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Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R4)

2013 TECHNICAL REPORT

Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R4)

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REPORT SUMMARY

The loss of pressure boundary material in piping and vessels to flow-accelerated corrosion (FAC) damage has caused a number of significant plant events over the last 25-plus years. This document presents the fourth revision of the EPRI Report "Recommendations for an Effective Flow-Accelerated Corrosion Program," NSAC-202L, issued in response to the tragic 1986 Surry pipe rupture event. Conforming FAC programs, established throughout the domestic nuclear fleet have allowed operating companies to identify, monitor, and mitigate FAC-related damage in advance of failure, preventing any FAC-related injuries since that time.

Background
FAC—sometimes referred to as flow-assisted corrosion or incorrectly as erosion-corrosion—leads to wall thinning (metal loss) of carbon steel piping exposed to flowing water, wet steam, or a combination of both. The rate of metal loss depends on the complex interaction of many parameters such as water chemistry, material composition, and hydrodynamics. Carbon steel piping components that carry wet steam are especially susceptible to FAC and represent an industrywide problem. Experience has shown that FAC damage to piping at fossil and nuclear plants can lead to costly outages or repairs and can affect plant reliability and safety. EPRI and the industry as a whole have worked steadily since 1986 to develop and refine monitoring programs in order to prevent FAC-induced failures.

This revision of NSAC-202L contains recommendations updated with the worldwide experience of members of the CHECWORKS™ Users Group (CHUG), and recent developments in detection, modeling, and mitigation technology. These recommendations are intended to refine and enhance those of earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs. The guidance contained in this document supersedes that contained in EPRI Report NP-3944 and all prior versions of NSAC-202L.

Objectives
To present a set of recommendations for nuclear power plants for implementing an effective program to detect and mitigate FAC.

Approach
Working together with the members of CHUG, EPRI developed a set of recommendations to help utility personnel design and implement a comprehensive FAC mitigation program.

Results
The Institute of Nuclear Power Operations (INPO), the Nuclear Energy Institute (NEI), the U.S. Nuclear Regulatory Commission (NRC), and the American Society of Mechanical Engineers (ASME) have all issued guidance related to the prevention of FAC failures. This report describes the organization and activities necessary to implement a successful FAC program. It identifies typical elements of an effective FAC program and describes the steps utilities should take to

minimize the chances of experiencing a FAC-induced failure and minimize the consequences of FAC-induced wall thinning in large-bore piping, small-bore piping, and equipment. However, since the approach is based on inspection of a prioritized sample of susceptible locations, the industry recognizes that it will never be possible to prevent all FAC-related leaks and ruptures.

Key elements of the guidelines include the following:

- Discussion of an effective FAC program design, with emphasis on corporate commitment, FAC operating experience, inspections, engineering judgment, and long-term strategies
- Description of implementation procedures and documentation, including use of a governing document
- Identification of recommended FAC program tasks, with key steps of identifying and ranking susceptible systems, performing FAC predictive analysis, selecting and scheduling components for inspection, performing inspections, evaluating inspection data, assessing worn components, and repairing or replacing components
- Explanation of how to develop a long-term strategy to reduce the rate of FAC throughout the plant, with discussions of FAC-resistant materials, water chemistry, and system design changes.

Applications, Value, and Use

All types of power and industrial process plants are susceptible to damage caused by FAC. The nuclear power industry has mounted a broad-based effort to reduce the occurrence of FAC and to uncover incidents of excessive FAC before failures are likely to occur. EPRI, NEI, and INPO have all contributed to this effort. Regardless of these efforts, problems caused by FAC have continued to occur.

Several major ruptures in the early 1990s, resulting in lost production and posing challenges to personnel safety, reinforced the importance of having an effective FAC program. In response, EPRI—with the support of CHUG— sponsored a series of plant visits to learn about the implementation of utility FAC programs. These visits showed that there were significant differences among utility programs that were reviewed. After these visits, EPRI and CHUG identified a need for a set of programmatic recommendations, which would be prepared for the utilities by EPRI. The original version of this document was a result of that decision. Later revisions have built on lessons learned from plant operating experiences, improvements to technology, and industry understanding of FAC. This revision incorporates lessons learned and new technology developments that have become available since the last revision of this document published in May 2006.

Keywords

Flow-accelerated corrosion
Erosion corrosion
Wall thinning
Piping systems
Reliability

ABSTRACT

This document presents a set of recommendations for an effective flow-accelerated corrosion program. These recommendations are the product of successful implementation of FAC inspection programs and experience of operating nuclear power plants. The essential ingredients for an effective FAC program are presented in this document, including the steps that utilities should take to minimize the chances of experiencing a FAC-induced consequential leak or rupture.

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1 INTRODUCTION

In December 1986, an elbow in the condensate system ruptured at the Surry Power Station. The failure caused four fatalities and tens of millions of dollars in repair costs and lost revenue. Flow-accelerated corrosion (FAC)[1] was found to be the cause of the failure.[2] Subsequent to this failure, EPRI developed the CHEC® family of computer codes (the current version of this technology is called the CHECWORKS™ Steam/Feedwater Application, hereinafter called CHECWORKS™ [1]). CHECWORKS™ was developed as a predictive tool to assist utilities in planning inspections and evaluating inspection data to reduce the frequency of piping failures caused by FAC. EPRI has also conducted many technology transfer workshops and user group meetings to promote the exchange of information among utility personnel and to help utilities address this issue. These technology and information exchanges have greatly reduced the incidence of FAC-related leaks and failures. Nevertheless, instances of severe thinning, leaks, and ruptures still occur. The most significant examples of recent failures occurred at Fort Calhoun in April 1997, at Point Beach in May 1999, the H. A. Wagner fossil power plant in July 2002, at Mihama Unit 3 (Japan) in August 2004[3], at the Edwards fossil plant in March 2005 and at the Iatan fossil plant in May 2007. A more complete listing of significant FAC-related piping and equipment failures is provided in Appendix C.

The continuing occurrence of FAC failures is evidence that plant programs to mitigate FAC should be maintained and improved, as necessary, as industry knowledge evolves and more operating experience and plant data become available. The CHECWORKS™ Users Group (CHUG), an industry-sponsored group formed to deal with FAC-induced wall thinning, authorized and provided major funding for EPRI to conduct a series of plant visits in the early 1990s to understand how the technology, plant experience, and engineering know-how were being used. One result of these visits was identification of the need for a set of recommendations to help utility personnel develop and effectively implement a comprehensive FAC program. Later revisions to this document have been based on successful utility experiences as well as improvements to FAC technology and understanding of the phenomena.

[1] Flow-accelerated corrosion is sometimes, but incorrectly, called erosion-corrosion. Erosion, it should be noted, is not part of the degradation mechanism. Erosive mechanisms that degrade power piping are discussed in [2, 3, 4].

[2] This was not the first instance that a rupture was caused by FAC, but it did bring the issue to prominence.

[3] It should be noted that CHECWORKS™ and this document were not in use at Mihama Unit 3 or at the Wagner, Edwards and Iatan fossil plants, at the time of the failures. Also, CHECWORKS™ was not used, nor was it designed to be used, to analyze the feedwater heater shell at Point Beach.

This document describes the organization and activities necessary to implement a successful FAC program. Typical elements of an effective FAC program are identified, and recommendations for implementation are made. This document is written to be of use to all utilities, irrespective of the predictive analytical methodology being used.

This document is directed at wall thinning caused by FAC. It is primarily directed at wall thinning in large-bore piping, although small-bore piping and FAC-susceptible equipment are also addressed. It does not cover other thinning mechanisms, such as cavitation, microbiologically-influenced corrosion (MIC), and erosive wear. It is planned that this document will be periodically updated to reflect the advances made in FAC mitigation.

1.1 Background

Flow-accelerated corrosion (FAC) is sometimes referred to as flow-assisted corrosion or incorrectly as erosion-corrosion. FAC leads to wall thinning (metal loss) of carbon steel piping exposed to flowing water or wet steam. The rate of metal loss depends on a complex interplay of many parameters including component geometry, water chemistry, material composition, and hydrodynamics. FAC damage to plant piping can lead to costly outages and repairs and can affect plant reliability, plant safety and personnel safety. Pipe wall thinning rates as high as 0.120 inch/year (3 mm/year) have been observed. Pipe ruptures and leaks caused by FAC have occurred at fossil plants, nuclear plants, and industrial processing plants. Carbon-steel piping and vessels that carry wet steam are especially susceptible to FAC and represent an industry-wide problem.

Although there were limited FAC programs in place before the Surry pipe rupture, it was not until after this accident that utilities expanded their inspection programs to reduce the risk of pipe ruptures caused by FAC. Since the Surry incident in December 1986, the industry has worked steadily to develop or refine their monitoring programs to prevent the failure of piping due to FAC. Additional historical background on FAC and development of the CHECWORKS™ technology is provided in Appendix D.

In July 1989, EPRI formed the CHEC®/CHECMATE™ Users Group, since renamed the CHECWORKS™ Users Group, CHUG. The key purpose of this group is to provide a forum for the exchange of information pertaining to FAC issues, to provide user support, maintenance, and enhancements for CHECWORKS™, and to support research into the causes, detection, and mitigation of FAC. CHUG also has published a number of position papers on various FAC issues. A current list of CHUG position papers is presented in Appendix E.

Other organizations have also provided guidance and criteria for mitigating FAC. They include:

- The American Society of Mechanical Engineers (ASME), which published Code Case N-597-2, “Requirements for Analytical Evaluation of Pipe Wall Thinning” [5], which provides structural acceptance criteria for Class 1, 2, and 3 piping components that have experienced wall thinning[4], and Non-mandatory Appendix IV to the B31.1 Code, “Corrosion Control for ASME B31.1 Power Piping Systems” [6].

[4] Some organizations are also using Code Case N-597 to evaluate ANSI B31.1 piping for FAC-related wall thinning.

- The Institute of Nuclear Plant Operations (INPO), which issued Significant Operating Experience Report (SOER) 87-3 in March 1987 [7], published Engineering Program Guide – FAC [8] and WANO SER 2006-1 [9].
- The U.S. Nuclear Regulatory Commission (NRC), which released Generic Letter 89-08 in 1989 [10] and Inspection Procedure 49001, "Inspection of Erosion-Corrosion/Flow-Accelerated-Corrosion Monitoring Programs" [11] in 1998.

1.2 This Document

Following the failure of two moisture separator drain lines at Millstone 3 in December 1990, EPRI conducted a series of visits to nuclear power plants to ascertain how well FAC programs had been implemented. The goal was to review the scope, implementation, current status, and effectiveness of individual FAC programs. It was found that, although the utilities had a common goal of reducing the frequency of leaks and ruptures, their approaches and rates of success in attaining this goal varied.

The recommendations in this document are provided to aid utilities in implementing an effective monitoring program at their plants and to establish a uniform industry approach toward mitigating FAC damage. It is believed that the implementation of these recommendations will prove to be a cost-effective method of increasing personnel safety, plant safety, and plant availability. These recommendations also have the potential to reduce forced outages and thus increase the capacity factor, while helping to reduce the cost of plant operations and maintenance. The implementation of recommendations found in this document should greatly reduce the probability of a consequential leak or rupture from occurring. However, since the approach is based on inspection of a prioritized sample of susceptible locations, it is recognized that it will never be possible to prevent all FAC-related leaks and ruptures from occurring.

The guidance contained in this document supersedes that contained in EPRI Report NP-3944 [12] and all prior versions of this document [13].

1.3 Current Industry Status

In recent years, the state of the FAC programs at US nuclear plants have been evaluated through a series of CHUG and EPRI sponsored assessments [14, 15, 16, 17]. At the time of this report the FAC Programs at 19 domestic sites, a total of 32 units, had been assessed, and in general each has been shown to be based upon this document and follow its recommendations quite closely, with few exceptions.

Further, some of the observations made during these assessments are being reflected in changes made to this revision of the document.

2
ELEMENTS OF AN EFFECTIVE FAC PROGRAM

Six interrelated key elements are necessary for a plant FAC program to be fully effective. These elements are illustrated in Figure 2-1 and described in more detail below.

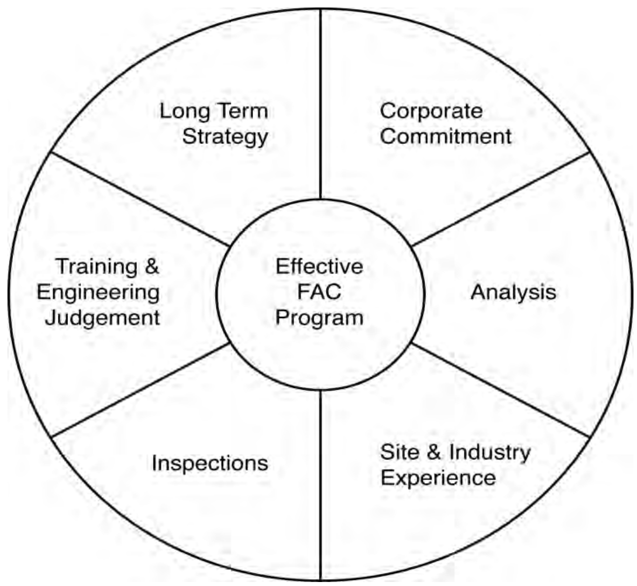

Figure 2-1
An Effective FAC Program is Founded on Interrelated Elements

2.1 Corporate Commitment

Corporate commitment is essential to an effective FAC program. It is recommended that this commitment include the following:

- Providing adequate financial resources to ensure that all tasks are properly completed.
- Ensuring that overall authority and task responsibilities are clearly defined, and that the assigned personnel have adequate time to complete the work.
- Ensuring that assigned personnel including supervisors and managers are properly qualified and trained for their area of technical responsibility. Ensuring that adequately trained, backup personnel are available to maintain program continuity in case of personnel unavailability.
- Ensuring that adequate and formal communications exist between various departments. Formalized sharing of data and information is essential.
- Ensuring that FAC operating experience is continuously monitored and evaluated, including regular participation by site FAC coordinators at CHUG meetings.

- Minimizing personnel turnover on the program, and providing sufficient transition when turnover does occur to ensure that plant and industry operating experience is not lost.
- Developing and implementing a long-term plan to reduce high FAC wear rates and to replace components in high wear rate, problematic lines with FAC resistant material.
- Ensuring that appropriate quality assurance is applied. This should include preparing and documenting procedures for tasks to be performed, properly documenting work, and providing for periodic independent reviews of all phases of the FAC program.
- Ensuring that procedures, analyses, the predictive model, and program documentation are kept current, and that outage reports are prepared in a timely manner.
- Developing and maintaining a Program Health Status composed of appropriate metrics [8].

2.2 Analysis

There are several thousand piping components in a typical nuclear power plant that are potentially susceptible to FAC damage. Without an accurate FAC predictive analysis of the plant, inspection drawings, and a piping database that includes inspection and replacement histories, the only way to prevent leaks and ruptures is to inspect each and every susceptible component during each outage. This would be a very costly inspection program.

A primary objective of FAC predictive analysis is to identify the most susceptible components, thereby reducing the number of inspections (the size of the sample being a strong function of both the plant susceptibility and the accuracy of the plant model and analysis method used). This limited sample should be chosen to select the components with the greatest susceptibility to FAC. In the past, some plants have used a simplified approach, often involving rating factors for this susceptibility analysis. However, due to the necessary conservatisms involved, a simplified analysis still results in a large number of inspections. Consequently, this approach is no longer used by domestic nuclear units.

Plants that have used simplified FAC analyses can inspect as many as 300 to 500 inspection locations[5] during each refueling cycle for large-bore piping alone in order to ensure plant and personnel safety. Experience has shown that until a comprehensive analysis of all susceptible systems has been completed, plant personnel cannot be confident that all highly susceptible components have been identified and are being monitored to prevent leakage or rupture.

Analytical methods should utilize the results of plant-specific inspection data to develop plant-specific correction factors. This correction accounts for uncertainties in plant data, and for systematic discrepancies caused by plant operation. The median numbers of inspections for utilities that have utilized inspection data to refine wear rate predictions and have reduced susceptibility are approximately 70 large-bore and 18 additional small-bore locations per refueling cycle. Although the number of inspection locations examined per refueling cycle is extremely plant-specific; depending on plant age, history, wall thickness margins, materials, length of refueling cycle, and susceptibility, the above figures reflect a sample of industry experience as of 2012.

[5] In this document, an inspection location consists of measurements on the component and the attached sections of upstream and downstream pipes.

For each piping component, an analytical method should be used to predict the FAC wear rate, and the estimated time until it should be re-inspected, repaired, or replaced. The analytical model can also be utilized for design studies. These studies are valuable for cost-benefit evaluations such as water chemistry changes, materials changes, power uprates, and design changes, considering various plant constraints for existing and new designs. The analytical model can also be used to develop a long-range inspection and repair/replacement plan.

2.2.1 Analytical Software

There are several computer programs available to perform FAC predictive analysis for Western reactor types. The three most commonly recognized ones are:

- BRT Cicero™ published by Électricité de France [18].
- CHECWORKS™ Steam Feedwater Application [1].
- COMSY (Condition Oriented ageing and plant life Monitoring System) published by Areva [19].

CHECWORKS™ is the most commonly used program in North American reactors.

2.3 Operating Experience

Review and incorporation of operating experience provides a valuable supplement to plant analysis and associated inspections. To assist utilities in assembling the relevant past data, EPRI maintains Plant Experience Reports on the CHUG web site and INPO maintains Operating Experience (OE) Reports on their web site, which summarize much of the relatively recent U.S. plant FAC operating experience. Utilities have found the following benefits from sharing operating experiences:

- Identifying generic plant problem areas where additional inspections may be warranted (e.g., Subsections 4.4.4 and A.6.2).
- Understanding differences in similar types of components (e.g., FAC wear rates of downstream piping is more severe when control valves made by certain manufacturers are used).
- Understanding the FAC consequences of using systems off-design (e.g., running bypass lines full time), power uprates, changes to water chemistry, etc.
- Sharing information on costs, materials, qualified suppliers, repair or replacement techniques, inspection techniques, new equipment, etc.

Membership in the CHUG is recommended as an excellent way for utilities to share operating experience.

2.4 Inspections

Accurate inspections are the foundation of an effective FAC program. Wall thickness measurements will establish the extent of wear in a given component, provide data to help evaluate FAC trends, and provide data to refine the predictive model. Thorough inspections are the key to fulfilling these needs. Thorough inspection of a few components is much more beneficial to a FAC program than a cursory inspection of a large number of components. One practice particularly not recommended is recording only the minimum thicknesses ascertained by UT scanning of large-bore components. Rather, a systematic method of collecting data is recommended. This will help to increase repeatability and allow for the trending of results.

