2024 TECHNICAL UPDATE

Risk-Informed High-Energy Line Break Evaluation Requirements

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ABSTRACT

The risk-informed methodology that is contained in this report provides an alternative means for assessing and confirming that plant structures, systems, and components that are important to safety are adequate to accommodate the effects of postulated accidents, including appropriate protection against the dynamic and environmental effects of postulated pipe ruptures.

This report provides a mechanism to identify the safety significance of postulated pipe ruptures and, as warranted, recommend appropriate plant actions (for example, plant modifications, inspection sample size), taking into account plant-specific design features and the safety benefit associated with possible plant modification while maintaining an adequate level of defense in depth. Although existing evidence and analyses have identified the potential for catastrophic pipe breaks (that is, double-ended guillotine breaks) as vanishingly low for well-engineered systems, prudence dictates that a reasonable assessment of postulated piping failures be conducted.

Keywords

High-energy line break
Probabilistic risk assessment
Risk-informed technology

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1 INTRODUCTION AND SUMMARY

The purpose of this report is to present an alternative methodology for meeting General Design Criteria 4 (GDC-4) [1]—that is, the risk-informed methodology that is contained in this report provides an acceptable means for assessing and confirming that plant structures, systems, and components (SSCs) that are important to safety are adequate to accommodate the effects of postulated accidents, including appropriate protection against the dynamic and environmental effects of postulated pipe ruptures.

The goal of this report is to identify the safety significance of postulated pipe ruptures and, as warranted, recommend appropriate plant actions (for example, plant modifications, inspection sample size), taking into account plant-specific design features and the safety benefit associated with possible plant modification while maintaining an adequate level of defense in depth (DID). Although existing evidence and analyses have identified the potential for catastrophic pipe breaks (that is, double-ended guillotine breaks [DEGBs]) as vanishingly low for this scope of piping, prudence dictates that a reasonable assessment of postulated piping failures be conducted. The initial application of this methodology is focused on the operating fleet and is limited to determining the risk significance of postulate piping failures and appropriate plant response strategies. Other plant designs and related programs (e.g., determining the scope of equipment required to be within an environmental qualification program) are outside the scope of this application.

1.1 Background

GDC-4 [1] requires that SSCs important to safety be designed to accommodate the effects of postulated accidents, including appropriate protection against the dynamic and environmental effects of postulated pipe ruptures.

Paraphrasing from NUREG-1061 [2], *design basis accident* and *maximum hypothetical accident* are terms that have been used to describe what was generally known as the DEGB. The concept was originated by the U.S. Atomic Energy Commission (AEC, forerunner of the Nuclear Regulatory Commission [NRC]) for the multiple purposes of sizing containments and establishing accident doses and later for sizing emergency core cooling systems. The original concept was quite straightforward—that an instantaneous DEGB of a major pipe in the primary system of a light water reactor would maximize the fluid release and establish an upper bound for the design pressure established for a containment.

As covered by NUREG-1061[2], later changes in regulatory philosophy tended to shift the DEGB from a hypothetical accident to one with increasing credibility. It was a relatively short step from the hypothetical to a belief in randomly occurring major pipe breaks.

The NRC has issued a number of documents that provide criteria for implementing the preceding requirement, including the scope of applicable systems, defining high-energy versus moderate-energy systems, and defining which individual locations within systems where breaks should be postulated to occur and those locations where breaks need not be postulated to occur. Specifically, the criteria define those systems, or portions of systems, where postulated breaks can be excluded from the design basis, methods for analyzing pipe whip forces and displacements, design of rupture restraints, and methods for evaluating the integrity of components subjected to the pipe rupture loads.

It should be noted that these requirements have evolved over time from issuance of the Giambusso letter (1972) [3] through issuance and revision of the applicable Standard Review Plan (SRP) sections (1975) [4]. Many other related requirements and programs that drive pressure boundary reliability, as well as understanding the risk benefits of such requirements, were also in the course of development or only recently issued/formulated. For example, Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Code (Rules for Inservice Inspection of Nuclear Reactor Coolant Systems [5]), was first published in 1970 and was limited to reactor coolant systems (RCSs). Subsequent requirements for the in-service inspection (ISI) of Class 2 and Class 3 systems did not occur until 1972 and 1974, respectively [6, 7].

Interestingly, although the 1974 version of ASME Section XI selected locations for inspection identified as postulated break locations according to design basis criteria (for example, SRP), later versions of ASME Section XI reflect more recent operating experience (for example, Footnote 7 of Table IWB-2500-1 (B-J) [8].

In addition, augmented inspection programs that factored in actual operating experience—for example, Generic Letter 89-08 [9] for flow-accelerated corrosion (FAC) and EPRI report 103581 [10] for thermal stratification, cycling, and striping (TASCS)—had not yet been foreseen.

Current guidelines for the identification and treatment of postulated rupture locations in piping systems are provided in NUREG-0800 SRPs 3.6.1 and 3.6.2 and associated Branch Technical Positions 3-3 and 3-4. These guidelines are generally unchanged from those developed in the early 1970s. Several public meetings have been held with the NRC concerning conservatism that is included in the branch technical positions. The majority of concern is centered around the cumulative usage factor requirements as they relate to environmental fatigue calculations that are required for long-term operation of the existing fleet. However, these concerns have forced both the regulator and industry to take a wholistic look at the requirements of addressing GDC-4 for all piping systems.

EPRI proposed a risk-informed alternative to the high-energy line break (HELB) postulation criteria in 2011 with report 1022873 [11]. Revision of the criteria was delayed until the extremely low probability of rupture (xLPR) Probabilistic Fracture Mechanics Code could be finished, because it was viewed as a useful tool to provide insights into the break assumptions. The xLPR Probabilistic Fracture Mechanics Code [12] was developed by EPRI and the U.S. NRC Office of Research to rigorously evaluate piping rupture events with initial emphasis on leak-before-break considering applicable active degradation mechanisms (DMs). xLPR is also being used to evaluate the frequency of loss-of-coolant accident (LOCA) events within the reactor coolant loop and associated branch piping.

In response to public meeting comments, the NRC formed a focus group to evaluate the feasibility of revising HELB criteria and leak locations. The initial goal was to develop an alternative HELB framework that is risk-informed while accounting for both the operating fleet and new/advanced reactor designs; however, that effort is still underway and currently resides in the Office of Research [13].

Currently each operating plant has a licensed approach for addressing the requirements of GDC-4. This is accomplished by meeting the requirements of NUREG-0800 (SRP) or a plant-specific alternative usually described in the plant's updated final safety analysis report (UFSAR). However, recent experiences have shown that there may be value in revisiting these previous commitments as a result of operating experience. For example, possible power uprates, license renewals, subsequent license renewals, and so forth can potentially add to the high-energy scope according to current requirements.

In support of this goal, an example plant application was also conducted to ensure that the defined process is robust and can be applied consistently. The example provided is for a non-safety-related system that was previously defined as a *moderate-energy system*.

1.2 Objective

Although, currently, each operating plant has a licensed approach for addressing the requirements of GDC-4, as stated previously, recent experiences have noted that these previous commitments may need to be revisited as a result of operating experience, including possible power uprates, license renewals, subsequent license renewals, and so forth.

The objectives of this report are to define an alternative risk-informed methodology for assessing and confirming that plant SSCs important to safety are adequate to accommodate the effects of postulated accidents, including appropriate protection against the dynamic and environmental effects of postulated pipe ruptures and to identify licensing processes for acceptable uses of this methodology based upon where the plant-specific commitment resides (for example UFSAR, Technical Specifications).

Additionally in parallel with issuance of this report, a pilot plant application (that is, submittal to NRC) is expected to occur in the 2024/2025 timeframe, for which this report will serve as the technical basis.

1.3 Approach

The approach undertaken consists of the following tasks:

- Review of the history and development and revision of SRP Sections 3.6.1 and 3.6.2
- Review of the history and development of methodologies for risk-informed categorization of pressure boundary components

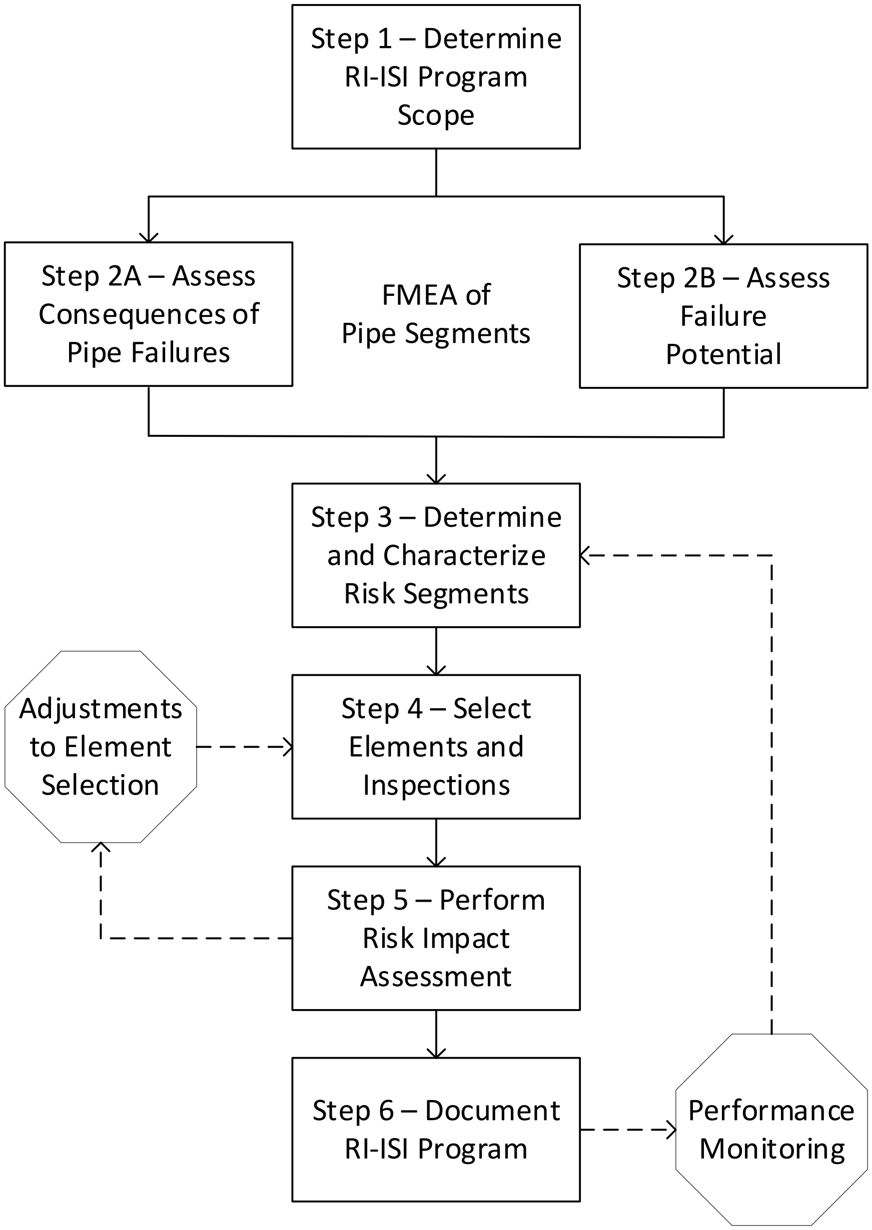
- Review of the history and developments of other related activities
- Review of the history and development of robust plant specific probabilistic risk assessments (PRA) (e.g. ASME/ANS RA-S, USNRC Regulatory Guide 1.200)
- Development of the risk-informed high-energy line break (RI-HELB) methodology, including test case results, which shows that the alternative methodology meets NRC Regulatory Guide (RG) 1.174 [14] risk-informed decision making and acceptance criteria

2 RISK-INFORMED HELB METHODOLOGY

As some background, EPRI TR-112657 Revision B-A [15], which was approved for use in developing a risk-informed in-service inspection (RI-ISI) program by the NRC in 1999 is the foundational methodology for a number of risk-informed applications related to SSCs that perform pressure boundary functions. The methodology contained in EPRI TR-112657 Revision B-A is summarized in Figure 2-1 and consists of two main analysis steps—that is, a Consequence of Failure Evaluation step and a Failure Potential Evaluation step. A timeline for development, approval, and use of TR-112657 and its daughter methodologies—for example, risk-informed break exclusion requirements (RI-BER) [16] and ASME Code Cases N-660 and N-752—is provided in Appendix B. The timeline in Appendix B also includes information related to other industry efforts that present the background, development, and technical robustness of the application of risk-informed technology to the pressure boundary function.

As with the methodology contained in TR-112657, application of the RI-HELB methodology requires the use of a robust plant-specific PRA which includes an assessment of key assumptions and sources of uncertainties. A plant-specific PRA that reflects the as-built/ as-operated plant and that has been peered reviewed and shown to meet capability category II of the ASME/ANS PRA standard as endorsed in USNRC Regulatory Guide 1.200 would meet this requirement. Other means of assuring PRA technical adequacy will need to be determined based upon interactions between the licensee and the applicable regulatory body.

Further, as with any risk-informed application, the RI-HELB methodology is an integrated decision-making process which requires the input and use of multiple disciplines including personnel with expertise in PRA, plant operation, system design, safety/accident analyses, and degradation mechanism evaluations.



FMEA = failure modes and effects analysis

Figure 2-1. Overview of the EPRI traditional RI-ISI methodology

As covered in the NRC's safety evaluation in EPRI TR-112657, the conditional core damage probability (CCDP) and conditional large early release probability (CLERP) metrics avoid the concerns identified during previous efforts using importance measures. For example, uncertainties associated with pressure boundary components that have very low failure probabilities are eliminated because failure is assumed (that is, a failure probability of 1.0 is used) for the consequence of failure evaluation. Additionally, use of the CCDP and CLERP metrics, which includes identifying all active functions that are and are not impacted by the postulated pressure boundary failure (PBF), identifies pressure boundary components as important from a DID perspective if there is limited or no redundancy given the postulated PBF even if the postulated PBF's overall contribution to risk (core damage frequency [CDF]/large early release frequency [LERF]) is low.

Using the foundational methodology contained in TR-112657 and its extension to other pressure boundary applications, the RI-HELB methodology (which is depicted in Figure 2-2) that is presented in the following sections provides a well-structured approach for determining active and passive components impacted by the postulated break and the resulting risk significance of these impacts, thereby providing an acceptable level of quality and safety.

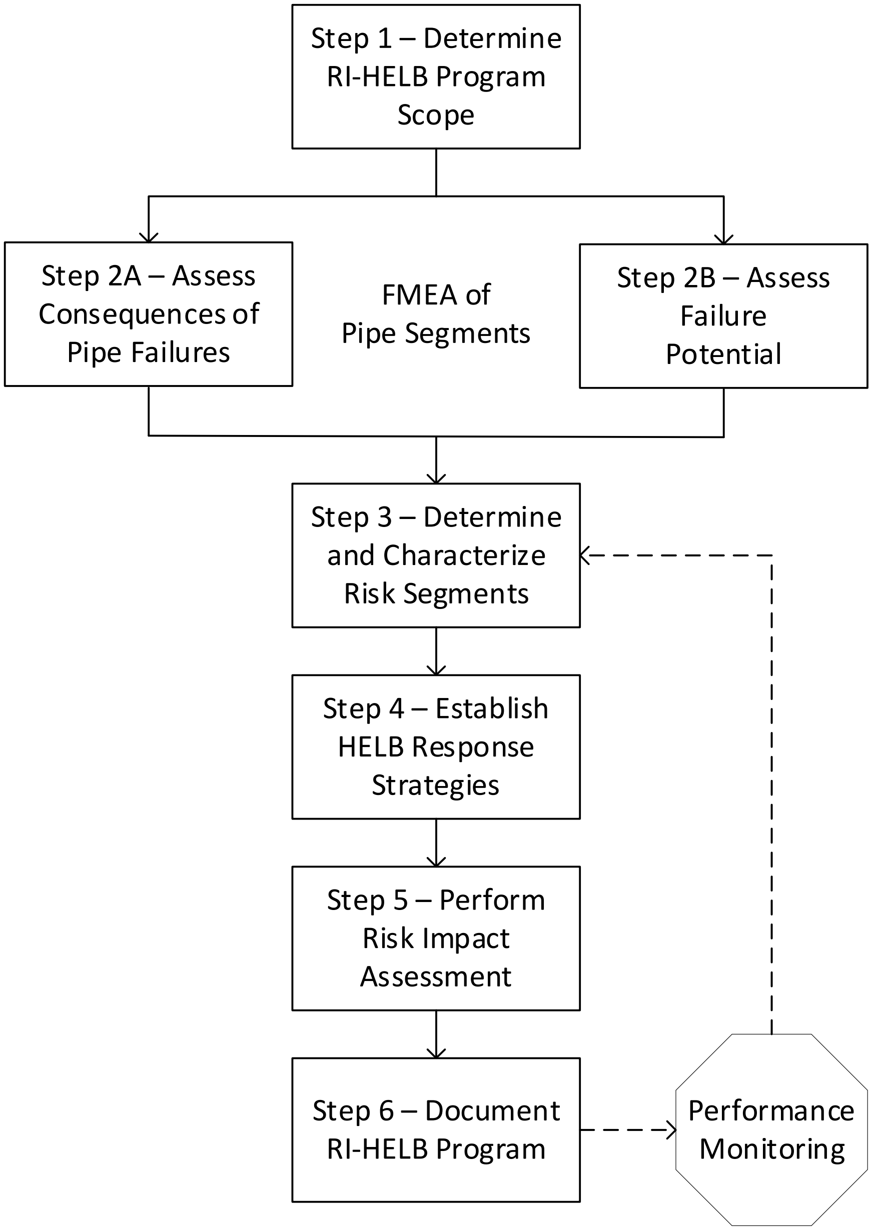


Figure 2-2. RI-HELB methodology overview

The RI-HELB methodology is implemented by the following six-step process:

1. Definition of RI-HELB program scope
2. FMEA of HELB scope.
    a. Evaluation of consequences of pipe failures
    b. Evaluation of pipe failure potential
3. Characterization of risk segments (risk matrix)
4. HELB response strategies
5. Evaluation of risk impact of changes to the HELB program
6. Incorporation of long-term RI-HELB program (performance monitoring)

Step 1: Define the RI-HELB Program Scope

The first step is to decide on the scope of the RI-HELB program. As covered previously, HELB programs are already in effect at all operating plants and for a number of new-build designs. Based on current knowledge, it is anticipated many users of the RI-HELB methodology will be licensees that go through a plant evolution (for example, power uprate, subsequent license renewal) and, as such, wish to keep their overall HELB program intact but address changes with a risk-informed approach. As such, options for using the RI-HELB methodology range from focused scope applications (for example, limited to a system or subsystem) to revisiting the entire current HELB program scope.

With respect to application of the RI-HELB methodology, it needs to be verified that for the candidate system (portion of system) the potential for water hammer is low. To demonstrate that water hammer is not a significant contributor to pipe rupture, reliance on historical frequencies of water hammer events in specific piping systems coupled with reviews of operating procedures and conditions can be used for this evaluation. Alternatively, design changes such as the use of J-tubes, vacuum breakers, and jockey pumps coupled with improved operating procedures can be used to reduce concerns from water hammer. It should also be established that any measures that are needed to abate water hammer frequency and magnitude will be effective for the life of the plant.

Also note that high-energy fluid system scope includes normally operating systems during power operation where the temperature and/or pressure conditions of the fluid exceed a certain threshold (for example, 200°F [93°C] and/or 275 psig [1896058 Pa]). As an example, power uprates have identified non-safety-related main steam cross-around piping from the high-pressure turbine to the moisture separators and from the moisture separators to the low-pressure turbines as exceeding these criteria. As an example, Figure 2-3 highlights this piping scope, and the evaluation of this scope is described in Section 3 of this report.

