Managing Systems Integrity of Terminal and Tank Facilities

Managing the Risk of Liquid Petroleum Releases

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FOREWORD

This publication provides an overall approach for risk management, including the principles of risk management and an approach to risk assessment. It presents an industry approach to the management practices necessary to implement the principles of risk management and risk assessment for terminal and tank operations. In addition, it illustrates a method for selecting environmental protection control measures from liquid releases based upon the control measures hierarchy presented in API Publication *340, Liquid Release Prevention and Detection Measures for Aboveground Storage Facilities.*

Although this document is intended for petroleum terminal and tank facilities associated with marketing, pipeline, and other facilities covered by API Standard 2610, *Design, Construction, Inspection and Maintenance of Petroleum Terminal and Tank Facilities*, and was developed to guide the management of terminal and tank facilities in evaluating cost-effective methods for protecting the environment, workers, and the public, it can be used in many ways, including the development of an overall corporate integrity/risk management program for terminal and tank facilities. Other potential uses include:

- Development of a corporate risk assessment methodology or utilization of the risk assessment methodology presented in the appendices of this document
- Motivation to consider modification of inspection intervals from those stipulated in API Std 653, *Tank Inspection, Repair, Alteration and Reconstruction,* and API Std 570, *Piping Inspection Code: Inspection, Repair, Alteration and Re-rating of In-Service Piping Systems*
- Provision of a risk-based approach to screen, evaluate, and if appropriate, select control measures that may prevent, detect, or protect the environment from liquid releases of petroleum
- Provision of an API-endorsed, consistent, and repeatable approach to risk management of terminal facilities
- Provision of a tool for negotiating with regulators in regards to implementation of proscriptive control measures that may not provide cost-effective control of terminal risks

The approaches detailed in this document are not mandatory; they are intended as a guide for those desiring to implement and/or use a risk assessment. Typically, a risk assessment is performed when a facility is changing equipment or processes. The appendices of this document present optional methods for conducting a risk assessment if a facility decides to do so. Other methods are available outside the scope of this document, or a company can decide to create its own method. API does not intend to imply sole endorsement of any particular method or that a risk assessment is required in all cases. The optional methods presented in this document are for demonstration purposes.

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SECTION 1—INTRODUCTION

An overall effective Risk Management Program (RMP) consists of several core elements which involve responsible management oversight, inclusion of site and corporate staff and an organized approach for determining and evaluating risks specific to the facility of operation. A typical RMP exhibits the following characteristics:

- Guided by a defined management philosophy
- Is planned, prepared and structured in an organized program which is repeatable through out the organization
- Is pertinent to the operations performed at the facility
- Includes a realistic and comprehensive evaluation of the facility risks
- Is capable of being performed in a reasonable time frame with a reasonable level of resources
- Is based on existing information, practices and technology but is capable of adapting to future improvements in this information, practices or technology
- Is capable of being economically implemented relative to the risks evaluated including the screening of mitigation measures
- Publicized within the organization

This document is intended to provide users with such an approach to managing and assessing risks specific to aboveground petroleum storage tank facilities. Furthermore, it can be used as part of an overall management program that will provide a consistent approach to:

- Identifying specific terminal risks
- Evaluating the potential consequences of those risks
- Evaluating the overall risk of a facility, a specific asset, or group of assets
- Evaluating comparative risks of facilities, individual assets, or group of assets

This document is not intended to define the absolute requirements of a risk management program for a company or to prescribe a specific approach to risk assessment or risk management. It also does not define a specific risk tolerance or mandate the mitigation measures for specific risks.

The information contained within this document can be further utilized in conjunction with API Publ 340, *Liquid Release Prevention and Detection Measures for Aboveground Storage Facilities*, to screen available control technologies that may mitigate risks (i.e., the frequency of occurrence and/or consequences) if deemed by management to be of value.

Ultimately, it is the corporation that typically defines, develops, and implements an RMP that follows its guiding corporate principles and details its specific tolerance for certain risks. The definition of risk tolerance, the level of acceptable risks, and the consequences of those risks will vary from organization to organization based on corporate philosophy, economic constraints, asset criticality, health and safety issues, environmental sensitivity, environmental awareness, regulatory drivers, public relations, corporate reputation, asset desired reliability, return on investment goals, market conditions, long-term asset viability, financial strength, and other principles defined by corporate management. These different risk tolerance drivers and corporate values will affect the focus and emphasis of the overall RMP and will affect the development of the risk assessment program that will in turn further affect the results of the risk assessment model. For example, a company whose primary corporate principle focuses on equipment reliability may elect to assign a higher risk assessment ranking (priority) to higher frequency events that affect equipment reliability even though the event has a low consequence when it occurs. Conversely, a company whose primary guiding principle is protection of the environment and which has a facility located in an ecologically sensitive area, may elect to mitigate very low-frequency events with potentially high consequences (e.g., a company with a facility located over a sole source aquifer may elect to provide added tank bottom integrity even though the overall risk is lower than other risks). Thus, corporate philosophy will not only affect the RMP, risk assessment methodology, and risk ranking, but it will also affect the approach to mitigation of risks.

1.1 PURPOSE AND OBJECTIVES

A risk management system (RMS) at liquid petroleum storage facilities provides the means to reduce the risks to the environment, population, and business from potential liquid releases. This is accomplished by implementing an overall facility program designed to establish procedures to identify, analyze, mitigate, and manage the inherent risks in operating a petroleum storage facility. This involves developing a management program and procedures to reduce the likelihood of failure (LOF) and/or the consequences of failure (COF) from a specific piece of equipment (e.g., tank, piping, loading area) or from a specific operation at a specific facility, such as a tank truck overfill. The purpose of this document is to provide:

- The basic elements for developing and implementing an RMS for aboveground liquid petroleum storage tank facilities
- A structured approach to risk assessment
- An organized methodology for the user to assess and evaluate risks between similar components (e.g., tank vs. tank risk), dissimilar components (e.g., tank overfill protection vs. diked area liners), and facility-to-facility risks
- Guidance on ranking and prioritization of risks
- Guidance on evaluating and selecting mitigation measures, such as those presented in API Publ 340

This document cites a number of references. The API references listed in Section 3 will aid the user in the development of an RMP. The other references cited in Section 3 were mentioned in this document or aided in the development of the publication, but they are not necessary for the development of an RMP.

1.2 SCOPE

Although the risk management principles and concepts in this document are universally applicable, this publication is specifically targeted at integrity management of aboveground liquid petroleum storage facilities. The applicable petroleum terminal and tank facilities covered in this document are associated with distribution, transportation, and refining facilities as described in API Std 2610 and API Publ 340.

This document covers the issues of overall risk management, risk assessment, risk ranking, risk mitigation, and the performance measures applicable to an overall integrity management program. The appendices include two possible methodologies for conducting a risk assessment and a workbook that can be used to perform the risk assessment method outlined in Appendix A. **It is important to note that it is not always necessary to perform a risk assessment. Typically, a risk assessment is performed if changes are being made to the facility. If a facility chooses to perform a risk assessment, it can use multiple methods. The appendices of this document present two available methodologies. If a facility decides to perform a risk assessment, it may elect to use one of these methods or a method obtained from a different source. The facility also may elect to develop its own risk assessment methodology. API does not intend to imply sole endorsement of any particular method used, and the ones presented in this document are for demonstration purposes only.**

The values stated for this document are in U.S. customary units with the International System of Units (SI) provided in parentheses.

1.3 TARGET AUDIENCE

The primary audience for this publication is corporate managers, who are responsible for the overall development of an RMP for their facilities, and the facility operators and engineering personnel who are primarily responsible for the mechanical integrity and operability of equipment, design or re-design of new and existing equipment, and the environmental conditions within which the facility operates (e.g., soil types, depth to groundwater, distance to sensitive ecological receptors, cost of remediation). The optional comprehensive analysis detailed in the appendices of this document requires that ONLY experienced personnel familiar with the facility and experienced in terminal facility design, operation, maintenance, and inspection be involved in the performance of analysis. The comprehensive nature of this document may require that the analysis be performed by teams of personnel from areas such as engineering, environmental, and operations. Others who are involved with terminals can benefit from the methodology, information, and approaches detailed in this document; however, they typically do not perform the risk assessment analysis detailed in the appendices without the proper training and experience.

1.3.1 How to Use This Document

Users can benefit from this document in several ways. First, it gives readers a brief overview of a basic RMP that they can use to develop their own corporate program. This is the first step in establishing an RMS. Second, users can develop their own risk assessment method, or they can use part, or all, of the optional risk assessment approaches detailed in the attached appendices. Third, users can develop a relative ranking of risks for various items, and using the guidance provided in this document, establish a risk-ranking matrix that helps them identify risks that may require remediation. Fourth, the user can use the approach detailed in the optional appendices to screen potential mitigation measures that are presented in API Publ 340. Last, users are provided a workbook, forms, checklists, and worked examples to aid in implementing their program. From these examples, the user can see the potential benefits in building a comprehensive Risk Assessment Program which meets the overall objectives of minimizing and mitigating the effects of liquid releases on the environment. Figure 1-1 illustrates the different approaches for using the document.

The framework for using this document, outlined in Figure 1-2, is a step-by-step process that allows users to customize a program to fit their individual needs. It includes the following steps:

Step 1—Users develop an overall company RMP that includes the program elements presented in Sections 4 and 5.

Step 2—Users determine if they want to perform a risk assessment as part of their overall RMP. There are varying types and complexities of risk assessments as outlined in section 5.2.2 and Section 6. Users may also elect to use one of the optional risk assessment approaches outlined in this document. This publication's optional risk assessment approach is briefly discussed in section 6.7, with detailed information and a workbook presented in the appendices.

Step 3—Users gather the appropriate facility information and data needed to develop an RMP and perform a risk assessment (if the user elects to perform a risk assessment), described in Sections 6 and 7.

Step 4—Performing the risk assessment requires determining the frequency or likelihood that a specific event will occur and the consequences if the event does occur (section 4.1).

Step 5—Once the risks are quantified by determining the likelihood and consequence, they can be ranked and evaluated (Section 4.2 and 8).

Step 6—Owners can determine, based upon their corporate principles, what risks, if any, require mitigation. This is discussed in Sections 5.2.3, 8, and 10.

Step 7—Mitigation measures are selected or screened for selection, and their effects on risk reduction are examined (Section 8).

Step 8—The likelihood and consequences of an event for each mitigation measure selected are recalculated. This allows the owner to select a mitigation measure based upon the owner-specified risk reduction goals, such as cost-benefit analysis (section 4.2.3).

Step 9—Once the previous step is complete, users can perform any necessary updates to the RMP (e.g., updating procedures or training).

Step 10—Finally, owners can monitor the management of change to the facility, equipment, procedures, process, etc., and perform periodic program audits to insure that the program is up-to-date, effective, and achieving owner-established performance measures (Sections 9, 10, and 11).

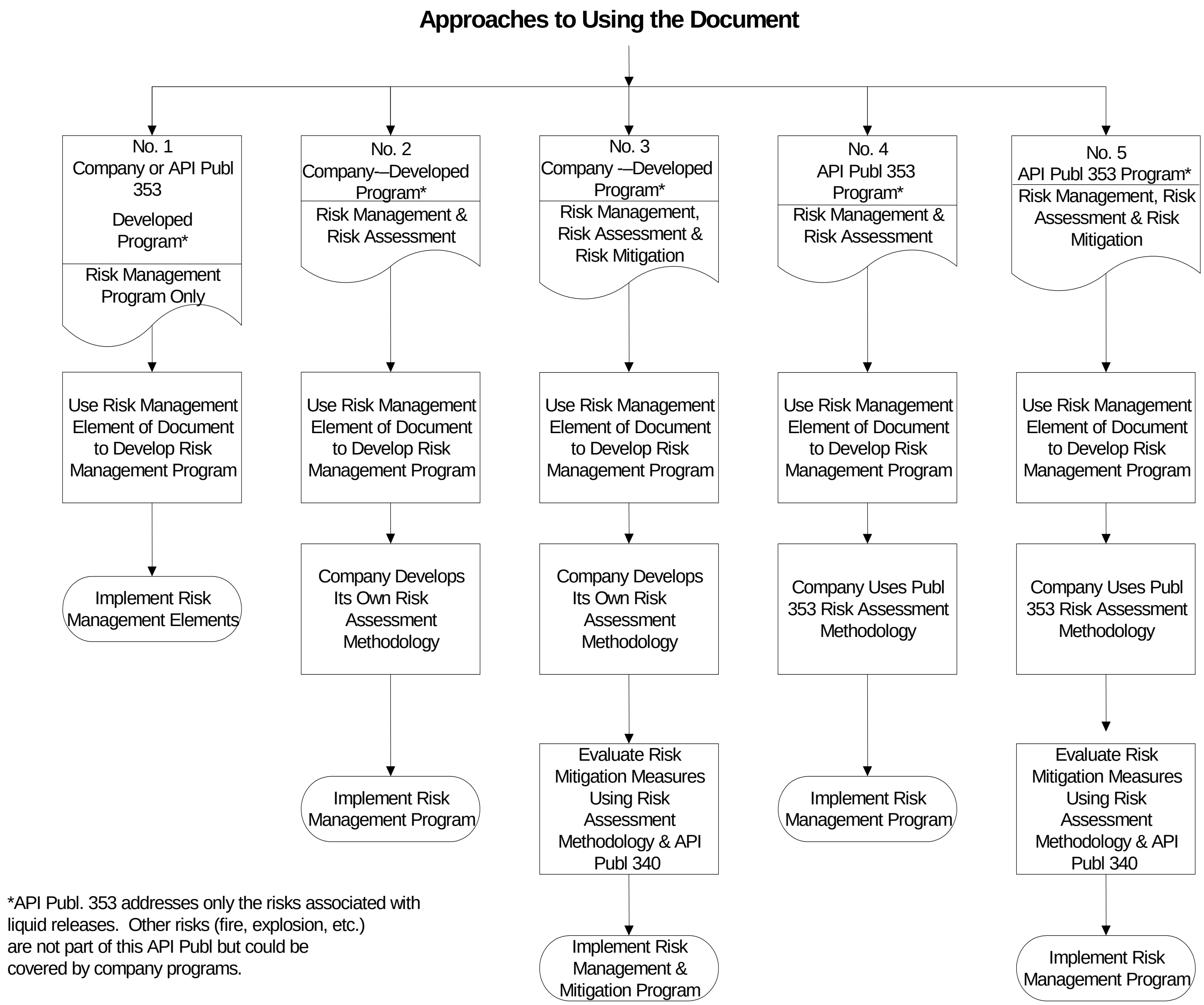

Figure 1-1: Approaches to Using the Document

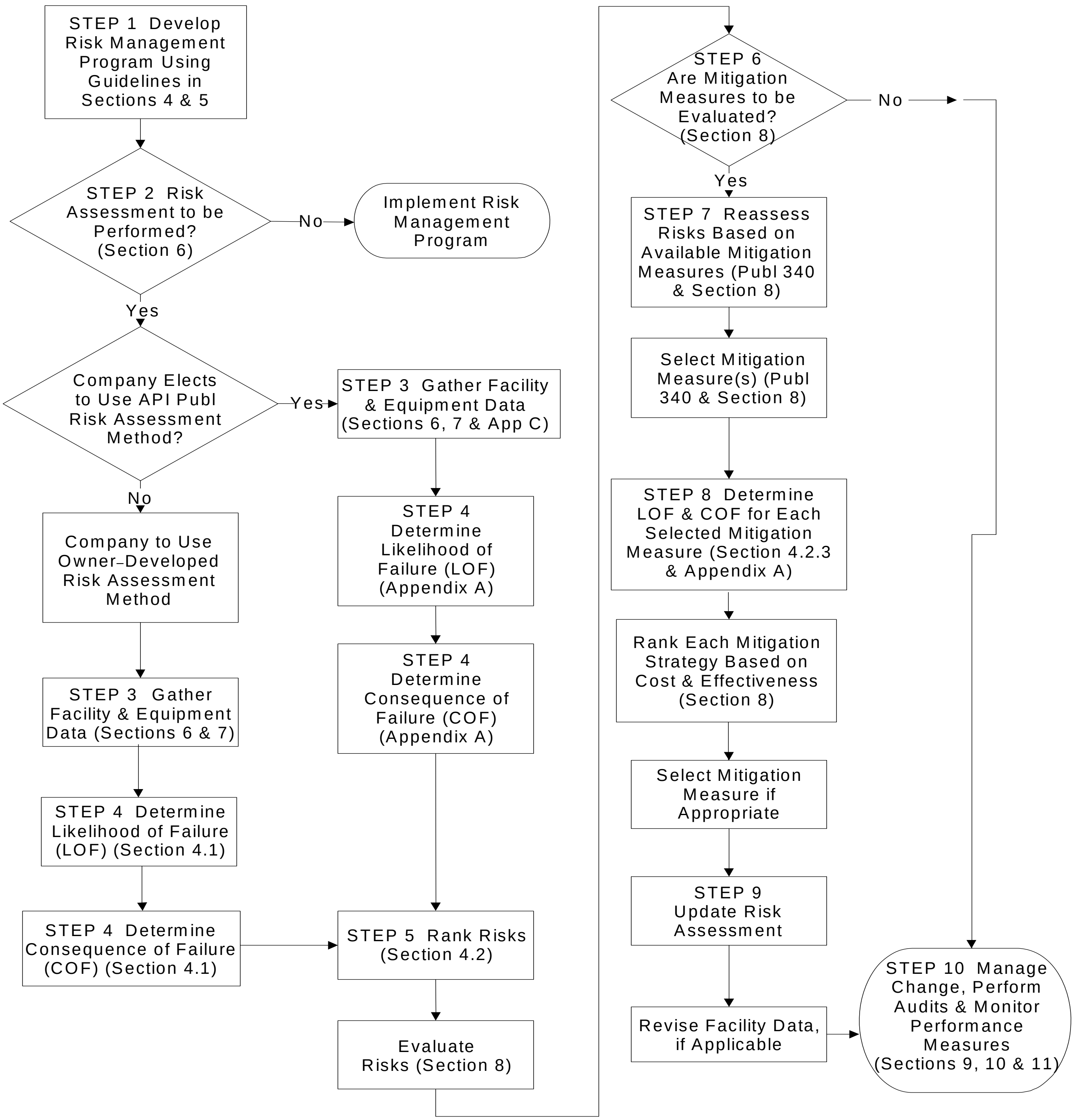

Figure 1-2: Framework for Using This API Publication

1.3.2 Roles and Responsibilities

Generally, one individual does not possess the background in all elements necessary to single-handedly conduct the analysis. Typically, a team of people with the requisite experience of the specific facility, the surrounding environment, the individual equipment, and the methodology presented in this document are essential to implementing the assessment. The required individuals or team members suggested in API RP 580 are listed below.

- *Team Leader*—This person is very familiar with terminal facilities and assembles the qualified individuals for the team. The team leader should be knowledgeable about the approach detailed in this document.
- *Risk Assessment Personnel*—This person(s) is responsible for assembling all of the data and carrying out the risk-based assessment including defining data required from other team members, defining the accuracy levels of the required data, verifying the quality of the data, completing workbook forms and calculating the LOF and the COF, summarizing the data, and recalculating the LOF and COF based on selected mitigation measures. They also may calculate the risk/benefit analysis of proposed mitigation measures.
- *Local Facility Operations Personnel*—These individuals are facility staff familiar with specific facility equipment, configuration, and inspection data. Operations and maintenance personnel are the persons responsible for providing data on occurrences when operations deviate from the limits of the process-operating envelope. They are also responsible for verifying that equipment repairs/replacements/additions have been included in the equipment condition data supplied by the equipment inspector. Operations and maintenance personnel are responsible for implementing recommendations that pertain to process or equipment modifications and monitoring.
- *Engineering Personnel*—These team members are company or contract staff who are familiar with terminal and tank facilities, including the applicable codes, standards, corrosion/degradation mechanisms, inspection requirements associated with tanks, piping, high-level alarms, containment, leak rates, risks, and LOF and COF. The facility engineer is responsible for providing the basis of design information, the as-built conditions, and the design operating conditions information. This information generally will be in the form of record drawing information, process flow diagrams, piping and instrumentation diagrams (P&IDs), equipment data sheets, etc. The engineer can evaluate/recommend methods of risk mitigation (likelihood or consequence) through changes in process conditions.
- *Environmental and Safety Personnel*—These are company or contract staff who are familiar with the local conditions including soil type, depth to groundwater, distance to and type of sensitive ecological receptors, regulatory requirements, etc. They can also recommend and assess mitigation measures on the COF. Environmental and safety personnel are responsible for providing data on the cost of the facility/equipment being analyzed and the financial impact of the shutdown of pieces of equipment or the facility. They also can recommend methods for mitigating the financial consequences of failure.
- *Inspection Personnel*—The equipment inspector or inspection specialist is generally responsible for gathering data on the condition and history of equipment in the risk assessment study. Generally, this information will be located in equipment, inspection, and maintenance files. If condition data are unavailable, the inspector/specialist, in conjunction with the materials and corrosion engineering or technical specialists, can provide predictions of the current condition. The inspector, along with company or contract engineers, is responsible for assessing the effectiveness of past inspections. The equipment inspector is typically responsible for implementing any recommended inspection plan derived from the risk assessment study.

- *Management*—These are the representatives of the company who set the management drivers and goals by which the RMP is established. Management's role is to provide sponsorship and resources (personnel and funding) for development of the RMP and performance of the risk assessment studies. They are responsible for making decisions on risk management or providing the framework/mechanism for others to make these decisions based on the results of the risk assessment studies. Finally, management is responsible for providing the resources and follow-up system to implement the risk mitigation decisions.
- *Financial/Business Personnel*—These individuals are the representatives of the company who provide financial input on the cost of money, money constraints, and some of the drivers to be utilized as part of the decision-making behind risk mitigation.

1.3.3 Training and Qualifications

The team leader and risk assessment personnel typically have a thorough understanding of risk analysis either through training, education, or experience. Moreover, they have usually received detailed training in the methodologies and procedures presented in this publication, including how data input and data assumptions may affect the final results. At facilities where internal risk assessment personnel conduct the analysis, management can have a procedure to document that personnel are sufficiently trained and qualified in the methodologies and procedures detailed in this document. Outside contractors or consultants who provide risk assessment services typically have a documented program of training qualified and experienced individuals in the methodologies presented in this publication. Individuals who are not experienced in the terminal facilities covered by this document are typically limited to completion of forms, inputting of data, and performance of calculations.

1.3.4 Governmental Requirements

This document is not intended to be utilized as a substitute for the requirements or reviews required by applicable federal, state, or local requirements. These requirements may include but are not limited to requirements for proscriptive inspection requirements and requirements for mandated engineered control measures.

This document could be utilized as a tool for negotiations with regulators to:

- Show the risk drivers and consequences of failure at regulated facilities
- Illustrate that control or mitigation measures are available that are as effective or more effective than proposed or mandated government requirements or serve as a means to demonstrate compliance with government regulations by utilization of the principles of risk management
- Illustrate that proscriptive inspection or control measures may not provide a reasonable benefit to environmental protection

1.4 Applicable Facilities

The petroleum industry is engaged in the manufacture, storage, transportation, blending, and distribution of crude oil and refined petroleum products. Individual terminal facilities and plants may perform one or more of these functions. This document is applicable to a range of liquid petroleum storage facilities from small distribution facilities (e.g., bulk plants) to large storage and distribution facilities (e.g., pipeline and marine terminals and wholesale plants). The specific application of this document is to those types of operations discussed below.

1.4.1 Petroleum Terminals

Petroleum terminals may include tank farms, loading and unloading areas, pipeline manifolds, storage areas, warehouses, docks, garages, laboratories, and office buildings. Products at these terminals are received and distributed by pipeline, marine transport, rail, or truck. Bulk quantities of refined products are stored in aboveground tanks for distribution in smaller quantities to industrial and commercial customers, and to retail and wholesale marketing facilities. Petroleum terminals may also store petroleum products in consumer packaging, bulk containers, or inside tanks and drums.

1.4.2 Pipeline Tankage Facilities

Pipeline tankage facilities consist of tanks and tank farms used to receive petroleum products (e.g., crude oil and refined products) from pipelines, trucks, railcars, or marine facilities and to provide surge relief from pipeline operations (see Title 49 Code of Federal Regulations (CFR), Part 195 and 33 CFR Parts 154 and 156).

1.4.3 Bulk Plants

Although bulk plants typically handle smaller quantities of product, operations and facilities at these plants are similar to those at petroleum terminals. Bulk plants typically receive and distribute product by truck, although some are serviced by rail, marine transport, or pipeline. Bulk plants may also store an inventory of petroleum products in consumer packaging, bulk containers, and inside tanks and drums.

1.4.4 Lube Blending and Packaging Facilities

Lube oil blending and packaging facilities blend refined base stock products with additives and then package the finished products in drums, pails, portable tanks, or consumer-size containers or ship to consumers in bulk. The additives and lube base stocks may be received and stored either in bulk or in containers. Lube blending and packaging facilities typically include warehouses, blending and packaging areas, quality control labs, base stock and additive storage areas, shipping and receiving areas, and office buildings.

1.4.5 Asphalt Facilities

Asphalt plants receive asphalt from petroleum refineries and blend it with additives to produce paving, roofing, and industrial-grade asphalt products. Asphalt facilities typically consist of a laboratory for quality control, a rail siding or marine dock, an aboveground tank farm, a warehouse, one or more unloading areas for raw materials and products, a manufacturing area, a package heating system, a truck scale, a loading rack, and an office.

1.4.6 Aviation Service Facilities

Aviation service facilities store light petroleum fuels in aboveground or underground storage tanks. Services provided may include the following: refueling, defueling, de-icing, washing, maintenance, and repair of aircraft. Aircraft fuel may be loaded into refueling trucks that service the aircraft or dispensed directly into aircraft from a fixed dispenser system or hydrant system cart.

1.4.7 Overlapping Facilities Coverage

This document may have overlapping applicability to facilities covered by API Standard 1160 (pipelines) and those covered by API RP 580 (refinery equipment).

Where overlapping coverage exists, users can select the most appropriate API document as their primary resource, but may also adopt elements from the other documents as part of their program. For example, a refinery would use API RP 580 as its primary reference document for risk-based inspection, but it could use the RMP elements described in the main text of this document to formulate its overall facility risk management program. Likewise, pipeline facilities covered under API Std 1160 would use that document as their primary reference document but could also use the tank risk assessment methodologies presented in the appendices of this document.

1.4.8 Non-applicable Facilities

The RMP features presented in this document can be utilized at a wide array of facilities other than those identified above. However, regulatory requirements may mandate specific programs, such as the Occupational Safety and Health Administration's (OSHA's) Process Safety Management or the Environmental Protection Agency's (EPA's) Risk Management Plan. The optional risk assessment methodologies presented in the appendices to this document were not intended to apply to the following installations:

- Retail facilities, such as service stations, garages, and automotive lubrication facilities
- Tanks that are part of oil and gas production or storage, natural gas processing plants, or offshore operations
- LNG facilities
- Facilities with primary storage of liquid petroleum in underground tanks
- Agriculture

SECTION 2—TERMS, DEFINITIONS, AND ACRONYMS

This section presents the terms, definitions, and acronyms used as part of the risk vocabulary including some terminal and tank definitions.

2.1 Terms and Definitions

For the purposes of this publication, the following definitions apply:

aboveground storage tank (AST): Atmospheric vertical, cylindrical, closed-top, open-top, or covered open-top steel aboveground storage containers of various sizes and capacities whose entire bottom is supported uniformly on the ground. An AST may also be a horizontal cylindrical container on saddles or other supports.

absolute risk: An ideal and accurate description and quantification of risk.

berm: The annular raised area around the tank, inside the dike, normally used for access to the tank and the equipment surrounding it.

combustible liquid: A liquid having a flash point at or above 100°F (37.8°C). (See NFPA 30 for discussion of combustible liquid classification.)

consequence: Outcome from an event. There may be one or more consequences from an event and they may range from positive to negative; however, consequences are always negative for safety aspects. Consequences may be expressed qualitatively or quantitatively.

deterioration: The reduction in the ability of a component to provide its intended purpose of containment of fluids. This can be caused by various deterioration mechanisms (e.g., thinning, cracking, mechanical). Damage or degradation may be used in place of deterioration.

event: Occurrence of a particular set of circumstances. The event may be certain or uncertain. The event can be singular or multiple. The likelihood associated with the event can be estimated for a given period of time.

external event: Events resulting from forces of nature, acts of God or sabotage, or such events as neighboring fires or explosions, neighboring hazardous material releases, electrical power failures, tornados, earthquakes, and intrusions of external transportation vehicles, such as aircraft, ships, trains, trucks, or automobiles. External events are usually beyond the direct or indirect control of persons employed at or by the facility.

facility: Any building, structure, installation, equipment, pipeline, or other physical feature used in petroleum refining, storage, transportation, and distribution. The boundaries of a facility may depend on several site-specific factors, including but not limited to, the ownership or operation of buildings, structures, and equipment on the same site, and the types of activity at the site.

failure: Termination of the ability of a system, structure, or component to perform its required function of containment of fluid (i.e., loss of containment). Failures may be unannounced and undetected until the next inspection (unannounced failure), or they may be announced and detected by any number of methods at the instance of occurrence (announced failure).

failure mode: The manner of failure. For risk-based assessment, the failure of concern is loss of product outside of the primary containment. Examples of failure modes are a through hole, crack, rupture, overfill, flange leak, etc.

flammable liquid: A liquid having a flash point below 100°F (37.8°C) and having a vapor pressure not exceeding 40 pounds per square inch (absolute) (2069 mm Hg) at 100°F (37.8°C). This is also classified as Class I liquid (see NFPA 30 for additional definitions and subclassifications).

hazard: A physical condition or a release of a hazardous material that could result from component failure and result in human injury or death, loss or damage, or environmental degradation. Hazard is the source of harm. Components that are used to transport, store, or process a hazardous material can be a source of hazard. Human error and external events may also create a hazard.

hazard and operability (HAZOP) study: A HAZOP study is a form of failure modes and effects analysis. HAZOP studies, which were originally developed for the process industry, use systematic techniques to identify hazards and operability issues throughout an entire facility. The study is particularly useful in identifying unforeseen hazards designed into facilities due to lack of information, or introduced into existing facilities due to changes in process conditions or operating procedures. The basic objectives of the techniques are to:

- produce a full description of the facility or process, including the intended design conditions
- systematically review every part of the facility or process to discover how deviations from the intention of the design can occur
- decide whether these deviations can lead to hazards or operability issues
- assess the effectiveness of safeguards

installations: Tanks, pumps, compressors, accessories, controls, piping, and all other associated equipment required for the receipt, transfer, storage, blending, packaging, and shipment of petroleum products.

integrity assessment: The process for determining the suitability of the equipment or system to serve its intended purpose without loss of its contained contents outside of the primary containment.

integrity management program: An overall program consisting of identifying potential threats to or from a facility, process, or discrete piece of equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk where appropriate by reducing the likelihood, the consequences, or both; and measuring the risk-reduction results achieved (see definition of *risk management program*).

likelihood: Extent to which an event is likely to occur within the time frame under consideration (see definition of *probability*).

mitigation or mitigative action: Taking appropriate action based on an assessment of risk factors to reduce the risk level and/or the consequence level to a point acceptable to facility management. Such action may consist of, but is not limited to, further testing and evaluation, changes to the physical environment, operational changes, continued monitoring, administrative or procedural changes, repairs, or any of the prevention, detection, or protection measures outlined in API Publ 340.

petroleum: Any crude oil, liquid, or gaseous complex combination of hydrocarbons and related derivatives (natural or manmade) that may be processed from crude oil for fractions, including natural gas, gasoline, naphtha, kerosene, fuel and lubricating oils, paraffin wax, additives, asphalt, and various derivative products.

probability: Extent to which an event is likely to occur within the time frame under consideration. The mathematical definition of probability is “a real number in the scale 0 to 1 attached to a random event.” Probability can be related to a long-run relative frequency of occurrence or to a degree of belief that an event will occur. For a high degree of belief, the probability is near one. Frequency rather than probability may be used in describing risk. Degrees of belief about probability can be chosen as classes or ranks such as “rare/unlikely/moderate/likely/almost certain” or “incredible/improbable/remote/occasional/probable/frequent.”

qualitative risk analysis (assessment): Methods that use engineering judgment and experience as the basis for the analysis of probabilities and consequences of failure. The results of qualitative risk analyses are dependent on the background and expertise of the analysts and the objectives of the analysis. Failure modes, effects, and criticality analysis (FMECA) and HAZOPs are examples of qualitative risk analysis techniques that become quantitative risk analysis methods when consequence and failure probability values are estimated along with the respective descriptive input.

quantitative risk analysis (assessment): An analysis that:

- identifies and delineates the combinations of events that, if they occur, will lead to a severe accident (e.g., major explosion) or any other undesired event
- estimates the frequency of occurrence for each combination
- estimates the consequences

Quantitative risk analysis integrates into a uniform methodology the relevant information about facility design, operating practices, operating history, component reliability, human actions, the physical progression of accidents, and potential environmental and health effects, usually in as realistic a manner as possible.

Quantitative risk analysis uses logic models depicting combinations of events that could result in severe accidents and physical models depicting the progression of accidents and the transport of a hazardous material to the environment. The models are evaluated probabilistically to provide both qualitative and quantitative insights about the level of risk and to identify the design, site, or operational characteristics that are the most important risk. Engineering judgment and experience-based parameters may be part of data gathering or analysis. A quantitative risk analysis may also be used to rank options for relative comparison.

Quantitative risk analysis logic models generally consist of event trees and fault trees. Event trees delineate initiating events and combinations of system successes and failures, while fault trees depict ways in which the system failures represented in the event trees can occur. These models are analyzed to estimate the frequency of each accident sequence.

relative risk: The comparative risk of a facility, process unit, system, equipment item or component to other facilities, process units, systems, equipment items or components, respectively.

release prevention barrier (RPB): The second lined bottom of double steel bottom tanks, synthetic materials, clay liners, and all other barriers or combination of barriers (e.g., a reinforced concrete slab under the full bottom of the tank without a membrane liner) placed in the bottom of or under an aboveground storage tank. The functions of the RPBs are to prevent the escape of contaminated material and contain or channel released material for leak detection. (See non-mandatory Appendix I of API Standard 650.)

release prevention system (RPS): The suite of API standards designed to maintain aboveground storage tank integrity, thus protecting the environment. These standards cover topics such as the frequency of routine external inspections, internal inspections, application of risk-based inspection principles, overfill prevention, lining the bottom of the tank interior, fitting the tank with RPBs, installing cathodic protection, or some combination of these measures depending on the operating environment and service of the tank. (See API Standard 2610.)

risk: A measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

risk analysis: A systematic analytical process to identify and evaluate potential hazards from facility operations (see definition of risk assessment).

risk assessment: A systematic analytical process, in which potential hazards from facility operations are identified, and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes and be performed at varying levels of detail depending on the operator's objectives (see Section 6).

risk management program (RMP): An overall program consisting of identifying potential threats to or from a facility, process, or discrete piece of equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk where appropriate by reducing the likelihood, the consequences, or both; and measuring the risk-reduction results achieved (see definition of integrity management program).

semi-quantitative risk analysis (assessment): An analysis that utilizes a combination of the two methods—the qualitative risk analysis method and the quantitative risk analysis method.

system: the facility's equipment and infrastructure whose intended purpose is to contain, transfer, or regulate petroleum product.

2.2 Acronyms

The following acronyms are used throughout this document.

AG:	aboveground
AIChE:	American Institute of Chemical Engineers
API:	American Petroleum Institute
ASME:	American Society of Mechanical Engineers
AST:	aboveground storage tank
CBA:	cost benefit analysis
CCPS:	Center for Chemical Process Safety
COF:	consequences of failure
EPA:	United States Environmental Protection Agency
FMEA:	failure modes and effects analysis
FMECA:	failure modes, effects, and criticality analysis
HAZOP:	hazard and operability study
IMP:	integrity management program (also known as risk management program)
LOF:	likelihood of failure
MOC:	management of change
NACE:	National Association of Corrosion Engineers
NDE:	non-destructive examination
NFPA:	National Fire Prevention Association
O&M:	operations and maintenance
OPA:	Oil Pollution Act
OSHA:	United States Occupational Safety and Health Administration
PHA:	process hazards analysis
P&ID:	piping and instrumentation diagram
Publ:	publication
QA/QC:	quality assurance/quality control
QCP:	quality control program
RBI:	risk-based inspection

RMP:	risk management program (also known as integrity management program)
RMS:	risk management system
ROI:	return on investment
RP:	recommended practice
RPB:	release prevention barrier
RPS:	release prevention system
SI:	International System of Units
SPCC:	spill prevention control and countermeasures plan
Std:	standard
UG:	underground
UT:	ultrasonic testing

SECTION 3—REFERENCES AND STANDARDS

Unless otherwise specified, the most recent editions of the following publications, standards, codes, and specifications should be used. The provisions of these publications are incorporated into this document only as explicitly specified in the text. The following API documents will aid users in the development of their systems integrity program.

API

Publl 340 Liquid Release Prevention and Detection Measures for Aboveground Storage Facilities

Publ 351	Overview of Soil Permeability Test Methods
Std 570	Piping Inspection Code: Inspection, Repair, Alteration, and Re-rating of In-Service Piping Systems
Std 650	Welded Steel Tanks for Oil Storage
RP 651	Cathodic Protection of Aboveground Storage Tanks
RP 652	Lining of Aboveground Petroleum Storage Tank Bottoms
Std 653	Tank Inspection, Repair, Alteration, and Reconstruction
RP 2350	Overfill Protection for Storage tanks in Petroleum Facilities
Std 2610	Design, Construction, Inspection and Maintenance of Petroleum Terminal and Tank Facilities
Publ 4700	Primer for Evaluating Ecological Risk at Petroleum Release Site

NFPA[1]

NFPA 30	Flammable and Combustible Liquids Code Handbook

The following references were used in the development of this document.

API

RP 580	Risk Based Inspection
Publ 581	Base Resource Document on Risk-Based Inspection
Std 1160	Managing System Integrity for Hazardous Liquid Pipelines
Publ 580	Risk Based Inspection Base Resource Document
RP 575	Inspection of Atmospheric and Low Pressure Storage Tanks
RP 572	Inspection of Pressure Vessels

ASME[2]

B31.8S	Managing System Integrity of Gas Pipelines

[1] National Fire Protection Administration (NFPA), 1Batterymarch Park, Quincy, Massachusetts, 02169-7471, www.nfpa.org.
[2]ASME International, Three Park Avenue, New York, NY 10016-5990, www.asme.org.

CCPS[3]

Guidelines for Hazard Evaluation Procedures, 2nd Edition

Greenberg & Cramer. "Risk Assessment & Risk Management for the Chemical Process Industry," Stone & Webster Engineering. VanNostrand Reinhold: New York, NY.

Mikkola, Myers, & Power. Secondary Containment Liners for Tank Farms – A New Approach; "Hydrocarbon Processing." May 2000.

[3] Center for Chemical Process Safety (CCPS) of the AICHE, 345 East 47 Street, New York, NY 10017, www.aiche.org.

SECTION 4—BASIC CONCEPTS OF RISK

In a perfect world, there would be an analytical technique that allowed a terminal owner to forecast exactly how and when a leak could occur. Equipped with this knowledge, the owner would take corrective actions, repairs, or refresher training the day before the leak was predicted and save the facility from the cost of the leak. In a perfect world, the corrections would be made at minimal cost. However, the world is full of uncertainty. The idyllic world described above is unachievable, due to uncertainty in natural processes. There exists an approach, however, that acknowledges the uncertainties in natural processes and uses that information to the best advantage of the decision-maker. That process is risk assessment and risk management. The world is full of hazards. One can never eliminate or sometimes even minimize risks, but the goal of those managing a risky business is usually to keep risks as low as reasonably practicable.

Risk assessment and risk management are strategic processes aimed at reducing either or both the likelihood (probability) and the severity (consequences) of hazardous events. It can be integrated into the decision-making process so that management can maintain risks at an acceptable level while trying to minimize cost. Once risks are understood via the risk assessment and risk management process, they can be better controlled.

4.1 Principles and Philosophy of Risk

The practice of risk management and risk assessment (risk analysis) is something that people perform on a regular basis without even realizing it. Risk management and risk assessment can be as simple as a driver slowing down while driving through a neighborhood with children playing, or glancing to the left and right before crossing a street, despite the fact that everything appears normal and safe. The thought process that causes a safe driver to slow down is risk management. The analytical process the driver follows in managing the risk is risk assessment.

A risk assessment has four fundamental tasks:

- Postulate that a certain scenario, or a chain of events, could occur
- Estimate chances that the scenario could occur
- Predict the severity of the scenario, should it occur
- Decide a course of action based on the chances and severity of the outcome

Anytime that there is the potential for an undesirable outcome, one can conduct a risk assessment. Risk assessment views scenarios as both stochastic and deterministic. The stochastic, or probabilistic view, states that there is randomness in every natural event. Therefore, predictions about natural events are uncertain. The deterministic view states that occurrences are causally determined by preceding events or natural laws. In risk analysis, the stochastic approach is used to determine likelihood, and the deterministic approach is used to estimate consequences.

4.1.1 What Is Risk?

The dictionary defines risk as “a factor, thing, element, or course involving uncertain danger; a hazard” or “the possibility of suffering harm or loss; danger.” However, the definition preferred in industrial risk analysis is “the probability of a given loss or injury to people or property,” which has several implications:

- Probability is part of the measure of risk
- Level of loss is part of the measure of risk
- The complete definition of risk requires a pair of data points, probability and consequence

Risk is the combination of the probability of some event occurring during a specified time period and the consequences (for the purpose of this document consequences are always negative) associated with the event. In mathematical terms, risk can be calculated by Equation 4-1:

$$\boxed{\textit{Risk} = \textit{Probability} \times \textit{Consequence}}$$

(Equation 4-1)

Another way of stating probability is likelihood. As a result, one might define risk as the *likelihood* of an event or condition that leads to a release (e.g., severe corrosion damage), and the *consequence* in the event of a release (e.g., petroleum entering a waterway). The mathematical representation of this statement is Equation 4-2:

$$\boxed{\textit{Risk} = \textit{Likelihood} \times \textit{Consequence}}$$

(Equation 4-2)

In both equations, risks can be evaluated in a numeric (quantitative) or non-numeric (qualitative) manner.

4.1.2 Likelihood of Occurrence

The likelihood or the probability of a scenario occurring is measured in terms of the frequency or occurrences per year for a specific event. This estimate covers the chain of events from initial failure through to eventual remediation, including conditions that could worsen the effects of a consequence. The estimation process involves determining the reliability of both equipment and human techniques. Subject matter experts, human reliability analysis, or failure logic models can be used to determine the likelihood of occurrence. In this document, the likelihood of occurrence is referred to as the likelihood of failure (LOF).

For the optional risk assessment method outlined in Appendix A, the likelihood of a scenario occurring is estimated by answering the questions provided in the risk assessment model. These questions are listed in the workbook in Appendix C and require detailed information on the specific item being evaluated (tank, pipe, etc.). Depending on the response for a specific facility or equipment, factors are used to adjust the frequencies (probabilities) up or down.

4.1.3 Consequence of Occurrence

The second objective of a risk assessment is to determine the physical consequences that occur as a result of the incident. The consequence of a scenario occurring is measured in terms of the damage, disruption, or financial impact associated with a particular event. The consequence of occurrence can be expressed as a dimensionless factor or dollar value, but it is expressed in terms of consequences per event. For example, if a tank subject to deterioration from corrosion develops a leak, a variety of consequences could occur. Some of the possible consequences are that the leak:

- forms a vapor cloud that could ignite causing injury and facility damage
- results in a spill that causes environmental damage to soil, surface water, and/or groundwater
- forces a shutdown, which has an adverse economic impact
- has minimal safety, health, environmental, and/or economic impact

In this document, the consequence of occurrence is referred to as the consequence of failure (COF).

4.1.4 Risk

Combining the likelihood of one or more of these events with its consequences will determine the risk to the operation. Some failures may occur relatively frequently without significant adverse safety, environmental, or economic impacts. Similarly, some failures have potentially serious consequences, but if the likelihood of the incident is low, then the risk may not warrant immediate action. However, if the likelihood and consequence combination (risk) is high enough to be unacceptable, then a mitigation action to predict or prevent the event is recommended.

Traditionally, organizations have focused solely on the consequences of failure or on the likelihood of failure without using systematic efforts to tie the two together. They have not considered how likely it is that an undesirable incident will occur. Only by considering both factors can effective risk-based decision-making take place. The owner can develop a set of risk acceptability criteria that recognizes that not every failure will lead to an undesirable incident having a serious consequence. Conversely, the criteria can also recognize that potentially serious outcomes may be the result of extremely low likelihood events.

Understanding the two-dimensional aspect of risk allows new insight into the use of risk management for inspection prioritization and planning, resource allocation, development of mitigation strategies, and financial planning.

4.2 Risk Scoring

Risk scoring involves the determination, measurement, and presentation of risks. As previously discussed, risks can be measured and presented as qualitative or quantitative or a combination of the two approaches. Section 6 further discusses the differences in performing a risk assessment for each approach. Risk scoring provides the user with tools to evaluate and compare risks. The user can evaluate and compare risks in several different ways by evaluating the risks of:

- different types of equipment at the same facility (e.g,. the risk of piping vs. the risk of tanks)
- different events at the same facility (e.g., the risk of a tank overfill vs. the risk of a tank bottom leak)
- the same equipment at the same facility (e.g., the risk of tank A vs. the risk of tank B)
- different facilities (e.g., the risk of facility A vs. the risk of facility B)

In order for the analysis to be meaningful, the user can define what constitutes an acceptable level of risk. The definition and determination of what is an acceptable risk is an owner-defined, company-specific process that is based on the company's management and guiding principles. Two different approaches to risk scoring, one qualitative and one quantitative, are presented below.

4.2.1 Risk Matrix Development

For risk ranking methodologies that use consequence and likelihood categories, presenting the results in a risk matrix is a very effective way of communicating the distribution of risks throughout a facility or equipment unit without assigning or developing numerical values. Various types of matrices can be used, but most are arranged such that the highest-ranking risk is toward the upper right-hand corner and the lowest-ranking risk is in the lower left-hand corner. Regardless of the matrix selected, the consequence and likelihood categories typically provide sufficient discrimination between the items assessed.

Risk categories may also be assigned to the boxes on the risk matrix. An example of risk categorization (higher, medium, or lower) in the risk matrix is shown in Figures 4.1 and 4.2. In this example, the risk categories are symmetrical; however, the categories could also be asymmetrical (i.e., the consequence category may be given higher weighting than the likelihood category).

Assessing or associating risk levels with squares on the matrix is a reflection of a company's policies and attitudes about risk acceptability. Many companies choose not to assign levels of risk within a matrix; however, if a company does decide to assign levels of risk, decisions can then be made regarding the disposition of various scenarios.

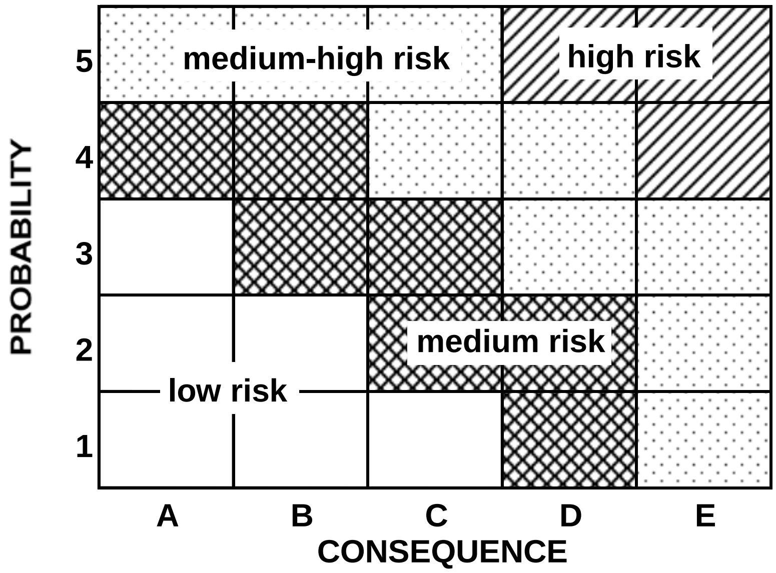

Figure 4-1: Example Risk Matrix Showing Levels of Risk (This is for demonstration only and not to be construed as endorsed matrix risk-level categorizations.)

The five-by-five matrix shown in Figure 4-1 portrays risk as neutral to likelihood or consequence. For instance, risk point C-1 has the same level of risk as A-3. To reflect aversion to one of the two elements of risk, the risk levels that are represented by the shaded areas are shifted, as shown in Figure 4-2 below. In Figure 4-2, an aversion to consequence is shown by assigning a higher risk level to higher consequences for some levels of likelihood.

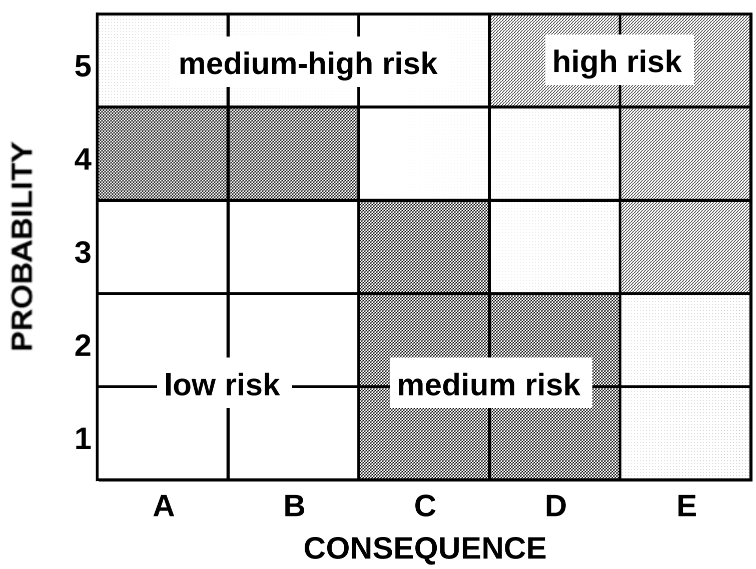

Figure 4-2: An Example Risk Matrix Showing Consequence-Aversion (This is for demonstration only and not to be construed as endorsed matrix risk-level categorizations.)

Note that, when compared to the unbiased matrix (Figure 4-1), risk point C-1 is assigned a risk level of “medium” rather than “low.” Other blocks on the matrix are changed to reflect aversion to consequence in Figure 4-2.

Equipment items residing towards the upper right corner of the plot or matrix will most likely take priority for inspection planning or other forms of mitigation because these items have the highest risk. Similarly, items residing in the lower left corner of the matrix will tend to take lower priority because these items have the lowest risk. Once the plots have been completed, the risk matrix can then be used as a screening tool during the prioritization process or for the selection of items or equipment requiring mitigation.

4.2.2 Quantitative Risk Analysis

Risks can also be presented in quantitative terms. Figure 4-3 shows an example of a quantitative numeric estimate of risk. In this plot, a scenario was found to have a likelihood of once in 1,000 years, resulting in a loss of $100,000.

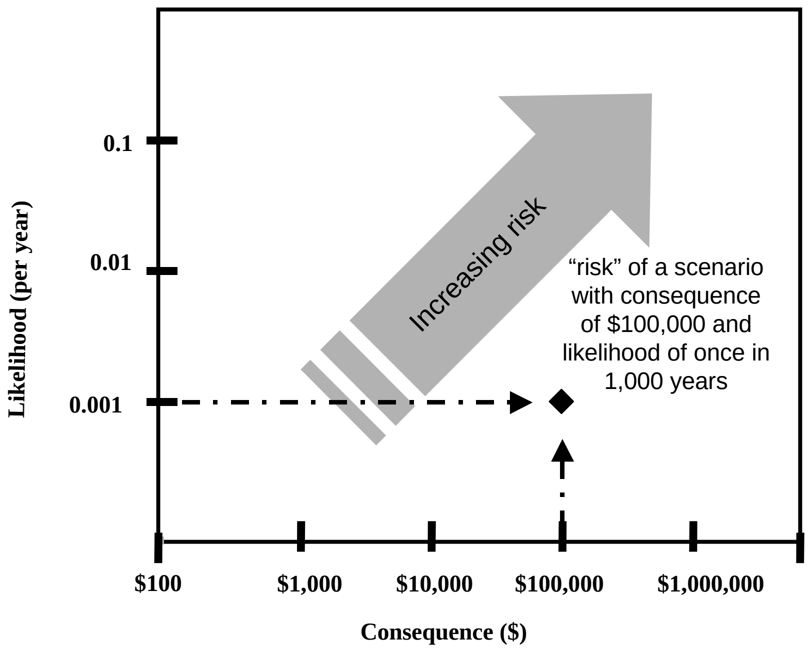

Figure 4-3: Example of Risk Point

When interpreting this plot, note that risk increases diagonally from the lower left corner to the upper right corner. Also note that the scale used in these plots is logarithmic for both likelihood and consequences. If we had eight scenarios for a given risk assessment and we estimated the likelihood and consequence of each scenario, we could produce a table similar to that of Table 4-1, where each scenario is labeled A through H.

Table 4-1: Example of Risk Points for a System

Scenario	Consequence ($)	Likelihood (per year)
A	$1,000	0.01
B	$2,000	0.05
C	$4,300	0.00035
D	$7,000	0.0085
E	$10,000	0.001
F	$80,000	0.032
G	$100,000	0.0032
H	$125,000	0.0005

There are many different ways to process and display the risk points such as those outlined in Table 4-1. For instance, Figure 4-3 shows the likelihood-consequence pair as a single point. However, if many scenarios exist, like those listed in Table 4-1, a plot would show the range of risks. Figure 4-4 shows an example of this.

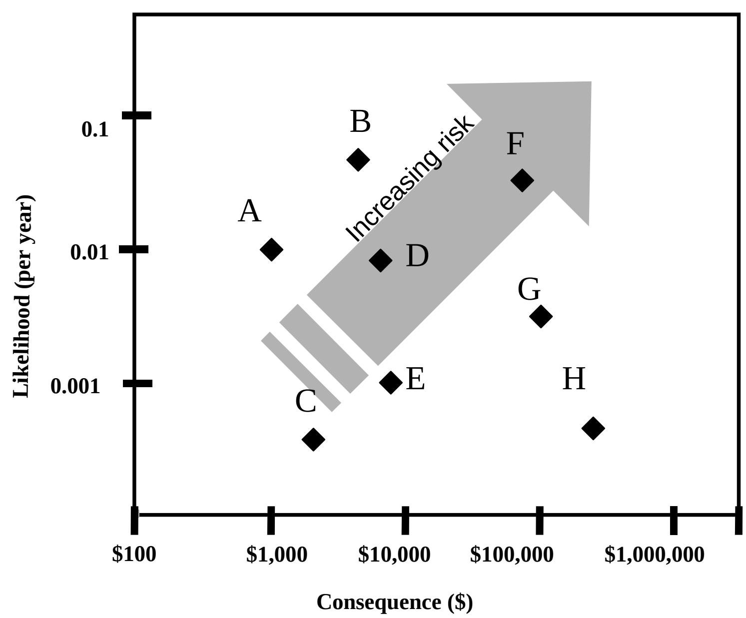

Figure 4-4: Example of Risk Plot for Multiple Scenarios

After plotting the various scenarios from Table 4-1, the following information can be readily extracted from Figure 4-4:

- Scenario B has the highest likelihood of occurrence
- Scenario C has the lowest likelihood of occurrence
- Scenario H produces the greatest consequence

- Scenario F has the highest risk
- Scenarios A and E have the same level of risk, since the "iso-risk" line is a straight line with a slope of –1

The advantage of Figure 4-4 is that it shows the risk of many scenarios plotted individually, but it does not show how the risks add up or accumulate for a facility. Since risk is a representation of a pair of points, you cannot simply add the values together to produce an accumulated risk. The approach typically used in risk analysis is to add together all of the probabilities of those particular scenarios that can produce a given loss *or greater*. In this way, the analyst can see the likelihood of exceeding a given level of loss. For example, the chances of having a loss between $1.2 and $1.3 million may be extremely small and there is little motivation for knowing those chances. What is worth knowing, however, is how often the damages may exceed $1.3 million.

For these reasons, risk analysts have devised a plot that shows the likelihood of exceeding a given level of loss for accumulated scenarios. The plot is produced by starting with the highest loss value and working down to the lowest loss value. In the process, the analyst progressively accumulates the probabilities from all higher consequence scenarios, so that the likelihood of smaller losses becomes higher and higher. This is demonstrated in Table 4-2, using the data from Table 4-1.

Table 4-2: Data for Accumulated Risk Plot

Scenario	**Consequence ($)**	**Likelihood (per year)**	**Accumulated Likelihood (per year)**
A	$1,000	0.01	0.106
B	$2,000	0.05	0.096
C	$4,300	0.00035	0.046
D	$7,000	0.0085	0.045
E	$10,000	0.001	0.037
F	$80,000	0.032	0.036
G	$100,000	0.0032	= 0.0037
H	$125,000	0.0005	+ 0.0005

Start here and accumulate likelihood as consequence decreases

Figure 4-5 shows the result of plotting accumulated likelihood versus level of loss. From this plot (or from Table 4-2), an analyst can estimate that the likelihood of having at least a $10,000 loss is about 0.037 per year or once in 27 years. The plot provides information on both the likelihood and consequence, so both elements of risk appear on the cumulative plot.

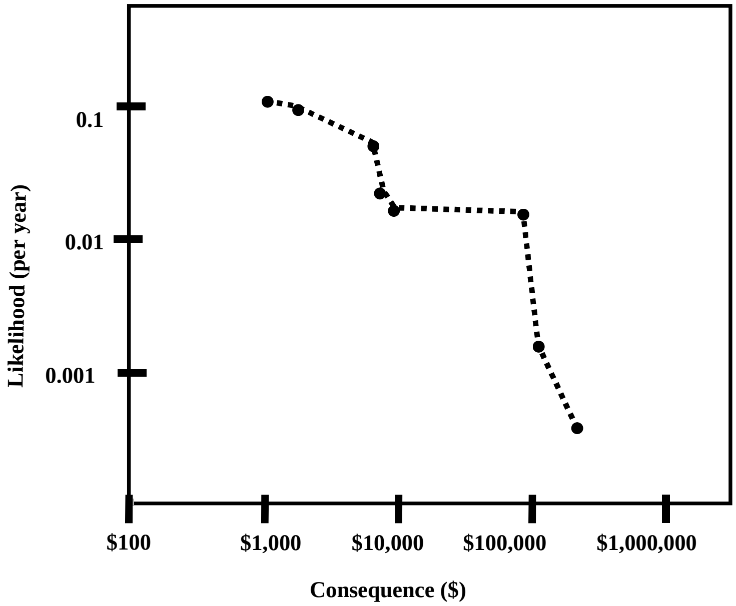

Figure 4-5: Example of a Cumulative Risk Curve

Another way to portray risk quantitatively is to produce a point-estimate of risk from the consequence-frequency data pair. Typically, this is done by multiplying the two likelihood and consequence data points together to produce a measure with units of "consequence per year." The mathematical expression for this score was described in Equation 4-2:

$$\boxed{Risk = Likelihood \times Consequence}$$

(Equation 4-2)

Multiplying likelihood by consequence is convenient because it reduces the risk measure to a single point. The single risk point is often referred to as the *expected value* of risk for a scenario, and it can be thought of as a likelihood-weighted consequence estimate. In combining likelihood and consequence, however, some information is lost; namely, the individual magnitudes of the likelihood and consequence. For example, a risk point of $100,000 at 0.01 per year has the same expected value as risk point $50,000 at 0.02 per year. Using the above example table (Table 4-2), a table of expected values or risk scores could be produced (Table 4-3).