2.5 Training and Engineering Judgment

Training of key personnel is essential to the success of a FAC program. It is recommended that:

- The FAC coordinator of each plant receive both the FAC 201 Training and the CHECWORKS™ Software Training sponsored by EPRI/CHUG, or equivalent,
- Each plant FAC coordinator have a trained backup, who has received at least the FAC201 Training, or equivalent, and possibly the CHECWORKS™ Software Training sponsored by EPRI/CHUG, or equivalent
- Site Program Engineering Supervision and Management should complete the EPRI CBT for Managers and Supervisors [20], or equivalent.
- Other plant personnel that are relied upon to successfully implement a comprehensive FAC program also receive training. These personnel may include, but not be limited to plant operators, systems engineers, maintenance engineers, thermal performance engineers, inspection personnel, water chemists and design engineers. The training should include an overview of FAC and how FAC affects their responsibilities. It can be given by a knowledgeable person such as the plant FAC coordinator. The EPRI CBT for non-FAC personnel [21] can be used for this purpose. Retraining frequency should be set by Station procedures.
- The FAC Program Manager should have a basic knowledge of steam side systems operations and thermodynamics.

Application of good engineering judgment is an important ingredient in each step of a FAC program. Judgment should be applied to all steps, from modeling decisions to evaluating inspection data. Accordingly, it is important that personnel involved in the program be aware of operating experience, be formally trained in an appropriate engineering discipline (such as mechanical engineering or engineering mechanics), be trained in FAC, and receive input from the systems engineers, thermal performance, plant operations, maintenance, and water chemistry departments [21, 22].

Although an important ingredient in a successful FAC program, training and engineering judgment cannot substitute for other factors, such as analysis or inspections. As described above, all of the six key elements are interrelated, and should be used together, not as substitutes for one another.

2.6 Long-Term Strategy

The establishment and implementation of a long-term strategy is essential to the success of a plant FAC program. This strategy should focus on reducing FAC wear rates and focusing inspections on the most susceptible locations. Monitoring of components is crucial to preventing failures. However, without a concerted effort to reduce FAC wear rates, the number of inspections necessary will increase as the operating hours increase, due to increased wear.

In addition, even with selective repair and replacement, the probability of experiencing a consequential leak or rupture may increase as operating hours increase.

It should be noted that there have been cases where utilities have tried to “manage wear.” That is, tracking the degradation and eventually replacing the wearing fittings. There have been several instances of unexpected failures in components known to be wearing, but not yet replaced. Therefore, as briefly discussed in Section 5 of this document, this practice rather than proactively replacing the wearing line should be used with caution.

3
PROCEDURES AND DOCUMENTATION

It is recommended that a comprehensive set of procedures (or instructions) be developed to define implementation of the FAC program, identify corporate and site responsibilities, and provide controls on how various tasks are performed. For utilities with multiple sites, it is recommended that the procedures (or instructions) and processes be as common to all sites as is practical. These procedures (or instructions) should be controlled documents.

3.1 Governing Document

It is recommended that a governing, corporate level document be developed to define the overall program and responsibilities. It is recommended that this document include the following elements:

- As described in Section 2.1, a corporate commitment to monitor and mitigate FAC.
- Identification of the tasks to be performed (including implementing procedures) and associated responsibilities.
- Identification of the position that has overall responsibility for the FAC program at each plant.
- Communication requirements between the lead position and other departments that have responsibility for performing support tasks.
- Quality assurance and record retention requirements.
- Identification of long-term goals and strategies for reducing high FAC wear rates.
- A method for evaluating plant performance against long-term goals.

It is recommended that the Governing Document be periodically reviewed and updated as necessary to reflect:

- Changes to the organization or to individual/organizational responsibilities.
- Changes to industry standards, Code requirements, and licensing requirements.

3.2 Implementing Procedures

It is recommended that implementing procedures (or instructions) be developed for each specific task conducted as part of the FAC program. These procedures (or instructions) should be organized in the manner most appropriate for the organization of the utility and program. These procedures (or instructions) should recognize any differences between safety-related and balance-of-plant systems and large-bore piping systems, small-bore piping systems, and susceptible equipment.

Procedures (or instructions) should be provided for controlling the major tasks of an effective FAC program:

- Identifying susceptible systems.
- Performing FAC predictive analysis.
- Selecting and scheduling components for inspection.
- Performing inspections.
- Determining trace alloy content, if performed as part of the inspection process.
- Evaluating inspection data.
- Expanding the inspection sample as necessary.
- Evaluating worn components.
- Repairing and replacing lines and components when necessary. An essential portion of this task is ensuring that proper records are kept to document the changes made. Maintaining configuration control is a necessity for a successful FAC program.
- Scheduling components for re-inspections.

Recommendations on how to implement these major tasks are provided in Section 4.

It is recommended that the implementing procedures be periodically reviewed and updated as necessary to reflect:

- Changes to individual or organizational responsibilities.
- Changes to industry standards, Code requirements, and licensing requirements.
- Evolution of knowledge and technology.

3.3 Other Program Documentation

The results of the major decisions and tasks should be documented, and appropriate records should be maintained. In addition to the Governing Procedure and implementing instructions, it is recommended that the documentation include:

- The Susceptibility Analysis (see Subsection 4.2).
- The Predictive Plant Model (see Subsections 4.1 and 4.3).
- A report for each inspection outage. This report should identify:
  - the components and equipment inspected and provide the basis for their selection, (*i.e.,* predictive ranking, operating experience, engineering judgment, trending, etc.),
  - the inspection results,
  - the deferred components and equipment and
  - the evaluation and disposition of components and equipment for continued service, or recommendations for repair or replacement.

The Susceptibility Analysis should be reviewed periodically or whenever plant changes are made that have an impact on overall susceptibility. Reviews and associated updates should include:

- Changes to system operation, including valve line-ups.
- Line, subsystem, and component material changes.
- Changes resulting from power uprates.
- Changes resulting from leaking valves and steam traps.
- Any new guidance provided by CHUG.
- Information obtained from plant operating experience.

The Predictive Plant Model should be updated after each outage to include:

- Inspection results of the most recent outage.
- Component replacements.
- Water chemistry, system operation, system design, or power uprate changes.

It is recommended that the Susceptibility Analysis, the Predictive Plant Model, the selection of inspection locations, component structural evaluations, the Outage Report, and all revisions to these evaluations be documented and independently checked by a qualified individual.

It is also recommended that records be maintained of significant FAC-related operating experiences that document site response to, and provide disposition of, the experience.

3.4 Records of Component and Line Replacements

It is recommended that plant records be thoroughly reviewed to identify any component and line replacements that have occurred in the past. All wear rate and remaining life predictions about such components and equipment need to take into account the actual date that it was entered into service. Information about such replacements should be included in the Predictive Plant Model, in the database used for the Susceptible-Not-Modeled program (see Subsection 4.4.2), and on any piping isometrics used for the FAC program. Thus, configuration control plays a key part in the FAC program [23, 24].

4 RECOMMENDATIONS FOR FAC TASKS

4.1 Definitions

As used in the remainder of this document, the following definitions apply to CHECWORKS™. Users of other analytical methods should consult their program documentation or computer program supplier for analogous information.

Analysis Line – An Analysis Line is one or more physical lines of piping that have been analyzed together in the Predictive Plant Model. A CHECWORKS™ Pass 2 analysis of one or more physical lines that utilize a common line correction factor is called a CHECWORKS™ run.

Calibrated Analysis Line – A CHECWORKS™ analysis line is judged to be "calibrated" when the analyst has a high degree of confidence in the accuracy of the Pass 2 predictions. This subject is discussed in depth in Section 4.3.1 and in [25].

Line Correction Factor – The Line Correction Factor is the median value of the ratios of measured wear for a given component divided by its predicted wear for a given Analysis Line. A Line Correction Factor of 1.0 is considered ideal as the measured wear equals the predicted wear (median value). The methodology used to determine the Line Correction Factor and alternate ways to calculate the Line Correction Factor are presented in [26].

New Lines – New Lines are those that have not been previously included in the FAC program. This may be due to changes to line susceptibility as a result of a system modification, valve alignment, power uprate, being overlooked, or some other cause.

Pass 1 Analysis – A Pass 1 Analysis is an analysis based solely on the Plant Predictive Model, and is not enhanced by results of the plant wall thickness measurements.

Pass 2 Analysis – A Pass 2 Analysis is an analysis where results of the plant wall thickness measurements are used to enhance the Pass 1 Analysis results.

Predictive Methodology – A predictive methodology uses formulas or relationships to predict the rate of wall thinning due to FAC and total amount of FAC-related wall thinning to date in a specific piping component such as an individual elbow, tee, or straight run. The predictions need to be based on factors such as the component geometry, material, and flow conditions. An example of a predictive methodology is the Chexal-Horowitz correlation incorporated in the CHECWORKS™ code [1]. Other software programs are mentioned in Section 2.2.1.

The CHECWORKS™ code was developed in accordance with the Quality Assurance policies of EPRI. These policies require a formal software plan and detailed program documentation. These policies also mandate that a list of program bugs be maintained.

A predictive methodology should incorporate the following attributes:

- Take into account the geometry, temperature, velocity, water chemistry, and material content of each component.
- Address the range of hydrodynamic conditions (i.e., diameter, fitting geometry, temperature, quality, and velocity) expected in a nuclear power plant. It is desirable to have the ability to calculate the flow and thermodynamic conditions in lines where only the line geometry and the end conditions are known.
- Consider the water treatments commonly used in nuclear power plants. The water chemistry parameters that should be addressed are the pH range, the concentration of dissolved oxygen, the pH control amine used (PWR only), the hydrazine concentration (PWR only), and the main steam line oxygen content (BWR only). It is particularly desirable to have a method of calculating the local chemistry conditions around the steam circuit.
- Cover the range of material alloy compositions found in nuclear power plants.
- Be able to determine the effects of power uprates, chemistry changes, and plant equipment and configuration changes to rates of FAC.
- Allow input of multiple operating conditions over the life of the plant.
- Use the hydrodynamic, water chemistry, and materials information discussed above to predict the FAC wear rate accurately. To do this, the model may be based on laboratory data scaled to plant conditions. The model should be validated by comparing its predictions with wear measured in power plants.
- Provide the user with the wear rates of components and the time remaining before a specified minimum wall thickness is reached. Various rankings should be provided as part of these calculations.
- Provide the capability to use measured wear data to improve the accuracy of the plant predictions (i.e., perform Pass 2 Analyses).
- The developer of the predictive methodology should also periodically review the accuracy of the predictive correlations and refine them as necessary.

Predictive Plant Model – A Predictive Plant Model is a mathematical representation of the power plant's FAC-susceptible lines and systems where the operating conditions are known. Typically, it utilizes a computer code that incorporates the attributes defined above. The Predictive Plant Model should also be developed on a component-by-component basis using a logical and unique naming convention for each component.

4.2 Identifying Susceptible Systems and Equipment

4.2.1 Potential Susceptible Systems and Equipment

The first evaluation task in the plant FAC program is to identify all piping systems and equipment, or portions of systems that could be susceptible to FAC. FAC is known to occur in piping systems made of carbon and low-alloy steel with flowing water or wet steam. All such systems should be considered susceptible to FAC. The plant line list and/or the Piping and

Instrumentation Drawings (P&IDs) can be used to ensure that all potentially susceptible systems are included in the program. Additionally, interviews with plant operators and systems engineers are useful to identify how lines and systems are actually being used (or have been used) in the various plant operating modes. Guidelines for such interviews can be found in reference [27].

Care should be taken to ensure that all susceptible lines, including lines not on the plant line list (including vendor lines such as gland steam and skid mounted piping), are included in the FAC program. Additionally, this evaluation should be periodically reviewed to ensure that it is kept current with plant design changes and ways that systems are being operated (see Subsection 3.3).

4.2.2 Exclusion of Systems from Evaluation

Some systems or portions of systems can be excluded from further evaluation due to their relatively low level of susceptibility. Based on laboratory and plant experience, the following systems can be safely excluded from further evaluation:

- Systems or portions of systems made of stainless-steel piping or low-alloy steel piping with nominal chromium content equal to or greater than 1.25 % (high content of FAC-resistant alloy). This exclusion pertains only to complete piping lines manufactured of FAC-resistant alloy. If some components in a high-alloy line are carbon steel (e.g., the valves), then the line should not be excluded. Also, in lines where only certain components or sections of piping have been replaced with a FAC-resistant alloy, the entire line, including the replaced components, should be identified as susceptible and analyzed. Note that high-chromium materials do not protect against other damage mechanisms, such as cavitation and liquid impingement erosion. Thus, if the wear mechanism has not been identified, the replaced components should remain in the inspection program.
- Experience has shown that piping constructed from carbon steel material (e.g., A106 Grade B) containing at least 0.1% chromium could also be excluded as discussed above.
- Superheated steam systems or portions of systems with no moisture content, regardless of temperature or pressure levels. However, drains, traps, and other potentially high-moisture content lines from superheated steam systems should not be excluded. Further, experience has shown that some systems and equipment designed to operate under superheated conditions may actually be operating with some moisture in off-normal or reduced power level conditions, or when upstream equipment is no longer operating as-designed. Care should be exercised not to exclude such systems.
- Systems or portions of systems with high levels of dissolved oxygen (oxygen > 1000 ppb), such as service water, circulating water, and fire protection.
- Single-phase systems or portions of systems with a temperature below 200°F (93°C, low temperature). Caution: if measurable wear is identified in downstream piping operating slightly above 200°F (93°C), it is recommended that the system's exclusion be reconsidered. There is no temperature exclusion limit that can be recommended for two-phase systems as damage has been seen in sub-atmospheric extraction lines. Note that other damage mechanisms, such as cavitation, are predominant below 200°F (93°C) and need to be taken into account. However, this document does not address these other damage mechanisms.

Furthermore, FAC can occur in low-temperature single-phase systems under unusual and severe operating conditions [28] (e.g., PWR lines upstream of chemical addition that operate at a neutral pH).

- Systems or portions of systems with no flow, or those that operate less than 2% of plant operating time (low operating time); or single-phase systems that operate with temperature > 200°F (93°C) less than 2% of the plant operating time. Caution—if the actual operating conditions of the system cannot be confirmed (e.g., leaking valve, time of system operation cannot be confirmed), or if the service is especially severe (e.g., flashing flow), that system should not be excluded from evaluation based on operating time alone. A further caution—some lines that operate less than 2% of the time have experienced damage caused by FAC. These lines include Feedwater Recirculation, startup condensate lines, High Pressure Coolant Injection (HPCI), by-pass lines to the condenser, and Reactor Coolant Inventory Control (RCIC). Such lines should be excluded only if no wear has been observed and continued operation under existing parameters is assured. Balancing lines between normally flowing lines should not be excluded based on this criterion.
- Care should be taken not to exclude piping downstream of leaking valves or malfunctioning steam traps[6]. Leaking valves and steam traps can be identified using means such as infrared thermography or thermocouples, often performed as part of a plant thermal performance evaluation. Acoustical monitoring can also be employed to detect leakage past normally closed valves and malfunctioning steam traps. Steam trap monitoring systems can be used to determine trap performance.

It is recommended that the Susceptibility Analysis identify the systems, or portions of systems excluded from the FAC program and the basis for their exclusion. This analysis should be appropriately documented and reviewed. It has proven useful to have plant operating personnel review the list of exclusions.

Systems, or portions of systems, should not be excluded from evaluation based on low pressure. Pressure does not affect the level of FAC wear. Pressure only affects the level of consequence should a failure occur. A failure in a low-pressure system could have significant consequences (e.g., failure in a low-pressure extraction line). Also, arbitrary ranges of velocity or other operating conditions should not be used to exclude a system from evaluation.

The systems or portions of systems excluded by these criteria will not experience significant FAC damage over the life of the plant. However, it should be noted that such systems or portions of systems could be susceptible to damage from other corrosion or degradation mechanisms. These include cavitation erosion, flashing erosion, liquid droplet impingement, pure water corrosion (also referred to as low-temperature FAC), stress corrosion cracking (SCC), microbiologically-influenced corrosion (MIC), chemical attack and solid particle erosion. These mechanisms are not part of a FAC program and should be evaluated separately.

[6] Following the repair of any leaking valve or steam trap and inspection of the downstream piping, the downstream piping can again be excluded from the FAC program provided that it meets the exclusion criteria provided herein.

4.3 Performing FAC predictive analysis

Once the susceptible, large-bore piping systems have been identified, it is recommended that a detailed FAC predictive analysis be performed for each system and line with known operating conditions using a predictive methodology such as CHECWORKS™. This should include all components of all parallel trains. A quantitative analysis is possible on lines with known operating conditions, but a qualitative approach must be used on lines with uncertain operating conditions (Subsection 4.4.2). The purpose of a quantitative analysis is to predict the FAC wear rate and to determine the remaining service life for each piping component, including uninspected components. Utilities may select any analytical tool that covers the necessary plant design, operating, and water chemistry conditions.

4.3.1 Calibrated Lines

There are two goals for performing a Pass 2 analysis:

- to modify the Pass 1 predictions to better correlate with the inspection data and
- to assist the analyst in determining the degree of confidence that the modeling has produced accurate results.

A CHECWORKS™ Pass 2 Analysis Line that is judged to have a high degree of confidence that the predictions are accurate is considered “calibrated” (additional guidance is provided in Sections 6.3.4 of [25]).

It is important to note that establishing calibration is a judgment call and the information presented below is for guidance. It is expected that the analyst will carefully evaluate each Analysis Line, determine whether it is considered calibrated or not and document the results.

4.3.1.1 General Considerations for Establishing Calibration

Generally, a line can be considered calibrated if it meets all of the following criteria:

1. All lines of piping which compose the Analysis Line should have very similar chemistry, time of operation, volumetric flow rate, temperature, fluid content (e.g., single- and two-phase lines should not be mixed in an analysis run), and steam quality.
2. The Analysis Line should have a minimum of five inspected components that have lifetime wear greater than 0.030” (0.8 mm); these components should be from main runs of elbows, pipes, nozzles, reducers, expanders, and tees, and from downstream pipe extensions of these components.
3. The Analysis Line should have a Line Correction Factor between 0.5 and 2.5.
4. A plot of predicted wear to measured wear shows a reasonably tight cluster of data along the 45° line.
5. The Predictive Plant Model includes the inspection data of the most recent outage.

