated using $t_{\text{acceptable}}$)

The contribution to pipe stress from all applicable loads (pressure and other loads) must not exceed $\sigma_{\text{acceptable risk}}$, which can be expressed as follows:

$$\sigma_{\text{pressure}} + \sigma_{\text{other loads}} \leq \sigma_{\text{acceptable risk}} \tag{7.4}$$

$\sigma_{\text{other loads}}$ is the stress level corresponding to other loads as described above. For this study, a reasonable value for expected pipe circumferential stress due to other loads (surcharge, groundwater, and live load) is 50% of the pipe material yield strength. American Lifelines Alliance Report (2001) recommends this criterion be used for through-wall bending stress from earth loads (static, live, surface impact). Following this approach, 50% of the yield strength results in 121 MPa (17,500 psi). The calculations described in Section 5.1 for the other loads satisfy this recommendation since they used 103 MPa (15,000 psi) as an upper limit. Using 121 MPa (17,500 psi) for $\sigma_{\text{other loads}}$ is slightly more conservative. Therefore,

$$\sigma_{\text{other loads}} = 121\,\text{MPa (17,500 psi)} \tag{7.5}$$

σ_{pressure} is the stress corresponding to the pressure loading when other loads are present and is given by:

$$\sigma_{\text{pressure}} = \frac{PD_{\text{ave using t min}}}{2t_{\text{min}}} \tag{7.6}$$

Substituting equations (7.3), (7.5), and (7.6) into equation (7.4), the variable t_{min} can be solved. The variable t_{min} represents the minimum required pipe wall thickness needed to accommodate both pressure and other loads. The solution of these equations is demonstrated with an example which follows.

Example

This example will consider a 40.6 cm (16 in. pipe), standard schedule (t = 0.953 cm (0.375 in.)), and design pressure equal to 4.34 MPa (630 psi). The acceptable degradation is based on 69.2% wall reduction obtained from the previous table for pressure loading alone. Degradation is assumed to occur at the outside pipe surface. The pipe stress corresponding to an acceptable level of risk is calculated using equation (7.3) as follows (in terms of psi):

$$\sigma_{\text{acceptable risk}} = \frac{(630)(16 - (2 \times .375) + .375(1 - .692))}{2(0.375 \times (1 - .692))} = 41{,}906\text{ psi} \quad (289\text{ MPa})$$

Substituting this value and the other terms into equation (7.4) results in the following (in terms of psi):

$$\frac{PD_{\text{ave using t min}}}{2t_{\text{min}}} + 17{,}500 \le 41{,}906$$

Assuming corrosion occurs on the outside surface, this leads to the following expression (in terms of psi):

$$\frac{P(D_{\text{inner}} + t_{\text{min}})}{2t_{\text{min}}} + 17{,}500 \le 41{,}906$$

This equation is solved for the required t_{min}, which is calculated to be 0.1994 in. (0.506 cm). Therefore, the acceptable percent reduction of the original nominal wall thickness is reduced from 69.2% (if pressure acts alone) to:

$$\frac{0.375 - 0.1994}{0.375}\ \text{x}\,100 = 46.83\%$$ when considering pressure and other loads.

This calculation was repeated for pipe sizes ranging from 5.08 cm to 107 cm (2 in. to 42 in.), assuming standard schedule pipe (except for the 107 cm (42 in. pipe) which requires a thickness of 1.43 cm (0.562 in.) to satisfy the D/t requirement of 80). The results of the calculation for the various pipe sizes are shown below. The percentage wall losses fall into a relatively narrow range between 45.0% and 48.6%.

Acceptable Percentage Wall Loss
For Category 1 Buried Piping Systems
(Considering Pressure and Other Loads)

Nominal Pipe Size cm / in.	Acceptable % Wall Loss
5.08 / 2	47.5
10.2 / 4	48.6
20.3 / 8	47.0
40.6 / 16	46.8
61.0 / 24	45.9
76.2 / 30	45.0
107 / 42	47.7

7.1.2 Category 2.2.a Buried Piping System

For a buried piping system that is normally in standby, and whose failure does not cause an initiating event, the methodology described in Section 6.6 was utilized to determine the maximum permissible wall loss. As shown in Section 6.6, the following equation can be used to calculate the increase in core damage probability (ΔCDP) for a Category 2.2.a buried piping system:

$$\Delta \text{CDP} = (8.5\text{E-}3 \text{ / year}) \sum_{i=1}^{M} \text{CP(i)} \tag{7.7}$$

As discussed in Section 6.6, the value of 8.5E-3 / year corresponds to the envelope of the expression [CDF(given pipe fails) - CDF(given pipe does not fail)] for all buried piping systems from the five plants. As described in Section 6.4, CP(i) is the conditional probability of failure of the piping at year i and is given by:

$$\text{CP(i)} = \frac{\text{F(i)} - \text{F(0)}}{1 - \text{F(0)}} \tag{7.8}$$

M is the number of years after the time of inspection and F(i) is the cumulative failure distribution of the time-to-failure of the pipe at the i th year (i.e., fragility value from the fragility curves).

A spreadsheet calculation was performed using these equations by creating a table which solves for ΔCDP progressively year by year, for a given degradation rate and for various observed wall loss percentages at the time of inspection. Table 7.2 presents a sample table created for a 40.6 cm (16 in.) diameter pipe which is degrading at a rate of 0.254 mm/year (0.01

in./year). The table shows the calculation of the various parameters needed to solve equations (7.7) and (7.8). The parameters used in Table 7.1 are explained in the footnotes to the table.

The approach for the Category 2.2a buried piping is very similar to the Category 1 buried piping. For a given degradation rate, the ΔCDP can be solved for increasing values of time, the number of years of operation after the time of inspection. At each year, the plant's calculated ΔCDP can be compared to the ΔCDP_A (acceptable CDP based on the change in core damage frequency (ΔCDF) criterion of 1E-6 /year). When the plant's calculated ΔCDP reaches ΔCDP_A, that defines the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. This becomes the degradation acceptance criterion in risk terms.

Using Table 7.2 as an example, for an observed wall loss of 60% at the time of inspection, the ΔCDP reaches ΔCDP_A (see shaded boxes) between 4 and 5 years. This corresponds to an estimated percentage wall loss (EPWL) equal to 73.2%. Considering the range of percent wall losses of 10% through 70% (Table 7.2 shows a partial tabulation of 10, 50, & 60%), the acceptable EPWL varies between 72.2% and 75.3%. Since this is a relatively small variation, the minimum acceptable EPWL value within each pipe size (72.2% in this case) was utilized to obtain the acceptable percentage wall loss. Additional calculations were also performed at other degradation rates 0.0254 and 2.54 mm/year (0.001 and 0.100 in./year). For this example, the 0.254 mm/year (0.010 in./year) degradation rate resulted in a slightly lower value of acceptable percentage wall loss. Since the differences in the acceptable percentage wall loss corresponding to varying degradation rates were small, the minimum values for acceptable percentage wall losses were utilized for the degradation acceptance criteria. The resulting acceptable percentage wall loss as a function of pipe size (enveloped across varying observed wall loss percentages at the time of inspection and across varying degradation rates), is tabulated below. Using the minimum value of percentage wall loss in the enveloping process provides some additional level of conservatism.

Acceptable Percentage Wall Loss
For Category 2.2.a Buried Piping Systems
(Considering Pressure Loading)

Nominal Pipe Size cm / in.	Acceptable % Wall Loss
5.08 / 2	74.2
10.2 / 4	73.2
20.3 / 8	72.7
40.6 / 16	72.2
61.0 / 24	71.8
76.2 / 30	71.6
107 / 42	72.1

As in the case of Category 1 buried piping systems, the acceptable percentage wall loss for Category 2.2.a piping systems was initially determined based on pressure loads alone. Therefore, an adjustment was made to account for other loads such as soil surcharge load, groundwater, and surface live loads. For each pipe size, the acceptable percentage wall loss listed above was reduced by an amount needed to accommodate these other loads. The same method described for Category 1 buried piping systems was utilized to account for other loads for Category 2.2.a buried piping systems. The results of the calculations for the various pipe sizes are shown below. The percentage wall losses fall into a range between 54.5% and 58.6%.

Acceptable Percentage Wall Loss
For Category 2.2a Buried Piping Systems
(Considering Pressure and Other Loads)

Nominal Pipe Size cm / in.	Acceptable % Wall Loss
5.08 / 2	58.6
10.2 / 4	56.6
20.3 / 8	55.8
40.6 / 16	55.2
61.0 / 24	54.5
76.2 / 30	54.6
107 / 42	55.5

7.1.3 DAC for Localized Loss of Material/Pitting

Section 5.3 evaluated the fragility for localized loss of material/pitting. This evaluation was based on tests on degraded buried piping which were reported in ASME B31G-1991. The test data and results presented in ASME B31G-1991 do not distinguish between general wall thinning or pits. Based on the description presented in the ASME B31G-1991, the data are considered to be applicable to loss of material including localized loss of material/pitting.

The analyses performed in Section 5.2.3 developed distributions of failure stress (% minimum yield) for degraded pipe in terms of the mean and standard deviation for three ranges of corrosion depths (40% to 60%, 60% to 80%, and 80% to 100%). The results demonstrated that the mean values for all three ranges of degradation were higher than those obtained from the fragility analyses for general wall thinning. Fragility curves were also developed in terms of probability of failure versus internal pipe pressure for the three ranges of degradation. These fragility curves also demonstrated that the results obtained from the fragility analyses for general wall thinning are conservative for localized loss of material/pitting.