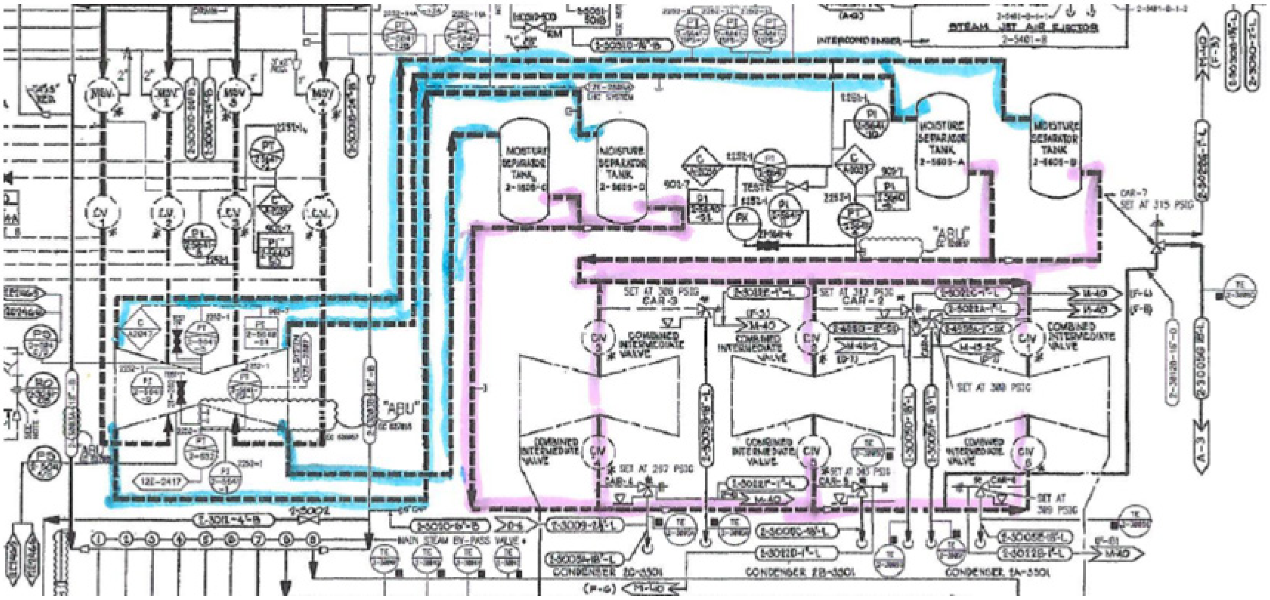


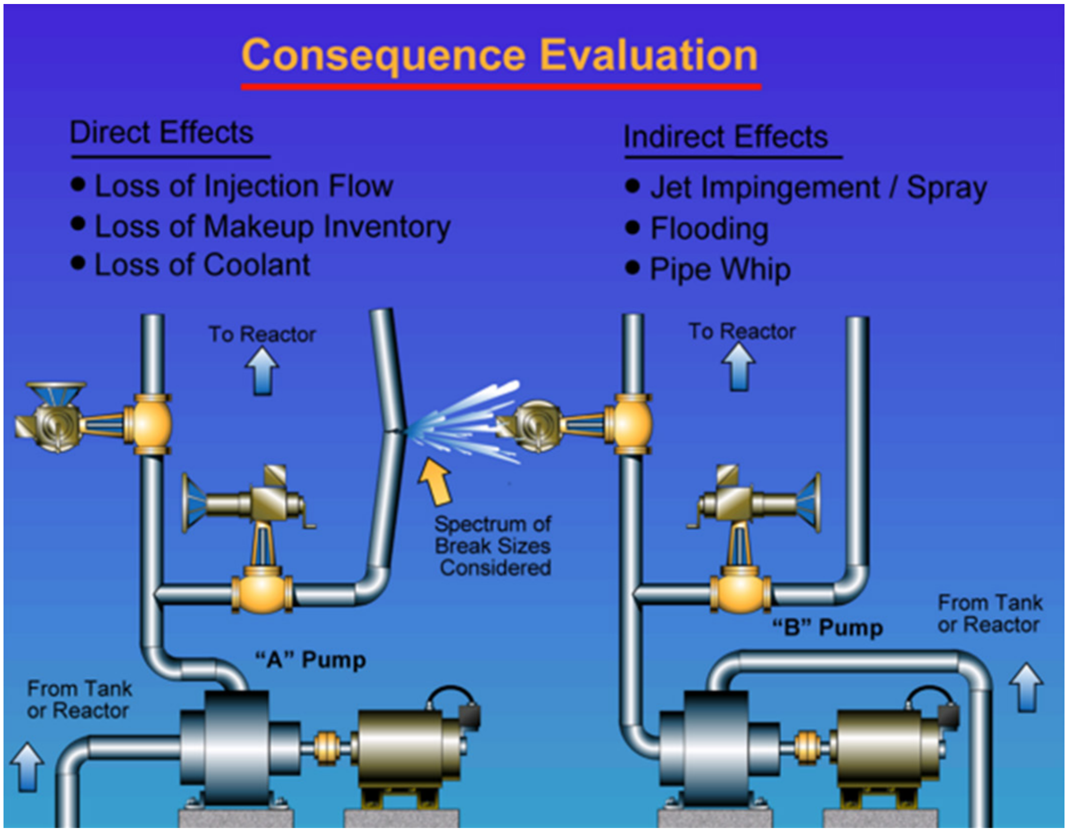
Figure 2-3. Example RI-HELB scope

Step 2: Failure Mode and Effects Analysis

This step performs the FMEA of the piping systems or portions of systems within the RI-HELB program scope. In Figure 2-1, this step is broken down into two distinct substeps because these are where most of the resources are applied in developing and implementing a RI-HELB program. The FMEA is typically performed on a system-by-system basis and leads to the definition of piping segments that have common potential of failure and common consequence of failure. Segments with the same failure potential and failure consequence are combined into common risk segments in Step 3.

Conducting the analysis on a segment basis is for ease of use rather than being a technical component of the analysis. As such, differences in segment definition or segment boundary definition will have no impact on the final results for applications using the RI-HELB methodology. Additionally, depending upon the scope of the RI-HELB application, the user may wish to document the process and result at the component level or group of components level.

The consequences of pipe rupture (see Figure 2-4) are measured in terms of the CCDP, given a pipe rupture, and the CLERP, given a pipe rupture. These measurements require quantitative risk estimates obtained from the plant-specific probabilistic risk assessment (PRA) models that are available for each plant. Application of this step and its basis is further covered in Section 2.1 of this report.



Consequence Evaluation

Direct Effects

- Loss of Injection Flow
- Loss of Makeup Inventory
- Loss of Coolant

Indirect Effects

- Jet Impingement / Spray
- Flooding
- Pipe Whip

Figure 2-4. Consequence of failure overview

In a similar fashion, the HELB scope needs to be assessed in terms of the relative potential for pipe rupture (see Figure 2-5). By evaluating physical conditions needed for various DMs to be operative against plant-specific operating and material conditions, failure potential can be correlated with quantitative estimates of pipe rupture frequency derived from service experience. Application of this step and its basis is further covered in Section 2.2 of this report. In addition, a service history review is required, as described in Section 2.2.

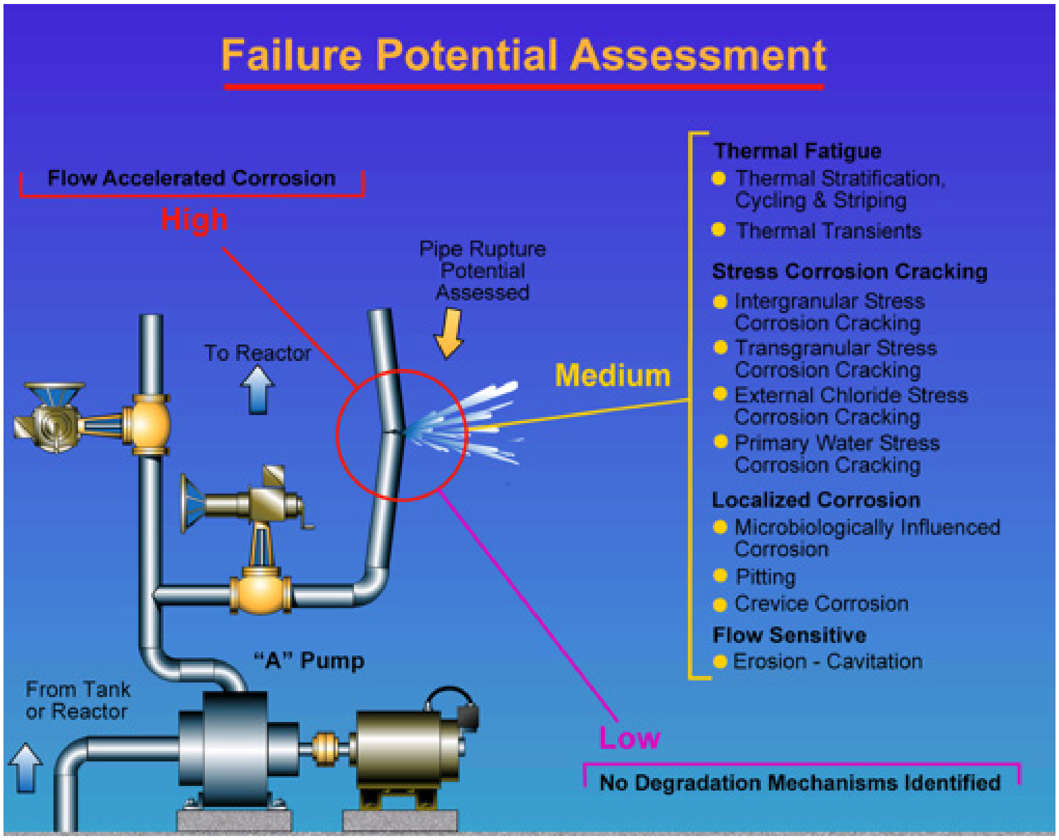
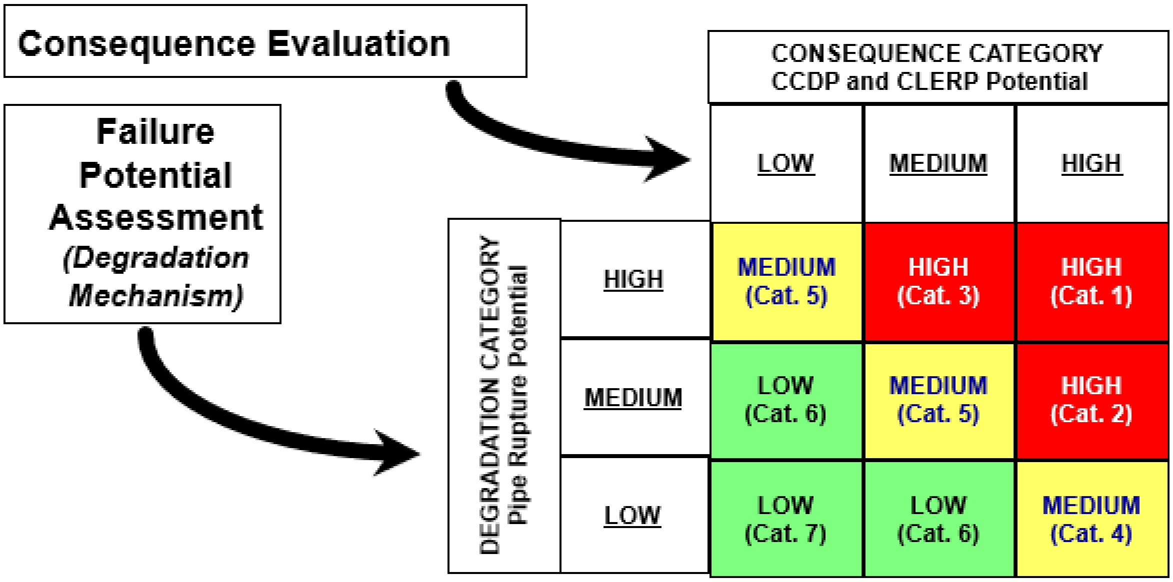


Figure 2-5. Failure potential overview

As covered previously, piping segments with the same failure potential and consequence of failure are combined as risk segments.

Step 3: Characterization of Risk Segments (Risk Matrix)

In Step 3, each segment is assigned to the appropriate place on the risk matrix, as shown in Figure 2-6, based on three broad categories of failure potential (High, Medium, or Low) and three broad categories of failure consequence (High, Medium, or Low). Based on the combination of failure potential and consequence categories, each location on the risk matrix is assigned to one of three broad risk regions that are correlated with ranges of absolute levels of CDF and LERF (see Section 2.3).



		CONSEQUENCE CATEGORY CCDP and CLERP Potential		
DEGRADATION CATEGORY Pipe Rupture Potential		LOW	MEDIUM	HIGH
	HIGH	MEDIUM (Cat. 5)	HIGH (Cat. 3)	HIGH (Cat. 1)
	MEDIUM	LOW (Cat. 6)	MEDIUM (Cat. 5)	HIGH (Cat. 2)
	LOW	LOW (Cat. 7)	LOW (Cat. 6)	MEDIUM (Cat. 4)

Figure 2-6. RI-HELB risk matrix

Step 4: Establish HELB Response Strategies

In this step, HELB response strategies and treatment practices to be applied will be a function of the risk significance of the postulated piping failures. Postulated piping failure that results in a High risk assignment or a High consequence of failure assignment would not be expected to be amenable to some type of performance-monitoring responses, and possible hardware or system modification is most likely the appropriate course of action. Postulated piping failures that result in Medium risk assignments can be addressed through performance monitoring where locations on the risk matrix are selected for the inspection program based on the segment’s risk ranking and a set of practical considerations that bear on the feasibility and effectiveness of the specific inspection. For those locations selected for nondestructive evaluation inspections, the inspections are focused on the type of DM identified in Step 2. The ability to focus the examination on specific DM(s) enhances the effectiveness of the retained inspections. Application of this step is further covered in Section 2.4 of this report.

Step 5: Assessment of Risk Impact

As a final analysis step (Step 5), it must be shown that the changes in risk resulting from changes in the HELB program do not have a significant risk impact as defined by changes in CDF and LERF. This approach has been designed to ensure that risk impacts associated with modification to the HELB program should be small because of postulating piping breaks at all locations within the scope of evaluation (for example, including welds with stress levels below a certain stress threshold) and focusing resources on High and Medium risk locations. Additionally, when performance monitoring is selected, examinations are geared toward those locations where the postulated degradation is most likely to be observed. Therefore, significant adjustments to the RI-HELB program strategies initially selected, to demonstrate that risk impact requirements are not exceeded, are not anticipated. Regardless, in this step, it must be confirmed that the initial selection of strategies does not produce an unfavorable and unacceptable risk impact. Application of this step is further covered in Section 2.5 of this report.

Step 6: Performance Monitoring

The periodic review of industry and plant operating experience, service history, ISI program, and so forth is necessary for the implementation of a long-term RI-HELB program.

The following sections cover the RI-HELB methodology in finer detail, beginning with the consequence of failure evaluation.

2.1 Consequence of Failure Evaluation

As portrayed in Figure 2-2, the consequence of failure evaluation is one part of the FMEA. The purpose of this part of the FMEA is to evaluate PBFs in terms of their impact on core damage and large early release (LER).

2.1.1 Fundamental Principles

As previously covered, to ease the documentation burden, this methodology uses the term *piping segment*. A piping segment can consist of a portion of piping for which a failure at any point in the segment results in the same consequence (for example, loss of the system or loss of a pump train) and includes piping subject to the same DM or DMs. Therefore, a piping segment can consist of a single piping component or multiple piping components (for example, piping, fittings, tanks, heat exchangers, moisture separator reheaters, pumps, valves). On the other hand, as previously covered, the use of *segments* is strictly for documentation convenience and is not a technical component of the RI-HELB methodology, as such, and, as provided in one of the examples in the Section 3, the new scope of HELB may have the consequences evaluated for the complete scope without the need to identify several segments.

As previously covered, the purpose of this part of the FMEA portion of the RI-HELB methodology is to evaluate PBFs in terms of their impact on core damage and LER. The consequence evaluation focuses on the impact of a pipe section failure (loss of pressure boundary integrity) on plant operation. This impact can be direct, indirect, or a combination of both, as follows:

- **Direct impacts**. A failure results in a diversion of flow and a loss of the train and/or system or an initiating event (such as a loss of main condenser, feedwater, or a turbine trip).
- **Indirect impacts**. A failure results in a flood, jet impingement or pipe whip, spatially affecting neighboring SSCs, or results in depletion of a tank and loss of the systems supplied by the tank.

The approach presented herein is intended to result in a comprehensive assessment of direct and indirect effects for a spectrum of piping failures, from pipe leaks to ruptures. The consequences resulting from indirect effects and direct effects are treated explicitly.

Spatial effects are an example of indirect effects caused by PBFs. These include the effects of high temperature, flood, jet impingement, and pipe whip on equipment located in the vicinity of the break. Spatial consequences of the break are determined based on the location of the analyzed break and the relative position of important equipment. Analyzed locations of the break should be consistent with locations analyzed in other spatial analyses performed for the plant (for example, internal flood [IF] analysis). The presence of important equipment in a specific location should be identified through these analyses and should be confirmed by a walkdown.

The possibility of isolating a break is also identified and accounted for as part of the consequence analysis. A break could be isolated by a protective check valve or a closed isolation valve, or it could be automatically isolated by an isolation valve that closes on a given signal. If not automatically isolated, a break can be isolated by an operator action, given successful diagnosis. The likelihood of isolating a break depends on the availability of isolation equipment, a means of detecting the break, the amount of time available to prevent specific consequences (for example, flooding of the room or draining of the tank), and human performance.

As application of the RI-HELB methodology applies to high energy systems, the likelihood of having significant time available for operator actions may be limited. Typically, only automatic isolation is credited for HELB events if the event does not prevent isolation from functioning. In considering very small breaks that do not generate automatic signals, detection and isolation is considered, but the spatial impacts are much less significant and there has to be time, detection, etc.

If isolation is possible, the consequence assessment should be conducted for both cases: successful and unsuccessful isolation. Operator recovery actions are further covered in Section 3.3.3.2 of EPRI TR-112657.

For each run of piping under evaluation, a spectrum of break sizes is evaluated. The break size ranges from a small leak to a rupture. Larger leaks and breaks have the potential to disable systems or trains and to cause initiating events, flooding, or diversions of water sources. Typically, small breaks (minor leakage) would not render a train inoperable. They may, however, depending on the energy level of the system, spray onto adjacent equipment and cause equipment malfunction, and they may also take longer to diagnose.

Numerous past evaluations have shown that the large break scenarios (worst-case breaks) result in the most limiting consequences. However, the methodology was specifically developed to require that a spectrum of break sizes be evaluated so that, if smaller breaks can cause a measurable or dominant consequence, they are identified and input into the risk-ranking process.

2.1.2 Consequence Ranking and Categorization

The goal of the consequence evaluation is to establish a process that consistently ranks consequences caused by a pressure boundary (for example, pipe) failure, based on its risk impact or safety significance. For example, a pipe break that results in loss of feedwater would be less important than a pipe break that results in loss of feedwater and has additional impacts on mitigation systems (for example, electrical switchgear). To address these different impacts consistently, consequences are categorized into different importance categories.

The consequences are ranked into those categories based on a combination of plant-specific PRA insights and results, which are explained in the following sections.

Three consequence importance categories have been defined based upon PRA evaluation. They are: High, Medium, and Low. The High category represents events with a significant impact on plant safety, and the Low category represents events with a minor impact on plant safety.

The consequence-ranking philosophy, used in this methodology, can be summarized as follows:

- **High consequence**. PBFs resulting in events that are important contributors to plant risk and/or PBFs that significantly degrade the plant's mitigative ability.
- **Low consequence**. PBFs resulting in anticipated operational events and/or PBFs that do not significantly impact the plant's mitigative ability.
- **Medium consequence**. This category is included to accommodate PBFs that fall between the High and Low rank.

Each consequence category has an assigned range of CCDP or CLERP, associated with the impact of a specific PBF. When considering uncertainties in estimating CCDP and CLERP values, mean values are used. The ranges that are used to numerically define each category are shown in Table 2-1.

Table 2-1. Correspondence of consequence categories to numerical estimates of CCDP and CLERP

Consequence Category	Corresponding CCDP Range	Corresponding CLERP Range
High	CCDP > 1E-4	CLERP > 1E-5
Medium	1E-6 < CCDP ≤ 1E-4	1E-7 < CLERP ≤ 1E-5
Low	CCDP ≤ 1E-6	CLERP ≤ 1E-7

CCDP and CLERP ranges are determined based on the estimates of the total risk associated with the piping failure. Risk is measured by CDF or LERF as follows:

CDF [given PBF]=[PBF frequency] * [CCDP]. Eq. 2-1

LERF [given PBF]=[PBF frequency] * [LERP]. Eq. 2-2

Based on the preceding expressions and using a conservative estimate of the total PBF frequency for the plant (estimated on the order of 1E-2 per year or less), CCDP and CLERP ranges are selected to guarantee that all pipe locations ranked in the Low consequence category do not have a potential CDF impact higher than 1E-8 per year or a potential LERF impact higher than 1E-9 per year. The boundaries between the High and Medium consequence categories, at CCDP and CLERP values of 1E-4 and 1E-5, respectively, are set to correspond with the definitions of small CDF and LERF values of 1E-6 and 1E-7 per year. The assumption that 1E-6 and 1E-7 represent suitably small CDF and LERF values is consistent with the decision criteria for acceptable changes in CDF and LERF found in RG 1.174. The Medium category is selected to cover the area between High and Low categories and to address uncertainties in the CCDP and CLERP estimates.

The process of conducting a consequence evaluation is organized and defined as follows:

1. Plant PRA models, systems, initiators, and supporting analysis are evaluated. The initial consequence rank is established, based on the PBF impact on CDF and LERF.
2. Containment performance is evaluated. The previously established consequence rank is reviewed and adjusted to reflect the PBF impact on containment performance, by evaluating impact on containment isolation and LOCA outside containment (containment bypass).

2.1.3 Consequence Evaluation

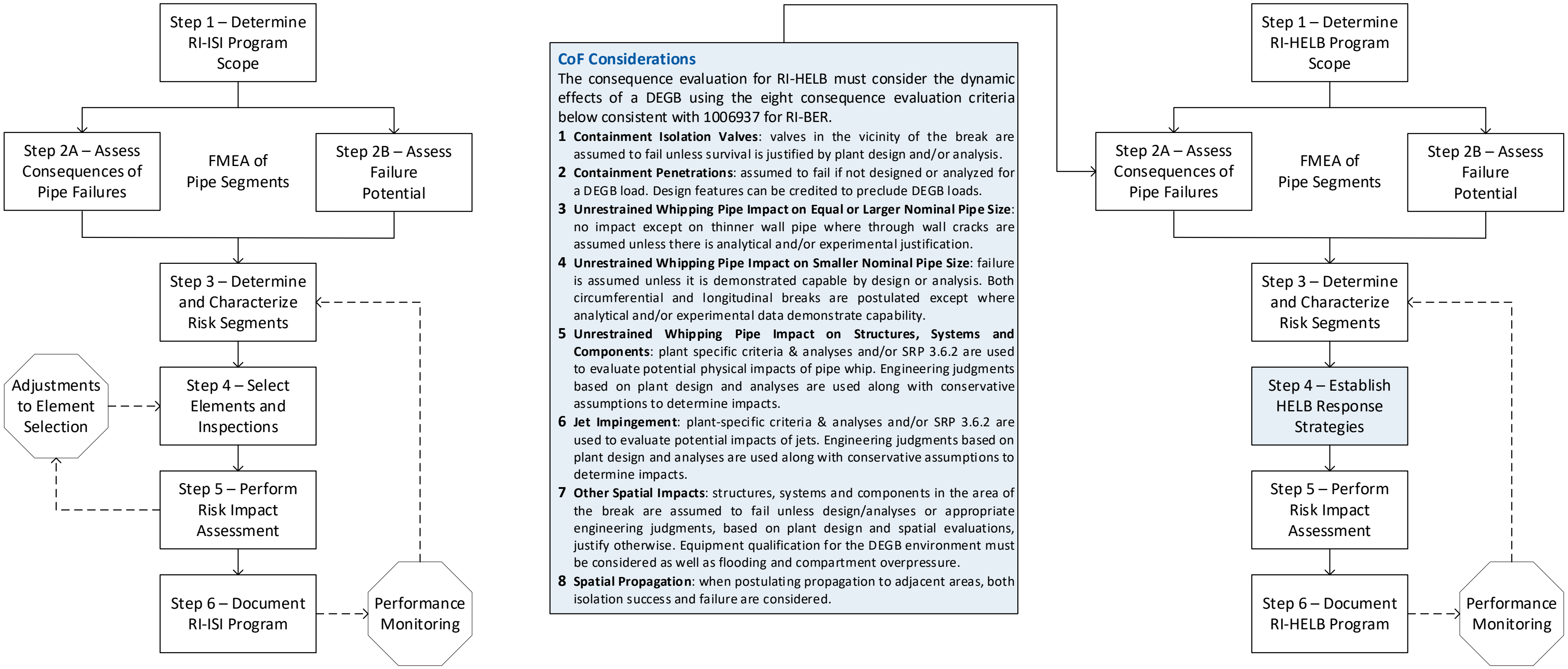
Because piping within the scope of a RI-HELB application is normally operating (that is, pressurized and at high temperature), the postulated PBF will result in an initiating event or forced plant shutdown. The evaluation of the impact of the postulated PBF should be accomplished using a plant-specific list of initiating events from the plant PRA and design basis documentation (that is, HELB documentation). For systems previously not within the scope of the current HELB program, this could also include events that might not be explicitly modeled by either process. When a PBF causes an initiating event that is not explicitly modeled in the PRA or causes an initiating event modeled in the PRA but with additional mitigating impacts, PRA quantification is required. The following provides a general procedure for the PRA quantification:

- Applicable Initiator is set to 1.0 (this provides a CCDP/CLERP result).
- All other initiating events are set to 0.0.
- Applicable Impacts are set to TRUE using basic events to simulate the impacts.
- The preceding is done for CDF and LERF quantification; the result is CCDP and CLERP.