4.3.1.2 Special Considerations for Establishing Calibration

In addition to the general requirements, presented above, there are a number of special situations where exceptions to the above criteria can be justified. Without being all encompassing, some of these situations will be described:

- *Low Wear* – An Analysis Line can also be treated as calibrated if it has been found to exhibit little to no wear and includes a minimum of ten inspected components if no trace alloy measurements were made of the inspected components. If little to no wear was found and measurements of trace alloy content were made of the inspected components, then fewer inspections are needed to treat the Analysis Line as calibrated.
- *Out of Range Line Correction Factor* – A value outside of the 0.5 to 2.5 range can be accepted if the reason for the high or low LCF is well understood and documented and a minimum of ten inspected components exist in the Analysis Line.
- *Few Components* – A line with fewer than five FAC-susceptible components can be considered calibrated if the other requirements are met.

4.3.1.3 Maintaining Calibration

Once lines are considered calibrated, Section 4.4.1.2 should be used to select inspection locations. It is not necessary to 're-calibrate' a line at every outage.

However, it should be noted that the calibration status of a line can change with time due to piping replacements, power uprates or other changes of operating conditions. Thus, when such changes occur, the calibration status of such lines should be reexamined and documented.

4.3.2 FAC predictive analysis and Power Uprates

It is recognized that even small power uprates can have a significant effect on FAC rates. This can be caused by changes to equipment and changes to system operating conditions such as flow rates, temperature, dissolved oxygen, and steam quality. When power uprates or power downrates are being considered, it is recommended that the proposed changes to operating conditions and any possible changes to the plant heat balance diagram be fully reviewed and evaluated using the Predictive Plant Model. Generally, a change to the plant heat balance diagram should require a new power level in the predictive model.

Potential changes to the Susceptible-Not-Modeled lines should also be considered. This should include identification of any piping areas and equipment where FAC rates are predicted to significantly increase such that material upgrades can be considered and changes to the plant inspection plan can be made.

The performance of the CHECWORKS™ code in analyzing recent Stretch Power Uprates (SPU) and Extended Power Uprates (EPU) was studied in a recent project [29]. It was shown that the CHECWORKS™ code performed properly in its role of identifying areas for inspection.

It is recognized that power uprates can be very minor or quite significant. It is recommended that each change to the plant heat balance diagram be evaluated for its effect on FAC in the susceptible systems.

4.4 Selecting and Scheduling Components for Inspection

For a given outage, the inspection sample should be composed of components selected from a variety of sources. These sources include:

1. Results of lines analyzed using the Predictive Plant Model.
2. Results of evaluations of lines that cannot be accurately analyzed in the Predictive Plant Model due to uncertain operating conditions. They are commonly called “Susceptible-Not-Modeled” lines. Lines with socket-welded fittings are typically not analyzed due to uncertainties in the fit-up gaps. Recommendations for small-bore lines are provided in Appendix A.
3. Extrapolations of prior inspection results, commonly called “trending”.
4. Plant experience.
5. Operating experience.
6. FAC-susceptible equipment.
7. Engineering judgment.
8. Entrance effect locations.

The inspection list generated from the categories above should be a reasonable mix of locations that have not been previously inspected and re-inspections. The inspection list for plants with relatively few inspections would be expected to be primarily composed of new locations, whereas the list for plants with large numbers of inspections would be expected to have more re-inspections. However, it should be stressed that there is no “magic mix” of components to be inspected. The inspection list has to be determined based on the conditions found in the individual unit.

It should be recognized that FAC can occur in difficult to inspect areas such as: buried lines, high radiation zones, encased lines and lines in whip restraints (pipe in pipe). Such areas should be evaluated (e.g., by considering areas in adjacent, easier to inspect areas), and inspected as necessary.

4.4.1 Inspection Locations Based on the Predictive Plant Model

Inspection locations from the predictive model will be either from areas not previously inspected, “New Lines” or from areas already inspected. The areas previously inspected can be further subdivided into “Calibrated Lines” and “Non-calibrated Lines.” Considerations for each will be presented.

4.4.1.1 New Lines

New Lines, or portions thereof, which have known operating conditions, should be evaluated using the Predictive Plant Model. With respect to the total number of locations to be inspected in the next outage, a proportionally greater number of inspections are recommended in New Lines. Emphasis should be placed on obtaining good quality inspection data and understanding line behavior. Baseline inspections should be performed prior to installation or startup whenever possible. Recommendations for selection of inspection locations in New Lines are as follows:

1. Select a sample from the components identified in the wear ranking as having the highest relative wear. To the extent practical, the sample should include components from each geometry type present in the Analysis Line[7] (e.g., elbows, reducers, expanders, tees, piping downstream of valves or orifices, equipment nozzles, piping downstream of other components, etc.). Engineering judgment should be employed to ensure that the most representative sample of the items with the highest probability of damage be examined. For example, if the three highest-ranked components are elbows, and the first tee in the rankings is the sixth highest ranked item, then that tee should be inspected in preference to the third ranked elbow. However, if the highest ranked tee is the hundredth item, it should not replace the third ranked elbow.
2. Select components with a predicted negative time to tcrit[8] unless they have already been dispositioned.
3. Select one or more components with the shortest relative remaining service life from the time rankings, if they are not already included in the sample discussed under Item (1) above.
4. A minimum of one component should be selected from each parallel train in a multi-train run. These components should be in similar locations for the purpose of comparing results. It is recommended that this location be one of the highest ranked items in the relative wear ranking.
5. Select a minimum of one location in each two-phase run of piping. This is necessary because it is difficult to accurately determine moisture content in two-phase lines.
6. Based on EPRI experience, the size of the sample based on the wear ranking should be a minimum of three to five components per Analysis Line, depending upon the number of components in the Analysis Line, the predicted wear, and its complexity. CAUTION: The minimum sample size of three to five components per Analysis Line is based on the demonstrated accuracy of the CHECWORKS™ code. If other methods are used to select inspection locations, then the sample size used should be justified.

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[7] See definition of Analysis Line in Subsection 4.1.

[8] Note that 'time to tcrit' is the CHECWORKS™ operating time to reach the user defined critical thickness. Clearly, a negative time to tcrit indicates that the program has predicted thinning past the critical thickness. See Section 4.7.2.

4.4.1.2 Calibrated Lines

Recommendations for selection of inspection locations in Calibrated Lines are as follows:

1. Inspections should be distributed among the susceptible lines, but concentrated on lines with the highest predicted Pass 2 wear rates and the shortest remaining service life.
2. Lines with low predicted Pass 2 wear rates and long remaining service life need to be inspected only occasionally to ensure that the line is wearing as predicted.
3. Components with measured chromium greater than 0.10% [30] and no significant wear found during the first inspection need not be re-inspected. This exclusion does not apply to components subject to damage from mechanisms other than FAC (e.g., cavitation, flashing or droplet impingement).
4. Components downstream of FAC-resistant components. Experience has shown that the entrance effect [31] will degrade the attachment weld area of the downstream component.

4.4.1.3 Non-Calibrated Lines

With respect to the total inspection sample for a given outage, a proportionally greater number of inspections are recommended in Non-Calibrated Lines as compared to Calibrated Lines. Emphasis should be placed on obtaining good quality inspection data and understanding line behavior. Recommendations for selection of inspection locations in Non-Calibrated Lines are as follows:

1. Inspections should be distributed among the susceptible lines, but concentrated on lines with the highest predicted wear rates and the shortest remaining service life.
2. Locations with the highest trended wear rates and lowest trended remaining lifetime should be re-inspected.
3. Components with measured chromium greater than 0.10% and no significant wear found during the first inspection need not be re-inspected. This exclusion does not apply to components subject to damage from mechanisms other than FAC (e.g., cavitation, flashing or droplet impingement).
4. Components downstream of FAC-resistant components. Experience has shown that the entrance effect will degrade the attachment weld area of the downstream component [31].

4.4.2 Susceptible-Not-Modeled Lines

Certain large bore systems, or portions of systems, such as auxiliary steam, drain collection headers and gland steam, may have unknown or widely varying operating conditions that prevent the development of reasonably accurate analytical models. These lines are sometimes called Susceptible-Not-Modeled Lines (SNM). Inspection locations on these lines should be conservatively selected considering:

1. Engineering judgment.
2. Evaluation of past inspection data to identify components with the highest trended wear rate and shortest remaining service life. Trended results should be adjusted for changes to power level and/or chemistry where such changes will increase wear rates.

3. Operating experience (see Subsection 4.4.4).
4. Plant experience (see Subsection 4.4.3).
5. Locations or runs with high relative susceptibility (e.g., high velocities, wet steam, temperatures near the peak of the FAC susceptibility curve [300-350°F (149-177°C)], etc.)
6. Locations with high consequence of failure, including, but not limited to:
    a. Large diameter, high-energy lines.
    b. Nuclear safety-related lines.
    c. Locations with close proximity to personnel.
    d. Locations with close proximity to safety-related equipment.
7. Components with measured chromium greater than 0.10% and no significant wear found during the first inspection need not be re-inspected. This exclusion does not apply to components subject to damage from mechanisms other than FAC (e.g., cavitation, flashing or droplet impingement).
8. Components downstream of FAC-resistant components. Experience has shown that the entrance effect will degrade the attachment weld area of the downstream component [31].

4.4.3 Inspection Locations Based on Plant Experience

Plant experience over the past operating cycle(s) should be reviewed to add components as appropriate to the inspection plan. These locations should include:

- Components whose inspection was deferred from a prior outage.
- Components downstream of a leaking steam trap or isolation valve.
- Components downstream of equipment that has been determined to be operating outside of design conditions.
- Components downstream of a control valve that is being used differently than in the past (i.e., being throttled more often or more severely than in the past).
- Components downstream of a control valve with actuator problems.
- Components downstream of FAC-related leaks or locations of significant wear, or in corresponding locations of parallel trains to locations that have leaked or demonstrated significant wear.
- Components based on information received from related plant organizations such as thermal performance, system engineering, valve engineers, heat exchanger engineers, maintenance, operations, etc.

4.4.4 Inspection Locations Based on Operating Experience

The following locations have been identified by operating experience to be highly susceptible to FAC and should be conservatively evaluated for inclusion in the outage inspection plan:

- Locations downstream of orifices, flow elements, venturis, thermowells, angle valves, flow control valves or level control valves.
- Locations or lines known to contain backing rings or counterbore.
- Field-fabricated tees and laterals.[9]
- Nozzles.
- Complex geometric locations such as components located within two diameters of each other (e.g., an elbow welded to a tee).
- Components downstream of replaced components (upstream if expander), and components that have been replaced in the past if not upgraded to resistant material.
- Components (including straight pipe) immediately downstream of FAC-resistant components (e.g., containing chromium greater than 0.10%) [31].
- Locations immediately downstream of turning vanes.
- Expansion joints.
- An occasional inspection of the main steam piping may be desirable until additional industry data become available to support the position that no further inspections are necessary.
- Superheated extraction lines should be occasionally inspected to confirm they are operating with superheat.

Operating experience has also found that carbon steel components, pup pieces, safe-ends, and nozzles are sometimes inadvertently left in lines or segments that are believed to be entirely constructed of non-susceptible material. Reasonable efforts should be made to locate and inspect (and preferably replace) such components. These efforts should include:

- A review of weld maps.
- A review of past work orders.
- Discussions with plant personnel.
- Use of alloy testing equipment when inspecting neighboring components (Subsection 4.5.7).

Additionally, operating experience should be periodically reviewed to identify other locations that should be evaluated for potential inclusion in the outage inspection plan. Sources for operating experience include:

- INPO or WANO Operating Experience.
- Internal Operating Experience

[9] Special attention is recommended for field-fabricated tees and laterals as they sometimes have protuberances into the flow stream (increasing local turbulence) and they often lack structural reinforcement.

- Presentations and reports provided at CHUG meetings.
- Plant Experience Reports provided on the CHUG web site.
- CHUG Bulletins.
- NRC Information Notices and Bulletins.
- CHUG Website Discussion Board topics.

4.4.5 Inspections of Susceptible Equipment

Equipment that is susceptible to FAC using the criteria of Subsection 4.2 should also be inspected. Recommendations for inspection of susceptible valves are provided in Subsection 4.5.6. Recommendations for prioritization and inspection of susceptible vessels and equipment are provided in Appendix B.

4.4.6 Expanded Sample Inspection

Under certain circumstances, it may be necessary to increase the inspection sample.

1. If inspection results *are unexpected and inconsistent* with predictions, and have a *significant negative* effect on component remaining service life, the reasons for those inconsistencies should be investigated. An updated FAC predictive analysis should be performed, and additional inspections conducted and material determinations (Subsection 4.5.7) made as appropriate. If they have not been recently inspected, the expanded sample should include the following:
    a. Any component within two diameters downstream of the component displaying significant wear or within two diameters upstream if that component is an expander or expanding elbow.
    b. A minimum of the next two most susceptible components from the relative wear ranking in the same train as that containing the piping component displaying significant wear.
    c. Corresponding components in each other train of a multi-train run with a configuration similar to that of the piping component displaying significant wear.
2. When inspections of the expanded sample specified under Item (1) above detect additional components with significant FAC wear, the sample should be further expanded to include:
    a. Any component within two diameters downstream of the component displaying significant wear or within two diameters upstream if that component is an expander or expanding elbow.
    b. A minimum of the next two most susceptible components from the relative wear ranking in the same train as that containing the piping component displaying significant wear.
3. When inspections of the expanded sample specified under Item (2) above detect additional components with significant wear, expansion of the sample specified under Item (2) should be repeated until no additional components with significant wear are detected.

4.5 Performing Inspections

4.5.1 Inspection Technique for Piping

Components can be inspected for FAC wear using ultrasonic techniques (UT), radiography techniques (RT), or by visual observation. Both UT and RT methods can be used to determine whether or not wear is present. However, the UT method provides more complete data for measuring the remaining wall thickness of large-bore piping. RT is commonly used for socket-welded fittings and components with irregular surfaces such as valves and flow nozzles. RT has the advantage of providing broad coverage with a visual indication of any wall loss. Additionally, RT can be performed without removing the pipe insulation, during plant operation, and, in some cases, with reduced scaffolding needs. Although radiography may provide cost and outage time savings, it may have impacts on other outage and non-outage tasks due to radiological requirements. Nearly all utilities are using the manual UT method with electronic data loggers for performing most of the large-bore inspections. Visual observation is often used for examination of very large diameter piping (e.g., cross-under and cross-over piping), followed by UT examinations of areas where significant damage is observed or suspected. Reference [32] provides details of various inspection methods.

For large-bore piping, the recommended UT inspection process consists of marking a grid pattern on the component and using the appropriate transducer and data acquisition equipment to take wall-thickness readings at the grid intersection points. If the readings indicate significant wall thinning, the region between the grid intersection points should also be scanned, or the size of the grid should be reduced to identify the extent and depth of the wall thinning.

Although scanning the entire component and recording the minimum thickness is not recommended, scanning within grids and recording the minimum found within each grid square is an acceptable alternative to the above method. However, it should also be noted that scanning within grids and recording the minimum can decrease the accuracy of using the point-to-point method of determining wear (Subsection 4.6.3).

The inspection data are used for four purposes:

1. To determine whether the component has experienced wear and to identify the location of maximum wall thinning.
2. To ascertain the extent and depth of the wall thinning.
3. To evaluate the wear rate and wear pattern to identify any trends.
4. To demonstrate fitness for service.

To attain all four objectives, it is recommended that the component be inspected using a complete grid with a grid size sufficient to detect worn areas (see Subsection 4.5.3). Although scanning will meet the first two objectives, it will not provide sufficient data to determine component wear rates or to develop sufficient data to perform a detailed stress analysis of a worn component. Further, scanning is of limited use in trending the wear found.

High-temperature paints, china markers, or other Station approved marking devices should be used to identify the grid intersection points where the measurements will be taken. This will ensure that future inspections can be repeated at the same locations. It is good practice to mark at least one location, such as the grid origin, with a low stress stamp or an etching tool. This provides a means of re-establishing the grid if the markings are removed or obscured. Note that approved marking materials should be used when gridding components. Templates may also be used to achieve repeatable inspections.

When a component is to be replaced with another component made of a non-FAC resistant material, it is recommended that baseline UT data should be obtained.[10] The new component should also be examined visually to observe the eccentricity, surface condition, roughness, and local thinning that may be caused by depressions in the surface or manufacturing flaws, etc. This information and data should be recorded and will provide a good baseline for determining future wear of the replaced component. Additionally, if there is any evidence that some of the wear may have been caused by a mechanism other than FAC (e.g., cavitation or droplet impingement), then consideration should be given to developing an appropriate inspection program to address the suspected phenomenon (e.g., reference [2]).

The inspection grid should have a unique identification for each measurement location. For compatibility with the CHECWORKS™ computer code, if used, it is recommended that letters designate circumferential locations, and numbers designate axial locations on grids. It is also recommended that the origin of the grid be on the upstream side of the component and the grid progress clockwise when looking in the direction of flow.

4.5.2 Grid Coverage for Piping Components

Experience has shown that it is very difficult to predict where the maximum wear will occur in a given component. (For the purpose of this section, a component refers to both fittings and straight pipes.) To ensure that the maximum FAC wear can be detected, the UT grid should fully cover the pipe fitting being inspected and cover the appropriate connection area of the attached pipes. A full-coverage grid of pipe fittings also provides a good baseline for future inspections. As wear can spread over time, a partial grid, even if larger than the original wear area, may be too small to ensure that the full extent of future wear can be detected.

It is also beneficial to inspect the area on both sides of each pipe-to-component weld. It is desirable to start the grid line on both sides of the weld, as close as possible to the toe of the weld, in order to locate potential thin areas adjacent to the weld. This will help detect the use of counterbore to match the two inner surfaces, or the localized wear that is sometimes found adjacent to welds[11]. Having data on the connected pipe can also be helpful in evaluating whether variation of wall thickness in the component is FAC wear or fabrication variations. In many cases, the grid in the counterbore region will have to be evaluated separately.

It is also suggested that when fittings are welded directly to fittings, the weld area on the upstream and downstream fittings be inspected. This will provide the same benefits as discussed above.

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[10] A baseline inspection is also recommended for FAC resistant material when the location is susceptible to non-FAC wear.

[11] This effect has been most frequently observed at locations where a carbon steel component is downstream of a more resistant component (chromium $\geq$ 0.1%). See [31].

The results of EPRI tests, as well as the evaluation of data from a large number of power plant inspections, show that FAC can also extend into the piping downstream of a component. Consequently, it is recommended that the inspection grid extend from two grid lines upstream of the toe of the upstream weld to a minimum of two grid lines or six inches (150 mm), whichever is greater, beyond the toe of the downstream weld (see Figure 4-1). For all types of components, the grid of the downstream extension should extend the full recommended distance regardless of whether or not it contains a circumferential weld. In this case, additional grids should be located at both toes of the additional weld encountered. If there is a straight pipe immediately downstream of the examined component and the measured wall thickness in the pipe is decreasing in the downstream direction, or if significant wear is present, the inspection grid should be continued downstream until an increasing thickness trend is established. If expanded inspections are performed on the downstream pipe, then the pipe should be separately evaluated for acceptance.