It should be noted that due to the small size of the test sample (47 tests), the fragility curves developed from the test data were not directly relied upon to develop the DAC. Instead, the results obtained from test data were compared to the results from the general wall thinning analysis. The comparison of these two sets of results demonstrated with reasonable confidence that the fragility curves developed by analysis for the general wall thinning case bound the test data for localized/pitting corrosion. Therefore, for purposes of developing the DAC for localized loss of material/pitting, the same acceptance limits developed for the general wall thinning case are recommended.

7.2 Development of Degradation Acceptance Criteria

This section of the report describes how the acceptable percentage wall loss values presented in Sections 7.1.1 and 7.1.2 were used to develop the degradation acceptance criteria in a form that is simple to use and considers degradation over time. Section 7.2.1 develops the degradation acceptance criteria without considering whether corrosion allowance was included in the original design of the buried piping system. Section 7.2.2 develops an approach which considers corrosion allowance, if it can be confirmed that it was included in the original design of the piping system.

7.2.1 Degradation Acceptance Criteria Without Consideration of Corrosion Allowance

The degradation acceptance criteria developed below is expected to be utilized for most cases because it does not require the user of the criteria to determine whether corrosion allowance was utilized in the original design of the buried piping system. Without this knowledge, however, the DAC may be somewhat conservative since it does not take advantage of the possibility that some of the observed wall loss in a degraded pipe may be within the corrosion allowance.

If it turns out that the DAC cannot be satisfied, then it is suggested that the design basis of the buried piping system be reviewed to determine whether corrosion allowance was provided and the magnitude of the corrosion allowance. This additional information can then be used to check the degraded condition at the time of inspection against the DAC developed in Section 7.2.2, which considers corrosion allowance that may have been incorporated in the original design of the piping system.

To simplify the development and application of the DAC for buried piping systems, without consideration for corrosion allowance, the envelope of the acceptable percentage wall loss from Category 1 and Category 2.2.a piping systems was utilized. This was achieved by noting that the percentage wall loss for Category 1 piping is less than Category 2.2.a for all pipe sizes. Therefore, the acceptable percentage wall loss for Category 1 buried piping was utilized to represent both categories of piping. Using the Category 1 values for both categories introduces some additional level of conservatism for the Category 2.2.a piping. The advantage of this approach is that it eliminates the need by the user of the DAC to utilize multiple tables. Therefore, the following (enveloped) acceptable percentage wall loss will be utilized for both types of buried piping systems when corrosion allowance is not being considered:

Acceptable Percentage Wall Loss
Without Consideration of Corrosion Allowance

Nominal Pipe Size cm / in.	Acceptable % Wall Loss
5.08 / 2	47.5
10.2 / 4	48.6
20.3 / 8	47.0
40.6 / 16	46.8
61.0 / 24	45.9
76.2 / 30	45.0
107 / 42	47.7

For a given pipe size having a standard schedule or thicker pipe (the case of the 107 cm (42 in.) pipe requires a thickness of 1.43 cm (0.562 in.) or more), these values represent the maximum acceptable wall loss which would lead to a potentially significant effect on plant risk. If the degradation of a particular buried pipe is observed to be close to these limits, then immediate attention is required to correct this problem. However, if the observed wall loss at the time of inspection is well below these limits, then the question that arises is how much longer can the system continue to operate before the degradation reaches a level which would potentially have a significant effect on plant risk? One should never plan to reach this level of degradation; however, it does provide a measure of time which may permit various steps to mitigate, monitor, and/or correct the degraded condition depending on the severity of the pipe degradation.

To predict the effects of degradation over time, it is required to estimate the degradation rate for the particular buried piping system. As discussed in Section 3.4 this is a function of environmental, metallurgical, and hydrodynamic variables. These variables include items such as pipe material; soil conditions; adequacy of coatings; fluid parameters such as temperature, pressure, velocity, and water quality; and type of corrosion/degradation. Since these parameters vary depending on the piping system and nuclear plant, it is beyond the scope of this report to define an appropriate degradation rate. Instead a description of the important parameters that should be reviewed to select an appropriate degradation rate are discussed and presented (see Section 3.4). In addition, information is provided in Section 3.4 which indicates some typical degradation rates that have been identified in the nuclear power industry. These include degradation rates for service water buried piping systems and degradation rates for specific degradation occurrences that have been reported in NRC Information Notices. Based on the EPRI Report TR-103403 (1993), general corrosion rates vary from 1 to >10 mils/year (1 mil per year = 0.0254 mm/year (0.001 in. per year)) for carbon steel and low alloy steels in fresh water at temperatures of 1.67°C to 40.6°C (35°F to 105°F). Based on Information Notices discussed in Section 3.4, degradation rates for above ground piping for severe cases of degradation were found to be higher, as much as 60 to 90 mils per year. Therefore, the DAC developed within this research program considered degradation rates ranging from 1 to 100 mils per year (0.0254 to 2.54 mm per year (0.001 to 0.100 in./year)).

To simplify the DAC, the degradation rates considered were assumed to remain constant over time. While degradation rates over long periods of time may increase, consideration of constant degradation rates is a good start, especially for shorter periods of time which is the primary concern. If results for increasing degradation rates are needed, then the same methodology described in this section can be applied to develop DAC for any definition of increasing degradation rates by assuming a linear, polynomial, exponential, or any other relationship between degradation rate and time.

By assuming a constant degradation rate, the equation shown below can be used to predict the number of years (N) required for the buried pipe to reach a degradation corresponding to the acceptable wall loss percentage calculated previously.

$$OL + \frac{N \times DR}{t_{nom}} \times 100 = AL \qquad (7.9)$$

where

OL = Observed wall loss at the time of inspection as a percentage of original nominal wall thickness

N = Number of years

DR = Degradation rate
t_{nom} = Nominal wall thickness
AL = Acceptable wall loss percentage

This equation was solved for the number of years (N) and then applied to varying degradation rates, varying observed wall losses at the time of inspection, and the full range of pipe sizes. The results of these calculations are presented in Table 7.3. Calculated values for the number of years were rounded down to the lower whole number since the results are not expected to be accurate to fractions of a year and rounding down eliminates any unconservatism that would arise if some of the results are rounded up. This table provides the DAC for degraded buried piping which can be used to determine how quickly a degraded pipe might reach a condition which would potentially have a significant effect on plant risk.

Separate DAC tabulations are presented in Table 7.3 for each pipe size. For a given pipe size, and knowing two variables consisting of observed wall loss at the time of inspection and degradation rate, the number of years to reach risk significance is found by reading the entry that intersects these two parameters. The DAC have been prepared for degradation rates varying from 0.0254 to 2.54 mm per year (0.001 to 0.100 in./year) as explained earlier. When the estimated degradation rate for a particular case falls between the tabulated values, the next higher degradation rate shown in the table should be used or equation (7.9) can be utilized. The percent wall loss values range from 0% to 50% since at a value of 50%, the maximum number of years is zero, for all pipe sizes. A value of zero for the number of years in Table 7.3 means that the degradation level has reached risk significance, and therefore, needs to be repaired immediately. For observed wall loss percentages at the time of inspection, that fall between tabulated values, the next higher observed wall loss should be used or equation (7.9) can be utilized.

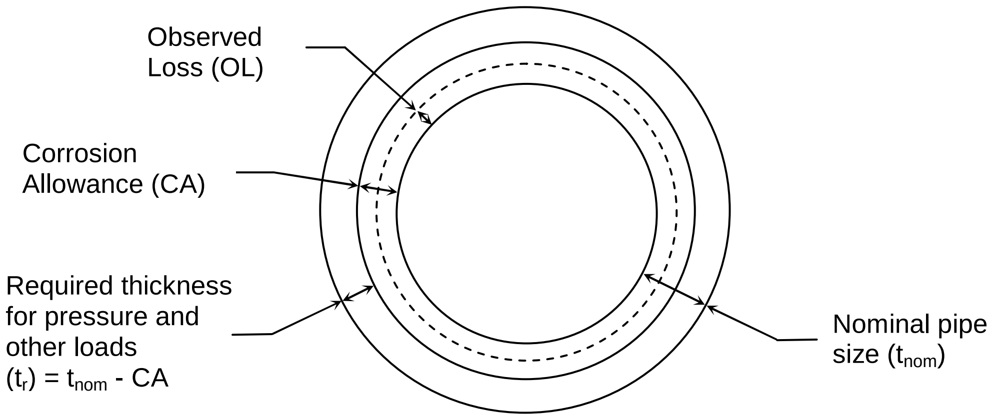
7.2.2 Degradation Acceptance Criteria With Consideration of Corrosion Allowance

The DAC presented in Table 7.3 should be used to determine the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. If this determination results in an unacceptable situation for the pipe, then the approach described in this section can be used to take advantage of any corrosion allowance that may have been included in the original design of the buried piping system. However, the amount of corrosion allowance that was originally provided for in the design for the particular buried piping system will need to be identified.

Rather than developing another set of tabulations for the consideration of corrosion allowance, an approach was developed which enables the use of the existing Table 7.3 (developed without the consideration of corrosion allowance). This approach eliminates the need for numerous tables which would be required for varying levels of corrosion allowance that might have been included in the original design of the buried piping systems. The approach that was developed evaluates two possibilities for an observed degraded condition. Either the observed loss at the time of inspection is less than or equal to the corrosion allowance, or it is greater than the corrosion allowance.