An initiating event is likely as a result of a HELB (for example, steam or feedwater line break); additional mitigation impacts can also occur, such as loss of a system (for example, loss of charging, feedwater, and so forth) because of an indirect effect (for example, spraying/jet impingement of an electrical bus, flooding of the room, and so forth). When conducting the evaluation of HELB impact, there are eight consequence evaluation criteria to be considered; each is summarized as follows (Note that these criteria must also be used for deterministic analysis of HELB as described in the SRPs.):

- **Containment isolation valves**. Valves in the vicinity of the break are assumed to fail unless survival is justified by plant design and/or analysis.
- **Containment penetrations**. Assumed to fail if not designed or analyzed for a DEGB load. Design features can be credited to preclude DEGB loads.
- **Unrestrained whipping pipe impact on equal or larger nominal pipe size (NPS)**. No impact except on thinner wall pipe where through-wall cracks are assumed unless there is analytical and/or experimental justification.
- **Unrestrained whipping pipe impact on smaller NPS**. Failure is assumed unless it is demonstrated capable by design or analysis. Circumferential and longitudinal breaks are postulated except where analytical and/or experimental data demonstrate capability.
- **Unrestrained whipping pipe impact on SSCs**. Plant-specific criteria and analyses and/or SRP 3.6.2 are used to evaluate potential physical impacts of pipe whip. Engineering judgments based on plant design and analyses are used along with conservative assumptions to determine impacts.
- **Jet impingement**. Plant-specific criteria and analyses and/or SRP 3.6.2 are used to evaluate potential impacts of jets. Engineering judgments based on plant design and analyses are used along with conservative assumptions to determine impacts.
- **Other spatial impacts**. SSCs in the area of the break are assumed to fail unless design/analyses or appropriate engineering judgments, based on plant design and spatial evaluations, justify otherwise. Equipment qualification for the DEGB environment must be considered, as well as flooding and compartment overpressure.
- **Spatial propagation**. When postulating propagation to adjacent areas, both isolation success and failure are considered.

The extension of the RI-ISI methodology to RI-BER and RI-HELB is depicted in Figure 2-7.



CoF Considerations

The consequence evaluation for RI-HELB must consider the dynamic effects of a DEGB using the eight consequence evaluation criteria below consistent with 1006937 for RI-BER.

1. **Containment Isolation Valves**: valves in the vicinity of the break are assumed to fail unless survival is justified by plant design and/or analysis.
2. **Containment Penetrations**: assumed to fail if not designed or analyzed for a DEGB load. Design features can be credited to preclude DEGB loads.
3. **Unrestrained Whipping Pipe Impact on Equal or Larger Nominal Pipe Size**: no impact except on thinner wall pipe where through wall cracks are assumed unless there is analytical and/or experimental justification.
4. **Unrestrained Whipping Pipe Impact on Smaller Nominal Pipe Size**: failure is assumed unless it is demonstrated capable by design or analysis. Both circumferential and longitudinal breaks are postulated except where analytical and/or experimental data demonstrate capability.
5. **Unrestrained Whipping Pipe Impact on Structures, Systems and Components**: plant specific criteria & analyses and/or SRP 3.6.2 are used to evaluate potential physical impacts of pipe whip. Engineering judgments based on plant design and analyses are used along with conservative assumptions to determine impacts.
6. **Jet Impingement**: plant-specific criteria & analyses and/or SRP 3.6.2 are used to evaluate potential impacts of jets. Engineering judgments based on plant design and analyses are used along with conservative assumptions to determine impacts.
7. **Other Spatial Impacts**: structures, systems and components in the area of the break are assumed to fail unless design/analyses or appropriate engineering judgments, based on plant design and spatial evaluations, justify otherwise. Equipment qualification for the DEGB environment must be considered as well as flooding and compartment overpressure.
8. **Spatial Propagation**: when postulating propagation to adjacent areas, both isolation success and failure are considered.

Figure 2-7. Extension of RI-ISI Methodology to RI-BER and RI-HELB

The importance of possible initiating events, caused by the pipe failure, must be assessed to assign it to its appropriate consequence category. To rank the impact of one initiating event versus another, the plant's mitigating abilities need to be addressed. The plant's mitigating abilities are usually much more favorable for events that are anticipated during the plant lifetime than for the events not expected to occur during the plant's life. Also, different plants are sensitive to different types of events to differing degrees, depending on their mitigating abilities.

Considering the preceding, a PBF that results in an initiating event, which in the plant design basis documents is expected to have a low frequency of occurrence but is a significant contributor to plant risk, should be categorized as High. An example of this would be a pipe failure causing a LOCA in a typical pressurized water reactor (PWR) plant. Conversely, a pipe failure that results in an initiating event, which in the plant design basis documents is expected to have a high frequency of occurrence but is a minor contributor to plant risk, should be categorized as Low. An example of this would be a pipe failure causing a normal transient, such as loss of charging in a typical PWR. The CCDP guidelines in Table 2-1 are to be used to numerically define the High, Medium, and Low thresholds for initiating events.

These principles are illustrated in Table 2-2. In Table 2-2, based on the expected frequency of occurrence, initiating events are grouped into four design basis event categories. The first category, routine operation, is not relevant to this analysis. If a postulated pipe failure results in a Category IV event or an event not expected to occur during the lifetime of a particular plant, the assigned consequence category, based on CCDP, is expected to be Medium or High, depending on plant-specific design features (primarily redundancy and diversity of mitigative systems). Conversely, if a postulated pipe failure results in a Category II event, anticipated operational occurrence, the significance of this impact is not expected to be High, and the assigned consequence category should be Low or Medium. Failures that result in Category III events, infrequent events, can vary between Medium and Low consequence categories, depending on the specific initiating event and importance of that event to plant risk. For example, loss of offsite power (LOSP) is expected to be a major risk contributor and, therefore, is expected to be assigned to a Medium consequence category, whereas excessive feedwater is not expected to be a significant risk contributor and, therefore, would likely be assigned to a Low consequence category. (**Note**: pipe failure can result in LOSP because of spatial considerations such as flooding of switchgear because of the HELB. Also, it is possible that Category II or III events on a plant-specific basis could result in a High consequence based on spatial impacts of the HELB.)

Table 2-2. General guidelines for assigning consequence categories to PBFs resulting in an initiating event

Design Basis		Initiating Event Examples	Expected Consequence Category
Initiating Event Category	**Description**		
I Routine operation	Routine operation	Startup, shutdown, standby, refueling, and so forth	N/A
II Anticipated operational occurrence	Events that might occur during a calendar year in a particular plant (frequency >0.1/yr)	Reactor trip, turbine trip, partial loss of main feedwater system	Low/Medium
III Infrequent events	Events that might occur during the lifetime of a particular plant (frequency 0.01/yr through 0.1/yr)	Excessive feedwater/ steam removal LOSP	Low/Medium
IV Limiting faults or accidents	Events not expected to occur during the plant's lifetime (frequency <0.01/yr)	SLOCA MLOCA/LLOCA SLB ISLOCA	Medium/High

SLOCA = small loss-of-coolant accident
MLOCA = medium loss-of-coolant accident
LLOCA = large loss-of-coolant accident
SLB = steam line break
ISLOCA = interfacing system loss-of-coolant accident

It should be noted that Table 2-2 is presented only to illustrate general guidelines. Consequence categories for PBFs leading to an initiating event are explicitly determined from the plant PRA results, based on the numerical guidelines defined in Table 2-1 (both CCDP and CLERP are considered). When a PBF causes an initiating event modeled in the PRA, the CCDP corresponding to that initiating event can be obtained directly from the PRA results. A plant-specific version of Table 2-2, from one of the RI-ISI pilot applications, is shown in Table 2-3. This example illustrates that final initiating event ranking is a function of plant-specific design features. It should be confirmed that the PRA model for initiating events is applicable for the specific initiators caused by a PBF. For example, recovery of offsite power, an important factor in PRA models, probably cannot be credited if a LOSP was caused by a PBF. A table similar to Table 2-3 should be generated for each plant-specific application, ensuring that plant-specific PRA model truncation issues are addressed.

Table 2-3. A plant-specific example of assigning consequence categories to PBFs resulting in an initiating event

Design Basis Initiating Event Category	Initiating Event	Initiating Event Frequency (1/yr)	CDF Resulting from Initiating Event (1/yr)	Corresponding CCDP	Consequence Category
II	Reactor trip	2	1E-6	5E-7	Low
	Turbine trip	1	1E-6	1E-6	Low
	Loss of PCS	3E-1	9E-7	3E-6	Medium
III	Loss of SW train	8E-2	2E-6	3E-5	Medium
	LOSP	5E-2	2E-6	4E-5	Medium
IV	SLB	1E-3	1E-9	1E-6	Medium
	Small LOCA	5E-3	2E-6	4E-4	High
	Medium LOCA	1E-3	2E-6	2E-3	High
	Large LOCA	1E-4	1.5E-6	1.5E-2	High

PCS = power conversion system
SW = service water

CLERP is addressed using the values provided in Table 2-1. Additionally, the impact on containment isolation and LOCA outside containment must also be evaluated if the HELB scope interfaces with containment. The following summarizes:

- **Containment isolation**. HELB components that are associated with containment penetrations but not connected to RCS are qualitatively reviewed to ensure redundancy.
  - Redundant containment isolation valves with one inside containment and one outside containment allow screening (CCDP governs).
  - Isolation valve outside containment with closed system inside containment allows screening (CCDP governs).
  - Most PRAs typically screen 2-in. (50.8-mm) lines and smaller (CCDP governs).
  - Open inside containment (piping from penetration outside containment needs to be evaluated). The following are options:
    - Can assume CCDP = CLERP and, if CCDP is <1E-5, the segment(s) are still at least a Medium consequence.
    - If CCDP is >1E-5, High consequence at least for the piping between the penetration and first isolation valve.
    - For piping beyond the first isolation valve, the failure to isolate CCDP is relevant. If CCDP is >1E-5 and dominated by operator reliability, a second chance at isolation might be appropriate; otherwise, this piping is also High consequence.
- **LOCA outside containment**. Segments outside containment that connect to RCS are evaluated with plant-specific calculations using Table 2-1.

2.1.4 Plant Walkdown

The impact of a pipe failure and resulting interactions with other components are assessed as part of the consequence evaluation. A system walkdown is conducted to support the assessment. Generally, direct effects are confined to the system itself; however, indirect impacts resulting from the failure of a pipe segment can affect neighboring equipment within the system or other system(s). Indirect impacts associated with pipe breaks are generally caused by flooding, spraying, or jet impingement of neighboring equipment. The objective of the walkdown is to identify these impacts and capture subtle interactions that could not be readily identified by reviewing the information contained in the plant’s internal flood screening study, the plant PSA, and the various plant design drawings.

For the pilot studies, this task involved a walkdown of the flow paths for each line included in the system boundaries. In performing this task, the various plant locations (i.e., flood zones) containing system piping were visited. Pipe breaks at various locations were postulated, and the significance of spatial impact due to flooding, spraying, or jet impingement was discussed among the team members. Based on physical barriers (i.e., larger piping and piping supports) in place that could minimize the spatial effects and the relative distance of equipment that might be impacted, a consensus was reached regarding the equipment that would most likely be impacted.

In case flooding occurred, the locations of equipment above floor level were noted and whether a significant amount of water could accumulate within the flood zone. Rooms with non-water-tight doors were judged to be incapable of accumulating a significant amount of water in a flood zone. In such cases, flooding of equipment within the flood zone was judged to be of no significance. The number of floor drains and the flood detection capabilities within the flood zone were noted as part of the walkdown. The propagation paths for the outflow from the flood initiation zone to the lowest elevation were noted during the walkdown. Features incorporated in the plant design to guard against flooding of safety-related equipment were examined in order to assess the significance of a pipe failure.

Equipment located in the vicinity of a postulated pipe break might be subject to spraying or jet impingement. Physical barriers in the trajectory path that provided protection were noted and credited in assessing the potential impact caused by spraying or jet impingement. Valve motors that were environmentally qualified were considered capable of performing their functions, even though spraying or jet impingement of these valves might occur.

The insights gained during the walkdown were incorporated in the consequence assessment. An example detailed walkdown assessment from one system in an earlier plant application is provided in reference [18].

2.2 Failure Potential Evaluation

As covered previously, the RI-HELB methodology requires an assessment of failure potential for the in-scope piping. This is accomplished by a two-step process that consists of conducting a DM evaluation in accordance with the requirements and criteria contained in EPRI TR-T112657 Revision B-A, which is summarized in Section 2.2.1. The second step consists of a plant-specific service history review. The purpose of this second step is twofold. First, the review of plant-specific operating experience (for example, pressure boundary flaws, failures) confirms that the plant is operating consistent with the data/information sources used to develop the TR-112657 approach. And secondly, the plant-specific review confirms that there are no new plant unique types of degradation that need to be added to the failure potential evaluation scope.

2.2.1 DM Evaluation

As covered previously, the RI-HELB methodology requires the applicable DM(s), if any, to be identified for the in-scope piping under evaluation. The DMs to be assessed are listed as follows, summarized in Table 2-4, and described in the subsequent paragraphs:

- Thermal stratification, cycling, striping (TASCS)
- Thermal transient (TT)
- Intergranular stress corrosion cracking (IGSCC)
- Transgranular stress corrosion cracking (TGSCC)
- External chloride stress corrosion cracking (ECSCC)
- Primary water stress corrosion cracking (PWSCC)
- Microbiologically-influenced corrosion (MIC)
- Pitting (PIT)
- Crevice corrosion (CC)
- Erosion-cavitation (E-C)
- Flow-accelerated corrosion (FAC)

Thermal Fatigue

Mechanism Description

Thermal fatigue can occur as a result of alternating stresses caused by thermal cycling of a component resulting in accumulated fatigue usage and leading to crack initiation and growth.

Attribute Criteria

Austenitic and carbon steel piping segments with operating temperatures less than 270° and 220°F (132°C and 104°C), respectively, are not susceptible to degradation by thermal fatigue. Piping segments having operating temperatures greater than these values are evaluated for the potential for degradation from TT and TASCS, as indicated in the following:

- **TT**. Areas considered susceptible to thermal fatigue include pipe segments where there is relatively rapid cold (hot) water injection with delta temperature greater than 150°F (66°C) for carbon steel pipe and 200°F (93°C) for austenitic steel pipe. When these temperature changes are exceeded, additional evaluations can be performed to determine whether delta temperature is greater than delta temperature allowable based on more realistic estimates of temperature and anticipated number of cycles.
- **TASCS**. Areas where there can be leakage past valves separating hot and cold fluids and regions where there might be intermittent mixing of hot and cold fluids caused by fluid injection are considered to be susceptible to degradation from thermal fatigue. Exceptions are for pipe segments where the pipe diameter is 1 in. (25.4 mm) or less, or the slope of the segment is 45° or more from the horizontal. When these criteria are exceeded, additional evaluations can be performed to determine whether the maximum delta temperature is greater than 50°F (28°C) or the Richardson number is greater than 4.0.

Stress Corrosion Cracking

Stress corrosion cracking (SCC) encompasses several mechanisms, as follows:

Intergranular Stress Corrosion Cracking

Mechanism Description

IGSCC results from a combination of sensitized materials (caused by a depletion of chromium in regions adjacent to the grain boundaries in weld heat-affected zones [HAZs]), high-stress applied and residual welding stresses, and a corrosive environment (high level of oxygen or other contaminants).

Attribute Criteria

Boiling water reactors (BWRs). Piping within the scope of the RI-ISI evaluation is typically compared to piping included in the existing plant IGSCC inspection program. Options include NRC Generic Letter 88-01, NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping or

EPRI BWRVIP-075. Piping in the RI-ISI evaluation scope should be identified as susceptible to IGSCC for the purpose of RI-ISI evaluation if it is inspected as part of the existing plant IGSCC inspection program.

PWRs. Welds and HAZs in wrought austenitic steel PWR piping having high dissolved oxygen content and stagnant flow (for example, stagnant, oxygenated borated water systems) are considered susceptible to degradation from IGSCC. Welds in materials considered to be resistant to sensitization from welding (see NUREG-0313, Rev. 2) are not susceptible to degradation from IGSCC.

Transgranular Stress Corrosion Cracking

Mechanism Description

Transgranular stress corrosion cracking (TGSCC) is stress corrosion cracking that occurs through the grains of the material and usually occurs in the presence of halogens and sulfides. It is not necessarily associated with a particular metallurgical condition, such as grain boundary sensitization, but is affected by high local residual stresses, such as caused by welding or local cold work.

Attribute Criteria

In BWR and PWR plants, austenitic stainless steels are susceptible to TGSCC in the presence of chlorides and oxygen. Nickel-alloy and low-alloy steels generally pit in the presence of chlorides and oxygen. Low-alloy and carbon steels can crack by TGSCC in sulfur-bearing environments, such as hydrogen sulfide. However, this environment is not of general interest to light water reactors.

External Chloride Stress Corrosion Cracking

Mechanism Description

The electrochemical reaction caused by a corrosive media upon a piping system.

Attribute Criteria

Austenitic steel piping and welds are considered susceptible to chloride corrosion cracking when exposed to chloride contamination (from insulation, brackish water, or concentration of fluids containing chlorides), temperatures greater than 150°F (66°C), and tensile stresses.

Primary Water Stress Corrosion Cracking

Mechanism Description

Primary water stress corrosion cracking (PWSCC) occurs when high-temperature primary water is the corrosive medium and is present in combination with a susceptible material and high tensile stress.

Attribute Criteria

Piping and attachments (for example, thermowells) are considered susceptible to PWSCC when they are fabricated from mill-annealed Alloy 600 (A82 and A182) that is cold-worked or cold-worked and welded without subsequent stress relief, are exposed to primary water, and operate at high temperatures.

The attribute criteria specified for PWSCC in this section are applicable to PWRs. The susceptibility to corrosion cracking from PWSCC is covered for BWRs in the section on IGSCC.

Localized Corrosion

Local corrosion encompasses several mechanisms, as follows:

Microbiologically Influenced Corrosion

Mechanism Description

Microbes, primarily bacteria, have been found to cause widespread damage to low-alloy and carbon steels. Similar damage has also been found at welds and HAZs for austenitic stainless steels.

Attribute Criteria

Areas considered susceptible to degradation from microbiologically influenced corrosion (MIC) are piping components with fluids containing organic material or with organic material deposits. The most vulnerable components are raw water systems, storage tanks, and transport systems. Systems with low to intermittent flow conditions, temperatures less than 150°F (66°C), and pH below 10 are primary candidates.

Pitting

Mechanism Description

Pitting (PIT) corrosion is a form of localized attack on exposed surfaces with greater corrosion rates at some locations than at others. High local concentrations of impurity ions, such as chlorides and sulfates, tend to concentrate in oxygen-depleted pits, giving rise to a potentially concentrated aggressive solution in this zone.

Attribute Criteria

All structural materials are potentially susceptible to PIT, including austenitic stainless steels, nickel alloys, and carbon and low-alloy steels. It can occur in low-flow or stagnant regions in components, or within crevices, in these materials. Susceptibility to PIT is a strong function of oxygen level and chloride level concentration.

Crevice Corrosion

Mechanism Description

Crevice corrosion is the electrochemical reaction caused by an oxygenated medum within a piping system.

Attribute Criteria

Regions containing crevices (narrow gaps) that can result in oxygen depletion and a relatively high concentration of chloride ions or other impurities are considered susceptible to crevice corrosion cracking.

Flow Sensitive

These mechanisms consist of FAC and E-C.

Erosion-Cavitation

Mechanism Description

This DM represents degradation caused by turbulent flow conditions, which erode (wear away the metal) the pipe wall by cavitation. Cavitation damage is the result of the formation and instantaneous collapse of small voids within fluid subjected to rapid pressure and velocity changes as it passes through a region where the flow is restricted (for example, a valve, pump, or orifice).

Attribute Criteria

Regions where $(p_d - p_v)/\Delta p < 5$, and $V > 30$ ft per second (9.1m/s) and fluid temperature <250°F (121°C) are considered susceptible to degradation from E-C. Where p_d is the static pressure downstream of the cavitation source (for example, pump, valve, or orifice), p_v is the vapor pressure, Δp is the pressure differential across the unit, and V is the flow mean velocity at the inlet of the unit. All pressures are gauge pressures.

The susceptible region might extend a distance equal to approximately 5 diameters downstream of a pump, flow orifice, throttling valve, pressure-reducing valve, or other potential sources of cavitation.

Standard reducers do not create the potential for erosion degradation. Regions where flow occurs for less than 100 hours per year are not considered to be susceptible to E-C degradation.

Flow-Accelerated Corrosion

Mechanism Description

FAC is a complex phenomenon that exhibits attributes of erosion and corrosion in combination. Factors that influence whether FAC is an issue are velocity, dissolved oxygen, pH, moisture content of steam, and material chromium content.