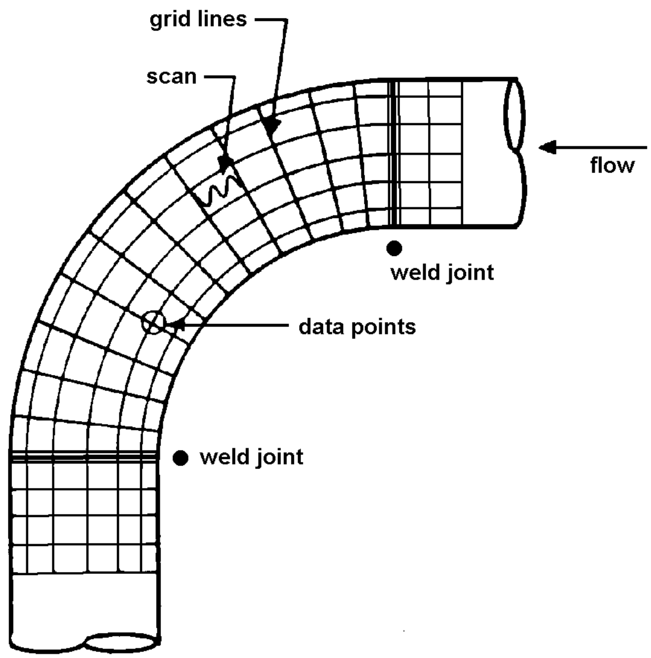

Figure 4-1
Grid Layout for an Elbow

Test results also show that in the case of expanders (or diffusers) and expanding elbows, FAC can occur upstream of the component as well. It is recommended that for these components the wall thickness in the upstream pipe be measured. The grid should be extended upstream two grid lines or six inches (150 mm), whichever is greater. The grid should be extended further upstream if necessary.

Maximum wear in straight pipe downstream of components typically occurs within two diameters of the connecting weld. Consideration should be given to extending the grid two diameters downstream (or two diameters upstream for expanders and expanding elbows). This may avoid extra inspection time during the outage to investigate the first two grids and then having to inspect further downstream.

Orifices, flow nozzles, and other like components cannot be inspected completely with UT techniques due to their shape and thickness. The pressure boundary can be inspected using either the UT technique or radiography (see Subsection 4.5.4). The internals can be inspected using either RT or visual examinations.

Equipment nozzles that are of irregular shape (non parallel interior and exterior surfaces) can be examined visually or by radiography (see Subsection 4.5.4). Additionally, their condition can be inferred by inspecting the downstream pipe for a distance of two diameters from the connecting weld, and, if possible, one or two grids on the nozzle itself. If significant wear is detected in the downstream pipe, the nozzle should also be examined. This approach is only applicable if the piping downstream is manufactured of material with equal or higher susceptibility (equal or lower chromium content), and has not been repaired or replaced. Equipment nozzles that have parallel inside and outside surfaces can be gridded and inspected similarly to piping components.

4.5.3 Grid Size for Piping Components

To be compatible with CHECWORKS™, if it is used, grid lines should be either perpendicular or parallel to the flow. For elbows, the lines perpendicular to the flow (inspection bands) are radial lines focusing on the center of curvature. This results in the same number of grid intersection points on both the intrados and the extrados of an elbow. The suggested grid layout is shown in Figure 4-1.

It is important that the grid size (maximum distance along the component surface between grid lines) be small enough to ensure that the thinned region can be identified. Experience and plant data have shown that the grid size should be such that the maximum distance between grid lines is no greater than $\pi D/12$, where D is the nominal outside diameter. The grid size need not be smaller than one inch (25 mm), and should not be larger than six inches (150 mm). The following table illustrates the maximum grid sizes for standard pipe sizes. The user should select convenient grid sizes equal to, or smaller than, those tabulated for the pipe sizes of interest.

The grid size given in Table 4-1 is sufficient to detect the presence of wear, but may not be small enough to determine the extent and maximum depth of that wear. Therefore, where inspections reveal significant FAC wall thinning, the grid size should be reduced to a size sufficient to map the depth and extent of the thinned area. A grid size of one-half the maximum size should be sufficient for mapping. The inspector may also need to perform scans in areas where low readings occur.

Because of the importance of grid layout in the inspection process and in the interpretation of the obtained data, it is important that the grid layouts used be well thought out and not be changed arbitrarily. This will provide the best possible value from the data sets obtained and for future inspections.

Table 4-1
Maximum Grid Sizes for Standard Pipe Sizes

Pipe Size, inch (mm)	Outside Diameter, inch (mm)	Maximum Grid Size, inch (mm)
2 (50)	2.375 (60.325)	1.00 (25)
3 (75)	3.500 (88.900)	1.00 (25)
4 (100)	4.500 (114.300)	1.17 (30)
6 (150)	6.625 (168.275)	1.73 (44)
8 (200)	8.625 (219.075)	2.25 (57)
10 (250)	10.750 (273.050)	2.81 (71)
12 (300)	12.750 (323.850)	3.33 (85)
14 (350)	14.000 (355.600)	3.67 (93)
16 (400)	16.000 (406.400)	4.19 (106)
18 (450)	18.000 (457.200)	4.71 (120)
20 (500)	20.000 (508.000)	5.23 (133)
24 (600)	24.000 (609.600)	6.00 (152)
>24 (600)	——	6.00 (152)

Although these recommendations should generally be used, occasionally special circumstances—most particularly high radiation fields—may justify the use of a larger grid. If larger grid spacings are used, then the evaluation of the data, the planning of future inspections, and the repair evaluations should be done with additional conservatisms.

4.5.4 Use of RT to Inspect Large-Bore Piping

RT can be used to inspect large-bore piping [33]. Either the tangential technique or the through-wall technique can be used. If the tangential technique is used, the comparator should be of known dimensions, and placed at the neutral axis of the pipe with respect to the location of the radioactive source. If the double wall technique is used, evidence should be provided such that the gray scale has been adequately correlated to wall thickness and has been corrected to the projected wall thickness of the pipe as viewed from the radioactive source.

An adequate number of film shots should be taken to characterize the wall thickness around the circumference of the pipe.

4.5.5 Use of Visual Inspections

Inspection of cross-around piping[12] is normally made visually from inside the pipe, with UT thickness readings taken at areas of suspected wall loss. The UT readings can be taken from either inside or outside the pipe.

Visual inspection is also commonly used to inspect for damage at turning vanes and other difficult to inspect areas such as mitered elbows.

[12] Cross-around piping is the very large piping (e.g., 36-60”, 900-1500 mm diameter) that carries wet steam from the high-pressure turbine to the moisture separator reheater and normally dry steam from the moisture separator reheater to the low-pressure turbine.

4.5.6 Inspection of Valves

Valves cannot be inspected with UT techniques due to their shape (i.e., non-parallel surfaces). Acceptable methods for examining valves are by one of the following methods:

1. Use of visual inspection. Valves susceptible to FAC should be internally visually inspected for wear during routine maintenance.
2. Use of radiography (RT, see Subsection 4.5.4).
3. Inspecting the downstream pipe for a distance of two diameters from the connecting weld. If possible, one or two grids can also be placed on the valve itself. If significant wear is detected in the downstream pipe, the valve should also be examined by one of the two methods identified above. This approach is only applicable if the piping downstream is manufactured of material with equal or higher susceptibility (equal or lower chromium content), and has not been repaired or replaced.

4.5.7 Measuring Trace Alloy Content

It is well known that the presence of small amounts of chromium—and to a lesser extent copper and molybdenum—will dramatically reduce the rate at which FAC occurs (e.g., [30] and [34]). The benefits of measuring trace alloy content of the component and connecting welds include:

- The alloy content can be factored into the Predictive Plant Model on a component-by-component basis to improve the accuracy of predictions and to ensure that the inspection program is directed at the fittings most likely to wear. These measurements are particularly useful in cases where the measured wear is substantially less than the predicted wear. This will help in both understanding the reason for the differences as well as improving the accuracy of the Predictive Plant Model. Note that material libraries built into computer codes such as CHECWORKS™, normally use minimum specified values for the alloy content.

  Note that adding the measured chromium to the CHECWORKS™ model may degrade the calculated line correction factor. Analysts should be aware of this fact, and carefully evaluate the performance of the predictive model in this situation.

- If the measured chromium content is greater than 0.10%, and no significant wear is encountered in the first inspection, then the component can be removed from future inspections (see Subsections 4.4.1.2, 4.4.1.3 and 4.4.2). This exclusion does not apply to components subject to damage from mechanisms other than FAC (e.g., cavitation, flashing or droplet impingement).
- Identifying locations that may be at greater risk for FAC due to being downstream of locations containing greater amounts of chromium [31, 35].
- Such measurements will help identify locations where carbon steel has inadvertently been used in lieu of higher alloy materials identified on plant design drawings.
- Alloy measurements of two adjacent components and the connecting weld can help identify locations where the base material has significantly more alloy content than the weld, thus making the weld potentially susceptible to galvanic corrosion [36]. The welds at such locations should be fully inspected using UT or RT.

If alloy measurements are used, the analyst must make certain that the measurements are accurate enough to ensure that the predictions remain conservative.

4.6 Evaluating Inspection Data

4.6.1 Evaluation Process

The purpose of evaluating the inspection data is to determine the location, extent, and amount of total wear for each inspected component. The evaluation process is complicated by several factors, including the following:

- Unknown initial wall thickness (if baseline data were not taken).
- Variation of as-built thickness along the axis and around the circumference of the component.
- Inaccuracies in NDE measurements.
- The possible presence of pipe-to-component misalignment, backing rings, or the use of counter-bore to match two surfaces.
- Data recording errors or data transfer errors.
- Obstructions that prevent complete gridding (e.g., a welded attachment).
- Difficulties associated with inspections performed through surface coatings (e.g., UT without removing the coating). Also, related difficulties encountered when performing screening with lagging and or insulation present (e.g., pulsed eddy current exams of feedwater heater shells).

The challenge is to minimize the effect of these problems by applying uniform evaluation methods and utilizing engineering judgment.

The large amount of inspection data can present a substantial data management problem. To manage the data, it is recommended that a scheme be utilized to organize and maintain the data logger files. A database should be used to store past inspection data and contain provisions to accommodate future inspection data. The database will provide an efficient means of organizing and accessing the data.

The evaluation process consists of reviewing the inspection data for accuracy, determining the total wear, and determining the wear rate for each inspected component. These processes are described below.

4.6.2 Data Review

The inspection data should be carefully reviewed to identify any data that are judged to be questionable. Questionable data points should be verified. High and low readings should be compared to adjacent readings to evaluate their validity. One high or low reading in an area of consistent thickness may indicate an erroneous reading. Finally, depending on the component type, the variation in thickness attributable to manufacturing variations should be separated from the FAC wear. Reviewing data from the attached upstream and downstream pipe can be helpful. Elbows, tees, nozzles, reducers and expanders are examples of components in which there is significant variation in thickness due to the manufacturing process. The presence of backing rings and counter-bore should be noted so that these effects can be separately evaluated. In particular, when counter-bore is noted, consideration should be given to evaluating the counter-bore area for wear and remaining service life independently from that of the remainder of the component.

Once the data set is acceptable, any wear region on the component should be identified. The location of a potential wear region should be compared with the component orientation, flow direction, and attached piping. The variation in thickness within this region should be compared to the adjacent region to confirm the existence of wear. If data from previous inspections are available, they should be compared with the current measurements, and wear trends/patterns should be identified.

4.6.3 Determining Total Wear and Wear Rate

Wear evaluations fall into two categories. The first category includes those components for which baseline (pre-service) thickness data are available. The second category includes those components for which no baseline data exist. The method used for calculating the component maximum wear (the maximum depth of wall thinning since the component was installed or repaired) will be different for the second case as the initial thickness is unknown.

There are eight methods commonly used for determining the wear of piping components from UT inspection data[13]. The methods are:

- Band Method.
- Averaged Band Method.
- Area Method.
- Moving Blanket Method.
- Strip or Axial Method.
- Point-to-Point Method.
- Least Squares Slope Method.
- Total Points Method.

The first five of the above methods –Band, Averaged Band, Area, Blanket and Strip– also estimate the components initial thickness and can be used to evaluate components with single outage inspection data. All the methods are predicated on the theory that the wear caused by FAC is typically found in a localized area or region. The methods are described in a number of references including [22, 25, 37].

[13] The validity of the methods to determine wear and to estimate the component's initial thickness is based on grid sizes and configurations consistent with those recommended in Subsection 4.5.

4.6.3.1 Summary

It is the responsibility of the owner to select the evaluation method for each set of UT data. Further information on each of these methods, along with guidance for evaluating various types of components including counterbore areas, is provided in the modeling guidance of [1, 25, 37].

4.7 Evaluating Worn Components

4.7.1 Acceptable Wall Thickness

A component can be considered suitable for continued service if the predicted wall thickness, t_p, at the time of the next inspection is greater than or equal to the minimum acceptable wall thickness, t_{accpt}

$$t_p \geq t_{accpt}$$

where:

t_p = Predicted remaining wall thickness at a given location on the component
t_{accpt} = Minimum acceptable wall thickness at location of t_p

Note that t_p can be rewritten in terms of the current thickness, t_c, as:

$$t_p = t_c - \text{“predicted wear”}$$

or

$$t_p = t_c - R \times T \times SF$$

where:

t_c = Current wall thickness at location of t_p
R = FAC wear rate at location of t_p
T = Time until next inspection
SF = Safety Factor, see Subsection 4.9

The wear rate and the amount of wear vary throughout a component. However, with most methods the component maximum wear rate is assumed to occur throughout the component, giving a predicted future thickness profile as shown in Figure 4-2. Note that this approach is conservative, as the amount of wear is overstated at all locations other than the point of maximum wear. See Subsection 4.7.2 for a method to determine the component maximum wear rate. An acceptable approach to determine the future thickness profile is to use the local wear rate from the point, band or area under consideration, combined with engineering judgment and a higher Safety Factor than if a uniform wear rate is assumed to occur.

For susceptible components that have not been inspected, the predicted thickness should be used to calculate the lifetime of the component. The component nominal wall thickness should be utilized as the initial thickness unless another value can be justified.

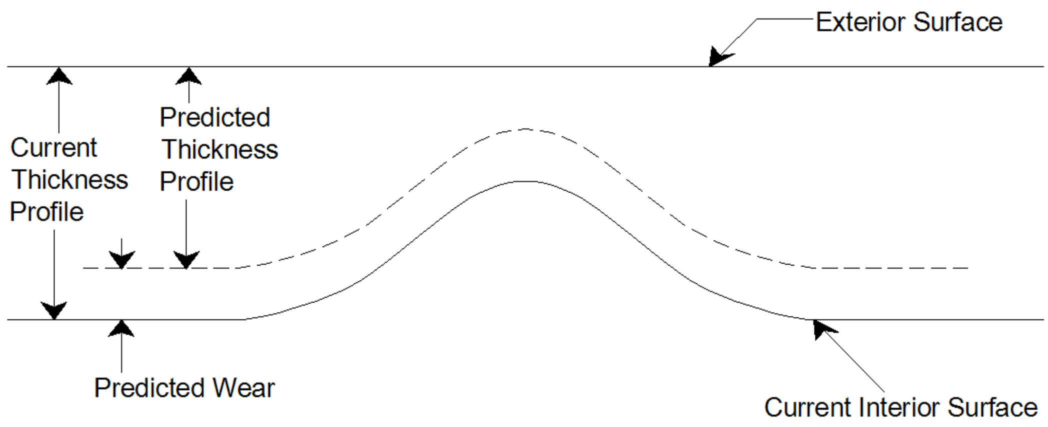

Figure 4-2
Predicted Thickness Profile

A reasonable Safety Factor (see Subsection 4.9) should be applied to the predicted wear rates to account for inaccuracies in the FAC wear rate calculations. This can also provide a mechanism by which the analyst may apply engineering judgment in setting the interval for re-inspection. As the plant program matures and several outages of good inspection data are collected, the Safety Factor can be changed based on the use of actual inspection data.

The minimum acceptable wall thickness for each component should be calculated. For ASME Class 1, 2 and 3 pipe, component acceptance criteria are typically based on the ASME Boiler and Pressure Vessel construction code of record for the plant [38], or using Code Case N-597-2 [5], which is based on EPRI report NP-5911 [39]. However, for application to safety-related piping, the U.S. Nuclear Regulatory Commission has placed certain conditions on the application of Code Case N-597-2 as identified in reference [40]. For ANSI B31.1 pipe [41], component acceptance criteria are typically based on the construction code of record for the plant, Non-mandatory Appendix IV of B31.1 [6], or from guidance provided by industry standards such as Code Case N-597-2.

It is recommended that the calculation of t_{accpt} be performed and documented by an engineer qualified to perform pipe stress analysis.

4.7.2 Maximum Wear Rate

The Predictive Plant Model should be used to predict the future maximum wear rate for every component analyzed, whether inspected or not. For those components that have been inspected, two methods have been used to determine the wear rate directly from the inspection data.

With the first method, the component maximum wear is divided by the period of service to obtain the average wear rate over the component lifetime. This past rate is then assumed to continue into the future. However, this method may cause several potential inaccuracies:

1. If baseline thickness data are not available, the initial thickness is unknown. Thus, the estimated wear may be considerably higher or lower than the actual wear. This effect is smoothed out in CHECWORKS™, by using several components with a statistically calculated line correction factor.

2. This method assumes that operating conditions that affect FAC wear rate, (e.g., water chemistry, plant power level) have not changed since plant startup. If changes did occur, the current wear rate could be considerably different from the average wear rate.
3. The method cannot accommodate potential future changes in operating conditions or chemistry.

Figure 4-3 shows the potential for error when using an average wear rate based on inspection data and changing operating conditions for determining component lifetimes.