Table 4-3: Example of Scenarios and Risk Scores for a System

Scenario	Consequence ($)	Likelihood (per year)	Risk ($ per year)
A	$1,000	0.01	$10
B	$2,000	0.05	$100
C	$4,300	0.00035	$2
D	$7,000	0.0085	$60
E	$10,000	0.001	$10
F	$80,000	0.032	$2560
G	$100,000	0.0032	$320
H	$125,000	0.0005	$63

From the risk score in the above table, an analyst could determine that Scenario F has the highest risk but would be unable to determine which scenario has the highest consequence or which has the highest likelihood. Risk analysts may use other systems to produce a risk score that emphasizes one risk element over another. Typically, systems are devised that emphasize consequence over likelihood, since most people are averse to large consequence events. For instance, people are generally more outraged by a plane crash that kills 250 people than by 250 individual fatalities in car accidents. From a technical viewpoint, car crashes are of far greater risk than airplane crashes, but airplane crashes always grab headlines over car accidents.

One way to express this aversion to high-consequence events is to use an expression that is non-linear and gives preference to higher consequence events. Equation 4-3 presents such an expression.

$$\boxed{Risk = Likelihood \times (Consequence^{K})}$$

(Equation 4-3)

In the above expression, to be consequence-averse, K would be greater than 1.0. The magnitude of K would reflect the degree of consequence aversion to be shown in the risk score. Note that the risk estimated by the above expression can only be referred to as an “expected value” when K is exactly 1.0. Typically, risk analysts use K values ranging from 1.5 to 2 when expressing consequence-aversion.

4.2.3 Risk Reduction

Risk reduction is the act of mitigating a known risk to a lower level of risk and is also referred to as hazard mitigation or risk mitigation. Risk reduction is required for those risks that the facility management determines to exceed a specific company-mandated threshold and can be accomplished through a wide range of measures including engineering and/or operational control measures. For facilities covered in this publication, the information provided in API Publ 340 provides a starting point for the screening and selection of risk reduction measures.

There are several potential approaches to decisions concerning risk reduction measures. These approaches include subjective, code-based, risk improvement, risk criteria, and cost-benefit. All are covered in more detail below.

In the **Subjective Approach,** the decision-makers consider the range of possible actions and then select those risk reduction measures that they believe are appropriate for the process. The advantage of using this approach is that it is flexible and automatically takes into account the economic and practical constraints in different operations. However, the disadvantage is that it has the potential to be inconsistent and open to abuse; therefore, this approach would be more practical for low-hazard activities.

A **Code-Based Approach** is one in which risk reduction measures are selected that conform to good engineering practice according to relevant industry guidelines and codes of practice. This approach gives objective guidance while taking account of practical constraints. The drawback is that it does not allow for flexibility or for exemptions that usually coincide with the low-likelihood conditions.

Risk Improvement Approaches are those in which improvements that are gained by risk reduction measures are evaluated against a fixed "base case." The overall objective in this approach is to reduce the risk by a pre-defined amount (e.g., cutting the risks in half or dropping the risk by at least one qualitative level). This approach tends to fit well into the qualitative matrix approach to risk where decisions would be made to drive risk from a higher risk level to a lower one. For quantitative studies, this approach places less emphasis on the absolute numbers in the risk analysis. Decisions can be made on a relative value of risk as opposed to an absolute value.

In the **Risk Criteria Approach,** the risk analyses are compared with a set of risk criteria. The criteria may be numerical for a quantitative system, or they may be associated with given levels of risk in a qualitative system. In their simplest form, these criteria indicate whether the activity is acceptable or not. If it is unacceptable, then risk reduction measures are typically adopted regardless of cost. If it is acceptable, then no further measures are needed. This has the advantage of giving clear guidance about when risk reduction is needed, but the level at which the criteria should be set is not well-established and varies throughout the world and across different industries.

Finally, in the **Cost-Benefit approach,** measures are selected if they have a favorable ratio of cost (e.g., expenditure and operating costs) to benefit (e.g., risk reduction). This approach is deemed the most powerful and rational of the various approaches and provides objective guidance on specific risk reduction measures, while accounting for economic constraints; however, this approach can be applied only to quantitative risk systems. The disadvantage is that this method may involve an explicit comparison between safety or environmental matters and mitigation economics. This comparison is usually cumbersome to explain to a public audience.

Refer to Section 8 for further discussion of the specific selection and screening processes used for risk mitigation.

SECTION 5—RISK MANAGEMENT PROGRAM OVERVIEW

A risk management program (RMP) is primarily a management tool that allows the user to identify, manage, and mitigate risks associated with petroleum terminal facilities. RMPs provide for management guidance and control; application of the technical analysis of risks; involvement of appropriate facility personnel in the program development, implementation, and maintenance; and the mitigation or management of high-risk items.

5.1 General

In developing this document for managing risks at terminal facilities, the authors followed certain guiding principles. These principles are reflected in many of the sections and are provided here to give the reader a sense of the need to view terminal integrity from a broad perspective.

Integrity management starts with the sound design and construction of the terminal. Equipment and operational integrity are typically built into the facility from the initial planning, design, and construction phases. A number of consensus standards, including API Std 2610, API Std 650, API Publ 340, NFPA 30, ASME B31.1, B31.3, and B31.4, provide guidance for new construction. API Std 2610 gives a more complete list of applicable codes, standards, and guidance. When these documents are applied to the design of a terminal, the designer usually considers the environmental setting of the facility, including the surrounding land use and the possible impacts on the surrounding environment and community. New construction is not a subject of this document, but the design specifications and as-built conditions of the facility provide important baseline information for an RMP.

Facility integrity depends on qualified people who use defined processes to operate and maintain facilities. The integrity of the physical facility is only part of the complete system that allows an owner to reduce both the number of incidents and the adverse effects of errors and incidents. The total system also takes into account the people who operate the facility and the work processes that the employees use and follow. Therefore, a comprehensive RMP typically addresses people, processes, and facilities.

Another significant aspect of an RMP is its flexibility as it is typically customized to support each facility's unique conditions. Furthermore, the program is typically evaluated continually and modified to accommodate changes in the facility design and operation, changes in the environment within which the facility operates, and changes in operating data and other integrity-related information. Continuous evaluation is essential to ensure that the program takes appropriate advantage of improved technology and that it remains integrated with the owner's business practices while effectively supporting the company's overall risk management goals.

Facilities have multiple options available for addressing risks. For example, components of the facility or system can be changed; additional training can be provided to the people who operate the system; processes or procedures can be modified; or a combination of actions can be taken that will have the greatest impact on reducing risk.

One of the key components of risk is the integration of available information, such as facility design and failure records, into the decision-making process. Since the information can come from a variety of sources, the owner of the facility is in the best position to gather and analyze the data. Once all of the relevant information is collected and integrated, the owner can begin to distinguish where the risks of an incident are the greatest and proceed to make prudent decisions to reduce the risk.

Preparing for and conducting a risk assessment is yet another key element in managing risk. Risk assessment is an analytical process through which an owner determines the types of adverse events or conditions that might impact system integrity; the likelihood that those events or conditions will lead to a loss of integrity; and the nature and severity of the consequences that might occur following a failure. This analytical process involves the integration and analysis of design, construction, operation, maintenance, testing, and other information about a terminal facility. Risk assessments can have varying scopes and levels of detail and use different methods; however, the ultimate goal of assessing risks is to identify and prioritize the most significant risks so that the owner can make informed decisions.

Assessing risks to terminal integrity is a continuous process where the owner will periodically gather additional information and operating experience that is then factored into the understanding of the risks associated with specific equipment or specific operations. As the significance and relevance of this additional information become understood, owners can adjust their integrity plan accordingly. This makes analyzing risks in a facility an iterative process. Adjustments in response to the data may lead to changes in inspection methods or frequency or additional modifications to the facility equipment or procedures. As changes are made, different companies and different facilities within a company will be at different places with regard to the goal of incident-free operation. Therefore, each facility and each company usually set specific goals and measures to monitor the improvements in integrity and to assess the need for additional changes.

Owners can act to address integrity issues that are raised from assessments and information analysis and then proceed to mitigate or eliminate injurious defects. Some of the high-risk events may require mitigation.

Owners can periodically assess the capabilities of new technologies and techniques that may provide improved understanding about the facility equipment condition or provide new opportunities to reduce risk. New technology can be evaluated and utilized as appropriate because it may enhance an owner's ability to assess, prevent, detect, or mitigate certain risks. Knowledge about what is available and effective will allow the owner to apply the most appropriate technologies or techniques to a specific risk. Owners are encouraged to perform internal reviews to ensure the effectiveness of their risk management program in achieving the goals stipulated by management.

5.2 Developing a Company Approach to Risk Management

Although individual terminals have unique design features and operating characteristics, an effective RMP typically comprises several key elements which are outlined in this section. The framework presented in this document provides recognized industry practices for developing these elements and a common structure upon which to establish a company-specific RMP.

In developing an RMP, owners can consider their unique risk management goals and objectives and then use existing approaches, or develop new processes, to achieve these goals. There are numerous approaches to implementing the different elements identified in this section, ranging from relatively simple to highly sophisticated and complex. There is no “best” approach that is applicable to all facilities for all situations. This publication recognizes the importance of flexibility in designing RMPs and provides guidance commensurate with this need.

It is important to recognize that an RMP is typically a highly integrated and iterative process. Although the elements detailed below are shown sequentially for ease in presentation, information flow and interaction between the different steps are significant. For example, the selection of a risk assessment approach depends in part on what facility-related data and information are available. Conversely, in the performance of a risk assessment, additional data needs are usually identified that better address potential equipment integrity issues; thus, the data-gathering and risk assessment elements are tightly coupled and may require several iterations until an owner is satisfied that the risk assessment appropriately characterizes the facility risks.

An RMP includes the following basic elements:

- Hazard Identification
- Risk Assessment

- Risk Evaluation, Control, Management, and Mitigation
- Procedures
- Training
- Emergency Planning and Emergency Response
- Incident Investigation and Root Cause Determination
- Management of Change
- Compliance Audits
- Program Performance Measurement

Figure 5-1 provides a flow chart illustrating how one would integrate the basic elements of a risk management program.

5.2.1 Hazard Identification

The hazard identification element of an RMP provides the foundation for the risk assessment. It requires the facility to perform a rigorous and comprehensive review of the facility equipment, operational procedures, petroleum handling operations, and hazards specific to petroleum facilities. Part of the hazard identification process is to determine if a hazard is credible and whether the hazard poses a significant risk. The process incorporates the historical experience of the company and the knowledge base and intuition of personnel familiar with facility processes by taking into account what has gone wrong in the past and what can go wrong in the future. A formal analytical approach is critical to identify what could go wrong, and the results of the review are typically documented for future reference. This information can be used before an equipment or operational change is made at the facility. Hazard identification can be performed utilizing a variety of formal analytical processes often referred to as process hazard analysis (PHA). PHA involves the use of any one of a number of techniques, such as checklists, what-if/checklists, hazard and operability studies (HAZOPs), failure modes and effects analysis (FMEA), and fault-tree analysis.

The selection of the hazard identification method depends on the experience of the person or teams of people performing the analysis, the development stage (e.g., new equipment, modified process, experience with equipment or process), corporate philosophy, and the depth of the analysis to be performed. Hazard identification methods can be applied to new equipment or processes, modified equipment or processes, and periodically to ongoing operations.

For API Publ 340, a group of experienced industry members assembled a list of causes for liquid releases and categorized the type and magnitude of the release from terminal equipment such as tanks, piping, loading/unloading operations, ancillary facility equipment, and system operating practices. Users can employ API Publ 340 as a base to identify hazards associated with terminal facilities; however, the hazard identification list in API Publ 340 does not include hazards associated with safety, vapor releases, or fire/explosion. Users may desire to expand their hazard identification process to include these hazards.

5.2.2 Risk Assessment Overview

Risk by definition is the evaluation of the likelihood of an event occurring and the consequences of that event occurring. The management of risks associated with identified hazards requires a thorough understanding of the likelihood of a hazard occurring and the projected consequences if the event does occur. Risk assessment is the process of taking an undesired credible event recognized in the hazard identification process (what can go wrong) and determining the likelihood (the probability or frequency of occurrence) and consequences (the impacts) of the undesired event. Risk assessment is an important part of an RMP because it quantifies the overall impact of an identified risk and provides the methodology for comparing risks.

The likelihood of an event occurring is a function of the type of equipment, specific site conditions, equipment age and maintenance, contained fluid, operating practices, weather, and several other factors. When the likelihood of an event is determined, the user estimates the likelihood (not the possibility) that a particular event will occur. The likelihood that an event will occur can be based on published information from the company data historian, regulatory information, industry available information, and manufacturer data. The likelihood that an event will occur can be reported in several different ways:

- In qualitative (relative) terms based upon experience, such as the event has a very low, low, medium, high, or very high likelihood of occurrence
- Quantitative terms, such as it occurs at 1 in 100 tanks, or 1 in 1000 fills
- A combination of qualitative and quantitative methods

As part of the development of this document, API assembled a group of experienced industry members who developed a model for the likelihood of occurrence of liquid releases for major terminal equipment, such as the risk of a tank bottom leak, a piping leak, an overflow, etc., and included the information in Appendix A. Users can implement this particular model, portions of this model, or develop their own model for determining the likelihood of an event occurring. Users can also base this model on historic data that they have gathered such as information on the success of installing high-level alarms in tanks to prevent overfills or on other probabilistic or empirical information to determine the likelihood of an identified hazard. The optional likelihood model presented in Appendix A does not address the hazards associated with safety, vapor releases, or fire/explosion.

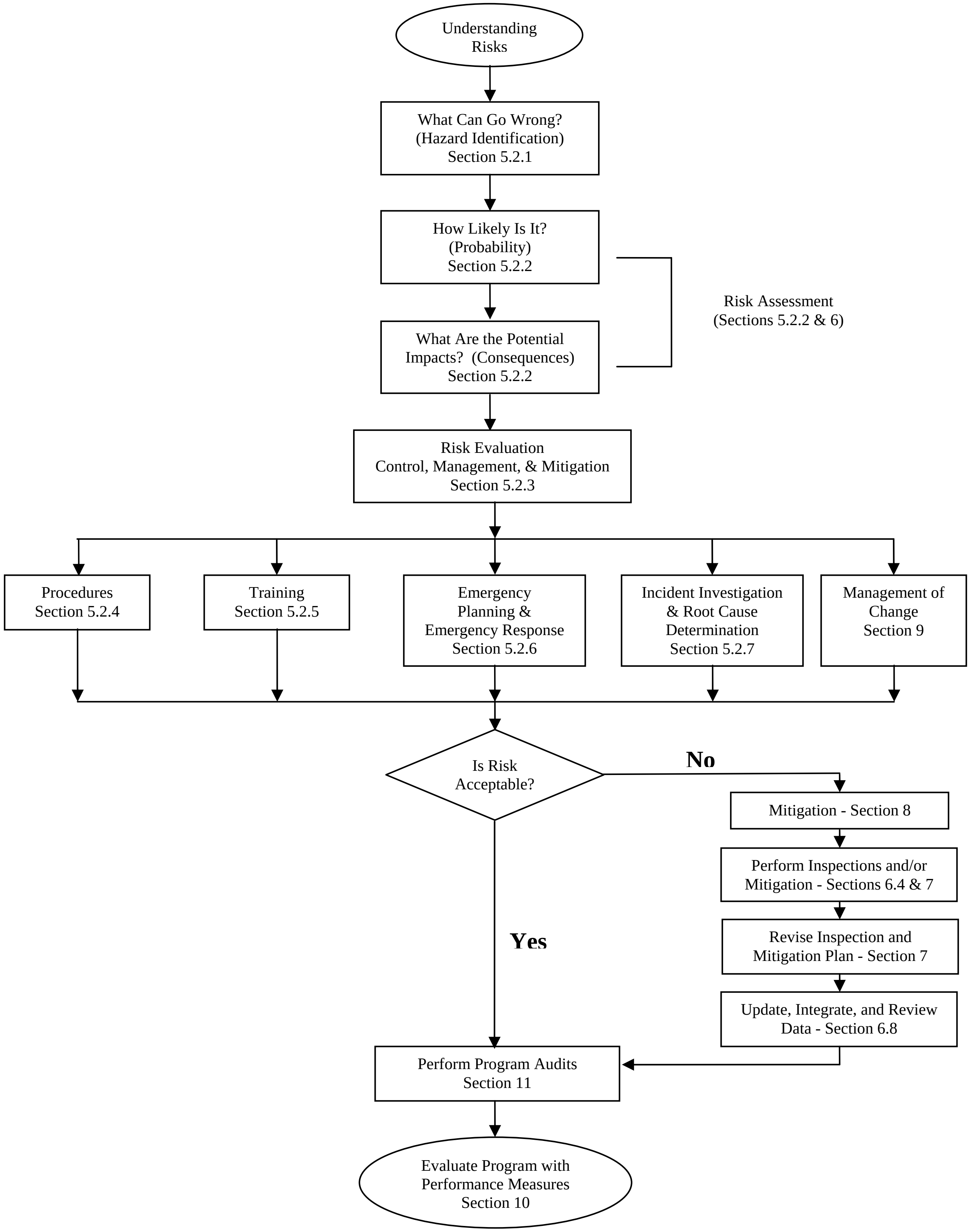

Figure 5-1: Risk Management Program

When the consequences of an event are calculated, environmental, economic, health, and safety issues, and items such as corporate reputation and philosophy, can be factored into the assessment. Furthermore, consequences are site specific and typically entail consideration of the type and magnitude of the hazard, site location, surrounding environment, land use, weather, population, regulatory environment, etc. The type and magnitude of consequences can be determined in several different ways:

- In qualitative (relative) terms such as a very small, small, medium, high, or very high spill; less than 1 gallon, 1 to 100 gallons; or other terms such as the spill is contained in the diked area, spill is contained on the property, offsite impact on groundwater, offsite impact on property, or offsite impact on surface water
- Quantitative terms such as dollars, volume spilled, environmental damage assessment
- A combination of qualitative and quantitative methods

As it did for the development of the model for the *likelihood* of occurrence, API assembled a group of experienced industry members who developed a model for the *consequences* of occurrence of liquid releases for major terminal equipment such as the risk of a tank bottom leak, a piping leak, an overflow, etc. This model is also included in Appendix A. Again, users can implement this model, portions of this model, or develop their own model for determining the consequences of an event. This model, like the one for likelihood of occurrence, can be based on historic data that the user has gathered such as information on the cost of cleaning up a spill in the containment area, or on other probabilistic or empirical information to determine the consequences of an identified hazard. The optional consequence model presented in Appendix A does not address the hazards associated with safety, vapor releases, or fire/explosion.

Section 6 covers the various types and approaches to risk assessment and includes an overview of the optional risk assessment methodology provided in the appendices.

<u>5.2.2.1 Recognizing Changes That Affect a Risk Assessment Program</u>. To keep the RMP current, the facility can identify the ways that changes to the facility, equipment, products, staffing, or procedures could impact the risk factors identified in the program. Examples of such changes are:

- Addition, deletion, or other modifications of the facility equipment
- Changes in the stored product
- Changes in operating conditions and spill control or other mitigation measures that are currently employed
- Changes to the piping system flow rate, operating pressure, or operating temperature
- Restart of equipment or systems that have been out of service for an extended time and/or systems that have not been maintained
- Changes to existing procedures or addition of new procedures

<u>5.2.2.2 Planning the Risk Assessment.</u> The purpose of this section is to help a user determine the scope and the priorities of a risk assessment. To focus the initial effort on the higher risk items, an initial screening can be performed of the equipment or systems at the facility. To further focus the effort, boundary limits can be identified to determine what is vital to include in the assessment and what constitutes a unit or equipment battery limit. Boundary limits are best set on process flow diagrams, piping and instrumentation diagrams (P&IDs), or site plans and can be established for sections of pipe, tanks, and loading/unloading areas. The boundary limits will then establish the discrete item, which will undergo the risk assessment. The organizing process of aligning priorities, screening risks, and identifying boundaries improves the efficiency and effectiveness of assessing and managing risk.

A risk assessment is typically undertaken with clear objectives and goals that are fully understood by all members of the team and by the facility management. An objective of the assessment may be to better understand the risks involved in the operation of the facility, or specific piece of equipment, and to understand the effects that inspection, maintenance, and mitigation actions have on the risks. From the understanding of risks, an inspection program may be designed that optimizes the use of inspection and facility maintenance resources.

Since a risk assessment is a team-based process, it is important to define the following objectives at the beginning of the exercise:

- Why is the assessment being performed?
- How will the risk assessment be carried out?
- What knowledge and skills are required for the risk assessment personnel?
- What individuals will compose the risk assessment team?
- What are their roles in the process?
- Who is responsible and accountable for what actions?
- Which facilities, assets, and components will be included?
- What data are to be used in the assessment?
- What codes and standards are applicable?
- When will the assessment be completed?
- How long will the assessment remain in effect, and when will it be updated?
- How will the results be used?
- Are there event-based conditions that would necessitate an update?

Moreover, a risk assessment will determine the risk associated with the items assessed. The risk assessment team and management may wish to judge whether the individual equipment item and cumulative risks are acceptable. Establishing risk criteria to judge the acceptability of risk could be an objective of the assessment if such criteria do not exist already within the user's company (refer to Section 10).

Once the risks have been identified, mitigation strategies, such as inspections, procedures, and engineering or operating controls, that reduce risk to an acceptable level may be undertaken. The results of managing and reducing risk are improved safety, avoided losses of containment, and avoided commercial losses. Note that these actions may be significantly different from the actions undertaken during a statutory or certification type inspection of a mitigation program.

5.2.3 Risk Evaluation, Control, Management, and Mitigation

The process of identifying credible risks and assessing those risks is a necessary precursor to the evaluation, control, management, and where the owner deems appropriate, mitigation of those risks. The results from the hazard identification (section 5.2.1) and risk assessment (section 5.2.2) phases will provide the owner with the information necessary to evaluate a given risk. Management needs to realize that the potential for incidents always exists no matter how many engineered control measures are utilized, and therefore they can establish administrative controls. These controls can give personnel the decision-making tools to evaluate the risk, determine the appropriate method to control or manage the risk, refer specific risks to remediation via engineered and/or administrative controls, and select and implement the appropriate mitigation. After evaluating the risk assessment information, owners may appropriately decide that the risks are acceptable and no further action is required; that additional information, inspection, or evaluation is necessary to make a decision; or that they may mitigate the risk. Mitigation can be accomplished via change in operating conditions; removal from service of the high-risk unit; change in operating practices, procedures, or training; or implementation of engineered control measures.

Management typically provides the authority and resources to the facility and engineering personnel to ensure that the design, specification, and construction phases of new or replacement equipment or facilities adhere to the appropriate company standards, industry standards, consensus codes, and applicable regulatory requirements. Section 4.2 explains the development of a risk scoring system, and Section 8 describes mitigation and control measure selection. Examples of risk mitigation strategies for environmental liquid release scenarios utilizing API Publ 340 are included in section 8.4.

5.2.4 Procedures

Facility operations require the use of instructions to plant personnel and/or contractors that take the form of written or verbal procedures. Procedures may be general in nature (e.g., housekeeping) or specific to a project task (e.g., gauging a tank), or they may address specific service conditions such as normal operations, maintenance, startup, safety, inspection, communications, or shutdown procedures. Procedures are a necessary part of a facility's RMP and are typically not just a "paper" program. They are usually specific to a facility task or company and are kept current to reflect:

- Changes to the facility or equipment
- Feedback from incident investigations
- The results of the risk assessment evaluation
- Changes to employee training

The use of properly established procedures may be the primary method, or in some cases the only method, for managing a specific risk. Changes to facility operating procedures are inevitable, and a program can be in place that governs the review, modification, training, and updating of facility procedures. These items will become part of other elements of the RMP including training (section 5.2.5), emergency planning and emergency response (section 5.2.6), incident investigation and root cause determination (section 5.2.7), and management of change (Section 9).

5.2.5 Training

Training of employees and contractors in the facility operations, hazards, and job tasks is part of any company's basic corporate management program and is also an important element of a facility's RMP. Training refers to the activities associated with educating plant personnel or contractors in the operation and safe work practices at the facility. It forms the basis for ensuring that facility personnel are instructed in facility-specific hazards, that they understand the facility operations, and that they are adept at performing on-the-job training. This may involve having a junior operator or new hire work with a senior operator to observe and properly repeat an assigned task. In addition to standard job training and safe work practices, facility personnel are typically properly trained in the operation and maintenance of release prevention systems, release detection systems, facility alarms, and non-routine operating conditions.

Training programs are typically documented to ensure the effectiveness of training and to document that personnel have met the qualifying criteria established by the company. Training is a dynamic program that requires updates and, when appropriate, provides refresher training to onsite company personnel and contractors. Management review of the training program can occur based on changes in facility equipment after the completion of a management of change review (Section 9), emergency planning and emergency response updates (section 5.2.6), changes in procedures (section 5.2.4), or as a result of the findings from an incident investigation and root cause determination (section 5.2.7).

5.2.6 Emergency Planning and Emergency Response

The goal of risk management is to identify the risks, evaluate the likelihood of occurrence of those risks, and reduce the likelihood of occurrence. However, since assuring zero risk is not practical or reasonable, effective risk management requires planning for, responding to, and mitigating reasonable release scenarios. This is the role of emergency planning and emergency response.

As part of the facility's hazard identification program (section 5.2.1) and risk assessment analysis (section 5.2.2), the facility has already evaluated the specific credible failure mechanisms, the likelihood of occurrence for these mechanisms, and the consequences of occurrence for each specific risk. The facility can then use this information to prepare response plans for specific release scenarios. The consequences of the risk can be mitigated or controlled through proper emergency planning and emergency response. Incorporating an emergency planning and emergency response program into an RMP requires that a facility:

- Develop written contingency plans for possible petroleum release scenarios
- Develop procedures (section 5.2.4) for implementing actions detailed in the plan
- Conduct appropriate training (section 5.2.5) and/or drills outlined in the plan
- Plan, procure, or retain the services, equipment, and personnel to implement the necessary emergency response as outlined in the plan
- Establish a program to conduct communication and coordination with a third party and local responders

It is important to develop response procedures and action plans that include:

- Definition of organizational lines of responsibility and notification for response to accidental releases
- Training of personnel responsible for accidental release events
- Rapid verification of releases, if necessary
- Isolation and control of the release source
- Control of the released product according to procedures developed for specific environmental impacts and release volumes

Emergency planning and emergency response is a dynamic program that requires periodic updating of the plans and program. A management review process can occur based on changes to facility equipment, the findings from an incident investigation and root cause determination (section 5.2.7), or completion of a Management of Change review (Section 9). As the emergency planning and emergency response program is modified, the facility typically reviews its training program (section 5.2.5) to determine if modifications are necessary.

5.2.7 Incident Investigation and Root Cause Determination

Incident investigation and root cause determination involve an organized approach to recording a loss or near-loss incident, investigating the sequence of events of what went wrong, determining the root cause of the incident, and developing and documenting remedial measures to prevent the same or similar incidents from occurring in the future. Incident investigation of losses or near losses helps to refocus the risk assessment (section 5.2.2), risk mitigation approach (Section 8), and emergency planning and emergency response (section 5.2.6) elements of the facility's overall RMP. This is accomplished by using actual incidents to refine the hazard identification process (section 5.2.1), the likelihood of occurrence, and consequences or potential consequences of occurrence.

Incident investigation and root cause determination require preparation of proper investigation procedures; use of properly trained and qualified investigators and personnel involved with, or knowledgeable about, the incident; determination of the root cause; development of recommendations to remediate the root cause; and implementation of the recommended remedial measures. The results of an incident investigation may require updating or modifying other RMP elements, such as training (section 5.2.5), procedures (section 5.2.4), management of change (Section 9), hazard identification (section 5.2.1), or risk assessment (section 5.2.2).

SECTION 6—RISK ASSESSMENT

As discussed in section 5.2.2, a risk assessment method typically collects and logically processes data to arrive at a risk result. Risk assessment methods are tools that define a relationship between the type and frequency of threats that can reduce facility or equipment integrity (e.g., corrosion, mechanical damage, equipment failure, procedural breakdown, etc.) and the consequences in the event of a release. The risk assessment typically deals with a variety of data and assumptions about how the facility and equipment are designed, constructed, operated, and maintained, and the environmental and external factors that can affect risk. Risk assessment methods "predict" the value of the output variable (i.e., risk) based on the input values of more easily measured or evaluated variables (e.g., tank bottom thickness, soil conditions, pipe wall thickness, coating condition, etc.). The quality of the prediction depends on the quality of the inputs and the soundness of the logical relationships inherent in the risk assessment method used to evaluate the input and output conditions.

It is important to distinguish between a risk management process and a risk assessment method. Risk assessment is the estimation of risk for the purposes of decision-making. Risk management is the overall process that includes the risk assessment, maintenance activity, and reintegration of data into subsequent risk assessments. Risk assessment methods can be powerful analytical tools to integrate data and information and to help identify the nature and locations of risks associated with terminal facilities. However, risk assessment methods alone are typically not relied on to establish risk or determine decisions about how risks can be addressed. Risk assessment methods can be used as part of a process that involves knowledgeable, experienced personnel who critically review the input, assumptions, and results. This review can integrate the risk assessment output with other factors not initially considered in the assessment, such as the impact of key assumptions and uncertainties created by the absence of data or the variability in assessment inputs. This can be completed before management makes decisions concerning risks and actions to reduce risk. The various approaches to risk assessment fall into three broad areas:

- The relative value of knowledge and data and their logical relationships within the risk assessment method
- The complexity and detail of the risk assessment method
- The nature of the output (probabilistic vs. relative measures of risk)

Independent of the risk assessment method used, all techniques incorporate the same basic components:

1. Identify potential events or conditions that threaten the facility or equipment's integrity
2. Determine the risk represented by these events or conditions by determining the likelihood of a release and the consequences of a release
3. Rank the risk assessment results
4. Identify and evaluate risk mitigation options (i.e., both net risk reduction and benefit/cost analyses)
5. Integrate maintenance project data (i.e., a feedback loop)
6. Reassess risk

Ultimately, it is up to the facility to develop, select, and apply the risk assessment method that best meets its specific requirements. It is in the best interest of the facility to develop a thorough understanding of the various risk assessment methods available and in use, including the respective strengths and limitations of the different methods, before determining a long-term risk assessment method strategy.

This section presents information on the different types and approaches to risk assessment. The optional risk assessment methodologies, which are included in Appendices A and B, are briefly discussed and presented to illustrate how a risk assessment process would be performed. The user may choose to develop a risk assessment methodology that addresses the approach, concepts, and equipment detailed in the appendices of this document. The user-developed risk assessment method does not have to address all the elements outlined in the optional Appendices A and B, and in some instances, the user-defined risk assessment program may extend beyond the equipment and scenarios outlined in this document. For example, Appendix A addresses the risk of liquid releases only, and the user may want to expand the risk to include vapor, safety, and other items that are important to the company.

6.1 Company Risk Assessment Program

Although individual liquid petroleum storage facilities have unique design features and operating characteristics, an effective risk management program (RMP) typically comprises several key elements outlined in this section. The framework presented in this document provides recognized industry practices for developing these elements and a common structure upon which to develop a company-specific RMP.

In developing this program, owners usually consider their unique risk management goals and objectives and then use existing approaches or develop new processes to ensure that these goals are achieved. Typical characteristics of a risk assessment program are listed below.

Structured: The underlying methodology is structured to provide a thorough analysis. Some methodologies employ a more rigid structure than others. More flexible structures may be easier to use; however, they generally require more input from subject matter experts. All risk assessment methods identify and use logic to determine how the data considered contribute to risk in terms of affecting the likelihood and/or consequences of potential incidents.

Given adequate resources: Appropriate personnel and adequate time should be allotted to fit the detail level of the analysis.

Experience-based: The frequency and severity of past events (in the subject or a similar system) are typically considered. The risk assessment can account for any corrective actions that have been made to prevent similar mishaps and consider the facility or company-specific operating history and other knowledge about the individual system that has been acquired by field operations and engineering personnel.

Predictive: A risk assessment is typically investigative in nature, seeking to identify previously unrecognized threats to equipment integrity. While it can make use of previous events, its focus should be on the potential for future mishaps, including credible scenarios that may never have occurred in the past.

Based on appropriate data: Some risk analysis decisions are judgment calls; however, relevant data and particularly data about the equipment or system under review, usually affect the confidence level placed in the decisions.

Able to provide for and identify means of feedback: Risk analysis is an iterative process. Actual field events and data collection efforts are typically used to validate (or invalidate) assumptions made during the risk assessment process.

6.2 Types of Risk Assessment

Detailed below are types of risk assessment approaches available to the user. These risk assessment approaches are based on those developed as part of API RP 580, API Publ 581, and API Std 1160. The user should note that API Publ 581 is primarily for scheduling inspections at refineries, while this document deals with managing and evaluating risks at liquid terminal facilities. Users can develop a qualitative, quantitative, or semi-quantitative risk assessment approach. The risk assessment approach presented in the optional Appendix A of this document is one method for performing a *quantitative approach* to risk assessment. The risk assessment approach presented in the optional Appendix B of this document is one method for performing a *qualitative approach* to risk assessment. Other models for risk assessment approaches are available but are beyond the scope of this document.

6.2.1 Qualitative Risk Assessment

The qualitative approach typically does not require all of the data required of a quantitative risk assessment method. Further, items required are typically categorized only into broad ranges or classified vis a vis a reference point. It is important to establish a set of rules to assure consistency in categorization or classification. One way in which risk can be represented is in qualitative terms, such as low, medium, or high. The qualitative assessments of likelihood and consequence can be assigned to categories. For instance, a low likelihood might be placed in Category 1, and a medium consequence might be assigned to Category C. These values can then be displayed in a matrix similar to that discussed in Section 4 where risk increases from the lower left corner to the upper right corner of the matrix.

This qualitative type of approach requires data inputs based on descriptive information using engineering judgment and experience as the basis for the analysis of likelihood and consequence of failure. As previously mentioned, inputs are often given in data ranges rather than discrete values; however, numerical values may be associated with these categories. The value of this type of analysis is that it enables completion of a risk assessment in the absence of detailed quantitative data. Generally, a qualitative analysis using broad ranges requires a higher level of judgment, skill, and understanding from the user than a quantitative approach. Ranges and summary fields may be evaluated for circumstances with widely varying conditions that require the user to carefully consider the impact of input on risk results.

The accuracy of results from a qualitative analysis depends on the background and expertise of the analyst, so, despite the approach's simplicity, it is important to have knowledgeable and skilled persons perform the qualitative risk assessment analysis.

6.2.2 Quantitative Risk Assessment

Quantitative risk assessment analysis integrates into a uniform methodology the relevant information about facility design, operating practices, operating history, component reliability, human actions, the physical progression of incidents that could result in a release, release quantities, and the potential environmental effects.

Quantitative risk analysis uses logic models depicting combinations of events that could result in severe accidents and physical models depicting the cause of releases, the progression of incidents resulting in a release, and the transport of liquid petroleum products to the environment. The models are evaluated probabilistically to provide both qualitative and quantitative insights about the level of risk and to identify the design, site, or operations characteristics that are the most important to risk; hence, more detailed information and data are needed for quantitative risk assessment in order to provide input for the models. Quantitative risk analysis is distinguished from the qualitative approach by the analysis depth and the integration of detailed assessments.

Quantitative risk assessment logic models generally consist of an organized methodological approach such as *event tree* and *fault tree* types of analysis. Event trees delineate initiating events and combinations of system successes and failures, while fault trees depict ways in which the system failures represented in the event trees can occur. These models are analyzed to estimate the likelihood of each accident sequence. Results using the approach are typically presented as risk numbers (e.g., cost per year) and are either plotted on a risk matrix or risk curve or a single value is found by utilizing a scoring system.

The traditional quantitative risk assessment is composed of five tasks:

1. Systems identification
2. Hazards identification
3. Likelihood assessment
4. Consequence analysis
5. Risk results

The system definition, hazard identification, and consequence analysis are integrally linked. A quantitative analysis deals with total risk, not just a risk associated with equipment failure, leakage, or overfills.

The quantitative assessment also involves a much more detailed evaluation of the following types of data:

- Existing hazard and operability study (HAZOP) or process hazards analysis results
- Dike, piping, tank design, and inspection information
- Hazard detection systems
- Release statistics
- Environmental factors
- Local site conditions
- Land use

Personnel experienced in the specific methodology (risk analysts) generally perform the analysis due to the extensive and detailed nature of the evaluation; however, the risk analyst also requires input from engineers and operations personnel.

6.2.3 Semi-Quantitative Risk Assessment

The semi-quantitative analysis typically requires the same data as a quantitative analysis but generally is not as detailed. For example, the fluid volumes may be estimated or grouped into ranges of low, medium, and high. Since the analysis may be less precise, the time required for data-gathering and analysis will also be less.

6.3 Precision vs. Accuracy

Risk assessment values can be represented in several different ways: a single numeric value (e.g., 102); a range of values (e.g., 100 to 200); a letter (e.g., "A", "B", "C", "D") where each letter represents a different risk criteria; an order of magnitude; a descriptive word (e.g., "low", "medium," "high," "very high"); or any way that is meaningful and helpful to the user. It is important to remember that precise numeric values, although implying a greater level of accuracy, do not mean a more thorough or complete analysis. Numeric values provide the air of precision, but not necessarily better accuracy. The element of uncertainty that is inherent in the probabilities and consequences model limits the accuracy of any given method. The accuracy of the output is a function of the methodology used and the quantity and quality of the data. In practice, there are often many factors that will affect the estimated likelihood of failure and the magnitude of the failure (consequences) that cannot be fully taken into account with a fixed model. It may be beneficial to use quantitative and qualitative methods in a complementary fashion to produce the most effective and efficient assessment. Risk assessment results (quantitative or qualitative) do not indicate whether the assessment type was qualitative or quantitative.

6.4 The Role of Inspection in Risk Assessment

Reducing inspection costs is not the primary objective of risk assessment, and the analysis may actually lead to increased inspection. Inspection optimization is frequently a side-effect of performing a risk assessment. The risk assessment review allows an owner to optimize the inspection quality and frequency based on the results of the risk assessment. The owner may even use the risk assessment to perform a "what if" comparison. When the inspection program is optimized based on an understanding of risk, one or more of the following cost reduction benefits may be realized:

- Ineffective, unnecessary, or inappropriate activities may be eliminated.
- Inspection of low-risk items may be eliminated or reduced.
- Online or non-invasive inspection methods may be substituted for invasive methods that require equipment shutdown.
- More effective, infrequent inspections may be substituted for less effective, frequent inspections.

Managing risks by using risk assessment can be useful in implementing an effective inspection program that meets performance-based safety and environmental requirements of the company. Risk assessment focuses efforts on areas where the greatest risk exists. It provides a systematic method to guide a user in the selection of equipment items to be included and the frequency, scope, and extent of inspection activities to be conducted to meet performance objectives.

The risk assessment may identify risks that may be managed by actions other than inspection. Some of these mitigation actions may include, but are not limited to:

- Modification of the process to eliminate conditions driving the risk
- Modification of operating procedures to avoid situations driving the risk
- Use of coatings to reduce deterioration rates/corrosion susceptibilities
- Upgrading of safety or detection systems

6.5 Risk Assessment Approach

The data within the risk assessment can be useful in determining the optimum economic strategy to reduce risk. The strategy may be different at different times in a facility's lifecycle. For example, it is usually more economic to modify the process when a facility is being designed than when it is operating and may be nearing the end of its lifecycle. A risk assessment performed on new equipment or on a new project in the design stage may yield important information on potential risks. This may allow the risks to be minimized by design, prior to actual installation.

Facilities approaching the end of their economic or operating service lives are a special case where application of risk assessment can be very useful. The end-of-life case for a facility is about gaining the maximum remaining economic benefit from an asset without undue personnel, environmental, or financial risk. End-of-life strategies focus inspection efforts directly on high-risk areas where the inspections will reduce risk during the remaining life of the facility. Inspection activities that do not affect risk during the remaining life are usually eliminated or reduced. It is important to revisit the risk assessment if the remaining equipment life is extended after the remaining life strategy has been developed and implemented.

Boundaries for physical assets included in the assessment are established consistent with the overall objectives. The level of data to be reviewed and the resources available to accomplish the objectives directly impact the extent of physical assets that can be assessed. The screening process is important in centering the focus on the most important physical assets so that time and resources are effectively applied.

The scope of a risk assessment may vary between the entire facility, set of equipment, or a single piece of equipment. Typically, risk assessment is performed on multiple pieces of equipment (e.g., all aboveground storage tanks (ASTs)) rather than on a single component.

Screening at the facility level may be performed by a simplified qualitative risk assessment, or by one of the following:

- Asset or product value
- History of problems/failures at each facility
- Age of facilities or age of equipment
- Proximity to the public
- Proximity to environmentally sensitive areas

Examples of key questions to answer at the facility level are:

- Is the facility located in a regulatory jurisdiction that will accept modifications to statutory inspection intervals based on risk assessment?
- Is the management of the facility willing to invest in the resources necessary to achieve the benefits of risk assessment?
- Does the facility have sufficient resources and expertise available to conduct the risk assessment?

If the risk assessment covers multiple facilities, then the first step is screening of all the facilities or tanks to rank relative risk. The screening points out areas that are higher in priority and suggests which facility or operating equipment merit first consideration. It also provides insight about the level of assessment that may be required for equipment at different facilities. Priorities may be assigned based on one of the following:

- Relative risk of the equipment
- Relative economic impact of loss of the equipment
- Relative consequence of failure from the equipment
- Relative reliability of the process units
- Inspection information
- Experience with similar equipment in similar service conditions

It is often advantageous to group equipment within a facility into systems where common environmental operating conditions exist based on stored product, operating temperature, equipment design, and operating history. By dividing a process unit into systems, the equipment can be screened together and time can be saved by not treating each piece of equipment separately.

A common practice utilizes block flow, or process flow diagrams, for the facility to identify the major pieces of equipment and their interconnection. Information about stored product, contained quantity, credible deterioration mechanisms, historical problems, etc., may be identified on the diagram for each system.

When an equipment unit is defined for the risk assessment and overall optimization is the goal, it is usually best to include similar equipment within the unit (e.g., aboveground piping located within a contained area). Practical considerations, such as resource availability, may require that the risk assessment be limited to one or more systems within the unit (e.g., total aboveground piping). Selection of systems may be based on:

- Relative risk of the systems
- Relative consequences of failure of systems
- Relative reliability of systems

In most facilities, a large percentage of the total risk will be concentrated in a relatively small percentage of the equipment items. These potentially high-risk items typically receive greater attention in the risk assessment. Equipment items are often screened to identify the higher risk items to carry forward to a more detailed risk assessment.

Risk assessment may be applied to all equipment containing petroleum products such as:

- Piping
- Aboveground tanks
- Underground tanks
- Pumps (pressure boundary), transfer equipment, and loading and unloading areas

Selection of equipment types to be included is based on meeting the objectives discussed previously. The following issues may be considered in screening the equipment for inclusion:

- Which types of equipment have had the most reliability problems?
- Under what conditions have the reliability problems been found?
- Which pieces of equipment have the highest consequence of failure (COF) if there is a failure?

The risk assessment is usually performed under the normal operating conditions of the facility. Abnormal startup, shutdown, and emergency operations risk review can be addressed in the facility's procedures (section 5.2.4), training (section 5.2.5), and management of change (Section 9).

Selection of the type of risk assessment depends on a variety of factors, such as:

- Whether the assessment is at a facility, equipment unit, or individual unit level
- Objective of the assessment
- Availability and quality of data
- Resource availability
- Perceived or previously evaluated risks
- Time constraints

A strategy can be developed matching the type of assessment to the expected or evaluated risk. For example, equipment or facilities that are expected to have lower risk may require only simple, fairly conservative methods to adequately accomplish the risk assessment objectives, whereas equipment or facilities that have higher expected risk may require more detailed methods. Another example of matching the type of assessment to the expected risk would be to evaluate all lower risk equipment qualitatively and then evaluate the identified higher risk items quantitatively.

The resources and time required to implement a risk assessment will vary widely between organizations depending on a number of factors, including:

- Implementation strategy/plans
- Knowledge and training of implementers
- Availability and quality of necessary data and information
- Availability and cost of resources needed for implementation
- Amount of equipment included in each level of risk assessment analysis
- Degree of complexity of the selected risk assessment analysis
- Degree of accuracy required

The estimate of scope and cost involved in completing a risk assessment might include the following:

- Number of facilities, equipment items, and components to be evaluated
- Time and resources required to gather data for the items to be evaluated
- Training time for implementers
- Time and resources required for risk assessment of data and information
- Time and resources to evaluate risk assessment results and develop inspection, maintenance, and mitigation plans

6.6 Risk Assessment Team

Risk assessment analysis requires data-gathering from many sources, specialized analysis, and risk management decision-making. As discussed in section 1.3.2, one individual does not possess the background or skills to single-handedly complete the entire study. Usually, a team of people with the requisite skills and background is needed to conduct an effective risk assessment. Depending on the application, some of the disciplines listed may not be required, and some team members may be part-time due to limited input needs. It is also possible that not all the team members listed will be required if other team members have the required skill and knowledge of multiple disciplines. In addition, it may be useful to have one of the team members serve as a facilitator of discussion sessions and team interactions.

The team leader is usually a stakeholder in the facility/equipment being analyzed and is typically responsible for:

- Forming the team and verifying that the team members have the necessary skills and knowledge
- Assuring that the study is conducted properly
    - Data gathered are accurate
    - Assumptions made are logical and documented
    - Appropriate personnel are utilized to provide data and assumptions
    - Appropriate quality and validity checks are employed on data gathered and on the data analysis
- Preparing a report on the risk assessment study and distributing it to the appropriate personnel who are responsible either for decisions on managing risks or for implementing actions to mitigate the risks
- Following up to ensure that the appropriate risk mitigation actions have been implemented.

Risk assessment personnel are responsible for assembling all of the data and carrying out the analysis. These people are typically responsible for:

- Defining data required from other team members
- Defining accuracy levels for the data
- Verifying through quality checks the soundness of data and assumptions
- Inputting/transferring data in the computer program and running the program (if one is used)
- Quality control of data input/output
- Calculating the measures of risk
- Displaying the results in an understandable way and preparing appropriate reports on the analysis
- Assisting the team in conducting a risk/benefit analysis if the analysis is necessary

Risk assessment personnel typically have a thorough understanding of risk analysis through education, training, or experience. They have usually received detailed training on the risk assessment methodology and on the procedures being used for the study so that they understand how the program operates and the vital issues that affect the final results.

The qualifications and training of all risk assessment personnel are usually documented. Whether contractors or internal personnel provide the risk assessment analysis, a program of training is typically in place along with a procedure to document that the personnel are sufficiently qualified.

The other team members can receive basic training on the risk assessment methodology and on the program(s) being used. This training can be geared primarily to an understanding and effective application of facility and equipment risk assessment. The risk assessment personnel on the team or another person knowledgeable about the company's specific risk assessment methodology and the program(s) being used can provide this training.

6.7 API Publication Appendix Risk Assessment Demonstration

This document includes an optional comprehensive quantitative risk assessment methodology that can be used to perform the risk assessment portion of the overall company RMP. Described in Appendix A, the methodology addresses only liquid releases; it does not address vapor releases. The optional Appendix A model can be used to quantitatively evaluate the likelihood of failure (LOF) and qualitatively evaluate the COF for environmental damage, business/economic impacts, and the population effects associated with community, health, safety, and fire. It is designed specifically to be used for the liquid release scenarios defined in the model.

The optional Appendix B model is a simplified qualitative risk assessment methodology that can be used to address the likelihood of occurrence and the consequences of occurrence on a weighted number basis. The risks can be evaluated for any user-defined release scenario.

Users have the option to incorporate these consequence models in their overall risk program or to develop their own risk assessment methodology. The optional models in Appendices A and B provide a contrast between a very detailed, narrowly focused comprehensive model and a broad user-defined approach to risk assessment.

6.7.1 API Example Risk Assessment Method for AST Facilities

The optional methods presented in the appendices are used to predict the LOF and COF. The determination of risk through establishment of the LOF and COF can then assist the user in the selection of control measures that prevent, detect, or protect against liquid releases. The methods can be used in a quantitative scoring system, in a qualitative scoring system, or in a risk matrix to estimate and rank risks. The approach can then assist the user in determining what risks may require mitigation and the risk reduction accomplished through possible available control measures. When applied rigorously, this tool can be used to answer the following questions:

- Is the current system acceptable when compared against a set risk level?
- Of several suggestions for improvement, which works best to reduce risks?
- If there are competing designs, which provides the most cost-effective way of reducing risks?

As described in the previous sections, all risk assessment systems analyze risk by estimating both the likelihood and consequence of a postulated scenario.

6.7.2 The Risk Scoring System

The risk scoring system provided in both optional Appendices A and B can be used to yield a single numeric value. The single numeric value has several benefits:

- It derives a single measure that can be used to rank the relative risk of competing options
- The results can be directly applied to a cost-benefit analysis
- It has the ability to aggregate risks for an entire system
- It can be used to evaluate single changes that may affect multiple equipment items

The risk scoring system is quantitative in nature, since it produces a numeric score for a facility or piece of equipment. To determine the score, the frequencies and the consequences of a pre-defined leak scenario are multiplied together. The risks for all scenarios are then summed to find the combined risk for that specific piece of equipment. The total risk for the system is then found by adding the risk scores for all equipment in the system. Table 6-1 shows an example of how the scoring system would be applied to a tank.

Table 6-1: Scoring System Example

Scenario	(Example) Estimated Frequency (events per year)	(Example) Estimated Consequence (dimensionless)	Risk Score (Risk/year)
Event #1	0.0036	10,000	36
Event #2	0.00002	1,250,000	25
Event #3	0.00017	150,000	26
Event #4	0.018	60,000	1080
Event #5	0.12	500	60
TOTAL RISK (per year)			1227

In the above example, the highest risk event is Event #4, which clearly dominates all other events. An event is defined as a specific release scenario for a specific piece of equipment that is undergoing a risk assessment. The user can add risks at different levels and define them as needed. For example, the overall risk of a tank release would be the addition of the "risk of bottom failure" plus the "risk of shell failure" plus the "risk of external hose failure." The risk presented by all tanks at a facility would be the addition of risks for each tank at the facility.

6.7.3 The Risk Matrix

The risk scoring system provided in this methodology can also be used to yield an x-y value. The risk matrix provides an alternate approach to risk assessment that fills some of the gaps in the scoring approach:

- It is easy to interpret the risk of each scenario
- Each component of risk (likelihood vs. consequence) is displayed
- High-risk scenarios are highlighted
- Levels of risk can be assigned to each scenario

The sample data from Table 6-1 can be displayed in a risk matrix as illustrated in Figure 6-1. The user has to define the areas shown in the matrix as low risk, medium risk, medium-high risk, and high risk. The shading of the various levels of risk determines how the scenarios are rated. Many companies may choose to leave the matrix unshaded.

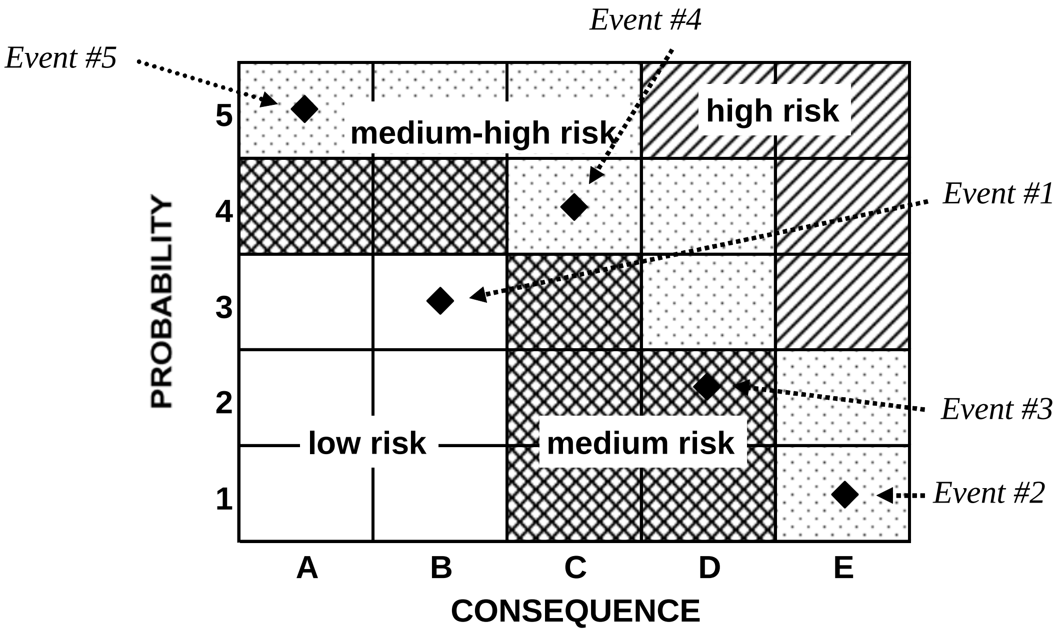

Figure 6-1: Example Risk Matrix Showing the Results of the Example Case Including Users' Bias to Consequence Aversion (Note: This matrix is for demonstration only and is not to be construed as endorsed matrix risk level categorizations.)

As shown in Figure 6-1, Events #2, #4, and #5 are all considered medium-high risk. This example demonstrates the consequence-aversion nature of the shading in the above matrix. Note that any scenario with a very high consequence (Level E) is rated as a medium-high or higher risk, regardless of the likelihood. Therefore, Event #4 would most likely take precedence in an evaluation of alternative remedial options.

6.7.4 Steps in Conducting the API Risk Assessment Model

Figure 6-2 shows the six basic steps in the risk analysis for an AST system. The process is repeated for each release scenario that the user desires to assess. The optional risk assessment model in Appendix A can analyze storage tanks, piping, and loading/unloading systems.

Figure 6-2 shows that the risk assessment for the established scenarios proceeds by estimating the likelihood and consequences of each scenario. The duration is needed to calculate spill volumes, so it is estimated prior to determining consequences. Likelihood and consequence are estimated separately and are then merged into a risk value as described above, with a risk score or a risk matrix. The final step, risk assessment and decision-making, is performed after the risk results have been checked for validity.

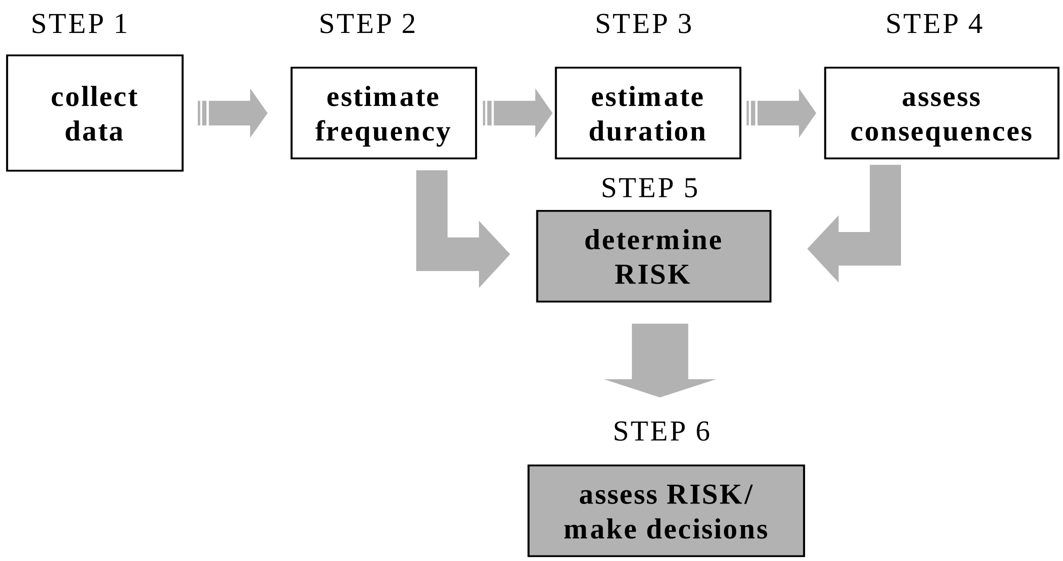

Figure 6-2: Overview of AST Risk Assessment Process

To make the process more manageable, the risk assessment system has been converted into a series of forms or worksheets that lead the analyst through all necessary calculations. Reference tables and charts are provided to circumvent the need to carry out complex calculations.

The following sections provide an overview of all steps, and the appendices contain the details of the process.

STEP 1—Data Collection

The data required for the optional Appendix A Risk Assessment are listed in Appendix C. In general, most of the data are readily available at the tank facilities; however, in some cases, personnel with experience in environmental issues may be asked to provide information regarding the impact of a spill. Appendix C provides forms that will facilitate data collection.

STEP 2—Likelihood (Frequency) Analysis

The likelihood of a scenario is measured in terms of frequency or occurrences per year for the risk assessment. This estimate covers the chain of events from initial failure through eventual remediation, including conditions that could worsen the effects of a spill. The estimation process involves reliability (equipment and human) techniques, such as human reliability analysis or failure logic models. The likelihood of a scenario is estimated by answering questions on a form. Depending on the response for a specific tank facility, factors are used to adjust probabilities up or down.

STEP 3—Spill Volume Duration Estimates

It is impossible to estimate consequences without an estimate of the duration of the spill volume for most scenarios. Therefore, a set of rules is provided to allow the analyst to estimate spill volume durations.

Appendix C provides data sheets to aid in the estimation of spill volume for the optional Appendix A model.

STEP 4—Consequence Analysis

Any release at an AST facility carries the potential for adverse effects to the surrounding environment, including contamination of soil and groundwater. Nearby potable water aquifers could also be contaminated, posing health threats to people living in the area. Moreover, lakes and streams could be affected, damaging wildlife or limiting drinking water or recreational use. All of these pathways for damage are included in the AST risk model. As with the likelihood side of the analysis, the consequences of each scenario are estimated by filling out a worksheet in Appendix C and answering basic questions relating to the environment around the AST facility. The answers are then used to determine a consequence estimate for the optional Appendix A model.

STEP 5—Risk Determination

Combining the likelihood and consequence information produces the risk result. As mentioned previously, the AST risk system can use either a risk matrix or a numeric scoring system to present the risk results for each item analyzed.

STEP 6—Assess Risk/Make Decisions

Once the various risks are determined, the user can employ that information to rank the various risks and assess the need and effect of different mitigation strategies.