Attribute Criteria

Carbon steel piping with chromium content greater than 1% and austenitic steel piping are not susceptible to degradation from FAC. Piping within the scope of the RI-ISI evaluation is compared to piping included in the existing plant FAC inspection program.

EPRI report 3002000563 [17], *Recommendations for an Effective Flow-Accelerated Corrosion Program* (NSAC-202L-R4), provides the general guidelines for the identification and inspection of components subject to FAC degradation.

Table 2-4. DM criteria and susceptible regions

DM		Criteria	Susceptible Regions
TF	TASCS	– NPS >1 in., and – Pipe segment has a slope <45° from horizontal (includes elbow or tee into a vertical pipe), and – Potential exists for low flow in a pipe section connected to a component allowing mixing of hot and cold fluids, or potential exists for leakage flow past a valve (that is, in-leakage, out-leakage, cross-leakage) allowing mixing of hot and cold fluids, or potential exists for convection heating in dead-ended pipe sections connected to a source of hot fluid, or potential exists for two phase (steam/water) flow, or potential exists for turbulent penetration into a relatively colder branch pipe connected to header piping containing hot fluid with turbulent flow, and – Calculated or measured ΔT >50°F, and – Richardson number >4.0	Nozzles, branch pipe connections, safe ends, welds, HAZs, base metal, and regions of stress concentration

Table 2-4 (continued). DM criteria and susceptible regions

DM		Criteria	Susceptible Regions
TF (continued)	TT	– Operating temperature >270°F for stainless steel, or operating temperature >220°F for carbon steel, and – Potential for relatively rapid temperature changes including: cold fluid injection into hot pipe segment, or hot fluid injection into cold pipe segment, and – $\lvert \Delta T \rvert$ >200°F for stainless steel, or $\lvert \Delta T \rvert$ >150°F for carbon steel, or $\lvert \Delta T \rvert > \Delta T$ allowable (applicable to both stainless and carbon)	
SCC	IGSCC (BWR)	– Evaluated in accordance with existing plant IGSCC program according to NRC Generic Letter 88-01	Welds and HAZs
	IGSCC (PWR)	– Austenitic stainless steel (carbon content ≥0.035%), and – Operating temperature >200°F, and – Tensile stress (including residual stress) is present, and – Oxygen or oxidizing species are present **OR** – Operating temperature <200°F, the preceding attributes apply, and – Initiating contaminants (for example, thiosulfate, fluoride, or chloride) are also required to be present	
	TGSCC	– Austenitic stainless steel, and – Operating temperature >150°F, and – Tensile stress (including residual stress) is present, and – Halides (for example, fluoride or chloride) are present, and – Oxygen or oxidizing species are present	Base metal, welds, and HAZs

Table 2-4 (continued). DM criteria and susceptible regions

DM		Criteria	Susceptible Regions
SCC (continued)	ECSCC	– Austenitic stainless steel, and – Operating temperature >150°F, and – Tensile stress is present, and – An outside piping surface is within five diameters of a probable leak path (for example, valve stems) and is covered with nonmetallic insulation that is not in compliance with RG 1.36, **OR** – Austenitic stainless steel, and – Tensile stress is present, and an outside piping surface is exposed to wetting from concentrated chloride-bearing environments (that is, sea water, brackish water, or brine)	Base metal, welds, and HAZs
	PWSCC	–Evaluated in accordance with the owner's existing PWSCC inspection program and, as applicable, the requirements endorsed by the regulatory authority having jurisdiction at the plant site (for example, 10CFR50.55a(g)(6)(ii)(F) dated June 21, 2011)	Nozzles, welds, and HAZs without stress relief
Localized corrosion	MIC	– Operating temperature <150°F, and – Low or intermittent flow, and – pH <10, and – Presence/intrusion of organic material (for example, raw water system), or – Water source is not treated with biocides	Fittings, welds, HAZs, base metal, dissimilar metal joints (for example, welds and flanges), and regions containing crevices
	PIT	– Potential exists for low flow, and – Oxygen or oxidizing species are present, and – Initiating contaminants (for example, fluoride or chloride) are present	

Table 2-4 (continued). DM criteria and susceptible regions

DM		Criteria	Susceptible Regions
Flow sensitive	CC	– Crevice condition exists (that is, thermal sleeves), and – Operating temperature >150°F, and – Oxygen or oxidizing species are present	
	E-C	– Cavitation source, and – Operating temperature <250°F, and – Flow present >100 h/yr, and – Velocity > 30 ft/s, and – $(P_d - P_v) / \Delta P < 5$	Fittings, welds, HAZs, and base metal
	FAC	– Evaluated In accordance with existing plant FAC program	According to plant FAC program

°F = °C x 9/5 + 32
1 in. = 25.4 mm
1 ft = 0.3 m

2.2.2 Plant-Specific Service History Review

A review of plant and industry databases (e.g. BWRVIP, MRP, GALL, Appendix W of ASME SIII, INPO, etc.) and station documents is required to characterize each station's operating experience with respect to piping pressure boundary degradation. This service history and susceptibility review is conducted for each in-scope system not to supplant but to supplement the industry review. Plant-specific data collection is considered appropriate because of the uniqueness of particular plant configurations and service conditions that may have resulted in the manifestation of a damage mechanism in such a manner as to not be identified in the EPRI industry review. Additionally, the site-specific review will identify any mechanisms or events potentially resulting in piping failures as well as actual through-wall failures. Plant-specific service history is considered a key element in identifying DM susceptibility. This information is also used in the element selection process, if applicable and necessary. Collection of these data allows fine-tuning of the element selection process, where applicable, and provides additional confirmation of the appropriate assignment of damage mechanisms to systems or portions thereof.

In assessing the potential for a water hammer event, though, a greater measure of variability exists between plants. The potential for a water hammer event is solely a function of a plant's unique system configuration and operational and maintenance practices. The configuration and operationally sensitive nature of the water hammer phenomenon can be substantiated by the plant's service history. When consideration of industry service experience is coupled with this phenomenon, as described in the following paragraph, the susceptibility of each system can be determined.

Each plant should also review and take into consideration the information provided in EPRI TR-106438, *Water Hammer Handbook for Nuclear Plant Engineers and Operators*, dated May 1996. This report, which provides a comprehensive compilation and analysis of water hammer events in U.S. plants, indicates that most water hammer events occurred in the early stages of plant operation. As experience was gained in the operation of the plants, the frequency of water hammer events has progressively decreased in the industry at large.

Results from a service history and susceptibility review conducted at one of the RI-ISI pilot plants are excerpted and provided in Table 2-6 [15].

2.2.3 DM Categories

As covered in TR-112657 Revision B-A, EPRI has performed additional work to investigate the correlations between the EPRI DM categories and numerical estimates of pipe rupture frequencies resulting from these mechanisms. This work has validated the basis for these categories as used in the EPRI risk matrix. Consistent with this approach, the RI-HELB classification scheme for assignment of piping to the three general classes of failure potential is depicted in Table 2-5.

Table 2-5. EPRI system for evaluation of pipe rupture potential

Pipe Rupture Potential	Expected Leak Conditions	DMs to Which the Segment Is Susceptible
High	Large	FAC
Medium	Small	Thermal Fatigue (TASCS and TT) SCC (IGSCC, TGSCC, PWSCC, and ECSCC) Localized Corrosion (MIC, CC, and PIT) E-C
Low	None	No degradation mechanisms present

As explained previously, the logic of this classification scheme is straightforward. If there are no known damage mechanisms present in the pipe, the potential for pipe rupture is classified as Low. In this case there is High confidence that the potential for rupture resulting from any known damage mechanism can be ruled out. The potential for pipe ruptures would in this case be determined solely by the likelihood of occurrence of severe loading conditions in excess of the pipe segment capacity, which can be reduced by the presence of some design and construction defects. Another possibility is the occurrence of a pipe rupture resulting from some heretofore-unknown damage mechanism, although this is considered unlikely for the reasons that are detailed in the following paragraphs.

When the pipe segment has been identified as having the conditions necessary for one or more well-defined damage mechanisms, the likelihood of pipe rupture is obviously higher. This is because the presence of damage mechanisms can lead to pipe failures directly, or they can reduce the capacity of the pipe segment to withstand transient and severe piping loads if and when they occur. Therefore, on a qualitative basis, it should be clear that the presence of conditions necessary for piping damage mechanisms would lead to a higher rate of occurrence of pipe failures and ruptures than the case where no such conditions are present, all other factors being equal. These considerations led to three natural categories of pipe failure potential.

When using the traditional RI-ISI methodology, it is also possible that a pipe segment, subject to a DM with a moderate break potential, can be moved into the High category if the pipe segment is known to be subject to water hammer loads. The dynamic condition may have already been analyzed and determined to be acceptable; however, if susceptibility to a DM is identified, the plant changes (for example, modifications) are imperative with regard to preventing such events in the future.

With respect to application of the RI-HELB methodology, it needs to be verified that the potential for water hammer in the candidate piping systems is low. To demonstrate that water hammer is not a significant contributor to pipe rupture, reliance on historical frequencies of water hammer events in specific piping systems coupled with reviews of operating procedures and conditions can be used for this evaluation. Alternatively, design changes, such as the use of J-tubes, vacuum breakers, and jockey pumps, coupled with improved operating procedures can be used to reduce concerns from water hammer. It should also be established that any measures needed to abate water hammer frequency and magnitude will be effective for the life of the plant. If these conditions are met, which is a requirement of the RI-HELB methodology as covered in Section 2.1, the failure potential rank can remain as a Medium consequence rank.

Table 2-6 [15] provides results from a service history and susceptibility review conducted at one of the RI-ISI pilot plants.

Table 2-6. Example service history and susceptibility review results for the RCS [15]

Source Documents/Databases Reviewed for Historical Piping Pressure Boundary Degradation Occurrences	Damage Mechanisms												Additionally Considered	
	Thermal Fatigue		Stress Corrosion Cracking				Localized Corrosion			Flow Sensitive		Mechanical	Water	Other
	TASCS	TT	IGSCC	TGSCC	ECSCC	PWSCC	MIC	PIT	CC	E-C	FAC	VF	Hammer	Findings
Station Information management system	None	None	None	None	None	None	None	None	None	None	None	**PBF**[3]	None	[1] **PD**[2]
Paperless condition reporting system	**PE**[4]	None	None	None	None	None	None	None	None	None	None	**PBF**[3]	None	None
Licensing research system	**PE**[4]	None	None	None	None	**PBF**[5]	None	None	None	None	None	**PBF**[3]	None	**PD**[2]
Nuclear plant reliability database system	None	None	None	None	None	None	None	None	None	None	None	None	None	None
ISI program records	None	None	None	None	None	None	None	None	None	None	None	None	None	[1]
Control room station log	None	None	None	None	None	None	None	None	None	None	None	None	None	None
System upper level documents	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Other station documents	**P**[6]	**P**[6]	None	None	None	**P**[6]	None	None	None	None	None	None	None	None

Legend:

P (precursor)—includes postulated damage mechanisms and loadings through knowledge of operating parameters, water chemistry, and so forth. No physical evidence of pressure boundary degradation currently exists. Also includes postulated mechanisms identified as result of this review.

PE (plant event)—includes postulated damage mechanisms and loadings as a result of observed or potential plant event (for example, water hammer). No physical evidence of pressure boundary degradation currently exists.

PD (physical damage) includes observed pressure boundary degradation as evidenced by cracking, pitting, wastage, thinning, physical deformation. or other deterioration.

PBF (pressure boundary failure)—includes through-wall flaws resulting from effects of identified damage mechanism.

Notes:

[1] Ref. JO 00770489 and ISI program records. Multiple indications (surface and subsurface) identified over time in the RCS. These indications were either removed (for example, gouges or linear surface flaws) or evaluated (for example, laminar or planar subsurface flaws) and determined to be Code acceptable. None of these indications was attributed to an in-service damage mechanism and is believed to have been non-service-induced (that is, fabrication or other origin).

[2] Ref. JO 00723183, LER 86-006 and IE 86-108, which document corrosion wastage (boric acid) on exterior of P-32A discharge cold leg high-pressure injection (HPI) nozzle resulting from leakage from above HPI isolation valve (body-to-bonnet leak).

[3] Ref. JO 00776670, JO 00776959, JO 00786058, CR 1-89-0029, CR 1-89-0312, CR 1-90-0010, LER 89-002, LER 89-010, and ANO correspondence to the NRC 1CAN107414, 1CAN107420, 1CAN027502, and 1CAN107507, which document small diameter (1 1/2- and 1-in. [38.1- and 25.4 mm] NPS) cold leg drain line leaks primarily attributable to vibrational fatigue.

[4] Ref. NRC Bulletin 88-08, NRC Bulletin 88-11, CR C-88-0047, CR 1-92-0327, CR 1-93-0164, CR 1-98-0117, and ANO correspondence to NRC 0CAN019102, 0CAN088912, 0CAN108806, 0CAN109104, 0CAN119007, 1CAN038903, 1CAN039101, 1CAN068906, 1CAN079201, 1CAN108914, 1CAN128910, and 1CAN129105, which address potential for thermal stratification in RCS.

[5] Ref. LER 90-021, which documents small diameter (1-in. NPS) pressurizer level tap nozzle leak attributed to PWSCC.

[6] Ref. Calc. No. EPRI-116-310 of ANO-1 RI-ISI pilot application submittal, which identifies potential for TASCS, TT, and PWSCC in reactor coolant.

2.3 Risk Characterization

The risk of pipe segment failure is evaluated on the basis of the expected likelihood of the event and the expected importance of the consequence. The importance of the consequences is presented by the consequence categories. The likelihood of failure in this analysis is estimated based on the segment exposure to different DMs and is represented by the DM categories.

As is common in a qualitative risk-informed approach, the graphic method is used to illustrate the effects of these two parameters and to serve as a base for the selection of risk-important segments. The graphic structure used in this analysis, known as the *risk matrix*, is shown in Figure 2-6. DM categories shown in Figure 2-6 are defined in Section 2.2. Consequence categories shown in Figure 2-6 are defined in Section 2.1. Figure 2-6 is used to define risk categories (RCs), which are identified on the risk matrix and described in the following paragraphs.

The three DM categories and three consequence categories are combined into seven RCs. Those categories are shown in risk matrix and defined as follows:

- RC1 (High risk): High consequence and High failure potential
- RC2 (High risk): High consequence and Medium failure potential
- RC3 (High risk): Medium consequence and High failure potential
- RC4 (Medium risk): High consequence and Low failure potential
- RC5 (Medium risk): Medium consequence and Medium failure potential, or Low consequences and High failure potential
- RC6 (Low risk): Medium consequence and Low failure potential, or Low consequences and Medium failure potential
- RC7 (Low risk): Low consequence and Low failure potential

The RCs shown in Figure 2-6 are then further combined into three risk regions (High, Medium, and Low, as shown previously) for more robust and more efficient utilization. These risk regions also account for uncertainties in the risk categorization and ensure that High consequence segments are considered for all likelihoods of failure and that segments with the potential for large leaks (high likelihood of failure) are considered for all consequence categories.

2.4 HELB Response Strategies

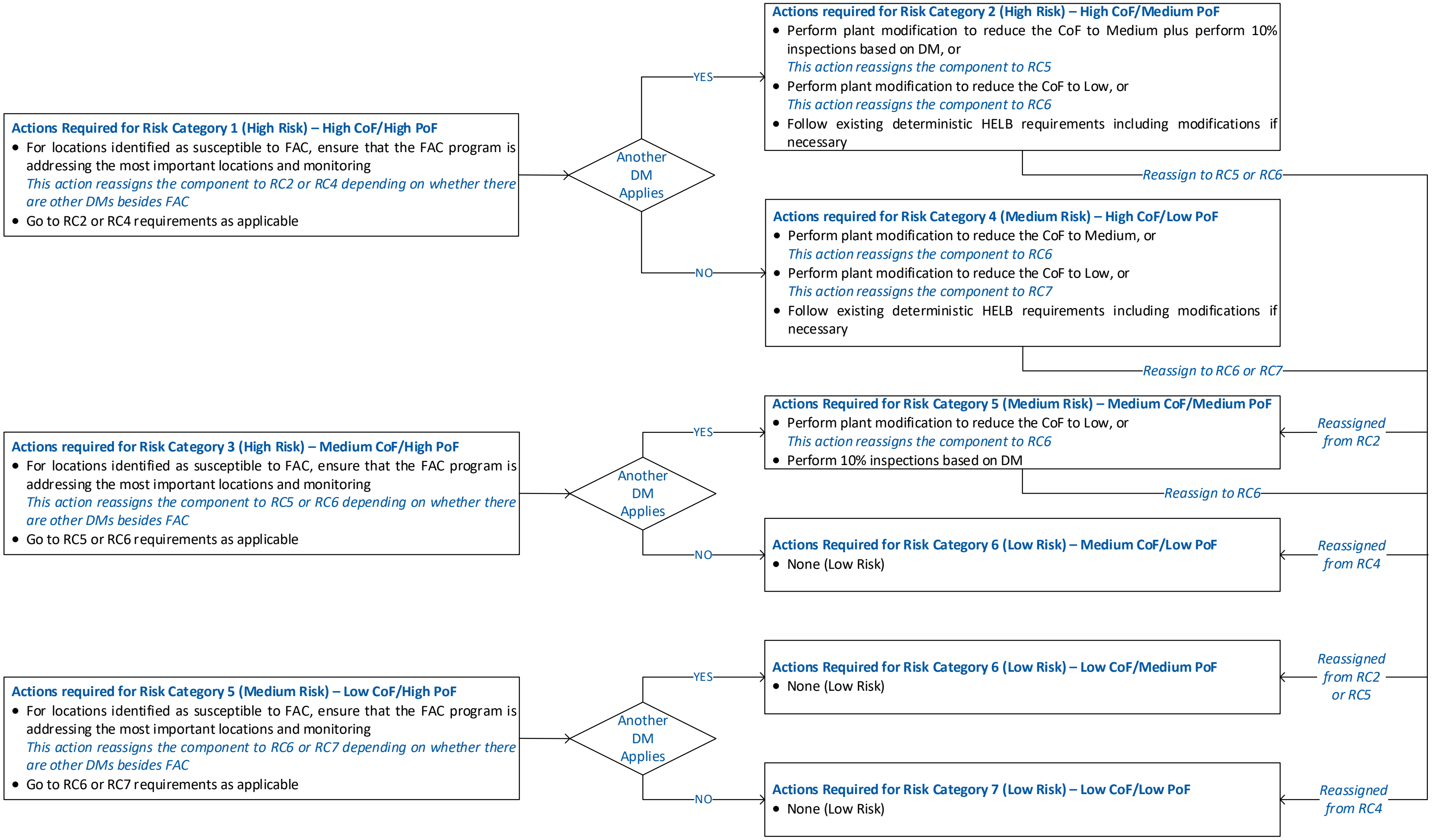
Section 2.3 identifies the risk significance of piping subjected to the RI-HELB methodology. These risk insights are then used to risk-inform plant decision-making as to the appropriate actions to be taken in order to risk-inform any strategies undertaken by a licensee.

As some perspective, from a RI-ISI and RI-BER program development perspective, the High risk region (Categories 1–3) requires a 25% inspection population, the Medium risk region (Categories 4 and 5) requires a 10% inspection population, and the Low risk region (Categories 6 and 7) requires a 0% inspection population. Consistent with this philosophy, the RI-HELB methodology requires that plant actions be a function of the risk significance of the subject components—that is, more significant plant actions are required for higher risk components and less significant actions are appropriate for lower risk components. Note: when actions such as plant modifications are listed, these actions must follow existing plant-specific licensing processes and commitments.

The following identifies those actions that needed to be taken, which are also summarized in Figure 2-8:

- High risk (RC1 or RC2 or RC3)
  - RC1: the following are required:
    - Locations identified as susceptible to FAC.
      - Ensure that the FAC program is addressing most important locations (this moves the component to RC2 or RC4 depending on whether there are other DMs besides FAC).
    - Follow RC2 or RC4 requirements as applicable.
  - RC2: the following are required:
    - Plant modification to reduce the consequence to Low (this moves the component to RC6), or
    - Plant modification to reduce consequence to Medium (this moves the component to RC5) plus 10% inspections based on DM, or
    - Follow existing deterministic HELB including modifications if necessary.
  - RC3: the following are required:
    - Locations identified as susceptible to FAC.
      - Ensure that the FAC program is addressing most important locations (this moves the component to RC5 or RC6 depending on whether there are other DMs besides FAC)
    - Follow RC5 or RC6 requirements as applicable.
- Medium risk (RC4 or RC5)
  - RC4: the following are required:
    - Plant modification to reduce the consequence to Medium (RC6) or Low (RC7), or
    - Follow existing deterministic HELB including modifications, if necessary

  - RC5 (without FAC): the following is required:
    - Plant modification to reduce consequence to Low (RC6) **or** 10% inspections based on DM
  - RC5 (with FAC): the following is required:
    - Ensure that the FAC program is addressing most important locations (this moves the component to RC6 or RC7 depending on whether there are other DMs besides FAC).
- Low risk (RC6 or RC7): no requirements (Low risk).



Actions Required for Risk Category 1 (High Risk) – High CoF/High PoF
- For locations identified as susceptible to FAC, ensure that the FAC program is addressing the most important locations and monitoring
  This action reassigns the component to RC2 or RC4 depending on whether there are other DMs besides FAC
- Go to RC2 or RC4 requirements as applicable

Actions required for Risk Category 2 (High Risk) – High CoF/Medium PoF
- Perform plant modification to reduce the CoF to Medium plus perform 10% inspections based on DM, or
  This action reassigns the component to RC5
- Perform plant modification to reduce the CoF to Low, or
  This action reassigns the component to RC6
- Follow existing deterministic HELB requirements including modifications if necessary

Actions required for Risk Category 4 (Medium Risk) – High CoF/Low PoF
- Perform plant modification to reduce the CoF to Medium, or
  This action reassigns the component to RC6
- Perform plant modification to reduce the CoF to Low, or
  This action reassigns the component to RC7
- Follow existing deterministic HELB requirements including modifications if necessary

Actions required for Risk Category 3 (High Risk) – Medium CoF/High PoF
- For locations identified as susceptible to FAC, ensure that the FAC program is addressing the most important locations and monitoring
  This action reassigns the component to RC5 or RC6 depending on whether there are other DMs besides FAC
- Go to RC5 or RC6 requirements as applicable

Actions Required for Risk Category 5 (Medium Risk) – Medium CoF/Medium PoF
- Perform plant modification to reduce the CoF to Low, or
  This action reassigns the component to RC6
- Perform 10% inspections based on DM

Actions Required for Risk Category 6 (Low Risk) – Medium CoF/Low PoF
- None (Low Risk)

Actions required for Risk Category 5 (Medium Risk) – Low CoF/High PoF
- For locations identified as susceptible to FAC, ensure that the FAC program is addressing the most important locations and monitoring
  This action reassigns the component to RC6 or RC7 depending on whether there are other DMs besides FAC
- Go to RC6 or RC7 requirements as applicable

Actions Required for Risk Category 6 (Low Risk) – Low CoF/Medium PoF
- None (Low Risk)

Actions Required for Risk Category 7 (Low Risk) – Low CoF/Low PoF
- None (Low Risk)

Figure 2-8. RI-HELB response strategies

2.5 Risk Impact

Risk impact can be estimated by taking the CCDP and CLERP values from the analysis (consequence of failure) and multiplying by 1E-2/year frequency of failure. The results are then compared to RG 1.174 (see Sections 2.1.2 and 3.6).