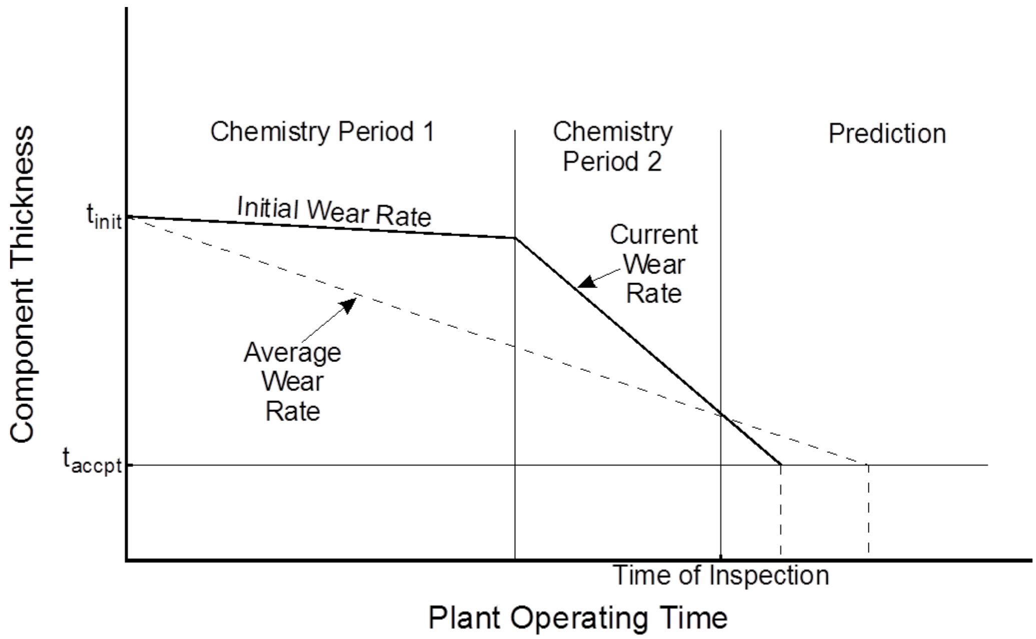

Figure 4-3
Potential for Error when Using Average Wear Rate Based on Inspection Data

When data from more than one inspection are available, point-to-point methods can be utilized (see Subsection 4.6.3). In the most common variant, the Maximum Method, the measured thickness at the point of maximum wear from the current outage is subtracted from the value measured at the previous outage. This difference is then divided by the time interval to obtain the average wear rate. It has the advantage of being mechanical—the maximum wear is simply the maximum difference between two sets of readings at the same location. Note that the user does not have to estimate initial thickness of the component in order to calculate the measured wear. The difficulties in using the point-to-point methods occur in cases where the wear between the outages is small. Two large numbers (wall thickness) are subtracted to obtain a small number (wear since previous outage) and then divided by another relatively small number (interval between outages) to determine the wear rate. UT measurement inaccuracies could cause significant calculation error with these methods. This is illustrated in Figure 4-4. However, in most cases where inspection data from several inspection outages are available, the point-to-point methods will provide more accurate determinations of wear than other methods. However, it is important to understand that point-to-point methods do not account for changes in operating conditions or in water chemistry that have occurred between the two measurements. Thus, if such changes have occurred, point-to-point methods should be used with caution. This is schematically illustrated in Figure 4-3.

If CHECWORKS™ is used, it is recommended that until data from several inspections are available, the CHECWORKS™ predicted "current" wear rate be used. CHECWORKS™ takes into account past and planned future operational changes, actual chromium content (if tested), and averages out some of the temporal variations of the input parameters. If the analyst chooses to use wear rates calculated from inspection data, they should first be compared with the predicted values. Note that the critical thickness, t_{crit}, used for each component is defined on a global basis[14]. Thus, t_{crit} of a given component may be different from the actual component-specific t_{accpt} value calculated by an experienced pipe stress analyst.

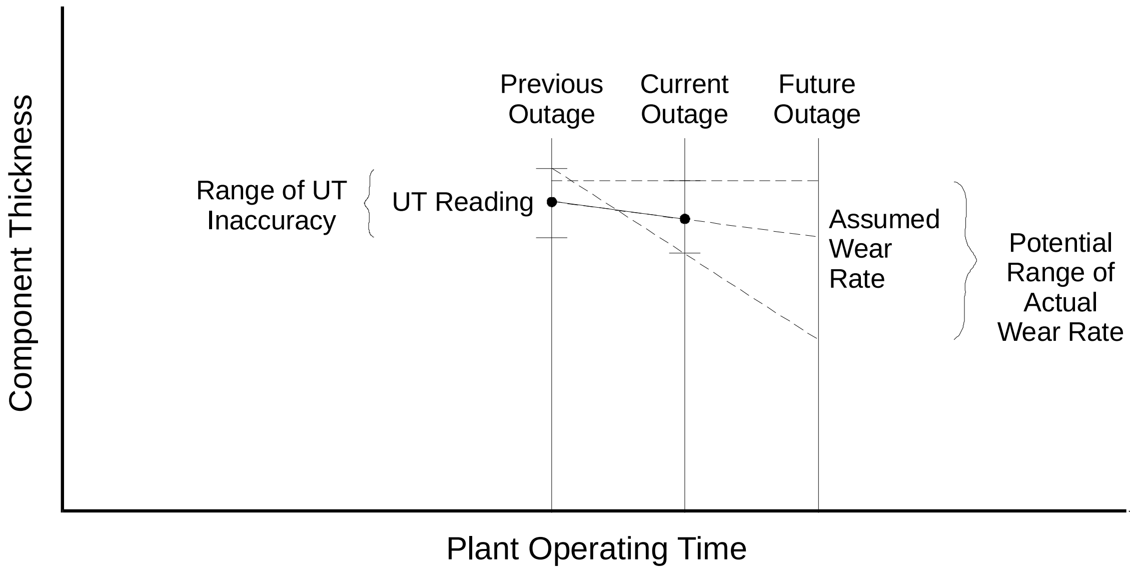

Figure 4-4
Danger of Using Wear Rate Based on Inspection Data from Two Inspections

4.7.3 Remaining Service Life

It is recommended to determine the remaining FAC service life, T_{life}, of each component,

T_{life} = (current thickness – minimum acceptable thickness)/ (current wear rate x SF)
T_{life} = $(t_c - t_{accpt})/(R \times SF)$

For those components that have been inspected, it is recommended that actual measured values be used for t_c. For components not inspected, t_c can be predicted utilizing predicted wear rates,

t_c = t_{init} - "predicted wear"
= $t_{init} - T \times R \times SF$

where:

T = Component service time to date
R = Average wear rate over time T
SF = Safety Factor, see Subsection 4.9

[14] t_{crit} is a value determined by CHECWORKS™ based on user-specified criteria. Most often, it is the thickness needed to satisfy the hoop stress allowable of the ASME Code. It should be noted that meeting the hoop stress allowable is not sufficient to ensure that ASME Code requirements are met (see Subsection 4.7.1).

If the predicted remaining service life is shorter than the amount of time until the next inspection, there are three options for disposition of the component:

1. Shorten the inspection interval.
2. Perform a detailed stress analysis to obtain a more accurate value of the acceptable thickness.
3. Repair or replace the component.

4.8 Repairing and Replacing Components

The following items should be considered in making replacement decisions:

- The cost and availability of replacement fittings.
- The need for skills and procedures to weld alloy steels and clad material to carbon steel.
- The pre- and post-weld heat treatments generally required for welding “chrome-moly” fittings[15]. This heat treatment may affect the outage schedule.
- The piping stress analysis required if a large portion of a carbon steel line is replaced with stainless steel.
- The feasibility of replacing the entire system with a more wear-resistant material.
- Limits on hexavalent chromium when cutting, grinding, and welding chromium-based materials [42].

If repair is decided upon, wall thickness restoration via an engineered external weld overlay may be appropriate. The rules of ASME B&PV Code Section XI, Code Cases N561-2 [43] and N562-2 [44] provide guidance for design and application of the overlay. Note that the service life of the overlay is to be determined by the licensee via inspection as described in the Cases. In some applications, the overlay may be permanent. Plants must ensure they are following their design requirements.

However, interior weld buildup is generally preferred to exterior buildup for the following reasons:

- Interior weld repair results in a smoother internal surface. Conversely, use of exterior buildup and leaving the interior surface irregular will tend to increase turbulence and accelerate the wear rate.
- By using interior weld repair, the resulting, smoother internal surface reduces the difficulty of making future UT inspections.
- An exterior weld buildup tends to result in a more complex state of stress.
- Exterior weld buildup has not been accepted by the NRC for the long-term repair of safety-grade piping.

However, interior weld buildup is often limited by accessibility.

[15] Some organizations have developed justification and procedures to exempt “chrome-moly” welds of one-half inch (13 mm) and less thickness from pre- and post-weld heat treatments.

Temporary clamping devices are often used to make temporary repairs to balance-of-plant piping. Repairs to ASME class piping should be performed in accordance with Section XI [45] and NRC requirements.

If repair or replacement of a component is necessary, it is recommended that the plant owner develop a strategy (e.g., replacement with a more resistant alloy) so that the wear process does not continue. A discussion of long-term options to reduce wear rates is provided in Section 5. The use of FAC-resistant material, especially when done on a line or spool piece basis, provides the following benefits:

- Assures that FAC is eliminated in this portion of the system.
- Eliminates the need for future FAC inspections in those portions of the line.
- Reduces iron transport to the steam generators or reactor vessel, as a disruptive deposition on flow measurement nozzles, and extends the life of demineralizer resin beds.
- Reduces the probability that a carbon steel component, pup piece, nozzle, or safe-end is left in the system and inadvertently left out of the inspection program.

However, there are cases in which use of like-for-like (*i.e.,* non-FAC resistant) material is appropriate. These cases include:

- The plant is now using a significantly better water chemistry or the line will experience less damaging operating conditions (e.g., a higher steam quality) such that the replacement is projected to last the remaining life of the plant.
- Procurement of a resistant material would delay plant restart. In this case, consideration should be given to upgrading the replacement with a resistant material at the next outage.
- The remaining life of the plant, including potential life extension, is such that a like-for-like replacement will perform satisfactorily.
- Life cycle costs and risk considerations associated with like-for-like replacement, including associated inspection costs, do not support change to FAC-resistant material.
- Note: Replacement carbon steel piping and components can be procured with sufficient chrome content to be FAC resistant and still maintain the original materials properties. (See Section 5.2.)

4.9 Determination of the Safety Factor

There are numerous places to apply safety factors throughout the process of making the Predictive Plant Model, selecting inspection locations, performing inspections, interpreting the inspection data, and determining fitness for continued service and remaining service life. It is recommended that only one safety factor be used in the process and that it be applied when determining fitness for continued service and the re-inspection interval. Application of safety factors earlier in the process can distort the inspection sample and divert inspection resources from higher risk areas to lower risk areas.

One example is the use of "conservative" operating conditions in the Predictive Plant Model. If the conservatism is not equal in all lines, then the inspection sample will be skewed to lines where the conservatism is the greatest. This will also distort the Line Correction Factor and make calibration of the line difficult. Another example is conservatism applied when determining measured wear and/or trended wear rates. This will tend to skew future inspections to re-inspections of components and not give proper consideration to components that have never been inspected.

Examples of multiple Safety Factors include two or more of the following:

- Applying a Safety Factor to the trended or predicted wear rate.
- Re-inspection of a component earlier than its remaining service life, rounded down to the next whole outage.
- Applying the maximum trended wear rate to the thinnest location on the component.
- Use of a prescribed wear rate regardless of the data.
- Use of envelope loads to determine the acceptable thickness.
- Assuming that tinit is greater than the nominal thickness without any supporting data.
- Re-inspecting when the predicted thickness is less than some arbitrary percentage of nominal thickness.
- Procedures that require a fixed percentage of components to be re-inspected each outage.

The Safety Factor can vary from line to line and component to component. Selection of the appropriate Safety Factor is the responsibility of the owner and should consider:

- The minimum Safety Factor should never be less than 1.1 [46].
- Cases where a greater Safety Factor should be considered include:
  - Locations where the predicted or trended minimum wall thickness is greater than the measured minimum wall thickness.
  - Lines or locations that are new to the FAC program (Subsection 4.4.1.1).
  - Lines that are not calibrated (Subsection 4.4.1.3).
  - Lines with uncertain operating conditions (Subsection 4.4.2).
  - Lines that are known to contain backing rings (Subsection 4.4.4).
  - Locations downstream of orifices or control valves (Subsection 4.4.4).
  - Locations that may be subject to degradation from other sources such as cavitation or liquid droplet impingement.
  - Lines and/or locations that are high energy and located in a high traffic area.
  - Line that are nuclear-safety-related.
  - Lines or locations that are high energy and located in close proximity to safety-related equipment.
  - Lines that have a history of problems or similar to lines with a history of problems.
  - Lines with limited inspection data and no measurements of trace chromium.

- Lines where the operating conditions have been made or will be made significantly more severe.
- Use of grid sizes larger than those recommended in Subsection 4.5.3.

Components where the local rate of thinning is determined at each point on the component, and used to determine the local remaining service life.

5 DEVELOPMENT OF A LONG-TERM STRATEGY

5.1 Need for a Long-Term Strategy

Development of a long-term strategy is recommended. The strategy should focus on reducing the plant FAC susceptibility. Optimizing the inspection planning process is important, but reduction of FAC wear rates is needed if both the number of inspections and the probability of failure are to be reduced (see Figure 5-1).

One mitigating approach that is sometimes used is to replace only those fittings that have experienced significant wear. This approach is satisfactory if the wear is highly localized. This is the case in which the wear is concentrated downstream of a flow control valve or an orifice. In most cases, though, the wear is widespread throughout a given system. Since flow conditions and water chemistry in a given line tend to be the same, it is only a matter of time until upstream or downstream fittings will also need to be replaced. This fitting-by-fitting replacement approach is less expensive in the short term, but is generally not cost effective over the long term. Plants using this selected replacement technique have also experienced unexpected failures in components scheduled for future replacement.

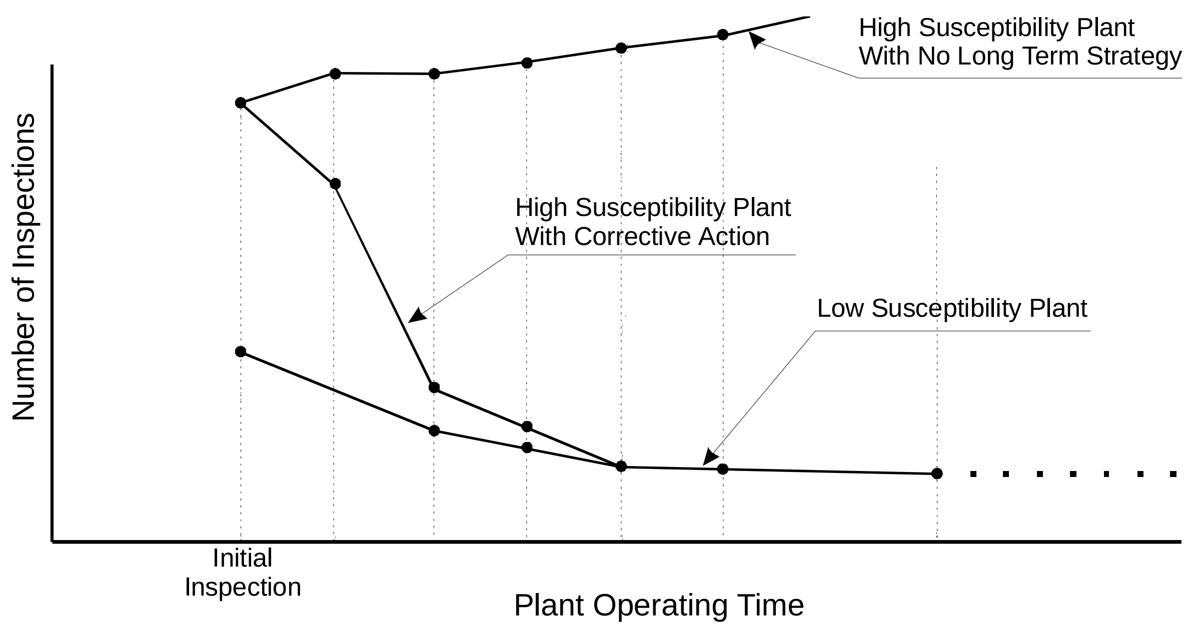

Figure 5-1
Expected Trends for Inspections Over a Plant's Life

It is recommended that in order to achieve the long-term goals of reduced cost and increased safety, a strategy of a systematic reduction of FAC rates be adopted. Three options are available to reduce FAC wear rates. These are:

1. Improvements in materials.
2. Improvements in water chemistry.
3. Local design changes.

Material improvements can reduce the wear rate to effectively zero. Depending on the location in the system, changes to PWR water chemistry can reduce the wear rate by up to a factor of ten. For BWRs, increases to condensate oxygen can significantly reduce FAC in the feed train. Reducing the venting of BWR feedwater heaters and reheaters can reduce FAC rates by increasing the oxygen in the steam side of BWRs. Design changes will result in improvements in specific areas. These three options are discussed in detail in [47] and summarized below.

5.2 FAC-Resistant Materials

It has been widely demonstrated that materials containing chromium are resistant to FAC damage [30, 34, 47]. Lesser improvements come from molybdenum and copper. Replacing carbon steel piping with “chrome-moly” alloy (SA335, Grade P11 or P22) or stainless steel (normally a 304 alloy) should alleviate FAC damage for the life of the plant. The benefit can also be achieved by coating the piping surface with a high-alloy layer (flame spraying or weld overlay) or using a clad pipe with a high-chromium or stainless-steel inner layer surrounded by a carbon steel outer layer. Another option is to specify that carbon steel replacement components (e.g., pipe, fittings, vessels, etc.) contain a minimum of 0.10% chromium.

Table 5-1 presents the degree of improvement associated with common piping alloys as predicted by CHECWORKS™, which is based on the data of Ducreux [34] and more recent plant and laboratory data for both single- and two-phase conditions [30].

Table 5-1
Performance of Common FAC-Resistant Alloys

Material	**Nominal Composition (*Chromium & Molybdenum Only*)**	$Rate_{carbon}/Rate_{alloy}$
A106B + 0.10% Cr	0.10% Cr	10
P11	1.25% Cr, 0.50% Mo	34
P22	2.25% Cr, 1.00%-Mo	65
304	18% Cr	>250

Material changes can be used to replace an entire system or to repair an especially troublesome area. However, material replacement may not reduce the wear rate if the damage is caused by a mechanism other than FAC. This is the case, for instance, if the damage is caused by cavitation, flashing or liquid droplet impingement.

5.3 Water Chemistry

Changes in plant water chemistry can reduce the rate of FAC damage. Increasing the pH at operating temperature (the hot pH) for a PWR or increasing the amount of dissolved oxygen for a BWR can reduce the rate of FAC damage significantly. Chemistry changes are attractive as they can reduce the damage rate globally, help reduce rates of iron transport and resulting steam generator or reactor vessel sludge, and extend the life of the demineralizers. However, it should be noted that chemistry changes only slow the rate of damage and do not restore the wall thickness of degraded pipe. Inspections will continue to be needed.