Case A: <u>Observed Loss is Less Than or Equal to the Corrosion Allowance</u>

As shown below, the observed loss (OL) is still within the corrosion allowance (CA). Since OL ≤ CA, this condition is the same as using the existing DAC in Table 7.3 corresponding to a pipe with a thickness of t_r (equals t_{nom} – CA) and 0% wall loss at the time of inspection. Therefore, the recommended approach for Case A, when OL ≤ CA, is to use the existing Table 7.3 for DAC and reading off the acceptable number of years at the row corresponding to 0% observed wall loss at the time of inspection. It should be noted that the figure presented below shows degradation occurring from the inside of the pipe; however, the approach is valid regardless whether the corrosion occurs from the inside surface, outside surface or a combination of both.

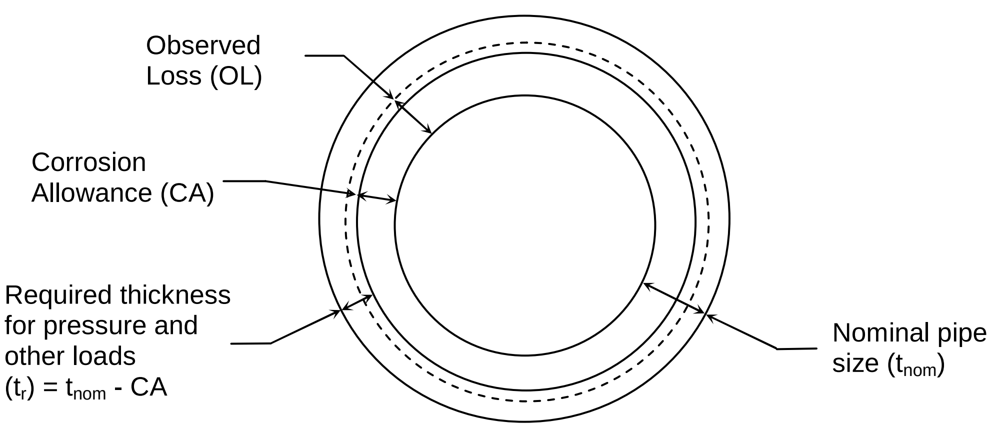


Case A: OL ≤ CA

Case B: Observed Loss is Greater Than the Corrosion Allowance

As shown below, the observed loss (OL) is greater than the corrosion allowance (CA) and has reduced some of the wall thickness required for pressure and other loads. For this case, where OL > CA, a term identified as the equivalent degradation percentage (ED) can be defined as:

$$ED = \frac{OL - CA}{t_r} \times 100 \qquad (7.10)$$



Case B: OL > CA

The ED provides the amount, in percentage terms, that was lost from the required wall thickness for pressure and other loads. Now the existing DAC table corresponding to a pipe with a thickness equal to (t_r) and percent wall loss equal to ED can be used to determine the number of years to reach a level of degradation that would potentially have a significant effect on plant risk. Therefore, the recommended approach for Case B, when OL > CA, is to use the existing Table 7.3 for DAC and reading off the number of years at the row corresponding to the equivalent observed wall loss percentage (ED) as defined above. An example of how to apply this approach to a pipe that is degraded beyond the corrosion allowance is provided in Section 7.3.

7.3 Guidance on the Use of Degradation Acceptance Criteria

If buried pipe degradation is identified at an NPP, it may not be evident whether the pipe still complies with the plant licensing commitments or whether the degradation potentially has an immediate significant effect on plant risk. Normally, the licensee performs an evaluation of the degraded condition which may include further inspections, testing, calculation/design review, and other actions to determine the severity of the condition, risk implications, and whether an immediate repair is needed. Since these steps may take time, often beyond a week, the methodology and DAC developed in this report provides guidance to the NRC staff for making an assessment in a timely manner whether the degraded condition potentially has an immediate significant effect on plant risk. This knowledge is important in order to provide input that can help determine whether immediate repairs are warranted, or whether the appropriate investigation, inspection, aging management, or other actions can be determined in the normal course of evaluating the condition. The methodology and DAC can not be used by the industry to justify existing degraded conditions; licensees are still required to meet their commitments regarding the plant’s current licensing basis.

This section provides the guidelines for using the DAC. It describes what the DAC are, how to use them, the acceptable range of conditions permitting their use, and recommendations if the DAC cannot be satisfied. More specifically, the DAC provides the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. To utilize the DAC, developed in Section 7.2, there were a number of variables and parameters that were used in the various stages of the research study. Therefore, a number of conditions must be satisfied to permit the use of the DAC. These conditions are described in this section of the report.

It should be noted that the analyses were performed for SA-106 Grade B carbon steel pipe. The results are considered applicable to stainless steel pipe as well because, most stainless steel buried piping systems use 304 and 316 type stainless steel material which have higher ultimate strength values and are more ductile than SA-106 Grade B carbon steel pipe.

The research described in this report developed DAC for general wall thinning and localized loss of material/pitting in buried piping. The types of buried piping systems, configurations, materials, and other conditions that must be satisfied to use the DAC have also been developed and presented below.

The results obtained are based on the service conditions that buried piping is designed for (e.g., pressure induced stresses less than ¼ of the minimum ultimate strength of the material and relatively low temperatures) and recognizing that seismic induced stresses in buried piping are self-limiting since deformations or strains are limited by seismic motions of the surrounding media. In addition, the DAC presented below arose from a probabilistic risk assessment which accounted for the contribution to risk of the postulated degradation of buried piping systems at NPPs. The measure of risk was based on the change in core damage frequency due to internal events during full power operation. It should be noted that even if the DAC show that there are still many years of acceptable operation left, it is expected that the licensee will evaluate the conditions that led to the degradation and may need to monitor, maintain, and/or repair the degraded pipe based on the evaluation findings, the level of degradation, and the plant's licensing commitments.

The DAC can not be used by the industry as a design tool to justify existing degraded conditions. Licensees are still required to meet their commitments regarding their current licensing basis. The DAC are intended to provide guidance to the NRC staff for making an assessment in a timely manner whether degraded conditions, identified at a plant site, potentially have an immediate significant effect on plant risk.

The DAC are applicable to the specific buried piping systems listed in Table 7.4 and can only be used if the conditions described in Section 7.3 and Table 7.5 are satisfied. The conditions were developed based on the limitations and requirements utilized in the various analyses described in Sections 5, 6, and 7. The buried piping systems listed in Table 7.4 were selected based on surveys and the LRAs which were described in Section 2. These piping systems should account for most buried piping systems found at NPPs. If a particular degraded buried pipe does not match one of the piping systems listed in Table 7.4, then it may still be possible to utilize the DAC. However, the buried piping system would have to first be categorized in accordance with Section 6.3. This would indicate which method should be followed for each category of buried piping system. In addition, care should be exercised to ensure that the buried piping system satisfies the conditions given in Section 7.3 and Table 7.5, and is bounded by the parameters used in the analyses described in Sections 5 through 7.

The DAC apply to piping directly buried in the ground (i.e., do not apply to piping installed within another larger diameter pipe or tunnel). In addition, the DAC are applicable to a single buried piping system and not a multiple set of buried piping systems. If degradation is identified in more than one buried piping system then this should be reviewed on a case-by-case basis.

The DAC are applicable to welded steel pipes consisting of straight sections of buried pipe and pipe components such as elbows, tees, branches, and reducers. Degradation of mechanical connections such as flanges, Dresser couplings, bell & spigot, and welds and adjacent heat affected zones should be considered on a case-by-case basis.

The DAC are not applicable to any degradation that includes pipe cracks; sharp discontinuities regardless of the size, width, or length of the crack/discontinuity; defects caused by mechanical damage, such as gouges and grooves; or defects introduced during manufacture. These conditions need to be evaluated immediately.

Degradation of coatings and/or linings is not considered to directly and immediately affect the safety of buried piping unless it has led to a loss of material of the base metal. Degradation of coatings and/or lining, however, is an indication that other locations along the pipe should be inspected because degradation at those locations might be more severe than at the observed locations. In addition, if the degradation to the pipe interior coating and/or lining is significant, it may cause fouling of the line and equipment (e.g., heat exchangers) which can affect the performance of the system. Another concern is that depending on the rate of coating or lining degradation, this loss of protection may lead to degradation of the steel pipe before the end of the design life of the piping. Therefore, even though coating degradation is not within the scope of the DAC, it needs to be inspected, monitored, and repaired when appropriate.

7.3.1 Degradation Acceptance Criteria (DAC)

In order to utilize the DAC, the conditions described above (within Section 7.3) and presented in Table 7.5 must first be satisfied.

To apply the DAC, two quantities must be known: the observed wall loss at the time of inspection and a degradation rate. The observed wall loss is to be calculated as a percentage of the nominal undegraded pipe wall thickness (or as specified in Section 7.2.2 when corrosion allowance is considered in the assessment). The degradation rate can be defined in terms of mm per year (in. per year). It is most accurate to base the degradation rate on measured values over time for the subject buried piping system at the plant, and therefore, this is the preferred method to obtain the degradation rate. Although a degradation rate equal to the loss of material divided by the total number of years that the plant has been operating provides one estimate, it may not be sufficiently accurate. Additional information on degradation rates for piping systems is provided in Section 7.2.1 and Section 3.4. This information is only provided as guidance on typical degradation rate values that have been reported in the nuclear industry. The selection of an appropriate degradation rate is the responsibility of the individual using these criteria, based on the conditions that exist at the plant for a particular buried piping system. The degradation rate selected for this assessment shall be the maximum rate throughout the particular piping system being evaluated. If there is some uncertainty whether the maximum degradation rate has been identified, then additional observations/measurements should be taken to ensure that the maximum (or at least a conservative) degradation rate is being utilized.