2.6 Performance Monitoring

The following performance-monitoring options should be considered:

- If FAC applies to any of the scope, the FAC program and service history should be reviewed to confirm that they are in accordance with industry state of practice (for example, use of system health reports).
- ISI inspection program.
- If any of the scope is accessible during power operations, operator walkdowns should be considered (for example, if not already in scope of walkdowns, consider adding).
- It may be possible to monitor inaccessible areas with ventilation performance, radiation monitors, and so forth.

3 EXAMPLE APPLICATION OF RI-HELB METHODOLOGY

This section of the report provides a demonstration of the RI-HELB methodology on a plant with the possible need to revisit its HELB program. As with the preceding discussion, this section is organized as follows:

- Scope
- Consequence of failure
- Failure potential
- Risk characterization
- HELB response strategies
- Risk impact
- Performance monitoring

3.1 Scope

The piping in question is the non-safety-related main steam cross-around piping from the high-pressure turbine to the moisture separators and from the moisture separators to the low-pressure turbines. The piping scope is highlighted in Figure 3-1.

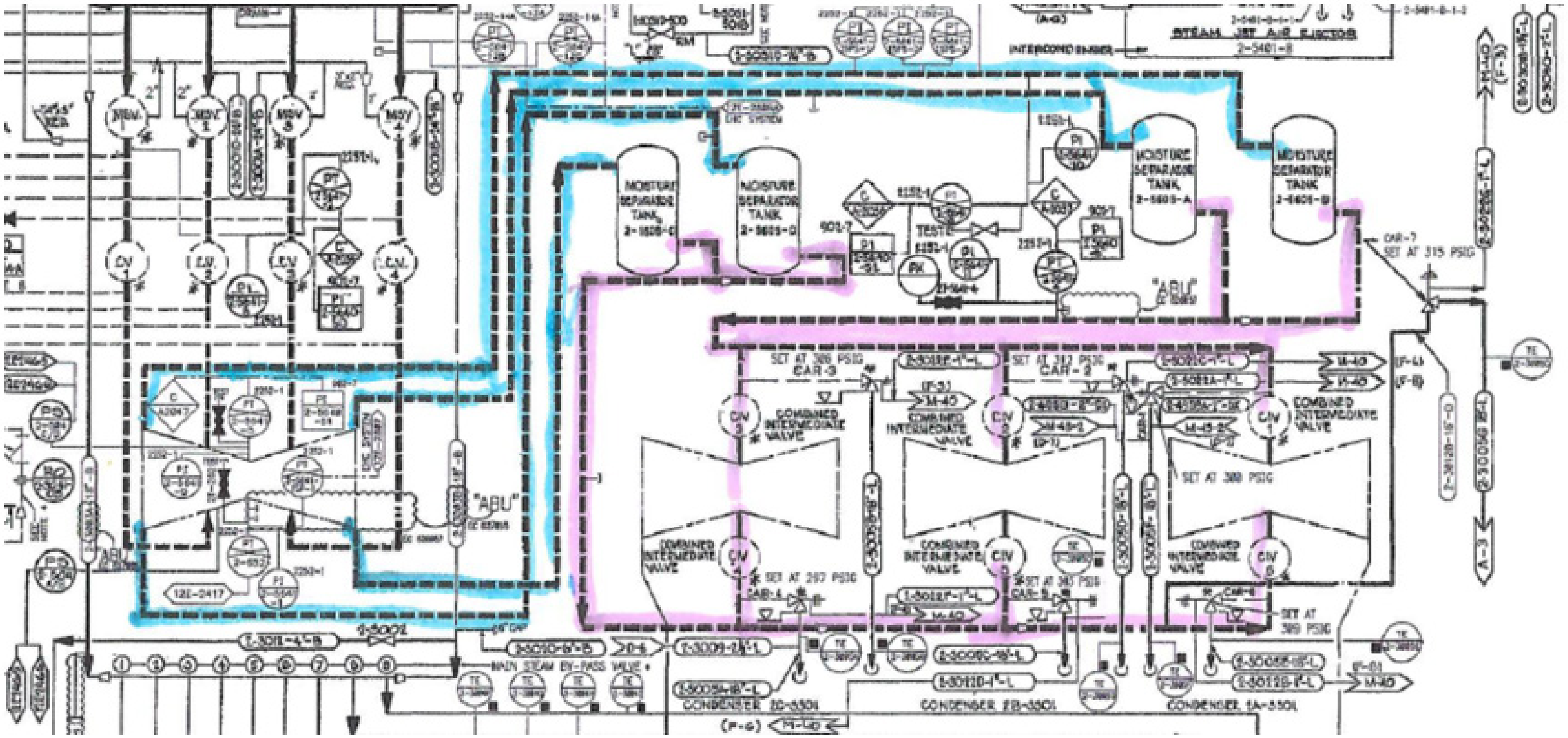


Figure 3-1. Example of new HELB scope

3.2 Consequence of Failure Evaluation

The consequences associated with cross-around PBFs are evaluated from the following perspectives:

- Deterministic HELB considerations as used in the present design basis for the main steam system are considered. Section 3.2.1 provides a review of the design and final safety analysis report (FSAR). Any issues that are identified need to be evaluated for potential modification as was included in the original HELB analysis. However, risk-informed insights with regard to the cost/benefits of such modification are also considered, if appropriate.
- Application of the additional considerations in Section 3.2.2 provides further insights into the risk significance of cross-around piping failures.

3.2.1 Design and PRA Review

Design Review

This section describes three key areas of the plant design with respect to the cross-around system, as follows:

- General description of the cross-around piping location and scope
- Plant response to PBFs
- FSAR Section 3.6 HELB and 3.11 Environmental Qualifications

General Description

The main steam cross-around piping system is located in the turbine building. The turbine building is shared by two units, and each unit consists of a turbine generator, exciter, condenser, feedwater heaters, feedwater and condensate pumps, condensate polishing filter-demineralizer system, condenser circulating water system, and electrical switchgear. The turbine building also includes the containment cooling service water (CCSW) pumps, control rod drive (CRD) pumps, batteries, and some switchgear.

The moisture separators and in-scope piping and valves are located in the turbine pipeway (also referred to as *turbine cavity*) along with the equalizing header, main stop valves, control valves, bypass valves, combined intermediate valves (CIVs), and other turbine support valves. Besides the cross-around piping, the following components are included in the scope:

- Moisture separators (four)
- CIVs (six)
- The cross-around relief valves (seven) (six of seven are on the main floor El 561 and one of seven in the pipeway) and piping

Figures 3-2 through 3-4 are partial captures of general arrangement drawings elevations (Els) 561, 541 and 517, respectively. The cross-around components are shaded as well as walls surrounding the turbine pipeway. The following summarizes:

- Figure 3-2 (the main operating floor, El 561) shows the cross-around piping and the CIVs entering the low-pressure turbines below El 561.
- Figure 3-3 shows the bulk of the piping and the moisture separators (El 541). Also, as shown, the main steam equalizing header and turbine stop and control valves are in the vicinity, as well as the turbine bypass valves (on the equalizing header). The cross-around piping and components are in the vicinity of El 537.
- Figure 3-4 shows the moisture separators from the ground floor (El 517). This piping is above El 517 (~El 537).

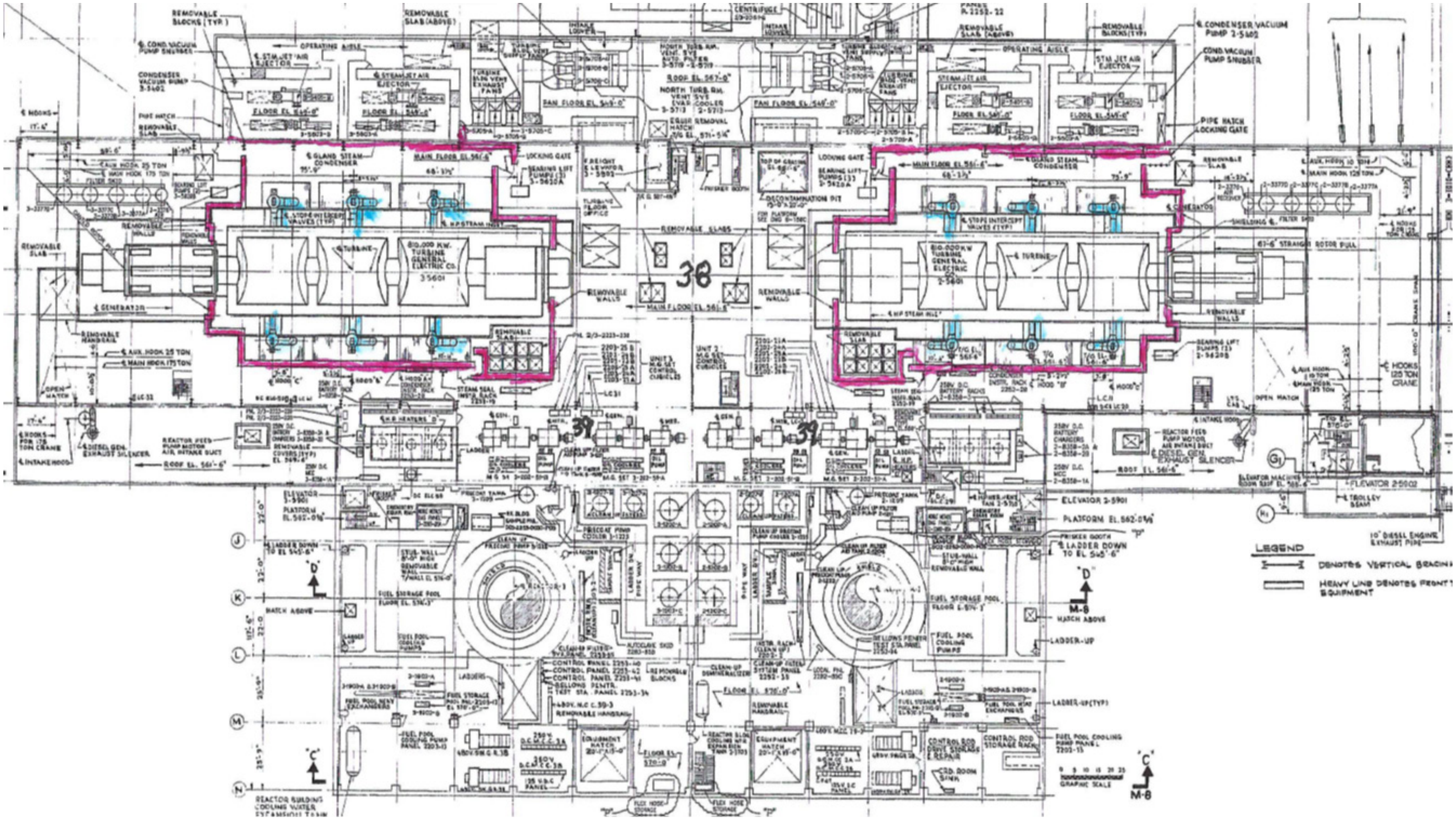


Figure 3-2. Turbine building main floor El 561 (M-2)

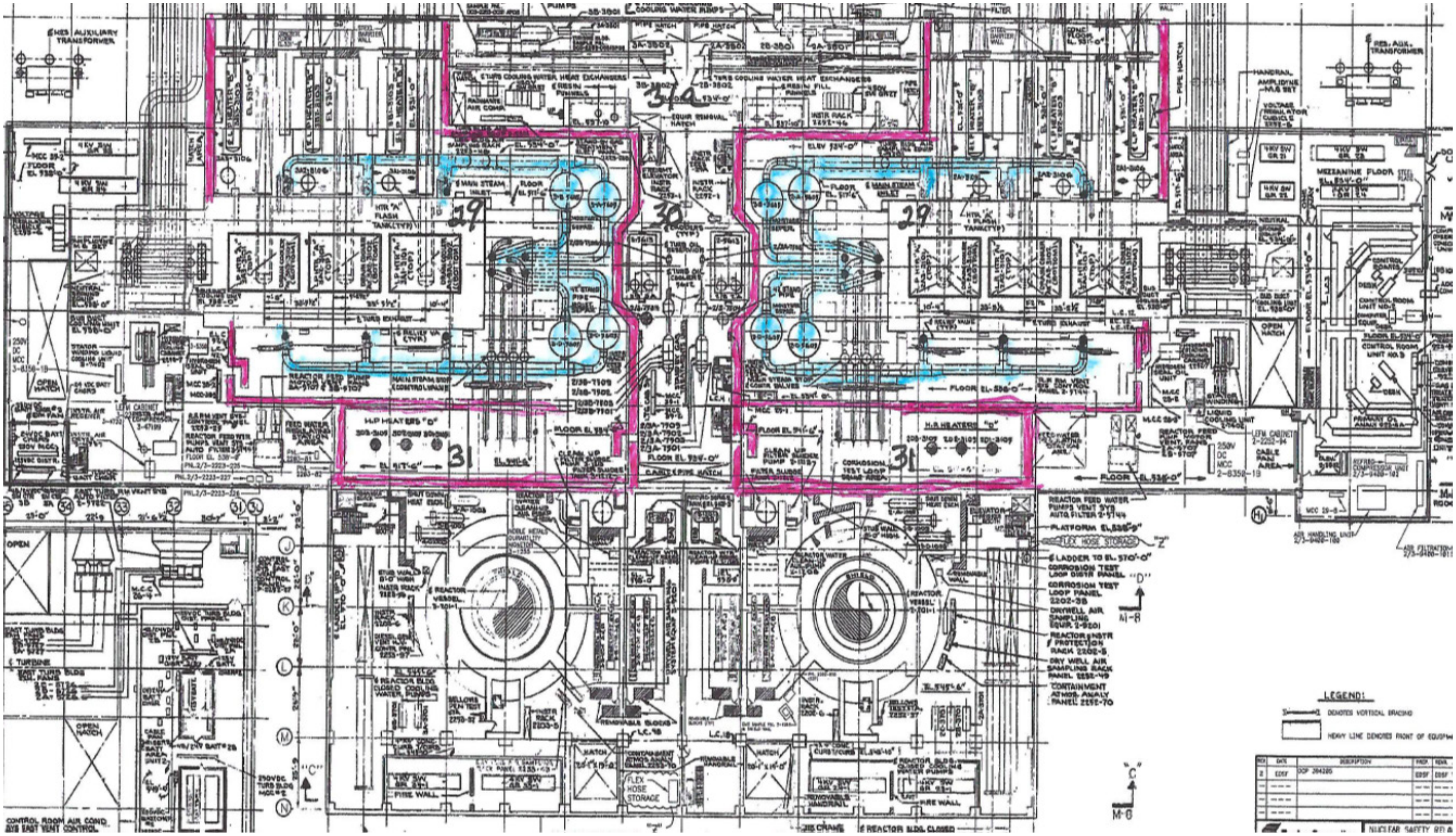


Figure 3-3. Turbine building mezzanine floor El 541 (M-3)

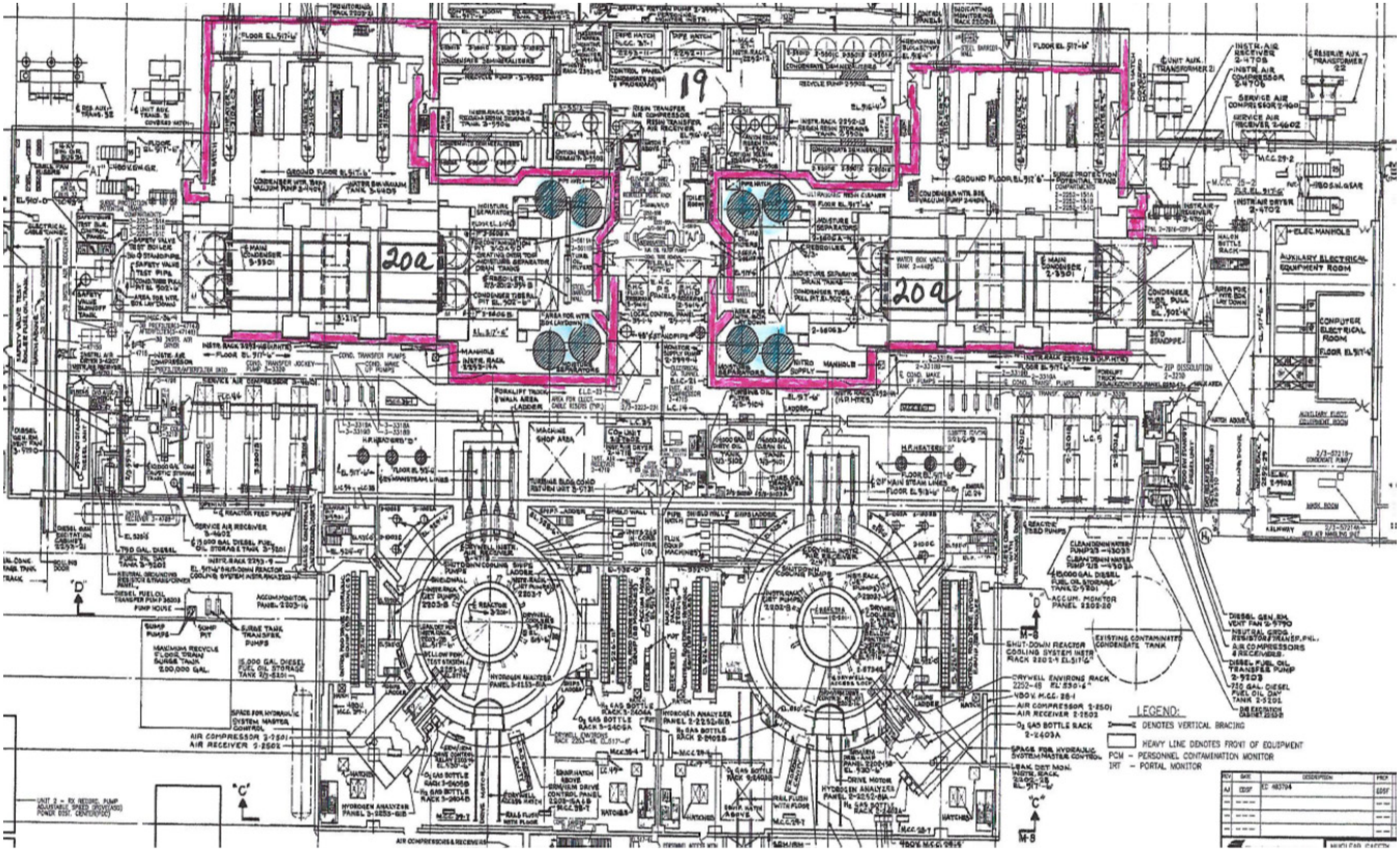


Figure 3-4. Turbine building ground floor El 517 (M-4)

Plant Response

The impact on plant operations from a cross-around break is dependent on break size. A large break up to the DEGB would likely result in the following:

- Main steam isolation valve (MSIV) closure is based on high steam flow (120%), which causes a scram.
- Low steam pressure (791 psig [5453753.00848 Pa] at the equalizing header) results in Group I containment isolation (MSIV closure), which causes a scram.
- Intermediate pressure signals the PLU l (power load unbalance) logic, which could generate a scram signal if turbine control valve fast closure occurs (40% mismatch between crossover pressure and generator stator amps).

For smaller breaks, it is anticipated that operator actions to scram the plant and turbine are expected to occur before an automatic action occurs. There are numerous indications to the operators as follows:

- Increased steam flow
- Pressure drops in the header that may cause reactor power to rise
- Generator output reduction
- Steam pressure screen—indications in the control room include High Pressure Exhaust Pressure (outlet of HP turbine) and Low Pressure Inlet Pressure (inlet of the LP turbine)
- Turbine trouble alarms (panel)
- Turbine building ventilation temperature
- Personnel in the turbine building
- Moisture separator level Hi-Hi generates a turbine trip (not expected for most breaks)

Also, loss of electrohydraulic control (EHC) pressure or control signals causes the control valves and the bypass valves to fail closed. PBF (for example, jet impingement) could cause this type of failure.

Because the turbine stop and control valves are in the vicinity of the cross-around piping, the possibility that a pair of stop and control valves (in series) could be hit and fail open is considered even though their design is to fail closed. If this were to happen, the MSIVs would provide backup for isolation of the break.

Final Safety Analysis Report

The plant evaluated HELB outside primary containment in response to an AEC letter dated December 1972. The following summarizes the FSAR's summary description of these HELB analyses:

- Protection of equipment and structures necessary to shut down the reactor and maintain it in a safe shutdown condition (assuming a concurrent and unrelated single active failure of protected equipment) should be provided from all effects resulting from ruptures in pipes carrying high-energy fluid, where the temperature or pressure conditions of the fluid exceed 200°F (93°C) and 275 psig (1896058 Pa), respectively, including the double-ended rupture of the largest pipe in the main steam and feedwater systems. The rupture effects to be considered include pipe whip, structural (including the effects of jet impingement), and environmental. (**Note**: these requirements are essentially the same as the criteria in Section 3.2.2 except that instead of assuming a single active failure, the HELB methodology is risk informed and using PRA insights, as applicable.)
- Postulated main steam and feedwater were analyzed. The following systems were considered but not analyzed because of physical separation or absence of impact on equipment important to safety:

  a. Extraction steam piping to heaters A, B, C, or D

  b. Heater drain piping from heaters C or D

  c. Condensate booster piping

  d. Moisture separator drain piping

  e. CRD hydraulic piping

  (Items a, b, and d are also in the vicinity of the cross-around.)