5.3.1 PWR Plants

5.3.1.1 Effect of pH and Amines on FAC

For PWRs, one way of achieving a higher pH at temperature is by increasing the cold (control) pH. Figure 5-2 presents a summary of the effects of changing the cold pH on FAC wear rate over a range of temperature for a typical single-phase line. As can be seen, increasing the pH reduces the FAC wear rate significantly.

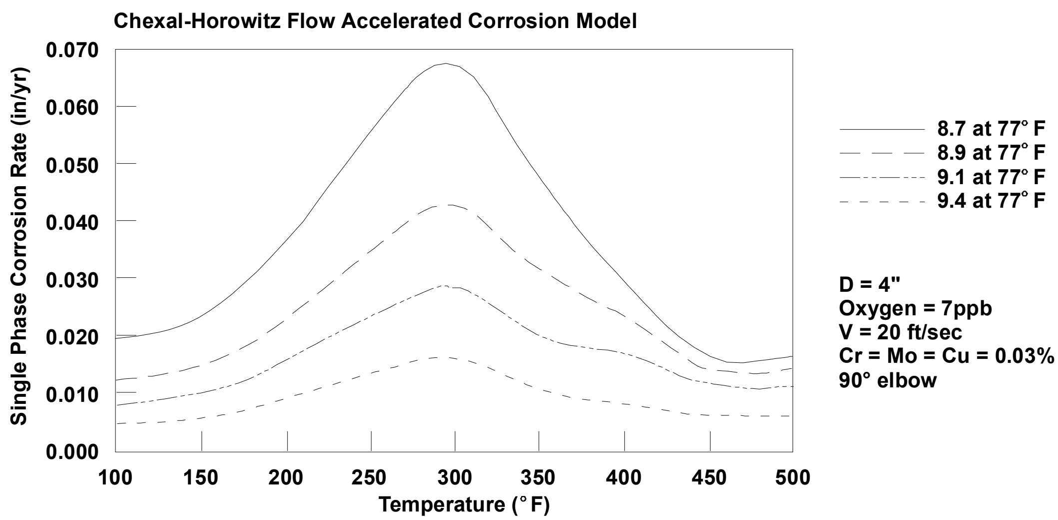

Figure 5-2
Impact of Change in pH Level on FAC (As Predicted by CHECWORKS™)

Another way of achieving a higher pH at temperature is by changing the pH control amine. Doing this will also change the pH in the two-phase portions of the system as different amines behave differently. This is mostly related to the tendency of amines to partition in two-phase flow conditions. Volatile amines such as ammonia tend to favor the vapor phase and tend not to provide much protection to two-phase lines. Less volatile amines such as morpholine, ethanolamine (ETA), and 5-aminopentanol (5-amp) are more effective in two-phase conditions. The selection of optimum water chemistry for PWR plants is a complex decision influenced by the presence or absence of copper in the system (e.g., in condenser or feedwater heater tubes), the type and capacity of the condensate polishers or demineralizers, concerns about organic acids produced by the decomposition of certain amines, and the condition of the steam generators. Considerations for selecting optimum chemistry for PWR plants are provided in the EPRI PWR Secondary Water Chemistry Guidelines [48]. A comparison of typical FAC wear rates at strategic locations around the secondary system is provided in Figure 5-3. Note that the comparisons shown in Figures 5-2 and 5-3 reflect a specific plant configuration and set of operating conditions, and will be different for other configurations and conditions.

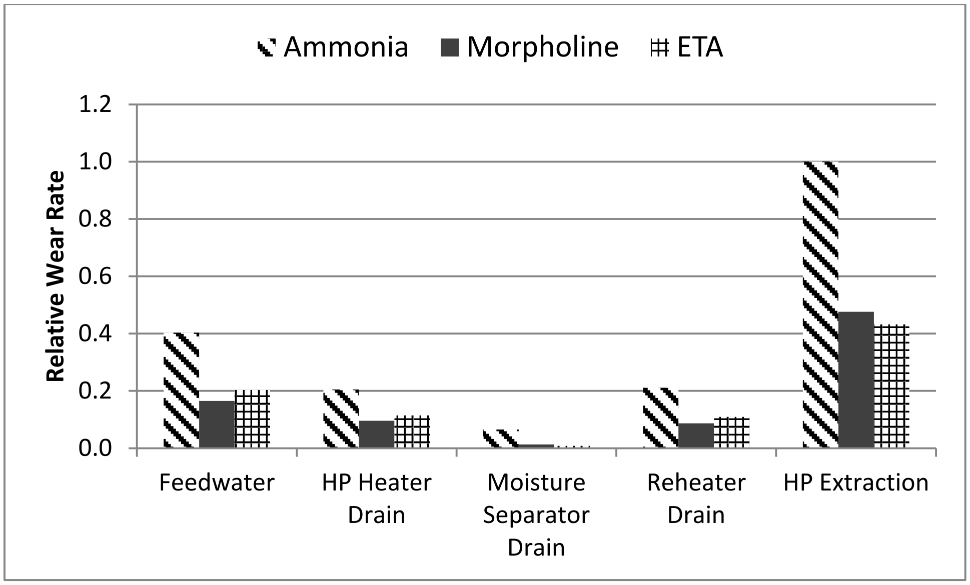

Figure 5-3
Amine Comparison – Typical Conditions at the Same Cold pH

5.3.1.2 Effect of Hydrazine on FAC

Historically, PWR plants located in the United States operated at about 20 ppb of hydrazine as measured in the condensate system. This concentration was implicit in the FAC predictive model included in the CHEC®, CHECMATE™, and earlier versions of the CHECWORKS™ code (through Version 1.0E). In an effort to create more reducing conditions in the steam generators and decrease the susceptibility of the tubes to stress corrosion cracking, many PWR plants increased the concentration of hydrazine in the mid to late 1990s. Subsequent laboratory testing found that at low temperatures (temperatures below approximately 356°F [180°C]) the hydrazine concentration had very little effect on FAC [49]. However, at high temperatures (temperature around 455°F [235°C]), some historic data indicate that the hydrazine concentration does have an effect on FAC.

However, more recent testing done at high temperatures has indicated that hydrazine concentration does not have an effect on FAC [50]. As a result of this newer finding, the hydrazine factor was removed from CHECWORKS™.

5.3.2 BWR Plants

BWR plants normally operate using one of four types of water chemistry. These chemistries do not affect oxygen in the feedwater system, but have a significant effect on oxygen in the steam systems. Briefly these are:

- *Normal Water Chemistry (NWC)* – this chemistry was the chemistry originally used in all BWRs. No hydrogen or other additives are used.[16] This chemistry results in the highest concentration of oxidants (i.e., a combination of oxygen and hydrogen peroxide) in the steam systems. Currently, there are no U.S. BWRs using Normal Water Chemistry.
- *Hydrogen Water Chemistry* – hydrogen is injected into the feedwater to lower the oxygen concentration (or more properly the electrochemical corrosion potential – ECP) in the recirculation lines and in the vessel, and reduce the susceptibility of these components to stress corrosion cracking.

  Conventionally, feedwater hydrogen addition in the range of 1.0 to 2.0 ppm is known as Moderate Hydrogen Water Chemistry (MHWC). This chemistry results in the lowest concentration of oxidants in the steam systems.
- *Noble Metal Chemical Addition (NMCA)*[17] – in addition to hydrogen injection, the vessel internals are treated with a solution containing the noble metals platinum and rhodium. These metals plate out on surfaces within the vessel. The presence of these metals on the reactor surfaces catalyzes the recombination of water lowering the oxidant concentration. This approach requires a much lower concentration of injected hydrogen to achieve essentially zero oxidant at metal surfaces (see [51] for more information). This chemistry results in an intermediate concentration of oxidants in the steam systems.
- *Online NobleChem™*[18] *Addition (OLNA)* – similar to NMCA, OLNA is an online process which periodically injects a solution containing noble metals into the feedwater. As this process provides similar benefits as NMCA with reduced outage time, it is replacing the use of NMCA in the BWR fleet.

5.3.2.1 Feedwater Side Oxygen

The amount of oxygen in the condensate and feedwater systems is primarily determined by the in-leakage of air into the condenser. If the level is too low[19], it can be supplemented by direct injection of oxygen into the condensate. A comparison of typical feedwater wear rates as a function of oxygen concentration is provided in Table 5-2. See [52] for a discussion of the oxygen factor used in CHECWORKS™.

[16] Subsequently to startup, Zinc has been added in most BWRs.

[17] Also known as NobleChem™, a trademark of General Electric.

[18] Online NobleChem™ is a trademark of General Electric Hitachi.

[19] The EPRI BWR Water Chemistry Guidelines [53] specify a feedwater oxygen level of between 30 and 200 ppb. From the perspective of FAC, operating at the high end of this range is more desirable.

Table 5-2
Effect of Oxygen on Typical Feedwater Wear Rates

Feedwater Oxygen (ppb)	*Relative Wear Rate*
10	1.00
30	0.30
50	0.18
100	0.11

5.3.2.2 Steam Side Oxygen

For the steam part of the system (extraction and drains), the oxygen level is determined (1) by the radiolysis that is occurring in the reactor core, and (2) the type of chemistry used. For plants with normal water chemistry (NWC), the steam line oxygen is typically around 18 ppm. For plants with moderate hydrogen water chemistry (MHWC), the steam line oxygen concentration will vary from about 4 to 7 ppm depending on the amount of hydrogen injected. For plants with noble metal chemical addition (NMCA), the steam line oxygen will vary from 11 to 15 ppm, depending on the amount of hydrogen injected and the reactor geometry.

Other than changing chemistry, it is normally not possible to control the oxygen levels in the main steam line as this level is a function of the neutron and gamma levels within the reactor core. However, if excessive venting of the moisture separator reheaters or feedwater heaters is occurring, then FAC can be reduced in the downstream piping and equipment by reducing the vent rates. The effects of varying steam line oxygen concentration in a typical BWR plant are shown in Figure 5-4. However, it should be noted that these results are for a specific plant and will vary for other plant designs.

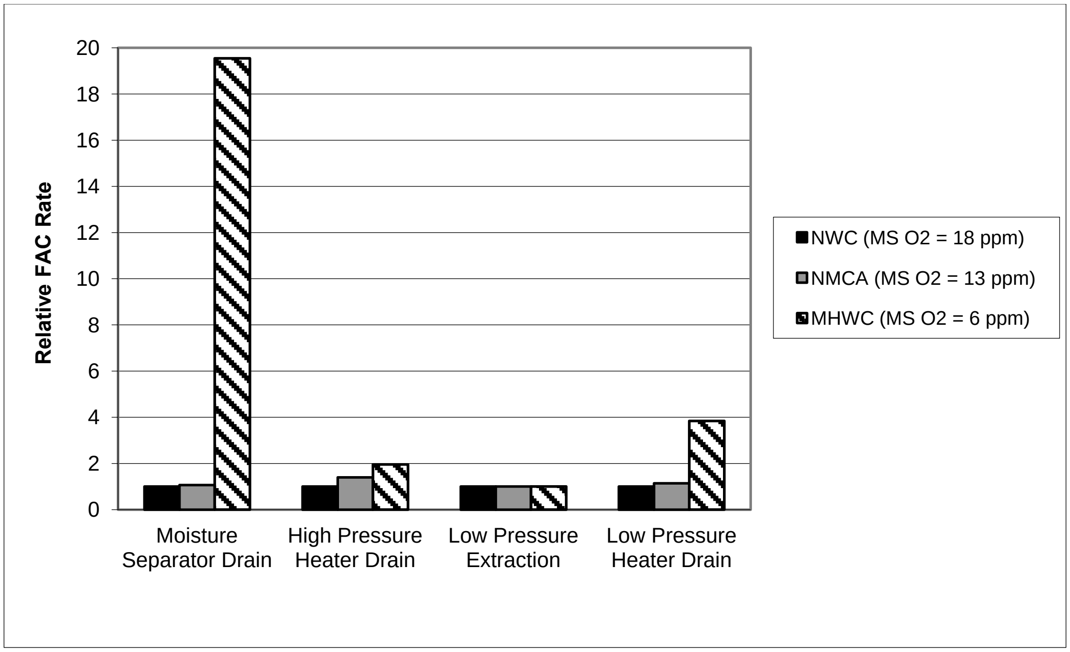

Figure 5-4
Effects of BWR Steam Line Oxygen Concentration

5.4 System Design Changes

In general, design changes result in only small reductions to the rate of FAC damage. For example, changing the diameter of a piping system from 12 to 14 inches (300 mm to 350 mm) will only reduce the FAC rate by about 20%. There are instances, however, where design changes can be effective:

- Increasing the pipe diameter to reduce the velocity in control valve stations. Valve stations are typically designed to accommodate the flow capacity of control valves. This typically results in a reduced diameter of about 60% of the line size and a consequent increase in the fluid velocity. This locally increased velocity has often caused damage downstream of the valve. Redesigning the valve station to reduce the local velocity and turbulence can greatly reduce the rate of FAC damage.
- In wet steam lines, the FAC wear rates can be reduced by reducing the local moisture content. This can be achieved by improving the efficiency of the existing moisture separator design or by installing additional moisture separation equipment. This will reduce the number of water droplets that impinge upon the downstream components. This method has been widely used in France and has proven to be effective in reducing the FAC damage in such components as cross-under lines and feedwater heater shells.

5.5 Documentation

As dictated by plant or corporate policies, the long term strategy to manage FAC should be documented in an appropriate plan. As discussed below, FAC programs are required for the life of plant or as long as there is FAC-susceptible piping in service. Thus regardless of what the planning horizon is in the strategy document, it should be recognized that the FAC program will be ongoing, likely through the life of the plant.

5.6 Summary

As can be seen from the above discussion, improved water chemistry in combination with highly resistant materials can help mitigate FAC. Utilities should evaluate these options carefully from a technical as well as a financial standpoint and make a determined effort to mitigate FAC.

Depending on plant and corporate policies, the long term strategy should be documented in an appropriate plan. It should be noted, that as long as there is FAC susceptible piping and components present, Generic Letter 89-08 [10] requires that FAC programs be in place for the life of the plant. Thus, the long term plan should reflect this fact regardless of the planning horizon used in this document.

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A
RECOMMENDATIONS FOR AN EFFECTIVE FAC PROGRAM FOR SMALL-BORE PIPING

A.1 Introduction

Many of the recommendations for large-bore piping can be applied to small-bore. However, there are significant differences that should be addressed. For example, predictive analysis of socket-welded, small-bore piping typically is neither feasible nor practical. Local operating conditions necessary for the analysis may prove difficult to obtain or may not be consistent, especially in vent lines and downstream of steam traps and leaking, normally closed valves. Additionally, since wear in small bore piping is heavily dependent on upstream component performance (steam traps, orifice, leaking bypass and isolation valves), wear may not be linear or time dependent and therefore difficult to calculate. Also, the lack of knowledge of the actual fit-up gap between a pipe and associated socket-welded fittings is common in small-bore piping and limits the applicability of analytical methods and wear trending. In addition, failures in small-bore piping are, in general, of less consequence than large-bore piping.

This Appendix provides recommendations for an effective FAC program for small-bore piping, which takes these differences into account. More detailed information is presented in [54]. An illustration of the program is provided in Figure A-1. For purpose of FAC evaluation, small-bore piping is defined as piping with a nominal diameter of two inches (50 mm) or less, or consisting of all socket-welded components.

A.2 Identifying Susceptible Systems

The first task in the recommended program is to identify all small-bore piping lines that are susceptible to FAC. This task should be done along with the large-bore piping, utilizing the recommendations of Subsection 4.2. Care should be taken to include lines supplied with equipment, as often they are not included in line lists and skid mounted piping. Also, in applying exclusion criteria, consideration should be given to the fact that operating conditions and maintenance are typically less certain in small-bore systems. This evaluation should be documented in the Susceptibility Analysis (Subsection 4.2).

A.3 Evaluating Susceptible Systems for Consequence of Failure

It is recommended that the small-bore program take into account the level of consequence of failure in systems under evaluation. Considerable savings can result without compromising safety or system availability. The program owner should closely consider the definition of failure and therefore the consequence of failure in determining the category of each line.