To simplify the process, the observed level of degradation without consideration of corrosion allowance can be used with the DAC. If this shows unacceptable results, then the approach that considers corrosion allowance should be used.

A. <u>Without Consideration of Corrosion Allowance</u>

It is acceptable and conservative to check the observed degradation against the DAC without consideration of corrosion allowance. The DAC for general wall thinning and localized loss of material/pitting are provided in Table 7.3. This table provides the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk.

<u>Example:</u>

A 76.2 cm (30 in.), standard schedule (0.953 cm (0.375 in.)) buried pipe has an observed wall loss at the time of inspection equal to 0.381 cm (0.15 in.). This represents a wall loss of 40 percent ([0.381/0.953] X 100). For an estimated degradation rate for this system equal to 0.254 mm/year (0.01 in./year), the number of years from the time of inspection for this system to reach risk significance can be found using Table 7.3. The number of years is read at the intersection of the 40% wall loss row and the 0.254 mm/year (0.01 in./year) degradation rate column. This results in 1 year left from the time of inspection to reach a level of degradation that would potentially have a significant effect on plant risk. Since the number of years to reach risk significance is only one year, further immediate evaluation or action is needed.

B. Considering Corrosion Allowance

If it turns out that the number of years is short (e.g., before the remaining life of the plant or before the next scheduled outage when the pipe will be repaired), then it is suggested that the design of the buried piping system be reviewed to determine whether corrosion allowance was provided in the original design of the piping system and the magnitude of the corrosion allowance.

If the observed wall loss is less than or equal to the corrosion allowance, then the approach described in Section 7.2.2 (Case A) should be followed. If the observed wall loss is greater than the corrosion allowance, then the approach described in Section 7.2.2 (Case B) should be followed.

Example:

Use the same example as above, except that the corrosion allowance included in the original design of the buried piping system was identified to be 0.159 cm (1/16 in.). Since the observed wall loss 0.381 cm (0.15 in.) is greater than the corrosion allowance of 0.159 cm (1/16 in.), the approach in Section 7.2.2 (Case B) will be followed.

From equation (7.10), the equivalent degradation percentage (ED) is calculated to be:

$$ED = \frac{OL - CA}{t_r} \times 100 = \frac{0.381 - 0.159}{0.953 - 0.159} \times 100 = 28\%$$

This means that the existing DAC in Table 7.3 with an observed wall loss of 28% and degradation rate of 0.254 mm/year (0.01 in./year) can be used to obtain the number of years. Rounding the observed wall loss up to 30% (which is conservative) leads to the number of years equal to 5. This is higher than the 1 year calculated in the previous example where corrosion allowance was not considered. It should be noted that even though 5 years is longer than 1 year, this indicates that some corrective action needs to be taken soon unless the remaining life of the plant is expected to be well below the 5 years found in this example.

7.3.2 If Conditions Cannot Be Satisfied or Unacceptable Results are Obtained

Step 1:

If the requirements and conditions described above and listed in Table 7.5 cannot be satisfied, then a detailed review can be performed to determine whether the DAC can still be utilized. This may very well be possible because to keep the DAC simple to use, the analytical methodology utilized some conservative assumptions in arriving at the acceptance limits. In addition, bounding values were sometimes used to cover various ranges of parameters. This avoided having an extensive set of criteria to account for every permutation of parameters.

As an example, if the depth of soil cover for a particular pipe D/t ratio exceeds the limits presented in the conditions described above, then a hand calculation of pipe stresses as described in Section 5.1 could be performed based on actual conditions at the site now or expected in the future. The stresses would have to meet the limits recommended in Section 5.1.

If unacceptable results are obtained advantage may be taken for a system that can be classified as Category 2.2.a (normally in standby, and whose failure does not cause an initiating event) since the Category 2.2.a criteria would be less restrictive than the Category 1 system (used to develop the DAC). The acceptable percentage wall loss table developed in Section 7.1.2 for a Category 2.2.a system can be used to obtain the number of years to reach risk significance, following the same approach described in Section 7.2. This would result in a somewhat longer time period to reach risk significance for all pipe diameters included in this study.

Step 2:

If the conditions still cannot be satisfied, then the DAC cannot be used and the degraded buried pipe must be reviewed on a case-by-case basis. If instead, the conditions can be met however the results are unacceptable, i.e., number of years to reach risk significance is short (e.g., before the next scheduled outage when the pipe will be repaired), then this indicates that a condition exists which potentially has a significant effect on plant risk. Therefore, additional detailed evaluation, and/or repair should be performed as soon as possible. Continued monitoring for this level of degradation to see if the condition worsens or removal of the cause of degradation to prevent further degradation would not be sufficient.

Table 7.1 Sample Calculation of Percentage Wall Loss Criteria
For Design Pressure Loading of Category 1 Buried Piping Systems
16 inch Nominal Pipe Size, Standard Schedule Pipe, 0.01 inches/year Constant Degradation Rate

% Wall Loss[1]	F(0)[2]	Para-Meters[2]	No. of Years[3] (M) ------>	1	2	3	4	4.32*	5	6	7	8	8.36*	9	. . .
10	1.67E-15	EPWL		12.67	15.33	18.00	20.67	21.52	23.33	26.00	28.67	31.33	32.29	34.00	
		F(M)		2.78E-15	4.55E-15	7.66E-15	1.34E-14	1.62E-14	2.44E-14	4.57E-14	8.92E-14	1.82E-13	2.38E-13	3.88E-13	
		CP(M)		1.11E-15	2.89E-15	6.00E-15	1.18E-14	1.45E-14	2.28E-14	4.41E-14	8.75E-14	1.80E-13	2.36E-13	3.87E-13	
		ΔCDP		3.77E-17	9.81E-17	2.04E-16	4.00E-16	4.94E-16	7.74E-16	1.50E-15	2.97E-15	6.12E-15	8.02E-15	1.31E-14	
		ΔCDP_A		1.00E-06	2.00E-06	3.00E-06	4.00E-06	4.32E-06	5.00E-06	6.00E-06	7.00E-06	8.00E-06	8.36E-06	9.00E-06	
20	1.17E-14	EPWL		22.67	25.33	28.00	30.67	31.52	33.33	36.00	38.67	41.33	42.29	44.00	
		F(M)		2.10E-14	3.90E-14	7.52E-14	1.52E-13	1.91E-13	3.20E-13	7.10E-13	1.67E-12	4.17E-12	5.89E-12	1.11E-11	
		CP(M)		9.33E-15	2.73E-14	6.35E-14	1.40E-13	1.80E-13	3.08E-13	6.98E-13	1.66E-12	4.15E-12	5.88E-12	1.11E-11	
		ΔCDP		3.17E-16	9.29E-16	2.16E-15	4.76E-15	6.11E-15	1.05E-14	2.37E-14	5.63E-14	1.41E-13	2.00E-13	3.78E-13	
		ΔCDP_A		1.00E-06	2.00E-06	3.00E-06	4.00E-06	4.32E-06	5.00E-06	6.00E-06	7.00E-06	8.00E-06	8.36E-06	9.00E-06	
.															
.															
.															
50	1.36E-10	EPWL		52.67	55.33	58.00	60.67	61.52	63.33	66.00	68.67	71.33	**72.29**	74.00	
		F(M)		4.79E-10	1.88E-09	8.24E-09	4.12E-08	7.09E-08	2.36E-07	1.57E-06	1.21E-05	1.07E-04	2.43E-04	1.06E-03	
		CP(M)		3.43E-10	1.74E-09	8.11E-09	4.10E-08	7.07E-08	2.36E-07	1.57E-06	1.21E-05	1.07E-04	2.43E-04	1.06E-03	
		ΔCDP		1.17E-11	5.91E-11	2.76E-10	1.40E-09	2.41E-09	8.02E-09	5.33E-08	4.11E-07	3.65E-06	**8.25E-06**	3.60E-05	
		ΔCDP_A		1.00E-06	2.00E-06	3.00E-06	4.00E-06	4.32E-06	5.00E-06	6.00E-06	7.00E-06	8.00E-06	**8.36E-06**	9.00E-06	
60	2.72E-08	EPWL		62.67	65.33	68.00	70.67	**71.52**	73.33	76.00	78.67	81.33	82.29	84.00	
		F(M)		1.51E-07	9.63E-07	7.16E-06	6.15E-05	1.26E-04	5.94E-04	6.04E-03	5.33E-02	3.37E-01	5.36E-01	8.75E-01	
		CP(M)		1.23E-07	9.36E-07	7.13E-06	6.14E-05	1.26E-04	5.94E-04	6.04E-03	5.53E-02	3.37E-01	5.36E-01	8.75E-01	
		ΔCDP		4.19E-09	3.18E-08	2.42E-07	2.09E-06	**4.27E-06**	2.02E-05	2.05E-04	1.88E-03	1.15E-02	1.82E-02	2.97E-02	
		ΔCDP_A		1.00E-06	2.00E-06	3.00E-06	4.00E-06	**4.32E-06**	5.00E-06	6.00E-06	7.00E-06	8.00E-06	8.36E-06	9.00E-06	

1 in. equals 2.54 cm

Footnotes:

1. % wall loss corresponds to the observed pipe wall loss at the time of inspection.