- Compartment pressurization pressure calculations for the turbine building produced no areas of concern with respect to safety-related equipment. (Note that the piping in this evaluation has lower temperatures and pressures in comparison to main steam and the cross-around piping is in the same pipeway that was evaluated for main steam.) The following summarizes temperatures and pressures from the heat balance:
  - Steam entering high-pressure turbine: 819 psia (5646806 Pa), 534°F (289°C) (main steam)
  - Steam exiting high-pressure turbine: 300 psia (2068427 Pa) (cross-around])
  - Steam exiting moisture separators: 290 psia (1999479 Pa), 414°F(212°C) (cross-around)
- The effects of pipe whip on structures and walls and safety-related components were calculated for postulated main steam and feedwater pipe breaks in the turbine building. In one of the unit's turbine building, a whipping feedwater pipe, resulting from circumferential breaks, could damage the wall adjacent to the emergency diesel generator (EDG). To

prevent such damage, a frame was constructed of cross-braced columns anchored to the floor. Postulated pipe whip calculations for HELBs in the other turbine building produced no areas of concern with respect to safety-related equipment.

(Note that the piping in this evaluation scope is not near the emergency diesels. The location of the cross-around is actually similar to main steam in the pipeway near the turbines.)

- Regarding compartment flooding, no impacts are indicated. (Note that steam breaks are not a significant flood source anyway.)
- Regarding environmental effects, it is indicated that equipment has been designed to limits in excess of postulated conditions that could arise from the HELB. (**Note**: as described previously, the cross-around piping operating temperatures and pressure are much lower than main steam and its location is similar to main steam—that is, turbine pipeway/cavity.)
- Regarding control room habitability, the main control room is physically located away from and isolated from all high-energy lines. Neither the control room equipment nor its ventilation system would be affected by environmental effects caused by a HELB. The control room would be habitable in the event of a HELB outside primary containment. (**Note**: the same is true for the piping in the scope of this evaluation.)
- Regarding postulated feedwater breaks in the main feed regulating valve area and main feed pump area, these breaks were identified as potential concerns, but the piping in the scope of this evaluation is not located in these areas.

FSAR Section 3.11 describes environmental qualification (EQ) of electrical equipment based on LOCA and HELB environments. This includes the identification of EQ zones, zone maps, and resulting HELB environmental conditions for equipment qualification (Section 3.2.2 Criterion 7 and the plant walkdown in Section 3.2.3 evaluate the potential for environmental affects).

Summary

Based on the preceding design and FSAR review, the following could be concluded:

- The deterministic analyses of main steam in response to the 1972 AEC letter did not result in any modification to the plant design. The wall modification was because of feedwater breaks.
- The impact of main steam piping would appear to envelope the cross-around piping, but the RI-BER (basically the same as deterministic HELB requirements for main steam) evaluation in Section 3.2.2 and the plant walkdown will confirm this. The main steam piping entering the high-pressure turbine has temperatures and pressures much higher than the cross-around piping.
- The increase in pressure resulting from measurement uncertainty recapture power uprate is a few pounds higher than the original design and slightly exceeds the 275-psig (1896058-Pa) level for HELB.

PRA Review

The main steam system, including turbine bypass and the main condenser are modeled in the internal events PRA; however, the turbine itself and its cross-around system are not modeled because they basically become unavailable given a plant trip. As a minimum, failure of the turbine or cross-around system could result in a turbine trip and/or MSIV closure, which are modeled in the PRA (CCDP <1E-6 and LERF <1E-7). However, it is possible that the main condenser would also be unavailable (for example, MSIV closure). This initiator has a CCDP barely above 1E-6 and CLERP above 1E-7.

The following summarizes the PRA HELB analysis of the main steam system outside containment:

- The PRA develops SLB initiating event frequencies, which include the probability of the two MSIVs failing to close (2.6E-5). The total frequency (sum of several segments and isolation capabilities) is 3.4E-9/year.
- The PRA screens isolation success for failures in the reactor building and turbine building resulting from low frequency of CDF and LERF.
- The PRA screens unisolated HELB in the turbine building resulting from low frequency of CDF and LERF.
- The PRA describes the modeling of breaks outside containment (BOCs) including main steam. It indicates that breaks outside the reactor building (for example, feedwater or steam line) can be mitigated by the isolation of the line or through emergency core cooling system (ECCS) operation. It is judged that there will be minimal adverse impact on ECCS equipment if the postulated break occurs outside the containment and reactor building—that is, the ECCS will remain functional to successfully mitigate the break with a high reliability. The initial volume of water in the suppression pool is adequate for low-pressure coolant injection (LPCI) and core spray (CS) operation until external injection can be aligned for makeup if required.
- The PRA describes the following two cases for modeling isolation failure:
  - **Case 1**. The break occurs in the reactor building where adverse environmental conditions occur. This does not apply to the cross-around piping in the turbine building nor the main steam and feedwater systems in the X-Area (Case 2).
  - **Case 2**. The break occurs in the X-area (steam tunnel) where blowout panels to the turbine building allow the energy discharge to the turbine building. This location does not apply to the cross-around piping in the turbine building; however, because there is propagation to the turbine building, insights from this analysis are considered here.

    This case involves a break in the X-area that discharges through blowout panels to the turbine building. As a result, the turbine building systems are not considered long-term successes. This includes CRD and condensate. Also, no credit is allowed for manual alignment of the station blackout diesel generator. However, the reactor building environment remains adequate and the ECCS systems (LPCI and CS) remain viable methods for inventory control. It is noted that breaks in the X-area are all from above reactor pressure vessel (RPV) Level 8 and the emergency operating procedure's direct RPV level control in the normal water level range—that is, below Level 8. Therefore, there is more than adequate RPV makeup in the torus and the condensate storage tanks to support adequate core cooling over the mission time.

Based on PRA, a main steam BOC initiating event is used for X-area break with blowout to the turbine building. Also, based on the PRA and the preceding, only CS and LPCI are credited for mitigation.

- Based on the PRA, this initiating event truncated out during quantification (CCDP in Table 3-1 is based on a PRA calculation that sets this initiator to 1.0).

Table 3-1. Select initiating event CCDPs and CLERPs

Initiating Event	Description	CCDP	CLERP
%LOOP	INIT: SINGLE-UNIT LOSS OF OFFSITE POWER	1.20E-05	1.90E-06
%TAC21	INIT: LOSS OF BUS 21	2.62E-07	<1E-7
%TAC22	INIT: LOSS OF BUS 22	2.62E-07	<1E-7
%TAC23	INIT: LOSS OF BUS 23	2.55E-06	3.61E-07
%TAC24	INIT: LOSS OF BUS 24	4.67E-06	4.70E-07
%TAC28	INIT: LOSS OF 480 VAC BUS 28	2.17E-06	2.37E-07
%TAC282	INIT: LOSS OF 480 VAC MCC 28-2	9.59E-07	1.71E-07
%LOOP	INIT: SINGLE-UNIT LOSS OF OFFSITE POWER	1.20E-05	1.90E-06
%TAC21	INIT: LOSS OF BUS 21	2.62E-07	<1E-7
%TBCCW	INIT: LOSS OF TBCCW	1.89E-07	2.53E-08
%TC	INIT: LOSS OF CONDENSER VACUUM	1.06E-06	1.91E-07
%TDC2	INIT: LOSS OF U2 MAIN DIRECT CURRENT (DC) BUS	4.51E-06	1.13E-06
%TDC3	INIT: LOSS OF U3 MAIN DC BUS	2.54E-06	3.30E-07
%TF	INIT: TRANSIENT WITH FW UNAVAILABLE AND MC AVAILABLE	9.36E-06	1.79E-06
%TIA	INIT: LOSS OF INSTRUMENT AIR (DRESDEN RAI)	5.02E-06	8.10E-07
%TM	INIT: MSIV CLOSURE	1.05E-06	1.67E-07
%TT	INIT: TRANSIENT WITH FW AND MC AVAILABLE	5.34E-07	9.26E-08
%BOC-MS [1]	INIT: MAIN STEAM BREAK IN X-AREA WITH BLOWOUT TO TURBINE BUILDING	1.56E-04	[1]

FW = feedwater

MC = main condenser

[1] %BOC-MS cutsets truncated out during quantification; so, the CCDP was calculated by setting the initiating event to 1.0. CLERP is assumed equal to CCDP

The following summarizes the IF PRA insights for the turbine building:

- HELBs are not included in the IF portion of the PRA logic model; they are included with other internal events in the model.
- In the turbine building, any racks and electrical cabinets affected by spray are likely to affect only the balance of plant. Spray in the turbine building would not cause direct failures of safety-related equipment in the reactor building. Spray could impact normal power feeds to dash buses but is not expected to prevent EDGs from providing power to ECCS and so forth. (Note that the cross-around system scope, because of its location, is not expected to have any impact similar to this.)
- There is a list of cabinets that are protected from spray. Spray events that could impact a single cabinet in the reactor building were screened. (Note that the cross-around system scope, because of its location, is not expected to have any impact on cabinets important to safety.)
- The turbine building is not screened for IF events. (Note that steam piping is not expected to have flooding impacts.)
- IF zones were reviewed relative to location of the cross-around piping and location of other equipment in the turbine building. The only potential impacts identified were the turbine stop and control valves and bypass valves.
- Water from any major flooding source will propagate to the condensate pump area, which has sump pumps. If the flood submerges the condensate pumps, loss of feedwater initiating event is assumed and is not recoverable. (Note that the cross-around system scope is steam and will not cause major flooding.)
- The main control room and the DC panel room and battery rooms located immediately above the condensate pump area are essentially immune from flooding concerns. No credible flooding sources are located in these areas. (These rooms will not be affected by the cross-around system scope.)
- Modifications were made to isolate the condenser pit from the condensate pump room at one of the units.
- Modifications were made to protect two of the four CCSW pumps at one of the units.
- Bus/MCC impacts are identified, but this is in the reactor building.
- Flood in the turbine building is modeled as loss of feedwater or main condenser.
- Flood zone screening is described.

Summary

The following summary is based on the PRA review:

- If postulated failures of the cross-around piping resulted in a turbine trip, the result was a Low consequence.
- If postulated failures of the cross-around piping resulted in loss of the main condenser because of MSIV closure or EHC and/or turbine bypass impacts, the result was Medium consequence.
- With regard to the isolation failure case, the consequence is Low based on the following:
    - CCDP for main steam BOC (main steam tunnel break) is conservative for the cross-around piping impacts because the model only credits LPCI and CS in the reactor building.
    - The CCDP for main steam BOC is 1.6E-4 but does not include isolation failure probability (2.6E-5 for the MSIVs). The effective CCDP is 4.2E-9.

3.2.2 Additional Consideration

The cross-around piping system is normally in operation during power operations and has no function when the plant is shut down. Therefore, it is clear that the PBF results in an initiating event (initiating event evaluation applies). This would result in a Medium consequence rank based on Section 3.2.1 and covered as follows:

- **Isolation success**. As described in Section 3.2.1, auto isolation is expected for large breaks and reliable operator isolation (scram, turbine trip, MSIV closure). Even if a turbine stop and control valve pair failed open because of jet impingement, the MSIVs provide backup isolation. If MSIV closure is assumed, this would be a Medium consequence.
- **Isolation failure**. %BOC-MS CCDP is 1.6E-4, but when the MSIV failure probability is included, the effective CCDP is a Low consequence.

The preceding provides the best estimate results for PBF, but the RI-HELB methodology requires further evaluation according to the eight criteria described in the remainder of this section. The following summarizes the evaluation of these criteria, which includes a plant walkdown described in Section 3.2.3:

1. **Containment isolation valves**. There are no containment isolation valves in the vicinity of the break area (pipeway/turbine building). (**Note**: this is also true for the main steam piping in in the turbine building.)
2. **Containment penetration**. The cross-around system breaks are far removed from containment penetrations; therefore, this does not apply. (**Note**: this is also true for the main steam piping in in the turbine building.)

3. **Unrestrained whipping pipe impact on equal or larger NPS**. Piping and components in the vicinity of the cross-around system scope are associated with the turbine controls (for example, turbine stop and control valves and bypass valves to the main condenser) and the pipeway/turbine cavity walls, which could be impacted by jet impingement and possibly pipe whip. Although loss of EHC would tend to be fail-safe, it is assumed at least one turbine stop and control valve pair fail open (MSIV isolation is assumed to be required to provide backup). Because the energy of the cross-around system is much less than main steam entering the high-pressure turbine, the impact on structures and walls is judged to be minor and enveloped by main steam breaks.
4. **Unrestrained whipping pipe impact on smaller NPS**. See Item 3.
5. **Unrestrained whipping pipe impact on SSCs**. See Item 3. Based on piping congestion inside the turbine shield wall in the pipeway/cavity, it is unlikely that severe structural damage would occur to the shield; however, during the walkdown (see Section 3.2.3), it was confirmed that there is no safety-related equipment anchored or in close proximity to the shield wall (see Section 3.2.3).
6. **Jet impingement**. As described in Item 3, it is possible that turbine controls could be impacted, including turbine stop and control valves. This analysis assumes at least one turbine stop and control valve pair fail open, but redundant MSIVs provide backup.
7. **Other spatial impacts**. There is no flooding impact because the scope of piping contains steam and, as described in Section 3.2.1, compartment overpressure is not an issue for main steam, which envelopes the cross-around system. However, there are potential spray (jet impingement) impacts as described previously (turbine stop and control valves, which also could not be credited for main steam breaks upstream). Impact on environmental conditions is also judged to be enveloped by main steam breaks but is reviewed here for completeness. FSAR Section 3.11 lists environmental zones, which are also identified on arrangement drawings (EQ maps). Table 3-2 summarizes the HELB zones by elevation in the turbine building with elevated temperatures above normal. All other zones have a maximum HELB temperature of 120°F (49°C) at atmospheric pressure (14.7 psia [101352 Pa]) consistent with normal conditions, but relative humidity is 100% under accident conditions whereas normal is 20–90% for these other zones (19, 30, 31a, 38, and 39).

Table 3-2. HELB zones by elevation

Floor	FSAR Drawing	Zone	HELB T (°F)	HELB PSIA
Ground (El 517)	3.11-2	20a	200	16.5
Mezzanine (El 541)	3.11-3	29	200	16.5
		31	200	16.5
Main (El 561)	3.11-4	None		

°F = °C x 9/5 + 32
1 psia = 6894.76 Pa

Note that normal relative humidity is 20–90% for the preceding, but accident conditions are 100%.

Zones 20a and 29 are associated with the turbine cavity and pipeway where main steam to the high-pressure turbine is located, as well as the cross-around piping. Zone 31 contains the high-pressure feedwater heaters. It appears that Zone 29 continues up to the main floor El 561. FSAR drawing 3.11-4 did not identify the area around the turbine at El 561 with a zone number; however, this area should have similar environmental conditions as Zones 29 and 20a because they all communicate and steam would flow up through El 561 to the upper part of the building.

The only EQ components in the preceding areas of the turbine building are in Zone 30, which means, as described previously, that the relative humidity increase to 100% is the qualification requirement. There are no EQ components in Zones 20a, 29, and 31, as expected.

A plant walkdown (see Section 3.2.3) was performed to inspect the areas around the turbine cavity with special focus on those areas close to openings into the cavity area. This walkdown also considers PRA equipment impact because EQ addresses only safety-related equipment required for HELB mitigation.

8. **Spatial propagation**. Steam will propagate up into the higher elevations of the turbine building, which is a very large area containing both units' turbine buildings. Steam will propagate in this manner because the turbine cavity is open up at El 561 (above the 12-ft [3.66-m] shield wall surrounding the turbine cavity on El 561). The cross-around piping is located mostly at the mezzanine level but approaches EL 517 and El 561 levels. The cavity essentially acts as a chimney up to 12 ft (3.66 m) above El 561 except for some openings at each El where some steam could escape especially for a large break. But the floors below El 561 have openings (large equipment hatches and stairways) to allow steam to rise up to El 561, and the walls above El 561 have blowout panels at 0.2 psig (1378. Pa) (see Section 3.2.3, Walkdown).

Summary

Based on this evaluation including the walkdown (see Section 3.2.3) insights, the cross-around piping system breaks are enveloped by the original main steam analysis. The high-pressure main steam postulated failures previously evaluated in the same area have a normal pressure greater than 800 psia (5515805 Pa) (534°F [279°C]) versus the cross-around pressure ~300 psia (2068427 Pa) (~414°F [212°C]). The walkdown confirmed minimal impacts from breaks in the pipeway/cavity. Section 3.2.4 provides the PRA calculations judged to envelope the consequences of postulated cross-around piping failures.

3.2.3 Walkdown

The primary objective of the walkdown was to assess potential spatial impacts especially in adjacent areas outside the turbine cavity/pipeway shield walls. The cross-around piping scope, as shown in Figures 3-2 through 3-4, is located close to the turbines for each unit and is not accessible during power operations. However, no PRA equipment was identified within the turbine cavity area other than turbine bypass valves, which are not safety-related and are not credited in this evaluation. The original HELB analysis indicates that there are safety-related cables, but these were not a concern for main steam breaks. A summary of the area is provided as follows:

- **Arrangement**. The areas where main steam enters the high-pressure turbine through the equalizing header and stop/control valves and the cross-around piping are interconnected and open from El 517 to 561, and there are numerous openings to allow steam to flow up above El 561. The floor grating panels (diamond decking) on both sides of the low-pressure turbines are solid but could lift if the break is big enough and pressure is high enough to require more relief.
- **Heating, ventilating, and air conditioning (HVAC)**. The exhaust system exclusively draws off the locked high radiation areas (LHRAs). There is a huge ductwork penetration that connects the turbine building exhaust fans to the area by the moisture separators. Given a large enough break, it is expected that this ductwork or the exhaust plenum would fail. Additionally, there are a large number of area differential pressure (dp) dampers (normally closed given the required dp) that will fail with a moderate dp and will fail to contain internal pressure. There are natural gaps in the LHRA boundaries (area dp dampers, openings around the turbine skirts, and so forth) that will relieve pressure. The exhaust system can readily dispose of steam leaks (each unit provides around 150,000 cfm (4247 m^3/min) actual; so, the difference between outside dewpoint and the 135°F (57.2°C) exhaust temperatures means a significant amount of steam will just go to humidification of exhaust air). The ductwork is just seamed with Pittsburg connections; so, it will not hold much more than 12 in. (304.8 mm) water gauge before splitting.

Based on the design (shield walls from El 517 up to El 561 and 12 ft [3.66 m] above EL 561), steam breaks in the cavity/pipeway would mostly propagate up to above El 561 (chimney effect) except for any leakage through the access opening at each elevation. Also, failure of the HVAC exhaust ducting is a propagation path for steam. Any steam that exits through openings on El 517 and 541 is expected to flow directly up to El 561 through large open hatches and open stairs. Therefore, another objective of the walkdown was to confirm this propagation pathway and identify any potential impact on equipment in the flow path. An additional objective was to locate equipment modeled in the PRA that is in the vicinity and confirm that steam is unlikely to impact that equipment. This was apparently done for the original main steam break analysis, but documentation supporting similar findings is not available or lacks specificity. Also, the original analysis scope considered impact on safety-related equipment whereas this evaluation is concerned with impact on PRA equipment that includes non-safety equipment as well as some safety-related equipment.

The following summarizes the walkdown observations by elevation:

Main Floor

This floor up to the ceiling (El 600+) is wide open. The combined Unit 2 and Unit 3 turbine building provides a huge space for steam to propagate to the ceiling. The following summarizes walkdown observations:

- No equipment modeled in the PRA is located near the ceiling.
- A significant amount of turbine building siding blows out at 0.2 psig (1378 Pa). Signage was observed identifying walls as blowout panels and directing that no modification can be made without prior contact with plant engineering.
- Because the cross-around piping is inside the turbine cavity walls, as expected, and based on looking at the turbine cavity openings, there are no spray/jet impingement issues (L-shaped openings help ensure protection, but no equipment was identified directly outside these openings). There are three access openings for each unit with no doors.
- No equipment modeled in the PRA is attached to or in close proximity to the cavity walls.
- Equipment identified from arrangement drawings and PRA and then during the walkdown was assessed for the potential impacts from steam escaping the shield wall openings or HVAC exhaust ducting (components are modeled in the PRA unless noted otherwise), as summarized in the Table 3-3.

Table 3-3. Walkdown observations—El 561

Main Floor El 561	Unit A	Unit B	Observations
Battery racks	8350-3	8350-3	No impact from cavity opening, ~25 ft from turbine cavity opening.
Battery charger	8350-2A	8350-2A	No impact from cavity opening, ~50 ft from turbine cavity opening. HVAC supply ducting identified in the area but not critical because of distance and low likelihood of this being a propagation path.
Battery charger	8350-2B	8350-2B	No impact from cavity opening, ~50 ft from turbine cavity opening. HVAC supply ducting identified in the area but not critical because of distance and low likelihood of this being a propagation path.
250-V DC MCC	8350-1A	8350-1A	No impact from cavity opening, ~60 ft from turbine cavity opening. HVAC supply ducting identified in the area but not critical because of distance and low likelihood of this being a propagation path.
Steam jet air ejectors	Yes	Yes	No impact—a wall separates this area with access from El 549 (north side), and impact is main condenser, which is assumed to be unavailable because of MSIV closure. Not modeled in PRA.
Ventilation equipment	Yes	Yes	No impact—a wall separates this area with access from El 549 (north side), and ventilation failure does not impact PRA modeled equipment.
MG sets	Yes	Yes	No impact—~30 ft from turbine cavity opening. Not modeled in PRA.
Instrument racks	Yes	Yes	No impacts—looked for any that might be modeled in the PRA and close to openings—none identified.
MCC	29-9	-	No impact, located on El 549 (north side).