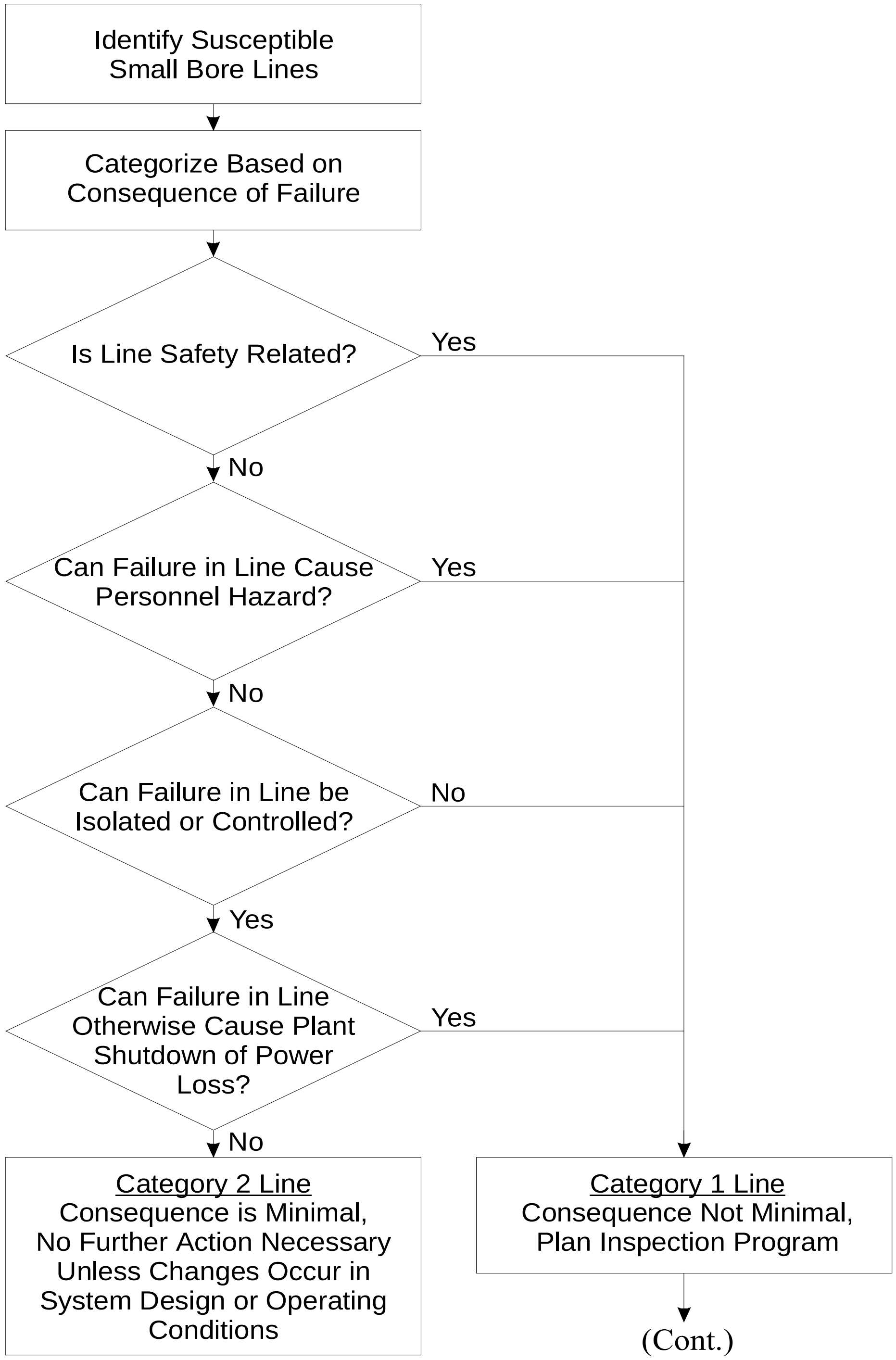

Figure A-1
Small Bore Piping FAC Program

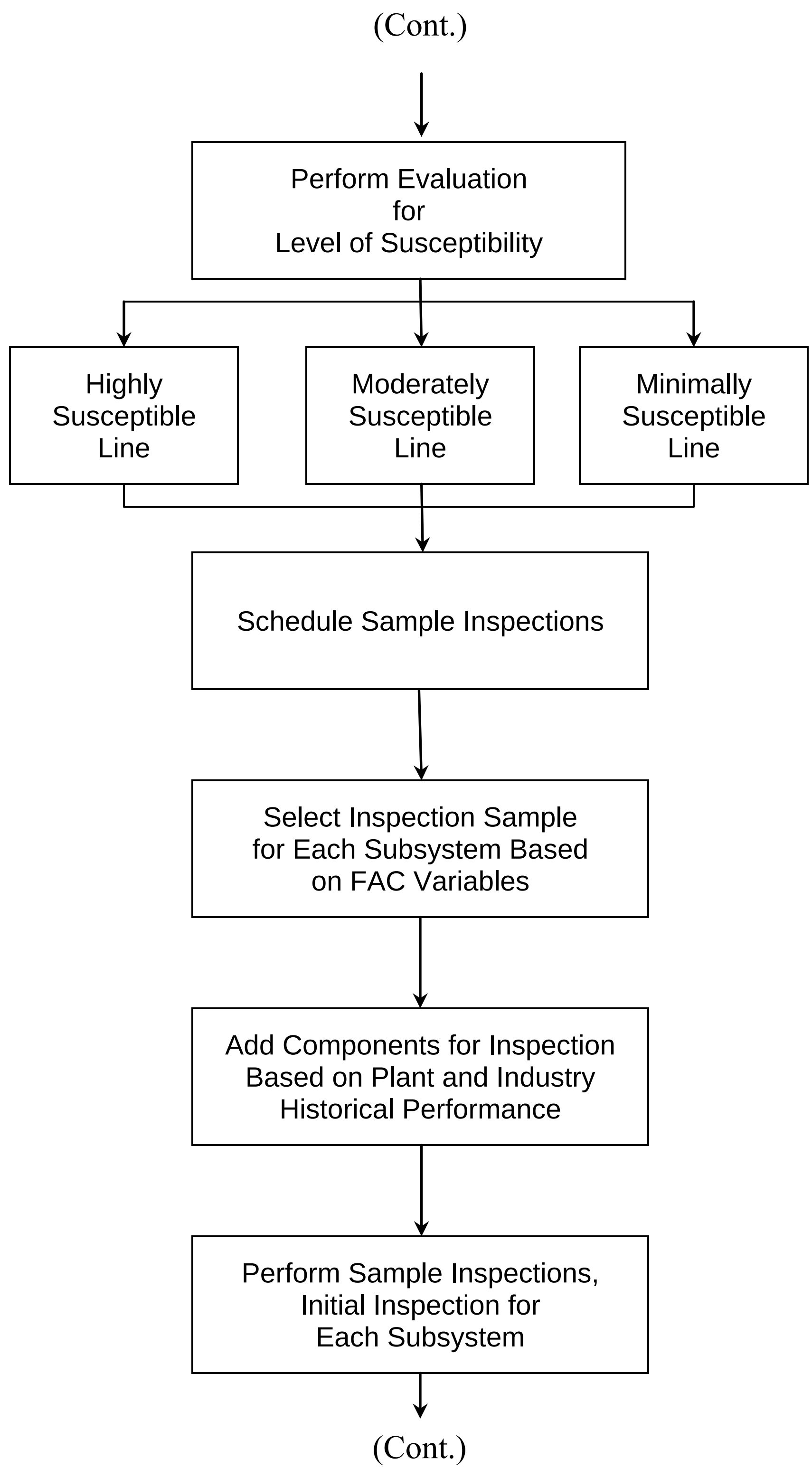

Figure A-1 (Continued)
Small Bore Piping FAC Program (Continued)

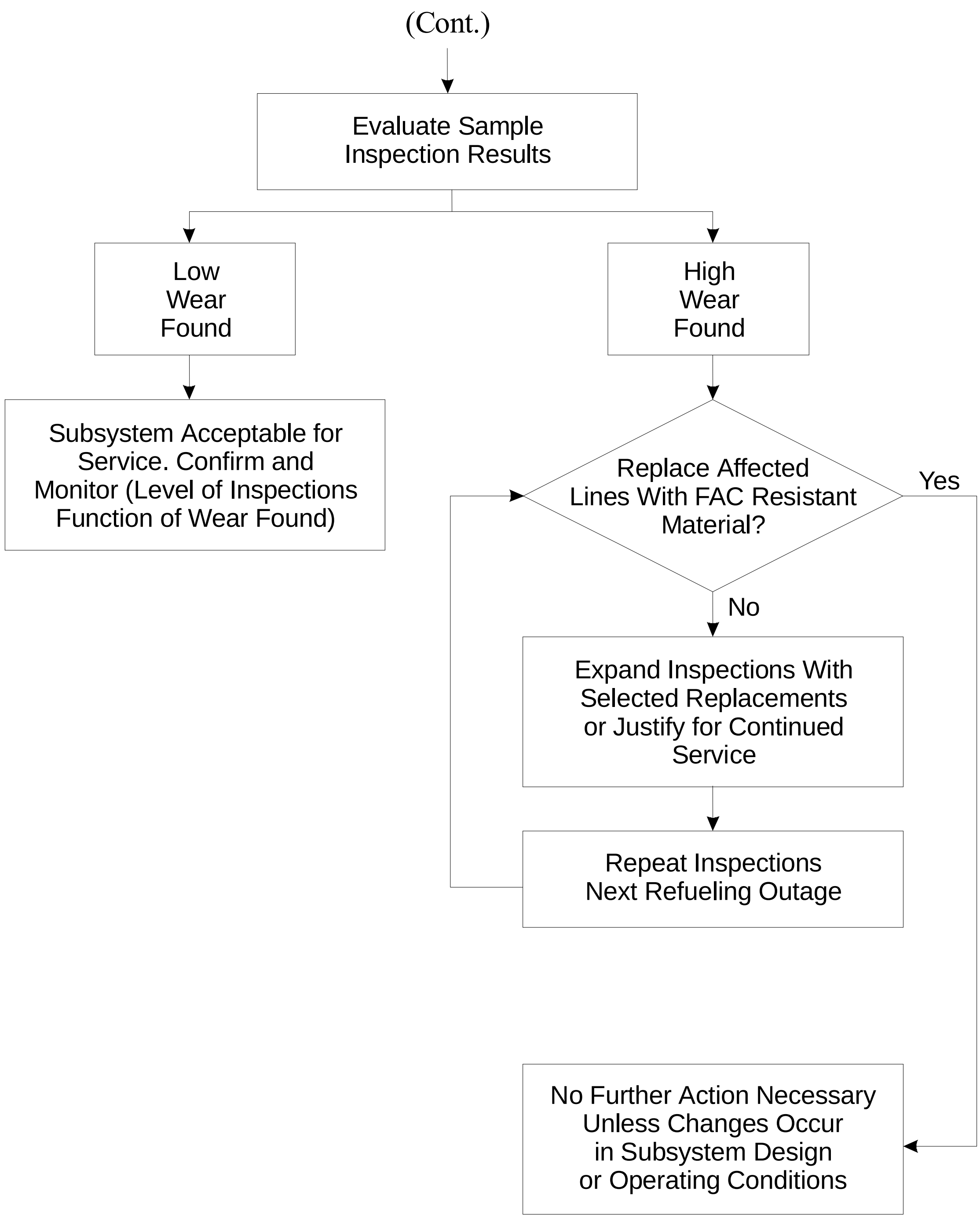

Figure A-1 (Continued)
Small Bore Piping FAC Program (Continued)

Each of the small-bore lines identified in A.2 as susceptible should be evaluated based on the consequence of a failure in the line and identified as Category 1 or Category 2. An acceptable alternative would be to designate all lines as Category 1.

Category 2 lines are those in which it can be demonstrated that a failure would be of minimal consequence. Lines can be demonstrated to be Category 2 if they meet all of the following:

1. The line is not part of a safety-related system.
2. A failure would not cause a reactor shutdown or measurable loss of power (*i.e.,* a major train shutdown), either by automatic trip or operator action.
3. A failure can be readily isolated or controlled (*i.e.,* repaired on-line) in time to prevent reactor or major train shutdown.
4. A failure would not likely result in personnel injury. The likely injury to personnel can be taken as a function of the line's accessibility and operating temperature. Piping in inaccessible or infrequently accessed areas can be considered unlikely to cause injury upon failure.

Plant owners who have conducted consequence of failure evaluations have reported that a significant number of susceptible small-bore lines can be designated as Category 2.

Category 1 lines are the remaining susceptible piping in which, by definition, a failure is potentially greater than of minimal consequence, and thus need further consideration.

This prioritization evaluation should be documented in a report, and periodically reviewed for impact of changes to plant design and operating conditions, related plant experience, and related operating experience. The report should include a discussion of the evaluation, identification of the susceptible small-bore piping with category assignment (Category 1 or 2), and the basis for that categorization.

A.4 Approaches for Mitigating FAC in Small-Bore Piping

There are several acceptable approaches for mitigating FAC in susceptible small-bore piping. These approaches include:

- Replace all susceptible small-bore piping with non-susceptible material.
- Replace all Category-1-susceptible small-bore piping with non-susceptible material.
- Conduct periodic inspections of Category-1-susceptible small-bore piping and repair or replace lines and components as needed.

For approaches that involve inspections of susceptible small-bore piping, guidelines for selecting inspection locations, performing inspections, evaluating inspection results, and dispositioning the inspection data are provided in A.5 through A.9.

A.5 Guidelines for Selecting Inspection Locations in Small-Bore Piping

A.5.1 Category 1 Piping

Due to the large volume of small-bore piping in a power plant, a FAC susceptibility level evaluation may be conducted of Category 1 lines and utilized to assist prioritizing inspection scheduling. It is recognized that it is not possible to predict levels of wear rate in most small bore piping with any accuracy. However, experience has shown that it is possible in most situations to categorize lines on a relative basis as potentially highly susceptible, moderately susceptible, or minimally susceptible.

Such an evaluation should consider all design and operating conditions that affect FAC. It is recognized that operating conditions for much of the small-bore piping may be difficult to determine, and considerable engineering judgment and conservatism may be required.

This FAC susceptibility level evaluation should be documented in a report. The report should include a description of the evaluation, the assignment of level of susceptibility for all Category 1 piping, and the basis for that assignment.

A.5.2 Category 2 Piping

Any further FAC program activities for Category 2 lines may be specified by the FAC program owner. Category 2 lines need not be scheduled for inspection due to the minimum consequence from a failure.

A.6 Selecting Components for Initial Inspection

A.6.1 Grouping Piping Lines into Sub-Systems

Category 1 piping lines should be grouped into sub-systems with similar flow and operating conditions, such that the sample inspection locations selected will represent the components in that sub-system. As flow and operating conditions in small-bore systems are typically not well defined, the boundaries of these sub-systems should be smaller than those that would be defined for a more rigorous analysis, such as in a CHECWORKS™ run. It is good practice to use isolation valves as the boundary when defining subsystems. Then when a subsystem fails, the entire segment can be removed from service.

A.6.2 Selecting Components for Inspection

Locations should be selected for initial inspection with the objective of identifying a sufficient number of appropriate locations to confirm system susceptibility and to establish the level of wear present. Locations should be selected for each sub-system as follows:

1. An inspection sample of components should be selected to represent the potentially high wear locations in the sub-system. Variables influencing FAC should be considered in the selection. As sub-systems by definition bound piping areas with similar operating conditions, of particular importance are components with high flow velocity and turbulence (*i.e.,* locations such as tees, and downstream of orifices and control valves). As flow and operating conditions for these sub-systems will typically not be well defined, engineering judgment by FAC experienced engineers should be utilized to ensure the sample is sufficient. The sample size selected should take into consideration the level of susceptibility as determined in the evaluations of A.5.1.

   Generally, it is recommended that sufficient inspections be performed to evaluate the wear characteristics of the lines that are grouped together.

2. Special consideration should be given to including components, along with piping downstream of those components, which are known within the industry to be particularly susceptible, including:

   - Control valves.
   - Component inlet and discharge nozzles.
   - Orifices.
   - Steam traps.
   - Reducing couplings.
   - Unusual geometry configurations.
   - Back-to-back fittings.
   - Components near the condenser.
   - Component at location, or downstream, of large pressure drops.
   - Entrance effect

   As with large bore piping, inspections of joints and piping downstream can be utilized as evidence of the state of wear in thick components such as valves and orifices.

3. Consideration should also be given to components and sections of piping that have any historical wear, or where similar areas in parallel trains or sister plants have historical wear, or if operating experience has demonstrated potential susceptibility.

4. Where small-bore piping sub-systems tie into headers that are of larger diameter piping (*i.e.*, drain headers), consideration should be given to extending inspections into the attached portions of those systems as part of the small-bore program. This is because of the large amount of operating experience with these headers, specifically experience with impingement damage.

A.7 Performing Inspections

A.7.1 Radiography Techniques (RT)

Radiography is the preferred method for inspecting socket-welded fittings due to its ability to "see" inside fittings. Radiography can be especially beneficial for conducting inspections on-line.

A.7.2 Ultrasonic Techniques (UT)

In many situations, radiography techniques are not practical. UT is also an acceptable method for inspection of small-bore components. In addition, UT can be used for measuring remaining wall thickness and thus establishing level of wear. Acceptable approaches for UT inspection include the following:

1. Gridding or scanning the downstream piping and expanding to the component if substantial wear is found.
2. Gridding the component and recording the readings.
3. Scanning the component and recording the minimum measured on the entire component or in quadrants.

Caution should be taken when utilizing UT on socket-welded connections. It is difficult to measure wall thickness close to the toe of the connection weld, where experience has shown significant wear can occur due to gaps caused by pipe-to-socket mismatch.

A.7.3 Thermography

Thermography is a tool that can enhance the identification of potential problem areas in small-bore piping. If available, thermography data should be examined to identify any leaking valves or steam traps that could accelerate FAC damage in downstream piping components.

A.7.4 Acoustical Monitoring

Steam traps and valves produce acoustical emissions which can be monitored to determine performance or failure. Normally closed but leaking valves can be easily identified through acoustical methods. Malfunctioning steam traps also produce acoustical emissions which can be evaluated to determine trap performance.

A.8 Evaluating Inspection Results

Trying to establish future wear rates is not recommended for small-bore piping with socket-welded fittings, or in subsystems where design and operating conditions are not sufficiently defined. Predicted wear rates in systems without known and constant operating conditions, whether calculated (such as with CHECWORKS™) or trended from inspection data, are not considered reliable for any significant length of time. Consequently, decisions on disposition of small-bore piping needs to be made at each inspection outage based on the results of inspections during that outage.

Inspection results from the initial inspection of a given sub-system should be evaluated to establish the level of FAC wear present in the components inspected. If little or no wear can be found, the sub-system can be classified as Low Wear, i.e., Category 2. If significant wear is established, the sub-system should be classified as potentially High Wear, i.e., Category 1. However, it should be kept in mind that these categorizations can change in the event of power uprates, or system design changes.

Recommendations for disposition of the subsystem are given in A.9 below based on their level of wear classification. Inspection data and evaluation results should be documented and maintained.

A.9 Disposition of Sub-Systems

A.9.1 Low Wear Sub-Systems

Sub-systems in which only low wear is found in the components inspected can be considered acceptable for continued service.

A representative number of the highest ranked components of that sub-system should be re-inspected during a future outage to confirm the level of wear.

If the level of wear is confirmed during the repeat inspection to be low or none, future monitoring can be limited to a minimum level to help ensure any changes in the FAC rate are not missed. The number of components to inspect, and the timing of those inspections, should be consistent with the size of the sub-system, its level of susceptibility, knowledge of the operating conditions present (*i.e.,* systems where operating conditions may have changed, or for which maintenance is unknown, may need to be watched more closely), and related operating and plant experience with that and comparable sub-systems. If such a subsystem was previously considered as Category 1, it can be reclassified as Category 2 to be consistent with the wear observed.

If significant wear is discovered during any re-inspection, the sub-system should be reclassified as High Wear, i.e., Category 1, and re-evaluated accordingly.

A.9.2 High Wear Sub-Systems

Sub-systems in which the components inspected are classified as High Wear should be addressed as soon as practical. It is recommended that High Wear sub-systems be replaced with FAC-resistant material before the sub-system is returned to service. Once that is accomplished, the subsystem can be removed from further consideration in the FAC program. However, if the wear is caused by a mechanism other than FAC (e.g., liquid droplet impingement, flashing, cavitation, etc.), it should not be excluded from future inspections, or it should be included in another program designed to mitigate these mechanisms.

If replacement of the sub-system with FAC-resistant material is not practical prior to return to service, inspections should be expanded and selected repairs/replacements made as follows:

1. For sections of piping with butt-welded joints, expand the inspections to include components in the vicinity of those inspected components showing significant wear, and in similar locations in sister trains. If significant wear is found in the expanded inspections, the expansion process should be continued to define the limits of the components with significant wear.
2. For sections of piping with socket-welded joints, expand the inspections to include other socket-welded locations.
3. Before the sub-system is returned to service, repair or replace components for which the inspections show significant wear, or justify adequacy until the next plant refueling outage. Guidance for repair and replacement is provided in Subsection 4.8.