6.7.5 Conducting Risk Assessment Decision-Making

Typically, risk scores are evaluated for a base or current case. This base case provides a benchmark for the current level of risk. Depending on the type of decisions to be made, it is common to evaluate a set of alternative cases, reflecting improvements in design, training, maintenance, or changes in environmental aspects of the facility. Once the analyst knows the base case level of risk, the control measures can be evaluated in several different ways. The framework provided in this document allows the user to evaluate risks in the following ways:

- Against a set criteria for decision-making
- Cost-benefit approach
- Risk-reduction approach

If desired, a company may impose risk criteria requiring that the total risk score for a system be below a predefined value. Since the total risk score derived above is a reflection of the expected value for losses in a year, insurance levels or previous experience may be used to set the criteria. Once criteria are applied, decisions can be made regarding the implementation of various programs to reduce risk. As discussed previously, criteria can be set at different levels, requiring different actions for varying levels of risk. This document does not suggest criteria; it only provides the framework for a system with criteria for decision-making.

Cost-benefit analysis (CBA) is a technique for making decisions by comparing the costs and benefits of a project. In risk assessment, it is used to assess *proposed* safety by comparing the cost of implementing the measure against the benefit of the measure in terms of the cost of the accidents it would avert. To make this comparison, the costs and benefits are expressed in common units (e.g., dollars). The purpose of CBA is to show whether the benefits of a measure outweigh its costs, and thus indicate whether it is appropriate to implement the measure.

Based on the results of the evaluations described above, a list of risk-reducing options is prepared based on both risk and cost-effectiveness. The analysis typically considers the lifetime costs and risks related to the installation of the measure, if appropriate. Further, likelihood-reducing measures usually have priority over consequence-reducing measures. For example, if two options have the same cost-effectiveness, the priority of the measures is typically:

1. Reduce frequency
2. Control the event in an area
3. Improve response (often contingency measures)

For AST facilities, the information provided in API Publ 340 forms the basis for risk reduction measures.

6.8 Gathering, Reviewing, and Integrating Data

Performance of a risk assessment will require the collection, review, and integration of a large amount of data that address the facility, equipment, and local environmental conditions at the site. This section presents an approach to data collection and summarizes the general types of data typically needed to perform a facility-specific risk assessment. The type and depth of the risk assessment will affect the required data and the level of detail.

6.8.1 Getting Started

<u>6.8.1.1 Risk Assessment Data Needs.</u> As previously discussed, a risk assessment study may use a qualitative, quantitative, or semi-quantitative approach. The fundamental difference among these approaches is the amount and detail of input, calculations, and output; therefore, the type of risk assessment will directly affect the type and quality of data required to perform the analysis.

Documentation of unique conditions, equipment, or system configuration is necessary for any level of study. It is important to document all bases for the study and assumptions from the onset for each method and to apply a consistent and rational approach. Any deviations from prescribed standard procedures are usually well documented. It may be helpful to collect information according to the particular piece of equipment, group of equipment, or location within the terminal site.

Typical data needed for a risk assessment analysis may include but are not limited to:

- Type of equipment
- Materials of construction
- Inspection, repair and replacement records
- Stored product
- Operating conditions
- Safety systems
- Detection systems
- Deterioration mechanisms, rates, and severity
- Interior and/or exterior coating and insulation data
- Equipment replacement costs
- Soil conditions
- Surrounding environmental receptors and area environmental sensitivity
- Environmental remediation costs

<u>6.8.1.2 Qualitative Risk Assessment Data Needs.</u> The qualitative approach typically requires limited information on the data needs listed above. Further, items required are typically only categorized into broad ranges or classified versus a reference point. It is important to establish a set of rules to assure consistency in categorization or classification.

6.8.1.3 Quantitative Risk Assessment Data Needs. Quantitative risk analysis requires the most detailed information on the available data. The data listed in Appendix C are typical of the level of information required to complete a quantitative risk analysis.

6.8.1.4 Semi-Quantitative Risk Assessment Data Needs. The semi-quantitative analysis typically requires the same data as a quantitative analysis but generally not as detailed. For example, the fluid volumes may be estimated, and although the precision of the analysis may be less, the time required for data-gathering and analysis will also be less and may not appreciably affect accuracy.

6.8.2 Data Sources

Information needed to perform the risk assessment can be found in many places within a facility. As briefly discussed in section 6.1, it is important to stress that the precision of the data usually matches the complexity of the risk assessment method being used. It is important for the individual or team to understand the sensitivity of the data needed for the program before gathering data. It may be advantageous to combine this data-gathering with other data-gathering (e.g., process hazard analysis (PHA), Spill Prevention Control and Countermeasures Plan, and Oil Pollution Act regulatory requirements). Interviews with onsite personnel and a field visit will be necessary to complete the forms and to collect the information required.

6.8.3 Identification and Location of Data

Specific potential sources of information include, but are not limited to:

a. Design and Construction Records/Drawings
    1. Piping & Instrumentation Diagrams, Process Flow Diagrams, etc.
    2. Piping mechanical or isometric drawings
    3. Engineering specification sheets
    4. Materials of construction records
    5. Construction QA/QC records
    6. Codes and standards used during construction or inspection
    7. Protective instrument systems
    8. Leak detection and monitoring systems
    9. Isolation systems
    10. Inventory records
    11. Safety systems
    12. Layout
b. Inspection Records
    1. Schedules and frequency
    2. Amount and types of inspection
    3. Repairs and alterations
    4. Maintenance records including replacement and preventive maintenance
    5. Inspection results
c. Process Data
    1. Contained product material safety data sheet (MSDS) information
    2. Operating procedures
    3. Site logs and records
    4. PHA data or reports
d. Management of Change (MOC) records
e. Offsite Data and Information—if consequence may affect offsite areas

f. Failure Data
    1. Generic failure frequency data—industry or in-house
    2. Industry-specific failure data
    3. Plant and equipment specific failure data
    4. Reliability and condition monitoring records
    5. Leak data
g. Site Conditions
    1. Climate/weather records
    2. Seismic activity records
    3. Proximity to surface, groundwater, and potable water supplies
    4. Regulatory requirements
    5. Public relations/other non-economic factors
h. Equipment Replacement Costs

6.8.4 Data Collection

Every effort is typically made to collect reliable data. When data of suspect quality or consistency are encountered, such data can be flagged so that appropriate consideration can be given to these concerns during the analysis process. Usually, no decision is addressed solely on the basis of suspect data.

Resolution of the input data can also be taken into account. Typically, every effort is made to use actually existing data (i.e., the analysis does not assume an entire system has uniform properties when more localized information is known). Widespread data assumptions are usually minimized, as they will not increase the overall accuracy of the analysis. If the needed data are not readily available, the risk assessment team can flag the absence of information and then discuss the necessity and urgency of collecting the missing information.

6.8.5 Data Integration

The quality of an ongoing risk assessment and the quality of data developed during routine facility maintenance and operation rely strongly on the use of available information and the monitoring of conditions over a period of time. A substantial amount of inspection and monitoring data is collected over the life of a tank or pipeline. Examples of such data are cathodic protection station checks, nondestructive testing inspection results, coating inspections, valve and gasket data, pressure test data, estimated spill volumes, etc. These data may reside within various departments and considerable effort can be involved in collecting, collating, and arranging these data in a form that allows ready comparison. The number of data points may become extensive when all repair, maintenance, inspection, and monitoring data for a facility are available for review. Data are typically stored in an electronic database or as collated hard copy records. Out-of-date or inaccurate data or inspection reports are not usually included in the analysis.

6.8.6 Data Gap Assumptions

The data quality has a direct relation to the accuracy of the analysis. Although the data requirements are quite different for the various types of analysis, the quality of input data is always important. It is beneficial to the integrity of a risk assessment analysis to ensure that the data are up-to-date and validated by knowledgeable persons.

As is true in any inspection program, data validation is essential to ensure that it doesn't rely on any of the following: outdated drawings and documentation, inspector error, clerical error, or references to replaced or repaired equipment. Another potential source of error in the analysis is assumptions on equipment history. For example, if baseline inspections were not performed or documented, nominal thickness may be used for the original thickness. This assumption can significantly affect the calculated corrosion rate early in the equipment's life. The effect may be to mask a high corrosion rate or to inflate a low corrosion rate. A similar situation exists when the remaining life of a piece of equipment with a low corrosion rate requires inspection more frequently. The measurement error may result in the calculated corrosion rate appearing artificially high or low. It is because of this result or error that it is critical to identify data gaps and then to reasonably approximate the data by using similar service data for the facility being studied.

This validation step stresses the importance of having a knowledgeable individual compare data from the inspections to the expected deterioration mechanism and rates. This person may also compare the results with previous measurements on that system, on similar systems at the site, or within the company or published data. Statistics may also be useful in this review. This review also typically factors in any changes to the system.

6.9 Record keeping

The guidelines provided in this section for recordkeeping are consistent with the recommendations provided in other API documents, including API RP 580 (refinery document) and API Std 1160 (pipeline document).

6.9.1 General Requirements

It is important to capture sufficient information to fully document the assessment. Typically, this documentation includes the following:

- Type of assessment
- Team members performing the assessment
- Time frame over which the assessment is applicable
- The inputs and sources used to determine risk
- Assumptions made during the assessment
- The risk assessment results (including information on likelihood and consequence)
- Follow-up mitigation strategy, if applicable, to manage risk
- The mitigated risk levels (i.e., residual risk after mitigation is implemented)
- References to codes or standards that have jurisdiction over extent or frequency of inspection

Ideally, sufficient data are captured and maintained so that the assessment can be recreated or updated at a later time by others who were not involved in the original assessment. Storing the information in a computerized database or other electronic form will enhance the retrieval and stewardship capabilities of the program.

6.9.2 Risk Assessment Methodology

The methodology used to perform the analysis is usually documented, as well as the likelihood and consequences of failure, so that it is clear what type of assessment was performed. If a specific software program is used to perform the assessment, it is typically documented and maintained. The documentation is usually sufficiently complete so that the basis and logic for the decision-making process can be checked or replicated at a later time.

6.9.3 Risk Assessment Personnel

The assessment of risk will depend on the knowledge, experience, and judgment of the personnel or team performing the analysis; therefore, a list of team members involved is typically recorded. This will be helpful in understanding the basis for the risk assessment when the analysis is repeated or updated.

6.9.4 Time Frame

The level of risk is usually a function of time either because it is a result of the time dependence of a failure mechanism (e.g., corrosion), or simply because of the potential for a release because of cumulative tank fills, loadings, or changes in the operation of equipment. Therefore, the time frame over which the analysis is applicable is usually defined and recorded in the final documentation. This will permit tracking and management of risk effectively over time.

6.9.5 Assessment of Risk

The various inputs used to assess both the LOF and COF are typically recorded and include, but are not limited to, the following information:

- Basic equipment data, pertinent inspection history, operating conditions, materials of construction, service exposure, corrosion rate, repair history, etc.
- Operative and credible deterioration mechanisms
- Criteria used to judge the severity of each deterioration mechanism
- Anticipated failure modes(s) (e.g., leak or rupture)
- Key factors used to judge the severity of each failure mode
- Criteria used to evaluate the various consequence categories, including safety, health, environmental, and financial
- Risk criteria used to evaluate the acceptability of the risks

6.9.6 Assumptions Made to Assess Risk

Risk analysis, by its very nature, requires that certain assumptions be made regarding the nature and severity of equipment failure. The assignment of a failure mode and the severity of the contemplated event will invariably be based on a variety of assumptions, regardless of whether the analysis is quantitative or qualitative. To understand the basis for the overall risk, these factors are typically clearly recorded in the final documentation. Clearly documenting the key assumptions made during the analysis of likelihood and consequence will greatly enhance the capability to either recreate or update the assessment.

6.9.7 Risk Assessment Results

The likelihood, consequence, and risk results are typically recorded in the documentation. For items that require risk mitigation, the results after mitigation are usually documented as well.

6.9.8 Mitigation and Follow-Up

One of the most important aspects of managing risk through an RMP is the development and use of mitigation strategies. Therefore, the specific risk mitigation required to reduce either likelihood or consequence or both is usually documented in the assessment. The mitigation "credit" assigned to a particular action is noted along with any time dependence. The methodology, process, and person(s) responsible for implementation of any mitigation can also be documented.

6.9.9 Codes, Standards, and Government Regulations

The number and type of codes and standards used by a facility can have a significant impact on risk assessment results, particularly during the data collection stage. Since various API documents, other industry codes and standards, and government regulations cover the inspection requirements for most pipe and tank equipment, reference to these documents is typically recorded as part of the risk assessment. This is particularly important where implementation of a qualitative or quantitative risk assessment is used to reduce either the extent or frequency of inspection.

SECTION 7—INTEGRITY ASSESSMENT

An integrity assessment establishes the priorities by which users (e.g., owner, facility) can address the integrity of their system and equipment. The risk assessment shows owners which equipment or operations represent the highest risk (i.e., highest total risk, highest likelihood event, and highest consequence events). Integrity assessment can then be used to:

- Further define or determine the equipment condition
- Validate the assumptions used in the risk assessment
- Monitor equipment integrity to ensure that risks do not increase as a result of the deterioration of equipment (i.e., corrosion over time)
- Mitigate risk

The primary means of performing integrity inspection is through planned, properly executed, and documented equipment inspections. It is important to remember that inspections (visual and non-destructive examination) provide an indication of defects. It is necessary that qualified individuals evaluate the results of the inspection to characterize the nature, significance, and repair, if necessary, of the identified defect or deterioration mechanism.

The following sections describe the integrity assessment methodology that is recommended for use as part of the overall company's risk management program (RMP). API standards, recommended practices, and publications provide a wealth of information on the inspection, evaluation, and repair procedures applicable to petroleum terminal and tank facilities. These documents include API Std 570, 650, 651, 652, and 653.

7.1 Methods of Inspection

One way that risk can be managed is by performing equipment inspections. For equipment that has been or will be inspected, risk can be reduced by increasing the frequency of current inspections or improving the effectiveness of the inspection (e.g., by changing the type of UT inspection). Obviously, inspection does not arrest or mitigate deterioration mechanisms; rather, it serves to identify, monitor, and measure the deterioration mechanism(s), and it is helpful input in predicting when the deterioration will reach a critical point. Correct applications of inspections will improve the user's ability to predict the deterioration mechanisms and rates of deterioration. The better the predictability, the less uncertainty there will be about when a failure may occur. Mitigation (e.g., repair, replacement, alterations, additions, re-design) can then be planned and implemented prior to the predicted failure date. The reduction in uncertainty and increase in predictability through inspection translate directly into a reduction in the likelihood of a failure and a reduction in the risk; however, it is important for users to diligently ensure that temporary inspection alternatives, in lieu of more permanent risk reductions, are effective.

Risk mitigation achieved through inspection presumes that the organization will act on the results of the inspection in a timely manner. The quality of the inspection data and the analysis or interpretation will greatly affect the level of risk mitigation. Risk mitigation is not achieved if inspection data are not properly analyzed and acted upon where needed; thus, proper inspection methods and data analysis tools are critical. Inspection may not always provide sufficient risk mitigation and is only one means available for mitigation.

Whether inspections will be effective or not depends on:

- Equipment type
- Determinable deterioration mechanism(s)
- Rate of deterioration or susceptibility
- Inspection methods, coverage, effectiveness, and frequency

- Accessibility to expected deterioration areas
- Shutdown/equipment out-of-service requirements
- Amount of achievable reduction in likelihood of occurrence; depending on factors such as the remaining life of the equipment and type of deterioration mechanism, risk management through inspection may have little or no effect; examples of such cases are:
    - Corrosion rates well-established and equipment nearing end of life
    - Instantaneous failures related to operating conditions such as brittle fracture
    - Inspection technology that is not sufficient to detect or quantify deterioration adequately
    - Too short a time frame from the onset of deterioration to final failure for periodic inspections to be effective (e.g., high-cycle fatigue cracking)
    - Event-driven failures (circumstances that cannot be predicted)

In cases where inspection will not be effective, an alternative form of mitigation may be required.

7.2 Methods of Assessment

After completion of the inspection, the company can review the results and determine whether repairs, additional inspection, more frequent inspection, or monitoring is required. Assessment of the inspection results and suitability for continued service are typically part of the integrity assessment that is performed by the owner. The assessment is based on review of the inspection results, service requirements, site-specific conditions, requirements of applicable codes and standards, and any applicable regulatory requirements. The particular assessment method will vary depending upon the type, nature, and extent of inspection performed. It is always important to have knowledgeable, experienced, and trained individuals perform the assessment.

7.3 Establishing Re-inspection Intervals and Mitigating Risk

Industry codes and standards or regulatory requirements often stipulate inspection intervals; however, the owner can establish inspection intervals based not just on these requirements, but also based on a thorough analysis of the inspection data, inspection quality, service history, inspection history, and risk. Decreasing inspection intervals may improve integrity assessment and decrease risk in some circumstances.

7.3.1 Establishing an Inspection Strategy Based on Risk Assessment

The results of the risk assessment may be used as the basis for development of an overall inspection strategy for the group of equipment included in the assessment, such as underground piping, aboveground piping, tanks, ancillary equipment, loading and unloading areas, equipment within a contained area, and equipment outside a contained area. The inspection strategy can be designed in conjunction with other mitigation plans so that all equipment items will have resultant risks that are acceptable. Users typically consider risk rank, risk drivers, equipment history, numbers and results of inspections, types and effectiveness of inspections, and equipment in similar service and its remaining life in the development of their inspection strategy.

Inspection is effective only if the inspection technique chosen is sufficient for detecting the deterioration mechanism and its severity. The level of risk reduction achieved by inspection will depend on:

- Mode of failure of the deterioration mechanism
- Time interval between the onset of deterioration and failure
- Detection capability of inspection technique
- Scope of inspection
- Frequency of inspection
- Inspection effectiveness

Companies can be deliberate and systematic in assigning the level of risk management achieved through inspection and are typically cautious not to assume that there is an unending capacity for risk management through inspection.

The inspection strategy is usually a documented, iterative process to ensure that inspection activities continually focus on items with higher risk and that the inspection activities effectively reduce risks.

7.3.2 Managing Risk with Inspection Activities

The effectiveness of past inspections is part of the determination of the present and future risk. Risk can be affected by future inspection activities. Risk assessment can be used as a “what if” tool to determine when, what, and how inspections can be conducted to yield an acceptable future risk level. Key parameters and examples that can affect the future risk are:

- **Frequency of inspection—**Increasing the frequency of inspections may serve to better define, identify, or monitor the deterioration mechanism(s), and thereby reduce the risk. Inspection frequencies can be optimized to provide maximum benefit.
- **Coverage**—Different zones or areas of inspection of an item or series of items can be modeled and evaluated to determine the coverage that will produce an acceptable level of risk.
- **Tools and techniques—**The selection and use of the appropriate inspection tools and techniques can be optimized to cost-effectively and safely reduce risk. In the selection of inspection tools and techniques, inspection personnel should consider that more than one technology may achieve risk mitigation; however, the level of mitigation achieved can vary depending on the choice.
- **Procedures and practices—**Inspection procedures and the actual inspection practices can affect the ability of inspection activities to identify, measure, and/or monitor deterioration mechanisms. If the inspection activities are executed effectively by well-trained and qualified inspectors, the expected risk management can be obtained. The user is cautioned not to assume that all inspectors and non-destructive examination (NDE) personnel are well-qualified and experienced, but rather to take steps to assure that they have the appropriate level of experience and qualifications.
- **Internal or external inspection**—Risk reductions by both internal and external inspections can be assessed. Often external inspection can provide useful data for risk assessment. In some cases, invasive inspections may cause deterioration and increase the risk of the equipment. Examples where this may happen include human errors in isolating, cleaning, and returning a system to service and risk associated with shutting down and starting up equipment.
- **In-service vs. out-of-service inspections—**In-service inspections, such as periodic external in-service inspections or internal in-service robotic inspections, can aid the user in identifying damage to the equipment as a substitute for, or in addition to, an internal out-of-service inspection.

The user can adjust these parameters to obtain the optimum inspection plan that manages risk and is also cost-effective and practical.

7.3.3 Assessing Inspection Results and Determining Corrective Action

Inspection results, such as deterioration mechanisms, rate of deterioration, and equipment tolerance to the types of deterioration, are typically used as variables in assessing remaining life and future inspection programs. The results can also be used for comparison or validation of the models that may have been used for likelihood of failure determination.

A documented mitigation action program can be developed for any equipment item requiring repair or replacement. The program can address the extent of the repair (or replacement), engineering and inspector recommendations, the proposed repair method(s), the appropriate QA/QC procedures, and the required date of completion for the repair/replacement.

SECTION 8—RISK MITIGATION

Risk mitigation is the process of reducing a known risk by decreasing the likelihood of occurrence, the consequences of occurrence, or both. An important part of risk management is the development and use of risk mitigation strategies. Part of the risk management process is to analyze the risks associated with the facility and compare those risk evaluations to the corporate-defined risk tolerance. The approach outlined in section 4.2.1 showed that a risk matrix can be used to rank risks and establish corporate criteria when high-risk items require some form of remediation or mitigation; therefore, for those items that a facility has identified as being too high-risk, some form of remediation or mitigation will be required. Analysis of the risk assessment will most likely result in a series of mitigation activities. Some of these mitigation activities may require immediate action, while others may be scheduled in a long-term corporate or facility plan. The criticality of mitigation actions and how they are scheduled will depend on the results of the risk assessment, integration of this information into an owner's overall risk management program (RMP), and the availability of different types of mitigation strategies (e.g., use of engineered controls, application of administrative controls, upgrading of the equipment, increased or improved inspections, removing the equipment from service, etc.).

The approaches outlined in this section are universally applicable to all risk assessment approaches regardless of the type of assessment performed. It is up to the facility owner to establish the criteria by which risks are screened and mitigation is required. The specific risk mitigation required to reduce either likelihood or consequences is usually documented as part of the RMP. This documentation includes:

- The mitigation "credit" assigned to a particular strategy
- Any time dependency associated with the mitigation measure
- The methodology or process used to screen the mitigation measures
- The persons responsible for implementing the mitigation measure

8.1 General

A facility's RMP will include applicable mitigation activities to prevent, detect, and minimize the consequences of unintended releases. Mitigation activities do not necessarily require justification through additional inspection data and can be identified during normal operation, initial risk assessment, implementation of the baseline inspection, or subsequent testing. Any effective mitigation activity will reduce the magnitude of the likelihood of failure (LOF) or the likelihood of consequences (COF).

8.2 Mitigation Approach and Options

API has developed a series of mitigation measures (referred to as control measures) that can be used to reduce the LOF, COF, or both, of an established risk for a specific release scenario. API Publ 340 describes this approach to mitigation in detail and focuses on the selection of appropriate release prevention measures as determined by the owner. The release prevention measures outlined in API Publ 340 pertain to control measures (e.g., engineering and administrative) that will prevent, detect, or protect the environment from **liquid** releases of petroleum only. Selection of appropriate control measures is a complex process that involves consideration of several criteria, including environmental concerns, operational considerations, and operational expertise based on experience. The criteria considered in the selection process vary from facility to facility; thus, the choice is site-specific and is typically tailored to meet the needs of each location. The following is a list of factors that are typically considered during the selection process:

Environmental and Population Factors

- Surrounding population, land use, and ecology
- Proximity to groundwater

- Aquifer location and gradient
- Proximity to navigable water
- Site geology, topography, and drainage
- Permeability of native soil and backfill
- Toxicological factors
- Epidemiological factors
- Product volume and type (toxicity, flammability, solubility, volatility, viscosity)

Operational Considerations

- Remaining service life of the facility, tank, or system
- Effectiveness of measure
- Type of facility
  - Staffed vs. unstaffed
  - Age of facility and equipment
  - Maintenance of equipment
- Type of product stored
- Inventory turnover rate (duration of storage)

Company/Industry Experience

- Previous use of control measures
- Maintenance history
- Operator experience
- Established training, maintenance, inspection, and operation system

Site-Specific Concerns

- Facility staff—training program, experience, management availability, event frequency
- Facility design
- Specific facility environmental or safety concerns
- Site access, operations, or environment restrictions
- Presence of local mutual aid

Business Needs

- Initial cost
- Long-term operation and maintenance cost
- Inspection, maintenance, operating, and testing requirements
- Company philosophy
- Risk assessment

Selection of any mitigation measure (control measure) will require an evaluation of the above-listed factors. Figure 8-1 illustrates a hierarchy that the owner may use as a guide when making a site-specific selection of control measures. The figure lists the three control measures addressed in API Publ 340 (prevention, detection, and protection) in the form of a pyramid. On the left side of the pyramid is an illustration of the effectiveness of a specific item that varies by the type of control measure. It increases from a low effectiveness at the base of the pyramid to high effectiveness at the top of the pyramid. The right side of the pyramid illustrates the level of potential environmental damage and increases from a low potential level at the top of the pyramid (prevention measures) to a high potential level at the bottom of the pyramid (protection or cleanup). The width of the pyramid illustrates the relative effectiveness of each type of control measure. At the top of the pyramid are all prevention type control measures, followed by detection control measures and then by protection control measures. At the base of the pyramid is the category termed cleanup/remediation. Cleanup/remediation does not represent a control measure; it is the undesired end result of a petroleum release. In general, cleanup/remediation is very costly to perform; thus, methods that prevent a release from occurring are typically more cost-effective control measures since they have no resultant environmental damage. Detection methods, which will rapidly identify a release, are typically less cost-effective (overall cost of the impact of the release) than prevention measures, but more cost-effective than protection measures. Similarly, detection measures potentially may have some resultant environmental damage in the event of a release, but not as much potential damage as protection measures. Protection measures are towards the bottom of the pyramid because protection measures by design are used to minimize the impact of a release on the environment; thus, protection measures will require some level of cleanup/remediation and will potentially cause greater environmental damage than either detection or prevention methods.

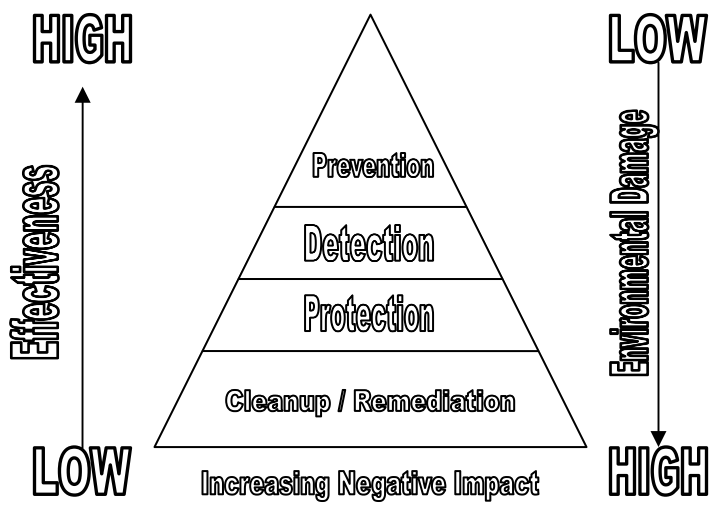

Figure 8-1: Hierarchy for Selection of Control Measures

In addition to the hierarchy and control measures detailed in API Publ 340, the mitigation activities could include general strategies to achieve the following goals:

- Control corrosion
- Detect unintended releases
- Minimize the consequences of unintended releases
- Prevent overfills

Facilities can also recognize that mitigation activities may require follow-up to assure effective implementation. Examples of follow-up actions for the above list of mitigation options would be:

- Monitor and maintain coatings and/or cathodic protection (CP) systems for control of corrosion
- Monitor leak detection devices such as telltale pipes on release prevention barriers
- Improve emergency response procedures
- Test and maintain high-level alarms

The most practical and cost-effective risk mitigation strategy can then be developed for each item.

One method of reducing risk for items with higher or unacceptable risk is through increased inspection. Usually, inspection provides a major part of the overall risk management strategy.

8.3 Using API Publication 340

API Publ 340 provides a ready reference of available control measures that can be used to mitigate the risks from liquid releases by reducing the frequency of occurrence, consequences of occurrence, or both. API Publ 340 utilized industry expert opinion to summarize and evaluate the different causes of liquid releases at aboveground storage terminals. For each category of equipment (e.g., tanks, piping, loading/unloading areas, etc.), the publication describes the cause of a liquid release and presents the available control measures to mitigate that scenario in table format. Mitigation control measures were divided into the following three different sets of control measures depending on how the control measure functions:

- Prevention control measures
- Detection control measures
- Protection control measures

Prevention measures are aimed at stopping a liquid release from occurring in the first place. Tank inspection utilizing the approach outlined in documents such as API Std 653 is an example of a prevention control measure. Detection control measures focus on those methods that discover a liquid release at the earliest opportunity after a liquid release has occurred. An under-tank petroleum product sensor is an example of a detection measure. Protection measures are those items that contain or mitigate a release to keep it from having a more adverse affect on the surrounding area. Diked area liners are an example of a protection control measure.

The facility operator/engineer can use API Publ 340 as a resource to identify and screen available control measures for items found by the owner to have an unacceptably high risk to the facility. API Publ 340 also provides information on the relative cost and required maintenance for individual control measures, and this range of costs helps the user understand the relative expense of a selected control measure.

The following examples detail an approach for utilizing API Publ 340 to screen control measures.

8.4 Summarized Examples

Selection of appropriate control measures is a complex process involving consideration of different local, company, regulatory, and site-specific criteria that balance environmental, operational, safety, local community, and business concerns. The following examples have been created to demonstrate different approaches to utilizing this document in the evaluation, selection, and implementation of release prevention, detection, and protection control measures. When applicable, the available control measures were taken directly from API Publ 340. The examples do not show all of the detail that goes into the calculation of risk (likelihood and consequences), nor do they provide all of the detail necessary to evaluate and select a control measure; however, they do show the reader the different approaches and steps to follow in risk mitigation. The examples start with a risk for a specific terminal scenario, which is described in the beginning of the section, and the change in risk is recalculated for each selected control measure. For the risk assessment calculation, the comprehensive risk assessment method provided in Appendix A of this document is used. The reader should note that several different types of available control measures detailed in API Publ 340 may not have a specific method for measuring the reduction in risk provided in the appendices of this document. For example, the incorporation of written operating procedures, improved training, inventory management procedures, management of change procedure, and other non-engineered (non-physical) control measures will have the effect of reducing risk by preventing spills or detecting them sooner; however, these risk mitigation measures are difficult to measure and the risk assessment method presented in this document does not specifically address them. These methods are, however, very important in overall risk management and risk mitigation strategies at any facility, and they do form the basis for the facility's RMP.

Prior to initiating a program for determining and selecting appropriate mitigation measures, the user typically determines and defines the appropriate or desired level of risk reduction. Examples of questions that the user can ask are:

- Is the purpose to decrease the likelihood of occurrence or decrease the consequences of occurrence or decrease both likelihood and consequences?
- Is the purpose to change a high-risk item on the risk matrix into a medium-risk item, so that the method of reduction (decrease in likelihood or decrease in consequences) is not important?
- Are there corporate or regulatory governing or guiding principles that drive the selection of control measures, such as focusing on preventive control measures?

The owner may be interested in identifying risks in the following different ways:

- Assigning risk rankings to all facilities and concentrating on mitigating the highest risk facilities first
- Identifying items with a high likelihood of occurrence that are universal to the majority of the company's facilities or assets and that would benefit from a corporate-driven initiative to reduce the overall company risk of these items
- Identifying high consequence areas

Determining risks and risk mitigation strategies at the equipment or unit level and at the facility level may not give the company the complete picture of the overall system-wide corporate risk. Instead, a company's management may want to determine risks across a class of equipment, geographic area, or facility classification. The benefits and effects of a particular risk mitigation strategy may be better evaluated at the facility or corporate level. This evaluation often involves determining the overall risk from a facility or group of assets, a type of asset or the location of the asset, or the regional distribution of assets. The corporate view can look at the effects of corporate initiatives on overall risk management and mitigation. For example, consider the risk reduction of upgrading high-level alarms on ASTs, or implementation of API Std 653 inspections on all tanks. It is often more difficult to measure the effects of training initiatives, improved operating procedures, or staffing without a corporate-level review over a period of time. Conversely, when viewed at the corporate level, it may be easier to address risks that vary dramatically between facilities because of the environmental, population, ecological, or regulatory sensitivity of the area.

The examples provided below illustrate the different approaches for evaluating risk at different levels and an approach to mitigating risks. The examples are not meant to demonstrate the method for calculating risk or to endorse a specific risk assessment method. Furthermore, the examples are not meant to endorse or mandate the selection of any particular control measure(s). The user will have to consider the need for proscriptive control measures that are required by the authority having jurisdiction where the facility is located. The facility could use the approach below to evaluate proscriptive control measures and compare them to the available control measures detailed in API Publ 340. In some instances, this evaluation may yield a better long-term reduction in risks and be more protective to the surrounding environment and population.

The examples presented below are divided into the following categories:

- Mitigation of potential releases at a unit level
- Mitigation of potential releases at a facility level
- Mitigation of potential releases at a corporate level

8.4.1 Mitigation of Potential Releases at a Unit Level

Risk management personnel may start the risk assessment process by first looking at risks at the unit level. The unit-level evaluation begins by comparing the risk of a particular item, such as an aboveground storage tank (AST) (unit), to the risk associated with other similar units (other ASTs).

Scenario 1—Evaluation of facility ASTs

Description: The facility has a total of eight ASTs containing a variety of petroleum products. Table 8-1 presents the particular tank data information. The tanks receive product via marine receipt. Each tank has two-stage, high-level alarms. The tanks have been inspected in accordance with API Std 653 with the exception of tanks 1 and 2, which are newer tanks and have never been inspected. The tanks are located in an earthen secondary containment area within 100 feet (30.5 meters) of a river. The underlying soils beneath the tanks and in the secondary containment area consist of silty sand with soil permeability to water of 0.28 feet/day ($1x10^{-4}$ cm/sec). The groundwater table at the facility is approximately 10 feet (3 meters) below the tank bottoms. Neither the river nor groundwater is used as a potable water supply. The river is a recreational area with regulated wetlands and a bird sanctuary.

Table 8-1: Data Table for Tanks Examined in Scenario 1

Tank #	Product	Diameter (ft)	Shell Height (ft)	Shell Age (yrs)	Floor Age	Last Inspection	Tnom Shell (mils)	Tnom Floor (mils)	Roof Type	Receipt Type & Rate (bbl/hr)	Hi-level Alarm	Inspect. Rating	Tank Capacity (bbl)
1	Gas	60	42	20	20	N/A	0.563	0.250	IFR	4800	2 stage	E	21,149
2	Gas	60	42	20	20	N/A	0.527	0.250	IFR	4800	2 stage	E	21,149
3	#2 F.O.	80	47	40	15	10	0.625	0.160	Fixed	4800	2 stage	B	37,599
4	#2 F.O.	80	47	40	15	10	0.625	0.160	Fixed	4800	2 stage	B	37,599
5	Gas	80	47	40	15	10	0.625	0.205	IFR	4800	2 stage	B	37,599
6	Gas	80	47	40	15	10	0.625	0.205	IFR	4800	2 stage	B	37,599
7	#2 F.O.	110	45	60	10	15	0.750	0.240	Fixed	4800	2 stage	B	71,085
8	#2 F.O.	110	45	60	10	15	0.750	0.240	Fixed	4800	2 stage	B	71,085

NA—Not Inspected
F.O.—Fuel Oil
1 bbl (US, petroleum) = 0.16 cubic meters

Using the approach in Appendix A, the LOF was calculated for each tank. It should be noted that likelihood values have units of events/year. Table 8-2 summarizes the results of the calculation. The gray shaded areas denote the summarized results for bottom, shell, and total LOF. The user should note that the addition of the LOF numbers, as illustrated by adding the bottom leak likelihood to the rapid bottom failure likelihood, is not meaningful if the consequences are dramatically different for each likelihood event. The external roof drain likelihood has been deleted because the tanks do not have external roof drains.

Table 8-2: Likelihood of Tank Failure Calculation Results for Tanks in Scenario 1*

Tank #	Bottom Leak	Rapid Bottom Failure	Total Bottom LOF	Shell Leak	Rapid Shell Failure	Total Shell LOF	Overfill LOF	External Roof Drain	Total Tank LOF
1	4.11E-02	8.57E-06	4.11E-02	2.05E-01	4.00E-06	2.05E-01	1.34E-03		2.47E-01
2	4.11E-02	8.57E-06	4.11E-02	2.05E-01	4.00E-06	2.05E-01	1.34E-03		2.47E-01
3	1.73E-02	6.00E-06	1.73E-02	7.30E-06	1.00E-07	7.40E-06	8.40E-04		1.81E-02
4	1.73E-02	6.00E-06	1.73E-02	7.30E-06	1.00E-07	7.40E-06	8.40E-04		1.81E-02
5	7.20E-07	6.00E-06	6.72E-06	1.00E-08	1.00E-07	1.10E-07	1.34E-03		1.35E-03
6	7.20E-07	6.00E-06	6.72E-06	1.00E-08	1.00E-07	1.10E-07	1.34E-03		1.35E-03
7	7.20E-07	6.00E-06	6.72E-06	1.00E-08	1.00E-07	1.10E-07	8.40E-04		8.47E-04
8	7.20E-07	6.00E-06	6.72E-06	1.00E-08	1.00E-07	1.10E-07	8.40E-04		8.47E-04
Total	1.17E-01	5.31E-05	1.17E-01	4.10E-01	8.60E-06	4.10E-01	8.72E-03		5.36E-01

* Likelihood values are events/year.

By performing a quick review of the data in the table, the user quickly notes the following trends for these tanks.

- Rapid bottom and rapid shell failures are extremely low likelihood events
- Small leaks from tank bottoms for tanks 1 through 4 have a high likelihood of occurrence when compared to the other tanks and the other events
- Small leaks from tank shells for tanks 1 and 2 have a high likelihood of occurrence when compared to the other tanks
- Tank overfills are the next most likely event to occur

A deeper probe into these findings from the likelihood analysis would lead the analyst to conclude that the absences of an internal and external inspection of tanks 1 and 2 have dramatically increased the likelihood that the tank will experience a small leak. Additionally, the thinner remaining bottom plate on tanks 3 and 4 has dramatically increased the likelihood that these tanks will experience a small bottom leak. The user could begin to develop a conclusion and formulate a mitigation strategy just by reviewing the data in the likelihood table. In order to develop a clear understanding of the risks, the user now needs to investigate the consequences of each event.

Again, utilizing the approach in Appendix A, the COF was calculated for each tank and summarized in Table 8-3. It should be noted that consequence values are dimensionless. Once again, the gray-shaded areas denote the summarized results for bottom, shell, and total LOF. The user should note that the addition of the COF numbers, as illustrated by adding the bottom leak consequence to the rapid bottom failure consequence, is not meaningful if the likelihoods are dramatically different for each consequence event. Once again, the external roof drain consequence has been deleted because the tanks do not have external roof drains.

Table 8-3: Consequences of Tank Failure Calculation Results for Tanks in Scenario 1 *

Tank #	Bottom Leak	Rapid Bottom Failure	Total Bottom COF	Shell Leak	Rapid Shell Failure	Total Shell COF	Overfill COF	External Roof Drain	Total Tank COF
1	16,500	74,250	90,750	263	67,500	67,763	131	0	158,644
2	16,500	74,250	90,750	263	67,500	67,763	131	0	158,644
3	5,500	99,000	104,500	175	45,000	45,175	88	0	149,763
4	5,500	99,000	104,500	175	45,000	45,175	88	0	149,763
5	16,500	148,500	165,000	263	67,500	67,763	131	0	232,894
6	16,500	16,500	33,000	263	67,500	67,763	131	0	100,894
7	5,500	99,000	104,500	175	45,000	45,175	88	0	149,763
8	5,500	99,000	104,500	175	45,000	45,175	88	0	149,763
Total	88,000	709,500	797,500	1,752	450,000	451,752	876	0	1,250,128

* Consequence values are dimensionless.

A quick review of the data in the table reveals the following trends for these tanks:

1. Rapid bottom and rapid shell failures are events with extremely high consequences
2. Small leaks from tank bottoms are the next highest consequence events, and the consequences for tanks 1, 2, 5, and 6 are three times worse than for the other tanks
3. Small leaks from tank shells and tank overfills are low-consequence events

A deeper probe of these findings from the consequence analysis would show that the rapid bottom and rapid shell failure scenarios have very high consequences because the volume of product released in both scenarios is high, and the product is anticipated to disperse widely from both of these events. By looking more closely, the user would also see that the difference in consequences between tanks 1, 2, 5, and 6 and tanks 3, 4, 7, and 8 is driven by the type of product stored. This is because gasoline has a lower viscosity than fuel oil and thus will travel more easily (faster) through soil than does diesel fuel; therefore, the end result has additional environmental impacts from the gasoline spill (more severe consequences). The user may once again be tempted to develop a conclusion and formulate a mitigation strategy just by reviewing the data in the consequence table but should be aware that mitigating the consequences of these events is difficult without developing a clear understanding of the likelihood and thus the overall risks from these two events.

The last part of the risk assessment analysis is to multiply the likelihood (Table 8-2) and the consequences (Table 8-3) values for each event and for each tank. Table 8-4 summarizes the results of this calculation.

Table 8-4: Tank Risk Calculation Results for Tanks in Scenario 1

Tank #	Bottom Leak	Rapid Bottom Failure	Total Bottom Risk	Shell Leak	Rapid Shell Failure	Total Shell Risk	Overfill Risk	External Roof Drain	Total Tank Risk
1	678.15	0.64	678.79	53.92	0.27	54.19	0.18	N/A	733.16
2	678.15	0.64	678.79	53.92	0.27	54.19	0.18	N/A	733.16
3	95.15	0.59	95.74	0.00	0.00	0.01	0.07	N/A	95.82
4	95.15	0.59	95.74	0.00	0.00	0.01	0.07	N/A	95. 82
5	0.01	0.89	0.90	0.00	0.01	0.01	0.18	N/A	1.09
6	0.01	0.10	0.11	0.00	0.01	0.01	0.18	N/A	0.30
7	0.00	0.59	0.59	0.00	0.00	0.00	0.07	N/A	0.66
8	0.00	0.59	0.59	0.00	0.00	0.00	0.07	N/A	0.66
Total	1546.62	4.63	1551.25	107.84	0.56	108.42	1.00	N/A	1660.67

Now a true evaluation of the tank risks can be performed. A review of the results of Table 8-4 clearly shows that the highest overall risk item is the risk of a small bottom leak from tanks 1 and 2, followed by the risk of a small bottom leak from tanks 3 and 4. The user should note the following additional important points related to the example in Table 8-4:

- Although several of the values display in the table as zero (as reported to two significant digits), the risk in absolute terms is never zero.
- The user can now compare the risks from different tanks (e.g., risk of tank 1 compared to the risk of tank 3) and from different failure modes (e.g., total tank bottom risks vs. total tank shell risks) in absolute terms.
- The user can in absolute terms understand the highest risk equipment (e.g., tank 1 and 2), the highest risk event (e.g., small tank bottom leaks), and the overall risk of the asset (e.g., all terminal ASTs).

Another way of presenting the data from Tables 8-2 and 8-3 is to present an X-Y plot of the likelihood and consequences for each of the tanks.

With this analysis complete, it is up to the user to decide whether a risk needs to be mitigated. As previously discussed, the decision to mitigate and what mitigation strategies to pursue are a corporate decision. At the very least, these results suggest a rank ordering of activities to reduce overall risk. The above results indicate that a mitigation measure that addresses the higher risk of tanks 1 and 2 might be an appropriate consideration. One strategy would be to perform an API Std 653 internal/external tank inspection. Because the tanks are of the same age, same product, and same construction, the user may elect to inspect only one of the tanks and apply the similar service evaluation criteria to the remaining tank.

8.4.2 Mitigation of Potential Releases at the Facility Level

Scenario 2—40-year-old facility located in a coastal zone with a densely populated local community

Half of the terminal piping is aboveground and the other half of the piping is underground. About equal halves of the aboveground piping are located in a containment area versus a non-containment area. The aboveground piping is inspected in accordance with the requirements of API Std 570. The underground piping has never been inspected, has no CP system, and has two sets of underground piping flanges.

The facility has seven aboveground storage tanks built to the API Std 650 code in place at the time of construction. The tanks have single steel bottoms and no high-level alarms on the tanks. The tanks are currently inspected in accordance with API Std 653 and have undergone one API Std 653 inspection.

The facility receives product via pipeline and has a four-bay truck loading rack. The facility receives, stores, and transports gasoline and light fuel oils via truck.

The terminal is located on fine silt and sand with shallow groundwater (<4 feet or 1.2 meters deep) and a salt bay/ marsh located approximately 1500 feet (457 meters) down gradient from the tank farm. The tank farm has an earthen native soil secondary containment system.

The terminal personnel using the risk assessment approach presented in Appendix A have computed the risk associated with the tanks and piping as shown in Table 8-5.

Table 8-5: Base Facility Risks

		Likelihood		Consequences		Risk
Underground Piping Risk	=	0.152	X	120,000	=	18,240
Aboveground Piping Risk	=	0.017	X	1,760	=	30
Total Piping Risk	=					18,270
		Likelihood		Consequences		Risk
Tank Bottom Risk	=	0.051	X	100,800	=	5141
Tank Shell Risk	=	0.000000269	X	35,040	=	<1
Tank Overfill Risk	=	0.4	X	500,000	=	200,000
Total Tank Risk	=					205,141

A quick review of the above information indicates that:

- The facility's environmental risk is dominated by the risk from a tank overfill.
- The overfill risk causes the tank risk to be inordinately high when compared to the piping risk.
- The piping risk is dominated by the underground piping risk.
- In both the underground piping case and the tank overfill risk case, the overall risk is impacted by high likelihood and high consequences.

The facility personnel would quickly conclude that as a first step the overfill risk needs to be reviewed for mitigation. Referring to API Publ 340 Table 4, the user would be able to determine that tank overfills are caused by human error and equipment failure.

Since the tanks are not equipped with any high-level alarm equipment that could fail, the cause of a tank overfill would be human error—someone trying to put more product in a tank than it can contain, which could have several possible causes (i.e., miscalculating the available volume, setting up the wrong tank, pipeline error, etc).

The focus in this scenario is screening the available control measures presented in Table 4 of API Publ 340. Based on Publ 340, the control measures in Table 8-6 are available for selection.

Table 8-6: Example Types of Available Control Measures

Control Measure	Type of Measure
• Written operating procedure/schedule	Prevention
• Operator training	Prevention
• Overfill protection system alarms & instrumentation	Prevention
• Manual product-level verification before & during receipt	Prevention
• Tank farm secondary containment dike and berms	Protection
• Tank farm dike yard liners	Protection

The facility quickly realizes that it already has in place several of these control measures, including written operating procedures, operator training, and requirements for manual product-level verification before and during receipt of product. These procedures and training requirements are part of the facility's RMP. Still, the cause of human error in this operation presents a significant risk to the facility. Additionally, the facility already has in place earthen secondary containment dikes and berms. The risk assessment analysis showed that in the event of an overfill, the relatively high permeability of the soils and depth to groundwater result in a high consequence to the surrounding environment. Therefore, this control measure has already been accounted for in the facility risk assessment. As shown in Table 8-7, just two available control measures remain.

Table 8-7: Example Remaining Control Measures

• Overfill protection system alarms & instrumentation	Prevention
• Tank farm dike yard liners	Protection

The facility wants to further explore the potential benefit of these additional control measures and the impact they would have on the risk of a tank overfill.

Overfill protection system alarms and instrumentation are a prevention type of control measure that alerts the operator when the fill height in a tank exceeds certain preset levels. In the API hierarchy, prevention measures are better options than protection measures because they help to keep petroleum products within their primary containment.

The facility elects to further investigate the use of this control measure and starts by obtaining information on the types, styles, systems, and costs of high-level alarms. It finds that API RP 2350 is a ready source of information on the configuration and operation of overfill prevention systems and learns that there are various types of devices (single-stage, two-stage, automatic shutdown, etc.).

The facility decides to explore the costs and benefits of a two-stage system with no automatic shutdown and an "A" compliance with API RP 2350. The facility then recalculates the risk of a tank overfill based on selection of this control measure and finds that the likelihood of occurrence has dropped significantly from 0.4 to 0.0009.

Now the facility needs to reevaluate the consequences of a release. In the old analysis, the facility assumed that it would take 30 minutes to detect an overfill. With the new system in place, the overfill would still go undetected for 30 minutes if the new system failed; therefore, the consequences of an overfill have not changed and remain at 500,000, but the overall risk of an overfill has changed as shown in Table 8-8.

Table 8-8: Option 1, High-Level Alarms—Revised Overfill Risks

		Likelihood		Consequences		Risk
NEW Tank Overfill Risk	=	0.0009	x	500,000	=	450
Existing Tank Overfill Risk	=	0.4	x	500,000	=	200,000

The facility obtains cost estimates from an equipment supplier and local contractor to install the system, and the cost for installation is budgeted at $250,000 for the seven facility tanks.

The facility now wants to review the use of another available mitigation measure, tank farm dike yard liners. The facility discovers that this system involves the placement of a very low-permeable liner system, or native clay materials, within the tank farm area to prevent, or mitigate, the flow of spilled petroleum below the liner into the groundwater, into deeper native soils, or outside the secondary containment. API Publ 340 defines liners as a spill protection measure; they do not help prevent a spill from occurring or detect a release after it occurs. The liner would, however, decrease the consequence from an overfill or other spill that could occur in the lined area. For this control measure, the application of liners to the secondary containment area would decrease the consequences not only for a tank overfill but also for other risks including the risk from a tank shell release and the risk from an aboveground piping release for piping located within the tank farm containment area. However, the liner system would not reduce the consequences from a release through the AST single steel bottom, from a release from aboveground piping located outside the lined secondary containment area, or from a release from underground piping.

The facility determines that the entire tank farm will need to be lined with the owner-selected diked area liner material for the liner system to be effective. Terminal personnel consult API Publ 340 on liner performance issues and engineering personnel familiar with the design and installation of these types of liner systems. The facility then recalculates the risk of a tank overfill based on selection of this control measure. The user notes that the selection of a protection measure does not affect the likelihood calculation, because the liner system does not reduce the likelihood of a tank overfill, but only mitigates the consequences. Thus, the likelihood of failure remains the same at 0.4 for this control measure.

Now the facility needs to reevaluate the consequences of release. In the initial analysis, the facility assumed that it would take 30 minutes to detect and stop the tank overfill. With the new liner system in place, the detection time remains unchanged at 30 minutes; however, the primary environmental area impacted by the release declines considerably, from a high of 60 to a low of 1 (based on the Appendix A risk assessment method). The basic assumption here is that the liner system performs as designed during the overfill event. This reduction represents the decrease in environmental impact by reducing the environmental damage caused by a tank overfill. By changing the consequences, the overall risk from a tank overfill changes as shown in Table 8-9.

Table 8-9: Option 2, Liners—Revised Overfill Risks

		Likelihood		Consequences		Risk
NEW Tank Overfill Risk	=	0.4	x	830	=	332
Existing Tank Overfill Risk	=	0.4	x	500,000	=	200,000

This analysis shows the facility that incorporation of this control measure would also reduce the consequences of a release from the aboveground piping located within the tank farm and from an AST shell release for tanks located in the lined containment area. Once again, the use of liners would not affect the likelihood of an event occurring, but it would affect the consequences of a release. The facility then proceeds to recalculate the new risks for these items, as shown in Table 8-10.

Table 8-10: Option 2A, Liners—Revised Risks for AG Piping & Tank Shell Releases

		Likelihood		Consequences		Risk
NEW Aboveground Piping Risk	=	0.017	x	352	=	6
Existing Aboveground Piping Risk	=	0.017	x	1,760	=	30
NEW Tank Shell Risk	=	0.000000269	x	584	=	<1
Existing Tank Shell Risk	=	0.000000269	x	35,040	=	<1

For these two items, the overall risk was small, so the mitigation measure of adding liners to the containment does not yield a meaningful difference in the results.

The facility obtains cost estimates to install the system for $2.5 million, depending on the system selected. In addition to the cost of the liner system, the facility needs to construct and maintain access roads over the lined containment area to minimize damage to the liner system (the terminal would have to consider cost in its normal operations and maintenance (O&M) work in the containment). Moreover, long-term liner inspection at these areas would be restricted.

From the preceding analysis, the facility has determined the following:

- Use of a high-level tank alarm system reduces the risk from 200,000 to 450 for an investment of approximately $250,000.
- The use of impermeable tank farm diked area liners reduces the risk from an AST overfill from 200,000 to 332 for a $2.5 million investment.

The risk reduction based on the cost of the mitigation measures makes it appear that the selection of the high-level alarm system is the optimal choice; however, the terminal wishes to check two more things before making a recommendation to management.

1. What would the AST overfill risk reduction be if both high-level alarms and dike liners were installed?
2. Could changes be made to the existing terminal training program, operating procedures, or staffing (attended receipts) that would mitigate the risk of a tank overfill?

The terminal now calculates the risk of a tank overfill using both high-level alarms and diked area liners. Given that they had previously recalculated both numbers independently, it is now simple to determine the new risk of using both mitigation measures together because the addition of high-level alarms affects only the likelihood side of the risk equation and adding liners affects only the consequence side of the risk equation. Table 8-11 shows the new risks when options 1 and 2 are combined.

Table 8-11: Option 3, High-Level Alarms & Liners—Revised Risks for Overfill Releases

		Likelihood		Consequences		New Risk	Pre-Mitigation Risk
Option 3—Tank Overfill Risk (mitigating with liners & alarms)	=	0.0009	x	830	=	0.75	200,000
Option 1—Tank Overfill Risk (high-level alarms only)	=	0.0009	x	500,000	=	450	200,000
Option 2—Tank Overfill Risk (tank farm liners only)	=	0.4	x	830	=	332	200,000

When the facility personnel see the dramatic reduction in overfill risk that results from combining the two mitigation measures (high-level alarms and tank farm liners), they think that this might be the best option because a very high risk activity has been reduced to almost no risk; however, the cost is high. To achieve this risk reduction would require an expenditure of close to $2.8 million.

Facility personnel reconsider the use of high-level alarms and whether the terminal can adjust the operating procedures, training, and staffing to decrease the consequences of a spill. To decrease the consequences, the facility would have to affect at least one of the following parameters:

- Decrease the time of discovery of a spill (current estimate is 30 minutes)
- Decrease the flow rate into the tank, so the volume spilled per unit of time is smaller (current flow rate is 5,000 bbl/hour or 795 cubic meters/hour).

Decreasing the flow rate is not an option because the pipeline supply company would not want to cut the rate, so personnel focus on changing the time to discovery. They had based their 30-minute discovery time on the following scenario:

- When a tank receipt is planned, the operator sets up the receipt tank (e.g., aligns the valves in their proper position, opens the receipt valve on the tank and pipeline manifold that is to receive the product, and ensures that all other tank receipt valves and pipeline manifold valves are closed).
- The operator then manually gauges the tank to determine the current tank volume. By consulting the tank strapping chart, the operator can determine the available “safe” fill capacity. He then checks with the delivery company on the time, duration, and volume of the receipt, and compares the available tank capacity to the receipt volume to confirm that the tank has adequate capacity.
- Ten minutes prior to the receipt, the operator walks out to the pipeline manifold and confirms the start of the receipt. As part of the terminal’s standard operating procedures, the operator is required to check the tank every 20 minutes during the receipt. The terminal estimated that if an overfill occurs, it might take a maximum of 20 minutes for the operator to discover the release and another 10 minutes for the pipeline company to shut down the receipt, thus yielding the 30-minute discovery time.

The facility personnel think that they can cut the operator’s response time by keeping the operator in the tank farm during the receipt. This of course would require more staff time and thus more costs; however, personnel demonstrate that they can further reduce the consequences and subsequently the overall risk of a tank overfill by reducing the volume released by decreasing the response time. Table 8-12 summarizes the results of this evaluation.

Table 8-12: Option 1A, Alarms & Procedures—Revised Risks for Tank Overfill

		Likelihood		Consequences		Risk
Tank Overfill Risk (alarms & new procedures)	=	0.0009	X	250,000	=	225
Tank Overfill Risk (alarms only)	=	0.0009	x	500,000	=	450

The facility decides that a change in operator procedure is the best option. Facility personnel recommend to management that the facility spend approximately $250,000 for AST high-level alarms and modify the operating and staffing procedures so that the operator stays with the receipt at an anticipated increase of $25,000 in annual personnel costs. Table 8-13 summarizes the reviewed mitigation items for tank overfill risks. The reader should note that although impervious liners reduced the risk to a near zero event, they were not the preferred method because:

- They were an order of magnitude more costly then the selected option.
- On a weighted risk scale, the revised risk for high-level alarms was comparable to the application of impervious liners.

- In the API hierarchy, prevention type mitigation measures are preferred over protection measures.
- API Publ 341 demonstrated that liner effectiveness will vary and change with time. Additionally, liners will require costly periodic maintenance that needs to be accounted for in the determination of the mitigation cost.

Table 8-13: Summary of Options for Tank Overfill Risk Mitigation*

Options	Option Description	Original Risk	Revised Risk	Mitigation Cost
1	High-Level Alarms	200,000	450	$250,000
1A	High-Level Alarms + New Operating Procedures	200,000	225	$275,000
2	Tank Farm Diked Area Impervious Liners	200,000	332	$2,500,000
3	High-Level Alarms + Impervious Liners	200,000	1	$2,750,000

*The reader needs to understand the constraints in assuming that the determined risk numbers are absolute, when in fact the numbers should be considered relative. Refer to section 8.2 for additional discussion of factors to be considered in utilizing the risk numbers.

Now that the facility has evaluated the overfill mitigation measures, it wants to review the risks associated with the underground piping to determine the methods and costs for mitigating these risks. Personnel consult Table 5.1 in API Publ 340 to determine the causes of underground piping releases and to obtain a list of available control measures to reduce the risks associated with underground piping. The terminal personnel discover that there are four main causes of pressurized underground piping failure:

- Corrosion failure, both internal and external to the pipe
- Pipe failure not associated with corrosion
- Underground flange leaks
- Miscellaneous sources of mechanical damage caused by third parties

The terminal then reviews more than 30 available control measures to mitigate the risk of underground piping and decides to investigate the benefits and costs of the mitigation measures listed in Table 8-14.

Table 8-14: Example Control Measures for Underground Piping Risk Mitigation

Control Measure	Type of Measure
• Inspection in conformance with API Std 570	Prevention
• Installation of a CP system	Prevention
• Removal of underground flanges	Prevention
• Raising of the lines aboveground	Prevention

In reviewing the available mitigation measures, the facility finds that it already uses several of the available control measures in its new RMP as listed in Table 8-15.

Table 8-15: Example Underground Piping Control Measures Already in Use

Control Measure	Type of Measure
• Performing a piping risk assessment	Prevention
• Utilizing a management of change program	Prevention
• Having a work permit procedure in place	Prevention
• Maintaining accurate as-built record drawing information	Prevention

The facility starts with the first mitigation strategy in Table 8-14 by determining what the impact on the underground piping risk would be if the facility performs an inspection in conformance with API Std 570. The facility consults API Std 570 and obtains quotations from several API Std 570 inspection companies. Personnel understand that the inspection can affect the risk calculation either negatively (show a higher risk) or positively by decreasing the risk (a drop in the likelihood of occurrence); therefore, it is difficult to estimate how an API STD 570 inspection would affect risk without having the results of the inspection. Personnel therefore decide to recommend to management that they perform the API Std 570 inspection of the underground piping and thereby better quantify the likelihood estimate.

The facility continues to review the use of the remaining three control measures and consults with an engineering/construction company that specializes in the design and installation of CP systems. Personnel discover that with some modifications to the existing facility piping (e.g., installation of insulating flanges), they could install an impressed current or passive CP system. Next, the facility wants to measure the impact of installation of the CP system on the underground (UG) piping risk. The facility recalculates the likelihood of occurrence since this control measure affects only the likelihood and not the consequences of occurrence. Table 8-16 shows the recalculated risk.