1 ft = 0.3 mm
MG = motor generator
MCC = motor control center

Mezzanine Floor

The majority of the cross-around piping is located inside the turbine cavity walls at this elevation. Based on plant drawings, there are large opening on both sides of the low-pressure turbines at El 561 with covers that would lift, given a large enough break to allow steam flow from the turbine cavity up to the ceiling area above El 561 (see preceding discussion). As described previously, there are several openings (for example, skirt and HVAC) that would also allow propagation up toward the ceiling. The turbine cavity and pipeway are open from El 517 to El 541. The following summarizes walkdown observations:

- Because the cross-around piping is inside the turbine cavity walls, as expected, and based on looking at the turbine cavity opening, there are no spray/jet impingement issues (L-shaped openings help ensure protection). There are two access opening for each unit. The following summarizes observations for each access opening:
    - **Unit A SW opening from HP heater bay**. There is a closed door that opens out from the heater bay, and there are MCCs in vicinity but not close enough to be affected. There is an open staircase nearby where steam will propagate up to El 561.
    - **Unit B SE opening from HP heater bay**. There is a closed door that opens out from the heater bay, and there are MCCs in vicinity but not close enough to be affected. There is an open staircase nearby where steam will propagate up to El 561.
    - **Unit A SE opening from cavity**. There is a closed door that opens out from the cavity, and MCCs 28-2 and 3 could be impacted if the door becomes a missile (even if it just opens, steam could strike the MCCs). Nearby there is an open staircase and a very large hatch opening up to EL 561. Because there is no analysis available that provides a basis for the doors withstanding a double-ended break, it is assumed that a large break would fail the door as well as the MCCs.
    - **Unit B SW opening from cavity**. There is a closed door that opens out from the cavity, and MCCs 38-2 and 3 could be impacted if the door becomes a missile (even if it just opens, steam could strike the MCCs). Nearby there is an open staircase and a very large hatch opening up to EL 561. Because there is no analysis available that provides a basis for the doors withstanding a double-ended break, it is assumed that a large break would fail the door as well as the MCCs.
- If steam escapes through the cavity wall openings, there are large hatch openings (one for each unit) and open staircases to El 561 that would allow steam to propagate up through floor El 561.
- No equipment modeled in the PRA is attached to or in close proximity to the cavity walls.
- Equipment identified from arrangement drawings, the PRA and then during the walkdown was assessed for the potential impacts from steam escaping the cavity wall openings or HVAC exhaust ducting (components are modeled in the PRA unless noted otherwise), as summarized in Table 3-4.

Table 3-4. Walkdown Observations—El 541

Main Floor El 541	Unit A	Unit B	Observations
Turbine building cooling water	Yes	Yes	No impact—walls isolate this area (northern end of building) from any impacts because of steam. The only opening to the turbine cavity is on the far southern end of the building for each unit, and there are open staircases up to El 561 on the south end as well as the north side.
Instrument racks	Yes	Yes	No impact—walkdown looked for any that might be in PRA and close to openings—none identified.
2500V DC MCC	2-8350-1B	3-8350-1B	No Impact—these are ~50 ft from a turbine cavity opening (each unit), and there is a large open hatch in the ceiling at El 561.
4-KV SWGR	21	-	No impact—21 is in far northeastern corner, and there is a large open hatch to El 561.
4-KV SWGR	22	-	No impact—22 is in far northeastern corner, and there is a large open hatch to El 561.
4-KV SWGR	23	33	No impact—Unit 2 is in far northeastern corner and there is a large open hatch to El 561. Unit 3 is in far northwestern corner, and there is a large open hatch to El 561.
4-KV SWGR	24	34	No impact—Unit 2 is in far northeastern corner, and there is a large open hatch to El 561. Unit 3 is in far northwestern corner, and there is a large open hatch to El 561.
MCC	-	39-2	No Impact—MCC 39-2 is near turbine cavity opening door but is not judged to be susceptible to impact from a door failure.
MCC	28-2	38-2	MCC 28-2 is near turbine cavity door and susceptible to door impact if door opens. MCC 38-2 is near turbine cavity door and susceptible to door impact if door opens.
MCC	28-3	38-3	MCC 28-3 is near turbine cavity door and susceptible to door impact if door opens. MCC 38-3 is near turbine cavity door and susceptible to door impact if door opens.
MCC	-	35-2	No impact—35-2 is in far northwestern corner, and there is a large open hatch.
MCC	25-1	35-1	No impact—near opening but even further from the opening than MCC 39-2.

SWGR = switchgear room

Ground Floor

Because the bulk of the cross-around piping is above this elevation and the natural flow of steam is up, the impact at this elevation is not significant. Still, this area was reviewed for completeness. The following summarizes walkdown observations:

- Because the cross-around piping is inside the turbine cavity walls, as expected, and based on observations of the turbine cavity openings, there are no spray/jet impingement issues (L-shaped openings help also ensure protection). There are three access openings for each unit. The following summarizes observations for each access opening:
  - **Unit A NW opening from condensate demineralizer area**. There is a closed door that opens out from this room, and there is no electrical equipment in the vicinity of the door. MCC 27-1 is around the corner from the opening, and there is an open staircase nearby that will allow steam to propagate up to El 561.
  - **Unit B NE opening from condensate demineralizer area**. There is a closed door that opens out from this room, and there is no electrical equipment in the vicinity of the door. MCC 37-1 is around the corner from the opening, and there is an open staircase nearby that will allow steam to propagate up to El 561.
  - **Unit A SW opening from cavity**. There is a closed door that opens out from this room, and there is no electrical equipment in the vicinity of the door. There is an open staircase nearby that will allow steam to propagate up to El 561.
  - **Unit B SE opening from cavity**. There is a closed door that opens out from this room, and there is no electrical equipment in the vicinity of the door. There is an open staircase nearby that will allow steam to propagate up to El 561.
  - **Unit A NE opening from cavity**. There is a closed door that opens out from the cavity and away from electrical equipment. This area is not in the RCA and propagation into this area is unique; it is not into the open turbine building as is the case for all other access openings. Steam will propagate to upper elevations so that no impact on electrical equipment in the area is likely to occur.
  - **Unit B NW opening from cavity**. There is a closed door that opens out from the cavity and electrical equipment is ~ 30 ft (9.14 m) away and not in direct path of opening. There is an opening near the door and a large equipment hatch for steam propagation.
- If steam escapes through the cavity wall openings, there are open stairs and equipment hatches to allow steam to flow up to EL 561 and above.
- No equipment modeled in the PRA is attached to or in close proximity to the cavity walls.
- Equipment identified from arrangement drawings and the PRA and then during the walkdown was assessed for the potential impacts from steam escaping the shield wall openings or HVAC exhaust ducting (components are modeled in the PRA unless noted otherwise), as summarized in Table 3-5.

Table 3-5. Walkdown observation—main floor

Main Floor	Unit A	Unit B	Observations
Reactor feed pumps	Yes	Yes	No impact—on southern side in room
Emergency diesel	Yes	Yes	No impact—on southern side in room
Instrument air	Yes	Yes	No impact—compressors noted throughout—none identified as directly near an opening, and, even if one were affected, there are others unaffected and unit crossties
Auxiliary electrical equipment room	Yes	Yes	No impact—in room on eastern wall
MCC	25-2	-	No impact—northeastern corner room
MCC	27-1	37-1	No impact—northern wall
MCC	29-2	-	No impact—northeastern corner room
SWGR	25	35	No impact—25 in northeastern corner; 35 in northwestern corner room
SWGR	26	36	No impact—26 in northeastern corner; 36 in northwestern corner room
SWGR	-	31	No impact—31 in northwestern corner room
SWGR	-	32	No impact—2 in northwestern corner room

3.2.4 Results

Based on the evaluations in Sections 3.2.1 through 3.2.3, the postulated cross-around piping system breaks are enveloped by the original main steam analysis. The high-pressure main steam piping previously evaluated in the same area has a normal pressure greater than 800 psia (5515805 Pa) (534°F [279°C]) versus the cross-around piping pressure of ~300 psia (2068427 Pa) (~414°F [212°C]). The walkdown confirmed minimal potential for impacts from breaks in the pipeway/cavity. For large breaks (that is, design basis including double-ended break), the following impacts are assumed:

- At least one pair of turbine stop and control valves is assumed to fail open because of jet impingement or pipe whip, and, therefore, MSIV closure is required for isolation because it was in the original main steam analysis. Note that the original main steam analysis did not take credit for these valves because they are not safety-related.
- Two MCCs are assumed to fail for each unit, as follows:
  - Unit A MCCs 28-2 and 28-3 are assumed to fail because there is no analysis that supports crediting the doors withstanding a double-ended break blowdown.
  - Unit B MCCs 38-2 and 38-3 are assumed to fail because there is no analysis that supports crediting the doors withstanding a double-ended break blowdown.

- MSIV will close, which can be modeled as initiator %TM set to 1.0 to calculate CCDP and CLERP. The MSIV isolation failure case is modeled the same as initiating event %BOC-MS (with %BOC-MS set to 1.0), which conservatively only credits LPCI and CS systems located in the reactor building. CCDP is assumed to be equal to CLERP given that MSIVs are open. For isolation failure, the CCDP includes the probability of MSIV isolation failure times %BOC-MS CCDP.

Table 3-6 summarizes the PRA calculations for the large break case. As shown, the CCDP/CLERP results for isolation success dominate with a Medium consequence.

Table 3-6. Large break PRA modeling and calculations

Unit	Large Break	Model		CCDP	CLERP
A	Isolation success	Initiating event	%TM = 1.0	1.1E-6	1.8E-7
		MCC 28-2 set to true	2ACBS28-2----F--		
		MCC 28-3 set to true	2ACBSMCC28-3-F--		
	Isolation failure	Initiating event	%BOC-MS = 1.0	4.0E-9	4.0E-9
		MCC 28-2 set to true	2ACBS28-2----F--		
		MCC 28-3 set to true	2ACBSMCC28-3-F--		
		CCDP from above	1.5E-04		
		MSIVs failure probability	2.6E-05		
		Final CCDP	4.0E-09		
B	Isolation success	Initiating event	%TM = 1.0	1.1E-6	1.8E-7
		MCC 38-2 set to true	2ACBS28-2----F--		
		MCC 38-3 set to true	2ACBSMCC28-3-F--		
	Isolation failure	Initiating event	%BOC-MS = 1.0	4.0E-9	4.0E-9
		MCC 38-2 set to true	2ACBS28-2----F--		
		MCC 38-3 set to true	2ACBSMCC28-3-F--		
		CCDP from above	1.5E-04		
		MSIVs failure probability	2.6E-05		
		Final CCDP	4.0E-09		

For small breaks that do not cause automatic MSIV isolation, the blowdown is assumed to continue until the operators scram the plant and close the MSIVs to isolate the break. For these breaks it is possible that the HVAC would mitigate the effects of most breaks (if not actually all) and the doors would most likely not blow out. As expected, the large double-ended break assumption covered previously envelopes the consequences of small breaks except that steam could be leaking into the turbine building for a longer duration. The following is assumed for small breaks:

- At least one pair of turbine stop and control valves are assumed to fail open because of jet impingement; therefore, MSIV closure is required by the operators to isolate the break.
- Doors are assumed not to blow open and fail MCCs. A sensitivity case is run with the MCCs failed to check the importance of this assumption.
- Small breaks have essentially no impact on PRA equipment until the MSIVs are closed and the main condenser is lost. To bound the impacts of these small breaks, the following scenarios are postulated:
    1. %TM initiating event set to 1.0 with no other impacts on PRA (successful scram and MSIV closure by the operators).
    2. To bound isolation failure, %TM initiating event is set to 1.0 (loss of main condenser), but operators do not or cannot close MSIVs. Because of this CCDP = CLERP and no credit is allowed for the isolation condenser (not credited for unisolated LOCA success), CRD makeup (limited makeup capacity), and HPCI (steam has limited capability to run HPCI in the long term). However, isolation condenser, CRD, and HPCI short-term success if feedwater failed would provide significant time for emergency depressurization if it is required (RPV may be depressurized by this time anyway); so, emergency depressurization could have been set to guaranteed success as it would be for a large break, but this is conservatively neglected.

Table 3-7 summarizes the PRA calculations. Also, a sensitivity case was calculated with the two MCCs failed for both the successful isolation and fail-to-isolate cases. The increase in CDF and LERF is in the second decimal place (no impact on the results). As shown, the CCDP/CLERP results for isolation success dominates, resulting in a Medium consequence rank for the cross-around piping.

Table 3-7. Small break PRA modeling and calculations

Unit	Large Break	Model		CCDP	CLERP
A	Isolation success	Initiating event	%TM = 1.0	1.1E-6	1.8E-7
	Isolation failure	Initiating event	%TM = 1.0	2.2E-9	2.2E-9
		IC set to true	2ICHE1302----R--		
		CRD set to true	2CRAV0302-6A-K--		
		HPCI set to true	2HICV2301-50AD--		
		CCDP from above	2.2E-6		
		MSIVs failure probability	1E-3[1]		
B	Isolation success	Initiating event	%TM = 1.0	1.1E-6	1.7E-7
	Isolation failure	Initiating event	%TM = 1.0	2.2E-9	2.2E-9
		IC set to true	2ICHE1302----R--		
		CRD set to true	2CRAV0302-6A-K--		
		HPCI set to true	2HICV2301-50AD--		
		CCDP from above	2.2E-6		
		MSIVs failure probability	1E-3[1]		

[1] A conservative probability of MSIV isolation failure is used because it is operator dependent.

3.3 Failure Potential Evaluation

The DMs to be assessed are listed in Section 2.2 of this report. The explicit criteria for assessing the potential for each DM to be active are provided in Section 2.2. A detailed checklist applying this process to the cross-around piping is provided in Appendix A. A summary of the input to this evaluation and the results of this evaluation are provided in Sections 3.3.1 and 3.3.2.

3.3.1 Summary of Inputs

The following is a summary of inputs:

Evaluation scope:

- Lines from high-pressure turbine to four moisture separator tanks (MSTs)
- Four MSTs
- Lines from MSTs to six combined intercept valves (CIVs)
- Six CIVs
- Seven branch lines to relief valves (upstream of CIVs)
- Seven relief valves

- Six lines from CIVs to low-pressure turbines

Materials:

- All piping (NPS 24 and smaller) = A106 Grade B Schedule 80 carbon steel
- Piping NPS 30 = A672 Grade C70 C70 Class 21 carbon steel
- Piping (other) = not austenitic stainless steel
- All valves (NPS 2.5 and larger) = carbon steel according to A216 Grade WCB
- MSTs = carbon steel or low-alloy steel (not austenitic stainless steel) (assumed)
- Summary = SCC DMs not active

Operating conditions:

- Pressure = 300.6P high-pressure turbine outlet; 290.4P MST outlet; 281.1P CIV outlet
- Temperature = 414.4°F MST outlet; all lines (including lines to relief valves) assumed to be the same temperature
- Summary = low-temperature DMs not active

Fluid chemistry:

- The full-flow condensate demineralizer system supplies water of required purity of the reactor. The demineralizer system removes corrosion products originating from the turbine, condenser, and the feedwater heaters; protects the reactor against impurities from tube leaks; and removes condensate impurities which might enter the system in the makeup water. The system can maintain effluent impurity levels at or below the following concentration limits:

Total dissolved solids	25 ppb
Total iron as Fe	2.1/5* ppb
Total copper as Cu	8 ppb
Total nickel as Ni	5 ppb
Total silica as SiO_2	10 ppb
Total chloride as Cl	1/5* ppb
Specific conductivity at 77°F	0.1 µmho/cm
pH at 77°F	7

ppb = parts per billion
77°F = 25°C

- Operates with hydrogen water chemistry and online noble metal chemistry; however, the subject piping and components may not fully benefit. It is assumed that oxygen in the subject piping and components would be <20 parts per million.
- Summary = chlorides/initiating contaminants controlled. Oxygen somewhat controlled (assumed).

Flow:

- High, constant flow of 2,906,414# to each MST; 2,626,055# outlet of each MST; 3,497,343# (/2) to each low-pressure turbine 1 CIV; 3,507,614# (/2) to each low-pressure turbine 2 CIV; 3,499,252# (/2) to each low-pressure turbine 3 CIV
- Lines to relief valves normally stagnant

Other:

- No IGSCC because no stainless-steel or Alloy 82/182 components in scope (assumed)
- No FAC because the cross-around piping is within the FAC program, but the expected wear rate is very low, and, therefore, wall thickness exams (for example, ultrasonic testing) are not necessary

3.3.2 Summary of Results

The following summarizes the results:

- None of the DMs listed at the beginning of this section is active in the cross-around piping according to the criteria of Section 2.2.
- All piping and components are, therefore, assigned a Low failure potential rank.

See Appendix A, Degradation Mechanism Checklist, for assessment details.

3.4 Risk Characterization

As covered in Section 2, the next step in the RI-HELB methodology process is to conduct a risk ranking, which will inform the HELB response strategies step. The focus of this section is on the risk ranking (risk significance) of the main steam cross-around piping as determined by application of the RI-HELB methodology.

As described in Section 2.3, the ranking depends on consequence rank (see Section 3.2) and failure potential (DM) rank (see Section 3.3). Given the Medium consequence rank and Low failure potential rank, according to Figure 2-6 (repeated as Figure 3-5 for convenience), a Low risk rank applies to the cross-around piping.

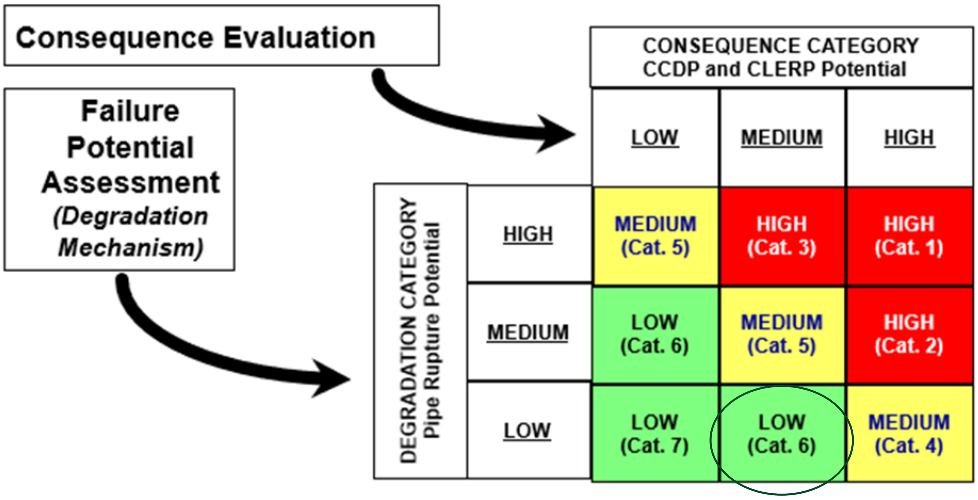


Figure 3-5. RI-HELB risk matrix

3.5 HELB Response Strategies

Based upon the failure potential results covered in Section 3.3.2, the cross-around piping is assigned a Low failure potential rank. Based upon the consequence of failure results covered in Section 3.2.4, the cross-around piping is assigned a Medium consequence rank. As such, the cross-around piping is assigned to RC6 (that is, Low risk region). According to the discussion provided in Section 2.4, given the Low risk associated with the cross-around piping, there are no HELB response strategies that need to be developed for this scope of piping.

3.6 Risk Impact

Because this example included new HELB scope, there were no strategies in place (for example, inspections) and, if the results of this evaluation required a modification or inspections, one could argue that would be a risk reduction. This is not really appropriate because for this example; it is more relevant to estimate the risk from this new scope (that is plant change resulting from the power uprate) and compare it to RG 1.174 with regard to acceptable increases in risk. The following summarizes:

- Risk is dominated by loss of main condenser (isolation success case) with CCDP and CLERP similar to that already modeled in the PRA. Therefore, this could be assumed to be subsumed by the PRA modeled initiating event frequency (essentially no measurable increase in risk).
- CCDP and CLERP for the isolation failure cases are orders of magnitude lower than acceptable risk increases in RG 1.174 even without consideration of break frequency.
- Even if one used the isolation success case with 1E-6 CCDP and 2E-7 CLERP, a very high break frequency ~1E-2 would result in very low risk increase that easily meets RG 1.174.

3.7 Performance Monitoring

The piping in question is the non-safety-related main steam cross-around piping from the high-pressure turbine to the moisture separators and from the moisture separators to the low-pressure turbines. The piping has been evaluated as part of the FAC program and shown to not require inspection. The FAC program is periodically updated, and, if as a result of that update inspection of the cross around piping is needed, those inspections will be incorporated into the FAC inspection plan. Additionally, plant practices require that operator walkdowns of the accessible areas of the turbine building be conducted. Finally, this plant has received approval to operate for 60 years (license renewal [LR]) according to 10CFR50.54). The LR process requires a set of time-limited aging analysis of pressure boundary components as well as a set of aging management program requirements.

As such, given the preceding there is no need to identify additional performance requirements.

4 CONFORMANCE WITH RISK-INFORMED DECISION-MAKING PRINCIPLES

In risk-informed decision-making, licensing basis changes are expected to meet a set of key principles (see Figure 4-1).

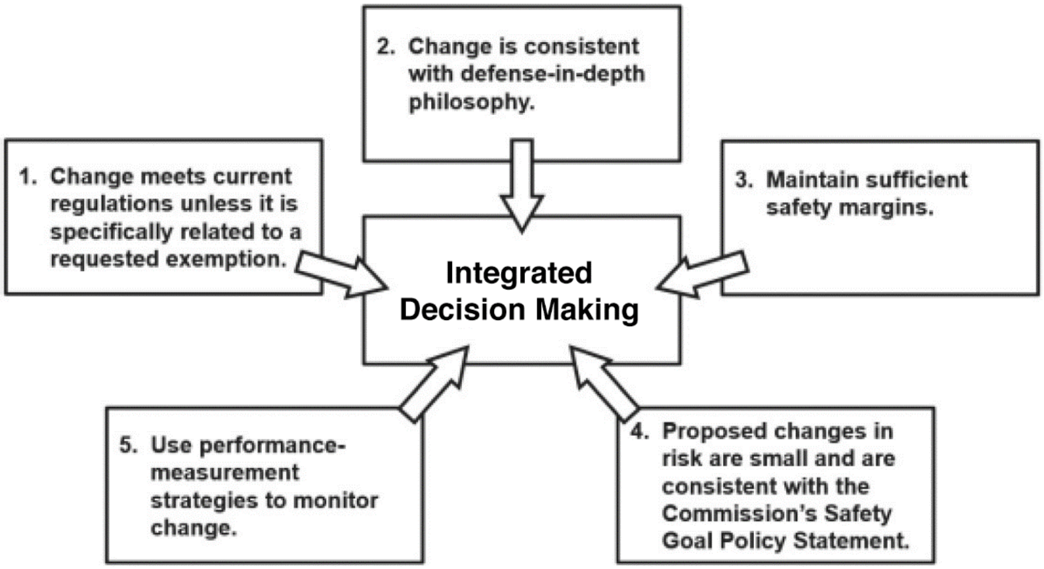


Figure 4-1. Principles guiding decision making
Source: Figure 2 of RG 1.174, Revision 3

These principles and how they are met by the RI-HELB methodology are as follows:

- **Principle 1**. The proposed licensing basis change meets the current regulations unless it is explicitly related to a requested exemption (that is, a specific exemption under 10CFR50.12).