2. The definition of each parameter is given below, with a detailed description presented in Section 6.2 to 6.5.

   F(0) = Unconditional probability of failure at the time of inspection (M=0), which can be obtained from the fragility curve at the % wall loss at the time of inspection

   EPWL = Estimated percentage wall loss at year M (calculated from the % wall loss at the time of inspection and the degradation rate)

   F(M) = Estimated unconditional probability of failure at year M corresponding to the EPWL, which can be obtained from the fragility curve

   $$CP(M) = \frac{F(M) - F(0)}{1 - F(0)}$$

   ΔCDP = 3.4E-2 CP(M)

   ΔCDP_A = Acceptable increase in core damage probability over M years after the time of inspection = 1.0E-6/year x M years

3. No. of Years (M) corresponds to the number of years after the time of inspection.

* In order to obtain a more accurate EPWL, at the point in time when risk significance is reached, interpolation was performed between the adjacent two years so that ΔCDP is as close as possible to ΔCDP_A .

Table 7.2 Sample Calculation of Percentage Wall Loss Criteria
For Design Pressure Loading of Category 2.2a Buried Piping Systems
16 inch Nominal Pipe Size, Standard Schedule Pipe, 0.01 inches/year Constant Degradation Rate

% Wall Loss[1]	F(0)[2]	Para-Meters[2]	No. of Years[3] (M) ------>	1	2	3	4	4.95*	5	6	7	8	8.96*	9	. . .
10	1.67E-15	EPWL		12.67	15.33	18.00	20.67	23.20	23.33	26.00	28.67	31.33	33.89	34.00	
		F(M)		2.78E-15	4.55E-15	7.66E-15	1.34E-14	2.36E-14	2.44E-14	4.57E-14	8.92E-14	1.82E-13	3.76E-13	3.88E-13	
		CP(M)		1.11E-15	2.89E-15	6.00E-15	1.18E-14	2.20E-14	2.28E-14	4.41E-14	8.75E-14	1.80E-13	3.75E-13	3.87E-13	
		Cum CP(M)		1.11E-15	4.00E-15	9.99E-15	2.18E-14	4.26E-14	4.38E-14	8.79E-14	1.75E-13	3.55E-13	7.15E-13	7.31E-13	
		ΔCDP		9.44E-18	3.40E-17	8.49E-17	1.85E-16	3.62E-16	3.72E-16	7.47E-16	1.49E-15	3.02E-15	6.08E-15	6.21E-15	
		ΔCDP_A		1.00E-06	2.00E-06	3.00E-06	4.00E-06	4.95E-06	5.00E-06	6.00E-06	7.00E-06	8.00E-06	8.96E-06	9.00E-06	
. . .															
50	1.36E-10	EPWL		52.67	55.33	58.00	60.67	63.20	63.33	66.00	68.67	71.33	**73.89**	74.00	
		F(M)		4.79E-10	1.88E-09	8.24E-09	4.12E-08	2.16E-07	2.36E-07	1.57E-06	1.21E-05	1.07E-04	9.66E-04	1.06E-03	
		CP(M)		3.43E-10	1.74E-09	8.11E-09	4.10E-08	2.15E-07	2.36E-07	1.57E-06	1.21E-05	1.07E-04	9.66E-04	1.06E-03	
		Cum CP(M)		3.43E-10	2.08E-09	1.02E-08	5.12E-08	2.56E-07	2.68E-07	1.84E-06	1.39E-05	1.21E-04	1.05E-03	1.09E-03	
		ΔCDP		2.92E-12	1.77E-11	8.66E-11	4.35E-10	2.18E-09	2.28E-09	1.56E-08	1.18E-07	1.03E-06	**8.92E-06**	9.28E-06	
		ΔCDP_A		1.00E-06	2.00E-06	3.00E-06	4.00E-06	4.95E-06	5.00E-06	6.00E-06	7.00E-06	8.00E-06	**8.96E-06**	9.00E-06	
60	2.72E-08	EPWL		62.67	65.33	68.00	70.67	**73.20**	73.33	76.00	78.67	81.33	83.89	84.00	
		F(M)		1.51E-07	9.63E-07	7.16E-06	6.15E-05	5.29E-04	5.94E-04	6.04E-03	5.53E-02	3.37E-01	8.59E-01	8.75E-01	
		CP(M)		1.23E-07	9.36E-07	7.13E-06	6.14E-05	5.29E-04	5.94E-04	6.04E-03	5.53E-02	3.37E-01	8.59E-01	8.75E-01	
		Cum CP(M)		1.23E-07	1.06E-06	8.19E-06	6.96E-05	5.73E-04	6.02E-04	6.64E-03	6.20E-02	3.99E-01	1.22E00	1.26E00	
		ΔCDP		1.05E-09	9.00E-09	6.96E-08	5.92E-07	**4.87E-06**	5.12E-06	5.64E-05	5.27E-04	3.39E-03	1.04E-02	1.07E-02	
		ΔCDP_A		1.00E-06	2.00E-06	3.00E-06	4.00E-06	**4.95E-06**	5.00E-06	6.00E-06	7.00E-06	8.00E-06	8.96E-06	9.00E-06	

1 in. equals 2.54 cm

Footnotes:

1. % wall loss corresponds to the observed pipe wall loss at the time of inspection.

2. The definition of each parameter is given below, with a detailed description presented in Section 6.2 to 6.6.

   F(0) = Unconditional probability of failure at the time of inspection (M=0), which can be obtained from the fragility curve at the % wall loss at the time of inspection

   EPWL = Estimated percentage wall loss at year M (calculated from the % wall loss at the time of inspection and the degradation rate)

   F(M) = Estimated unconditional probability of failure at year M corresponding to the EPWL, which can be obtained from the fragility curve

   $$CP(M) = \frac{F(M) - F(0)}{1 - F(0)}$$

   $$\text{Cumulative } CP(M) = \sum_{i=1}^{M} CP(i)$$

   ΔCDP = 8.5E-3 / year x Cumulative CP(M)

   ΔCDP_A = Acceptable increase in core damage probability over M years after the time of inspection = 1.0E-6/year x M years

3. No. of Years (M) corresponds to the number of years after the time of inspection.

* In order to obtain a more accurate EPWL, at the point in time when risk significance is reached, interpolation was performed between the adjacent two years so that ΔCDP is as close as possible to ΔCDP_A .

Table 7.3 Degradation Acceptance Criteria Providing The Number Of Years That Would Potentially Have a Significant Effect On Plant Risk*

2 Inch Nominal Pipe, Nominal Wall Thickness Equal to or Greater Than 0.154 Inches

% Wall Loss at the Time of Inspection	Number Of Years After the Time of Inspection That Would Potentially Have a Significant Effect On Plant Risk For Degradation Rates (inches/year) Equal To:										
	0.001	0.002	0.004	0.006	0.008	0.010	0.020	0.040	0.060	0.080	0.100
0	73	36	18	12	9	7	3	1	1	0	0
5	65	32	16	10	8	6	3	1	1		
10	57	28	14	9	7	5	2	1	0		
15	50	25	12	8	6	5	2	1			
20	42	21	10	7	5	4	2	1			
25	34	17	8	5	4	3	1	0			
30	26	13	6	4	3	2	1				
35	19	9	4	3	2	1	0				
40	11	5	2	1	1	1					
45	3	1	0	0	0	0					
50	0	0									

4 Inch Nominal Pipe, Nominal Wall Thickness Equal to or Greater Than 0.237 Inches

% Wall Loss at the Time of Inspection	Number Of Years After the Time of Inspection That Would Potentially Have a Significant Effect On Plant Risk For Degradation Rates (inches/year) Equal To:										
	0.001	0.002	0.004	0.006	0.008	0.010	0.020	0.040	0.060	0.080	0.100
0	115	57	28	19	14	11	5	2	1	1	1
5	103	51	25	17	12	10	5	2	1	1	1
10	91	45	22	15	11	9	4	2	1	1	0
15	79	39	19	13	9	7	3	1	1	0	
20	67	33	16	11	8	6	3	1	1		
25	55	27	13	9	6	5	2	1	0		
30	44	22	11	7	5	4	2	1			
35	32	16	8	5	4	3	1	0			
40	20	10	5	3	2	2	1				
45	8	4	2	1	1	0	0				
50	0	0	0	0	0						

8 Inch Nominal Pipe, Nominal Wall Thickness Equal to or Greater Than 0.322 Inches

% Wall Loss at the Time of Inspection	Number Of Years After the Time of Inspection That Would Potentially Have a Significant Effect On Plant Risk For Degradation Rates (inches/year) Equal To:										
	0.001	0.002	0.004	0.006	0.008	0.010	0.020	0.040	0.060	0.080	0.100
0	151	75	37	25	18	15	7	3	2	1	1
5	135	67	33	22	16	13	6	3	2	1	1
10	119	59	29	19	14	11	5	2	1	1	1
15	103	51	25	17	12	10	5	2	1	1	1
20	87	43	21	14	10	8	4	2	1	1	0
25	70	35	17	11	8	7	3	1	1	0	
30	54	27	13	9	6	5	2	1	0		
35	38	19	9	6	4	3	1	0			
40	22	11	5	3	2	2	1				
45	6	3	1	1	0	0	0				
50	0	0	0	0							