Table 8-16: Option 4, Effect on Risk of Installing a Cathodic Protection System on the UG Piping

		Likelihood		Consequences		Risk
Existing UG Piping Risk	=	0.152	x	120,000	=	18,240
New UG Piping Risk (CP Installed)	=	0.051	x	120,000	=	6,120

The addition of a CP system effectively decreases the likelihood of occurrence by 66 percent but has no effect on the consequences. The facility obtains cost estimates for this work and budgets $65,000 for installation of four flanges and an impressed current CP system.

The facility then considers removal of the underground flanges. There are three flanges in the 12-inch (30.5 cm) pipe that served as a suction line for the premium and no-lead gasoline. The flanges were originally installed as a convenience 40 years ago when the piping system was first constructed. Removal of the flanges requires a facility outage, drain-down of the lines, inerting of the lines, and welding in three spool pieces where the flanges are to be removed. The facility is concerned about the cost, safety, and inconvenience of performing this task and does not want to undertake the removal if it will not substantially reduce the overall risk. Facility personnel met with the site mechanical contractor to develop construction cost estimates for this work.

Facility personnel also want to measure the impact that removal of the flanges would have on the UG piping risk. They recalculate the likelihood of occurrence because this control measure affects only the likelihood and not the consequences of occurrence. Table 8-17 shows the effect on removing the underground piping flanges.

Table 8-17: Option 5, Effect on Risk of Removal of Underground Piping Flanges

		Likelihood		Consequences		Risk
Existing UG Piping Risk	=	0.152	x	120,000	=	18,240
New UG Piping Risk (UG Flanges Removed))	=	0.1518	x	120,000	=	18,216

The removal of the two sets of underground flanges reduces the piping likelihood by a negligible 0.0002 events per year (2 flanges * 1x10-4 events/yr/flange); therefore, the effects on overall risk are practically nonexistent. The cost estimate for this work is $50,000.

The facility reviews the last option to be considered, which is complete removal of the underground piping. Because of a concern that raising the lines aboveground would affect the facility's piping hydraulics, personnel consult with the engineering staff concerning some preliminary engineering design converting the lines to above ground, abandoning the below ground lines, and estimating the potential impact on product pump hydraulics for the proposed aboveground piping.

Abandonment of the UG piping will require a facility outage, drain-down of the lines, inerting of the lines, and welding in four tie points. Facility personnel decide that most of the lines can remain in service while the new piping is installed. The cut-over would occur over a long weekend to minimize downtime. Again, the facility was very concerned about the cost, safety, and inconvenience of performing this task and did not want to undertake this measure unless it would substantially reduce the overall risk. Personnel meet with the site mechanical contractor to develop construction cost estimates for this work based upon the preliminary engineering work performed by the company's engineering department. They note that several sections will require rerouting of traffic or the installation of cased crossovers.

The facility now wants to measure the impact that abandonment of the underground piping would have on piping risk. Personnel recalculate both the likelihood of occurrence and the consequence of occurrence since this measure affects both aspects of the risk equation. Table 8-18 summarizes the results of this analysis.

Table 8-18: Option 6, Effect on Risk of Replacement of UG Piping with AG Piping

		Likelihood		Consequences		Risk
Existing UG Piping Risk	=	0.152	x	120,000	=	18,240
NEW AG Piping Risk (No UG Piping)	=	0.010	x	1,760	=	18

The conversion of the underground piping to aboveground piping has a dramatic effect on the overall piping risk by eliminating the underground piping risk and converting it to an aboveground piping risk. The cost estimate for this work is $1.05 million.

Table 8-19 summarizes the options reviewed by the terminal for risk mitigation.

Table 8-19: Summary of Mitigation Options, Costs, and Benefits

Options	**Option Description**	**Original Risk**	**Revised Risk**	**Risk Reduction Ratio**	**Mitigation Cost**	**Consequence Cost**	**Payback (yrs)**	**C/B ratio**
1	High-Level Alarms	200,000	450	444	$250,000	$128,000	1.95	0.20
1A	High-Level Alarms + New Operating Procedures	200,000	225	889	$275,000	$128,000	2.15	0.21
2	Tank Farm Diked Area Impervious Liners	200,000	332	602	$2,500,000	$128,000	19.53	1.95
3	High-Level Alarms + Impervious Liners	200,000	1	200,000	$2,750,000	$128,000	21.48	2.15
4	Cathodic Protection of UG Pipe	18,240	6,120	3	$65,000	$48,320	1.35	0.13
5	Remove Underground Piping Flanges	18,240	18,216	1	$50,000	$48,320	1.03	0.10
6	Convert UG Pipe to AG Pipe	18,240	18	1,013	$1,050,000	$48,320	21.73	2.17

Table Notes

1. Consequences assume 800 bbl spill for tank overfill and a 302 bbl leak for UG piping

2. Assumed a cost of $400/bbl for cleanup

3. Consequence cost = spill volume x cleanup cost per bbl x annual likelihood of occurrence

4. Analysis assumes straight line with no escalation for inflation, interest, or adjustment for O&M

5. Cost to benefit analysis assumes 10-year service life with no escalation for inflation, interest, or adjustment for O&M

6. 1 bbl (US, petroleum) = 0.16 cubic meter

For this example, the payback is defined as the cost for the proposed mitigation divided by the estimated cost associated with the consequences of a particular event occurring. The user estimates the consequence cost which may include costs associated with environmental, population, and business impacts.

Based on the risk mitigation evaluations performed for the above-reviewed control measures and the need to gather additional information on the underground piping, the facility personnel decide to recommend the following to management:

- Install high-level alarms on aboveground storage tanks to mitigate storage tank risks coupled with changes to tank filling procedures and training. Perform process hazards analysis and

management of change of high-level alarms and provide new training and procedures for high-level alarm system.
- Perform API Std 570 inspection of underground piping system. Revisit risk assessment after completion of the inspection to recalculate risks associated with underground piping.

As stated in the previous example, Option 3, although providing a near-zero risk, is an order of magnitude more costly then the selected option. Additionally, on a weighted risk scale, the revised risk for the selected remedy was comparable to the application of impervious liners. In the API hierarchy, prevention-type mitigation measures are preferred over protection measures, and liners are not foolproof and require costly periodic maintenance.

8.4.3 Risk Mitigation at a Corporate Level

Corporate risk management personnel may want to look at risks from a more global perspective. The corporation may be interested in identifying risks in the following different ways:

- Assign risk rankings to all facilities and concentrate on mitigating the highest risk facilities first
- Identify items with a high likelihood of occurrence that are universal to the majority of the company's facilities or assets and which would benefit from a corporate-driven initiative to reduce the overall company risk of these items
- Identify high-consequence areas

Determining risks and risk mitigation strategies at the equipment or unit level and at the facility level may not provide the company with the complete picture of the overall system-wide corporate risk. Instead, a company's management may want to determine risks across a class of equipment, geographic area, or facility classification. The benefits and effects of a particular risk mitigation strategy may be better evaluated at the corporate level. This evaluation often involves determining the overall risk from a group of assets, a type of asset, the location of the asset, or the regional distribution of assets. The corporate view can see the effects of corporate initiatives on overall risk management and mitigation. For example, the corporation can determine what the risk reduction is for all tanks if management looks to upgrade the tank overfill prevention systems, or what risk reduction would occur if the corporation began an implementation of level "B" internal API Std 653 tank inspections on all corporate tanks.

Similarly, the management may want to evaluate the risk reduction gained from implementation of new or updated training programs. The user needs to understand the inherent difficulty in quantifying the improvement from training initiatives, improved operating procedures, or staffing at the corporate level. It is also easier to address risks that vary dramatically between facilities because of the environmental/ecological or regulatory sensitivity of the area.

The application of risk evaluation, risk mitigation, and risk reduction methods are similar to the approaches illustrated in sections 8.4.1 and 8.4.2.

SECTION 9—MANAGEMENT OF CHANGE

Once a risk management program (RMP) is established, it is critical that the facility monitors and improves the program. Changes to the facility made by the company and changes affecting the area surrounding the facility could affect the priorities of the program and the risk control measures employed. To ensure continued validity of the program, facilities can:

- Recognize changes before or shortly after they occur
- Ensure that those changes do not unnecessarily increase risks (either likelihood or consequences)
- Update the affected portion(s) of the RMP

Facilities with an existing management of change (MOC) program can verify that the types of changes mentioned in this section are included in their MOC program. For other facilities, a system can be established to recognize and manage changes relevant to their RMPs.

Management of change ensures that the integrity management process remains viable and effective as changes to the system occur and/or new, revised, or corrected data become available. Any change to equipment or procedures has the potential to affect a facility's integrity. Most changes, however small, will have a consequent effect on another aspect of the system. For example, many equipment changes will require a corresponding technical or procedural change, and all changes are typically identified and reviewed before implementation. An MOC procedure provides a means of maintaining order during periods of change in the system and helps to preserve confidence in the integrity of the program.

To keep the integrity of the program current, the manager can identify and document the ways a terminal/facility may be modified that could have an impact on any of the risk factors identified in the integrity program. Examples of such changes include:

- Additions, deletions, or other modifications to the terminal/facility equipment
- Changes in the fluid transported and/or its operating conditions in the pipe that may also affect the risk prioritization and any spill control or other mitigation measures employed
- Changes to flow rate and/or operating pressure
- Restarting equipment or systems that have been out of service for an extended time and/or systems that have not been maintained
- Changes to existing procedures, or addition of new procedures
- Changes along the right-of-way, such as changes in land use
- Regulatory changes

The manager is responsible for recognizing these changes and ensuring that they are appropriately reviewed and that these changes are communicated to any affected parties.

SECTION 10—PERFORMANCE MEASURES

The intent of this section is to provide facilities with a methodology for evaluating the effectiveness of their risk management programs (RMPs). The goal of any liquid petroleum storage terminal is to operate the facility in such a way that there are no adverse effects on employees, the environment, the public, or its customers as a result of its operations. Periodic evaluations can be performed to review the effectiveness of the facility's RMP, and a program evaluation can help an owner answer the following questions:

- Did you do what you said you were going to do?
- Was what you said you were going to do effective in addressing the issues of equipment integrity in your facility?

In order to evaluate a facility's performance, it is necessary to collect information and periodically evaluate the effectiveness of the risk assessment methods and preventive and mitigative risk control activities, including the repair program, inspection program, training, procedures, and management of change. The facility also can evaluate the effectiveness of its management systems and processes in supporting risk management decisions. A combination of performance measures and system audits is necessary to evaluate the overall effectiveness of the RMP.

10.1 Performance Measure Characteristics

Performance measures include a distribution of leading, lagging, and deterioration measures based on an understanding of the failure mechanisms or threats to the integrity of the equipment or the system being operated. Leading indicators are those items which when measured or documented will precede the actual deterioration mechanism (e.g., confirmation of proper operational measurement at the corrosion protection test station). Lagging indicators are those which when measured or documented will show that the actual deterioration is occurring, to what extent, and at what rate (e.g., UT measurement of wall thicknesses).

These measures can be used to demonstrate the suitability of the program or the need to improve the program through the measurement and documentation of items such as:

- Reduction in the total volume from unintended releases
- Reduction in the total number of unintended releases
- Documentation of the number or percentage of risk management activities completed during the calendar year (e.g., number of tank inspections, number of risk assessments)
- The tracking and evaluation of the effectiveness of the implementation of the emergency planning and emergency response activities carried out during an unintended release
- Measurement to document and demonstrate that the company's RMP over time reduces risk (may focus on measurement of high-risk items)
- The evaluation of whether the incidents that do not occur are consistent with the assumptions and expectations of the risk assessment
- The evaluation of whether mitigation measures once implemented are effective in reducing the overall risk

10.2 Process or Activity Measures

Process measures include those metrics that monitor a facility's inspection and release prevention activities. These measures indicate how well the owner is implementing the various elements of the RMP, such as procedures (section 5.2.4), training (section 5.2.5), emergency planning (section 5.2.6), and management of change (Section 9). These measures answer the question: "Once the program has been implemented, how well are the details being executed?" Typically, activity measures are thoughtfully selected since they will not all effectively measure performance.

10.3 Operation Measures

Operation measures include records or trends that are identified as part of the facility operations or maintenance system. Operational measures establish improving trends to show how well the facility system is responding to the integrity management program. For example, installation of a cathodic protection system or use of coatings typically demonstrates a decreased corrosion rate over time. It is important to note that it may take years or decades for trends to develop.

10.4 Direct Integrity Measures

Direct integrity measures include the actual occurrence of incidents such as leaks, releases, overfills, spills, injuries, equipment failure, etc. Direct integrity measures are experienced events.

10.5 Performance Measurement Methodology

The focus of risk assessment is to identify high-risk items, manage those risks, and provide mitigation measures where appropriate. Risk management and risk mitigation usually have the intended effect of reducing the likelihood and consequences of a product release; however, actual measurement in the field of reduction in these parameters is difficult. Ultimately, the performance measurement of a facility's RMP is the degree to which accidental releases are eliminated. A typical RMP will contain many elements, and the program will operate over long time periods; thus, an RMP cannot be evaluated based on any one measure. The user can develop an approach to monitoring performance of the components of an RMP with the expectation that progress will correlate with overall program success. Performance measures actually form a continuum from leading indicators (before releases or failures) to lagging indicators (after releases or failures) and include process measures, measures of deterioration, and measures of actual failures or releases. The methodology has to address both leading and lagging indicators, and the distinction between many of these measures will not always be clear.

10.6 Performance Measurement—Intra-System

Each facility can evaluate its current performance against past performance and previously established goals. Internal comparisons over time are suitable for analyzing trends. For example, the number of tanks inspected during the last 12 months vs. the entire tank population can be plotted on a rolling basis once per quarter. An increasing trend would indicate that the average age of inspection data is improving. Internal comparisons from one geographic region to another geographic region within the company or from one business unit to another business unit may be helpful in identifying areas with deficiencies.

10.7 Performance Measurement—Industry-Based

External comparisons may be more difficult to obtain. This is particularly true for the metrics related to preventive and mitigation actions. Benchmarking among different companies may prove impractical when those facilities are in direct competition. Care is typically taken to ensure that benchmarking is conducted in a way that information is comparable among the benchmarking companies or systems. Companies can also conduct periodic evaluations of their own performance in comparison with industry-wide or governmental data sources.

10.8 Performance Improvement

Risk program evaluations can be conducted on an ongoing basis, and information is typically accumulated and documented over time. Since the details of a facility's RMP will vary, so will the appropriate set of performance measures. Internal and external audits can be used as additional information sources for determining the effectiveness of the RMP. Recommendations for program improvement can be developed based on the results of performance evaluations and audits. The performance measurement results and audit results can also be factored into future risk assessments.

The results of performance measurement and audits, including follow-up recommendations, can be reported to those individuals within the company who are responsible for risk management and facility operations. Performance is typically reviewed at least annually, and issues brought up during this review can be addressed by the facility.

SECTION 11—QUALITY CONTROL

The final element in a risk management program (RMP) is quality control. Quality control is the system for ensuring the implementation and maintenance of company programs or standards by periodic random inspection of the system. In risk management, quality control involves the development of a program to perform periodic audits of the RMP to ensure that it is current, required documentation is kept, follow-up actions occur, and trained and knowledgeable staff are implementing the plan. Specifically, quality control for an RMP involves the performance of two items:

1. Development of a quality control program as an element of the RMP
2. Performance of periodic, planned, and documented audits of the RMP

11.1 Characteristics of a Quality Control Program

A quality control program (QCP) generally consists of documentation, implementation, and maintenance of the RMP. The following six activities are usually required as part of a QCP:

1. Identify the processes that will be included in the program
2. Determine the sequence and interaction of these processes
3. Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective
4. Provide the resources and information necessary to support the operation and monitoring of these processes
5. Monitor, measure, and analyze these processes
6. Implement action as necessary to achieve program results and continued improvement of these processes

Specifically, processes that can be included in the QCP are:

- Determination of the documentation required is typically included in the program. These documents are typically controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include the risk assessments, the risk management plan, integrity management reports, and data documents.
- The responsibilities and authorities under this program are usually clearly and formally defined.
- Results of the risk/integrity management program and the QCP are typically reviewed at predetermined intervals. If appropriate, recommendations for improvement are made.
- The people involved in the program are usually competent and familiar with the program and all of its activities. Documentation of such competence, awareness, and qualification, and the processes for their achievement, can be part of the QCP.
- The operator usually determines how to monitor the program to show that it is being implemented according to plan and documents these steps. These control points, criteria, and/or performance metrics are typically defined.
- Periodic internal audits of the program and its quality plan are recommended. An independent third-party review of the entire program may also be useful.
- Corrective actions to improve the program or quality plan are typically documented and the effectiveness of their implementation monitored.
- When an owner chooses to use outside resources to conduct any process (e.g., welding, inspection, maintenance) that may affect the quality or the integrity of the facility, the owner typically ensures control of such processes and documents them within the QCP.

11.2 Risk Management Program Audits

Periodic audits of the RMP are another important element for evaluating the effectiveness of the program and identifying areas for improvement. Auditors from outside the organization or personnel within the organization may perform the audits (self- assessments.) Examples of questions that RMP audits can address include:

- Are activities being performed as outlined in the program documentation?
- Is someone assigned responsibility for each subject area?
- Are appropriate references available to those who need them?
- Are the people who perform the work appropriately trained in the subject area?
- Are qualified people used when required by the company, or by applicable code or regulation?
- Are activities being performed using an appropriate RMP framework, such as the one outlined in this document?
- Are required activities properly documented?
- Are action items followed up, closed, appropriately resolved, mitigated, or remediated?
- Is there a formal review of the rationale used for developing the risk criteria used by the facility?
- Are there established criteria for repairing, re-rating, replacing, or decommissioning terminal equipment, such as pumps, tanks, product piping, safety, overfill prevention, and containment systems?

APPENDIX A
OPTIONAL
COMPREHENSIVE RISK ASSESSMENT METHOD I

LIKELIHOOD & CONSEQUENCE ANALYSIS

APPENDIX A TABLE OF CONTENTS

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A.1. Introduction

This appendix presents a comprehensive approach to performing a risk assessment at liquid petroleum storage terminals for the most credible and severe risks. This appendix was developed based on work performed by DNV, USA Inc., under contract to the American Petroleum Institute. The DNV base resource documents are referenced at the end of this appendix. The approach in this method is similar to the approach performed under API's risk-based inspection (RBI) initiative. The methodology for terminal risk assessment presented here is optional and is provided to the user as an example of a comprehensive approach to terminal risk assessment. The approach is quite complex and will require the user to spend significant time in learning the process and in performing the actual risk assessment. The information presented is not meant to be a theoretical presentation but rather an explanation of the approach, including the various factors involved in the assessment. This risk assessment method does not address every possible risk at a terminal but instead focuses on the most credible severe risks at these facilities. Evaluating all risks using this detailed approach would be cumbersome. This approach assumes that the assessment, evaluation, and mitigation of severe credible scenarios adequately accounts for the less severe and less credible risks. The adjustment factors in this appendix closely match those in API Publ 581 on risk-based inspection (RBI), as intended by the authors of this document. There are also intentional differences in the tank bottom and shell modification factors used by both publications because the documents serve two different objectives (see the notes below Table A.2.2.3 and A.2.3.4). Many of the data and technical decisions required the engineering expertise and experience of the sponsor members. Expert opinions were used to formulate the basis of this document, and it is meant to be used by experts. Exceptions to this are noted and referenced accordingly.

Typically, a risk assessment is performed when changes are being made to equipment or processes at a facility. **This appendix presents <u>optional</u> methods for conducting a risk assessment if a facility decides to do so. Other methods are available outside the scope of this appendix, or a company can decide to create its own method. API does not intend to imply sole endorsement of any particular method. The optional methods presented here are for demonstration purposes.** The accompanying workbook for this approach will aid the user in the application of the method presented. The method is complex and intended to be performed by knowledgeable individuals. For users interested in a less difficult and less rigorous model for risk assessment, Appendix B presents a simplified qualitative approach to terminal risk assessment.

Background

The assessment methods described in the API Risk Assessment Manual for aboveground storage tank (AST) facilities are based on the following premise:

$$\text{Risk} = \text{Likelihood} \times \text{Consequence}$$

(Equation A.1)

As indicated in the main body of this report, the scope of this document is limited to the risks associated with terminal liquid releases. Additionally, the risk assessment model presented in this appendix is limited to addressing specific liquid release scenarios (LRSs). The LRSs summarized in Table A.1.1 represent the most credible and severe risks typically associated with liquid petroleum storage facilities.

Table A.1.1: Liquid Release Scenarios Analyzed in the Terminals Risk Assessment Method I

	Description	Comment
ABOVEGROUND STORAGE TANKS		
1	Small bottom leak. Leak may persist for an extended period, depending on leak monitoring methods.	One hole size is considered: small leak (≤½-inch diameter hole).
2	Rapid bottom failure, instantaneous release of tank contents from failure at the critical zone.	One scenario, catastrophic failure and entire tank contents lost.
3	Small shell leak. Leak detected visually or by monitoring.	One hole size scenario: $^{1}/_{8}$-inch diameter hole.
4	Rapid shell failure, instantaneous release of tank contents from brittle fracture of the tank shell.	One scenario, catastrophic failure and entire tank contents lost.
5	Tank fittings leaks represent a small leak from attached tank fittings.	Two hole size scenarios: $^{1}/_{8}$ inch, and full bore of attached pipe, nozzle, or valve.
6	Overfill release through vents. Leak is eventually detected and stopped.	One scenario: leak rate equals fill rate.
7	Roof drain leak.	Two hole size scenarios: $^{1}/_{8}$ inch and roof drain valve diameter.
PIPING SYSTEMS		
8	Underground piping leak.	One hole size scenario: small leak, $^{1}/_{8}$ to ¼ inch.
9	Aboveground piping leak.	One hole size scenario: small leak, $^{1}/_{8}$ to ¼ inch.
10	Flange leak.	Considered a small pipeline leak: $^{1}/_{8}$ inch.
TRANSFER SYSTEMS		
11	Overfill of tank truck.	One scenario: leak rate equals fill rate.
12	Transfer equipment leak.	Two hole size scenarios: $^{1}/_{8}$ inch, and full bore of hose or articulated pipe.

For other LRSs or for evaluation of vapor emission scenarios, users will have to develop their own risk assessment models or use the more qualitative method presented in Appendix B.

A.2. LIKELIHOOD OF FAILURE METHOD

A.2.1 Overview of Frequency Estimation

The basic approach used in this method is to modify a base release frequency (base likelihood) for each equipment item. This is done by using a factor that is related to the potential degradation occurring in the particular service and to the type of inspection and/or monitoring performed. This modifier is referred to as the modifying factor. In mathematical terms, the leak frequency is found using the following expression:

$$Leak\ Frequency(likelihood) = \quad Base\ Failure\ Frequency \times Modifying\ Factor$$

(Equation A.2)

When appropriate, leak frequencies having similar consequences can be combined to produce an overall equipment spill frequency. For leak frequencies having different consequences, the leak frequencies can also be combined to produce an overall equipment spill frequency; however, the total equipment risk cannot be determined without considering the differing consequences of each leak scenario. Section A.4 presents details of how components are combined in the scenarios of the risk analysis.

For each component, the likelihood of the various hole sizes was used as an input to the risk analysis. As a result, the leak frequencies presented in this method represent the combined leak frequency for the fraction of leaks for a given size to derive the total leak frequency. Refer to Section A.6 for frequency distribution analysis.

Overview of Documentation

The documentation in this appendix follows a consistent format for each of the major components (tank bottom and shell), as listed below:

- Base failure frequency—supporting information for the derivation of the leak frequency is presented at the end of this appendix
- Scope of the analysis
- Required data
- Basic assumptions
- Internal corrosion rate—base corrosion rate and adjustment factors[1]
- External corrosion rate—base corrosion rate and adjustment factors[1]
- Combined corrosion rate
- Number and rating of inspections
- Determination of modifying factor from *ar/t* table;
- Determination of leak frequency with hole size distribution
- Summary

Overfills, piping, roof drains, and transfer equipment are covered separately in subsequent sections of this document. Tank fittings are included as part of the tank shell.

Figure A.2.1.1 provides a flow chart of the general approach to the frequency analysis. Figures A.2.1.2, A.2.1.3, and A.2.1.4 provide more detail for the tank bottoms, tank shell, and piping since these components tend to be more complicated than overfill and transfer leaks.

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[1] The reader is encouraged to use established corrosion rates (rather than the base rate and modifying factors) if available. If corrosion rates are available or if corrosion data from tanks in similar services are available and appropriate, the corrosion calculation can be bypassed, and the reader can go directly to the modifying factor table (*ar/t*) for the appropriate component.

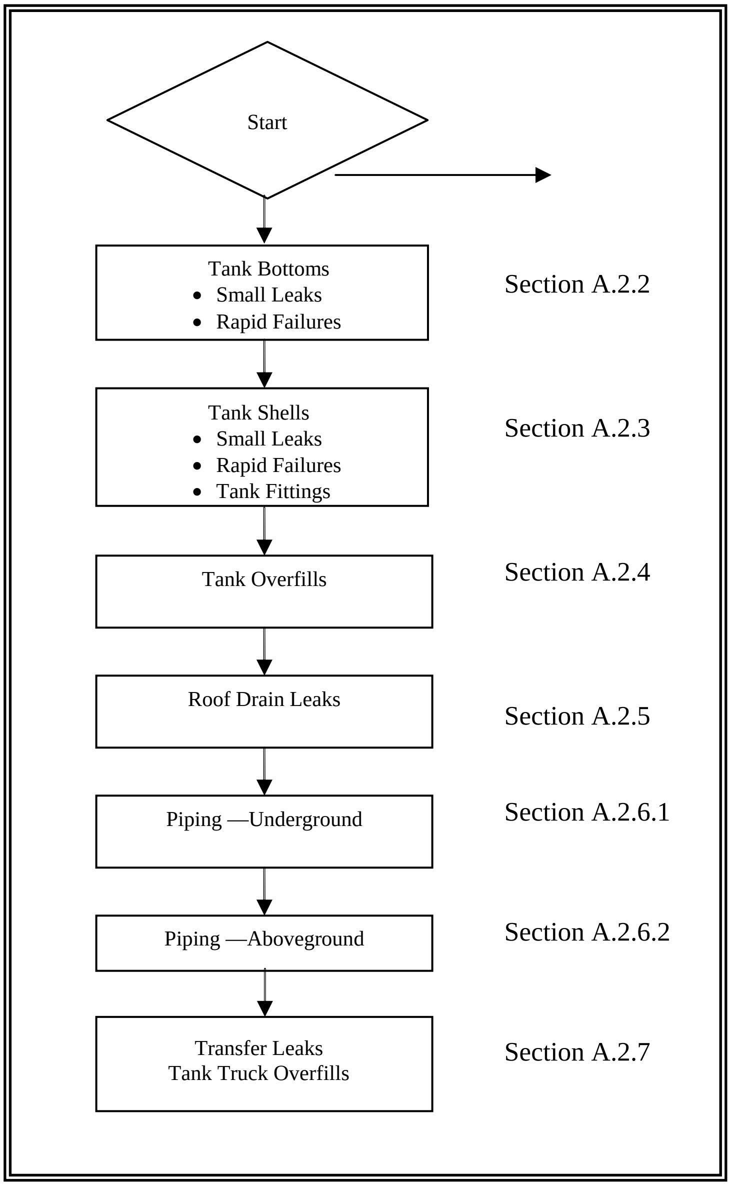


Figure A.2.1.1: Overview of Frequency Assessment Process for Atmospheric Storage Tanks

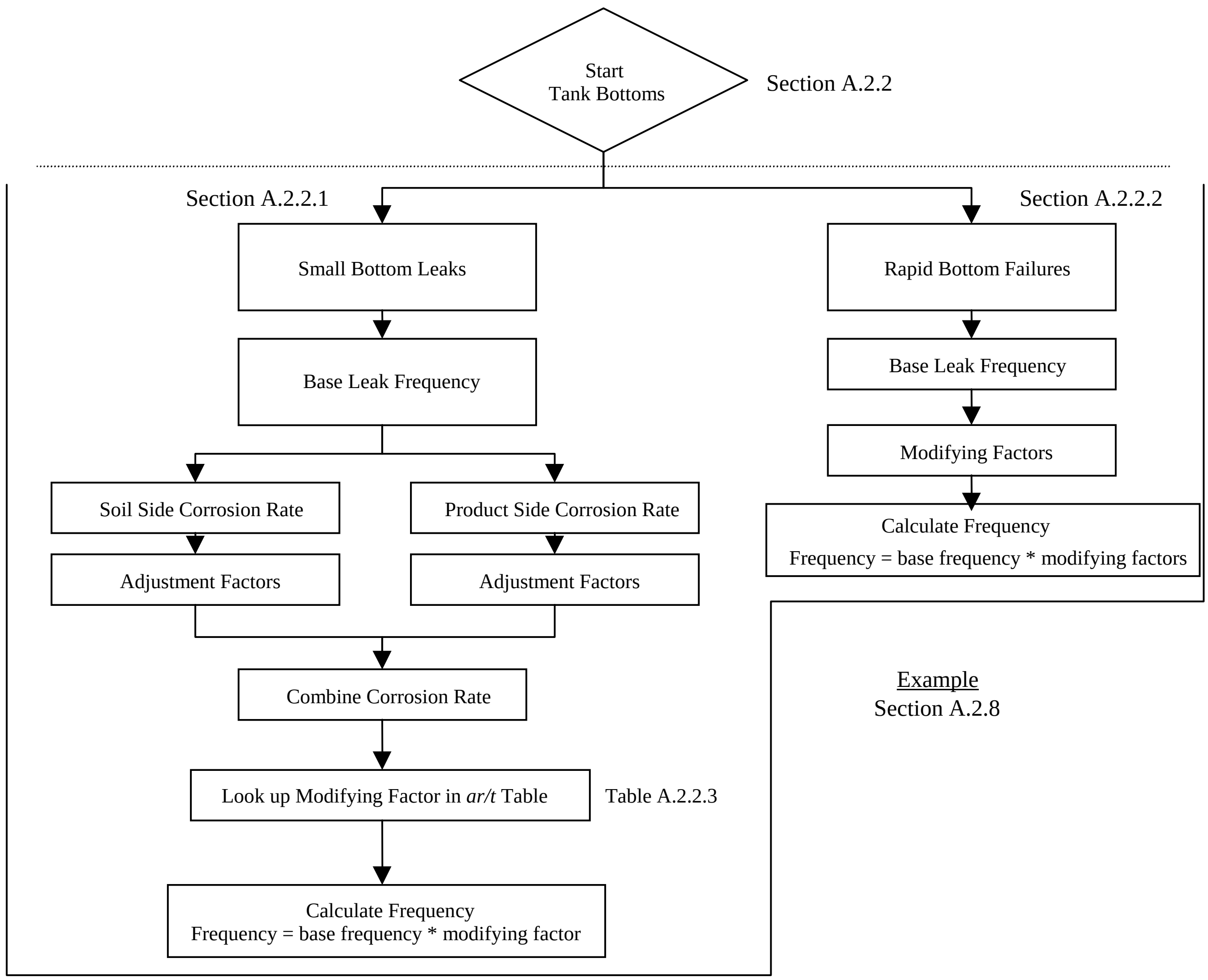


Figure A.2.1.2: Overview of the Tank Bottom Frequency Analysis

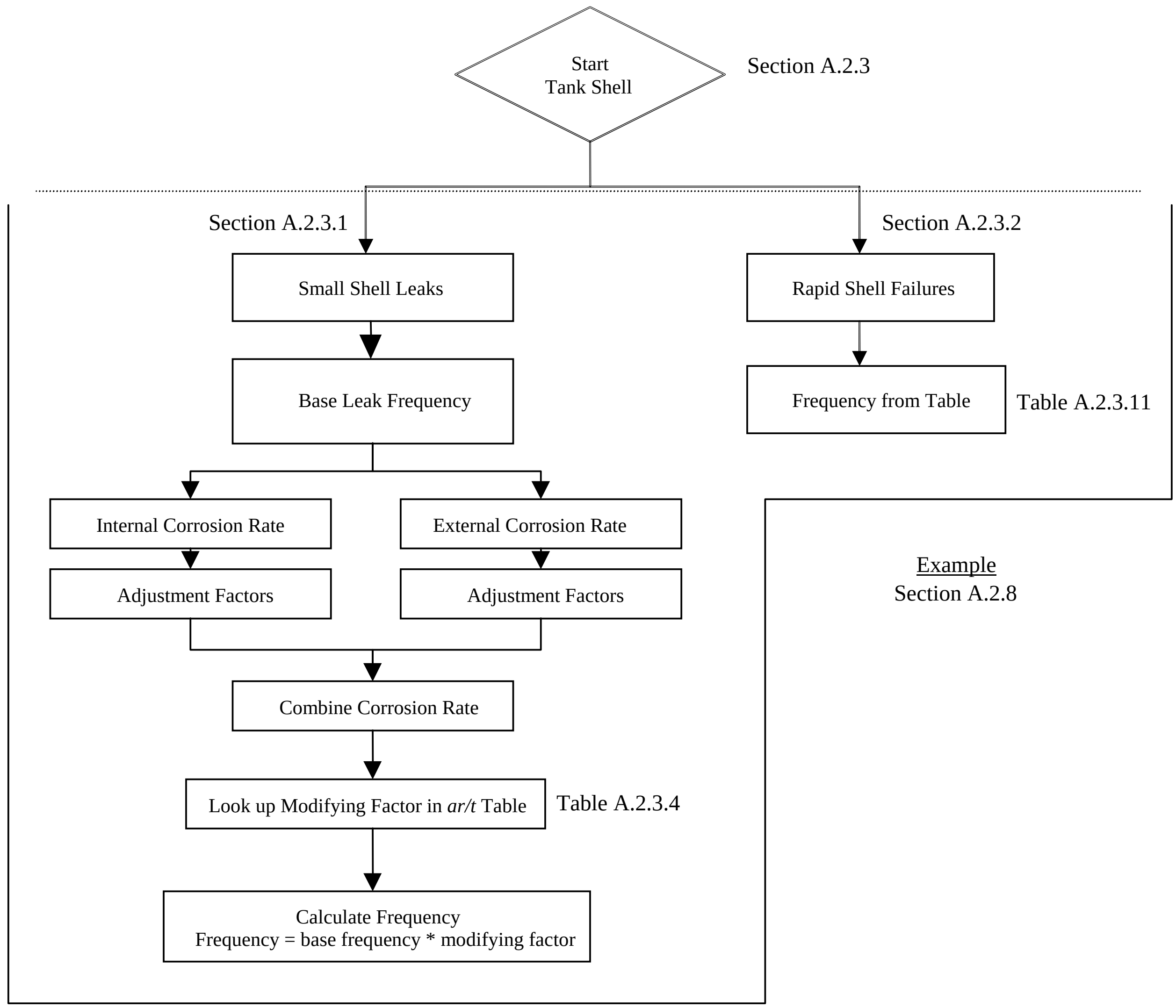


Figure A.2.1.3: Overview of the Tank Shell Frequency Analysis

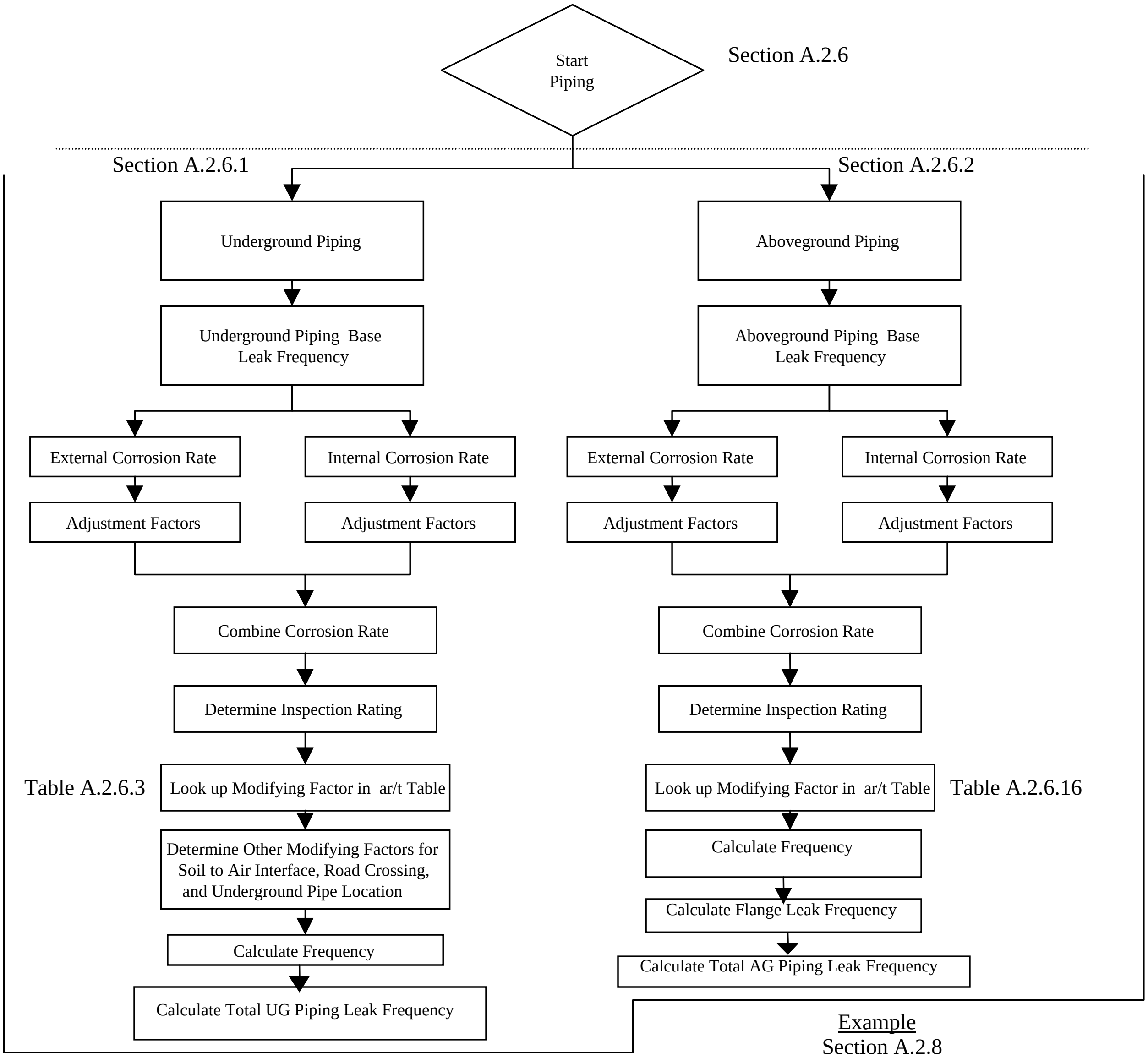


Figure A.2.1.4: Overview of the Piping Frequency Analysis

GENERAL NOTE:

Many of the data and technical decisions required the engineering expertise and experience of the sponsor members. Expert opinions were used to formulate the basis of this document, and it is meant to be used by experts. Exceptions to this are noted and referenced accordingly.

A.2.2 Tank Bottom Leak Frequency Scenarios

Tank bottom leak frequency scenarios consist of analyzing two failure scenarios:

- Scenario 1—Small Tank Bottom Leaks Due to Corrosion
  - Case 1—Tank Bottom Corrosion Rate Established
  - Case 2—Tank Bottom Corrosion Rate Not Established
- Scenario 2—Rapid Bottom Failure

Because the consequences of these two scenarios are very different, the user will have two likelihood numbers at the end of the analysis that cannot be combined. The user will have to analyze the consequences for each of these scenarios prior to developing an overall risk for tank bottoms.

A.2.2.1 Scenario 1—Small Tank Bottom Leaks Due to Corrosion

Bottom leaks typically are caused by corrosion of the steel tank bottom and represent a small leak caused by a through hole in the tank steel bottom plate. Corrosion may occur from the top or bottom or a combination of both. The base failure frequency for the leak of a tank bottom was derived based upon information in the American Petroleum Institute publication, *A Survey of API Members' Aboveground Storage Tank Facilities*. This leak frequency was determined to be:

$$\textit{AST Bottom Leak Frequency} = 7.2 \times 10^{-3} \textit{ leaks / year / tank}$$

(Equation A.3)

The age of the tank, bottom metal thickness, and bottom corrosion rate are accounted for elsewhere in the model. These factors represent the percent wall loss as a modifying factor that is a function of the tank age, corrosion rate, and original wall thickness. The percent wall loss is the basis of a modifier to the AST bottom base leak frequency stipulated above; thus, a very young tank with minimal corrosion will have a frequency modifier less than one, which will lower its leak frequency accordingly.

The model also accounts for the quality of tank inspection. This modifying factor assumes that the thinning mechanism has resulted in a constant rate of thinning/pitting over the time period defined in the basic data. The likelihood of failure is estimated by examining the possibility that the corrosion rate is greater than expected. The likelihood of discovering these higher rates is determined by the type of the most recent inspection. The more thorough the inspection, the less likely the chance that the corrosion rate is greater than anticipated.

For tanks where the bottom corrosion rate is known, the user can perform the analysis described in Case 1 below. If the tank bottom corrosion rate is not known, the user can adopt the approach in Case 2.

A.2.2.1.1 Case 1—Tank Bottom Corrosion Rate Established

The first case applies to tank bottoms where the existing bottom corrosion rate is known or can be extrapolated from a similar service comparison. The approach used for AST tank bottom leaks applies to tank bottoms subject to damage from internal and external corrosion. Widespread corrosion and localized corrosion, which includes pitting and erosion-corrosion, are within the scope of this method.

Required Data (Corrosion Rate Established)

The basic data listed in Table A.2.2.1 are the minimum required to determine a modifying factor for thinning when a corrosion rate has been established by one or more tank inspections performed in conformance with API Std 653. The user is encouraged to apply established corrosion rates developed from tank inspections when available. If corrosion rates are available or if corrosion data from tanks in similar service are available and appropriate, the base leak frequency will be modified by the *ar/t* factor.

Table A.2.2.1: Basic Data Required for Bottom Leak Analysis When Corrosion Rate Established

Basic Data	Comments
Bottom Corrosion Rate (mpy)	The observed internal and external corrosion rate for the tank under consideration. The corrosion rate should account for whether the thinning is widespread or localized. Widespread corrosion is defined as affecting more than 10% of the surface area with a wall thickness variation less than 50 mils. Localized corrosion is defined as affecting less than 10% of the surface area or a wall thickness variation greater than 50 mils.
Thickness (mils)	The actual measured thickness upon being placed in the <u>current service</u>, **or** the minimum construction thickness. The thickness used must be the thickness at the beginning of the time in service reported below.
Age (years)	The number of years that the equipment has been exposed to the current process conditions that produced the corrosion rate used. The default is the equipment age. However, if the corrosion rate changed significantly, perhaps as a result of changes in process conditions, the time period and the thickness should be adjusted accordingly. The time period will be from the time of the change, and the thickness will be the minimum wall thickness at the time of the change (which may be different from the original wall thickness).

Determination of Tank Bottom Leak Frequency

Inspection Rating Category

Inspections are rated according to their expected effectiveness at detecting corrosion and correctly predicting the rate of corrosion. Table A.2.2.2 provides inspection ratings for different inspection activities for the soil side and product (top) side of the tank bottom. The guidelines are to be applied twice (once for the soil side and once for the product side).

Table A.2.2.2: Guidelines for Assigning Inspection Ratings—Tank Bottom

Inspection Rating Category	**Soil Side**	**Product (Top) Side**
A	• Floor scan 90+% and UT follow-up	• Commercial blast • Effective supplementary light • Visual 100% (API 653) • Pit depth gauge • 100% vacuum box test or tracer gas test
B	• Partial floor scan and UT follow-up OR • EVA or other statistical method with floor scan follow-up if warranted by the result	• Brush blast • Effective supplementary light • Visual 100% (API 653) • Pit depth gauge
C	• Floor scan 5–10% plates; supplement with scanning near shell and UT follow-up • Progressively increase if damage found during scanning • Hammer test	• Broom swept • Effective supplementary light • Visual 100% • Pit depth gauge
D	• Spot UT • Hammer test	• Broom swept • No effective supplementary lighting • Visual 25–50%
E	None	None

Note: The methods listed in this table should be applied in accordance with API Standard 653 under the direction of an API 653 certified inspector. The above combinations of inspection techniques are for demonstration only and are not intended to specify inspection methods or to preclude the use of new technology.

Determination of Modifying Factor

To determine the base leak frequency modifying factor for the tank bottom, the user estimates a dimensionless quantity known as the "*ar/t*" value and consults a table to look up the modifying factor for the base failure frequency.

The *ar/t* is found as follows:

$$ar\ /\ t = \frac{age \times rate}{thickness}$$

(Equation A.4)

where

a = the age of the tank bottom, in years
r = the maximum corrosion rate in mils per year
t = the original thickness of the tank bottom, in mils[2]

The "*ar/t* method" assumes that the corrosion rate r is constant over the life of the tank or the service interval analyzed. The value of *ar/t* is actually the fraction of the original tank bottom that has been lost due to corrosion.

The calculated *ar/t* value and the inspection rating are used to determine the modifying factor from Table A.2.2.3. Sponsors developed the *ar/t* table based on engineering expertise and field experience with atmospheric storage tank failures and corrosion. *(Note: The corresponding ar/t table in API Publ 581 on RBI yields more conservative outcomes since its intention is to schedule inspections. The table below provides a wider range of factors and lower probabilities since its intended use is to rank order relative risks.)*

[2] "t" is the nominal thickness in mils when there is no measured corrosion thickness. The exception to this is when the tank has experienced repairs. In this case "t" is the repaired thickness and, the age should be based on the repair date if the user is confident in the measured thickness after repairs. The age should be reset according to the repair date.

Table A.2.2.3: Tank Bottom Modifying Factors

	Inspection Rating				
ar/t	E	D	C	B	A
0.15	0.0210	0.0003	0.0001	0.0001	0.0001
0.20	0.139	0.005	0.0002	0.0001	0.0001
0.25	0.521	0.041	0.0032	0.0001	0.0001
0.30	1.405	0.190	0.025	0.001	0.0001
0.35	3.05	0.62	0.12	0.01	0.0002
0.40	5.71	1.58	0.41	0.05	0.003
0.45	9.59	3.39	1.14	0.22	0.02
0.50	14.82	6.40	2.64	0.72	0.11
0.55	21.50	10.95	5.34	1.92	0.42
0.60	29.64	17.29	9.71	4.34	1.33
0.65	39.23	25.64	16.19	8.67	3.47
0.70	50.2	36.1	25.2	15.6	7.8
0.75	62.5	48.6	37.0	26.0	15.5
0.80	75.9	63.3	51.7	40.2	27.9
0.85	90.4	79.8	69.4	58.6	45.9
0.90	106	98	90	81	70
0.95	122	118	113	108	102
1.00	139	139	139	139	139

(1) *A, B, C, D,* and *E* refer to the inspection rating category (see Table A.2.2.2).
(2) Shading represents area where lining, repairs, or replacement may be required for ¼-inch tank bottoms according to API Std 653 (Section 4.4). The notable exception is for those ASTs that are assessed using an RBI approach.
(3) A value of 0.0001 in the table indicates that the actual value is less than or equal to 0.0001.
(4) Values between *ar/t* should be linearly interpolated from the table.
(5) *a*, *r*, and *t* are defined in Equation A.4.

Determination of Tank-Specific Leak Frequencies

The leak frequency for a specific tank is obtained by multiplying the base leak frequency for tank bottoms by the modifying factor obtained from Table A.2.2.3.

$$\textit{AST Bottom Leak Frequency (known Corrosion Rate)} = 7.2 \times 10^{-3}\ \textit{leaks / year / tank} * MF(ar/t)$$

(Equation A.5)

Rapid bottom failure frequencies are calculated separately as outlined in Section A.2.2.2.

Summary of Approach for Small Tank Bottom Leaks

A summary of the steps required to determine the tank bottom leak frequency for small leaks is presented below:

1. Start with the base leak frequency for tank bottoms (7.2×10^{-3} leaks per year).
2. Use the bottom corrosion rate (*r* in mpy) established in the inspection report. Determine the age of the tank bottom in years and the original nominal tank bottom thickness in mils. Calculate the *ar/t*.
3. Look up the modifying factor in Table A.2.2.3. Use the *ar/t* value and the rating of the most recent inspection to determine the modifying factor. In consulting the *ar/t* table, the rating of the soil side inspection takes precedence in those cases where the corrosion is additive.
4. Multiply the base leak frequency (step 1) by the modifying factor (step 3) to obtain the (tank-specific) bottom leak frequency.

A.2.2.1.2 Case 2—Tank Bottom Corrosion Rate Not Established

The second case applies to tank bottoms where the existing bottom corrosion rate is NOT known or CANNOT be extrapolated from a similar service comparison. The approach used for AST tank bottom leaks applies to tank bottoms subject to damage from internal and external corrosion. Widespread corrosion and localized corrosion, which includes pitting and erosion-corrosion, are included within the scope of this method.

Required Data (Corrosion Rate Not Established)

The basic data listed in Table A.2.2.4 are the minimum required to determine a modifying factor for thinning when a corrosion rate has not been established by one or more tank inspections performed in conformance with API Std 653. Again, the reader is encouraged to use established corrosion rates developed from tank inspections, if available. If corrosion rates are available or if corrosion data from tanks in similar service are available and appropriate, the approach detailed in Section A.2.2.1.1 should be used.

Table A.2.2.4: Basic Data Required for Bottom Leak Analysis

Basic Data	Comments
Bottom External Corrosion Rate (mpy)	The expected external corrosion rate for a “typical” tank under “average” conditions, i.e., neither highly susceptible to corrosion nor especially resistant to corrosion.
Bottom Internal Corrosion Rate (mpy)	The expected internal corrosion rate of the tank bottom.
Bottom Thinning Type (Widespread or Localized)	Determine whether the thinning is widespread or localized for inspection results of effective inspections. Widespread corrosion is defined as affecting more than 10% of the surface area and having a wall thickness variation of less than 50 mils. Localized corrosion is defined as affecting less than 10% of the surface area or having a wall thickness variation greater than 50 mils.
Operating Temperature (°F)	The highest operating temperature expected during operation (considering both normal and unusual operating conditions).
Soil Resistivity (ohm – cm)	Soil resistivity under the tank or dike field. (A common method of measuring soil resistivity is described in ASTM G 57.)
Tank Pad	The type of material upon which the tank rests. In the case of a tank supported on a ring wall, the material used for fill inside the wall.
Tank Drainage	The effectiveness with which rain water is drained away from the tank, and prevented from collecting under the bottom.
Cathodic Protection	The existence of a cathodic protection system for the tank bottom, and the proper installation and operation of such a system, based on API RP 651.

Basic Data	Comments
Internal Lining Needed	Yes or No. Is a lining needed to protect the tank bottom and shell from the corrosive nature of the product?
Internal Lining Age (years)	Based on the installation date, or the last date of lining rehabilitation.
Tank Steam Coil Heater	Yes or No. If a steam coil heater is utilized, the internal corrosion is adjusted upwards slightly due to extra heat, and the possibility of steam leaks.
Water Draws	Water draws when consistently used can greatly reduce the damaging effects of water at the bottom of the tank.
Inspection Rating Category	The rating category of the most recent inspection that has been performed on the tank bottom during the time period (specified above). For this case, the inspection is assumed to be a "D" or an "E."

Determination of Modifying Factors

Figure A.2.2.1 shows a flow chart of the steps required to determine the leak frequency modifying factor for tank bottoms when the corrosion rates are not established. This section presents these steps, along with the required tables.

Soil Side Corrosion Rate

Establish Base Corrosion Rate for Under Bottom (External) Corrosion

The base corrosion rate for soil side corrosion is 5 mpy. The base corrosion rate is the expected or observed corrosion rate for a typical tank under average conditions (i.e., neither highly susceptible to corrosion nor especially resistant to corrosion). The base corrosion rate is determined by the conditions listed in Table A.2.2.5.

Table A.2.2.5: Summary of Conditions for Soil Side Base Corrosion Rate

Factor	Base Corrosion Rate Conditions
Soil Resistivity	Moderately corrosive (1000-2000 ohm-cm)
Tank Pad Material	Continuous asphalt or concrete
Tank Drainage	Storm water does not collect around base of tank
Cathodic Protection	None or not functioning
Bottom Type	Single bottom
Bulk Fluid Temperature	Below 75°F or ambient temperature

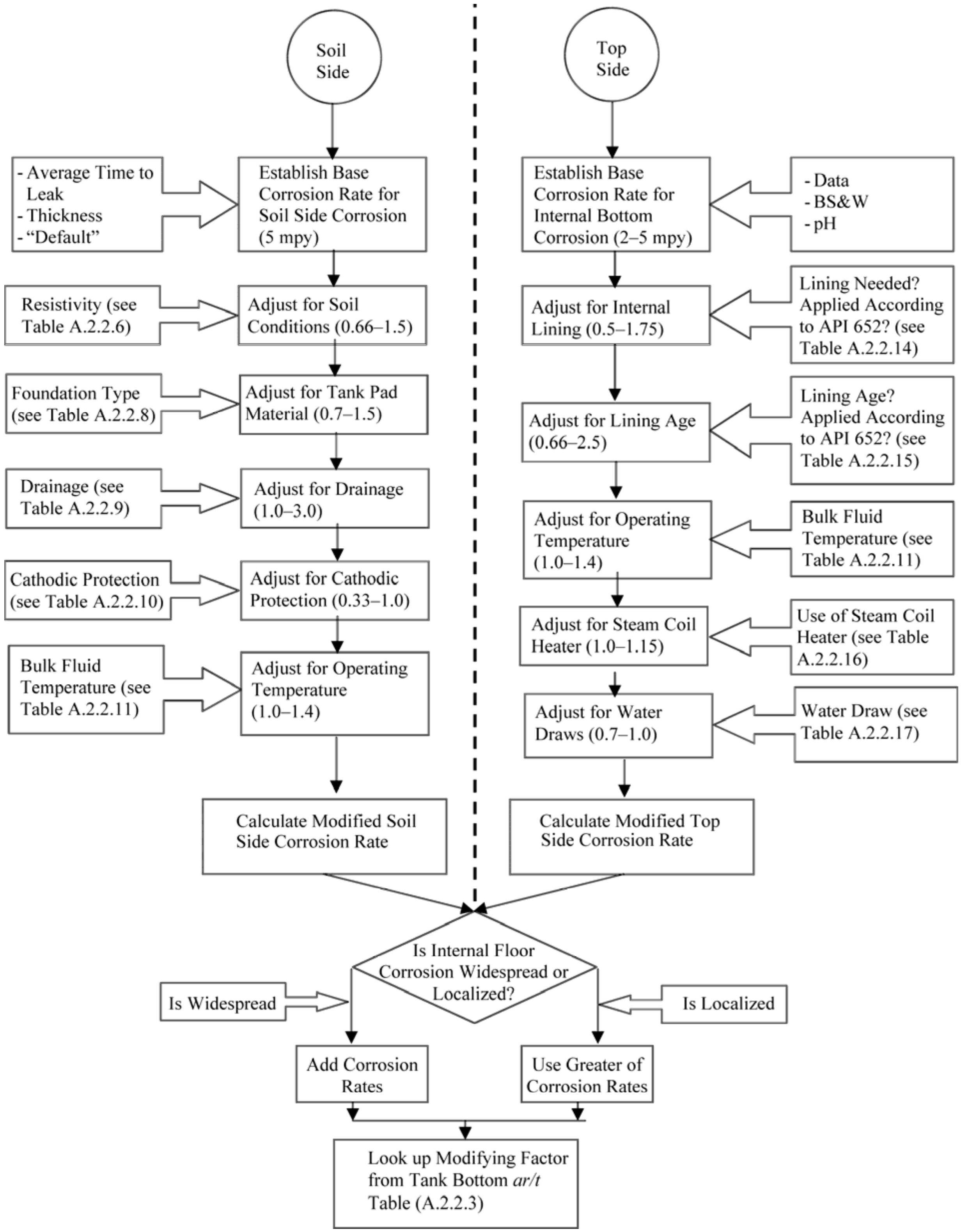


Figure A.2.2.1: Flow Chart to Determine Modifying Factor for Tank Bottoms

The resistivity of the native soil beneath the tank pad can affect the corrosion rate of the tank bottom. The resistivity of the tank pad material may be higher than that of the existing surrounding soil; however, corrosive soil beneath the high resistivity tank pad material may contaminate the tank pad fill by capillary action (refer to API RP 651, Section 5.3.1, for further information). Thus, resistivity of the surrounding native soil may be used to determine the likelihood of corrosion on the tank bottom. Table A.2.2.6 gives corrosion rate adjustment factors for soil resistivities. A common method of measuring soil resistivity is described in ASTM G 57. **If the soil resistivity is not known, then assume moderately corrosive soil (adjustment factor equals 1).** An adjustment factor of 1 should be used for tanks with release prevention barriers (RPBs), since RPBs effectively prevent the contamination of the tank pad material by the native soil. Table A.2.2.7 provides general guidelines for soil resistivities in different areas of the United States. If specific soil resistivity data are not available for the site, the user should employ conservative estimates for the area. In general, sandy soils are high on the resistivity scale (less corrosive), whereas clay soils have low resistivity (more corrosive). Soils contaminated by chlorides, such as areas where saline water intrudes into the area or areas where varying soil conditions exist (non-uniform soil conditions such as sand with debris or clay balls), will generally be more corrosive.

Table A.2.2.6: Native Soil Resistivity Adjustment

Resistivity (ohm-cm)	Potential Corrosion Activity	Adjustment Factor
<500	Very Corrosive	1.5
500–1000	Corrosive	1.25
1000–2000	Moderately Corrosive	1
2000–10000	Mildly Corrosive	0.83
>10000	Progressively Less Corrosive	0.66
Tank with RPB		1

Table A.2.2.7: Native Soil Resistivity Data Ranges

Area and/or Soil Type	Resistivity Range
Brackish water lowlands, poor or slow drainage, coastal areas	150–1,200
Coastal plains, low elevation	600–1,500
Central coastal areas, satisfactory to good drainage	1,200–5,000
South central, midwest and central, farm and range lands	3,500–10,000
West central desert plains, mountains	5,000–25,000
Eastern and northeast high country, excellent drainage, dry and arid	10,000–25,000

Adjustment for Tank Pad (Foundation Type)

The type of pad or foundation that the tank rests upon will influence its corrosion rate. The adjustment factors are assigned in a similar manner to those for the native soil beneath the tank pad. Table A.2.2.8 gives corrosion rate adjustment factors for tank pads.

Table A.2.2.8: Tank Pad Adjustment Factors

Type	Adjustment Factor
Soils with high concentrations of salts	1.5
Crushed limestone	1.4
Native soil	1.3
Construction grade sand	1.15
Continuous asphalt	1
Continuous concrete	1
Oil sand	0.7
High resistivity, low chloride sand	0.7

Adjustment for Drainage

Rainwater collecting around the base of the tank can greatly increase corrosion. Table A.2.2.9 gives corrosion rate adjustment factors for drainage conditions. The adjustment is made so that storm water collecting around a tank will cause the base corrosion rate to increase by a factor of 2. If the drainage is so poor that more than one-third of the circumference of the bottom edge of the tank is under water for extended periods of time, then the base corrosion rate is increased by a factor of 3. Good drainage is considered normal, so the multiplier is set to 1 if water does not normally collect around the base of the tank.