  Licensees’ implementation of the methodology contained in this report will be through the applicable change control process as endorsed by the NRC.

- **Principle 2**. The proposed licensing basis change is consistent with the DID philosophy.

  Piping systems in a nuclear power plant contribute to DID in two important ways: the piping of the reactor coolant pressure boundary provides one of the sets of barriers in the barrier DID arrangement. This barrier protects the release pathway from the reactor core to containment release pathways, and part of it is responsible for protecting against potential containment bypass pathways. This RI-HELB methodology is not applicable to the reactor coolant pressure boundary, and, as such, there is no adverse impact to this DID arrangement.

Second, piping contributes to DID in its role in the protection of the core through providing critical safety functions that require piping system integrity. As can be seen in the preceding sections, the RI-HELB methodology requires that PBFs that would fail a critical safety function be categorized as high safety-significant. These include those failures that would impact key inventory sources, plant-specific outliers that contribute to core damage or containment performance, and failure of the ultimate heat sink and component that can have intersystem impact.

Third, a foundation of this risk-technology is that those postulated piping failures that challenge defense in depth shall be categorized as high consequence ranks (e.g. CCDP > 1E-04 / CLERP > 1E-05).

- **Principle 3**. The proposed licensing basis change maintains sufficient safety margins.

  Existing safety analyses are not impacted by implementation of a RI-HELB program. The RI-HELB methodology requires that all in-scope piping be evaluated (that is not limited to high design stress locations and terminal ends), thus safety improvements are envisioned via its application. Additionally, other related programs (e.g. determining the scope of equipment required to be within an environmental qualification program) are outside the scope of this application.

- **Principle 4**. When proposed licensing basis changes result in an increase in risk, the increases should be small and consistent with the intent of the NRC's policy statement on safety goals for the operations of nuclear power plants.

  The RI-HELB methodology is structured with the characteristic that no significant risk increases should be expected. In fact, for most applications it is expected that strict adherence to the RI-HELB principles for assignment of pipe segments to the risk matrix, the RI-HELB strategies (for example, where applicable the use of inspection percentages, specific element selection criteria and implementation of an inspection for cause approach) will result in reductions in pipe rupture frequencies and associated impacts in CDF and LERF.

- **Principle 5:** The impact of the proposed licensing basis change should be monitored using performance measurement strategies.

  The licensee is expected to incorporate the results of the application of the RI-HELB methodology into plant-specific program procedures that are consistent with the performance-based implementation and monitoring strategies specified in RG 1.174 and existing UFSAR commitments. These include maintaining the plant-specific PRA and any supplemental analyses (e.g., the RI-HELB evaluations) current and reflective of the as built / as operated plant. Therefore, there are no unique aspects of the RI-HELB methodology insofar as monitoring requirements are concerned.

5 SUMMARY

The purpose of this report is to present an alternative methodology for meeting GDC-4 [1]. That is, the risk-informed methodology contained in this report provides an acceptable means for assessing and confirming that plant SSCs important to safety are adequate to accommodate the effects of postulated accidents, including appropriate protection against the dynamic and environmental effects of postulated pipe ruptures.

This report provides a mechanism to identify the safety significance of postulated pipe ruptures and, as warranted, recommend appropriate plant actions (for example, plant modifications, inspection sample size), taking into account plant-specific design features and the safety benefit associated with possible plant modification while maintaining an adequate level of DID. Although existing evidence and analyses have identified the potential for catastrophic pipe breaks (that is, DEGBs) as vanishingly low for well-engineered systems, prudence dictates that a reasonable assessment of postulated piping failures be conducted.

The initial application of this methodology is focused on the operating fleet and is limited to determining the risk significance of postulate piping failures and appropriate plant response strategies. Other plant designs and related programs (e.g. determining the scope of equipment required to be within an environmental qualification program) are outside the scope of this application.

6 REFERENCES

1. NRC Regulations Title 10, Code of Federal Regulations Part 50, Appendix A, General Design Criteria for Nuclear Power Plants, Number 4, Environmental and Dynamic Effects Design Bases.
2. U.S. Nuclear Regulatory Commission, NUREG-1061, Report of the US Nuclear Regulatory Commission Piping Review Committee, dated December 1984.
3. Letter from A. Giambusso, “General Information Required for Consideration of the Effects of a Piping System Break Outside Containment, Atomic Energy Commission, December 1972.
4. NRC SRPs.
    a. U.S. Nuclear Regulatory Commission, NUREG-0800, SRP 3.6.1, Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment, including Branch Technical Position ASB 3-1.
    b. U.S. Nuclear Regulatory Commission NUREG-0800, SRP 3.6.2, Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping, including Branch Technical Position MEB 3-1.
5. ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems, 1970 Edition, January 1, 1970, American Society of Mechanical Engineers United Engineering Center, New York.
6. ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, 1971 Edition through Winter 1972 Addenda, American Society of Mechanical Engineers United Engineering Center, New York.
7. ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, 1974 Edition, American Society of Mechanical Engineers United Engineering Center, New York.
8. 2017 ASME Boiler and Pressure Vessel Code, 2017 Edition, American Society of Mechanical Engineers. New York: July 2017.
9. NRC Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning.”
10. *Thermal Stratification, Cycling, and Striping (TASCS)*. EPRI. Palo Alto, CA: 1999. 103581.
11. *Improved Basis and Requirements for Break Location Postulation*. EPRI. Palo Alto, CA: 2011. 1022873.
12. *Extremely Low Probability of Rupture Version 2 Probabilistic Fracture Mechanics Code*. EPRI. Palo Alto, CA: 2021. 3002013307.
13. ML23010A250 (NRC meeting slides) dated January 11, 2023.
14. NRC RG 1.174, Revision 2, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions for Plant-Specific Changes to the Licensing Basis.

15. EPRI TR-112657, *Revised Risk-Informed Inservice Inspection Evaluation Procedure*, *Final Report*, Revision B-A. EPRI. Palo Alto, CA: 1999.
16. *Extension of the EPRI Risk-Informed Inservice Inspection (RI-ISI) Methodology to Break Exclusion Region (BER) Programs*, Rev. 0-A. EPRI. Palo Alto, CA: 2002. 1006937.
17. *Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R4)*. EPRI. Palo Alto, CA: 2013. 3002000563.
18. *Application of EPRI Risk Informed Inservice Inspection Guidelines to CE Plants*. EPRI, Palo Alto, CA: 1997. TR-107531.

A DEGRADATION MECHANISM CHECKLIST

The following is a detailed checklist.

No.	Attributes to be Considered	Yes	No	N/C	N/A	Remarks
TASCS-1	*NPS $>$1 in. (DN 25), and*	☒	☐	☐	☐	
TASCS-2	*Pipe segment has a slope $<$45° from horizontal (includes elbow or tee into a vertical pipe), and*	☒	☐	☐	☐	Some pipe segments
TASCS-3-1	*Potential exists for low flow in a pipe section connected to a component allowing mixing of hot and cold fluids, or*	☐	☒	☐	☐	
TASCS-3-2	*Potential exists for leakage flow past a valve (that is, in-leakage, out-leakage, cross-leakage) allowing mixing of hot and cold fluids (*use MRP-146 results if available), or*	☐	☒	☐	☐	
TASCS-3-3	*Potential exists for convection heating in dead-ended pipe sections connected to a source of hot fluid, or*	☐	☒	☐	☐	
TASCS-3-4	*Potential exists for two phase (steam/water) flow, or*	☐	☒	☐	☐	
TASCS-3-5	*Potential exists for turbulent penetration into a relatively colder branch pipe connected to header piping containing hot fluid with high turbulent flow (*use MRP-146 results if available), and*	☐	☒	☐	☐	
TASCS-4	*Calculated or measured $\Delta T > 50$°F (28°C), and*	☐	☐	☐	☒	
TASCS-5	*Richardson number $>$4.0*	☐	☐	☐	☒	
In conclusion, not susceptible.						
TT-1-1	*Operating temperature $>$270°F (130°C) for stainless steel, or*	☐	☐	☐	☒	
TT-1-2	*Operating temperature $>$220°F (105°C) for carbon steel, and*	☒	☐	☐	☐	
	Potential for relatively rapid temperature changes including					
TT-2-1	*Cold fluid injection into hot pipe segment, or*	☐	☒	☐	☐	
TT-2-2	*Hot fluid injection into cold pipe segment, and*	☐	☒	☐	☐	
TT-3-1	*$|\Delta T| >$200°F (93°C) for stainless steel, or*	☐	☐	☐	☒	
TT-3-2	*$|\Delta T| >$150°F (65°C) for carbon steel, or*	☐	☐	☐	☒	
TT-3-3	*$|\Delta T| > \Delta T$ allowable (applicable to both stainless and carbon)*	☐	☐	☐	☒	
In conclusion, not susceptible.						
IGSCC-B-1	*Evaluated in accordance with the owner's existing IGSCC inspection program following NRC Generic Letter 88-01, or alternative (for example, BWRVIP-075)*	☐	☒	☐	☐	Extremely unlikely in this scope
In conclusion, not susceptible.						
IGSCC-P-1	*Operating temperature $>$200°F (93°C), and*	☐	☐	☐	☒	DM applicable to PWRs only
IGSCC-P-2	*Susceptible material (carbon content $\geq$ 0.035%), and*	☐	☐	☐	☒	DM applicable to PWRs only
IGSCC-P-3	*Tensile stress (including residual stress) is present, and*	☐	☐	☐	☒	DM applicable to PWRs only
IGSCC-P-4	*Oxygen or oxidizing species are present*	☐	☐	☐	☒	DM applicable to PWRs only
	OR					
IGSCC-P-5	*Operating temperature $<$200°F (93°C), the attributes above apply, and*	☐	☐	☐	☒	DM applicable to PWRs only
IGSCC-P-6	*Initiating contaminants (for example, thiosulfate, fluoride, chloride) are also required to be present*	☐	☐	☐	☒	DM applicable to PWRs only
In conclusion, not susceptible.						

Degradation Mechanism Assessment Worksheet						
No.	***Attributes to be Considered***	***Yes***	***No***	***N/C***	***N/A***	***Remarks***
TGSCC-1	*Austenitic stainless steel, and*	☐	☒	☐	☐	
TGSCC-2	*Operating temperature >150°F (65°C), and*	☐	☐	☒	☐	
TGSCC-3	*Tensile stress (including residual stress) is present, and*	☐	☐	☒	☐	
TGSCC-4	*Halides (for example, fluoride or chloride) are present, or caustic (NaOH) is present, and*	☐	☐	☒	☐	
TGSCC-5	*Oxygen or oxidizing species are present (only required to be present in conjunction with halides, not required with caustic)*	☐	☐	☒	☐	
In conclusion, not susceptible.						
ECSCC-1	*Austenitic stainless steel, and*	☐	☒	☐	☐	
ECSCC-2	*Operating temperature >150°F (65°C), and*	☐	☐	☒	☐	
ECSCC-3	*An outside piping surface is within five diameters of a probable leak path (for example, valve stems) and is covered with nonmetallic insulation that is not in compliance with RG 1.36, or*	☐	☐	☒	☐	
ECSCC-4	*An outside piping surface is exposed to wetting from concentrated chloride bearing environments (for example, sea water, brackish water, brine)*	☐	☐	☒	☐	
In conclusion, not susceptible.						
PWSCC-1	*Evaluated in accordance with the owner's existing PWSCC inspection program and, as applicable, the requirements endorsed by the regulatory authority having jurisdiction at the plant site (for example, 10CFR50.55a(g)(6)(ii)(F) dated June 21, 2011)*	☐	☐	☐	☒	DM applicable to PWRs only
In conclusion, not susceptible.						
MIC-1	*Operating temperature <150°F (65°C), and*	☐	☒	☐	☐	
MIC-2	*Low or intermittent flow, and*	☐	☐	☒	☐	
MIC-3	*pH <10, and*	☐	☐	☒	☐	
MIC-4-1	*Presence/intrusion of organic material (for example, raw water system), or*	☐	☐	☒	☐	
MIC-4-2	*Water source is not treated with biocides (for example, refueling water tank)*	☐	☐	☒	☐	
In conclusion, not susceptible.						
PIT-1	*Potential exists for low flow, and*	☒	☐	☐	☐	Only near relief valves
PIT-2	*Oxygen or oxidizing species are present, and*	☐	☐	☒	☐	
PIT-3	*Initiating contaminants (for example, fluoride, chloride) are present*	☐	☒	☐	☐	Chemistry control
In conclusion, not susceptible.						

Degradation Mechanism Assessment Worksheet						
No.	***Attributes to be Considered***	***Yes***	***No***	***N/C***	***N/A***	***Remarks***
CC-1	*Crevice condition exists (for example, thermal sleeves), and*	☐	☒	☐	☐	
CC-2	*Operating temperature >150°F (65°C), and*	☐	☐	☒	☐	
CC-3	*Oxygen or oxidizing species are present*	☐	☐	☒	☐	
In conclusion, not susceptible.						
E-C-1	*Existence of cavitation source (that is, throttling of pressure reducing valves or orifices), and*	☐	☐	☒	☐	CIVs?
E-C-2	*Operating temperature <250°F (120°C), and*	☐	☒	☐	☐	
E-C-3	*Flow present >100 h /yr, and*	☐	☐	☒	☐	
E-C-4	*Velocity >30 ft/s (9.1 m/s), and*	☐	☐	☒	☐	
E-C-5	$(P_d - P_v) / \Delta P < 5$ *where* P_d *= static pressure downstream of the cavitation source,* P_v *= vapor pressure, and* ΔP *= pressure difference across the cavitation source*	☐	☐	☒	☐	
In conclusion, not susceptible.						
FAC-1	*Evaluated in accordance with the owner's existing plant FAC inspection program*	☐	☒	☐	☐	The cross-around piping is within the FAC program, but the expected wear rate is very low and, therefore, wall thickness exams (for example, ultrasonic testing) are not necessary.
In conclusion, not susceptible.						

B TIMELINE FOR THE APPLICATION OF RISK TECHNOLOGY TO THE PRESSURE BOUNDARY

The following is a risk-informed pressure boundary timeline:

1991	American Society of Mechanical Engineers, "Risk-Based Inspection—Development of Guidelines, Volume 1, General Document," CRTD-Vol. 20-1, ASME Research Task Force on Risk-Based Inspection Guidelines, Washington, D.C.
1996	American Society of Mechanical Engineers, Case N-560, Alternative Examination Requirements for Class 1, B-J Piping Welds, Section XI, Division 1, August 9, 1996.
1997	American Society of Mechanical Engineers, Case N-578, Risk Informed Requirements for Class 1, 2, and 3 Piping, Method B, Section XI, Division 1, September 2, 1997.
1997	Letter, dated September 30, 1997, D. C. Mims (Entergy Operations, Inc.) to Document Control Desk (NRC), containing results of pilot plant study for risk-informed ISI program, letter submitting eight system evaluations, dated Sept 30, 1997 (ADAMS Accession No. ML20217E899).
1998	Letter, dated March 31, 1998, D. C. Mims (Entergy Operations, Inc.) to Document Control Desk (NRC), requesting approval of a risk-informed alternative for examination of piping systems, letter submitting service water system evaluation dated March 31, 1998 (cover letter is at ADAMS Accession No. ML20217N833).
1998	VY Safety Evaluation, Request to Use Code Case N560 as an Alternative to the Requirements of ASME Code Section XI Table IWB-2500-1 at Vermont Yankee Nuclear Power Station—Issuance of Amendment (TAC No. 269 RE: M999389), dated November 9, 1998 (cover letter is at ADAMS Accession No. ML20195C403; the enclosed Safety Evaluation is ML20195C416) **Includes RAIs and responses**.
1998	ANO-2 Safety Evaluation, Request to Use a Risk-Informed Alternative to the Requirements of ASME Code Section XI, Table IWX-2500 at Arkansas Nuclear One, Unit No. 2 (TAC NO. M99756) ANO-2 SE dated December 29, 1998 (cover letter at ML20198M762 and enclosed SE at ML20198M784) **Includes RAIs and responses**.
1998	American Society of Mechanical Engineers, "Risk-Based Inspection—Development of Guidelines, Volume 2-Part 1 and Volume 2-Part 2, Light Water Reactor (LWR) Nuclear Power Plant Components," CRTD-Vol. 20-2 and 20-4, ASME Research Task Force on Risk-Based Inspection Guidelines, Washington, D.C. (searched—cannot locate in ADAMS).
1999	Advisory Committee on Reactor Safeguards (ACRS) Letter dated September 15, 1999, Dana Powers (Chairman, ACRS), to Dr. William Travers (USNRC), "Safety Evaluation Report Related to Electric Power Research Institute Risk-Informed Methods to Inservice Inspection of Piping" (ADAMS Accession No. ML992650028) **ACRS meetings May 1999 and September 1999**.
1999	Safety evaluation on TR-112657 dated October 28, 1999 (Cover letter at ML993190460 and Safety evaluation at ML993190474).

1999 EPRI T TR-112657 Revision B-A, *Revised Risk-Informed Inservice Inspection Evaluation Procedure*, dated December 1999. (The “A” version of the Topical Report was transmitted to the NRC by letter dated 2/10/2000; ADAMS Accession No. ML013470102) **Includes RAIs and responses**.

2002 NRC Safety Evaluation on EPRI report 1006937, *Extension of the EPRI Risk-Informed Inservice Inspection (RI-ISI) Methodology to Break Exclusion Region (BER) Programs*, June 27, 2002.

2002 American Society of Mechanical Engineers, Case N-660, Risk-Informed Safety Classification for use in Risk-informed Repair/Replacement Activities, Section XI, Division 1, July 23, 2002.

2004 Report on the Regulatory Experience of Risk-Informed Inservice Inspection of Nuclear Power Plant Components and Common Views, Prepared by the Nuclear Regulators Working Group, Task Force on Risk-Informed Inservice Inspection, dated August 2004 (report is easily retrievable with Internet search but not located in ADAMS).

2005 European Framework Document for Risk-Informed In-Service Inspection, European Network on Inspection and Qualification (ENIQ), Task Group Risk (TGR). (could not find in Internet search or ADAMS but did find full citation: “Chapman O J V, Gandossi L, Mengolini A, Simola K, Eyre T, and Walker A E (Eds.), “European framework document for risk informed in-service inspection,” ENIQ Report No. 23, JRC-Petten, EUR 21581/EN, 2005.”

2005 ASME Code Case N660 approved in Regulatory Guide 1.147, Revision 14, for RI-categorizing pressure boundary components, dated August 2002.

2006 American Society of Mechanical Engineers, Case N-716, Alternative Piping Classification and Examination Requirements, Section XI, Division 1, April 19, 2006.

2007 Request for Alternative ANO2-R&R-004, Revision 1 Request to Use Risk-Informed Safety Classification and Treatment for Repair/Replacement Activities in Class 2 and 3 Moderate Energy Systems, dated April 17, 2007 (ADAMS Accession No. ML071150108).

2007 Request for Alternative ANO2-R&R-004, Revision 1 Response to NRC Request for Additional Information, dated August 6, 2007 (ADAMS Accession No. ML072220160).

2009 Arkansas Nuclear One, Unit 2—Approval of Request for Alternative ANO2-R&R-004, Revision 1, Request to use Risk-Informed Safety Classification and Treatment for Repair/Replacement Activities in Class 2 and 3 Moderate and High Energy Systems (TAC NO. MD5250), dated April 22, 2009 (ADAMS Accession No. ML090930246).

2010 EC-JRC/OECD-NEA Benchmark Study on Risk-Informed Inservice Inspection Methodologies (RISMET), CSNI Integrity and Ageing Working Group (IAGE) dated November 2010.

2010 Using the EPRI Risk-Informed ISI Methodology on Piping Systems in Forsmark 3, 2010:42, Swedish Radiation Safety Authority, SSM, dated December, 2010 (easily found with Internet search but not located in ADAMS).

2011 COG Risk-Informed In-service Inspection Pilot Study, COG-JP-4369-001, dated July 2011.

2012 Vogtle Electric Generating Plant Pilot 10CFR50.69 License Amendment to Adopt 10CFR50.69, Risk-Request, dated August 31, 2012 (ADAMS Accession No. ML12248A035).

2013 American Society of Mechanical Engineers, Case N-716-1, Alternative Piping Classification and Examination Requirements, Section XI, Division 1, January 27, 2013.

2014 Risk-Informed In-Service Inspection (RI-ISI) Methodology for CANDU Conventional Systems and Components, COG JP-4425, dated March 2014.

2014 ASME Code Case N716-1 approved in Regulatory Guide 1.147, Revision 17, dated August 2014.

2014 Vogtle Electric Generating Plant, Units 1 and 2—Issuance of Amendments Re: Use of 10 CFR 50.69 (TAC NOS. ME9472 AND ME9473), dated December 17, 2014 (ADAMS Accession No. ML14237A034).

2015 Periodic Inspection of CANDU nuclear power plant balance-of-plant systems and components, Canadian Standards Association, CSA N285.7-15, dated November 2015.

2018 *10 CFR 50.69 Categorization Guidance Document*. EPRI, Palo Alto, CA: 2018. 3002012984.

2019 ENIQ Framework Document for Risk-Informed In-Service Inspection, Issue 2, ENIQ Report No. 51, NUGENIA Technical Area 8, dated March 2019 (easily retrievable with Internet search).

2019 American Society of Mechanical Engineers, Case N-752, Risk-Informed Categorization and Treatment for Risk-informed Repair/Replacement Activities in Class 2 and 3 Systems, Section XI, Division 1, July 23, 2019.

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