16 Inch Nominal Pipe, Nominal Wall Thickness Equal to or Greater Than 0.375 Inches

% Wall Loss at the Time of Inspection	Number Of Years After the Time of Inspection That Would Potentially Have a Significant Effect On Plant Risk For Degradation Rates (inches/year) Equal To:										
	0.001	0.002	0.004	0.006	0.008	0.010	0.020	0.040	0.060	0.080	0.100
0	175	87	43	29	21	17	8	4	2	2	1
5	156	78	39	26	19	15	7	3	2	1	1
10	138	69	34	23	17	13	6	3	2	1	1
15	119	59	29	19	14	11	5	2	1	1	1
20	100	50	25	16	12	10	5	2	1	1	1
25	81	40	20	13	10	8	4	2	1	1	0
30	63	31	15	10	7	6	3	1	1	0	
35	44	22	11	7	5	4	2	1	0		
40	25	12	6	4	3	2	1	0			
45	6	3	1	1	0	0	0				
50	0	0	0	0							

24 Inch Nominal Pipe, Nominal Wall Thickness Equal to or Greater Than 0.375 Inches

% Wall Loss at the Time of Inspection	Number Of Years After the Time of Inspection That Would Potentially Have a Significant Effect On Plant Risk For Degradation Rates (inches/year) Equal To:										
	0.001	0.002	0.004	0.006	0.008	0.010	0.020	0.040	0.060	0.080	0.100
0	172	86	43	28	21	17	8	4	2	2	1
5	153	76	38	25	19	15	7	3	2	1	1
10	134	67	33	22	16	13	6	3	2	1	1
15	115	57	28	19	14	11	5	2	1	1	1
20	97	48	24	16	12	9	4	2	1	1	0
25	78	39	19	13	9	7	3	1	1	0	
30	59	29	14	9	7	5	2	1	0		
35	40	20	10	6	5	4	2	1			
40	22	11	5	3	2	2	1	0			
45	3	1	0	0	0	0	0				
50	0	0									

30 Inch Nominal Pipe, Nominal Wall Thickness Equal to or Greater Than 0.375 Inches

% Wall Loss at the Time of Inspection	Number Of Years After the Time of Inspection That Would Potentially Have a Significant Effect On Plant Risk For Degradation Rates (inches/year) Equal To:										
	0.001	0.002	0.004	0.006	0.008	0.010	0.020	0.040	0.060	0.080	0.100
0	168	84	42	28	21	16	8	4	2	2	1
5	149	74	37	24	18	14	7	3	2	1	1
10	131	65	32	21	16	13	6	3	2	1	1
15	112	56	28	18	14	11	5	2	1	1	1
20	93	46	23	15	11	9	4	2	1	1	0
25	74	37	18	12	9	7	3	1	1	0	
30	56	28	14	9	7	5	2	1	0		
35	37	18	9	6	4	3	1	0			
40	18	9	4	3	2	1	0				
45	0	0	0	0	0	0					
50											

42 Inch Nominal Pipe, Nominal Wall Thickness Equal to or Greater Than 0.562 Inches

% Wall Loss at the Time of Inspection	Number Of Years After the Time of Inspection That Would Potentially Have a Significant Effect On Plant Risk For Degradation Rates (inches/year) Equal To:										
	0.001	0.002	0.004	0.006	0.008	0.010	0.020	0.040	0.060	0.080	0.100
0	268	134	67	44	33	26	13	6	4	3	2
5	239	119	59	39	29	23	11	5	3	2	2
10	211	105	52	35	26	21	10	5	3	2	2
15	183	91	45	30	22	18	9	4	3	2	1
20	155	77	38	25	19	15	7	3	2	1	1
25	127	63	31	21	15	12	6	3	2	1	1
30	99	49	24	16	12	9	4	2	1	1	0
35	71	35	17	11	8	7	3	1	1	0	
40	43	21	10	7	5	4	2	1	0		
45	15	7	3	2	1	1	0	0			
50	0	0	0	0	0	0					

* 1 in. equals 2.54 cm.

This table is applicable to pipe wall loss degradation from the inside surface, outside surface, or a combination of both.

Nominal pipe size corresponds to a standardized outside diameter (O.D.) as defined in ASME B36.10M-2004. For nominal pipe sizes 14 inches and above, the actual O.D. is equal to the nominal pipe size. For nominal pipe sizes 12 in. and smaller, the actual O.D. is greater than the nominal pipe size, (e.g., 2 inch nominal pipe actually corresponds to 2.375 in. O.D.).

Nominal pipe wall thickness is the thickness of the pipe wall specified by ASME B36.10M-2004 without consideration for manufacturing tolerance.

Degradation rates are assumed to be constant. For a discussion on increasing degradation rates, see Section 7.2.1.

% Wall Loss at the time of inspection is calculated as a percentage of the pipe nominal wall thickness as shown at the heading of each tabulation (or as specified in Section 7.2.2 when corrosion allowance is considered in the assessment).

Interpolation between degradation rate values should not be used. Instead, the next higher degradation rate shown in the table should be used or equation (7.9) can be utilized.

Interpolation between observed percent wall loss values at the time of inspection should not be used. Instead, the next higher observed wall loss shown in the table should be used or equation (7.9) can be utilized.

A value of zero for the number of years means that the threshold limit has already been reached.

For other explanations and conditions that must be satisfied, see Table 7.5 and Section 7.3.

Table 7.4 Applicable Buried Piping Systems for use of Degradation Acceptance Criteria[1]

Service Water[2]
Diesel Fuel Oil[3]
Emergency Feedwater [4]
Condenser Circulating Water [5]
Condensate
Safety Injection
High Pressure Coolant Injection
Reactor Core Isolation Cooling
Residual Heat Removal

Notes:

1. For other buried piping systems not listed see discussion in Section 7.3.
2. Includes Service Water, Emergency Service Water, Auxiliary Salt Water, Saltwater, Nuclear Service Water, Residual Heat Removal Service Water, Plant Service Water, High Pressure Service Water, Intake Cooling Water.
3. Includes Diesel Fuel Oil, Emergency Diesel Fuel Oil, Diesel Fuel Oil Storage, Fuel Oil, Diesel Generator Fuel Oil, Standby Shutdown Diesel, Diesel Fuel Oil Supply, Emergency Diesel Generator, Diesel Generator Services, Standby Shutdown Facility Diesel Fuel Oil.
4. Includes Emergency Feedwater, Auxiliary Feedwater, Feedwater, Standby Steam Generator Feedwater.
5. Includes Condenser Circulating Water and Condenser Cooling Water.

Table 7.5 Risk-Informed Degradation Acceptance Criteria Summary
For Buried Piping Systems At NPPs

Degradation Acceptance Criteria (DAC)

Without Consideration of Corrosion Allowance	Use Table 7.3	
Considering Corrosion Allowance	Observed Wall Loss at the Time of Inspection is Less Than or Equal to Corrosion Allowance	Follow approach in Section 7.2.2 Case A
	Observed Wall Loss at the Time of Inspection is Greater Than Corrosion Allowance	Follow approach in Section 7.2.2 Case B

NOTE**:**

Additional information, guidance, and examples are provided in Sections 7.2 and 7.3.
In order to utilize the above DAC, the conditions listed below, in addition to those presented in Section 7.3, must be satisfied.

Conditions for use of DAC

CONDITION	REQUIREMENT							
Aging effects	Loss of material: general wall thinning and localized loss of material/pitting[1]							
Pipe material type	Ductile steel pipe (carbon steel, stainless steel)							
Piping design	ASME B31.1 or ASME Section III, NC/ND-3600							
Pipe nominal diameter	2 in. to 42 in							
Minimum pipe schedule (thickness)	Standard[2]							
Maximum diameter/thickness (D/t)	80							
Max operating temperature	150° F							
Max ground surface live load[3]	AASHTO H20 truck load = 32,000 lb axle load							
Minimum soil cover depth[4]	3 ft							
Max soil cover depth as a function of D/t ratio[4]	Diameter to thickness ratio (D/t)	20	30	40	50	60	70	80
	Max soil cover (ft)	63	30	19	14	12	10	10
Soil material (min. requirements)[5]	Well-graded and moderate compaction							

CONDITION	REQUIREMENT
Soil conditions	No current indication or past history of soil settlement or building structure settlement at the site; no concern with buoyancy (large diameter pipe close to surface)
Other Loadings	Pipe is not subject to significant fluid transient loads, significant cyclic loads, or surface impact loads
Risk parameters for the plant and system being evaluated (See Sections 6.3 through 6.6 for an explanation of the terms used)	a) Plant baseline total CDF less than 5×10^{-4} /year (this is expected to be satisfied for most NPPs) b) For a Category 1 buried piping system: CCDP $\leq 3.4 \times 10^{-2}$ c) For a Category 2.2.a buried piping system: [CDF (given pipe fails) – CDF (given pipe does not fail)] $\leq 8.5 \times 10^{-3}$/ year

1 in. = 2.54 cm; 1 ft = 30.48 cm; 1 lb = 4.45 N; $^{\circ}C = (^{\circ}F - 32)/1.8$

Footnotes:

1. The other major aging effect which is reduction in flow due to fouling/biofouling can be addressed by monitoring system performance parameters such as system flow and pressure, periodic examination of equipment fed by piping system, and other means (see Section 3.2, Operating Experience).

2. Applicable for all pipe sizes except 42 in. (107 cm) pipe diameter, which requires a minimum wall thickness of 0.562 in. (1.43 cm).

3. This also requires no surface loads such as railway, building structure, fill material, or other surcharge loads over the buried piping, unless the effects of the surface load are shown to be less than the effects due to the H20 truck load.

4. Soil cover is the distance between the top of the buried pipe and the ground surface

5. If desired, quantitative information for this requirement (i.e., modulus of soil reaction (E’) of 1,000 psi [6.89 MPa]) is available in Table 3.4 of Moser (2001).