Table A.2.2.9: Tank Drainage Adjustment

Type of Drainage	Adjustment Factor
More than one-third of the bottom edge of the tank is frequently under water.	3
Storm water usually collects around the base of the tank.	2
Storm water does not usually collect around the base of the tank.	1

Adjustment for Cathodic Protection

Cathodic protection (CP) is one of the primary methods used to avoid corrosion of tank bottoms from the soil side. For CP to be effective, the system must be installed and maintained properly. Table A.2.2.10 gives corrosion rate adjustment factors for CP. The factor is established so that the most credit is given for a properly functioning CP system that is built and maintained in accordance with API RP 651, but no penalty is assessed for lack of CP. This assumes that the base corrosion rate is for tank bottoms without CP.

Table A.2.2.10: Adjustment for Cathodic Protection

Functional Cathodic Protection in Place?	Adjustment Factor
No	1
Yes (not per API Std 651)	0.66
Yes (installed and maintained per API Std 651)	0.33

Adjustment for Operating (Fluid) Temperature

The operating (fluid) temperature of the tank may influence external corrosion. For tanks operating at ambient air temperatures or heated below 75°F, the factor is neutral (1). For average annual operating temperatures between 75°F and 150°F, the factor is 1.1. If the operating temperature is between 150°F and 200°F, the factor is 1.3, and if the average temperature measures between 200°F and 250°F, the factor is 1.4. Above 250°F, the factor returns to 1. Table A.2.2.11 gives corrosion rate adjustment factors for bulk fluid temperatures.

Table A.2.2.11: Adjustment for Fluid Temperature

Bulk Fluid Temperature (°F)	Adjustment Factor
≤ 75 or Ambient Air Temperature	1
76–150	1.1
151–200	1.3
201–250	1.4
>250	1

Product (Top) Side Corrosion Rate

Establish Base Corrosion Rate for Product Side (Internal) Corrosion

Tank bottoms can corrode from the inside of the tank (product, or top, side) as well as the underside (bottom side). Base corrosion rates for product side corrosion can be obtained from previous internal inspection data, or they may be assumed to approximate the corrosion in the lower inch or two of the shell, if significant bottom sediments and water (BS&W) are present. For product tanks with no water typically present on the bottom (referred to as dry product tanks), the internal corrosion can be insignificant. For product tanks with water typically present or where water bottoms are not routinely managed (referred to as wet product tanks), the internal corrosion can be significant. Table A.2.2.12 shows the suggested base corrosion rates for “dry” and “wet” product tanks.

Table A.2.2.12: Product Side Base Corrosion Rates

Product Condition	Base Corrosion Rate (mpy)
Dry	2
Wet	5

Table A.2.2.13 summarizes the conditions assumed for the product side base corrosion rate.

Table A.2.2.13: Summary of Conditions for "Base" Product Side Corrosion Rate

Factor	Base Corrosion Rate Conditions
Internal lining	Internal lining not needed for corrosion protection and none applied
Bulk fluid temperature	Below 75°F or ambient air temperature
Steam coil heater	No
Water draws	No (water draws conducted neither weekly nor after every receipt)

Adjustment for Internal Lining

To protect the tank bottom from the corrosive nature of the product, an internal lining may be needed. If an internal lining is needed, the adjustment factor is 1.15; if not, the factor is 1. If the required lining is applied per API RP 652, then there is a further reduction to 0.5 as shown in Table A.2.2.14. The table also shows the benefit of applying an internal lining when none is required (0.3–0.6) and the demerit of failing to apply a lining when needed (1.75). Further adjustment is made based on the age of the lining, as illustrated in Table A.2.2.15. If there is no lining, then Table A.2.2.15 is ignored and only one adjustment factor is used—either 1 or 1.75 from Table A.2.2.14.

Table A.2.2.14: Internal Lining Adjustment

Is internal lining needed for corrosion protection?	Adjustment Factor
Yes (but no internal lining or unknown)	1.75
Yes (internal lining applied, but not per API 652)	1.15
Yes (internal lining applied per API 652)	0.5
No (and no lining applied)	1
No (internal lining applied anyway but not per API 652)	0.9
No (but internal lining applied per API 652)	0.8

Note: To determine the need for internal bottom lining, see API RP 652.

Table A.2.2.15: Lining Age Adjustment

Lining Application and Age	Adjustment Factor
Lining applied per API 652	
> 20 years—limited or no data to assess lining condition	2.5
> 20 years—data to demonstrate that lining is in good condition	1
10–20 years	1
< 10 years	0.66
Lining not applied per API 652	
> 10 years—limited or no data to assess lining condition	1.5
> 10 years—data to demonstrate that lining is in good condition	1
5–10 years	1
< 5 years	0.87

Adjustment for Operating (Fluid) Temperature

The operating temperature of the tank may influence internal corrosion. For tanks operating at ambient air temperatures or heated but below 75°F, the factor is neutral (1). For average annual operating temperatures between 75°F and 150°F, the factor is 1.1. If the average operating temperature is between 150°F and 200°F, the factor is 1.3. For temperatures between 200°F and 250°F, the factor is 1.4. Above 250°F, the factor returns to 1. Table A.2.2.11 above gives corrosion rate adjustment factors for bulk fluid temperatures.

Adjustment for Steam Coil Heater

If a steam coil heater is present, the internal corrosion rate is adjusted upwards slightly due to extra heat and the possibility of steam leaks from the internal coil. Table A.2.2.16 gives corrosion rate adjustment factors for steam coil heaters.

Table A.2.2.16: Steam Coil Heater Adjustment

Does tank have a steam coil heater?	Adjustment Factor
Yes	1.15
No	1

Adjustment for Water Draws

Water draws, when consistently used, can greatly reduce the damaging effects of water at the bottom of the tank. To receive the full benefit, water must be drawn weekly or after every receipt. Table A.2.2.17 shows the adjustment factors for water draws.

Table A.2.2.17: Water Draw Adjustment

Are water draws conducted either weekly or after every receipt?	Adjustment Factor
No	1
Yes	0.7

Determination of Tank Bottom Leak Frequency

Estimate Internal and External Corrosion Rates

The internal and external corrosion rates are estimated by multiplying the base corrosion rate by the respective adjustment factors as shown in Equations A.6 and A.7 below. This will produce two separate corrosion rates that are combined as described below. It is assumed that the soil side corrosion will be localized in nature, while the product side corrosion will be either widespread or localized.

$$R_{Soil\ side} = 5\ mpy * AF_{Resistivity} * AF_{Foundation\ Type} * AF_{Drainage} * AF_{CP} * AF_{Fluid\ Temp}$$

(Equation A.6)

$$R_{Top\ side} = 2\text{-}5\ mpy * AF_{Internal\ lining} * AF_{Lining\ age} * AF_{Fluid\ Temp} * AF_{Steam\ coil} * AF_{Water\ draw}$$

(Equation A.7)

Combine Corrosion Rates

Option 1: If the internal corrosion is widespread, the corrosion areas will likely overlap such that the bottom thickness is simultaneously reduced by both internal and external influences. In this case, the internal and external rates are additive.

Option 2: For pitting, the chances are low that internal and external rates can combine to produce an additive effect on wall loss. In this case, the user chooses the greater of the two corrosion rates as the governing rate.

To avoid underestimating the corrosion rate, if the type of internal corrosion is unknown, widespread corrosion should be assumed. **In order to avoid understating the risk, it is recommended that the combined corrosion rate should not be set lower than 2 mils per year.**

Inspection Rating Category

Inspections are rated according to their expected effectiveness at detecting corrosion and correctly predicting the rate of corrosion. Because the user has calculated a corrosion rate instead of using a corrosion rate established by an inspection, the user should select an "E" or "D" inspection level unless very particular circumstances make selection of a higher quality inspection (one performed without establishing a corrosion rate) reasonable.

Determination of Tank-Specific Leak Frequencies

The user should employ the process developed in Section A.2.2.1.1.

Summary of Approach for Small Tank Bottom Leaks

A summary of the steps required to determine the tank bottom leak frequency for small leaks is presented below:

1. Use the base leak frequency for tank bottoms (7.2×10^{-3} leaks per year).
2. Start with an estimate of the base corrosion rate for the soil side of the tank bottom and multiply that rate by the following factors:
   a. Soil conditions (resistivity)
   b. Tank pad (Foundation Type)
   c. Drainage
   d. Cathodic protection
   e. Operating (fluid) temperature
3. Start with an estimate of the base corrosion rate for the product (top) side of the tank bottom and multiply that rate by the following factors:
   a. Existence of internal lining
   b. Age of internal lining
   c. Operating (fluid) temperature
   d. Steam coil heater
   e. Water draws
4. If the corrosion is widespread, add the two corrosion rates (one for top side, one for soil side). If the corrosion is localized, use the greater of the two corrosion rates. To avoid understating the risk, it is recommended that the combined corrosion rate should not be set lower than 2 mils per year.
5. Look up the modifying factor in Table A.2.2.3. Use the *ar/t* value and the rating of the most recent inspection to determine the modifying factor. In consulting the *ar/t* table, give precedence to the rating of the soil side inspection in those cases where the corrosion is additive.
6. Multiply the base leak frequency (step 1) by the modifying factor (step 5) to obtain the (tank-specific) bottom leak frequency.

A.2.2.2 Scenario 2—Rapid Bottom Failures

Rapid bottom failures (or failures at the bottom/shell interface) have a base frequency of 2.0×10^{-5} per year per tank. This failure rate is then modified by three factors:

1. Whether the tank is designed, fabricated, and maintained according to recognized industry standards
2. The extent of corrosion
3. Inspection for and presence of tank settlement

The following equation shows the calculation to determine the frequency of rapid bottom failures:

$$Rapid\ Bottom\ Failure\ Frequency = 2 \times 10^{-5} / \ year * MF_{Design} * MF_{Corrosion} * MF_{Settlement}$$

(Equation A.8)

Tank Design and Maintenance

If the AST is designed and maintained according to recognized industry standards, it will be less likely to encounter a rapid bottom failure. Table A.2.2.18 shows the modifying factors for those tanks that have and have not been designed and fabricated according to recognized industry standards and maintained according to API Std 650 and 653.

Table A.2.2.18: Modifying Factor for Tank Design and Maintenance

Is the tank designed according to a recognized industry standard and maintained according to API 650 & 653?	Modifying Factor
No	5
Yes	1

Corrosion

The effects of corrosion on the critical bottom/shell interface will be similar to the effects of corrosion on the tank bottom. A modifying factor for tank bottom corrosion was previously determined from Table A.2.2.3 as outlined in the tank bottom flow chart (Figure A.2.2.1). This modifying factor can now be used in determining a modifying factor for rapid bottom failures. The corrosion modifying factor for rapid bottom failures is the modifying factor from Table A.2.2.3 divided by 20 with a minimum value of 0.2.

Tank Settlement

Rigid body tilting, out-of-plane settlement, and edge settlement can all induce additional stresses at the critical bottom/shell interface. API Std 653 recommends inspecting for tank settlement as part of the routine in-service inspection. These stresses (especially in conjunction with corrosion at the critical joint) increase the likelihood of a rapid bottom failure. The modifying factors for tank settlement are shown in Table A.2.2.19.

Table A.2.2.19: Modifying Factor for Tank Settlement

API 653 Settlement Inspection?	Settlement Found?	
	Yes	**No**
Yes	2	1
No	1.5	

A.2.3 Tank Shell Leak Frequency Scenarios

Tank shell leak frequency scenarios consist of the following scenarios:

- Scenario 1—Small Tank Shell Leaks
  - Case 1—Small Shell Leak Due to Corrosion, Corrosion Rate Established
  - Case 2—Small Shell Leak Due to Corrosion, Corrosion Rate NOT Established
  - Case 3—Small Shell Leaks Due to Tank Fitting Failure or Leak
- Scenario 2—Tank Rapid Shell Failure

The approach to calculating the frequency of a tank shell leak is similar to the approach established for tank bottom leaks.

- Select a base leak frequency for each scenario (see Table A.2.3.1)
- Use or establish a corrosion rate (r) (recommended); if no corrosion rate available, estimate using the method in Section A.2.3.1.2.
- Calculate *ar/t*
- Calculate leak frequency for small shell leak due to corrosion, fitting failure, rapid shell failure, and external floating roof arm failure

A.2.3.1 Scenario 1—Small Tank Shell Leaks Due to Corrosion

Small shell leaks caused by corrosion of the steel tank shell represent a small leak caused by a through hole in the shell plate. Table A.2.3.1 shows the base failure frequencies for shell leaks addressed in this method.

Table A.2.3.1: Base Leak Frequencies for Tank Shell

Failure Type	**Tank Shell**	**Base Frequency (events per year)**
Small Shell Leak	Welded Tanks	1.0×10^{-4}
	Riveted Tanks	1.0×10^{-3}

The age of the tank, shell metal thickness and shell corrosion rate are accounted for elsewhere in the model. These factors represent the percent wall loss as a modifying factor that is a function of the tank age, corrosion rate, and original wall thickness. The percent wall loss is the basis of a modifier to the tank shell base leak frequency stipulated above; thus, a very young tank with minimal corrosion will have a frequency modifier less than 1, which will lower its leak frequency accordingly.

The model also accounts for the quality of tank inspection. This modifying factor assumes that the thinning mechanism has resulted in a constant rate of thinning/pitting over the time period defined in the basic data, and the likelihood of failure is estimated by examining the possibility that the corrosion rate is greater than expected. The likelihood of discovering these higher rates is determined by the type of the most recent inspection. The more thorough the inspection, the less likely the chance that the corrosion rate is greater than anticipated.

For tanks where the shell corrosion rate is known, the user can perform the analysis stipulated in Case 1 below. If the tank shell corrosion rate is not known, the user can employ the approach in Case 2.

A.2.3.1.1 Case 1—Small Shell Leak Due to Corrosion, Corrosion Rate Established

The first case applies to tank shells where the existing shell corrosion rate is known or can be extrapolated from a similar service comparison. The approach used for AST tank shell leaks applies to tank shells subject to damage from internal and external corrosion. Widespread corrosion and localized corrosion, which includes pitting and erosion-corrosion, are included within the scope of this method. The tank course(s) to be analyzed is left to the user's discretion. It is suggested that the user consider different drivers for damage mechanisms (e.g., water level, water content, liquid line vapor space, etc.) when considering which course(s) to analyze. **This approach is applicable only for small leaks from welded shells. The leak frequency for small leaks from riveted shells is specified in Table A.2.3.1 and is not adjusted by a modifying factor.**

Required Data (Corrosion Rate Established)

The basic data listed in Table A.2.3.2 are the minimum required to determine a modifying factor for thinning when a corrosion rate has been established by one or more tank inspections performed in conformance with API Std 653. The user is encouraged to adopt established corrosion rates developed from tank inspections when available. If corrosion rates are available or if corrosion data from tanks in similar service are available and appropriate, the base leak frequency will be modified by the *ar/t* factor.

Table A.2.3.2: Basic Data Required for Shell Leak Analysis

Basic Data	**Comments**
Shell Corrosion Rate "r" (in mpy)	The observed corrosion rate on the shell of the tank for the shell course or shell courses under consideration.
Thickness (mils)	The actual measured thickness upon being placed in the current service, **or** the minimum construction thickness (nominal plate thickness) for the tank shell course or tank shell courses under consideration. The thickness used must be the thickness at the beginning of the time in service reported below.
Age (years)	The number of years that the equipment has been exposed to the current process conditions that produced the corrosion rate used below. The default is the equipment age. However, if the corrosion rate changed significantly, perhaps as a result of changes in process conditions, the time period and the thickness should be adjusted accordingly. The time period will be from the time of the change, and the thickness will be the minimum wall thickness at the time of the change (which may be different from the original wall thickness).
Inspection Rating Category	The rating category of each inspection (internal and external) that has been performed on the equipment during the time period (specified above). Separate evaluations are required for the internal and external shell.
Number of Inspections	The number of inspections in each rating category (both internal and external) that have been performed during the time period (specified above).

Determination of Tank Shell Leak Frequency

Inspection Rating Category

Inspections are rated according to their expected effectiveness at detecting corrosion and correctly predicting the rate of corrosion. The actual rating of a given inspection technique depends on the characteristics of the corrosion (i.e., whether it is widespread or localized).

Determination of Number and Rating of Inspections

The rating of each inspection performed within the designated time period should be characterized in accordance with Table A.2.3.3. The number of highest rated inspections will be used to determine the modifying factor.

Table A.2.3.3: Guidelines for Assigning Inspection Ratings—Tank Shell

Inspection Rating Category	**Inspection**
A	Intrusive inspection – good visuals with pit depth gage measurements at suspect locations
B	External spot/scanning UT based on visual information from previous internal inspection of this tank or similar service tanks
C	External spot/scanning UT at susceptible locations without benefit of any internal inspection information on tank type/service
D	External spot UT at susceptible locations without benefit of any internal inspection information on tank type/service
E	No inspection

Note: The methods listed in this table should be applied in accordance with API Standard 653 under the direction of an API 653 certified inspector.

Determination of Modifying Factor

To determine the modifying factor for the tank shell, a dimensionless quantity known as the "*ar/t*" value is estimated, and a table is consulted to find the modifying factor for the base failure frequency.

The *ar/t* is found as follows:

$$ar / t = \frac{age \times rate}{thickness}$$

(Equation A.9)

where

a = the age of the equipment in years;
r = the maximum corrosion rate in mpy; and
t = the original nominal thickness of the tank shell in mils when there is no measured corrosion thickness.

The exception to this is when the tank has experienced repairs. In this case *t* is the repaired thickness and, the age should be based on the repair date if the user is confident in the measured thickness after repairs. The age should be reset according to the repair date. The *ar/t* method assumes that the corrosion rate *r* is constant over the life of the tank. The value is actually the fraction of the original tank shell that has been lost due to corrosion.

The calculated *ar/t* value and the inspection rating are used to determine the modifying factor from Table A.2.3.4. DNV developed the *ar/t* table with input from contributing API member companies drawing on engineering expertise and field experience of atmospheric storage tank failures and corrosion.

Determination of Tank-Specific Leak Frequencies

The calculated *ar/t* and the number of highest rated inspections are used to determine the modifying factor from Table A.2.3.4. The small shell leak frequency due to corrosion for a specific tank is obtained by multiplying the base leak frequency for small shell leaks (Table A.2.3.1) by the modifying factor obtained from Table A.2.3.4.

*AST Shell Leak Frequency (known Corrosion Rate) = Base Leak Frequency * MF (ar/t)*

(Equation A.10)

Summary of Approach for Small Tank Shell Leaks

The steps required to determine the tank shell leak frequency for small leaks are summarized below:

1. Select the base leak frequency for small shell leaks (welded tanks) due to corrosion (Table A.2.3.1).
2. Use the tank inspection report or measured shell plate thickness to establish a corrosion rate (*r* in mpy). Determine the age of the tank shell in years and the original shell plate thickness in mils. Calculate *ar/t*.
3. Look up the modifying factor in Table A.2.3.4 using the *ar/t* value, number of inspections, and the rating of those inspections.
4. Multiply the base leak frequency (step 1) by the modifying factor (step 3) to obtain the (tank-specific) small shell leak frequency.
5. For small shell leaks from riveted tanks, the leak frequency is taken directly from Table A.2.3.1.

Table A.2.3.4: Tank Shell Modifying Factors

	Number of Inspections																
	0	**1**				**2**				**3**				**4**			
ar/t	E	D	C	B	A	D	C	B	A	D	C	B	A	D	C	B	A
0.05	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.10	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.15	0.314	0.240	0.165	0.0730	0.0202	0.180	0.0785	0.0121	0.0008	0.132	0.0348	0.0018	0.0001	0.0958	0.0148	0.0003	0.0001
0.20	177	135	92.9	41.1	11.3	101	44.1	6.82	0.435	74.4	19.6	1.01	0.0155	53.9	8.31	0.146	0.0005
0.25	2000	1530	1053	465	128	1146	500	77.2	4.92	843	222	11.5	0.176	610	94.1	1.66	0.0062
0.30	2000	1530	1053	465	129	1146	500	77.3	4.94	843	222	11.5	0.178	610	94.2	1.67	0.0066
0.35	2031	1559	1077	479	136	1172	517	82.0	6.13	866	233	12.9	0.349	631	101	2.07	0.0307
0.40	2265	1777	1262	588	197	1372	649	118	15.3	1046	321	23.7	1.66	790	157	5.17	0.217
0.45	2822	2298	1702	848	340	1849	962	204	37.3	1475	529	49.3	4.79	1170	290	12.6	0.659
0.50	5000	4334	3421	1860	899	3713	2188	541	123	3150	1343.5	149	17.0	2652	809	41.5	2.39
0.55	5000	4334	3421	1861	899	3713	2188	541	123	3150	1343.5	149	17.1	2652	809	41.5	2.44
0.60	5001	4335	3422	1862	901	3714	2189	542	125	3151	1344.8	151	18.6	2654	810	43.0	3.96
0.65	5009	4344	3433	1875	916	3725	2202	558	141	3163	1359.1	167	35.0	2666	825	59.4	20.4
0.70	5051	4392	3489	1944	993	3778	2268	638	224	3221	1432.3	250	119	2728	903	144	105
0.75	5179	4537	3657	2152	1225	3938	2467	879	477	3395	1653.3	502	374	2915	1138	398	360
0.80	5441	4835	4002	2579	1703	4268	2877	1376	995	3755	2108	1019	898	3301	1620	921	885
0.85	5850	5298	4540	3245	2447	4782	3516	2149	1803	4315	2816	1825	1715	3902	2372	1735	1703
0.90	6370	5887	5224	4091	3393	5436	4329	3133	2830	5028	3716	2849	2753	4666	3328	2771	2742
0.95	6940	6533	5974	5019	4431	6153	5219	4211	3955	5808	4702	3972	3891	5503	4375	3906	3882
1.00	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000

Notes:

A, B, C, and *D* refer to the inspection rating category. *E* indicates that there have been no inspections.

A value of 0.0001 in the table indicates that the actual value is 0.0001 or less.

The corresponding table in API Publ 581 on RBI yields more conservative outcomes since its intention is to schedule inspections. The table above provides a wider range of factors and lower probabilities since its intended use it to rank order relative risks.

A.2.3.1.2 Case 2—Small Shell Leak Due to Corrosion, Corrosion Rate Not Established

The second case applies to tank shells where the existing shell corrosion rate is NOT known or CANNOT be extrapolated from a similar service comparison. The approach used for small tank shell leaks applies to tank shells subject to damage from internal and external corrosion. Widespread corrosion and localized corrosion, which includes pitting and erosion-corrosion, are included within the scope of this method

Required Data (Corrosion Rate Not Established)

The basic data listed in Table A.2.3.5 are the minimum required to determine a modifying factor for thinning when a corrosion rate has not been established by one or more effective inspections. The reader is encouraged to use established corrosion rates if available instead of the modifying approach.

Table A.2.3.5: Basic Data Required for Shell Leak Analysis

Basic Data	Comments
Type of Climate (marine/temperate/ arid)	Type of climate is used as a parameter to estimate external corrosion rate of the shell.
Shell Internal Base Corrosion Rate (mpy)	The expected internal corrosion rate on the shell of the tank.
Internal Lining Needed?	Yes or No. Is a lining needed to protect the tank bottom and shell from the corrosive nature of the product?
Internal Lining Age (years)	Based on the installation date, or the last date of lining rehabilitation.
External Coating Age (years)	Based on the installation date, or the last date of coating rehabilitation.
Quality of External Coating	High, medium, or low/none.
Inspection Rating Category	The rating category of each inspection (internal and external) performed on the equipment during the time period (Table A.2.3.3). Separate evaluations are required for the internal and external shell.
Number of Inspections	The number of inspections in each rating category (both internal and external) performed during the time period (Table A.2.3.3).

Determination of Modifying Factor

Figure A.2.3.1 shows a flow chart of the steps required to determine the leak frequency modifying factor for tank shells. The following sections discuss these steps and present the required tables. **This approach is applicable only for small leaks from welded shells. The leak frequency for small leaks from riveted shells is specified in Table A.2.3.1 and is not changed by any modifying factor.**

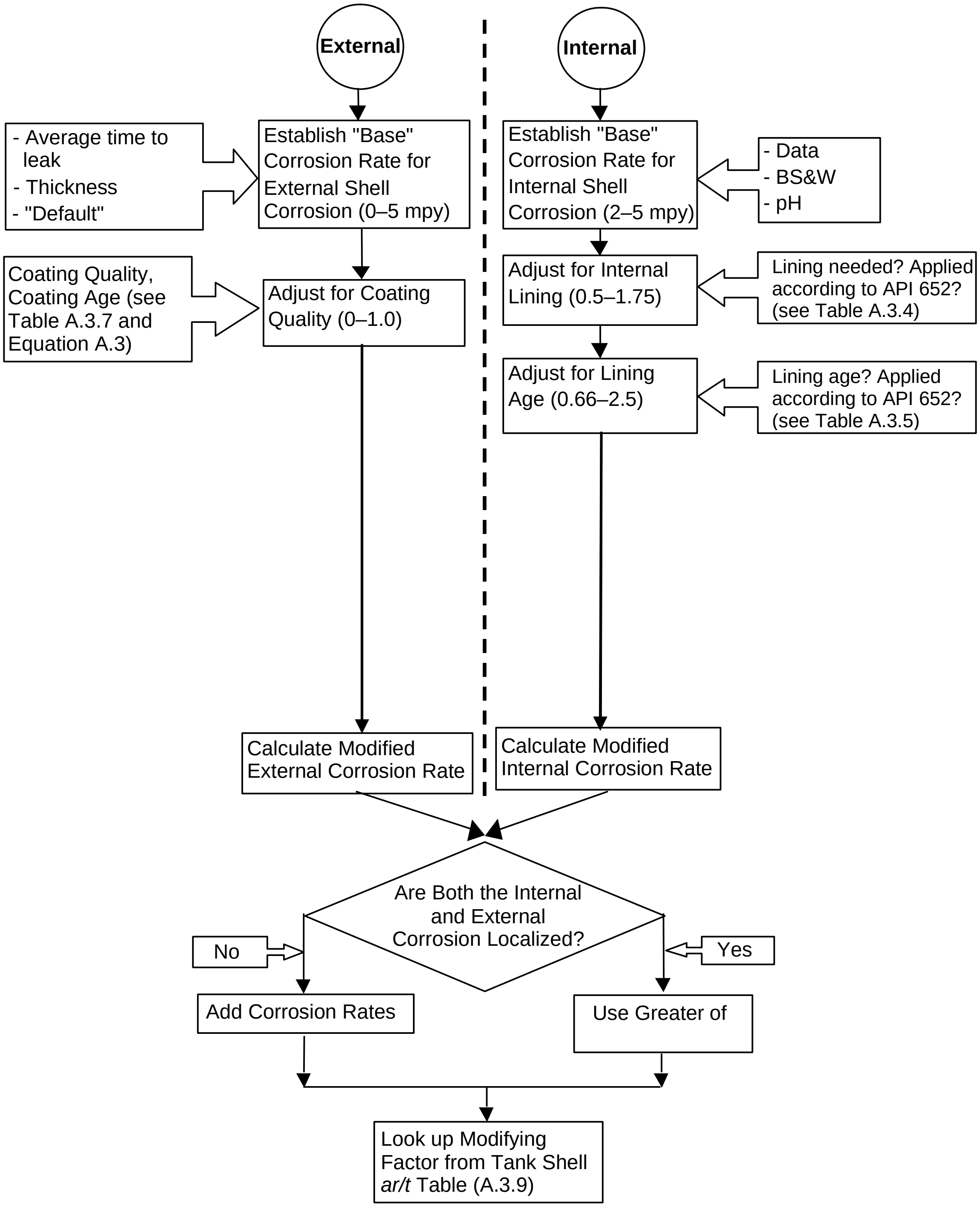


Figure A.2.3.1: Flow Chart to Determine Modifying Factor for Shell

Internal Corrosion Rate

Establish Base Corrosion Rate for Shell Internal Corrosion

Tank shells can corrode from the inside of the tank as well as from the outside. Base corrosion rates for internal corrosion can be obtained from previous internal inspection data or may be assumed to approximate the corrosion in the lower inch or two of the shell if significant BS&W is present. For dry product tanks, those tanks where BS&W is minimal and water bottoms are well managed, the internal corrosion can be insignificant.

Under normal circumstances and for the purpose of this assessment, the base internal corrosion rate was set to be 2 mpy for dry products. However, if significant bottom sediments and water are present, the base corrosion rate was set to be 5 mpy. Table A.2.3.6 shows the suggested base corrosion rates.

Table A.2.3.6: Tank Shell Base Corrosion Rates

Product Condition	**Base Corrosion Rate (mpy)**
Dry	2
Wet	5

Adjustment for Internal Lining

To protect the tank shell from the corrosive nature of the product, an internal lining may be needed. If an internal lining is needed, the adjustment factor is 1.15; if not, the factor is 1. If the required lining is applied per API RP 652, then there is a further reduction of the factor to 0.5 as shown in Table A.2.3.7. The table also shows the benefit of applying an internal lining when none is required (0.8–0.9) and the demerit of failing to apply a lining when needed (1.75). Further adjustment is made based on the age of the lining, as illustrated in Table A.2.3.8. If there is no lining, then Table A.2.3.8 is ignored, and only one adjustment factor is used—either 1 or 1.75 from Table A.2.3.7.

Table A.2.3.7: Internal Lining Adjustment

Is internal lining needed for corrosion protection?	**Adjustment Factor**
Yes (but no internal lining or unknown)	1.75
Yes (internal lining applied, but not per API 652)	1.15
Yes (internal lining applied per API 652)	0.5
No (and no lining applied)	1
No (internal lining applied anyway but not per API 652)	0.9
No (but internal lining applied per API 652)	0.8

Table A.2.3.8: Lining Age Adjustment

Lining Application and Age	**Adjustment Factor**
Lining applied per API 652	
> 20 years—limited or no data to assess lining condition	2.5
> 20 years—data to demonstrate that lining is in good condition	1
10–20 years	1
< 10 years	0.66
Lining not applied per API 652	
> 10 years—limited or no data to assess lining condition	1.5
> 10 years—data to demonstrate that lining is in good condition	1
5–10 years	1
< 5 years	0.87

The adjusted internal corrosion rate is then calculated as follows:

$$r_{int} = r_{int\text{-}base} * AF_{Lining} * AF_{Lining\ Age} \qquad \text{(Equation A.11)}$$

External Corrosion Rate

Establish Base Corrosion Rate for Shell External Corrosion

Shell external corrosion for carbon and low-alloy steels is calculated based on the type of climate and the average annual operating temperature. Three types of climates are considered—marine, temperate, and arid. Table A.2.3.9 presents ranges of bulk fluid temperatures and corresponding corrosion rates for each climate.

Table A.2.3.9: Base Corrosion Rates for Shell External Corrosion

Bulk Fluid Temperature (°F)	**Climate**		
	Marine/Cooling Tower Drift Area	**Temperate**	**Arid /Dry**
121–200	5 mpy	2 mpy	1 mpy
61–120	2 mpy	1 mpy	0 mpy
11–60	5 mpy	3 mpy	1 mpy
≤ 10	0 mpy	0 mpy	0 mpy

Figure A.2.3.2 shows the locations for the three climate types in the continental United States. Locations with a marine climate receive more than 40 inches of precipitation per year or have an average chloride concentration in rainwater of at least 1.0 mg/l. Locations with temperate climates are assumed to receive 20–40 inches of precipitation per year. Arid climates exist in those areas receiving less than 20 inches of precipitation per year.

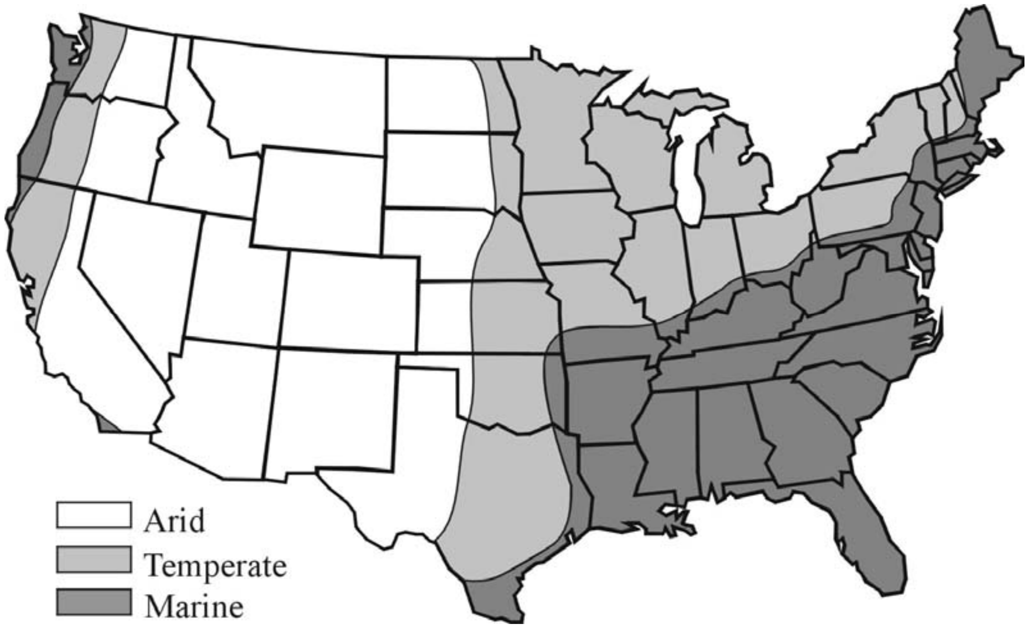


Figure A.2.3.2: Climate Map for the United States

Adjustment for External Coating

To account for the benefits of an external coating, it is assumed that no external corrosion takes place during the first 5 or 10 years after the tank is coated with a medium- or high-quality coating, respectively. An adjustment factor is then calculated by first determining the number of years in which the external shell is subject to corrosion and then dividing that by the age of the tank. For those tanks that are repeatedly coated, this factor may be close to 0. Table A.2.3.10 presents the adjustments to the shell external corrosion rate. The calculation of the adjustment factor for coating quality is shown in Equation A.12.

Table A.2.3.10: Adjustment for Quality of Coating

Coating Quality	**Adjustment**
High	Assume that no corrosion occurs during the first 10 years after coating application
Medium	Assume that no corrosion occurs during the first 5 years after coating application
Low/None	No credit given

Note: If the external shell is pitted, no credit should be given for coating the tank.

$$AF_{Coating\ Quality} = \frac{Number\ of\ Years\ Tank\ Unprotected}{Tank\ Age}$$

(Equation A.12)

In the application of Equation A.12, consideration should be given to the amount of time that the tank is bare; if a high-quality coating is over 10 years old; or if a medium-quality coating is over 5 years old. During such time periods, the tank is assumed to be unprotected. This assumption can be viewed as conservative, and the user may want to give some credit for coatings beyond their warranted life.

The adjusted external corrosion rate is then calculated as follows:

$$r_{ext} = r_{ext\text{-}base} * AF_{Coating\ Quality}$$

(Equation A.13)

Determination of Tank Shell Leak Frequency

Estimate Internal and External Corrosion Rates

The internal and external corrosion rates are estimated by multiplying the base corrosion rate by the respective adjustment factors. This will produce two separate corrosion rates that are combined as described below.

Combine Corrosion Rates

Option 1: If the internal corrosion is widespread, the corrosion areas will likely overlap such that the shell thickness is simultaneously reduced by both internal and external influences. In this case, the internal and external rates are additive.

Option 2: For pitting, the chances are low that internal and external rates can combine to produce an additive effect on wall loss. In this case, the user chooses the greater of the two corrosion rates as the governing rate.

To avoid underestimating the corrosion rate, if the type of internal corrosion is unknown, widespread corrosion should be assumed. **In order to avoid understating the risk, it is recommended that the combined corrosion rate should not be set lower than 2 mils per year.**

Inspection Rating Category

Inspections are rated according to their expected effectiveness in detecting corrosion and correctly predicting the rate of corrosion. Because the user has calculated a corrosion rate instead of using a corrosion rate established by inspection, the user should select an “E” or “D” inspection level unless very particular circumstances make selection of a higher quality inspection (one performed without establishing a corrosion rate) reasonable.

Determination of Tank-Specific Leak Frequencies

The user should adopt the process developed in Section A.2.3.1.1.

Summary of Approach for Small Tank Shell Leaks

A summary of the steps required to determine the tank shell leak frequency for small leaks is presented below:

1. Select the base leak frequency for small shell leaks (welded tanks).
2. Start with an estimate of the base corrosion rate for the product side of the tank shell and multiply that rate by the following factors:
   a. Existence of internal lining
   b. Age of internal lining
3. Start with an estimate of the base corrosion rate for the external side of the tank shell. An approach that accounts for type of climate is suggested.

4. Adjust the age of the external shell by accounting for the age and quality of exterior coatings.
5. If either the internal or external corrosion is widespread, then add the two corrosion rates. If both the internal and external corrosion are localized, use the greater of the two corrosion rates. In order to avoid understating the risk, it is recommended that the combined corrosion rate should not be set lower than 2 mils per year.
6. Determine the age of the tank shell in years and the original shell plate thickness in mils. Calculate *ar/t*.
7. Look up the modifying factor in Table A.2.3.4 using the *ar/t* value, number of inspections, and the rating of those inspections.
8. Multiply the base leak frequency (step 1) by the modifying factor (step 7) to obtain the (tank-specific) small shell leak frequency.
9. For small shell leaks from riveted tanks, the leak frequency is taken directly from Table A.2.3.1.

A.2.3.1.3 Case 3—Small Shell Leaks Due to Tank Fitting Failure or Leak

Leaks from tank fittings include leaks from manways, tank valves, and tank pipe appurtenances, and normally small leaks from gaskets and packing. The leak frequency for fittings where the leaked product reaches the ground is 1.0×10^{-5} leaks per fitting per year.

A.2.3.2 Scenario 2—Tank Rapid Shell Failure

The frequencies for rapid shell failures are as shown in Table A.2.3.11 and represent the base failure frequencies to be used. They are not influenced by any modifying factors.

Table A.2.3.11: Base Leak Frequencies for Tank Rapid Shell Failures

Failure Type	**Tank Shell**	**Base Frequency (events per year)**
Rapid Shell Failures	Tank is not maintained to API 653.	4.0×10^{-6}
	Tank is maintained to API 653.	1.0×10^{-7}

A.2.4 Tank Overfill Frequency

Overfilling an AST represents an event that can have varying consequences that cannot necessarily be combined with other tank likelihood events; therefore, the likelihood of overfilling a tank has been analyzed separately. The base frequency of overfilling an aboveground storage tank is:

$$\textit{AST Overfill Frequency} = 1.0 \times 10^{-4} \textit{ events per tank fill / year / tank}$$

(Equation A.14)

The user provides the number of tank fills per year. The number of tank fills is the average number of batch fill operations per year that have the potential for causing an overfill of the tank. For pipeline breakout tanks, this would be the number of tank high levels experienced in one year. A high level is defined as an operating condition where the tank level is 80 percent or more of the specified tank safe fill capacity. If there are seasonal demands, an average value for an entire year is used.

Modifying Factors

There are many different operating strategies for filling ASTs. In order to account for the different configurations for detection and shutdown, the base frequency given above is modified by the following factors:

- quality of operation

- level gauging
- automatic shutdown system
- attendance at fill operation

Required Data

The basic data required for the overfill analysis are shown in Table A.2.4.1.

Table A.2.4.1: Basic Data Required for Overfill Analysis

Basic Data	**Comments**
Type of fill procedures	Examines how well procedures have been written
Planning of product receipts	Degree of planning of product receipts
Testing of instruments	Data on how often level instruments are checked
Emergency preparedness	How are operators trained and exercised in off-normal operations for tank fill
Training	Specific training for filling operation
Testing of overfill protection system	Applies to overfill protection system
Number of fills per year	For breakout tankage, this would be the number of high levels per year. A high level is represented by an operating condition where the tank level is 80% or more of the safe fill capacity.
Type of level detection	One or two stage
Type of shutdown	Automatic—yes/no
Level of attendance at fill operation	Personnel are full time, part time, or not in attendance at the facility during tank fill operations

Determination of Modifying Factors

Adjustment for Quality of Operations

The strongest influence on the likelihood of an overfill event is the quality of fill operations. The quality of filling operations is assessed by determining the effect of management systems on operator performance. API RP 2350 was used as the basis of good engineering practices for AST overfill protection. In general, following API RP 2350 should result in relatively low probabilities for human error during the tank fill operation. This recommended practice also provides excellent guidance on the testing of the overfill protection system. For this analysis, the quality of operations is assessed using a scoring system, as shown in Table A.2.4.2.

Table A.2.4.2: Assessing Quality of Overfill Management Systems

LINE	QUALITY ASSESSMENT QUESTIONS	SCORE
1	What is the quality of your fill procedures? A. Written procedures in accordance with API RP 2350, score =20 B. Written procedures, not in full accordance with API RP 2350, score = 10 C. no written procedures, score =0	
2	How well do you plan product receipts? A. Planning of product receipt in accordance with API RP 2350, score = 10 B. Planning of product receipt, not in full accordance with API RP 2350, score = 5 C. no planning of product receipt, score = 0	
3	How well do you test electronic systems associated with tank fill operations? A. in accordance with API RP 2350, score =10 B. testing once per month, score = 5 C. no testing or no electronic systems, score =0	
4	How well have you prepared for emergencies? A. in accordance with API RP 2350, score = 10 B. written procedures in place, drills conducted, not in full accordance with API RP 2350, score = 5 C. little or no emergency preparedness, score = 0	
5	How well do you conduct training and performance evaluations? A. in accordance with API RP 2350, score = 10 B. specific training and evaluation for overfill operations, but not in full accordance with API RP 2350, score = 5 C. little or no specific training for operators on overfill operations, score =0	
6	How well do you test and inspect the overfill protection system? A. in accordance with API RP 2350, score = 20 B. some testing and inspection, not in full accordance with API RP 2350, score = 10 C. little or no testing or inspection on overfill protection, score =0	
	Add lines 1 through 6. Refer to the table below to assess the overall rating for the quality of overfill management systems. Total Score =	

QUALITY OF OPERATIONS MODIFYING FACTOR

Total Score	Quality	Modifying Factor
50 – 80	A	0.3
30 – 49	B	1
0 – 29	C	3

Adjustment for Level Gauging

Level gauging also affects the likelihood of an overfill. An instrumented level gauging system has high-level detection at preset points above the normal fill level. The preset points are specified such that the alarms will allow sufficient time for product shutoff or diversion before an overfill occurs. A two-stage level gauging system has a first stage that alarms above the normal fill level before the safe level is reached. A second stage alarms when the safe level is reached, allowing time to avoid an overfill. It is assumed for this modifying factor that the two stages are independent. If they are not independent, the user is to choose the “instrumented level gauging” modifying factor from Table A.2.4.3.

Table A.2.4.3: Adjustment for Level Gauging

Type of Level Gauging	Modifying Factor
Two-stage independent level gauging	0.5
Instrumented level gauging	0.8
Ground level gauging	1

Adjustment for Automatic Shutdown

If an automatic shutdown system is installed, the modifying factor is 0.1; otherwise, the factor is 1.0.

Adjustment for Attendance at AST Fill Operations

The modifying factor for attendance at fill operations during receipt was based on the probability that the overfill would occur during the time that an operator was not present to divert product. Some adjustment was also made to account for the quality of operations and the fact that operators may be less attentive to the fill operation if an automatic shutdown system is in place. Table A.2.4.4 shows the modifying factors.

Table A.2.4.4: Adjustment for Attendance at AST Fill Operations

Type of Shutdown	Level of Attendance at Fill Operations	Quality Rating		
		A	B	C
Automatic shutdown	Full time (90–100% present)	0.6	1	1.5
	Partial (25–90% present)	0.8	1.5	3
	Unattended (0–25% present)	1	3	5
Manual shutdown	Full time (90–100% present)	0.3	0.7	1
	Partial (25–90% present)	0.7	1	2
	Unattended (0–25% present)	not considered		

Calculation of Overfill Frequency

The risk of overfill during a fill operation can be calculated by multiplying the base probability of overfill (1×10^{-4}/ fill) by each of the modifying factors. This value can then be multiplied by the number of fills per year to obtain the annual frequency of overfill as shown in Equation A.15.

$$Overfill\ Frequency = 1\times10^{-4} / \ fill * MF_{Quality} * MF_{Level\ Gauging} * MF_{Auto\ Shut.} * MF_{Attend.} * \ fills / year$$

(Equation A.15)

Summary of Approach for Tank Overfill Releases

The steps required to determine the tank overfill release frequency are summarized below:

1. Start with the base release frequency for tank overfills (1.0×10^{-4} events per year).
2. Determine the appropriate modifying factors from above.
3. Determine the number of fills per year for the tank being analyzed.
4. Multiply the base leak frequency (step 1) by the modifying factors (step 2) by the number of fills per year (step 3) to obtain the tank-specific overfill release frequency.

A.2.5 Tank External Floating Roof Drain Leak Frequency

This section applies only to ASTs with uncovered external floating roofs and not to tanks with fixed roofs or those tanks that originally had external floating roofs which have subsequently been retrofitted with geodesic domes or other types of fixed roofs.

ASTs with external floating roofs are equipped with roof drains to remove rainwater from the roof. The hose or articulated pipe from the drain sits submerged inside the stored liquid of the tank until passing through the tank shell. A manual valve at the base of the shell is opened to drain the roof. Leaking roof drain hoses or pipes can be the conduit for a liquid release, if the roof drain valve has been left open.

Required Data

The basic data required for the overfill analysis are shown in Table A.2.5.1.

Table A.2.5.1: Basic Data Required for External Floating Roof Drain Analysis

Basic Data	**Comments**
Type of external floating roof drain	Hose or articulated pipe
Roof drain valves normal operation status	Normally open or normally closed

Base Failure Frequencies

Failure rates for roof drain hoses and articulated pipes are shown in Tables A.2.5.2 and A.2.5.3. If the roof drain valve is always left open, then the leak and rupture rates presented in Table A.2.5.2 would indicate the likelihood of a release for two different scenarios:

1. The hose or pipe ruptures completely allowing the product to flow out of the tank roof valve.
2. The hose or pipe develops a 1/8-inch diameter through hole.

Table A.2.5.2: External Floating Roof Drain Likelihood Rates—Valves Normally Open

Equipment Item	**Rupture Leak Rate (/yr)**	**^{1}/8-in Hole Leak Rate (/yr)**
Roof drain hose	5×10^{-4}	2×10^{-2}
Articulated pipe	3×10^{-4}	3×10^{-2}

Note: This table presents release rates for those tanks where the roof drain is always left open.

If the roof drain valve is generally closed, the possibility still exists that the roof drain valves are accidentally left open. This second conditional probability is included to account for human error in leaving the roof drain valve open. Table A.2.5.3 shows the likelihood of roof drain related releases to the environment for those tanks where the roof drain is generally kept closed. The same two scenarios from above apply.

Table A.2.5.3: External Floating Roof Drain Likelihood Rates—Valves Normally Closed

Equipment Item	Rupture Leak Rate (/yr)	$^{1}/_{8}$-in Hole Leak Rate (/yr)
Roof drain hose	5×10^{-6}	2×10^{-4}
Articulated pipe	3×10^{-6}	3×10^{-4}

Note: This table is used for those tanks where the roof drain is generally kept closed.

Summary of Approach for External Floating Roof Drain Leaks

A summary of the steps required to determine the leak frequency for external floating roof drain leaks is presented below:

(1) Determine the leak scenario, the type of equipment used for draining external floating roofs, and the normal operations status of the drain valves.

(2) Select a failure frequency from Table A.2.5.2 or A.2.5.3.

A.2.6 Piping

Tank facility piping includes the pressurized and gravity feed product piping that exists throughout the terminal. This piping traverses a number of different environments (some piping is located over land, some may be over water, some may be contained in a diked area or loading rack). The terminal facility piping should to be grouped or divided into like sections for analysis and the grouping is based upon a number of conditions. The following major criteria should be considered in grouping piping segments:

- Aboveground and underground piping need to be separately considered.
- Gravity or pressurized piping segments need to be separately considered.
- Piping can be grouped along segments having similar characteristics; for example similar operating conditions (e.g., temperature, pressure, flow rates) and similar service conditions (e.g., product type, piping age, piping condition, inspection history).
- Piping can be grouped along segments having similar consequences (e.g., product type, resources impacted, presence or absence of containment, piping overland, piping over water).

If the above characteristics change, then a new piping segment should be defined. The leak frequencies stipulated in this document have a nominal pipe length of 100 feet (30.5 meters) for this analysis; therefore, a segment of piping defined by the user as 3000 feet (915 meters) long would have a multiplier of 30. A leak frequency will be determined for each defined segment of piping based on the piping characteristics, actual piping length, the number of air-to-soil interfaces (for underground piping) and the number of road crossings (for underground piping). Flange leak frequencies are calculated separately from the piping segment itself. A base flange leak frequency multiplied by the number of flanges in the segment of piping is used to determine a leak frequency for flanges. (Although a flange leak will not have a hole size per se, the release rate is assumed to be similar to that of a small hole in the piping.) The piping and flange leak frequencies are then combined to obtain the overall piping leak frequency for the section of piping under consideration.

A.2.6.1 Underground Piping

The approach used for underground piping leaks considers the damage mechanisms of internal and external corrosion, external forces, material problems, operation or equipment malfunction, and miscellaneous causes of underground piping leaks.

Underground piping leak frequency analysis can be divided into two cases:

- Case 1—Underground piping corrosion rate is established based upon previous inspection information
- Case 2—Underground piping corrosion rate is not established

Base Failure Frequency

Underground piping leak frequencies were based on a distribution of underground leaks by various causes. A number of sources can cause underground piping leaks. They include corrosion, external forces, material, and operation or equipment malfunction. Section A.6.5.1 provides the cause of failure distribution for underground piping and the method for development of the underground piping leak frequency. The frequency of an underground piping leak was determined to be:

$$\textit{Underground Piping Leak Frequency} = 5.0x10^{-6} \textit{ leaks per 100 ft-year.}$$

(Equation A.16)

A.2.6.1.1 Case 1—Underground Piping, Corrosion Rate Established

The first case applies to underground piping where the piping corrosion rate has been established, the corrosion rate is known, the piping has been inspected in accordance with the requirements of API Std 570, or the corrosion rate can be extrapolated from a similar service comparison. When the corrosion rate is known, it is assumed that the thinning mechanism has resulted in an average rate of thinning/pitting over the time period defined in the basic data. The likelihood of failure is estimated by examining the possibility that the corrosion rate is greater than expected. The likelihood of discovering these higher rates is determined by the number and type of inspections that have been performed. The more thorough the inspection and the greater the number of inspections, the less likely it is that the corrosion rate is greater than anticipated.

Required Data (Corrosion Rate Established)

The basic data listed in Table A.2.6.1 are the minimum required to determine a modifying factor for underground piping failure when a known corrosion rate has been established by one or more piping inspections. The user is encouraged to adopt established corrosion rates developed from underground piping inspections when available. If corrosion rates are available or if corrosion data from pipes in similar service are available and appropriate, these data can be used. The base frequency calculation is modified by the *ar/t* factor as detailed

Table A.2.6.1: Basic Data Required for Underground Piping Analysis

Basic Data	Comments
Piping Corrosion Rate (mpy)	The observed corrosion rate for a "representative" section of buried piping under the specified inspection conditions.
Thickness (mils)	The actual measured thickness of the piping upon being placed in the current service, **or** the minimum nominal thickness. The thickness used must be the thickness at the beginning of the time in current service.
Age (years)	The number of years that the piping has been exposed to the current process conditions that produced the corrosion rate used below. The default is the piping age. However, if the corrosion rate changed significantly, perhaps as a result of changes in process conditions, the time period and the thickness should be adjusted accordingly. The time period will be from the time of the change, and the thickness will be the minimum wall thickness at the time of the change (which may be different from the original wall thickness).
Number of Inspections	The number of inspections in each rating category that have been performed during the time period (specified above).
Number of Air-to-Soil Interfaces	The number of times that the piping goes from buried to aboveground. All of these air-to-soil interfaces are counted in the underground piping analysis.
Number of Cased Road Crossings	The number of times that the piping (with a casing) passes under a roadway.

Determination of Underground Piping Leak Frequency

Inspection Rating Category

Inspections are rated according to their expected effectiveness at detecting corrosion and correctly predicting the rate of corrosion. Table A.2.6.2 below provides inspection ratings for underground piping inspections. The number of highest rated inspections is used to determine the modifying factor.

Table A.2.6.2: Guidelines for Assigning Inspection Ratings—Underground Piping

Inspection Rating Category	Method of Underground Piping Inspection
A	Smart pigging.
B	Visual examination of all air-to-soil interfaces, as well as cased road crossings, and piping at selected excavation areas. **AND** Point thickness measurements supplemented with ultrasonic scanning or profile radiography on these areas.
C	Visual examination of overburden and piping at selected excavation areas. **AND** Spot thickness measurements using pit gauges, ultrasonic scanning, or profile radiography on these areas.
D	Spot UT thickness measurements in aboveground sections of the piping and visual examination of overburden and air-to-soil interfaces.
E	No inspection, less than above recommendations, or ineffective technique used.

Note: The methods listed in this table should be applied in accordance with API 570 under the direction of an API 570 certified inspector.

The guidelines given in Table A.2.6.2 recognize that the extent and quality of data resulting from inspections will impact the value of *ar/t*, which in turn governs the likelihood of a leak. While these data are based on conventional and current inspection methods, this table can be modified by increasing or decreasing the inspection frequency based on other factors, such as leak testing or pressure testing. Due to the wide variety of leak testing and integrity testing methods, this document does not provide guidance on how or if the *inspection rating category* should be changed. The owner/user must make this decision by considering the quality of the basic inspection methods; the ability of the pressure, leak, or hydrostatic testing methods to determine piping integrity; and whether this testing is conducted in addition to, or in lieu of, the basic inspection methods listed in the table.

Determination of Modifying Factor

To determine the initial modifying factor for a given section of underground piping, a dimensionless quantity known as the *ar/t* value is estimated and a table is consulted to look up the modifying factor for the base failure frequency.

The *ar/t* is calculated as follows:

$$ar\ /\ t = \frac{age \times rate}{thickness}$$

(Equation A.17)

where

a = the age of the piping in years
r = the maximum corrosion rate in mpy (as determined by inspection results)
t = the original thickness (t nominal) of the piping, in mils

The “*ar/t* method” assumes that the corrosion rate *r* is constant over the life of the piping. The value *ar/t* is actually the fraction of the original piping wall that has been lost due to corrosion.
The calculated value and the inspection rating category are used to determine the modifying factor from Table A.2.6.3.

Table A.2.6.3: Underground Piping Modifying Factors

	Number of Inspections																
	0	**1**				**2**				**3**				**4**			
ar/t	E	D	C	B	A	D	C	B	A	D	C	B	A	D	C	B	A
0.05	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.10	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.15	0.0241	0.0185	0.0127	0.0056	0.0005	0.0138	0.0060	0.0009	0.0001	0.0102	0.0027	0.0001	0.0001	0.0074	0.0011	0.0001	0.0001
0.20	13.6	10.4	7.15	3.16	0.284	7.78	3.40	0.524	0.0033	5.72	1.51	0.0780	0.0001	4.14	0.639	0.0113	0.0001
0.25	154	118	81	35.8	3.21	88.1	38.5	5.94	0.0378	64.8	17.0	0.884	0.0004	46.9	7.24	0.128	0.0001
0.30	154	118	81	35.8	3.22	88.2	38.5	5.95	0.0385	64.8	17.1	0.885	0.0005	47.0	7.25	0.128	0.0001
0.35	156	120	83	36.9	3.66	90.2	39.8	6.31	0.0848	66.6	17.9	0.992	0.0052	48.5	7.80	0.159	0.0005
0.40	174	137	97	45.3	7.04	106	49.9	9.09	0.443	80.5	24.7	1.82	0.0411	60.8	12.1	0.398	0.0041
0.45	217	177	131	65.2	15.1	142	74.0	15.7	1.30	113	40.7	3.79	0.127	90.0	22.3	0.967	0.0127
0.50	385	333	263	143	46.6	286	168	41.6	4.63	242	103	11.5	0.462	204	62.2	3.19	0.0462
0.55	385	333	263	143	46.6	286	168	41.6	4.63	242	103	11.5	0.465	204	62.2	3.19	0.0499
0.60	385	333	263	143	46.7	286	168	41.7	4.75	242	103	11.6	0.582	204	62.3	3.31	0.167
0.65	385	334	264	144	47.9	287	169	42.9	6.00	243	105	12.9	1.85	205	63.5	4.57	1.43
0.70	389	338	268	150	54.0	291	174	49.0	12.5	248	110	19.3	8.35	210	69.5	11.1	7.94
0.75	398	349	281	166	72.4	303	190	67.6	32.0	261	127	38.6	28.0	224	87.5	30.6	27.6
0.80	419	372	308	198	110	328	221	106	72.1	289	162	78.4	68.3	254	125	70.8	68.0
0.85	450	408	349	250	169	368	270	165	135	332	217	140	131	300	182	133	131
0.90	490	453	402	315	245	418	333	241	214	387	286	219	211	359	256	213	211
0.95	534	503	460	386	327	473	401	324	301	447	362	306	299	423	337	300	299
1.00	769	769	769	769	769	769	769	769	769	769	769	769	769	769	769	769	769

Notes

A, B, C, D, and E refer to the inspection rating category (see Table A.2.6.2).

This table applies to Class 150 piping.

A value of 0.0001 in the table indicates that the actual value is 0.0001 or less.

Determination of Modifying Factor for Soil-to-Air Interfaces

The next modifying factor is the soil-to-air interfaces factor. Soil-to-air interfaces for piping can lead to corrosion because the CP is less effective at this point. In addition, water can collect around the piping where it enters the ground, and the likelihood of a release increases as the number of soil-to-air interfaces increases. Equation A.18 can be used to determine the soil-to-air interfaces modifying factor for a given section of piping. The number of soil-to-air interfaces per 100 feet (30.5 meters) of piping is used in this equation. This number would typically be less than 1.

$$MF_{Soil-to-Air} = 1 + (0.5)(\#\ Soil-to-Air\ Interfaces\ per\ 100\ ft\ of\ Piping)x(QF)$$

(Equation A.18)

The quality factor (QF) is determined based on the criteria shown in Table A.2.6.4.