Repeat the above steps in each following refueling outage until replacement with FAC-resistant material can be accomplished.

A.10 Long Term Strategy

The recommendations of Section 5 in most cases apply to small-bore as well as large-bore piping. It is recommended that special consideration be given to replacement of susceptible small-bore piping with FAC-resistant material. Plant owners have reported that replacement can be significantly more economical that conducting evaluations and performing inspections of such systems.

Steam trap and small bore valve maintenance is critical to limiting wear in small bore piping systems. Normally closed but leaking bypass and isolation valves as well as malfunctioning steam traps are major contributors to small bore piping failures. An aggressive steam trap and small bore valve maintenance program will eliminate many small bore piping failures and contribute to the thermal performance of the station.

As dictated by plant or corporate policies, the long term strategy to manage small-bore piping should be documented in an appropriate plan. As mentioned in Section 5, FAC programs are required for the life of plant or as long as there is FAC-susceptible piping in service. Thus regardless of what the planning horizon is in the strategy document, it should be recognized that the small-bore program will be ongoing, likely through the life of the plant.

B
RECOMMENDED INSPECTION PROGRAM FOR VESSELS AND EQUIPMENT

B.1 Recommended Inspection Program for Feedwater Heaters

Feedwater heaters, including the shell, nozzles, internals (e.g., tube sheets, stay bars, etc.) and drain coolers should be considered for inspection. Feedwater heaters can be prioritized for inspection using the following guidance:

- Relative susceptibility of the extraction steam piping using results of the Predictive Plant Model or results of piping inspections.
- Moisture content of the inlet steam as provided by the design plant heat balance diagram or plant specific thermal performance analysis (preferred to the design heat balance diagram).
- Years in service.
- An operating temperature near 300 – 350°F (149 – 177°C).
- Shells with measured values of trace chromium greater than 0.10% (the chromium content of all plates used to construct the shell needs to be greater than 0.10%) can be considered exempt from FAC inspections. However, they should not be excluded from examination if plant operating experience has found them to have been damaged by droplet impingement. If so, they should be evaluated for inspection at the stations using procedures for detecting mechanical damage mechanisms.
- Feedwater heaters with inlet extraction steam that is superheated should not be excluded from examination as operating experience has found them to be damaged during operation at power levels less than 100% and during off-normal operation.
- Operating experience [55].

B.1.1 Inspection of Feedwater Heater Shells and Nozzles

Inspection of feedwater heater and tank shells and nozzles may be made by UT methods with a grid size of 2” to 4” (50 to 100 mm). However, a grid size of 4” (100 mm) may be too coarse near a small nozzle (e.g., 6” or 8” [150 or 200 mm]). Alternately, the following grid sizes, see Table B-1, can be used, which, for nozzles, are compatible with the grid sizes recommended in Table 4-1.

In cases where the shell grids from two nozzles overlap, it is recommended that the smaller grid size be used for both inspections.

Table B-1
Recommended Grid Sizes for Feedwater Heaters

Nozzle Size inch (mm)	Max. Nozzle Grid Size inch (mm)[20]	Heater Shell Grid Size inch (mm)
6 (150)	1.73 (44)	2 (50)
8 (200)	2.25 (57)	2 (50)
10 (250)	2.81 (71)	2 (50)
12 (300)	3.33 (85)	3 (75)
14 (350)	3.67 (93)	3 (75)
16 (400)	4.19 (106)	4 (100)
18 (450)	4.71 (120)	4 (100)
20 (500)	5.23 (133)	4 (100)
≥24 (600)	6.00 (152)	4 (100)

The above grid sizes should be sufficient to detect the presence of wear, but may not be small enough to determine the extent and maximum depth of the wear. Therefore, where inspections reveal wall thinning reduced grid sizes should be used to map the depth and extent of the thinned area. Scanning between the grid points can also be used for mapping the wear and determining the minimum wall thickness of the heater shell.

Operating experience has found that highly localized wear can occur where vessel internals come in close proximity to the shell [55] and possibly be missed by 2” x 2” (50 mm x 50 mm) grids. Thus, the heater internals drawings should be reviewed when planning for inspection. In these localized areas, scanning between grid points and/or UT at grid sizes smaller than those in Table B-1 should be used.

The gridding of feedwater heater shells should be a minimum of 30º past each side of the impingement plate and 60º from the centerline of the inlet nozzle, but need not extend more than 90º past the centerline of the inlet nozzle. See Figure B-1. For the case of a feedwater heater without a liner, gridding in the axial direction should extend a minimum of two times the diameter of the inlet nozzle on each side of the nozzle. For feedwater heaters with a liner, gridding in the axial direction should extend a minimum of one times the diameter of the inlet nozzle on each side of the liner. See Figure B-2.

Additional scrutiny will need to be applied if the nozzles have a reinforcing plate on the shell. If the wall thickness readings at the toe of the reinforcing plate weld are decreasing in the direction of the nozzle, the reinforcing plate may need to be removed to allow for inspection of the shell.

[20] Also see Table 4-1.

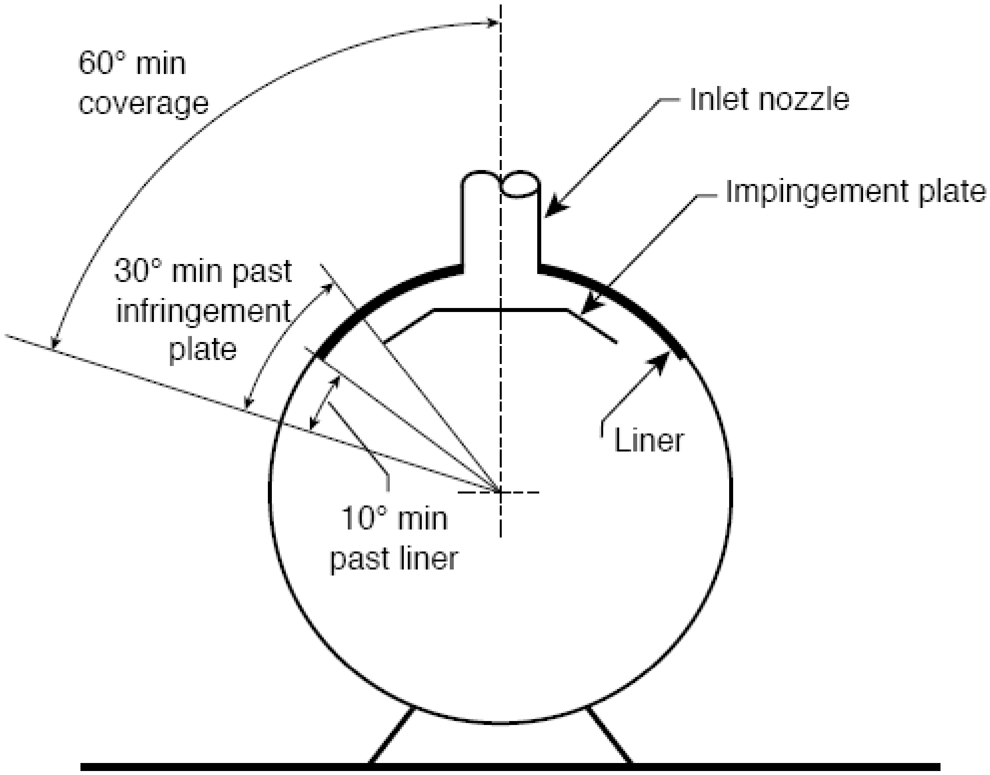

Figure B-1
Recommended Feedwater Heater Coverage, Circumferential Direction

Grids should be located as close as practical to both toes of any longitudinal or circumferential welds encountered.

The pulsed eddy current technique can be used to screen vessels for wall loss in areas away from internals that are close to the vessel wall.

Additional guidance for FAC-related inspections of feedwater heaters is provided in reference [55]. Other information related to degradation, inspection, maintenance, repair and replacement of feedwater heaters can be found in a number of EPRI documents.

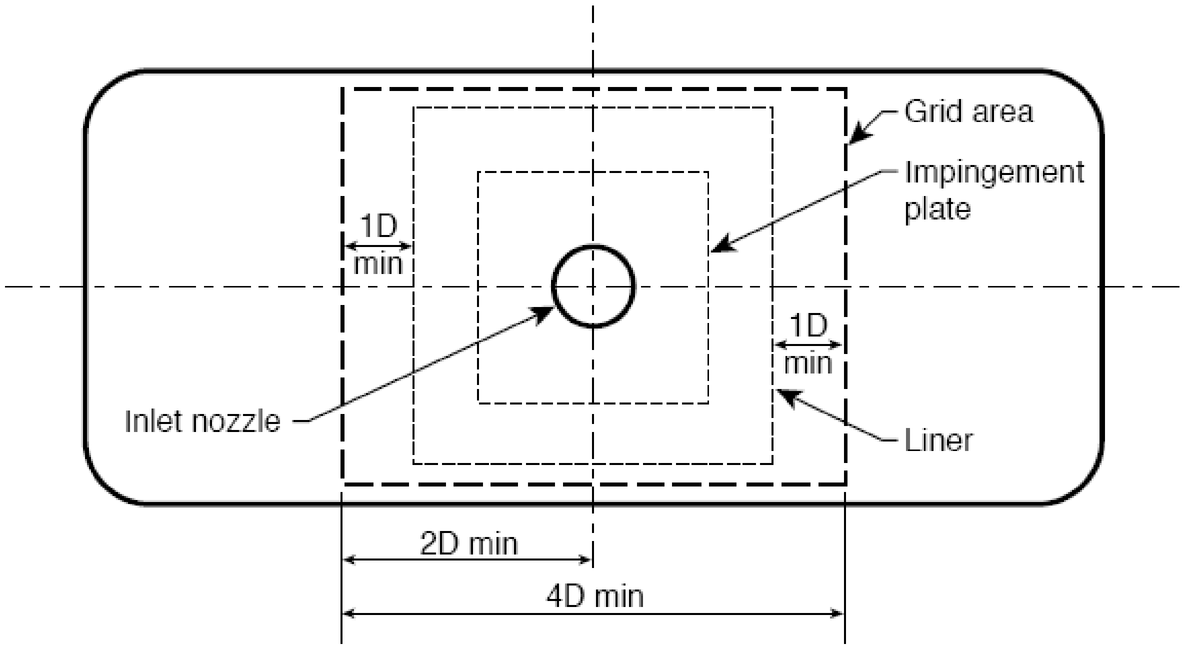

Figure B-2
Recommended Feedwater Heater Coverage, Longitudinal Direction

B.1.2 Inspection of Internal Elements

Inspection of internal elements can be made by visual methods.

B.2 Recommended Inspection Program for Other Vessels and Equipment

Other vessels and equipment should be evaluated for susceptibility to FAC using the criteria of Subsection 4.2. Such vessels and equipment may include:

- Moisture Separator/Reheater, including the shell, nozzles and internals.
- Moisture separator drain tanks, including the shell and nozzles.
- Steam generator blowdown tank, including the shell and nozzles.
- Susceptible portions of the steam generators. This may include the feed ring, J-tubes, thermal sleeves, tube support plates, and separator swirl vanes and barrels.
- Turbine outlet nozzles.

The prioritization of such equipment for inspection and the inspection methods to be used are the responsibility of the owner.

C
MOST SIGNIFICANT FAC EXPERIENCE EVENTS THROUGH 12/2012

Plant	NRC/INPO Reference	Type	Date	Single-Phase?	System	Comments
Oconee	IN-82-22	PWR	6/82	No	Extraction	Large hole in elbow in HP extraction line.
Navajo	——	Fossil	11/82	Yes	Feedwater	Similar conditions to Surry
Surry	IN 86-106, Bull. 87-01 IN 88-17 INPO SOER 87-03	PWR	12/86	Yes	Condensate	Four fatalities
Trojan	IN 87-36 IN 88-17 INPO OE2109	PWR	6/87	Yes	Feedwater	Major damage found; however, no failure. IN 87-36 contains incorrect information (repeated in IN 88-17) about thinning in straight sections.
Arkansas Nuclear One	IN 89-53	PWR	4/89	No	Extraction	Accident occurred in the CE unit.
Santa Maria de Garona, Spain	INPO OE3690	BWR	12/89	Yes	Feedwater	Fist size blowout. Low oxygen chemistry.
Loviisa, Finland	IN 91-18	PWR	5/90	Yes	Feedwater	
Millstone 3	IN 91-18	PWR	12/90	Yes	Separator Drain	

Plant	NRC/INPO Reference	Type	Date	Single-Phase?	System	Comments
Millstone 2	IN 91-18 Supp. 1 INPO OE4923	PWR	11/91	Yes	Reheater Drain	
Sequoyah	INPO OE 5847	PWR	3/93	No	Extraction	
Sequoyah	IN 95-11 SER 6-95	PWR	11/94	Yes	Condensate	“Unknown” flow element
Pleasant Prairie Power Plant	——	Fossil	2/95	Yes	Feedwater	Two fatalities. See [56] and [57].
Millstone 2	INPO OE 7420 SER 21-95	PWR	8/95	Yes	Heater Drain	
Fort Calhoun	IN 97-84 INPO SEN 164	PWR	4/97	No	Extraction	
Point Beach 1	IN 99-19	PWR	5/99	No	Feedwater Heater Shell	
Callaway	NRC Event Notification 36015 INPO SEN 203 INPO OE10171	PWR	8/99	No	Reheater Drain	
H. A. Wagner 3 Power Plant	——	Fossil	7/02		Feedwater Heater Drain	
Mihama 3, Japan	INPO OE19368 INPO OE18895	PWR	8/04	Yes	Feedwater	Five fatalities.
Edwards Power Plant	——	Fossil	3/05	Yes	Feedwater	
South Ukraine 2	WANO MER MOW 05-019	VVER	7/05		Feedwater Heater Drain	
South Ukraine 2	WANO MER MOW 05-021	VVER	8/05		Reheater Drain	
Iatan	------	Fossil	5/07	Yes	Attemperator spray	Two fatalities.

D
HISTORICAL BACKGROUND

Although there were limited FAC programs in place before the Surry pipe rupture, it was not until after this accident that utilities expanded their inspection programs to reduce the risk of pipe ruptures caused by FAC in susceptible single-phase systems. Since the Surry incident in December 1986, the industry has worked steadily to develop or refine their monitoring programs to prevent the failure of piping due to FAC. In March 1987, INPO issued SOER 87-3 [7], which recommended that a continuing program be established at all U.S. nuclear power plants. The program should include analyses for predicting wear rates and selecting intervals for regular inspections. In July 1987, the USNRC issued bulletin 87-01 asking licensees to monitor the pipe wall thickness in high-energy piping systems and to report any areas where wall thinning had been identified.

In June 1987, NUMARC[21] and EPRI developed a resolution approach for FAC in single-phase piping systems and provided the utilities with recommendations for a program [46]. This document recommended that utilities do the following:

1. Conduct appropriate analysis and a limited but thorough initial inspection of susceptible single-phase piping.
2. Determine the extent of thinning, and repair or replace worn piping components as necessary.
3. Perform follow-up inspections to confirm or quantify rates of thinning.
4. Take long term corrective action.

Based on the NUMARC/EPRI document, the U.S. industry conducted the initial inspections of nuclear plant piping systems during 1987 and 1988. The USNRC monitored the results of these inspections and in May 1989 issued Generic Letter 89-08 [10]. This, in essence, required that operators of nuclear power plants perform the following:

1. Implement a long-term FAC monitoring program.
2. Include all susceptible high-energy carbon-steel piping systems.
3. Include both single- and two-phase systems.
4. Utilize the NUMARC/EPRI or other equally effective analysis method.

[21] In 1993, NUMARC and several other industry organizations were combined to form the Nuclear Energy Institute - NEI.

To support the industry effort, EPRI began developing the CHEC® [58] and CHECMATE™[59] computer codes for predicting FAC wear rates in piping containing single- and two-phase flow. These codes were developed specifically to assist the utility industry in planning and implementing inspection programs to prevent FAC failures. The codes could also be used to evaluate the effect of changes in piping design or operating conditions on FAC wear rates.

In response to utility requests for assistance in managing and evaluating the NDE data acquired during inspections, the CHEC-NDE™ [60] computer code was developed and released in April 1991. To assist utilities in performing stress analysis of worn fittings, EPRI developed the CHEC-T™ computer code [61], which is based on [39]. In July 1989, EPRI formed the CHEC®/CHECMATE™ Users Group, since renamed the CHECWORKS™ Users Group, CHUG. The key purpose of this group is to provide a forum for the exchange of information pertaining to FAC issues and to provide user support and maintenance for the EPRI codes.

EPRI has continued to develop technology to help utilities control FAC. In December 1993, the CHECWORKS™ Flow-Accelerated Corrosion Application was released, which has since been re-named the Steam/Feedwater Application [1]. In summary, CHECWORKS™ integrated and updated the capability of the previous four codes, and was written to take advantage of the advances in computer technology. Additionally, capability was added to help utilities manage related plant data and to automate many of the analysis and reporting tasks conducted during an inspection outage.

In response to utility requests, ASME has published Code Case N-597-2, "Requirements for Analytical Evaluation of Pipe Wall Thinning," which provides rules for evaluating piping for FAC. These rules [5] provide structural acceptance criteria for Class 1, 2, and 3 piping components that have experienced wall thinning[22]. Note that the NRC has limited the applicability of the use of this Code Case for Safety Related Piping. See Regulatory Guide1.147 [40].

More recently, in response to user requests, EPRI has enhanced CHECWORKS™ SFA to include erosive damage mechanisms including cavitation erosion, flashing erosion and liquid droplet impingement [1].

[22] Some organizations are also using Code Case N-597-2 to evaluate B31.1 piping for FAC related wall thinning.

E
CHUG POSITION PAPERS

This appendix presents a list of Position Papers published by the CHECWORKS™ Users Group (CHUG). These papers are available from the CHUG website.

Number	Title
1	Guidelines for Interviewing Plant Personnel within an FAC Program
2	Inspection of Pipe and Equipment for Damage caused by FAC
3	Summary of Task and Resources for an FAC Program
4	Recommendations for Inspection Feedwater Heater Shells for FAC
5	Chromium Sampling
6	Small Bore Pipe Recommendations
7	Self Assessments of FAC Programs
8	Determination of Measured Wear
9	Development of a Figure of Merit for Evaluating CHECWORKS™ SFA Pass 2 Results
10	Investigation into Combining Single and Multiple Outage Inspection Data
11	Investigation into Statistical Methods of Analyzing Multiple Inspection Data
12	Review of Line Correction Factor Methodology
13	Independent Review of the FAC Degradation of the High Pressure Extraction Lines at Catawba
14	Evaluation of New Network Flow Analysis Model In CHECWORKS™ SFA

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