8 CONCLUSIONS AND RECOMMENDATIONS

If buried pipe degradation is identified at an NPP, it may not be evident whether the pipe still complies with the plant licensing commitments or whether the degradation potentially has an immediate significant effect on plant risk. Normally, the licensee performs an evaluation of the degraded condition which may include further inspections, testing, calculation/design review, and other actions to determine the severity of the condition, risk implications, and whether an immediate repair is needed. Since these steps may take time, often beyond a week, the methodology and degradation acceptance criteria (DAC) developed in this report provide guidance to the NRC staff for making an assessment in a timely manner whether the degraded condition potentially has an immediate significant effect on plant risk. This knowledge is important in order to provide input that can help determine whether immediate repairs are warranted, or whether the appropriate investigation, inspection, aging management, or other actions can be determined in the normal course of evaluating the condition. The methodology and DAC can not be used by the industry to justify existing degraded conditions; licensees are still required to meet their commitments regarding the plant's current licensing basis.

To achieve the objectives of this study, fragility modeling procedures for degraded buried piping have been developed and the effect of degradation on fragility and plant risk has been determined. The effects of degradation over time were also included in the methodology. The analytical approach provides the technical basis for evaluating degraded buried piping at NPPs and provides guidelines for assessing the effects of degraded conditions on plant risk. The guidelines, which are identified as degradation acceptance criteria (DAC), are presented in tabular form for ease of use.

The effects of degradation over time were considered in developing the DAC in a manner that provides the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk. If the degraded condition exceeds the criteria, then immediate repair would be required unless otherwise justified. If the degradation level is less than the criteria, then it is expected that the licensee will still evaluate the conditions that led to the degradation and may need to repair the degraded pipe based on the evaluation findings, the level of degradation, and the plant's current licensing basis.

8.1 Conclusions

8.1.1 Understanding of the Degradation of Buried Piping

The types of buried piping systems, material and design parameters, and analysis and design methods that can be used for buried piping at NPPs have been collected and evaluated. Based on a survey and review of license renewal applications, there are many different buried piping systems used at NPPs; however, the most predominant types are the service water, diesel fuel, fire protection, and emergency feedwater systems. The materials used for buried piping are primarily carbon steel and to a lesser extent stainless steel. Other materials which are not as common are low-alloy steel, galvanized steel, cast iron, fiberglass, copper nickel, ductile iron and Yoloy. Methods for the structural analysis and design of buried piping are available in the general literature and in various industry codes, standards, and guides.

The predominant aging effects and associated aging mechanisms for buried piping have been identified and summarized in this report. The predominant aging effects are loss of material and fouling/biofouling. Most occurrences of loss of material are manifested as either general wall thinning or localized loss of material/pitting. A number of occurrences of degraded buried piping at NPPs have been reported in NRC generic correspondences, license renewal applications submitted to the NRC, industry reports, and research reports. For this study the aging effect of loss of material was selected because there are programs that have already been developed to address fouling/biofouling in buried piping.

8.1.2 Detection of Age-Related Degradation and Condition Assessment

Inspection methods for the degradation of buried piping can be based on visual, non-destructive, or destructive methods. Since degradation mechanisms can cause aging effects on the interior and/or exterior of buried piping systems, information about the condition of the inside and outside surface of buried piping is important. Large diameter lines such as portions of the service water system usually can be examined by personnel by close visual examination provided there is access to the line. Smaller diameter lines however, are not easily accessible and require other techniques which have been improved significantly over recent years. The use of a particular method depends on the size of the line, access to the interior or exterior surface, pipe material, aging effect of interest, and cost.

The inspection methods available for examining buried piping include visual inspection, cameras, ultrasonic test (UT), electromagnetic test, and pipeline pigs. Indirect indications of degradation can also be identified by monitoring the performance of the cathodic protection system, if such a system was installed at the plant. Other methods that have been developed using different technologies or variations of the technologies described previously include remote field eddy current, magnetic flux leakage, and infrared thermography.

8.1.3 Regulatory and Industry Guidance

There are several regulatory requirements and technical guidance documents that relate to degradation of buried piping. These include 10 CFR 50.65 – Maintenance Rule, 10 CFR Part 54 – License Renewal Rule, Generic Aging Lessons Learned (GALL), NRC Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, NRC generic correspondences, and NRC Inspection Procedures. The industry has also developed some guidance documents which support licensees in implementing the Maintenance Rule and the License Renewal Rule. Although these documents describe the buried piping materials, aging effects and mechanisms, environment, and acceptable aging management programs, they do not provide specific quantitative acceptance criteria for judging the adequacy of a degraded buried pipe. This is left to the licensee to define on a plant-specific basis. As a result, this study is particularly useful for the NRC staff to support their licensing review activities related to current operating plants.

8.1.4 Fragility Evaluation of Degraded Buried Piping

A review of the design loads on buried piping systems was conducted to identify the critical loads which may lead to pipe rupture failure as a direct result of loss of material in the pipe wall caused by age-related degradation. The design loads considered were internal pressure, soil surcharge (dead weight), groundwater, surface loads, seismic, and thermal expansion. Within the expected range of parameters for NPP buried piping applications, it was shown that soil surcharge, groundwater and surface loads produce low stresses which are not significantly affected by wall thinning. Thermal and seismic loads in buried piping systems produce self-limiting secondary stresses which are also not significantly affected by reductions in wall thickness. On the other hand, stresses due to internal pressure are primary stresses which are directly affected by loss of material due to age-related degradation of the pipe wall. As a pipe wall becomes thinner, the pressure induced stress increases, thereby increasing the probability of a pipe rupture failure.

Using the properties of buried carbon steel pipe, a methodology for developing buried piping fragility curves to predict probability of failure versus internal pressure was developed. Based on allowable variations in material and dimensional properties, it was shown that the tensile strength was the most significant random variable affecting the probability of failure. By using the minimum strength properties allowed by the material specification and by making reasonable assumptions on mean and upper limit strength values, a normal distribution of material strength was developed. Using this material strength distribution, pipe stress equations, and the assumption of uniform wall thinning, a series of fragility curves were analytically developed for undegraded pipes and for degraded pipes with different levels of percentage wall loss. In addition, a statistical evaluation of available test data on pressure tests of degraded pipes removed from service was performed to confirm the conservatism of these fragility curves and to demonstrate that the curves are applicable to piping with localized or pitting corrosion as well as uniform wall thinning.

Using the same methodology, a series of fragility curves were developed for carbon steel pipe ranging in size from 5.08 to 107 cm (2 in. to 42 in.) in diameter. These curves were developed for both undegraded and degraded pipes. Finally, by assuming that the internal pipe pressure is equal to the design pressure allowed by Code rules, plots of probability of failure versus percent wall loss were generated. These curves were combined on a single graph and showed that under design pressure, the variability of the probability of failure of degraded pipe at different percentage wall losses is within a factor of about 5.

8.1.5 Risk Evaluation of Degraded Buried Piping Systems

Buried piping systems at an NPP can degrade, as described in the previous sections of this report. Such deterioration potentially could impair the operation of the system that contains the buried piping, and thus impact the overall risk of an NPP. To develop a methodology that can estimate the effect of degraded buried piping on plant risk, a definition of the criterion to be used as a measure of significant risk was needed. For this study, the measure of significant plant risk was based on a change in core damage frequency (ΔCDF) of $1.0\text{x}10^{-6}$ per year. This was selected based on the guidelines provided in NRC RG 1.174, Rev. 1.

To determine the effects of buried piping degradation on plant risk, five NPP (sites) were selected for evaluation. The plants selected consist of McGuire 1 and 2; North Anna 1 and 2; Oconee 1, 2, and 3; Surry 1 & 2; and Hatch 1 & 2. These plants were selected because they contain many different buried piping systems and they have different attributes consisting of: reactor types, NSSS suppliers, containment types, architect/engineers, and locations in the United States. In addition, they contain both “frontline” and “support” systems with buried piping.

For the purpose of evaluating the contribution of the degradation of a buried piping system to plant risk, the systems in any NPP can be classified into several categories depending on whether the system’s failure causes an initiating event, whether the system is normally operating, and other criteria. A review of the buried piping systems at these five plants determined that they fell into two categories. Analytical time-dependent methods were developed for these two categories to estimate the increase in plant risk due to degraded buried piping. Some parameters required by these methods were obtained by using the Standardized Plant Analysis Risk (SPAR) version 3 models of the five selected plants. A SPAR model is a level-1 probabilistic risk assessment (PRA) model of internal events during full-power operation.

Bounding values for these risk parameters were utilized to cover the five plants. Enveloping the results for the five plants and the other conservatisms identified within this report, help generalize the results to most other NPPs in the US.

The risk evaluations and formulations that were developed provide a methodology which can be used to determine analytically how degraded buried piping affects plant risk. The formulations permit the solution of how many years are required for the buried pipe to reach a degradation level that would equal the defined measure of risk significance.

8.1.6 Degradation Acceptance Criteria

The Degradation Acceptance Criteria (DAC) are risk-informed acceptance limits that can be used to provide information for determining whether a degraded buried piping condition would potentially have an immediate significant effect on plant risk. The effects of degradation over time were included in developing the DAC and the DAC is applicable to most steel buried piping systems found at NPPs.