Table A.2.6.4: Quality Factor (QF) for Soil-to-Air Interfaces

Soil-to-Air Interface Description	**Quality Factor**
Applies for high-quality soil-to-air interfaces. The coating is wrapped onto the piping and sealed either by a mastic or epoxy and extends aboveground at least 2 feet (0.6 meters) where the full circumference of the interface of the termination of the section of underground piping is subject to full visual inspection.	0.4
Applies for all bare pipe soil-to-air interfaces, interfaces that terminate through a concrete box, or interfaces where the ability to inspect the coating does not meet the criteria for QF=0.4.	1

Determination of Modifying Factor for Cased Road Crossings

Buried piping may be encased in a second pipe or concrete at road crossings. This is effective in preventing the piping from being crushed, but can also provide an environment that is favorable to corrosion. Equation A.19 can be used to determine the road crossing modifying factor for a given section of piping. The number of cased road crossings per 100 feet (30.5 meters) of piping is used in this equation. This number would typically be less than 1.

$$MF_{Road\ Cross.} = 1 + (0.5)(\#\ Cased\ Road\ Crossings\ per\ 100\ ft\ of\ Piping)$$

(Equation A.19)

Knowledge of Underground Piping Location Modifying Factor

It is important to know the precise location of underground piping. This knowledge will greatly reduce the likelihood of leaks due to external forces. If the location of underground piping is accurately identified, the overall likelihood of occurrence is reduced. Table A.2.6.5 presents the modifying factor for piping location.

Table A.2.6.5: Modifying Factor for Piping Location

Is the location of the underground piping accurately identified?	Modifying Factor
No	1
Yes	0.85

Determination of Piping Specific Leak Frequency

The leak frequency for a specific section of underground piping is obtained by multiplying the base leak frequency (*$5.0x10^{-06}$ leaks per 100 ft-year*) by the *ar/t* modifying factor obtained from Table A.2.6.3, the *soil-to-air interfaces* modifying factor obtained from Equation A.18, the *cased road crossings* modifying factor from Equation A.19, the *piping location* modifying factor from Table A.2.6.5, and the number of 100-foot sections in the piping segment being analyzed. This is illustrated in Equation A.20.

$$\textit{Underground Piping Leak Freq.} = 5.0\times10^{-6}/100\ \textit{ft-yr} * MF_{ar/t} * MF_{Soil\text{-}to\text{-}Air} * MF_{Road\ Cross.} * MF_{Pipe\ Loc.} * \#\ \textit{of}\ \ 100\ \textit{ft Sections}$$

(Equation A.20)

Underground Piping Flange Leak Frequency

The failure mechanism for piping flanges is different than the failure mechanism for the piping itself. A leak frequency is determined per flange-year and is multiplied by the number of flanges in the section of piping. A base flange leak frequency of 1.0×10^{-4} per year per flange is used for terminals and tank farms in the petroleum industry.

$$\textit{Underground Piping Flange Leak Frequency} = 1.0\times10^{-4}\ \textit{events / year / flange} * \#\ \textit{of Flanges}$$

(Equation A.21)

Total Underground Piping Leak Frequency

The total underground piping leak frequency is the combination of the leak frequency for the underground piping segment under consideration plus the leak frequency for the number of flanges in that pipe segment.

$$\textit{Total Underground Piping Leak Frequency} = \textit{Underground Piping Leak Freq.} + \textit{UG Piping Flange Leak Freq.}$$

(Equation A.22)

A.2.6.1.2 Case 2—Underground Piping, Corrosion Rate NOT Established

The second case applies to underground piping where the piping corrosion rate has NOT been established and the corrosion rate is therefore unknown. The underground piping modifying factors are the same as Case 1 with the additional requirement to estimate an internal and external corrosion rate for the underground piping segment under consideration.

Basic Assumptions

The estimated *r* to be used in the calculation of the *ar/t* value assumes that the thinning mechanism has resulted in an average rate of thinning/pitting over the time period defined in the basic data.

Required Data (Corrosion Rate Not Established)

The data in Table A.2.6.6 are required for estimating the corrosion rate of underground piping. The reader is encouraged to use established corrosion rates if available instead of the modifying approach.

Table A.2.6.6: Basic Data Required for Underground Piping Analysis

Basic Data	Comments
Piping External Corrosion Rate (mpy)	The expected or observed external corrosion rate for a "typical" section of buried piping under "average" conditions, i.e. neither highly susceptible to corrosion nor especially resistant to corrosion.
Piping Internal Corrosion Rate (mpy)	The expected or observed internal corrosion rate of the piping.
Soil Resistivity (ohm – cm)	Resistivity of the soil in contact with the piping. (A common method of measuring soil resistivity is described in ASTM G 57.)
Cathodic Protection	The existence of a CP system for the piping, and the proper installation and operation of such a system, based on NACE RP0169 and API RP 651.
Exterior Coating or Pipe Wrap	Is the piping coated or wrapped? What is the age of the coating or pipe wrap? Type? Installation issues?
Product	Product carried in piping.

Determination of Corrosion Rate Modifying Factor

Figure A.2.6.1 shows a flow chart of the steps required to determine the leak frequency modifying factor for underground piping. This section discusses these steps and presents the required tables.

Underground Piping Corrosion Rate

Establish Base Corrosion Rate for Underground Piping

The base corrosion rate is the expected or observed corrosion rate for a typical section of underground piping under average conditions (i.e., neither highly susceptible to corrosion nor especially resistant to corrosion). Table A.2.6.7 presents the suggested base corrosion rates. The base corrosion rates are founded on the conditions stated in Table A.2.6.8.

Table A.2.6.7: Base Corrosion Rates for Underground Piping

Location	Base Corrosion Rate
Internal	2 mpy
External	5 mpy

Table A.2.6.8: Summary of Conditions for Underground Piping Base Corrosion Rate

Factor	**Base Corrosion Rate Conditions**
Soil Resistivity	1000–2000 ohm-cm
Cathodic Protection	None or not functioning
Pipe Coating or Wrap	Yes; 10–20 years; assumed to be in good condition
Pipe Location	None
Air-to-Soil Interfaces	None
Cased Road Crossings	None
Product	Crude oil in continuous flow

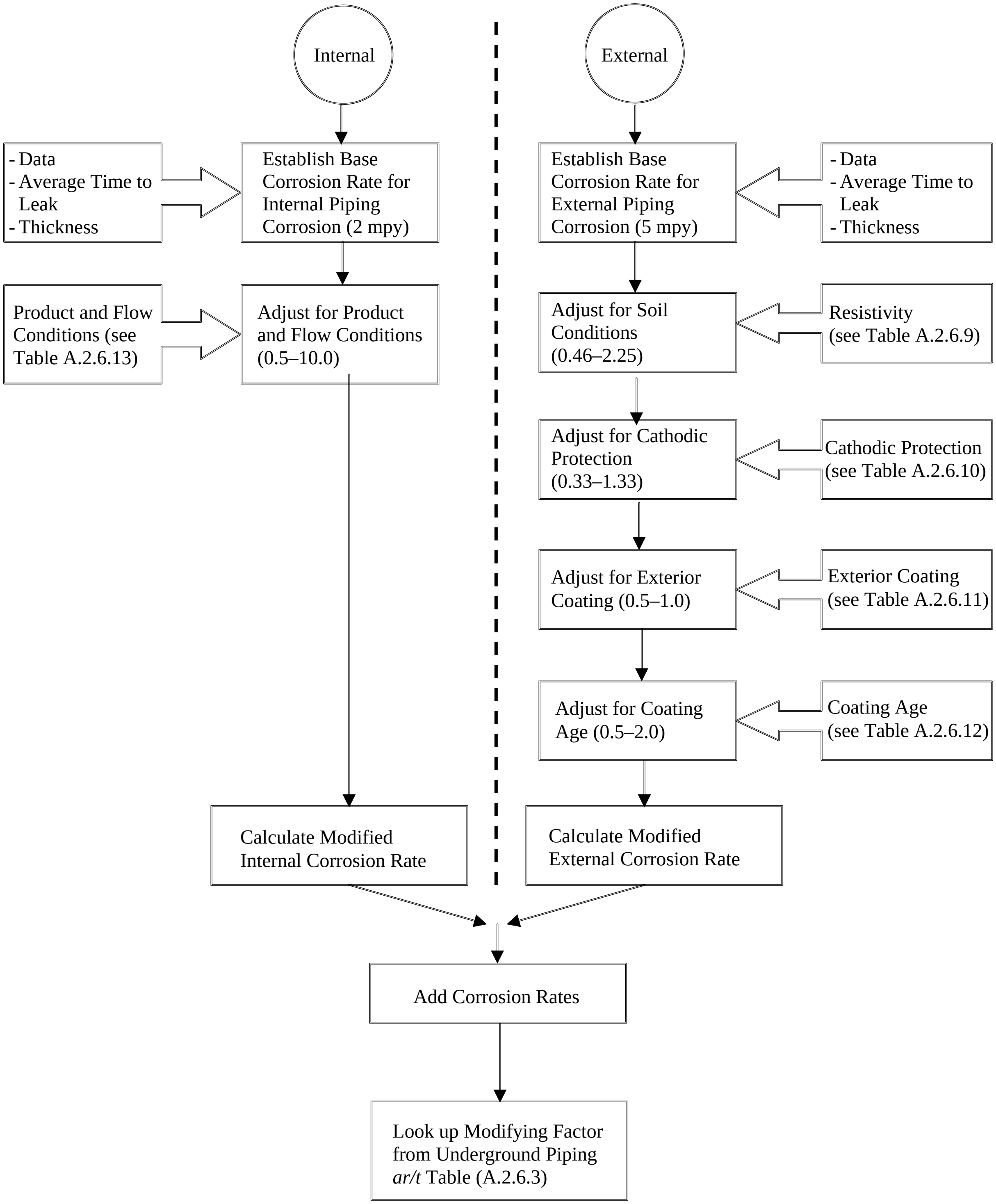


Figure A.2.6.1: Flow Chart to Determine Modifying Factor for Underground Piping

External Corrosion Rate

Adjustment for Soil Conditions

The resistivity of the soil in contact with the buried piping can affect the corrosion rate. Corrosion of bare or poorly coated piping is often caused by a mixture of different soils in contact with the piping surface. The corrosiveness of the soils can be determined by a measurement of the soil resistivity. Lower levels of resistivity are relatively more corrosive than higher levels, especially in areas where the piping is exposed to both areas of high and low soil resistivity. Table A.2.6.9 gives corrosion rate adjustment factors for soil resistivities. If the piping has an operating CP system, the soil resistivity adjustment factor is set to 1.

Table A.2.6.9: Soil Resistivity Adjustment*

Resistivity (ohm-cm)	Potential Corrosion Activity	Adjustment Factor
<500	Very Corrosive	2.25
500–1000	Corrosive	1.6
1000–2000	Moderately Corrosive	1
2000–10000	Mildly Corrosive	0.7
>10000	Progressively Less Corrosive	0.46

*A value of 1 shall be used if there is cathodic protection.

Adjustment for Cathodic Protection

Cathodic protection is one of the primary methods used to avoid corrosion of underground piping; however, the system must be installed and maintained properly. NACE RP0169 and Section 11 of API RP 651 provide applicable guidance for inspecting and maintaining CP systems for underground piping (see also API Std 570, Section 9.1.5). Table A.2.6.10 provides corrosion rate adjustment factors for piping CP. The factor is established so that the most credit is given for a properly functioning CP system in accordance with NACE RP0169 and Section 11 of API RP 651, but no penalty is assessed for lack of CP with no coating. This assumes that the base corrosion rate is for systems without CP. Pipelines with coating that do not have CP are more likely to experience high corrosion rates than are bare pipelines because of the unfavorable anode/cathode ratio.

Table A.2.6.10: Adjustment for Cathodic Protection

Functional CP in Place?	Adjustment Factor
No CP with Coating	1.33
No CP, No Coating	1.0
Yes (not per NACE RP0169 and API 651)	0.66
Yes (per NACE RP0169 and API 651)	0.33

Adjustments for Exterior Coating or Pipe Wrap

To protect the exterior of the piping from the corrosive nature of the soil, an exterior coating or pipe wrap will be needed if a fully effective CP system is not in place. Adjustments for exterior coating or pipe wrap are provided in Tables A.2.6.11 and A.2.6.12.

Table A.2.6.11: Adjustment for Exterior Coating or Pipe Wrap

Coating Type	Adjustment Factor
No exterior coating or pipe wrap	2
Exterior coating or pipe wrap	1

Table A.2.6.12: Exterior Coating Age Adjustment

Coating Age	Adjustment Factor
> 20 years—limited or no data to assess coating condition	2.0
> 20 years—data to demonstrate that coating is in good condition	0.8
10–20 years	0.8
< 10 years	0.5

The adjusted external corrosion rate (r_{ext}) is calculated as follows:

$$r_{ext} = r_{ext\text{-}base} * AF_{Soil\ Cond.} * AF_{Cath.\ Prot.} * AF_{Ext.\ Coating.} * AF_{Coating\ Age}$$

(Equation A.23)

Internal Corrosion Rate

The base internal corrosion rate is 2 mpy. This rate is adjusted based on the type of product in the piping and the flow conditions.

Adjustment for Type of Product and Flow Conditions

Piping systems carrying refined product are generally less susceptible to corrosion than piping systems carrying crude oil; however, regardless of the product, the piping system will experience increased corrosion rates if dead legs are created. The adjustment factors for product and flow conditions are presented in Table A.2.6.13.

Table A.2.6.13: Product and Flow Condition Adjustment

Product and Flow Conditions	Adjustment Factor
Refined Product (Gasoline, Diesel, etc.)	
-- Active Line	0.5
-- No Flow (Deadleg)	5
Crude Oil	
-- Active Line	1
-- No Flow (Deadleg)	10

The adjusted internal corrosion rate (r_{int}) is calculated as follows:

$$r_{int} = r_{int\text{-}base} * AF_{Prod/Flow}$$

(Equation A.24)

Combine Corrosion Rates

It is assumed that the external corrosion will be localized, while the internal corrosion will likely be widespread (with localized corrosion such as microbiologically induced corrosion (MIC) being a notable exception). The corrosion areas, therefore, will likely overlap such that the piping thickness is simultaneously reduced by both internal and external influences. It is therefore assumed that the internal and external corrosion rates are typically additive.

$$r_{est} = r_{\mathrm{int}} + r_{ext}$$

(Equation A.25)

A.2.6.2 Aboveground Piping

The approach used for aboveground piping leaks includes consideration of the damage mechanisms of internal and external corrosion, external forces, material problems, operation or equipment malfunction, and miscellaneous causes of aboveground piping leaks.

Aboveground piping leak frequency analysis can be divided into two cases:

- Case 1—Aboveground piping corrosion rate is established based upon previous inspection information.
- Case 2—Aboveground piping corrosion rate is not established.

Base Failure Frequency

Aboveground piping leak frequencies were based on a distribution of aboveground leaks by various causes. Aboveground piping leaks have a number of causes including corrosion, external forces, material, and operation or equipment malfunction. Section A.6.6 presents the cause of failure distribution for aboveground piping and the method for development of the aboveground piping leak frequency. The base leak frequency of an aboveground piping leak was determined to be:

$$\textit{Aboveground Piping Leak Frequency} = 2.7x10^{-6} \textit{ leaks per 100 ft-year.}$$

(Equation A.26)

A.2.6.2.1 Case 1—Aboveground Piping, Corrosion Rate Established

The first case applies to aboveground piping where the piping corrosion rate has been established, the corrosion rate is known, the piping has been inspected in accordance with the requirements of API Std 570, or the corrosion rate can be extrapolated from a similar service comparison. When the corrosion rate is known, it is assumed that the thinning mechanism has resulted in an average rate of thinning/pitting over the time period defined in the basic data. The likelihood of failure is estimated by examining the possibility that the corrosion rate is greater than expected. The likelihood of discovering these higher rates is determined by the number and type of inspections that have been performed. The more thorough the inspection and the greater the number of inspections, the less likely it is that the corrosion rate is greater than anticipated.

Required Data (Corrosion Rate Established)

The basic data listed in Table A.2.6.14 are the minimum required to determine a modifying factor for aboveground piping when a known corrosion rate has been established by one or more piping inspections. The user is encouraged to adopt established corrosion rates developed from underground piping inspections when available. If corrosion rates are available or if corrosion data from pipes in similar service are available and appropriate, these data can be used. The base frequency calculation is modified by the *ar/t* factor as detailed below.

Table A.2.6.14: Basic Data Required for Aboveground Piping Analysis

Basic Data	Comments
Piping Corrosion Rate (mpy)	The observed corrosion rate for both external and internal corrosion for a "typical" section of aboveground piping under "average" conditions (i.e., neither highly susceptible to corrosion nor especially resistant to corrosion).
Thickness (mils)	The actual measured thickness of the piping upon being placed in the current service **or** the minimum nominal thickness. The thickness used must be the thickness at the beginning of the time in current service.
Age (years)	The number of years that the piping has been exposed to the current process conditions that produced the corrosion rate used below. The default is the piping age. However, if the corrosion rate changed significantly, perhaps as a result of changes in process conditions, the time period and the thickness should be adjusted accordingly. The time period will be from the time of the change, and the thickness will be the minimum wall thickness at the time of the change (which may be different from the original wall thickness).
Inspection Rating Category	The rating category of each inspection that has been performed on the section of piping during the time period (specified above).
Number of Inspections	The number of inspections in each rating category that have been performed during the time period (specified above).

Determination of Aboveground Piping Leak Frequency

Inspection-Determined Corrosion Rates

The user needs to select a representative corrosion rate for the piping section being analyzed. The corrosion rate should account for internal and external corrosion and represent the average corrosion rate for the section of pipe under consideration.

Determination of Number and Rating of Inspections

Inspections are rated according to their expected effectiveness in detecting corrosion and correctly predicting the rate of corrosion. The rating of each inspection performed within the designated time period should be characterized in accordance with Table A.2.6.15. The number of highest rated inspections will be used to determine the modifying factor.

Table A.2.6.15: Guidelines for Assigning Inspection Ratings—Aboveground Piping

Inspection Rating Category	Method of Aboveground Piping Inspection
A	For the total length of the piping: • Visual examination (API 570) **AND** • Thickness measurements using ultrasonic scanning or profile radiography on selected thickness measurement locations (TMLs) (API 570) and statistical analysis of the data
B	For the total length of the piping: • Visual examination (API 570) **AND** • Point thickness measurements supplemented with ultrasonic scanning, or profile radiography on selected TMLs (API 570)
C	For the total length of the piping: • Visual examination per API 570 **AND** • Spot UT thickness measurements per API 570
D	Spot UT thickness measurements
E	No inspection, less than above recommendations, or ineffective technique used

Determination of Modifying Factor

To determine the modifying factor for the given section of aboveground piping, a dimensionless quantity known as the *ar/t* value is estimated, and a table is consulted to look up the modifying factor for the base failure frequency.

The *ar/t* is found as follows:

$$ar\ /\ t = \frac{age \times rate}{thickness}$$

(Equation A.27)

where

a = the age of the piping, in years
r = the established or estimated corrosion rate in mpy
t = the original thickness of the piping, in mils
The “*ar/t* method” assumes that the corrosion rate r is constant over the life of the piping. The value is actually the fraction of the original piping wall that has been lost due to corrosion. The calculated *ar/t* and the number of highest rated inspections should be used to determine the modifying factor from Table A.2.6.16.

Table A.2.6.16: Aboveground Piping Modifying Factors

	Number of Inspections																
	0	**1**				**2**				**3**				**4**			
ar/t	E	D	C	B	A	D	C	B	A	D	C	B	A	D	C	B	A
0.05	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.10	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.15	0.0424	0.0324	0.0223	0.0099	0.0009	0.0243	0.0106	0.0016	0.0001	0.0178	0.0047	0.0002	0.0001	0.0129	0.0020	0.0001	0.0001
0.20	23.8	18.2	12.5	5.54	0.498	13.7	5.96	0.920	0.0058	10.0	2.64	0.137	0.0001	7.27	1.12	0.0198	0.0001
0.25	270	206	142	62.8	5.63	155	67.5	10.4	0.0662	114	29.9	1.55	0.0007	82.3	12.7	0.224	0.0001
0.30	270	207	142	62.8	5.65	155	67.5	10.4	0.0675	114	29.9	1.55	0.0009	82.4	12.7	0.225	0.0001
0.35	274	210	145	64.7	6.42	158	69.8	11.1	0.149	117	31.5	1.74	0.0090	85.2	13.7	0.279	0.0008
0.40	306	240	170	79.4	12.4	185	87.6	15.9	0.777	141	43.3	3.19	0.0722	107	21.2	0.698	0.0072
0.45	381	310	230	114	26.5	250	130	27.6	2.27	199	71.4	6.65	0.223	158	39.1	1.70	0.0222
0.50	675	585	462	251	81.7	501	295	72.9	8.11	425	181	20.2	0.810	358	109	5.60	0.0810
0.55	675	585	462	251	81.7	501	295	73.0	8.12	425	181	20.2	0.817	358	109	5.60	0.0876
0.60	675	585	462	251	81.9	501	295	73.1	8.33	425	181	20.4	1.02	358	109	5.81	0.293
0.65	676	586	463	253	84.0	503	297	75.3	10.5	427	183	22.6	3.24	360	111	8.02	2.52
0.70	682	593	471	262	94.7	510	306	86.0	21.9	435	193	33.8	14.7	368	122	19.4	13.9
0.75	699	612	493	290	127	531	333	119	56.1	458	223	67.7	49.1	393	154	53.7	48.4
0.80	734	652	540	348	194	576	388	186	127	507	284	138	120	445	219	124	119
0.85	790	715	613	438	297	645	475	290	236	582	380	246	230	527	320	234	230
0.90	860	794	705	552	429	734	584	423	376	678	501	384	370	630	449	374	370
0.95	937	882	806	677	574	830	704	568	529	784	635	536	524	743	590	527	524
1.00	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350

Notes
A, B, C, D, and E refer to the inspection rating category (see Table A.9.22).
This table applies to Class 150 piping.
A value of 0.0001 in the table indicates that the actual value is 0.0001 or less.

Determination of Piping-Specific Leak Frequencies

The leak frequency for a specific section of aboveground piping is obtained by multiplying the base leak frequency for aboveground piping (Equation A.26) by the modifying factor obtained from Table A.2.6.16 and by the length of piping in the section (in feet) divided by 100. This is illustrated in Equation A.28.

$$\textit{Aboveground Piping Leak Freq.} = 2.7\times10^{-6}/100\ \textit{ft-yr}*MF_{ar/t}*\ \#\ \textit{of 100 ft Sections}$$

(Equation A.28)

Aboveground Piping Flange Leak Frequency

The failure mechanism for piping flanges is different than the failure mechanism for the piping itself. A leak frequency is determined per flange-year and is multiplied by the number of flanges in the section of piping. A base flange leak frequency of 1.0×10^{-4} per year per flange is used for terminals and tank farms in the petroleum industry.

$$\textit{Aboveground Piping Flange Leak Frequency} = 1.0\times10^{-4}\ \textit{events / year / flange} *\ \#\ \textit{of Flanges}$$

(Equation A.29)

Total Aboveground Piping Leak Frequency

The total aboveground piping leak frequency is the combination of the leak frequency for the aboveground piping segment under consideration plus the leak frequency for the number of flanges in that pipe segment.

$$\textit{Total Aboveground Piping Leak Frequency} = \textit{Aboveground Piping Leak Freq.} + \textit{AG Piping Flange Leak Freq.}$$

(Equation A.30)

A.2.6.2.2 Case 2—Aboveground Piping, Corrosion Rate Not Established

The second case applies to aboveground piping where the piping corrosion rate has NOT been established and the corrosion rate is therefore unknown. The aboveground piping modifying factors are the same as in Case 1 with the additional requirement to estimate an internal and external corrosion rate for the aboveground piping segment under consideration.

Basic Assumptions

For this case, the corrosion rate *r* to be used in the calculation of the *ar/t* value is estimated through the process detailed below. The estimated *r* assumes that the thinning mechanism has resulted in an average rate of thinning/pitting over the time period defined in the basic data.

Required Data (Corrosion Rate Not Established)

The basic data listed in Table A.2.6.17 are the minimum required to determine a modifying factor for aboveground piping. The reader is encouraged to use established corrosion rates if available instead of the modifying approach.

Table A.2.6.17: Basic Data Required for Aboveground Piping Analysis

Basic Data	Comments
Piping External Corrosion Rate (mpy)	The expected external corrosion rate for a "typical" section of aboveground piping under "average" conditions (i.e., neither highly susceptible to corrosion nor especially resistant to corrosion).
Piping Internal Corrosion Rate (mpy)	The expected internal corrosion rate of the piping.
Exterior Coating	Is the piping coated? What is the age of the coating?
Product	Product carried in piping.

Determination of Modifying Factor

Figure A.2.6.2 shows a flow chart of the steps required to determine the leak frequency modifying factor for aboveground piping. The following sections discuss these steps and present the required tables.

Aboveground Piping Corrosion Rate

Establish Base Corrosion Rate for Aboveground Piping

The base corrosion rate is the expected or observed corrosion rate for a typical section of aboveground piping under average conditions (i.e., neither highly susceptible to corrosion nor especially resistant to corrosion). The base internal corrosion rate is 2 mpy, the same as for underground piping.

Aboveground piping external corrosion for carbon and low-alloy steels is calculated based on the type of climate and the operating temperature. Three types of climates were considered—marine, temperate, and arid. Table A.2.6.18 presents ranges of bulk fluid temperatures and corresponding corrosion rates for each climate. This table was developed by API RBI Base Resource Document, Appendix V, p. 244, Table TM9A.2.

Table A.2.6.18: Base Corrosion Rates for Aboveground Piping External Corrosion

Bulk Average Fluid Temperature (°F) under Heated or Ambient Air Conditions	Climate		
	Marine/Cooling Tower Drift Area	Temperate	Arid/Dry
121–200	5 mpy	2 mpy	1 mpy
61–120	2 mpy	1 mpy	0 mpy
11–60	5 mpy	3 mpy	1 mpy
≤ 10	0 mpy	0 mpy	0 mpy

Figure A.2.6.3 shows the locations for the three climate types in the continental United States. Locations with a marine climate receive more than 40 inches of precipitation per year or have an average chloride concentration in rainwater of at least 1.0 mg/l. Locations with temperate climates are assumed to receive 20 – 40 inches of precipitation per year. Arid climates exist in those areas receiving less than 20 inches of precipitation per year.

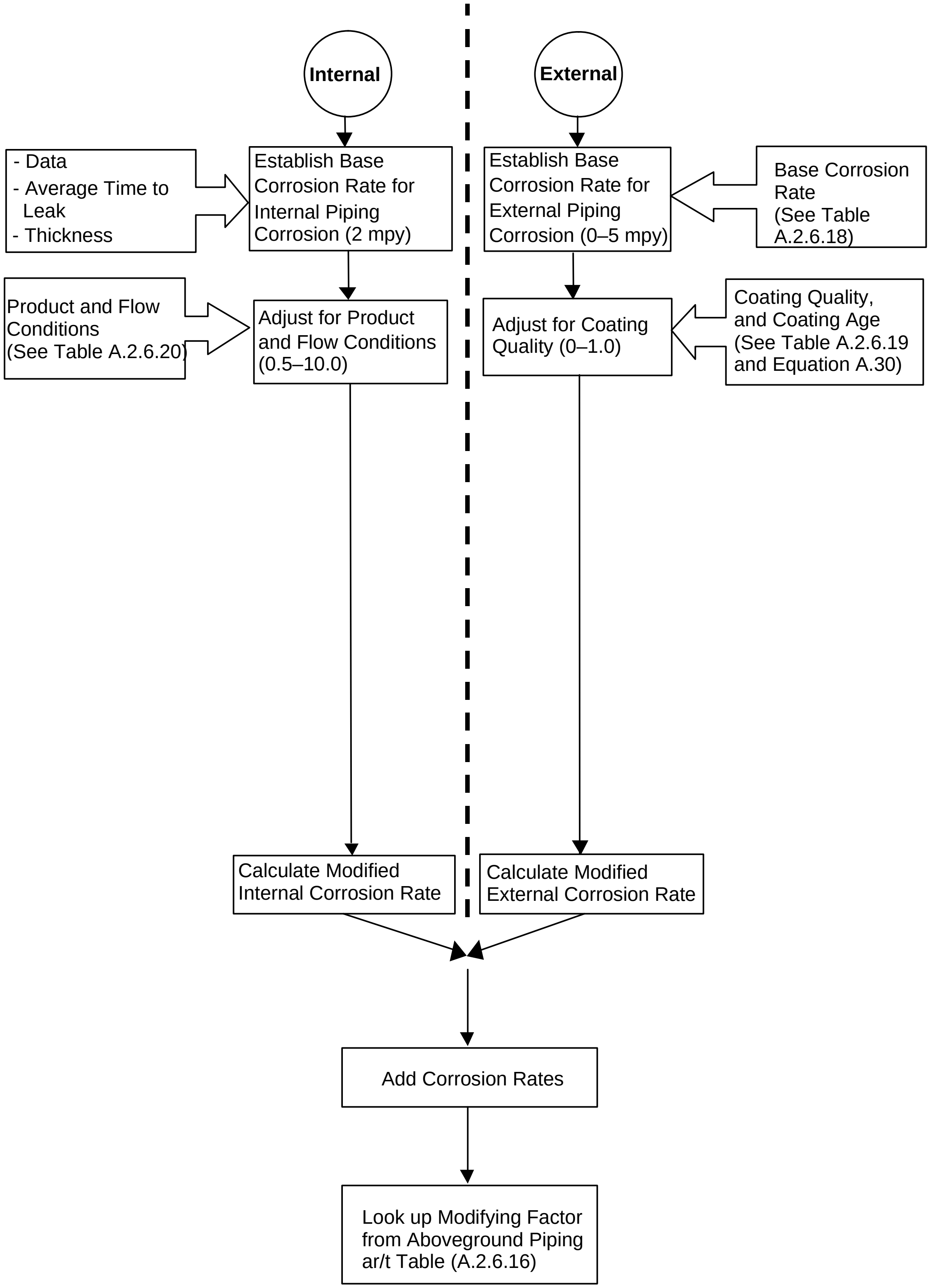


Figure A.2.6.2: Flow Chart to Determine Modifying Factor for Aboveground Piping

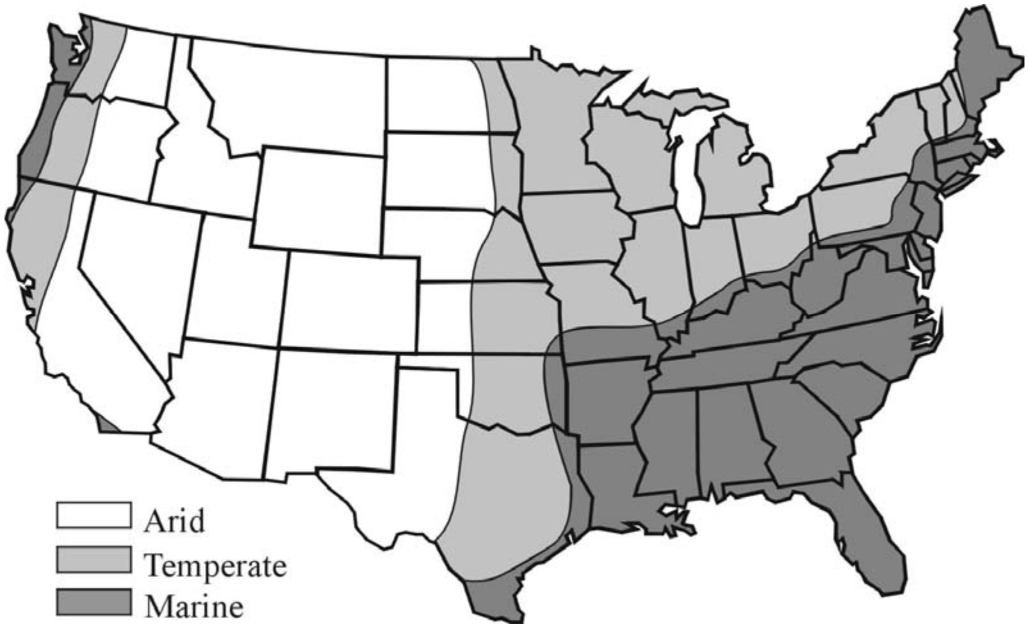


Figure A.2.6.3: Climate Map for the United States

External Corrosion Rate

Adjustment for External Coating

To account for the benefits of an external coating, it is assumed that no external corrosion takes place during the first 5 or 10 years after the piping is coated with a medium- or high-quality coating respectively. An adjustment factor is then calculated by first determining the number of years in which the aboveground external piping is subject to corrosion and then dividing that by the age of the piping. For sections of piping that are repeatedly coated, this factor may be close to 0. Table A.2.6.19 presents the adjustments to the piping external corrosion rate. The calculation of the adjustment factor for coating quality is shown in Equation A.31.

Table A.2.6.19: Adjustment for Quality of Coating

Coating Quality	**Adjustment**
High	Assume that no corrosion occurs during the first 10 years after coating application
Medium	Assume that no corrosion occurs during the first 5 years after coating application
Low/None	No credit given

Note: If the external piping is pitted, no credit should be given for coating the pipe.

$$AF_{Coating\ Quality} = \frac{Number\ of\ \ years\ \ piping\ unprotected}{Piping\ age}$$

(Equation A.31)

In the application of Equation A.31, consideration should be given to the amount of time that the piping is bare; whether a high-quality coating is over 10 years old; or whether a medium-quality coating is over 5 years old. During such time periods, the piping is assumed to be unprotected. This can be viewed as a conservative assumption, and the user may want to give some credit for coatings beyond their warranted life.

The adjusted external corrosion rate (r_{ext}) is calculated as follows:

$$r_{ext} = r_{ext\text{-}base} * AF_{Coating\ Quality}$$

(Equation A.32)

Internal Corrosion Rate

The base internal corrosion rate is 2 mpy. This rate is adjusted based on the type of product in the piping and the flow conditions. The internal corrosion rate calculation is handled in the same manner as for underground piping.

Adjustment for Type of Product and Flow Conditions

Piping carrying refined product is generally less susceptible to corrosion than piping carrying crude oil; however, regardless of the product, the piping will experience increased corrosion rates if dead legs are created. Table A.2.6.20 presents the adjustment factors for product and flow conditions.

Table A.2.6.20: Product and Flow Condition Adjustment

Product and Flow Conditions	**Adjustment Factor**
Refined Product (Gasoline, Diesel, etc.)	
-- Active Line	0.5
-- No Flow (Deadleg)	5
Crude Oil	
-- Active Line	1
-- No Flow (Deadleg)	10

The adjusted internal corrosion rate (r_{int}) is calculated as follows:

$$r_{int} = r_{int\text{-}base} * AF_{Prod/Flow}$$

(Equation A.33)

Combine Corrosion Rates

It is assumed that the external corrosion will be localized, while the internal corrosion will be widespread (with the notable exception of localized corrosion such as MIC). Therefore, the corrosion areas will likely overlap, so that the piping thickness is simultaneously reduced by both internal and external influences. It is thus assumed that the internal and external rates are additive.

$$r_{est} = r_{\mathrm{int}} + r_{ext}$$

(Equation A.34)

The user now takes the r_{est} and returns to Section A.2.6.2.1 to complete the analysis.

A.2.7 Transfer Equipment Leak Frequencies

Transfer equipment leaks were divided into three categories that include transfers from tank trucks and rail, transfer from marine vessels, and tank truck overfills.

A.2.7.1 Tank Truck and Rail

Tank trucks and rail cars generally use flexible hoses to transfer product. The causes for failure of these devices are usually mechanical failure during storage or handling of the hose or the result of corrosion. Other causes of hose failure have included over-pressuring the hose and using the wrong or incompatible materials. Massive connection failures or complete rupture of the hose can also occur. These events and leaks resulting from drive-offs are included in the leak rates provided below. Table A.2.7.1 presents the failure rates for flexible hoses.

Table A.2.7.1: Flexible Hose Failure Rates Including Drive-offs

Transfers per Transfer Point	**$^1/_8$-in Leak Rate (/yr)**	**Rupture Rate (/yr)**
≤ 20 / week	2.03×10^{-2}	7.0×10^{-4}
21–40 / week	3.37×10^{-2}	1.25×10^{-3}
41–80 / week	5.13×10^{-2}	2.0×10^{-3}
> 80 / week	6.87×10^{-2}	3.0×10^{-3}

If an articulated arm is used to transfer the product instead of a flexible hose, then the leak frequencies in Table A.2.7.2 should be used. These leak frequencies represent a 60 percent reduction in the frequency rates compared to flexible hose failures.

Table A.2.7.2: Articulated Hose Failure Rates Including Drive-offs

Transfers per Transfer Point	**$^1/_8$-in Leak Rate (/yr)**	**Rupture Rate (/yr)**
≤ 20 / week	8.12×10^{-3}	2.8×10^{-4}
21–40 / week	1.35×10^{-2}	5.0×10^{-4}
41–80 / week	2.05×10^{-2}	8.0×10^{-4}
> 80 / week	2.75×10^{-2}	1.2×10^{-3}

A.2.7.2 Marine Vessel

Table A.2.7.3 provides leak frequencies for ship to shore transfers in port. The leak frequencies are for leaks exceeding 300 gallons.

Table A.2.7.3: Marine Transfer Leak Frequencies

Equipment	**Leak Frequency (per transfer operation)**
Flexible Hose	1.8×10^{-4}
Articulated Arm	7.6×10^{-5}

A.2.7.3 Tank Truck Overfill

The base frequency for overfilling a tank truck is 1×10^{-5} overfills per tank truck compartment fill per year. This base frequency is modified by the following factors:

- quality of operations
- control systems

Adjustment for Quality of Operations

The quality of filling operations is assessed by determining whether appropriate industry standards are being followed. API RP 1004 was used as the basis for good practices for overfill protection for MC-306 tank trucks. In general, following this RP should lower the probability of a release during the fill operation. Table A.2.7.4 shows the credits given for loadings done according to API RP 1004. The foundation of the base probability of overfill is the performance of loading operations in accordance with API RP 1004.

Table A.2.7.4: Adjustment for Quality of Operations

Type of Fill Operation	Modifying Factor
Loading operation in accordance with API RP 1004 (for MC-306 tank trucks only)	1
All others	2

Adjustment for Control Systems (Automatic Shutdown)

Control systems can greatly reduce the likelihood of an overfill. Primary control systems typically consist of a pre-set loading meter and a control valve that provides a positive means of selecting and loading a predetermined quantity of product. A secondary control system generally consists of a level sensor in each compartment being loaded that signals high level and activates a control valve to shut off flow.

The foundation for the base probability of overfill is a primary plus secondary control system; thus, that system is given a modifying factor of 1. A primary control system is given a modifying factor of 10. If there is no control system, the modifying factor would be 100.

Table A.2.7.5: Adjustment for Control Systems

Type of Fill Operation	Modifying Factor
None	100
Primary control system (e.g., a preset loading meter and a control valve)	10
Primary plus secondary control systems (e.g., level sensor that activates automatic shutoff)	1

Calculation of Overfill Frequency

The risk of overfill during a truck fill operation can be calculated by multiplying the base overfill frequency (1.0×10^{-5} / fill) by each of the modifying factors. This value can then be multiplied by the number of fills per year to obtain the annual frequency of overfill as shown in Equation A.35.

$$Overfill\ Frequency = 1 \times 10^{-5}\ /\ fill * MF_{Quality} * MF_{Control\ Sys.} * \ fills\ /\ year$$

(Equation A.35)

A.2.8 Applications and Examples of Likelihood Calculations

A.2.8.1 Tanks with Similar Service

The inspection history and observed corrosion rate of a tank in similar service (Tank A) can be used to estimate the corrosion rate of the tank under consideration (Tank B). Tanks are considered to be in *similar service* if they have the same characteristics (e.g., CP, internal lining, product, and soil conditions). The maximum wall loss is seen in the similar service tank. Tank A is used to calculate the combined internal and external corrosion rate of Tank B as shown in Equation A.36.

$$Combined\ Corrosion\ Rate\ (mpy) = \frac{t_{orig.}(mils) - t_{\min.}(mils)}{age\ (years)}$$

(Equation A.36)

This similar service corrosion rate is now assumed to apply to Tank B. The appropriate *ar/t* table (A.2.2.3 or A.2.3.4) is consulted to determine the modifying factor where *r* is the combined corrosion rate, *a* is the age of the tank, and *t* is the original thickness of the tank (bottom or shell as appropriate). When consulting the *ar/t* table, the user should drop one category in inspection rating; thus, if Tank A has an A-level inspection, then assume a B-level inspection for Tank B.

The modifying factor is then multiplied by the bottom or shell leak frequency as appropriate to obtain the tank-specific leak frequency.

A.2.8.2 Measured Corrosion

The actual measured corrosion rate from a previous inspection should always be used if it is greater than the corrosion rate predicted by the model. If the measured corrosion rate is less than that predicted by the model, the measured rate can be used if it is from a *B*- or *A-level inspection*. (In this module, the measured corrosion rate always refers to the maximum measured corrosion rate.)

Using the measured corrosion rate *r* (combined internal and external), the age of the tank *a*, and the original bottom or shell thickness *t*, the applicable modifying factor is obtained from the *ar/t* Table A.2.2.3 for bottoms and A.2.3.4 for shells. Generally, the "1 Inspection" column will be used for shells. If, however, this measured corrosion rate is the maximum seen in two similarly rated inspections, the "2 Inspection" column is used.

The modifying factor is then multiplied by the bottom or shell leak frequency as appropriate to obtain the tank-specific leak frequency.

A.2.8.3 Repair and Replacement

If sections of the tank are repaired or replaced, the model must be recalibrated. Typically, sections of the tank bottom are repaired or replaced when excessive wall loss is detected. This will be handled in the model by resetting the age of the tank bottom to zero and using the minimum measured thickness of the tank bottom as the *original thickness.* This minimum measured thickness will likely be from an unrepaired area of the tank bottom. It should be noted that the "clock is reset" for the tank bottom only, not the shell. The maximum measured corrosion rate (which led to the repair or replacement) should be used in predicting wall loss at future points in time.

A.2.8.4 Examples

Example 1—Corrosion Rate Unknown

This example illustrates the use of the risk model without a measured corrosion rate. It is for a tank that has not been inspected and provides an estimate of the likelihood of a bottom leak.

Tank Characteristics

Tank Bottom Thickness:	250 mils
Age:	10 years
Base Bottom Leak Frequency:	0.0072/year
Base Corrosion Rate (Soil Side):	5 mpy (localized) (Section A.2.2.1.2)
Base Corrosion Rate (Product Side):	5 mpy (widespread) (Table A.2.2.12)
Inspections:	None

Tank Bottom Soil Side Corrosion

The base corrosion rate for the soil side of the tank bottom is modified by the following adjustment factors:

Soil Conditions (Table A.2.2.6):	600 ohm-cm	$AF_{Soil\ Cond.} = 1.25$
Tank Pad Material (Table A.2.2.8):	Construction grade sand	$AF_{Tank\ Pad} = 1.15$
Drainage (Table A.2.2.9):	Storm water does not collect at tank base	$AF_{Drainage} = 1.0$
Cathodic Protection (Table A.2.2.10):	Yes; but not per API RP 651	$AF_{Cath.\ Prot.} = 0.66$
Operating Temperature (Table A.2.2.11):	100^oF	$AF_{Oper.\ Temp.} = 1.1$

The adjusted corrosion rate (r) is calculated from Equation A.6 as follows:

$$r = r_{base} * AF_{Soil\ Cond.} * AF_{Tank\ Pad} * AF_{Drainage} * AF_{Cath.\ Prot.} * AF_{Oper.\ Temp.}$$

thus

$$r = 5.0 \bullet 1.25 \bullet 1.15 \bullet 1.0 \bullet 0.66 \bullet 1.1 = 5.22\, mpy$$

Tank Bottom Product Side Corrosion

The base corrosion rate for the product side of the tank bottom is modified by the following adjustment factors:

Internal Lining Needed (Table A.2.2.14):	Yes, applied per API RP 652	$AF_{Lining} = 0.5$
Lining Age (Table A.2.2.15):	10 years	$AF_{Lining\ Age} = 1.0$
Operating Temperature (Table A.2.2.11):	100^oF	$AF_{Oper.\ Temp.} = 1.1$
Steam Coil Heater (Table A.2.2.16):	No	$AF_{Coil\ Heater} = 1.0$
Water Draws (Table A.2.2.17):	Yes, after every receipt	$AF_{Water\ Draws} = 0.7$

The adjusted corrosion rate (r) is calculated from Equation A.7 as follows:

$$r = r_{base} * AF_{Lining} * AF_{Lining\ Age} * AF_{Oper.\ Temp.} * AF_{Coil\ Heater} * AF_{Water\ Draws}$$

thus

Combine Corrosion Rates

Since there was no inspection of the tank, it is assumed that the product side corrosion is widespread and the corrosion rates are additive:

$$r = 5.22\,mpy + 1.93\,mpy = 7.15\,mpy$$

Calculate *ar/t* from Equation A.4 for use in *ar/t* lookup table:

$$ar/t = \frac{(10\,years)(7.15\,mpy)}{250\,mils} = 0.286$$

Then using the *ar/t* table for tank bottoms (Table A.2.2.3) for an E-level inspection (i.e., no inspection), the modifying factor can be determined by interpolation.

MF = 1.16

Tank Bottom Leak Frequency = 1.16 * 0.0072 = **8.35×10^{-3}/year**

Rapid Bottom Failure Frequency

Base leak frequency (Section A.2.2.2)	**2.0x10-5**
Designed and maintained (API 650 and API 653) (Table A.2.2.18)	$MF_{Design} = 1$
Corrosion = MF(*ar/t*)/20 or 0.2 (whichever is greater)	$MF_{Corrosion} = 0.2$
Settlement—no inspection done (Table A.2.2.19)	$MF_{Settlement} = 1.5$

thus

Rapid Bottom Failure Frequency = 2×10^{-5}/year * 1 * 0.2 * 1.5 = 6×10^{-6}/year

In summary, the frequencies for tank bottom leaks would be:

Leak Frequencies for Tank Bottom

Leak Type	Frequency (per year)
Small Bottom Leak	8.35×10^{-3}
Rapid Bottom Failure	6×10^{-6}
Total	8.36×10^{-3}

Example 2—Corrosion Rate Known

If the maximum corrosion rate of the tank is known based on an A- or B-level inspection, this corrosion rate will supersede any estimate of the corrosion rate using the model. The results of a lower level inspection should be used only if they predict a higher maximum corrosion rate than the model-estimated rate. As with the previous example, the maximum corrosion rate is converted into a modifying factor for the leak frequency by use of the *ar/t* table (A.2.2.3).

Tank Characteristics:

Tank Bottom Thickness:	250 mils
Age:	10 years
Base Bottom Leak Frequency:	0.0072/year (Section A.2.2.1)
Inspections:	A-level inspection at 10 years
Inspection Result:	Maximum corrosion rate of 5.5 mpy

Assume that based on the findings in Example 1, an A-level inspection was conducted and found a maximum corrosion rate of 5.5 mpy. The maximum corrosion rate found by the inspection will supersede that predicted by the model (7.15 mpy). Thus:

$$ar/t = \frac{(10\,years)(5.5\,mpy)}{250\,mils} = 0.220$$

For a Level A inspection, from the *ar/t* table (A.2.2.3):

$$\text{MF} = 0.0001$$

Tank Bottom Leak Frequency = 0.0001 * 0.0072 = **7.2×10^{-7}/year**

Rapid Bottom Failure Frequency

Base leak frequency (Section A.2.2.2)	**2.0×10^{-5}**
Designed and maintained (API 650 and API 653) (Table 2.2.18)	$MF_{Design} = 1$
Corrosion = MF *ar/t*/20 or 0.2 (whichever is greater)	$MF_{Corrosion} = 0.2$
Settlement—no settlement found (Table A.2.2.19)	$MF_{Settlement} = 1$

thus

Rapid Bottom Failure Frequency = 2×10^{-5}/year * 1 * 0.2 * 1 = 4.0×10^{-6}/year

In summary, the frequencies for tank bottom leaks would be:

Leak Frequencies for Tank Bottom

Leak Type	Frequency (per year)
Small Bottom Leak	7.2×10^{-7}
Rapid Bottom Failure	4.0×10^{-6}
Total	4.7×10^{-6}

Example 3—Tanks in Similar Service

Tanks in similar service to a tank with a measured corrosion rate can be assumed to have the same corrosion rate, but with a lower confidence level. This is reflected in using a lower level of inspection when consulting the *ar/t* table. For this example, Tank B is assumed to be in similar service to Tank A. Tank A had an A-level inspection at 15 years. The maximum corrosion rate measured during that inspection will be used in predicting the bottom loss to Tank B; however, a B-level inspection will be assumed when consulting the *ar/t* table (A.2.2.3).

Tank A Characteristics

Tank Bottom Thickness (original):	250 mils
Tank Bottom Thickness (min. measured):	215 mils
Age:	20 years
Inspection:	A-level inspection at 15 years
Base Bottom Leak Frequency:	0.0072/year
Combined (internal/external) measured corrosion rate:	3.5 mpy

Tank B Characteristics

Tank Bottom Thickness:	250 mils
Age:	25 years
Base Bottom Leak Frequency:	0.0072/year
Inspections:	0 inspections
Combined (internal/external) corrosion rate:	3.5 mpy; based on similar service to Tank A

Calculate *ar/t* for Tank B for use in *ar/t* lookup table (Table A.2.2.3):

$$ar/t = \frac{(25\,years)(3.5\,mpy)}{250\,mils} = 0.35$$

Then, using the *ar/t* table for tank bottoms (Table A.2.2.3) for a B-level inspection (one inspection rating category less than for Tank A (see Section A.2.8)), the modifying factor can be determined directly from the table:

$$MF = 0.01$$

Tank Bottom Leak Frequency = 0.01 * 0.0072 = $\mathbf{7.2 \times 10^{-5}}$**/year**

Rapid Bottom Failure Frequency

Base leak frequency (Section A.2.2.2)	$\mathbf{2.0x10^{-5}}$
Designed and maintained (API 650 and NOT API 653) (Table 2.2.18)	$MF_{Design} = 5$
Corrosion = MF *ar/t* /20 or 0.2 (whichever is greater)	$MF_{Corrosion} = 0.2$
Settlement—no API 653 settlement inspections (Table A.2.2.19)	$MF_{Settlement} = 1.5$

thus

Rapid Bottom Failure Frequency = 2×10^{-5}/year * 5 * 0.2 *1.5 = 3.0×10^{-5}/year

In summary, the frequencies for tank bottom leaks would be:

Leak Frequencies for Tank Bottom

Leak Type	**Frequency (per year)**
Small Bottom Leak	7.2×10^{-5}
Rapid Bottom Failure	3.0×10^{-5}
Total	1.02×10^{-4}

Example 4—Tank Bottom Repairs and Shell Example

This example shows how to incorporate tank bottom repairs into future predictions of corrosion rates and the likelihood of leaks. Example 4 also illustrates the use of the shell model.

Tank Characteristics (welded tank)

Tank Bottom Thickness:	250 mils
Bottom Shell Course Thickness:	625 mils
Age:	25 years
Base Bottom Leak Frequency:	0.0072/year
Base Shell Leak Frequency:	1.0×10^{-4}/year
Base Bottom Corrosion Rate (Soil Side):	5 mpy (localized)
Base Bottom Corrosion Rate (Product Side):	2 mpy (widespread)
Base Shell Corrosion Rate (Product Side):	2 mpy (widespread)
Bulk Fluid Temperature:	80°F
Climate:	Temperate

B-level inspection of tank bottom at 12 years
Three C-level shell inspections at 10, 15, and 20 years
Bottom—Damage Level as predicted by model
Shell—Damage Level as predicted by model

The bulk fluid temperature and the climate are required information to determine the shell external corrosion rate. By applying the bulk fluid temperature and the climate to Table A.2.3.9, the shell external corrosion rate is found to be 1 mpy.

Tank Bottom Soil Side Base Corrosion

The base corrosion rate for the soil side of the tank bottom is modified by six adjustment factors:

Soil Conditions (Table A.2.2.6): 3000 ohm-cm	$AF_{Soil\ Cond.} = 0.83$
Tank Pad Material (Table A.2.2.8): High resistivity, low chloride sand	$AF_{Tank\ Pad} = 0.7$
Drainage (Table A.2.2.9): Storm water does not collect at tank base	$AF_{Drainage} = 1.0$
Cathodic Protection (Table A.2.2.10): No	$AF_{Cath.\ Prot.} = 1.0$
Operating Temperature (Table A.2.2.11): 80°F	$AF_{Oper.\ Temp.} = 1.1$

The adjusted corrosion rate (r) is calculated as follows:

$$r = r_{base} * AF_{Soil\ Cond.} * AF_{Tank\ Pad} * AF_{Drainage} * AF_{Cath.\ Prot.} * AF_{Oper.\ Temp.}$$

thus

$$r = 5.0 \bullet 0.83 \bullet 0.7 \bullet 1.0 \bullet 1.0 \bullet 1.1 = 3.20\,mpy$$

Tank Bottom Product Side Corrosion

The base corrosion rate for the product side of the tank bottom is modified by five adjustment factors:

Internal Lining Needed (Table A.2.2.14): Yes, not applied per API 652 — $AF_{Lining} = 1.15$
Lining Age (Table A.2.2.15): 25 years (no data to assess condition) — $AF_{Lining\ Age} = 2.5$
Operating Temperature (Table A.2.2.11): 80°F — $AF_{Oper.\ Temp.} = 1.1$
Steam Coil Heater (Table A.2.2.16): No — $AF_{Coil\ Heater} = 1.0$
Water Draws (Table A.2.2.17): No — $AF_{Water\ Draws} = 1.0$
The adjusted corrosion rate (r) is calculated as follows:

$$r = r_{base} * AF_{Lining} * AF_{Lining\ Age} * AF_{Oper.\ Temp.} * AF_{Coil\ Heater} * AF_{Water\ Draws}$$

thus

$$r = 2.0 \bullet 1.15 \bullet 1.5 \bullet 1.1 \bullet 1.0 \bullet 1.0 = 3.80\,mpy$$

Combine Corrosion Rates

$$r = 3.20\,mpy + 3.80\,mpy = 7.00\,mpy$$

Calculate *ar/t* for use in *ar/t* lookup table (Table A.2.2.3):

$$ar/t = \frac{(25\,years)(7.00\,mpy)}{250\,mils} = 0.700$$

Then, by using the *ar/t* table for tank bottoms (Table A.2.2.3), for a B-level inspection, it can be seen that API Std 653 should be consulted regarding requirements for tank repair. Based on API Std 653, the tank bottom should be lined, repaired, or replaced since the bottom thickness is below the required 100 mils (and an RBI program is not in place for the tank).

In order to confirm the level of corrosion before repairing the tank bottom, a second B-level inspection is conducted. This inspection finds 60 percent bottom loss (6 mpy corrosion rate).

Tank Bottom Repair

A section of the tank bottom is replaced after the second inspection. The nominal thickness is 250 mils, and the new minimum thickness is 210 mils. The thinnest point is from that portion of the bottom that was not replaced. A new internal liner is installed in the tank, and the age of the tank bottom is reset to zero.

The corrosion rate used in predicting bottom loss at future points in time will be the measured corrosion rate of 6 mpy.

Shell Internal Corrosion

The base corrosion rate for the product side of the tank shell is modified by the following adjustment factors:

Internal Lining Needed (Table A.2.3.7): Yes, not applied per API 652	$AF_{Lining} = 1.15$
Lining Age (Table A.2.3.8): 25 years (no data to assess condition)	$AF_{Lining\ Age} = 1.5$

The adjusted corrosion rate (*r*) is calculated as follows:

$$r = r_{base} * AF_{Lining} * AF_{Lining\ Age}$$

thus

$$r = 2.0 \bullet 1.15 \bullet 1.5 = 3.45\, mpy$$

Shell External Corrosion Rate

Base Corrosion Rate:	1 mpy
Quality of External Coating: (Equation A.12)	Medium-quality coating applied when tank was built; second medium-quality coating applied at 12 years

$$AF_{Coating\ Quality} = \frac{Number\ of\ Years\ Tank\ Unprotected}{Tank\ Age}$$

thus (using Table A.2.3.10)

$$AF_{Coating\ Quality} = \frac{25\ yrs - (5yrs)(2)}{25\ yrs} = 0.60$$

The adjusted shell external corrosion rate (r) is calculated as follows:

$$r = r_{base} * AF_{Coating\ Quality}$$

$$r = 0.6 \text{ mpy}$$

Combine Shell Corrosion Rates

$$r = 3.45\, mpy + 0.60\, mpy = 4.05\, mpy$$

Calculate *ar/t* for use in *ar/t* lookup table:

$$ar / t = \frac{(25\, years)(4.05\, mpy)}{625\ mils} = 0.162$$

By using the *ar/t* table (Table A.2.3.4) for tank shells for three C-level inspections, the modifying factor can be interpolated as follows:

$$MF = 4.73$$

Tank Shell Leak Frequency = $4.73 * 1.0 \times 10^{-4}$ = $\mathbf{4.73 \times 10^{-4}}$**/year**

In summary, the frequencies for shell leaks would be:

Leak Frequencies for Tank Shell

Leak Type	Frequency (per year)
Small Shell Leak	4.73×10^{-4}
Rapid Shell Failure (Table A.2.3.11)	4.0×10^{-6}
Total	4.77×10^{-4}

Future Shell Corrosion Projections

Although the clock was reset for the tank bottom due to replacement of a section of the bottom, the clock will not be reset for the tank shell for future corrosion and leak frequency projections.

Piping Examples

Example 1—Underground Piping Section

This example shows the standard use of the piping model for an underground section of piping. Leak frequency modifying factors for soil-to-air interfaces and cased road crossings are included in addition to the *ar/t* modifying factor. Flange leak frequencies are calculated separately from the piping and are then incorporated into the total leak frequency for the section of piping.

Piping/Flow Characteristics

Product:	Crude Oil
Flow:	Active Line (No deadlegs)
Piping:	10 inch Schedule 20
Piping Length:	200 feet
Piping Thickness:	250 mils
Age:	19 years
Base Underground Leak Frequency:	5.0×10^{-6}/100 ft-year
Base Corrosion Rate (External) (Table A.2.6.7):	5 mpy (localized)
Base Corrosion Rate (Internal) (Table A.2.6.7):	2 mpy (widespread)
Inspections:	None
Soil-to-Air Interfaces:	1
Soil-to-Air Int. Quality Factor:	1
Cased Road Crossings:	1
Flanges:	4
Location of Piping Accurately Known:	Yes

External Piping Corrosion

The base corrosion rate for the piping exterior is modified by four adjustment factors:

Soil Conditions (Table A.2.6.9): 5000 ohm-cm	$AF_{Soil\ Cond.} = 0.7$
Cathodic Protection (Table A.2.6.10): Yes, per NACE and API	$AF_{Cath.\ Prot} = 0.33$
Exterior Coating or Pipe Wrap (Table A.2.6.11): Yes	$AF_{Ext.\ Coating} = 1.0$
Coating Age (Table A.2.6.12): 19 years	$AF_{Coating\ Age} = 0.8$

The adjusted corrosion rate (*r*) is calculated as follows (Equation A.23):

$$r = r_{ext\text{-}base} * AF_{Soil\ Cond.} * AF_{Cath.\ Prot.} * AF_{Ext.\ Coating} * AF_{Coating\ Age}$$

thus

$$r = 5.0 \bullet 0.7 \bullet 0.33 \bullet 1 \bullet 0.8 = 0.924\,mpy$$

Internal Piping Corrosion

The base corrosion rate for the piping interior is modified by one adjustment factor:

Product & Flow Cond. (Table A.2.6.13): Crude, Active Line	$AF_{Prod.\ \&\ Flow} = 1.0$

The adjusted corrosion rate (*r*) is calculated as follows:

$$r = r_{int\text{-}base} * AF_{Prod.\ \&\ Flow}$$

thus

$$r = 2.0 \bullet 1.0 = 2.0\,mpy$$

Combine Corrosion Rates

$$r = 0.924\,mpy + 2.0\,mpy = 2.92\,mpy$$

Calculate *ar/t* for use in *ar/t* lookup table:

$$ar/t = \frac{(19\,years)(2.92\,mpy)}{250\,mils} = 0.222$$

Then using the *ar/t* table for underground piping (Table A.2.6.3) for No Inspection (one E-level inspection), the modifying factor can be determined by interpolation.

$$MF_{ar/t} = 75.4$$

The modifying factor for soil-to-air interfaces is determined from Equation A.18.

$$MF_{Soil\text{-}to\text{-}Air} = 1.25$$

The modifying factor for cased road crossings is determined from Equation A.19.

$$MF_{\text{Road Cross.}} = 1.25$$

The modifying factor for accurate knowledge of the underground piping location is determined from Table A.2.6.5.

$$MF_{\text{Pipe Loc.}} = 0.85$$

Underground Piping Leak Frequency = $75.4 * 1.25 * 1.25 * 0.85 * 5.0\times10^{-6}$
= $\mathbf{5.0\times10^{-4}}$**/100 ft-year**

For the actual length of piping (200 feet), the leak frequency is as follows:

Underground Piping Leak Frequency = $5.0 * 10^{-4}$
= $\mathbf{1\times10^{-3}}$**/year**

This section of piping has four flanges. The flange failure frequency is 1.0×10^{-4} events per year per flange. Although a flange leak will not have a hole size per se, the release rate is assumed to be similar to that of a small piping leak.

Flange Leak Frequency = $1.0\times10^{-4} * 4$ flanges
= 4.0×10^{-4}

Thus, the combined leak frequencies for the 200-foot section of underground piping including the four flanges are as shown in the following table:

Leak Frequencies for Underground Piping Including Flanges

Leak Type	Frequency (per year)
Piping Leak	1×10^{-3}
Flange Leak	4.0×10^{-4}
Total	1.4×10^{-3}

Example 2—Aboveground Piping Section

This example shows the standard use of the piping model for an aboveground section of piping. The only modifier to the base leak frequency is the *ar/t* modifying factor. As for underground piping, flange leak frequencies are calculated separately from the piping and are then incorporated into the total leak frequency for the section of piping.

Piping/Flow Characteristics

Product:	Crude Oil
Flow:	Active Line (No deadlegs)
Piping:	8 inch Schedule 40
Piping Length:	400 feet
Piping Thickness:	322 mils
Age:	19 years
Bulk Fluid Temperature:	80^{o}F
Climate:	Marine

Base Aboveground Leak Frequency (Section A.2.6.2):	2.7×10^{-6}/100 ft-year
Base Corrosion Rate (External) (Table A.2.6.18):	2 mpy (localized)
Base Corrosion Rate (Internal) (Section A.2.6.2.2):	2 mpy (widespread)
Inspections:	1 B- then 2 C-Level Inspections
External Coating:	1 High Quality Coating
Flanges:	3

External Piping Corrosion

The base corrosion rate for the piping exterior is modified by one adjustment factor for coating quality and age:

Coating Quality (Equation A.31): one high quality coating (using Table A.2.6.19)

$$AF_{Coating\ Quality} = \frac{19\ yrs - (10\ yrs)\ (1)}{19\ yrs} = 0.47$$

The adjusted corrosion rate (r) is calculated as follows (Equation A.32):

$$r = r_{ext\text{-}base} * AF_{Coating\ Quality}$$

thus

$$r = 2.0 \bullet 0.47 = 0.94\, mpy$$

Internal Piping Corrosion

The base corrosion rate for the piping interior is modified by one adjustment factor for product and flow conditions:

Product & Flow Cond. (Table A.2.6.20): Crude, Active Line AFProd. & Flow = 1.0

The adjusted corrosion rate (r) is calculated as follows (Equation A.33):

$$r = r_{base} * AF_{Prod.\ \&\ Flow}$$

thus

$$r = 2.0 \bullet 1.0 = 2.0\, mpy$$

Combine Corrosion Rates

$$r = 0.94\, mpy + 2.0\, mpy = 2.94\, mpy$$

Calculate *ar/t* for use in *ar/t* lookup table:

$$ar / t = \frac{(19\, years)(2.94\, mpy)}{322\, mils} = 0.173$$

The two C-level inspections can be equated to one B-level inspection. By using the *ar/t* table for aboveground piping (Table A.2.6.16) for two B-level inspections, the modifying factor can be determined by interpolation.

$$MF_{ar/t} = 0.424$$

Aboveground Piping Leak Frequency = $0.424 * 2.7\times10^{-6}$
= $\mathbf{1.1\times10^{-6}}$**/100 ft-year**

For the actual length of piping (400 feet), the leak frequency is the following:

Aboveground Piping Leak Frequency = $4 * 1.1\times10^{-6}$
= $\mathbf{4.4\times10^{-6}}$**/year**

This section of piping has three flanges. The flange failure frequency is 1.0×10^{-4} events per year per flange. Although a flange leak will not have a hole size per se, the release rate is assumed to be similar to that of a small piping leak.

Flange Leak Frequency = 1.0×10^{-4} * 3 flanges
= 3.0×10^{-4}

Thus, the combined leak frequencies for the 400-foot section of aboveground piping including the three flanges are as shown in the following table:

Leak Frequencies for Underground Piping Including Flanges

Leak Type	Frequency (per year)
Piping Leak	4.4×10^{-6}
Flange Leak	3.0×10^{-4}
Total	3.04×10^{-4}

Example 3—Terminal Application

Example 3 illustrates the use of the piping model for a typical gasoline terminal application. The terminal piping consists of two underground sections and one aboveground section with a mix of Schedule 20 and Schedule 40 pipe. There is no CP for the piping, but it is coated. Although the piping is 30 years old, the coating is still in good condition. Two C-level inspections have been conducted over the life of the piping.

Piping/Flow Characteristics

Product:	Gasoline
Flow:	Active Lines (No deadlegs)
Piping Section 1:	200 ft underground, 10 inch Sch. 20, 2 soil/air interfaces
Piping Section 2:	300 ft underground, 8 inch Sch. 40, 1 soil/air interface
Piping Section 3:	500 ft aboveground, 8 inch Sch. 40, 3 flanges
Soil-to-Air Int. Quality Factor:	0.4
Age:	30 years
Base Underground Leak Frequency (Equation A.16):	5.0×10^{-6}/100 ft-year

Base Corrosion Rate (External) (Table A.2.6.7):	5 mpy (localized)
Base Corrosion Rate (Internal) (Table A.2.6.7):	2 mpy (widespread)
Bulk Fluid Temperature:	80°F
Climate:	Temperate
Base Aboveground Leak Frequency (Equation A.26):	2.7×10^{-6}/100 ft-year
Base Corrosion Rate (External) (Table A.2.6.18):	1 mpy (localized)
Base Corrosion Rate (Internal) (Section A.2.6.2):	2 mpy (widespread)
Inspections:	2 C-Level Inspections
Cased Road Crossings:	None
Location of Piping Accurately Known:	No
External Coating:	2 High-Quality Coatings

Underground External Piping Corrosion

The base corrosion rate for the piping exterior is modified by four adjustment factors:

Soil Conditions (Table A.2.6.9): 15,000 ohm-cm	$AF_{Soil\ Cond.} = 0.46$
Cathodic Protection (Table A.2.6.10): No	$AF_{Cath.\ Prot} = 1.33$
Exterior Coating or Pipe Wrap (Table A.2.6.11): Yes	$AF_{Ext.\ Coating} = 0.5$
Coating Age (Table A.2.6.12): 30 years, good condition	$AF_{Coating\ Age} = 0.8$

The adjusted external corrosion rate (r) is calculated as follows:

$$r = r_{ext\text{-}base} * AF_{Soil\ Cond.} * AF_{Cath.\ Prot.} * AF_{Ext.\ Coating} * AF_{Coating\ Age}$$

thus

$$r = 5.0 \bullet 0.46 \bullet 1.33 \bullet 1 \bullet 0.8 = 2.45\, mpy$$

Aboveground External Piping Corrosion

The base corrosion rate for the aboveground piping exterior is modified by one adjustment factor for coating quality and age:

Coating Quality (Equation A.31):

$$AF_{Coating\ Quality} = \frac{30\ yrs - (10\ yrs)\ (2)}{30\ yrs} = 0.33$$

The adjusted corrosion rate (r) is calculated as follows (Equation A.32):

$$r = r_{ext\text{-}base} * AF_{Coating\ Quality}$$

thus

$$r = 1.0 \bullet 0.33 = 0.33\, mpy$$

Internal Piping Corrosion (Underground or Aboveground)

The base corrosion rate for the piping interior is modified by one adjustment factor:

Product & Flow Cond. (Table A.2.6.13 & A.2.6.20): Gasoline, Active Line $AF_{Prod.\ \&\ Flow} = 0.5$

The adjusted corrosion rate (*r*) is calculated as follows (Equations A.24 and A.34):

$$r = r_{base} * AF_{Prod.\ \&\ Flow}$$

thus

$$r = 2.0 \bullet 0.5 = 1.0\,mpy$$

Section 1 Underground Piping Leak Frequency

$$r = 2.45\,mpy + 1.0\,mpy = 3.45mpy$$

Calculate *ar/t* for use in *ar/t* lookup table:

$$ar/t = \frac{(30\,years)(3.45\,mpy)}{250\,mils} = 0.414$$

By using the *ar/t* table for underground piping (Table A.2.6.3) for two C-level inspections, the modifying factor can be determined by interpolation.

$$MF_{ar/t} = 56.6$$

The modifying factor for two soil-to-air interfaces over 200 feet and a QF of 0.4 is determined from Equation A.18.

$$MF_{Soil\text{-}to\text{-}Air} = 1.2$$

The modifying factor for cased road crossings is determined from Equation A.19.

$$MF_{Road\ Cross.} = 1.0$$

The modifying factor for accurate knowledge of the underground piping location is determined from Table A.2.6.5.

$$MF_{Pipe\ Loc.} = 1.0$$

Section 1 Piping Leak Freq. $= 56.6 * 1.2 * 1.0 * 1.0 * 5.0\times10^{-6} =$ $\mathbf{3.4\times10^{-4}}$**/100 ft-year**

For the actual length of piping (200 feet), the leak frequency is as follows:

Section 1 Piping Leak Frequency $= 2.0 * 3.4\times10^{-4} =$ $\mathbf{6.8\times10^{-4}}$**/year**

Section 2 Underground Piping Leak Frequency

$$r = 2.45\,mpy + 1.0\,mpy = 3.45mpy$$

Calculate *ar/t* for use in *ar/t* lookup table:

$$ar/t = \frac{(30\,years)(3.45\,mpy)}{322\,mils} = 0.321$$

By using the *ar/t* table for underground piping (Table A.2.6.3) for two C-level inspections, the modifying factor can be determined by interpolation.

$MF_{ar/t} = 39.0$

The modifying factor for one soil-to-air interface over 300 feet of piping and a QF of 0.4 is determined from Equation A.18.

$MF_{\text{Soil-to-Air}} = 1.07$

The modifying factor for cased road crossings is determined from Equation A.19.

$MF_{\text{Road Cross.}} = 1.0$

The modifying factor for accurate knowledge of the underground piping location is determined from Table A.2.6.5.

$MF_{\text{Pipe Loc.}} = 1.0$

Sect. 2 Piping Leak Freq. = 39.0 * 1.07 * 1.0 * 1.0* 5.0×10^{-6} = **2.09×10^{-4}/100 ft-year**

For the actual length of piping (300 feet), the leak frequency is as follows:

Section 2 Piping Leak Frequency = 3.0 * 2.09×10^{-4} = **6.27×10^{-4}/year**

Section 3 Aboveground Piping Leak Frequency

$$r = 0.33\,mpy + 1.0\,mpy = 1.33\,mpy$$

Calculate *ar/t* for use in *ar/t* lookup table:

$$ar/t = \frac{(30\,years)(1.33\,mpy)}{322\,mils} = 0.124$$

By using the *ar/t* table for aboveground piping (Table A.2.6.16) for two C-level inspections, the modifying factor can be determined by interpolation.

$MF_{ar/t} = 0.00514$

Aboveground Piping Leak Frequency = 0.00514 * 2.7×10^{-6} = **1.39×10^{-8}/100 ft-year**

For the actual length of piping (500 feet), the leak frequency is as follows:

Section 3 Piping Leak Frequency = 5 * 1.39×10^{-8} = **6.95×10^{-8}/year**

The combined leak frequency for Sections 1 through 3 is shown below:

***Total Leak Frequency for Sections 1–3*:**

Total = 6.8×10^{-4}/year + 6.27×10^{-4}/year + 6.95×10^{-8}/year = 1.3×10^{-3}/year

The aboveground section of piping has three flanges. The flange failure rate is 1.0×10^{-4} events per year per flange.

Flange Leak Frequency = 1.0×10^{-4} * 3 flanges = 3.0×10^{-4}

Thus, the combined leak frequencies for the terminal piping, including the three flanges are as shown in the following table:

Leak Frequencies for Underground Piping Including Flanges

Leak Type	Frequency (per year)
Piping Leak	1.3×10^{-3}
Flange Leak	3.0×10^{-4}
Total	1.6×10^{-3}

A.3. RISK CONSEQUENCE MODEL OVERVIEW

As discussed in the main body of this document, risk consists of three basic components:

- What can go wrong?
- How likely is the event to occur?
- What are the impacts (consequences) if the event does occur?

The purpose of this section is to provide the user with the basis for a model for analyzing the consequences of a particular event. The consequence model presented in this document is meant to be used with the likelihood model presented in the previous sections of this appendix. The format, presentation, and covered release scenarios match those scenarios presented in previous sections; however, the user could elect to employ elements of this section or the approach in this model to form the basis of a user-developed consequence model.

API Publ 340 and Section 8.4 of this document's main text include descriptions of the Liquid Release Scenarios (LRSs) that are typically associated with petroleum terminals (what can go wrong). The beginning sections of this appendix describe a methodology that could be used to estimate the likelihood (probability) that a specific LRS might occur at a facility (how likely is it to occur). After the likelihood has been determined for a specific LRS, this section is used to assess the impacts (consequences) of the specific LRS.

As indicated in Section A.1.1, the scope of the document is limited to the risks associated with potential releases of petroleum liquids. The consequence methodology provided in this section can be expanded to include vapor releases, but the consequences demonstrated here are exclusively based on the LRSs detailed in this document.

The performance of a risk assessment as described in the main body of this document is based on the following premise:

$$\text{Risk} = \text{Likelihood of Failure (LOF)} \times \text{Consequence of Failure (COF)}$$

(Equation A.37)

The following sections describe the methodology that may be used to estimate the consequence of a specific LRS. Consequences of failure in this section are broadly divided into the following three categories:

1. Environmental consequences of failure (ECOF) to the surrounding environment
2. Population consequences of failure (PCOF) which include health, safety and fire impacts to the facility and surrounding community; and
3. Business consequences of failure (BCOF) which include economic and enterprise impacts on the corporation

Users may study one of the above consequence categories, such as ECOF, or they can analyze all three consequence categories. If all three consequence categories are studied, they can be combined using various weighting factors to provide a total consequence number. If the user wants to study only one of the categories, or if the user wants to apply the results for the category with the highest value, then the user can set the remaining weighting factors to 0. The weighting factors are assigned to the three categories so when combined, they equal 100 percent. Consequence categories are additive for this model. In some instances, two or even all three categories may have the same consequence value. Figure A.3.1 illustrates the Consequence Model Process.

$$\text{Consequence Score} = \text{WF Environmental} \times \text{ECOF} + \text{WF Population} \times \text{PCOF} + \text{WF Business} \times \text{BCOF}$$

(Equation A.38)

where

WF Environmental = the weighting factor assigned by the user for environmental consequences. It is expressed as a fraction of a percentage between 0% and 100% and represents the user or company's value system.
ECOF = environmental consequences of failure.
WF Population = the weighting factor assigned by the user for population consequences. It is expressed as a fraction or percentage between 0% and 100% and represents the user or company's value system.
PCOF = population consequences of failure.
WF Business = the weighting factor assigned by the user for business consequences. It is expressed as a fraction or percentage between 0% and 100% and represents the user or company's value system.
BCOF = business consequences of failure.

All petroleum liquid release consequences are driven by the following primary factors:

- Type of product released
- Volume of release
- Media impacted by the release
- Soil conditions and the presence and types of pathways for conveyance or impedance of the movement of released petroleum
- Damage as a result of the release to the environment, community, equipment, and operations and the duration of the damage or disruption to the environment, community, and equipment
- Site-specific conditions such as surrounding ecology, population density, facility configuration, etc., all of which can make the consequences of a release either better or worse

The consequence analysis section uses these various factors to develop a consequence rating score for each of the three primary consequence types. Several of the questions are the same for each type of consequence. These same or similar questions represent the driving mechanism behind the consequence.

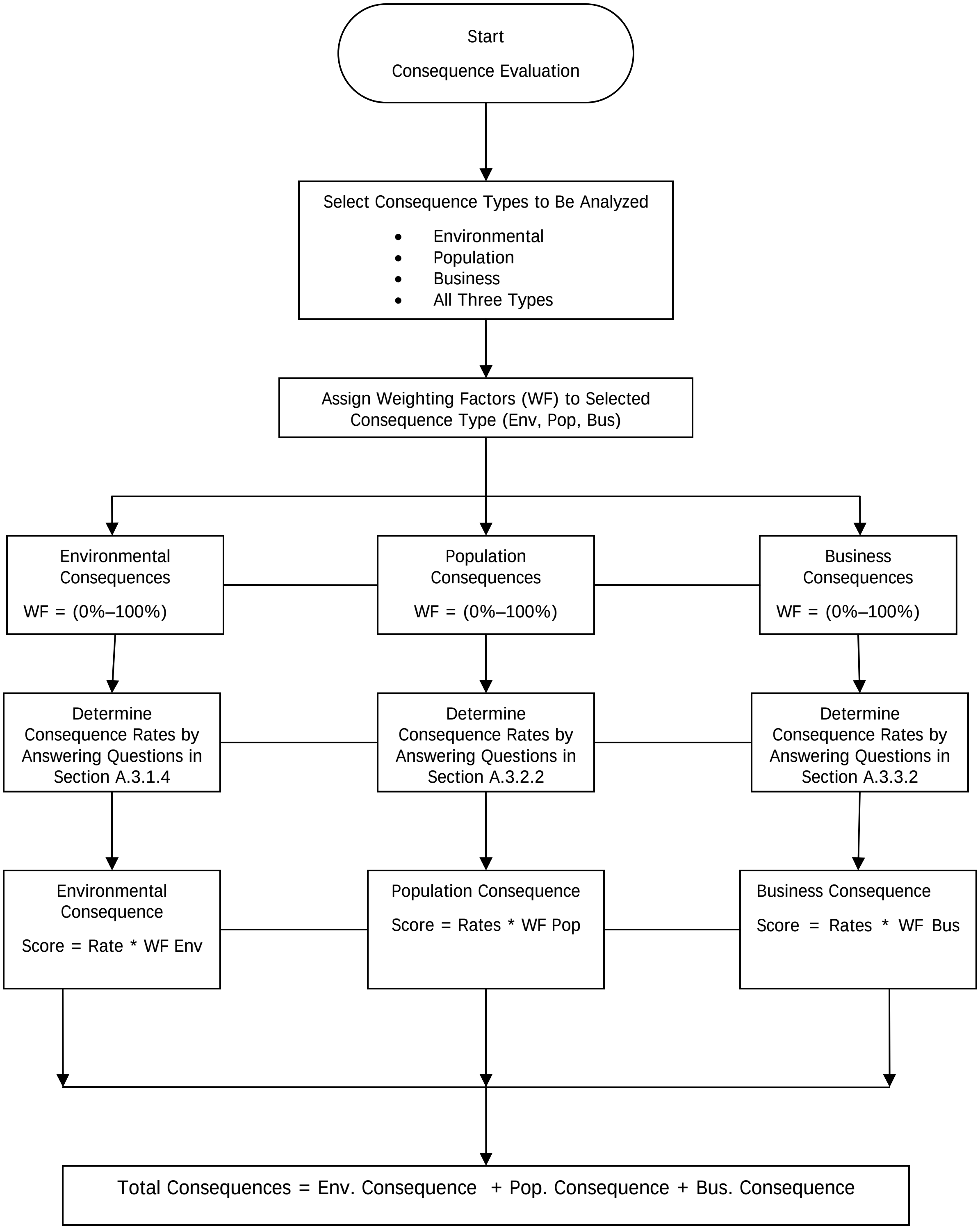


Figure A.3.1: Consequence Model

The specific LRSs analyzed in the consequence model of this section include the following:

- Aboveground Storage Tank LRSs
  - Small Tank Bottom Leaks Due to Corrosion
  - Rapid Bottom Failure
  - Small Tank Shell Leaks Due to Corrosion
  - Small Shell Leaks Due to Tank Fittings
  - Rapid Shell Failure
  - Tank Overfills
  - External Floating Roofs Drain Leaks
- Piping (aboveground and underground)
  - Corrosion Leaks
  - Flange Leaks
- Transfer Equipment Leaks
  - Transfer loss
  - Truck Overfill

For each of these scenarios, the user would determine the consequences of that specific event. For example, to consider the consequences of a tank overfill, the user would determine the consequences of this event as it related to environmental, population, and business impacts. The consequences could be determined for only one category or all three. The user would then determine the consequences of the next LRS (e.g., a small tank shell leak).

An overview of the different categories of consequences is presented below. More detailed information on the approach, meaning, and methodology for each category of consequences is presented in the following sections.

Environmental Consequences of Failure (ECOF) Overview

Environmental consequences of failure involve those effects that occur to the owner's property, adjacent ecology, and surrounding community as a result of an unintended release of stored petroleum product. ECOF encompasses the full range of impacts to the environment with the exception of non-environmental impacts to local populations and the health and safety of workers, contractors, and the surrounding population that are covered under PCOF, and company financial impacts resulting from the unintended release that are covered under BCOF. ECOF covers the cost implications resulting from a release of petroleum such as the cost of emergency response and remediation, but it does not address items associated with business interruption, out-of-service equipment costs, equipment repair time, etc.

The potential range of ECOF resulting from a specific LRS is driven by the following items:

- Quantity/volume released to the environment
- Resource/media impacted by the release (soil, groundwater, surface water, etc.)
- Site-specific conditions such as the physical properties of the released product, surrounding land use, ecological sensitivity of the area, soil and groundwater conditions, etc.

Population Consequences of Failure (PCOF) Overview

Population consequences of failure involve the evaluation of the probable consequences associated with health and safety impacts to the surrounding community and onsite employees/contractors, the potential for fire or explosion resulting from the liquid petroleum release, the number of individuals impacted by the release, and the surrounding community use. PCOF from a specific LRS could result in a fire, explosion, injury, illness, or death. Population consequences are driven by several distinct factors:

- Flammability of the product
- Physical hazards of the product
- Magnitude and proximity of the release to personnel and the surrounding community
- Location and configuration of the equipment and facility

- Surrounding community in terms of proximity to the event, the population density, and the presence of critical infrastructure

The PCOF model recognizes that the potential health and safety impacts from fire or explosion resulting from a release of a flammable product, such as gasoline, is much higher than a release of various combustible products, such as fuel oil and motor oil. The PCOF model also recognizes that the surrounding community type, land use, and density affect the consequences of an LRS. The model accounts for the proximity of personnel to the LRS at the time of the release and the proximity of personnel during the cleanup or mitigation of a release.

Business Consequences of Failure (BCOF) Overview

Business consequences of failure involve the evaluation of the probable consequences that would result from a specific LRS and its effect on the business, economics, and enterprise function of the company. BCOF affects items such as costs associated with loss of business, business interruption, equipment repair, loss of product, market impacts, litigation, and other business impacts which result from a LRS. Business consequences are driven by several distinct factors:

- Loss of use of the asset or the facility as a result of an LRS
- Cost of repairs to facilities or equipment
- Cost of lost product

The BCOF model addresses the impacts on a business as a result of a release. It addresses the tangible as well as non-tangible values, such community complaints, additional regulatory burden, loss of organizational focus, redirection of capital and staff, and the potentially enterprise-ending effects of a significant event.

Governing Consequence

As discussed above, the user may elect to study one or all three of the listed consequence categories. Scores between consequence categories are additive. The consequence category score is multiplied by the weighting factor assigned by the user for the specific type of consequence for that particular LRS on that particular piece of equipment and for that particular petroleum product. If any of these variables changes significantly, the consequence score, and therefore, governing consequence may change.

A.3.1 Environmental Consequences of Failure

The ECOF model addresses impacts to the environment and to the environmental resources surrounding the site. The ECOF model recognizes that the surrounding environment affects the consequences of a liquid release. For example, a release at a facility located near a wetland area or overlying a drinking water aquifer can have more severe consequences as opposed to a facility located in an industrial area.

Environmental consequences are driven by the volume (quantity in bbls) and type of product released, the environmental media affected, and the site-specific conditions, such as the adjacent ecology and land use, physical properties of the product released, and other factors that affect the mobility of the release. The first step in determining environmental consequences for a particular LRS is to estimate the petroleum liquid volume that would be released as a result of the specific scenario (Section A.3.1.3.1). The second step is to determine what environmental media will be affected by the LRS (Section A.3.1.3.2). The third step is to account for the site-specific conditions, general arrangement, surrounding land use, ecology, geology of the site and surrounding area which affect the magnitude of the environmental consequences (Section A.3.1.4). In all cases, the release detection time and source removal time are key in determining the media that may be impacted by a release. Long or protracted detection times may cause an impact on media that would not have occurred with faster detection times.

A.3.1.1 Environmental Consequences of Failure Model Overview

The following model was developed to evaluate the ECOF associated with the specific liquid release scenarios detailed in this appendix. In this model, the user answers questions about the probable environmental consequences associated with a particular event. The ECOF questions are addressed for the following liquid release scenarios that have corresponding "likelihood" numbers from the previous analysis.

The environmental consequences associated with a specific LRS depend on a number of site-specific conditions that include the following:

- Surrounding ecology
- Local regulatory environment
- Surrounding community
- Product type
- Adjacent land use
- Facility's ability to respond
- On-site environmental conditions such as soil permeability and geology
- Facility configuration
- Time to discover a release and volume released

The environmental consequences that might result from releasing a barrel of petroleum that is contained within a diked area vs. releasing a barrel of petroleum that reaches the groundwater or surface water are dramatically different. Additionally, the consequences from releasing a barrel of petroleum that impacts surficial soils in an ecologically sensitive area are very different from those of releasing a barrel of petroleum that impacts surficial soils in a heavily industrialized area. The consequence model needs to reflect these differences.

The user needs to recognize that site-specific conditions will significantly influence environmental consequences. Therefore, a range of consequences needs to be developed which allows the user to adjust the consequence score up or down based on product spilled, spill size, local conditions, and/or regulatory requirements. The environmental consequence assessment method described in this appendix follows these steps:

Step 1: Select the equipment or process to be reviewed (tank, pipe, transfer).
Step 2: Identify applicable LRSs (e.g., tank overfill, pipe leak).
Step 3: Estimate the probable volumes that may be released for the specific LRS.
Step 4: Identify the impacted environmental media/environmental receptor(s)
Step 5: Select a category percentage variable weighting factor between 0 and 100 percent.
Step 6: Complete the consequences scoring using the appropriate modifying factors.

Figure A.3.1.1 illustrates how the methods in this appendix can be applied in determining environmental consequences and illustrates the relationship between release types (e.g., tank bottom, shell/piping, overfills) and potentially affected environmental media (e.g., surface soils, groundwater, etc.).

A.3.1.2 Environmental Consequences of Failure Model

The ECOF model determines the consequence value for an LRS for a specific equipment item. It first involves assigning a weighting factor for environmental consequences. The weighting factor reflects the relative importance that the company and the user apply to the various types of consequences (environmental, population, and business). The variable weighting factor is expressed as a percentage between 0 and 100 percent. The sum of the weighting factors for the various types of consequences is equal to 100 percent. The specific environmental consequences are further defined by answering the following questions:

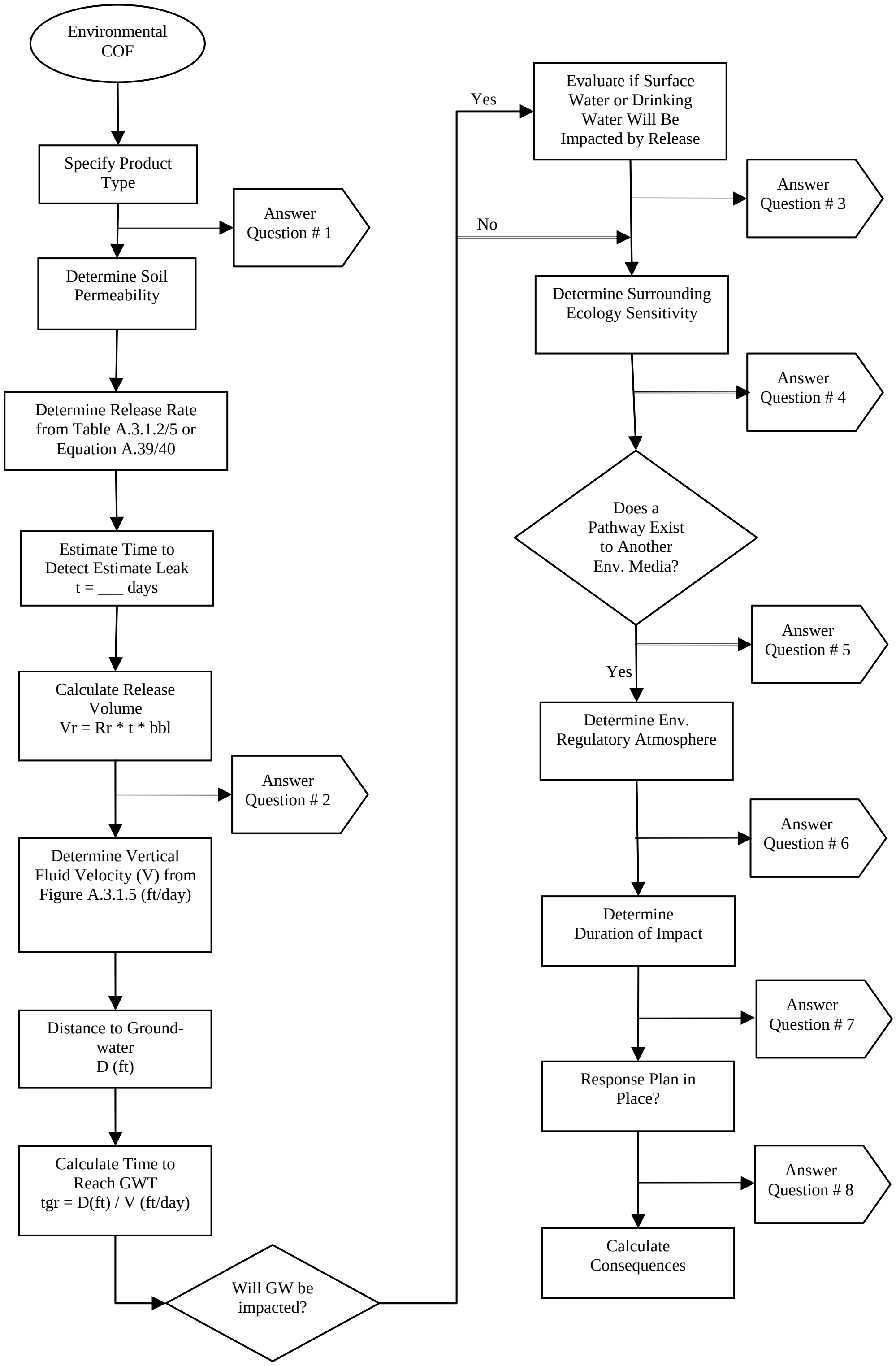


Figure A.3.1.1: Environmental Consequences Process Flow Diagram

1. What is the released product type?
2. What is the anticipated volume of released liquid petroleum (in bbls)?
3. What are the primary media impacted by the release?
4. What is the surrounding ecology?
5. What is the environmental regulatory atmosphere (local)?
6. What is the surrounding community impact?
7. What are the adjacent human use resources?
8. What are the response plans and response capabilities?

The ECOF model is presented step-by-step below with italicized annotations to aid the user in understanding the meaning of the questions and the possible answers. The ECOF model forms are included in Appendix C without these annotations.

Consequence Variable Weighting Factor for ECOF = _50%_

The user starts by assigning a user-defined weighting factor to the consequence between 0 and 100%. This factor stipulates the importance is the user assigns to this consequence event compared to other consequences, such as those related to business or population. Here the user has assigned a weighting factor of 50%.

EVENT: _Tank Overfill_ UNIT Operation: _Tank 10_
List the specific LRS as detailed above *Note the Unit Operation (i.e., Tank 10)*

Question #1

1.	**Product Type**	**Score**
A	Heavy oil (heavy crudes, #6 FO, asphalt, and motor oil)	0.5
B	Medium oil (most crudes)	0.75
C	Light oil (diesel, #2, light crudes)	1
D	Very light oil (gasoline and jet fuels)	1.5

ANSWER Q_1 = _1_

The physical properties of the petroleum product released dramatically affect the overall environmental consequences for the specific LRS. In answering the question concerning which environmental media were impacted, we have already taken into account some aspects of the products' physical characteristics as they relate to mobility of the product. This question, however, addresses the specific effect these properties will have on environmental consequences. Because of their toxicity and viscosity, very light oils are more mobile and subject to dispersion in soils and water. These products become more persistent in the environment and thus more difficult to clean up. As the products become heavier, the toxicity and mobility of the product drop. Note that the above modification factors are for environmental releases on land or near shore. For spills offshore, the opposite weighting factors would be more appropriate.

Question #2

2.	**Anticipated Volume of Released Liquid Petroleum**	**Score**
A	< 25 bbl (~ 1,000 gal)	1
B	25 bbl to 250 bbl	5
C	251 bbl to 2,500 bbl	10
D	2,501 bbl to 25,000 bbl	45
E	>25,001 bbl	90

ANSWER Q_2 =_5_

The user needs to estimate the probable anticipated quantity of petroleum released for the specific LRS. The guidance provided in Section A.3.1.3.1 will assist the user in developing this estimate. The volumes of petroleum released along with primary media impacted (Question #3, below) are the principal predictors of the overall consequences on the environment of a liquid release.

Question #3

3.	**Primary Media Impacted by Release**	**Score**
A	Release contained in an impermeable diked area	1
B	Release impacts onsite soils only	5
C	Release impacts offsite soils	25
D	Release impacts subsurface soils	40
E	Release impacts groundwater	60
F	Release impacts surface waters	50
G	Release impacts drinking waters (surface or groundwater)	100

ANSWER Q_3=_5_

Determine the most likely primary environmental media impacted by a particular LRS. If multiple media may be impacted, use the resource with the highest score. For example, if a tank bottom leak is determined to impact both onsite soil and onsite groundwater, the user should select the higher score for onsite groundwater. If multiple media may be impacted, it is recommended that the owner use the most ***probable*** *media to be impacted, not all possible media. Refer to Section A.3.1.3.2 for guidance on determining impacted media.*

Question #4

4.	**Surrounding Ecology Sensitivity (Site Conditions)**	**Score**
A	Not an ecologically sensitive area	1
B	Close proximity to aquatic habitats or regulated wetlands	25
C	Sensitive biological, species, or ecologic receptors	50
D	Unusually sensitive biological species	100

ANSWER Q_4=_1_

This question adjusts the potential environmental consequences by accounting for the sensitivity associated with the area around the facility. The importance of the surrounding ecology is often driven by impacts from facility liquid releases that impact that ecology; however, the presence of surrounding sensitive ecology will usually subject the facility to tighter scrutiny for small releases that have no impact outside the facility. The presence of the local sensitive area often drives the regulatory requirements and oversight experienced by a facility. Determinations of the potential damage to sensitive ecological areas must also account for long-term impacts that may result from damage to these areas.

Question #5

5.	**Pathway Assessment to Sensitive Ecology**	**Score**
A	Unlikely, limited, or negligible impact to surrounding ecology	0.5
B	Likely impact to surrounding ecology	2.0

ANSWER: Q $_5$ =_*0.5*_

The risk to the surrounding ecology is directly affected by the proximity to the facility and an assessment of the likelihood that the release for the specific LRS will have a pathway that allows impact to the sensitive receptor. If there is a low likelihood of impacting a sensitive receptor, the risk to that receptor is reduced, although it is not eliminated.

Question #6

6.	**Environmental Regulatory Atmosphere**	**Score**
A	Efficient, timely, and pragmatic regulatory environment	0.5
B	Moderate regulatory environment	1
C	Strict proscriptive regulatory and enforcement action	2

ANSWER Q $_6$=_*1*_

The local environmental regulatory atmosphere will often drive the environmental consequences because the regulatory authority having jurisdiction (local, state, or federal or all three) can stipulate compliance, response, cleanup, and closure requirements, remedial objectives, cleanup standards, and penalties and potentially stipulate engineered control measures both for remediation and continued or return to service operations. Because these standards often differ from jurisdiction to jurisdiction, region to region, and regulator to regulator, the local environmental regulator can dramatically affect the consequences of a release, especially those that extend beyond a containment area. The user needs to be familiar with the local environmental regulatory atmosphere or consult with persons familiar with the local jurisdiction in order to answer this question. The regulatory oversight of the initial emergency response plan should be relatively uniform through out the United States and typically is not a factor in answering this question.

Question #7

7.	**Duration of Environmental Impact (Ecology or Surrounding Off-site Environment)**	**Score**
A	No or negligible impact (less than 1 week)	0.5
B	Short-term impact up to 1 month	1.0
C	Moderate impact up to 1 year	5
D	Long-term impact > 1 year	10

ANSWER: Q $_7$= _*1*_

The impact or the potential impact to the local environment as a result of the LRS will affect the overall environmental consequences. A protracted impact or threat of contamination from an impact to a critical ecological resource will cause *dramatic escalation in the environmental consequences. In addition to strict environmental considerations, community impacts that relate to the environment should be considered in answering the above question. These impacts include addressing the following items: recreational resource loss of use (e.g., boating, fishing, hiking, and biking), transportation loss of use (e.g., road, rail, boat transportation network closure or disruption), quality of life issues (e.g., noise, dust, odor, and aesthetics), and economic issues (e.g., impact on property value, mobility, local economy). These impacts are also included in aspects of the other types of consequences (business and population) questions presented in the other models. For environmental consequences, the real driving force in determining community impacts is the duration of the impact as a result of the event.*

Question #8

8.	**Response Plans and Response Effectiveness**	**Score**
A	Written spill response plan, drills, and OSRO in place with ability to perform a rapid effective response to the incident	1
B	No response plan in place or response contingency plan of limited effectiveness due to the nature of the incident	1.5

ANSWER: Q_8 = _1_

The ability to anticipate, plan, and effectively respond to an incident helps to mitigate the impacts of a liquid release incident. A formal written response and contingency plan is considered to be the industry norm, and no credit is given for having an effective response plan in place. An overall increase in the consequences is provided by this question if there is a lack of a formal written response and contingency plan or for those incidents where the presence of a formal written response and contingency plan does not aid in the mitigation effort of the overall consequences for that specific event.

$$ECOF_{Score(i)} = Q1_{Product} \times Q2_{Volume} \times (Q3_{Media} + Q4_{Ecology} \times Q5_{Pathway}) \times Q6_{Regulatory} \times Q7_{Duration} \times Q8_{Response}$$

Equation A.39

where (*i*) is the environmental consequence of failure score for the particular event and distinct piece of equipment (specific LRS).

Apply the scores from the above questions to the Equation A.39. The ECOF score provides the consequence portion of risk for environmental factors relative to this particular event and for this particular piece of equipment. Other appropriate events and equipment should be analyzed similarly in order to develop the complete ECOF score for environmental factors.

$ECOF_{Score(x)} = \underline{1}_{Product} \times \underline{5}_{Volume} \times (\underline{5}_{Media} + \underline{1}_{Ecology} \times \underline{0.5}_{Pathway}) \times \underline{1}_{Regulatory} \times \underline{1}_{Duration} \times \underline{1}_{Response}$

Total Score for Environmental Consequences of Failure (ECOF)x = _27.5_

The data range of consequence values is discussed in Section A.4.

A.3.1.3 Estimating Spilled Quantity and Impacted Media

For environmental consequences, two of the most important quantifiable factors that this model needs to determine are:

1. The volume of product released during a specific LRS
2. The media impacted by the release

For some LRSs, determining the volume released and the resource impacted is relatively straightforward, while in other LRSs these factors are substantially more difficult to determine. The following sections provide an overview of the approach for estimating the volume released and the media impacted depending on the type of release. First, Section A.3.1.3.3 presents an overview of soil permeability and flow through soils. Forms to assist in calculating the volume of the release and media affected are included in Appendix C.

A.3.1.3.1 Estimating Volume Released

When determining the severity of the environmental consequences resulting from liquid releases, the environmental damage is directly related to the volume of petroleum released. Therefore, it is important to estimate with some accuracy the probable range of volume of product which may be released for any particular LRS. The user may already have a basic understanding or "feel" for the range of values resulting from a particular LRS. The release volume for the probable scenario should be used and not unrealistically high "possible" numbers or unrealistically low "hopeful" numbers. For example, the volume of a release from a tank overfill would be the maximum flow rate into the tank multiplied by the time required to detect and stop the flow once the tank starts to spill outside of the tank. The volume released from a tank as a result of a catastrophic failure, such as a rapid shell or rapid bottom failure, is the safe fill capacity of the tank. Other volumes are not so easily determined.

Sections A.3.1.3.4 through A.3.1.3.6 guide the user in determining the volume of product released for a specific LRS. The user needs to develop a "feel" for these numbers to ensure that they are not grossly overestimating or underestimating the probable release volume. The user should review the environmental consequences methodology and numerical volume caps prior to proceeding. Numerical volume caps are provided because the environmental media or ecologically sensitive area impacted by the release becomes the governing concern once a spill exceeds 25,000 bbls (approximately 1 million gallons). Data ranges are provided for the released quantity because the circumstances governing the release make precise determination of the quantity difficult.

For the other non-environmental consequences, the volume of petroleum released is also of importance, along with other factors such as the flammability of the product or disruption of business.

A.3.1.3.2 Determining Media Impacted by a Liquid Release

A key component in determining what resources and media may be impacted by a release is the surrounding soil permeability. Section A.3.1.3.3 and the subsequent sections provide general guidance on determining permeability for the specified soil type and various petroleum products. The user should note that soil permeability is reported typically in terms of water permeability and that actual soil permeability for the released product will be a function of the viscosity of the released product.

When evaluating the severity of environmental consequences, determining what media will be most adversely affected by the release (e.g., diked area, onsite soil, offsite soil, subsurface soil, surface water, and groundwater) is as important as determining the volume released. The media impacted directly affect the cost of cleanup, the environmental detrimental effects, and the overall severity of a spill. Certain media are more difficult to clean up, or the media itself may become a transport mechanism (pathway) to areas critical to ecology or human use, such as drinking water supplies or wildlife habitats. For some ecological areas, even if cleanup is effective, the long-term ecological damage may be devastating. The affected environmental media is a site-specific function that is driven by the local environmental conditions and site-specific properties and configuration. Guidance on determining what media may be impacted by a petroleum liquid release is provided in Sections A.3.1.3.4 through A.3.1.3.6. Environmental media are defined below.

Environmental Media and Media Definitions
For environmental consequences, Figure A.3.1.2 illustrates the potential environmental media that may be impacted by a release scenario. The figure illustrates that releases could:

- Impact soils both on site and off site
- Impact surface water
- Impact groundwater
- Result in essentially no impact if the spilled liquids are contained inside the dike area surrounding a storage tank, or in catch basins/drainage pads associated with pumps or loading/unloading equipment

For a specific LRS, some, all, or none of the environmental media detailed in this figure may be impacted. The potentially impacted media include the following:

1. Diked area
2. Onsite soil
3. Offsite soil
4. Subsurface soil
5. Groundwater
6. Surface water
7. Drinking water supply

AST Consequence Analysis
Overview of Leak Scenarios

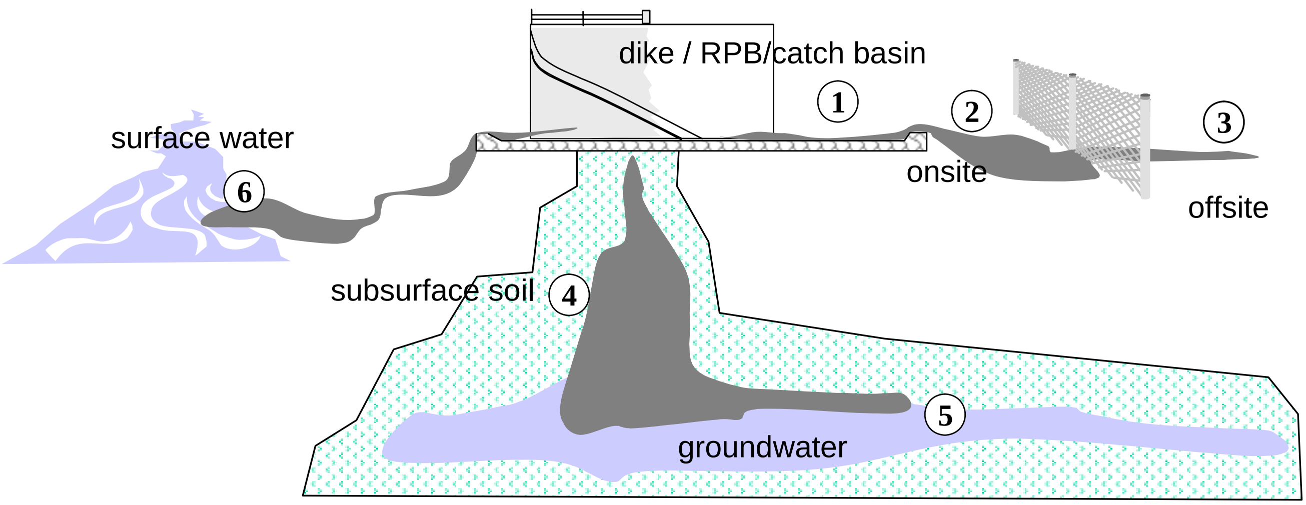


Figure A.3.1.2: Overview of Environmental Media

These environmental media have the following general definitions when applied to environmental consequences:

1. Diked Area—A release of petroleum products is contained within a diked area or other secondary containment system such as an RPB, spill catch basin, or spill tank. The "diked area" impacted media assumes the spill is of a size and physical characteristics to be contained within a system that is sufficiently impermeable to prevent migration of the spill off site, prevent contamination of groundwater and surface water, and minimize the volume of impacted onsite soil. Minimal onsite soil impact is defined as less than 12 inches in depth of soil contamination in a 72-hour period. An earthen secondary containment system that contains a release of petroleum may be considered a "diked area" if the soil permeability and stored material properties are sufficient to meet the above definition. For example, a secondary containment system constructed from a uniform sandy soil which is containing asphalt or other heavy petroleum products would be considered "diked" because a release into the containment is not expected to impact other media (e.g., limited onsite soil impact, no offsite soil, no groundwater or surface water impacts). Conversely, the same system containing gasoline may not meet this definition.

2. Onsite Soil—A release of petroleum products is limited to contaminating onsite surficial soils. "Onsite" refers to the area within the physical property boundary limits of the facility. "Surficial soils" refers to the upper 2 feet (0.6 meters) of soil that could be readily removed in the event of a spill. The volume spilled, location of spill, site grade, size of the property, soil permeability, and stored material properties are important in determining whether a spill will be contained on site. For example, a flange leak on a section of aboveground piping may be limited to impacting a small section of onsite soils.

3. Offsite Soil—A release of petroleum products contaminates offsite surficial soils. "Offsite" refers to the property outside of the physical property boundary limits of the facility. "Surficial soils" refers to the upper 2 feet (0.6 meters) of soil that could be readily removed in the event of a spill. The volume spilled, location of spill, site grade, land use of the offsite impacted property, soil permeability, and stored material properties are important in determining the impacts to offsite property.

4. Subsurface Soil—A release of petroleum products contaminates subsurface soils. Subsurface impacts may or may not be contained within the physical property boundary limits of the facility. "Subsurface soils" refers to soils deeper than 2 feet (0.6 meters) or those soils that cannot be readily removed in the event of a spill, such as soils beneath a field-erected tank or building slab. The soil permeability, stored material properties, and location of the spill are important in determining the extent of the environmental consequences associated with subsurface soil impacts. For example, a release of petroleum from an AST bottom that rests on native clay soils will have minor subsurface impacts relative to the same tank which is located on native sand soil.

5. Groundwater—A release of petroleum products contaminates groundwater. "Groundwater" refers to the first encountered phreatic water table that may exist subsurface at a facility. Groundwater elevation may fluctuate seasonally, and different groundwater tables may exist at a site (e.g., possible shallow soil water table and a deep bedrock water table). The depth to groundwater, soil permeability, stored material properties, and location of the spill are important in determining the extent of the environmental consequences associated with groundwater impacts. The nature of the subsurface soils and depth to groundwater will dictate the time required for a spill to impact the groundwater and the severity of the impact.

6. Surface Water—A release of petroleum products contaminates offsite surface water. Conveyance of spilled product to surface waters is primarily by overland flow, but may also occur through subsurface soils. "Surface water" refers to non-intermittent surficial waters from canals, lakes, streams, ponds, creeks, rivers, seas, or oceans and includes both fresh and salt water. Surface waters may or may not be navigable. The stored material properties, type of surface water, proximity of the surface water to the site, and response capabilities are important in determining the extent of the environmental consequences associated with surface water impacts.

7. Drinking Water Supply—A release of petroleum products contaminates a surface water or groundwater drinking supply.

In determining what media would most likely be impacted by the LRS, users need to ensure that they account for the time required to detect a release, stop the release, and remove the recoverable free liquid released. The time to initiate a remedial activity or plan to mitigate impacts to other media must also be considered.

A.3.1.3.3. Approach to Specific LRS Environmental Consequence Modeling

The following guidance has been developed to aid the user in evaluating the environmental consequences of specific LRSs. The approach outlines the method used to define the volume released from a specific LRS and the media likely to be impacted. The discussion is organized by the following LRSs:

- Aboveground tanks
- Piping both aboveground and underground
- Transfer equipment

First, general concepts of liquid flow through soils and holes are discussed. This background is the basis for the subsequent sections.

A.3.1.3.3.1 Three-Dimensional Fluid Flow through Soils

The analysis of flow from a spill into the underlying or surrounding soils depends upon the material properties of the soil layer under consideration. The flow of petroleum from the spill into the underlying soils is three-dimensional. The three-dimensional flow conditions can be estimated from a hole in the base of a tank or from flow though the liner into the soil using the empirical relationship developed by Giroud and Bonaparte (1989) in SI units:

$$q = C\, h^{0.9}\, a^{0.1}\, k^{0.74}$$

(Equation A.40)

where

q = flow rate (m^3/sec);
C = adjustment factor for degree of contact with soil: 0.21 for good contact, 1.15 for poor contact;
h = depth of liquid (m);
a = area of hole (m^2); and
k = hydraulic conductivity of soil (m/sec).

A.3.1.3.3.2 Basis of Flow Rate of Fluid to Atmosphere

For a slow shell leak or fitting leak, the release occurs through a hole in the shell of the tank or through a fitting on the tank. The drop in pressure from the tank to the atmosphere drives the fluid through the hole (Figure A.3.1.3). These release rates are modeled using Equation A.41 below for liquid discharge to the atmosphere through an orifice driven by the tank hydraulic head. The results of this calculation are given in Table A.3.1.5 in Section A.3.1.3.4.2 for different values of tank head. The results in the table are applicable for all typical petroleum product liquids.

$$R_r = C_d \frac{\pi d^2}{4} \sqrt{2g\Delta h} * 4.45$$

(Equation A.41)

where

$\boldsymbol{R_r}$ = volumetric flow rate (bbl/hour);
$\boldsymbol{C_d}$ = discharge coefficient (dimensionless, suggested value of 0.61 for hydrocarbon liquids);

d = hole diameter (inches, suggest a 1/8" hole);
g = gravitational acceleration (32.2 ft/sec^2);
Δh = liquid head at the leak (ft); and
4.45 = factor used to convert to bbl/hr.

Although the leak could occur at any point in the shell, because a high percentage of shell leaks occur at or near the bottom of the tank, it is assumed that the leak occurs at the bottom of the shell. $\Delta \boldsymbol{h}$ is then equal to the total liquid head of the tank. This assumption is used for small shell leaks, fitting leaks, and roof drain hose leaks.

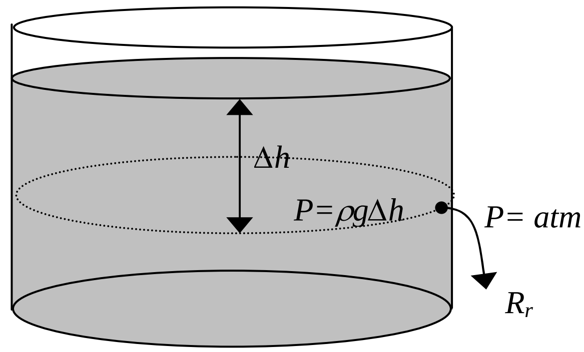


Figure A.3.1.3: Release from Tank Shell

A.3.1.3.4 Aboveground Tank Liquid Release Scenarios

The tank LRSs used in this model apply exclusively to API Std 650 field-erected tanks or their predecessors. Tank LRSs documented in the consequence and likelihood model involve unintended releases as a result of the following sources:

- Small bottom leak
- Small shell leak
- Rapid shell or rapid bottom failure
- Tank overfill
- Tank drain failure (external floating roofs only)

The following subsections detail the approach for determining the volume released and estimating the media impacted by the release. The approach presented below makes the assumption that the tank in the LRS is an API Std 650 carbon steel field-erected tank located in a containment or remote impoundment area that is in compliance with NFPA 30 or other applicable code.

A.3.1.3.4.1 Small Tank Bottom Leaks

Determining the volume lost and the environmental media impacted by a leak through an on-grade, field-erected steel bottom tank is based on the soil conditions encountered at the site and the size of the hole in the floor of the tank. In determining the environmental media impacted by the tank bottom release, the user needs to account for several key variables:

- The length of time from formation of the bottom hole to the time the leak is detected and stopped
- The difficulty in accessing the area underneath the tank to mitigate or remediate a release
- The soil and groundwater conditions existing under the tank and surrounding area

The information presented in Figure A.3.1.4 can be used to determine the rate of flow from a hole in the tank bottom. The downward rate of flow can be estimated if the vertical permeability of the soil underneath the tank is known from Figure

A.3.1.5. For example, in soils with a moderate permeability ($1x10^{-4}$ cm/sec or higher), a leak through a tank bottom will travel a minimum of 0.28 ft/day; therefore, an analysis to determine whether a release will reach the groundwater can be easily performed if the depth to groundwater is known and the time to detect, stop, and mitigate a release can be estimated. For example, a tank bottom resting on silty sand soil (soil permeability of 0.28 ft/day or $1x10^{-4}$ cm/sec) with groundwater at 10 feet (3 meters) below ground surface will result in a tank bottom release reaching the groundwater within 36 days. Therefore, from the time a leak in the tank bottom occurs until the time remediation is initiated, the spill would have to be mitigated in less than 36 days. If the time to detect, stop, and mitigate the release from the tank bottom is greater than 36 days, one could conclude that the spill would impact the groundwater.

Tank Bottom Release Volume

The following methodology has been developed to estimate the volume of product released from a typical API Std 650 field-erected steel storage tank. The release is assumed to occur through a corrosion hole occurring in the bottom of the tank. The size of the hole is based upon what industry experience has determined to be a typical hole (≤ ½ inch).

Foundation Conditions

Foundation designs for petroleum storage tanks are governed by API Standard 650 or its predecessor documents. API Std 650 (Optional Appendix B) addresses the foundation conditions for different foundation types, including ringwall and earth pads.

For newer storage tanks built or altered to meet the API Std 650 Seventh Edition, the API standard also provides several designs for leak detection and release prevention systems. A release prevention system (RPS) aids in the detection of a tank bottom release and the protection of the soils underneath the tank. A release prevention barrier inhibits petroleum from penetrating the subsurface soils supporting the tank but may not necessarily provide a means for detecting a release. A tank leak detection system provides a means of detecting a release through the tank bottom, but not a barrier to prevent the leak from impacting subsurface soils or groundwater. A tank with a leak detection system only is considered to be a single steel bottom system. A tank with an RPS or RPB is considered to be a double-bottom tank or single-bottom tank with an under-tank liner. The RPS or RPB may include a 30-mil to 40-mil flexible geomembrane liner placed below the sand pad and on top of the soil sublayer, and it may also include concrete or native soils with a low permeability (soils with a permeability typically $\leq$ 0.0028 ft/day (1×10^{-6} cm/sec)). The analysis presented below is for those cases where a tank bottom leak results in fluids entering the soil beneath the storage tank. Typically, this would not be the case for tanks built with an RPB, RPS, or equivalent system.

A typical API Std 650 tank sub-base would include a 3- to 6-inch thick layer of sand cushion or oil sand placed immediately beneath the storage tank bottom. This sand pad creates a smooth surface of consistent material for support and point corrosion protection of the tank bottom. The sand layer provides potentially a higher permeable layer that may aid in detecting a release from the tank bottom if the native subgrade soils are much less permeable than the sand cushion. Beneath the sand layer is typically a subgrade layer that is designed to support the weight of the steel tank and the contained fluid. This subgrade layer can be of any type of soil or stone, but it is often obtained from the soils that are readily available on site, or it consists of undisturbed native soils. In some cases, the subgrade is an engineered fill that is placed and compacted to certain density specifications.

Refer to *Aboveground Storage Tanks* by P. Myers and to API Std 650 for further discussion on tank foundation types and construction features.

Calculation of Release Volume

As discussed previously, the analysis of flow from the tank bottom into the underlying soils depends on the material properties of the soil layer under consideration. The flow of petroleum from the tank into the underlying soils is three-dimensional. As previously stated in Section A.3.1.3.3.1, the three-dimensional flow conditions that exist under this condition can be estimated using Equation A.40.

$$q = C\,h^{0.9}\,a^{0.1}\,k^{0.74}$$

(Equation A.40)

As shown in Equation A.42, the volume that leaks from the tank is found by multiplying the leak rate (Figure A.3.1.4) by the duration of the leak (Table A.3.1.1).

Small Bottom Leak Volume = Leak Rate **Rr** (bbls/day) x Duration of the Leak (days)

(Equation A.42)

The leak duration is the time estimated by the user in hours from the time the leak occurred to the time the leak could be stopped and downward flow mitigated. For example, if the facility estimated that a release would go undetected for no more than 30 days (the time to know that a leak was occurring because of change in inventory, visual detection of release, etc.), and it further estimated that it would take no more than 1 day to stop the leak (e.g., de-inventory the tank) and then another 7 days to mitigate the downward flow of the product that was released (e.g., removal or mitigation of free-flowing product through soil), then the facility would assume that the total leak duration was approximately 37 days. Detection time is based on soil conditions, use of periodic walk-around inspections of tanks, inventory reconciliation, and leak detection capabilities. (Refer to Hydrocarbon Processing article by Mikkola, Myers, and Power (*Secondary Containment Liners for Tank Farms—A New Approach*) for determining behavior of petroleum as it flows through soil.) Users can apply their own estimate of leak durations or adopt the guidance values shown in Table A.3.1.1.