This study developed DAC for general wall thinning and localized loss of material/pitting in buried piping. The types of buried piping systems, configurations, materials, and other conditions that must be satisfied to use the DAC have also been developed and presented in Section 7.3 and Table 7.5. The results obtained are based on the service conditions that buried piping is designed for (e.g., pressure induced stresses less than ¼ of the minimum ultimate strength of the material and relatively low temperatures) and recognizing that seismic induced stresses in buried piping are self-limiting since deformations or strains are limited by seismic motion of the surrounding media. In addition, the DAC presented in Section 7.3 arose from a probabilistic risk assessment which accounted for the contribution to risk of the postulated degradation of buried piping systems at NPPs. It should be noted that even if a degraded buried pipe meets the DAC, it is expected that the licensee will still evaluate the conditions that led to the degradation and may need to repair the degraded pipe based on the evaluation findings, the level of degradation, and the plant’s current licensing basis.

The DAC are applicable to the specific buried piping systems listed in Table 7.4 and can only be used if the conditions described in Section 7.3 and Table 7.5 are satisfied. The conditions were developed based on the limitations and requirements utilized in the various analyses described in Sections 5, 6, and 7. The buried piping systems listed in Table 7.4 were selected based on surveys and the LRAs which were described in Section 2. These piping systems should account for most buried piping systems found at NPPs. If a particular degraded buried pipe does not match one of the piping systems listed in Table 7.4, then it may still be possible to utilize the DAC. However, the buried piping system would have to first be categorized in accordance with Section 6.3. This would indicate which method should be followed for each category of buried piping system. In addition, care should be exercised to ensure that the buried piping system satisfies the conditions given in Section 7.3 and Table 7.5, and is bounded by the parameters used in the analyses described in Sections 5 through 7.

The DAC are applicable to welded steel pipes consisting of straight sections of buried pipe and pipe components such as elbows, tees, branches, and reducers. Degradation of mechanical connections (e.g., flanges, Dresser couplings, bell & spigot, and welds and adjacent heat affected zones) should be considered on a case-by-case basis.

The DAC are not applicable to any degradations that include pipe cracks; sharp discontinuities regardless of the size, width, or length of the crack/discontinuity; defects caused by mechanical damage, such as gouges and grooves; or defects introduced during manufacture.

Conclusions for Degradation Acceptance Criteria (DAC)

The results of this study demonstrate that for a buried pipe meeting the conditions of the DAC, a pipe thickness loss less than approximately 45% of the original nominal pipe wall thickness, identified at the time of inspection, is not expected to have an immediate significant effect on plant risk. Risk-informed degradation acceptance criteria (DAC) were developed and presented in Table 7.3 for each pipe diameter in the range of 5.08 to 107 cm (2 to 42 in.). Based on the observed percentage wall loss at the time of inspection and the applicable degradation rate for the pipe, the number of years required for the buried pipe to reach a degradation level that would potentially have a significant effect on plant risk can be found. Additional information, guidance, and examples are provided in Section 7. In order to utilize the DAC, the conditions described earlier within Section 7.3 and presented in Table 7.5 must be satisfied.

As a first step, corrosion allowance that may have been provided in the original design of a buried piping system may be neglected and the criteria in Table 7.3 may be used. If the DAC cannot be satisfied, then an approach described in Section 7.2.2 can be followed to take advantage of any corrosion allowance that may have been included in the design of the piping system.

For all pipe sizes, the results in Table 7.3 demonstrate that as the observed percentage wall loss increases, the number of years required for the buried pipe to reach risk significance reduce. Table 7.3 also indicates that for small degradation rates and percentage wall losses of about 20% or less, the number of years required to reach risk significance is quite large. As an example, for all pipe diameters 5.08 to 107 cm (2 to 42 in.), degradation rate of 0.0254 mm/year (0.001 in./year), and observed percentage wall loss of 20% or less, the results in the table indicate that it would take 42 years or more for the buried pipe to reach a level of degradation that would potentially have a significant effect on plant risk. However, for higher degradation rates, the results indicate that the number of years can drop substantially depending on the degradation rate being used.

If Conditions are Not Satisfied

If the requirements and conditions described above cannot be satisfied, then a detailed review can be performed to determine whether the DAC can still be utilized. This may very well be possible because to keep the DAC simple to use, the analytical methodology utilized conservative assumptions in arriving at the acceptance limits. In addition, bounding values were often used to cover various ranges of parameters. This avoided having an extensive set of criteria (tables) to account for every permutation of parameters. Further guidance on how to treat degraded buried piping systems if the conditions of the DAC cannot be satisfied is provided in Section 7.3.

8.2 Recommendations

In light of the insights gained during this research, there are some recommendations for additional studies that could be implemented to remove some of the conservatisms, incorporate updated plant information, and extend the applicability of the degradation acceptance criteria (DAC) to other buried piping designs. These improvements would be applicable to a number of the analyses performed in this study which encompass the various loadings, fragility analyses, and risk evaluations.

8.2.1 Conservatisms

In order to develop a relatively simple set of DAC which could be used by various individuals with different levels of knowledge or expertise, it was necessary to select bounding values for a number of design and analysis parameters. These bounding values in effect introduce conservatisms which could be identified and relaxed where appropriate. The benefit would be somewhat more lenient degradation acceptance criteria.

This task could be performed by identifying, for each design and analysis parameter, whether there is sufficient benefit for developing a separate set of DAC for the range of the parameter being studied. This could lead to more relaxed acceptance limits and/or developing additional tables within the DAC that would provide improved limits corresponding to the range of the selected parameters.

Some examples of variables that could be evaluated for reduction in conservatism rather than using bounding values are different values for pipe schedules, soil properties, surface load types and magnitudes, and temperatures.

The analytical development of fragility curves was based on a conservative assumption that the wall thinning is uniformly distributed around the circumference and length of the pipe. In reality, however, the effects of pipe corrosion are more likely to be localized. A review of limited pressure test data of corroded pipes removed from service demonstrated the conservatism of the analytical assumption. If additional test results were available, it is expected that a case could be made for the generation of less conservative fragility curves based on test results.

The development of the normal distribution of material tensile strength was based on the assumption that the minimum value defined in the material specification is the 5th percentile lower bound value, the mean is 20 percent higher, and the 95th percentile upper bound value is 40 percent higher. A sensitivity analysis indicated that these assumptions were conservative. If additional material test results were available (manufacturer data or open literature), the use of less conservative values could be justified.

In developing the plots of probability of failure versus wall loss, it was assumed that the pipe is subjected to the maximum pressure equal to the code based design pressure. For small standard weight pipes, the design pressure may be over 6.89 MPa (1000 psi). However, the WRC Bulletin 446 survey did not identify pressures in buried piping higher than 150 psi (see Table 2.1). The use of actual plant operating pressures would reduce the probabilities of failure for most pipes.

As described in Section 6, to cover all five selected plants included in this study and to generalize the results for most NPPs, plant specific risk parameters such as the conditional core damage probability (CCDP) were conservatively enveloped across all buried piping systems within a given plant and across the five plants. A specific piping system at a plant may have lower parameters than the enveloped values, and therefore, a plant specific evaluation may result in a relaxation of the conservatism inherent in the DAC.

Since detailed information about the buried piping systems (e.g., the layout of each piping system and associated components – valves, pumps, etc.) was unavailable for the risk evaluations, a conservative assumption was made that if degradation caused the failure of any section of a buried pipe, the entire system is unavailable. This assumption may have led to conservative risk evaluations in some cases. Therefore, we recommend obtaining detailed information for some of the plants having buried piping using their specific layout. This would enable an assessment that is as realistic as possible and will provide an indication of the extent of conservatism inherent within the current analysis approach.

8.2.2 Consideration of Updated Information

It is advisable to consider updated information that was not available during the early phases of this study, in order to verify and enhance the methods and results presented in this report. Several examples of areas that would be very beneficial are described below.

Because of the difficulties in obtaining some input information regarding buried piping at NPPs, some of the input parameters (e.g., types of systems, pipe materials, operating experience) were based on the 12 license renewal applications (LRAs) that were available at the early phase of this research study. Based on some recent submittals to the NRC, there are more LRAs that are available that were not included in this study. Additional submittals of LRAs by licensees are also expected in the near future.

The risk evaluations could be expanded to more plants to confirm the risk parameters used in developing the formulations presented in Section 6 of the report. The study described in this report considered five plants for performing the risk evaluations. This could be expanded to consider additional plants and to different types of plants to enhance the applicability of the DAC.

The risk evaluation considered a level-1 PRA of internal events during full-power operation. Hence, the assessments did not include the impact of degraded buried piping for other modes of operation, other levels of PRA, and other challenges (such as external events). Those buried piping systems that are mainly used to prevent or mitigate those challenges (e.g., fire protection system and containment spray system), which were removed from consideration for the degradation acceptance criteria, currently need to be considered on a case-by-case basis. Therefore, further research is recommended for those buried piping systems that were not included in the scope of this study.

8.2.3 Extend Applicability of Degradation Acceptance Criteria

This study focused on the most prevalent types of buried piping found at NPPs which are ductile steel pipe made of carbon steel and stainless steel material. It would be beneficial to perform similar analyses to expand the DAC for other types of metallic pipe material which are less frequently used, but for which degradation acceptance criteria is lacking.

Additional improvements in the DAC are possible by expanding on the range of parameters beyond the limits presented in the existing DAC. Such enhancements could include considering the effects of the following parameters beyond the current limits: soil cover, D/t (diameter to thickness ratio), temperature, ground surface loads, and loadings beyond those considered in this study (e.g., transient loading).

The current risk evaluations developed analytical methods and degradation acceptance criteria for an observed degradation of a single buried piping system. Although it would be more complicated, analytical methods could be developed to consider the degradation effects caused by multiple (different) buried piping systems occurring at the same time.

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