Table A.3.1.1: Small Bottom Leak Duration Times

Site Conditions	**Leak Duration Time**
RPB or Sand Pad over Clay	5 to 15 days
Impervious Soil Layer under Tank Sand Pad	15 to 30days
Semi-Impervious under Tank Soil	30 to 90 days
Pervious Soil	90 plus days

The results for calculations of flow from the tank into the soil are given in Figure A.3.1.4 using the equation (Equation A.40) developed by Bonaparte and Giroud (1989). These results are based on the assumption of a constant 30-foot head from petroleum-based fluid in the tank. The contact coefficient was 0.21 since the contact between the tank and the soil is subject to substantial overburden pressure and is likely to be very good. The flow, in barrels per hour, is shown as a relationship with soil hydraulic conductivity

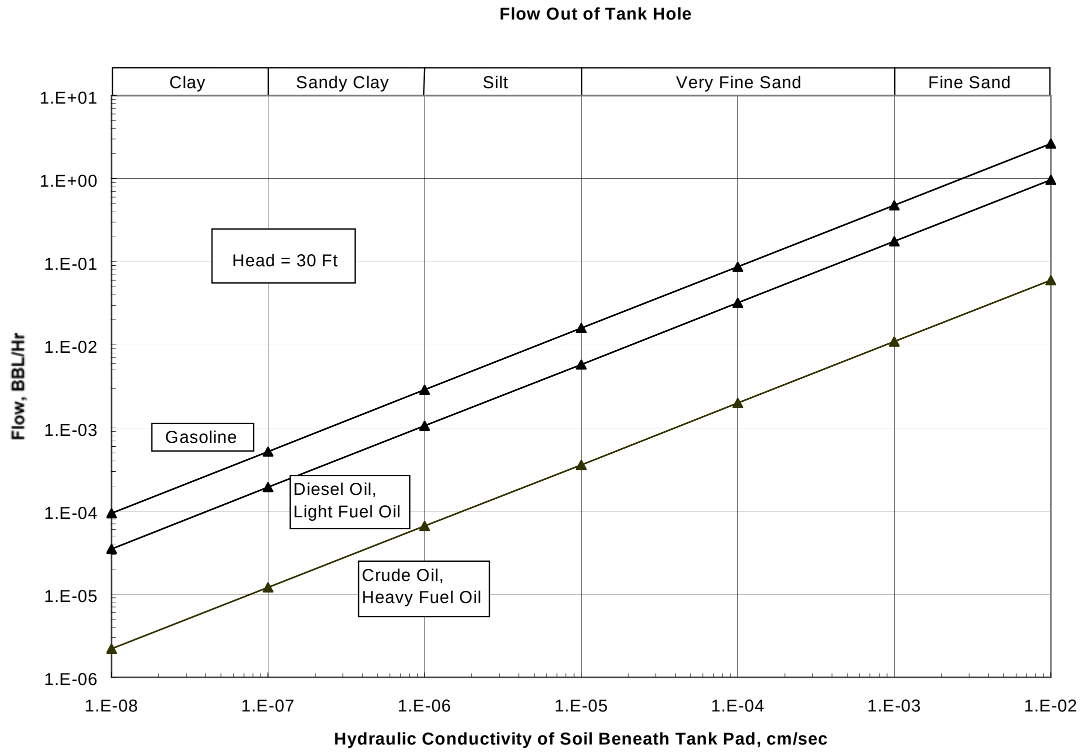


Figure A.3.1.4: Flow through Soil at Hydraulic Gradient = 1

Flow from an RPB/RPS or Equivalent System

As discussed above, tanks with RPB/RPS or an equivalent system may have a normal opening into the tank farm area. These openings may consist of 1-inch drain pipes used as telltales, the unwelded upper seam of a steel double bottomed tank, or the gap between the steel bottom plate and the underlying concrete slab. If this system has an opening(s) that can release product into the surrounding soils or into the diked area as a result of a hole in the primary bottom, the user needs to review the impact of this release. For these types of releases, the user must account for potential impacts to soil, subsurface soils, or groundwater from product exiting the RPB/RPS system. In general, the detection times for these types of releases will be much faster because the release should be readily detectable outside the tank. For estimating the detection time and determination of media impacted from a tank bottom for an RPB/RPS, it is recommended that the user apply the approach outlined in Section A.3.1.3.4.2 for small tank shell leaks.

If the RPB/RPS consists of a totally contained system where leakage from the double bottom into the surrounding environment is not possible or where the leak is limited and occurs in an impermeable diked area, this analysis may not be meaningful.

Tank Bottom Release Media Impacted

If the tank has a single steel floor, the consequence model determines if some portion of the leak can reach offsite soils or groundwater, migrate to surface waters, or impact other offsite receptors. To discover whether the release will reach groundwater or other media or receptors, the user must first determine the type of soil below the tank pad and the vertical distance to groundwater directly below the tank or distance to a receptor of concern. Knowing the type of soil under the tank, the user selects an appropriate hydraulic conductivity from Figure A.3.1.4 and a ½-inch hole size to determine the flow from the tank. Hydraulic conductivities can be estimated using Figure A.3.1.5, if the soil type is known. The user should be careful in selecting a hydraulic conductivity because the travel time is directly related to the hydraulic conductivity, and hydraulic conductivities can easily vary orders of magnitude from those shown.

Again, knowing the hydraulic conductivity, the downward vertical velocity in feet per day is found from Figure A.3.1.5. The time to reach groundwater (days) is calculated by dividing the vertical distance to groundwater (feet) by the downward vertical velocity (feet/day). (It should be noted that the downward velocity model, as represented in Figure A.3.1.5, tends to be conservative as it assumes that there is enough product being released to wet all of the soilsand surfaces as the spill travels downward.)

The results of the downward vertical fluid velocity calculations are shown on the left axis of Figure A.3.1.5 for flow from the tank bottom hole, through the sand pad, and into the subsoil assuming one-dimensional flow conditions. These results are based on the assumption that the hydraulic gradient is 1.0, which is generally met. Also, in order to determine the velocity, the soil porosity is assumed to be 0.35. The resulting flow rates range from 0.0001 feet/day in clays to 40 feet/day in fine sand.

Once the time to reach groundwater is known, the total leak time is used to determine if the groundwater is affected. If the duration of the leak is shorter than the time to reach groundwater, then the spill is assumed not to affect groundwater as long as the leak can be stopped and release mitigation or remediation measures can be put in place to prevent or minimize impacts.

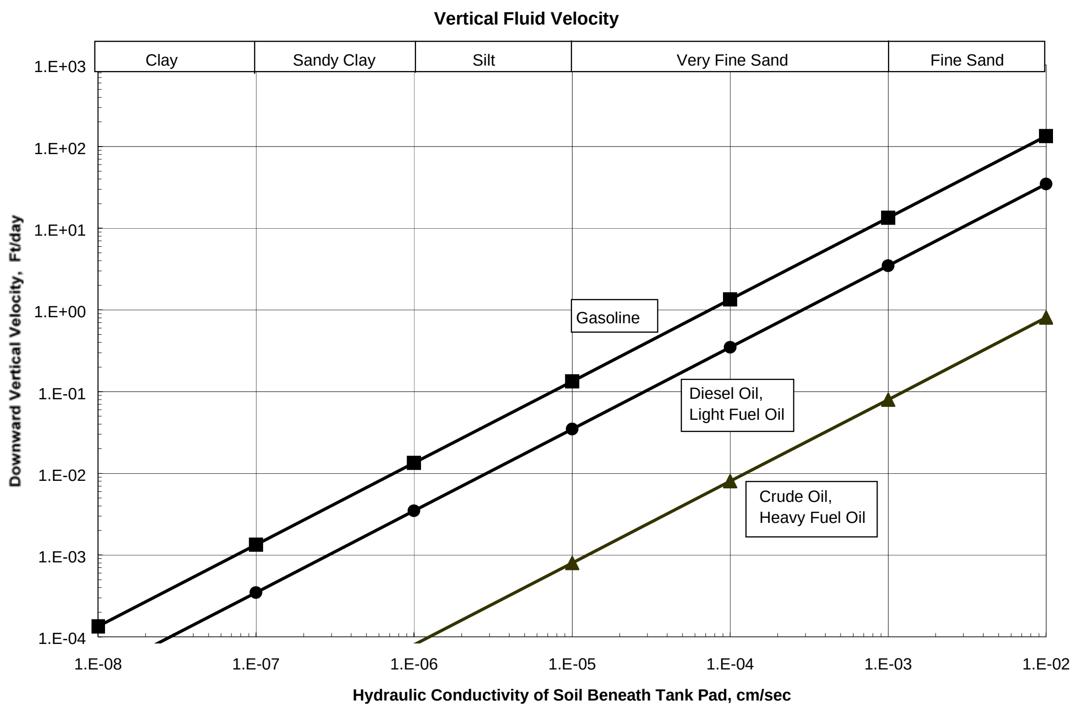


Figure A.3.1.5: Vertical Fluid Velocity

Note: The fluid velocity in the soil beneath a surface spill of petroleum will initially be dictated by the hydrostatic head of the spill; however, after the product has spread out and the head is eliminated, the flow velocity will transition from being controlled by fluid pressure to being controlled by gravitational forces. The resulting equilibrium downward vertical velocity is as shown in Figure A.3.1.5.

For a more simplified approach to the release rate from a tank and its downward velocity, Tables A.3.1.2 and A.3.1.3 can be used instead of Figures A.3.1.4 and A.3.1.2. The release rates shown in Table A.3.1.2 are for small holes (≤ ½ inch) in the tank bottom.

Table A.3.1.2: Release Rates for Small Bottom Leaks (bbl/hr)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	1	0.5	0.03
Very Fine Sand	0.08	0.03	0.002
Silt	0.006	0.003	0.0002
Sandy Clay	0.001	0.0005	0.00003
Clay	0.0002	0.00008	0.000005

Table A.3.1.3: Vertical Fluid Velocity through Soil for Leaks from Tank (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

For tanks with an RPB, a leak from the primary steel tank floor may still result in petroleum entering soils under or around the tank. This results from petroleum exiting from tell-tales, the gap between the tank shell and the RPB, or from defects in the RPB. For the purposes of this model, it was assumed that if a release occurs in a tank with an RPB system, the evaluation of media impacted would be similar to the small tank shell release because the release should be readily identifiable.

<u>Basis of Tank Bottom Leak Rate and Seepage into Soil</u>

Material Properties

Figures A.3.1.4 and A.3.1.5 present flow rate and vertical fluid velocity curves for gasoline, diesel oil/light fuel oil, and crude oil/heavy fuel oil. Table A.3.1.4 shows the assumed properties for those products. Other assumptions used for the basis of tank bottom leak rates and seepage into soils are presented below.

Table A.3.1.4: Material Properties

Product	**Density (lb/ft^3)**	**Viscosity (lb-sec/ft^2)**
Gasoline	45.0	9.0×10^{-6} (0.42 cp)
Diesel oil/light fuel oil	53.7	3.9 × 10-5 (1.81 cp)
Crude oil/heavy fuel oil	59.2	2.0×10^{-3} (93 cp)

Head

The storage tank is assumed to have a fluid level of 30 feet (9 meters). The level can vary between 0 and 60 feet (18 meters), and since the flow out of the tank into the subsoil is through small holes, the 30-foot (9 meters) fluid level was assumed to be constant.

Hydraulic Conductivity

The assumption regarding the soils present at the site ranged from clay to fine sand. This resulted in assumptions in hydraulic conductivity ranging from 2.8×10^{-5} ft/day (1×10^{-8} cm/sec) for clay to 28 ft/day (0.01 cm/sec) for fine sand. The hydraulic conductivity values in this report are those based on water.

Hydraulic conductivity is also impacted by whether the soil is saturated and by the soil capillary capacity. The effects of soil suction capacity have been researched and can be significant but have been ignored for this analysis because making general assumptions about soil suction forces would be unreliable.

Hydraulic Gradient

The hydraulic gradient, defined as the change in head divided by the length of travel perpendicular to the flow path, is necessary to determine the flow rate in the sublayer. The hydraulic gradient is 1.0 for downward gravitational flow, and since the head in the sand pad was assumed to be 4 inches, the hydraulic gradient in the sublayer would be greater than 1.0; however, the hydraulic gradient will rapidly approach 1.0 within a few feet of the top of the sublayer. Therefore, this analysis was performed using a hydraulic gradient of 1.0.

A.3.1.3.4.2 Small Shell Leaks

Small shell leaks can result from a through hole corrosion of the steel shell plate, mechanical damage, or failure of a gasket on a tank appurtenant such as a connected fitting. Tank shell leaks in this LRS do not include rapid shell failures (see Section A.3.1.3.4.3) or attached product piping failures (see Section A.3.1.3.5). If a leak occurs in a part of the AST that is aboveground, such as the tank shell, the following approach is used to estimate the spill size.

Tank Shell Release Volume

In order to estimate the released volume from an aboveground leak, the size of the hole in the shell must be estimated. Smaller diameter holes can be assumed for normally attended facilities where daily walk-around inspections are common. Larger diameter holes can be used to model gasket leaks from manholes or mechanical damage to attached tank appurtenances. The user can first find the leak rate in Table A.3.1.5 for the specific hole diameter and then multiply the leak rate by the estimated leak duration (hours).

Table A.3.1.5: Release Rates for Flow to Atmosphere (for all fluid types)

Head (ft)	R_r (bbl/hr)		
	1/8"	1/2"	2"
10	0.85	13.5	216.4
15	1.04	16.6	265.1
20	1.20	19.1	306.1
25	1.34	21.4	342.2
30	1.46	23.4	374.8
35	1.58	25.3	404.9
40	1.69	27.1	432.8

For other diameter holes or different product head, the formula in Equation A.41 of Section A.3.1.3.3.2 can be used to calculate the leak rate. The leak duration is the time estimated by the user in hours from the time the leak occurred to the time the leak could be stopped or captured. For example, if the facility conducts daily walk-around inspections of the tanks and has wood pegs or other means to rapidly stop a leak once it is detected, leak duration is potentially 24 hours.

$$\text{Small Shell Leak Volume} = \text{Leak Rate } \mathbf{Rr} \text{ (bbls/hr)} \times \text{Duration of the Leak (hrs)} \quad \text{(Equation A.43)}$$

Tank Shell Release Media Impacted

The method of determining the media impacted is the same as described in the previous section. Generally speaking, the small shell leak will enter into the containment area immediately around the base of the tank and will flow via gravity along the normal stormwater paths. The product flow within the secondary containment area, including into the surrounding soils and possibly under the tank(s), will be a function of the design of the secondary containment system, the surficial soil conditions, the calculated volume of the leak, and the time it takes to remove the free product. Based on this information, one can determine (using the previous infiltration equations) if spilled product in the containment area will impact media outside of the containment, including surface water, groundwater, or off site. If a spill is detected quickly, if free product can be removed rapidly, and if the underlying soils have a low permeability, it may be assumed that no seepage occurs outside of the secondary containment and a surface cleanup is sufficient. If a surface cleanup is not sufficient, the consequence models can be used to further discern whether or not the spill migrates further off site impacting other media or sensitive ecological receptors.

For spills that can persist for a long time, go undetected for an extended period of time, or enter highly permeable soils, the petroleum seepage may extend into subsurface soil, groundwater, or surface waters.

A.3.1.3.4.3 Rapid Shell or Rapid Bottom Failure

This section considers the consequences of the instantaneous loss of the tank shell or tank bottom resulting in the loss of the entire tank contents and, potentially, a wave of product overflowing the dike wall. This type of release is typically a tank shell brittle fracture failure similar to the Ashland tank failure in Floreffe, Pennsylvania, in 1988. The following analysis assumes that the release does not wash out the dike walls. In some instances, the dike walls may be damaged during the tank failure (e.g., due to the proximity of the tank to the dike wall). If the user believes the resultant tank failure will cause the entire contents of the tank to be lost to the area outside of the tank containment area, then 100 percent of the contents of the tank should be routed into the surrounding environment.

Rapid Shell or Rapid Bottom Failure Volume Loss
For this LRS, 100 percent of the safe fill capacity of the tank is assumed to be released into the surrounding diked area. The time it takes to remove free product is important to determining if soils within the dike will be penetrated and if groundwater will be affected. It is also important to determine how much of the tank contents (volume) makes it outside of the diked area. The time it takes to remove free product is also important when evaluating the release outside of the dike.

Rapid Shell or Rapid Bottom Failure Media Impacted
A storage tank is often surrounded by a dike that is designed such that the volume of the dike will hold 110 percent of the volume of the largest tank in the dike; however, theoretical, experimental, and practical evidence exists to suggest that this design strategy will not completely contain the spill resulting from a rapid shell or rapid bottom failure. The following model was developed to provide a rough estimate of the amount of liquid that overflows the dike during a tank rapid failure condition. The model is based on predictions made using computational fluid dynamics (CFD).

Table A.3.1.6 presents the fraction of the tank contents that would be expected to overflow the dike subsequent to a rapid shell failure. This value is based on the volume of the tank in relation to the capacity of the diked area.

Table A.3.1.6: Rapid Shell Failure Dike Overflow

$V_{Tank\ Contents}/V_{Dike}$	Fraction of Tank Contents Overflowing Dike
0.4	0.05
0.5	0.2
0.6	0.35
0.7	0.5
0.8	0.6
0.9	0.7

If the tank shell fails in a brittle fracture manner and the shell is within 20 feet (6 meters) of the exterior diked wall, it is probable that a portion of the dike wall will be lost due to physical damage or scour of the dike. In this case, 100 percent of the tank contents is assumed lost to the surrounding environment.

The product flow within the secondary containment area, including into the surrounding soils and possibly under the tank(s), will be a function of the design of the secondary containment system, the surficial soil conditions, the calculated volume of the leak, and the time it takes to remove the free product. Based on this information, one can determine (using the previous infiltration equations) if spilled product in the containment area will impact media outside the containment, including surface water, groundwater, or off site. The same analysis can be performed for the fraction of tank contents that overflows the dike to determine what media are impacted outside the diked area.

A.3.1.3.4.4 Tank Overfills

A tank overfill involves a petroleum product release from the overfill vents of the tank during loading. The volume of the release can be determined as follows:

Overfill Volume
The amount of petroleum product released as the result of overfilling an AST is simply the fill rate multiplied by the sum of the time required to detect the overfill and the time required to shut down the fill. For ASTs, API RP 2350 provides guidance on the use of high level alarms and response rates. In general, an overfill occurs during the time the product leaves the overfill vent until the time the product stops entering the tank. The time required to detect and stop the overfill is a facility- and company-specific issue that relates to the configuration of the facility, presence of high level alarms, alarm annunciation, fill rates, response time, and time required to stop product flow into the tank. For example, a facility operator may determine that his specific response time (i.e., the time between detecting a release and the time a release is shut down) is 10 minutes. If the fill rate is 3000 bbl/hr, the spill would be calculated to be V= 3,000 bbl/hr x 1/6 hr = 500 bbl.

$$\text{AST Overfill Volume} = \text{Fill Rate (bbls/hr)} \times \text{Duration of Overfill (hrs)}$$

(Equation A.44)

As a point of reference, the average overfill release quantity for one major operating company with a tank high level alarm system in place which was compliant with API RP 2350 was 90 bbls. This facility's distribution on AST overfill release volume is presented in Table A.3.1.7.

Table A.3.1.7: AST Overfill Spill Size Distribution

Release Volume	Percent
< 10 bbls	50%
10–100 bbls	35%
100–500 bbls	10%
> 500 bbls	5%

Overfill Media Impacted
Generally speaking, the AST overfill petroleum will enter into the containment area immediately around the base of the tank and will flow via gravity along the normal stormwater paths. The product flow within the secondary containment area, including into the surrounding soils and possibly under the tank(s), will be a function of the design of the secondary containment system, the surficial soil conditions, the calculated volume of the leak, and the time it takes to remove the free product. Based on this information, one can determine (using the previous infiltration equations) if spilled product in the containment area will impact media outside the containment, including surface water, groundwater, or off site. If a spill is detected quickly, if free product can be removed rapidly, and if the underlying soils have a low permeability, it may be assumed that no seepage occurs outside of the secondary containment and a surface cleanup is sufficient. If a

surface cleanup is not sufficient, the consequence models can be used to further discern whether the spill migrates off site impacting other media or sensitive ecological receptors.

For spills that persist for a long time, go undetected for an extended period of time, or enter highly permeable soils, the petroleum seepage may extend into subsurface soil, groundwater, or surface waters.

A.3.1.3.4.5 Tank Drain Leaks (External Floating Roofs Only)

For tanks with external floating roofs where the climate does not allow for the roof drain valves to be left closed, or when valves are opened to drain water and they are left unattended or unintentionally left open, or if there is a hole in the hose or articulated pipe, a potential pathway exists to release product into the containment area around the tank and/or into the tank farm stormwater drainage system. In this LRS, the roof drain hose or articulated pipe developed a leak that is then conveyed into the area surrounding the tank or stormwater drainage system through the open tank valve. The release is to the diked area or surficial soils surrounding the tank. It is assumed that a high percentage of the leaks occurring from this LRS will be small, $^1/_8$-inch holes in the drain lines. However, a small percentage of the release may result from ruptures of the hose or articulated drain pipe which will release at the full internal diameter of the drain pipe flowing with product.

Tank Drain Leak Volume
The release rate can be calculated using Equation A.41 where **d** is $^1/_8$ inch for small leaks or the internal diameter of the roof drain hose or pipe for failures. The value of **Δh** is the liquid head at the roof drain valve. The duration of the leak is based on operator experience in detecting the release either through level gauges or periodic inspection of the tank farm area.

Tank Drain Leak Media Impacted
The primary media impacted will be the diked area and surficial soils in the diked area. The approach used for small tank shell releases, Figures A.3.1.4 and A.3.1.5, Table A.3.1.5, and Equation A.41 can be used to determine the resources impacted within the diked area. If the stormwater drainage system provides a direct pathway of this release to areas outside the secondary containment system, then this media will need to be reviewed for potential impacts.

A.3.1.3.5 Piping Liquid Release Scenarios (Aboveground and Underground)

Piping leak rates are based on small leaks, typically $^1/_8$ to $^1/_4$ inch in diameter. An operating company experience showed that 90 percent of the corrosion-related piping leaks were $^1/_8$-inch in diameter, and approximately 10 percent of the corrosion holes were $^1/_4$ inch in diameter. Corrosion holes larger than $^1/_4$ inch were unusual, although damage to piping from mechanical means or piping appurtenances sometimes resulted in non-corrosion holes of 1-inch diameter. Piping systems in this section are divided into three categories:

- Releases from pressurized piping (approximately 100 psig during pump operation)
- Releases from tank head pressurized suction piping (approximately 20 psig suction piping)
- Releases from underground gravity flow non-pressurized terminal piping (approximately 0.5 psig gravity flow piping)

When performing the analysis, the user can divide the terminal piping into the categories described above. The vast majority of the piping consequences will come from the pressurized underground piping.

Piping Leak Volume

Aboveground and Underground Pump Pressurized Piping
For aboveground and underground pump-pressurized piping systems, the piping leak volumes can be determined based on Equation A.41 using a Δh that simulates the actual pressure in the pipe. For simplicity and due to the higher pressure in the pipe, for underground piping, it is assumed that the soil provides no resistance to the release of product from the pipe. Table A.3.1.8 shows the leak rates for small pipeline leaks ($^1/_8$-inch hole size) at 100 psig. **All flange leaks are treated as small pipeline leaks.**

Table A.3.1.8: Piping Leak Rates during Pumping (100 psig)

Product	Small Leak Rate (bbl/hr)
Gasoline	6.2
Diesel oil/light fuel oil	5.7
Crude oil/heavy fuel oil	5.5

Underground Gravity and Underground Suction Piping

Tables A.3.1.9 and A.3.1.10 show the leak rates for small holes in underground suction piping and gravity flow piping, respectively. Because the pressure in suction and gravity flow piping is much less than in pump-pressurized piping, the soil resistance is accounted for in determining the piping leak rate. The empirical relationship developed by Giroud and Bonaparte is used (Equation A.40) to develop the leak rates for these piping systems; thus, the release rate is highly dependent on the soil type (hydraulic conductivity) but is only slightly dependent on the hole size. At these low pressures, the release rate from a 1-inch hole is only 50 percent greater than that for a $^{1}/_{8}$-inch hole; therefore, leak rates are standardized on the smaller hole diameters of $^{1}/_{8}$ inch.

Table A.3.1.9: Small Leak Rates for Underground Suction Piping (20 psig)

Soil Type	Leak Rate (bbl/hr) Gasoline	Leak Rate (bbl/hr) Diesel Oil Light Fuel Oil	Leak Rate (bbl/hr) Crude Oil Heavy Fuel Oil
Fine Sand	2	1	0.04
Very Fine Sand	0.2	0.06	0.004
Silt	0.01	0.006	0.0004
Sandy Clay	0.002	0.001	6×10^{-5}
Clay	0.0004	0.0002	1×10^{-5}

Table A.3.1.10: Small Leak Rates for Underground Gravity Flow Piping (0.5 psig)

Soil Type	Leak Rate (bbl/hr) Gasoline	Leak Rate (bbl/hr) Diesel Oil Light Fuel Oil	Leak Rate (bbl/hr) Crude Oil Heavy Fuel Oil
Fine Sand	0.07	0.03	0.001
Very Fine Sand	0.005	0.002	0.0001
Silt	0.0004	0.0002	1×10^{-5}
Sandy Clay	7×10^{-5}	3×10^{-5}	2×10^{-6}
Clay	1×10^{-5}	5×10^{-6}	3×10^{-7}

Aboveground Suction Piping

For aboveground suction piping systems, the piping leak volumes can be determined based on Equation A.41 using a Δh that simulates the actual pressure in the pipe. Table A.3.1.11 shows the leak rates for small holes in aboveground suction piping.

Table A.3.1.11: Leak Rates for Aboveground Suction Piping (20 psig)

Product	**Small Leak Rate (bbl/hr)**
Gasoline	2.7
Diesel oil/light fuel oil	2.6
Crude oil/heavy fuel oil	2.5

Piping Release Media Impacted
If the pipe is an underground pipe, the subsurface soil is assumed to be impacted. The potential for impacting groundwater, surface water, or other ecological receptors will depend on the soil conditions, depth to groundwater, distance to surface waters, pathway to sensitive ecological receptors, and leak detection time. The approach previously discussed for predicting a leak from a single steel floor is used to determine if some portion of the underground piping leak could reach groundwater, surface water, or other ecological receptors. For example, to determine if the release will reach the groundwater, the user must first determine the type of soil surrounding the pipe and the vertical distance to groundwater directly below the pipe. Knowing the type of soil under the pipe, the user can select an appropriate hydraulic conductivity from Figure A.3.1.5 to determine the flow velocity in feet/day of petroleum from the pipe to the receptor. The user must be careful in selecting a hydraulic conductivity because the travel time is directly proportional to the hydraulic conductivity, and hydraulic conductivities can easily vary orders of magnitude from those shown.

Again once the hydraulic conductivity is known, the downward vertical velocity in feet per day can be found from Figure A.3.1.5. The time to reach groundwater (days) is calculated by dividing the vertical distance to groundwater (feet) by the downward vertical velocity (feet/day). (It should be noted that the downward velocity model, as represented in Figure A.3.1.5, tends to be conservative, as it assumes that there is enough product being released to wet all of the soil/sand surfaces as the spill travels downward.)

With a known time to reach groundwater, the total leak time is used to determine if the groundwater is affected. If the duration of the leak is shorter than the time to reach groundwater, then the spill is assumed not to affect groundwater, as long as the leak can be stopped and release mitigation or remediation measures can be put in place to prevent or minimize impact to the groundwater. For some site-specific conditions, underground piping releases may potentially impact surface water.

A.3.1.3.6 Transfer Equipment Liquid Release Scenarios

Loading and unloading area LRSs documented in the consequence and likelihood models involve unintended releases as a result of the following sources:

- Tank truck overfills
- Transfer equipment leaks

The following subsections detail the approach for determining volume released and for estimating the possible media impacted by the release. The approach below makes the following assumptions: the loading and unloading area is limited to Department of Transportation (DOT)-approved tank trucks; and the tank truck is located within a containment area or pad or has a remote impoundment area.

A.3.1.3.6.1 Tank Truck Overfills

Volume Released
The amount of petroleum product released as the result of overfilling a tank truck is simply the fill rate multiplied by the sum of the time required to detect the overfill and the time required to shut down the fill. In general, an overfill occurs during the time the product leaves the overfill vent until the time the product stops entering the truck tank. The time required to detect and stop the overfill is a facility- and company-specific issue that relates to the configuration of the

facility, proximity of the operator, presence of high level alarms, response time, etc. For tank truck overfills, the response time is usually fast because the loading operation is normally attended. For example, a facility operator may determine that his specific response time (time between detecting a release and the time a release is shutdown) is 1 minute. If the fill rate is 420 gpm (10 bbl/min), the spill would be calculated to be V = 10 bbl/min x 1min = 10 bbl.

Table A.3.1.12 presents a distribution on tank truck overfill spill sizes based on the detailed spill records of one of the major operating companies. The average spill size is 60 gallons (1.4 bbls).

Table A.3.1.12: Tank Truck Overfill Spill Size Distribution

Spill Size (gal)	Spill Size (bbls)	Percent
< 11	< 0.25	36%
11–21	0.25 – 0.5	22%
22–42	0.5 – 1.0	13%
43–126	1.0 – 3.0	13%
127–210	3.0 – 5.0	8%
> 210	> 5.0	8%

Tank Truck Overfill Media Impacted

Based on the design of the secondary containment system and the calculated volume of the leak, an operator can determine if the release will be contained within the diked area or if surface or subsurface soils may be impacted. Tank truck overfills would not normally impact other media, but the time to remove free product should be used to determine if groundwater is impacted using the previous infiltration equations for within the dike and outside the dike, if applicable

A.3.1.3.6.2 Transfer Equipment Leaks

Transfer equipment leaks normally involve small volumes released from hoses, couplings, or pump seals. The model for small transfer equipment leaks is a $^1/_8$-inch hole.

Transfer Equipment Volume Released

Based on company operating procedures and control systems for transfer operations, the user needs to estimate the duration of small leaks and ruptures. Based on hose size and pumping pressure (and possibly past spill incidents) and the duration of the release, an estimate needs to be made for spill volumes for $^1/8$-inch leaks and ruptures.

Media Impacted by Transfer Equipment Leaks

Based on the design of the secondary containment system and the calculated volume of the leak, an operator can determine if the release will be contained within the diked area or if surface or subsurface soils may be impacted. Transfer equipment leaks that are not in contained areas or that are allowed to persist for extended periods of time have the potential to impact media other than the containment materials or surface soils. Typically, these releases will have a smaller impact on the subsurface soils or groundwater. The previous infiltration analysis can be used to determine if groundwater is impacted.

A.3.1.4 Surrounding Ecological Sensitivity

In addition to volume released and media impacted, the user needs to determine the absence or presence of relevant local ecological receptors. If a sensitive ecological receptor is present, the category of the receptor will impact the overall environmental consequences of a spill that reaches it. In addition to the category of the receptor, distance of the release from the receptor, existence of a pathway from the release to the ecologically sensitive area, the spill response capabilities, the product type, volume spilled, regulatory atmosphere, and overall duration of the impact to the ecologically sensitive areas will affect the environmental consequences. The sensitivity of the ecology (category) will impact the magnitude of the damage consequences to these areas. The sensitivity of the local ecology is defined below, and API Publication 4700 provides guidance on evaluating ecological risk at petroleum release sites. The potentially impacted ecological sensitivity addressed in the ECOF model includes the following items:

1. Close Proximity to Aquatic Habitat or Regulated Wetlands—Wetlands as defined and regulated by the state or federal authorities (Army Corps of Engineers) include tidal marshes and freshwater wetlands. Aquatic habitats include streams, rivers, lakes, and estuaries. The aquatic habitat needs to be in close proximity to the site (within 3000 feet or 915 meters) or in a location such that a specific LRS would likely impact the receptor. Receptors that are not within close proximity and that cannot be impacted by a specific LRS do not typically need to be considered.

2. Sensitive Biology, Species, or Ecologic Receptors (Critical Habitat, National Park, Wildlife Refuge)—These areas include habitats designated by a government authority as sensitive or of special interest or designated as a sanctuary, park, recreational area, refuge hatchery, or environmental management area.

3. Unusually Sensitive Biological Species (Threatened or Endangered Species)—These include environmental resources specifically designated by a government authority as an area of critical environmental concern that contains a threatened or endangered species.

In evaluating the potential impacts on a sensitive ecological receptor, the user needs to investigate the presence of completed exposure pathways to the receptor for the specific LRS. For example, a small leak contained within a diked area may be determined to have no pathway to the ecological receptor, but a release that reaches the surface waters may have a pathway to a downstream ecologically sensitive area.

A.3.2 Population Consequences of Failure

Population consequences of failure (PCOF) may result from any LRS that potentially impacts the health and safety of onsite personnel, including employees and contractors, or the offsite public. PCOFs include those exposures that may result from a fire or explosion at a facility as the result of a liquid release. This model does not cover fire and explosion consequences derived from vapor emissions that do not have a precipitating liquid release event. For example, the fire consequence from a liquid release from an underground product line, which results in the ignition of the liquid, would be covered, but the fire consequence from a lightning strike on a tank is not covered.

Population consequences include those impacts to the local facility staff and surrounding public impacted off site. Consequences are often thought of in terms of injuries or adverse impacts to the surrounding community as a result of a specific event. PCOFs are analyzed for two discrete events: (1) the exposure of an individual or groups of individuals to a direct hazard (e.g., fire or explosion); or (2) a disruption in service (e.g., loss of transportation access) as a result of a specific event occurring. These hazards include:

- Injury or death resulting from a fire or explosion immediately following the LRS
- Injury or death resulting from a physical or toxicological hazard associated with an acute exposure to a specific LRS; the user can consider the physical and toxicological hazards, such as contact with a spilled, heated product, direct immersion in spilled product, or inhalation of toxic concentrations of vapors that are Immediately Dangerous to Life and Health (IDLH)
- Nature and duration of impacts to the community associated with disruption to critical infrastructure, such as loss of transportation networks, traffic congestion, loss of recreational areas, loss of supply, etc.

This model does not directly address or reflect several PCOFs, including the following:

- The PCOF model can be used to account for acute (short-term) impacts on population from petroleum product toxicity exposure, fire radiation exposure, flash fire exposure, and overpressure (blast wave) exposure; however, the consequence model does not provide the information or guidance on the methodology(s) to predict the size, shape, and orientation of hazard zones created by a specific LRS, nor does the model establish endpoints that set identical impacts (e.g., 1 percent mortality). These model endpoints are typically obtained from published probit equations that are appropriate for each hazard being considered. It is up to the user to decide which probit equations are appropriate for the specific application.

- The model does not account for potential long-term chronic health effects from the exposure to petroleum compounds.
- The model does not predict, nor does it provide guidance on, the likelihood of a release resulting in a fire or explosion.

PCOF can be viewed on their own or in conjunction with ECOF and BCOF. PCOF look strictly at the community and health and safety implications of a particular LRS. Review of PCOF allows the user to make informed decisions on how specific events may impact the local community and onsite personnel. The major items that dictate the severity of the PCOF are:

- Volume of the spill
- Dispersion of the release
- Physical properties of the released product (flammability)
- Proximity of personnel and the public to the release

The same methodology discussed in Section A.3.1. can be used to determine the critical impacts caused by a liquid release.

A.3.2.1 Population Consequences of Failure Model Overview

The following model was developed to evaluate the PCOF associated with a specific LRS. The user answers the model questions relative to the probable PCOF associated with a particular event. The PCOF questions need to be addressed for the LRSs that will have a corresponding “likelihood” number developed during the previous analysis. The approach for analyzing individual assets or groups of assets is discussed in the main body this document in Section 8.4.

A.3.2.2 Population Consequences of Failure Model

The PCOF model approach is presented step-by-step below with italicized annotations to aid the user in understanding the meaning of the questions and the possible answers. The PCOF model forms are included in Appendix C without these annotations.

Population Consequences of Failure Model

Consequence Variable Weighting Factor for PCOF = *30%*

The user starts by assigning a user-defined weighting factor between 0% and 100% to the consequence model and determines the importance assigned to this consequence event relative to other consequences, such as environmental or business consequences. Here, the user has assigned a weighting factor of 30%.

EVENT: *Tank Overfill*_____ UNIT Operation: _____*Tank 10*_____

List the specific LRS as detailed above *Note: the Unit Operation (i.e., Tank 10)*

Question #1

1.	Anticipated Volume of Released Liquid Petroleum	Score
A	< 25 bbl (~ 1,000 gal)	1
B	25 bbl to 250 bbl	5
C	251 bbl to 2,500 bbl	10
D	2,501 bbl to 25,000 bbl	45
E	>25,001 bbl	90

ANSWER Q_1=__*5*_

The user needs to estimate the anticipated quantity of petroleum released for the specific LRS. This quantity was previously estimated in Section A.3.1. as part of the environmental consequences, Question #2. Guidance provided in Section A.3.1.3 will assist the user in developing this estimate if environmental consequences were not part of the user's consequence analysis. The volume of petroleum released, along with the type or product released (Question #2), and the dispersion of released petroleum (Question #3) are the primary predictors of the overall population consequences of a liquid release.

Question #2

2.	**Stored Product Flammability/Combustibility**	**Score**
A	Combustible liquids including motor oils, lubricants, hydraulic oils	0.5
B	Combustible liquids including #2, #1, Kero, diesel, Jet A, JP-8	1
C	Flammable liquids including most crude oils	5
D	Flammable liquids including gasoline all grades, ethanol	10

ANSWER Q_2 =__*1*_

The physical properties of the petroleum product released affect the overall population consequences for the specific LRS. This question addresses the specific effect these properties will have on consequences of a fire or explosion occurring from the release. Flammable liquids are more volatile and have a greater risk of resulting in a fire or explosion. These products will affect offsite communities if the quantity released and the dispersion mechanism are sufficient to reach offsite populations. As the product type changes from a flammable to combustible liquid, the risk of fire or explosion decreases, and therefore, the consequence decreases.

Question #3

3.	**Fire Response Capabilities (Fire Suppression or Spill Dispersant Capabilities)**	**Score**
A	Fixed fire suppression systems in place on flammable loading areas and flammable storage tanks	0.2
B	Local or portable fire suppression systems available for flammable and combustible liquids	1.0
C	No local or sufficient portable firefighting or spill dispersant capabilities on site; local response available but response time anticipated to be greater than 30 minutes	2.0

ANSWER Q_3 :___*1*__

The ability to suppress a fire or the ability to disperse a spill aids in the mitigation of the consequences of a release of petroleum. The presence of a fixed fire suppression system for flammable products provides the most credit (mitigation). The presence of a local or portable firefighting system is considered average and receives no credit. Offsite response that would take more than 30 minutes would result in worse consequences if a fire were to occur as a result of the spill.

Question #4

4.	**Health and Safety Impact to Personnel, Contractors, or the Public**	**Score**
A	No injury or near miss	1
B	Minor injury	15
C	Serious injury or fatality	100

ANSWER Q_4 :_*15*____

The user must judge whether a release for a specific LRS may result in injury to onsite personnel and contractors or the surrounding community. The type of release, the normal location of personnel during an event, the product spilled, and *the dispersion of the released product will all affect the impact on people. In general, the risk of injury from a release is related to two primary causes: proximity to the equipment when the failure occurs (e.g., physical or acute toxic exposure hazard) or fire or explosion occurring after the release. In general, short-term exposures to petroleum products do not normally represent a significant acute toxic or physical hazard.*

The normal proximity of personnel during the exposure and the type of product will dictate the extent of the physical hazards. For example, releases contained on site in normally unoccupied areas will result in a near miss or no injury to onsite personnel and the offsite community. A release from a corrosion hole in the tank bottom also does not normally represent a significant risk to onsite personnel or the public; however, a small release of a flammable product in a contained loading area from a truck overfill, pipe, or flange failure can result in a fire that causes serious injury or death to personnel normally present in this area during these operations. A tank failure that results in the release of a flammable product outside the secondary containment or into a local community could result in serious injury to the surrounding public if the liquid is ignited. The release of heated product on personnel close to the source or in a confined area can result in burns or vapor concentrations that are acutely toxic.

Question #5

5.	**Dispersion of Released Product (Area of Impact)**	**Score**
A	Release contained in an impermeable diked area	1
B	Release contained on site	5
C	Release impacts off site property (soil or groundwater)	25
D	Release impacts on recreational surface waters	50
E	Release impacts on drinking waters (surface or groundwater)	100

ANSWER Q $_5$:__*5*___

The user must determine the extent of the dispersion of the released product. If multiple media may be impacted, the resource with the highest score should be used. For example, for a release that impacts recreational surface waters and drinking water, the higher score for drinking water should be selected. The guidance provided in the environmental consequence section can be used to determine the extent of the spill dispersion. It is recommended that the most ***probable*** *extent of dispersion be used and not the possible extent. (Refer to Section A.3.1.3 for guidance on determining impacted media.)*

Question #6

6.	**Surrounding Community Impact Duration**	**Score**
A	No or negligible community impact	1
B	Short-term community impact (up to 1 week)	2
C	Medium-term community impact (up to 1 month)	5
D	Long-term community impact (> 1 month)	14

ANSWER Q $_6$:_*5*____

The impact or the potential impact to the local community as a result of the LRS will affect the overall population consequences. A protracted impact to a critical resource, such as the contamination or threat of contamination in a drinking water supply, will cause dramatic escalation in the population consequences. Community impacts that should be considered in answering the above question include: recreational resource loss of use (e.g., boating, fishing, hiking, biking); transportation loss of use (e.g., road, rail, boat transportation network closure or disruption); quality of life issues (e.g., noise, dust, odor, aesthetics); and economic issues (e.g., impact on property value, mobility, local economy). The local community impacts will affect the environmental, population, and business consequences, and they are therefore included in aspects of these other types of consequences.

Question #7

7.	Adjacent Human Use/Population Sensitive Areas	Score
A	Limited or negligible human use in the affected area	0.5
B	Light commercial/industrial	1.0
C	School, hospital, stadium, church, residential area, heavy commercial in the affected area	2.5
D	Historical, recreational, transportation, or water resource sensitive area	5

ANSWER Q_7 : _1_

Adjacent human use population sensitive areas will magnify the consequences of a release. Facilities located in remote areas will have different impacts than facilities located in heavily populated areas.

Question #8

8.	Response Plans and Response Effectiveness	Score
A	Written spill response plan, drills, and OSRO in place with ability to perform a rapid, effective response to the incident	1
B	No response plan in place or response contingency plan of limited effectiveness due to the nature of the incident	1.5

ANSWER Q_8 : _1_

The ability to anticipate, plan, and effectively respond to an incident helps to mitigate the impacts of a liquid release incident. A formal written response and contingency plan are considered to be the industry norm, and no credit is provided for having an effective response plan in place. An overall increase in the consequences is provided if there is a lack of a formal written response and contingency plan or for those incidents where the presence of a formal written response and contingency plan does not aid in the mitigation for that specific event.

$$PCOF_{\text{Score(i)}} = Q1_{\text{Volume}} \times (Q2_{\text{Product}} \times Q3_{\text{Response Capabilities}} \times Q4_{\text{Health/Safety}} + Q5_{\text{Dispersion}} \times Q6_{\text{Community}} \times Q7_{\text{Adjacent Use}}) \times Q8_{\text{Response Plans}}$$

(Equation A.45)

where (*i*) is the safety consequence score for the particular event and distinct piece of equipment.

Apply the scores from the above questions to the following equation. The PCOF score provides the consequence portion of the risk equation for safety, health, and fire hazard factors relative to this particular event (LRS) and for this particular equipment. Other appropriate events and equipment should be analyzed similarly in order to develop the complete consequence score for safety factors.

$$PCOF_{\text{Score(x)}} = \underline{5}_{\text{ Volume}} \times (\underline{1}_{\text{ Product}} \times \underline{1}_{\text{ Response Capabilities}} \times \underline{15}_{\text{ Health /Safety}} + \underline{5}_{\text{ Dispersion}} \times \underline{5}_{\text{ Community}} \times \underline{1}_{\text{ Adjacent Use}}) \times \underline{1}_{\text{ Response Plans}}$$

Total Score for Population Consequences of Failure (PCOF)x = ___*200*___

The data range of consequence values is discussed in Section A.4. The population consequences process flow diagram is illustrated in Figure A.3.2.1.

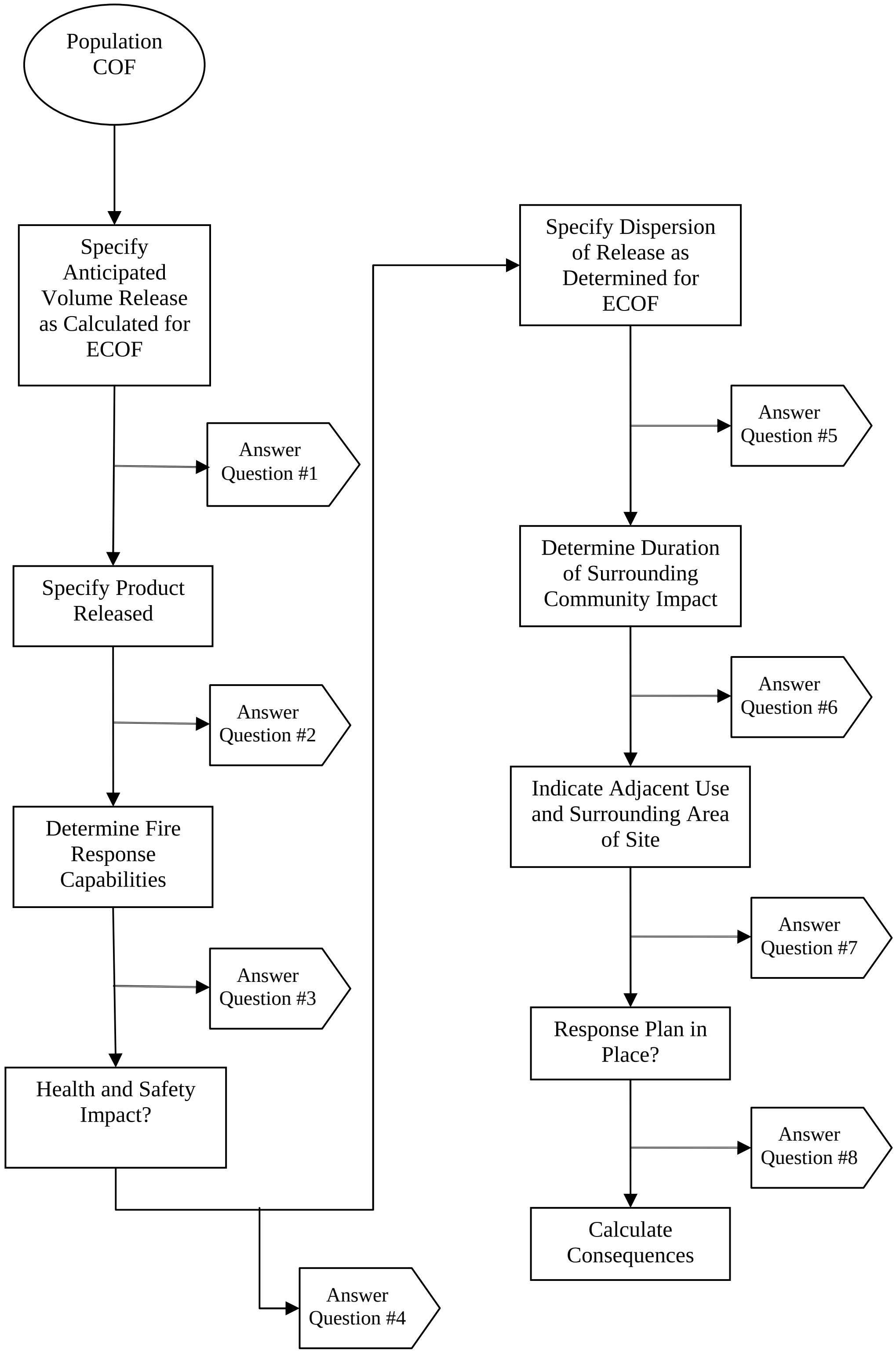


Figure A.3.2.1: Population Consequences Process Flow Diagram

A.3.3 Business Consequences of Failure

Business consequences of failure (BCOF) may result from any LRS that impacts the business operations of the facility or the company. The BCOF include those exposures that affect a facility's normal operations, expenses, maintenance, operations schedule, customer service and delivery, capital costs, loss of goodwill, community relations, regulatory and enforcement costs, and cleanup costs. The BCOF are often thought of in terms of economics (dollars and cents). These direct economic items include:

- Cost of cleanup and remediation resulting from a spill
- Equipment or facility repair, replacement, or maintenance costs
- Business interruption costs (loss of business)
- Cost of lost product
- Diminution of property or facility value
- Costs of insurance coverage for workers' compensation, environmental impairment liability, and general liability

There are a number of business consequences that do not directly reflect a "dollars and cents" analysis, including:

- Effect on company reputation or standing in the community
- Effects of adverse and prolonged media coverage
- Future insurability
- Corporate enterprise-ending events
- Distraction of corporate staff and resources
- Legal challenges
- Regulatory enforcement or new regulatory initiatives

By their very nature, BCOF are intertwined with ECOF and PCOF. The BCOF, however, look strictly at the business implications of particular events. Review of BCOF also allows the user to make informed decisions on how specific events (specific LRSs) may affect the facility and its overall operations.

The major items that dictate the severity of the BCOF are the direct costs associated with the event. The first step in determining the business consequences is to list the potential cost items associated with a specific event and assign an estimated cost to each item. These items were listed above. Analysis of BCOF is normally relegated to major LRS events or grouped assets. For example, performing a BCOF analysis on a transfer equipment leak in a low-risk environmental area is probably not a meaningful exercise.

A.3.3.1 Business Consequences of Failure Model Overview

The following model was developed to evaluate the BCOF associated with specific LRSs detailed in this appendix. The user is to answer the following questions relative to the probable BCOF associated with a particular event. The business consequence questions need to be addressed for the LRSs that will have corresponding "likelihood" numbers from the previous analysis. The approach for analyzing individual assets or groups of assets is discussed in Section 8.4 of the main text of the document. The LRS events covered by this model are presented in Table A.1.1.

A.3.3.2 Business Consequences of Failure Model

The BCOF model approach is presented step-by-step below with italicized annotations to aid the user in understanding the meaning of the questions and the possible answers. The BCOF model forms are included in Appendix C without these annotations. A form to help determine direct costs resulting from a release scenario is also included.

Business Consequence of Failure Model

Consequence Variable Weighting Factor for BCOF = *20%*

The user starts by assigning a user-defined weighting factor to the consequence model. The weighting factor is between 0% and 100% and stipulates the importance that is assigned to this consequence relative to others, such as environmental or population consequences. Here the user has assigned a weighting factor of 20%.

EVENT: *Rapid Shell Failure*_____ UNIT Operation: _____*Tank 10*____
List the specific LRS as detailed above *Note: the Unit Operation (i.e., Tank 10)*

Question #1

1.	**Estimated Cost of Loss**	**Score**
A	< $10,000	1
B	$10,000 to $100,000	5
C	$100,000 to $1,000,000	10
D	$1,000,000 to $10,000,000	25
E	> $10,000,000	49

ANSWER Q_1 :_*5*_

The estimated cost of loss question requires the user to estimate the overall financial impact of a specific LRS to the company. The estimated cost should include loss of business due to business interruption, loss of stored product, equipment repair or replacement costs, environmental costs, health and safety costs, environmental impairment loss, loss of community services cost, and possibly legal costs, fines, or damages. This number is determined by adding the cost of economic items listed in Section A.3.3.

Question #2

2.	**Impact on Facility Operation**	**Score**
A	No facility or equipment loss of service	0.1
B	Equipment out of service for < 1 month	1
C	Equipment out of service for > 1 month	1.5
D	Facility out of service for < 1 month	2.5
E	Effectively shuts down facility operation for > 1 month	5

ANSWER Q_2 :__*1*__

The loss of facility and equipment due to a specific LRS has a direct impact on tangible costs that can be captured in Question #1, but the equipment or facility outage also has implications beyond the immediate loss of business or business interruption. This question accounts for factors related to extended loss of use of equipment, such as loss of business to competitors, loss of product supply, or storage capacity.

Question #3

3.	**Effect on Company Reputation or Standing in Community**	**Score**
A	No or minimal public complaint	1
B	Local public complaints only	1.5
C	Significant local and some regional public complaints	2.5
D	Widespread national or regional public complaints	5

ANSWER Q_3 :__*1*_

A company's reputation and public image is an intangible value that has an inherent, not easily quantifiable value to the company. Significant LRSs that come to the public's attention through the media or government may result in loss of reputation or standing in the community. The basis for a company's image is the public's perception of the company's guiding principles, values, and ethics. A loss of reputation, image, or standing in the community can lead not only to a *loss in financial means (liquidity and market cap), but also to a loss of ability to carry out business plans, goals, and objectives.*

Question #4

4.	**Regulatory Involvement as a Result of the LSR**	**Score**
A	No regulatory involvement	0.5
B	Only local regulatory oversight	1
C	Local and state regulatory involvement with cleanup, inspection, or startup of the facility after the incident	2.5
D	Will most likely lead to additional enforcement at other facilities or for the industry as a whole	5

ANSWER Q $_4$:_*2.5*__

Severe events often bring additional regulatory oversight of the specific facility, other facilities owned by the company, or even industry-wide regulation. In the United States, most major regulations of the oil industry can be traced back to precipitating LRS events. Regulatory oversight often results in increased business costs that cannot be directly measured in Question #1. Regulatory involvement may require that in addition to remediation, the facility upgrade existing equipment or systems. This question adjusts the business consequences based on the user's estimate of the regulatory fallout that may occur as a result of a specific LRS. The action or intrusion of regulators into the business will be driven by the severity of the LRS, the media coverage of the event, and the public position on the need for government oversight or regulation of the cleanup, inspection, startup, and operation of the facility or other facilities owned by the company or of the industry as a whole.

Question #5

5.	**Loss of Business**	**Score**
A	No loss of business	1
B	Results in short-term loss of business (< 1 month)	1.5
C	Results in long-term loss of business (1 to 12 months)	2
D	Results in nearly permanent loss of business (>1 year)	5

ANSWER Q $_5$:__*1*__

Although Question #1 attempts to quantify the loss of business costs specifically associated with the LRS, it is difficult to fully quantify all the effects of lost business. The costs may include the immediate loss resulting from the facility or equipment being out of service; the loss resulting from customers permanently changing to other suppliers; the loss associated with missed business opportunities; or the loss to the company because of redirection of company resources and personnel to respond to the event. The user needs to estimate the length of time that the loss of business is believed to continue for a particular LRS. If the facility or major equipment is damaged such that it cannot provide a product or service for a period greater than 1 year, the loss of business is considered nearly permanent because alternate suppliers are now firmly in place. For short-term and long-term loss of business up to 12 months, the likelihood is that the company will experience some permanent loss of business, but most of the business will come back. If the facility is able to operate providing the same products to the same clients on the agreed upon schedule, no loss of business occurs.

Question #6

6.	**Media Coverage**	**Score**
A	No media coverage, local officials and response personnel only	1
B	Only local media coverage	1.5
C	Significant local and some national coverage of event	5
D	Extended local and national coverage of event	8

ANSWER Q $_6$:_*1*___

The effects of media coverage surrounding an incident can cause short-term or long-term damage to a company's reputation and could even result in the company's going out of business (enterprise-ending events). Spills of petroleum are normally viewed as failures by the company to properly manage its business, not as "an act of God" or an accident; thus, these events are often portrayed in a negative light in terms of injury, ecological damage, and community impacts. Media portrayal, as well as level and length of coverage, can lead to a host of problems for the company, including shareholder action for publicly traded companies, public distrust of the company or its brand, additional regulatory involvement in the company, and an overall degradation of public perception for the oil industry. The business consequences of a specific LRS need to account for the potential impacts of media coverage on the company.

Question #7

7.	**Effect on Property**	**Score**
A	No change in property or equipment value	1
B	Some diminishment of the property and equipment	1.5
C	Significant diminishment of the value of the facility	2

ANSWER Q_7 :__*1*__

A release of liquid petroleum product can diminish the value of a facility or property in several different ways. It can contaminate the property requiring long-term cleanup or cause damage to equipment, or a fire/explosion could destroy facility equipment and structures. Business interruption costs are typically associated with effect on property (i.e., property damage).

Question #8

8.	**Insurability and Coverage**	**Score**
A	No effect on insurance	1
B	Event fully insured but claim will affect company rating	1.5
C	Event has insurable portions but will affect future costs and coverage	2
D	Self-insured up to event costs	2.5

ANSWER Q_8 :_*1*___

Insurance plays a key role in risk management because all risk cannot be completely eliminated and companies need a means for transferring or financing risk. Insurance allows a business to manage these potential financial losses from unusual circumstances; however, the different types of insurance, policy coverage provisions, policy limits, deductibles, claims history, and the prevalence of sel- insurance make this a key business consequence area. This question addresses the availability and implications associated with insurance coverage and insurability of a specific LRS. Insurability decreases overall risk by transferring costs associated with a loss to the insurance company; however, frequent claims, loss history, and settlement costs may affect the cost to the company of this insurance and may ultimately make insurance unavailable. Conversely, those companies with large deductibles or self-insurance decrease or eliminate the benefit of insurance as a means of risk management.

The user should apply the scores from the above questions to the following equation. The BCOF score provides the consequence portion of risk for business factors relative to this particular event and for this particular equipment. Other appropriate events and equipment should be analyzed similarly in order to develop the complete consequence score for safety factors.

$$BCOF_{\text{Score(i)}} = Q1_{\text{Cost}} \times Q2_{\text{Impact on Operation}} \times Q3_{\text{Community Reputation}} \times Q4_{\text{Regulatory}} \times Q5_{\text{Loss of Business}} \times Q6_{\text{Media}} \times Q7_{\text{Effect on Property}} \times Q8_{\text{Insurability}} \quad \text{(Equation A.46)}$$

where (*i*) is the business consequence score for the particular event and distinct piece of equipment.

Apply the scores from the above questions to the following equation. The BCOF score provides the consequence portion of the risk equation for business factors relative to this particular event (LRS) and for this particular equipment. Other appropriate events and equipment should be analyzed similarly in order to develop the complete consequence score for safety factors.

BCOF $_{\text{Score(x)}}$ = *5* $_{\text{Cost}}$ x *1* $_{\text{Impact on Operation}}$ x *1* $_{\text{Community Reputation}}$ x *2.5* $_{\text{Regulatory}}$ x *1* $_{\text{Loss of Business}}$ x *1* $_{\text{Media}}$ x *1* $_{\text{Effect on Property}}$ x *1* $_{\text{Insurability}}$

Total Score for Business Consequences of Failure (BCOF)x = ___*12.5*___

Section A.4 discusses the data range of consequence values. The Business Consequences Process Flow Diagram appears in Figure A.3.3.1.

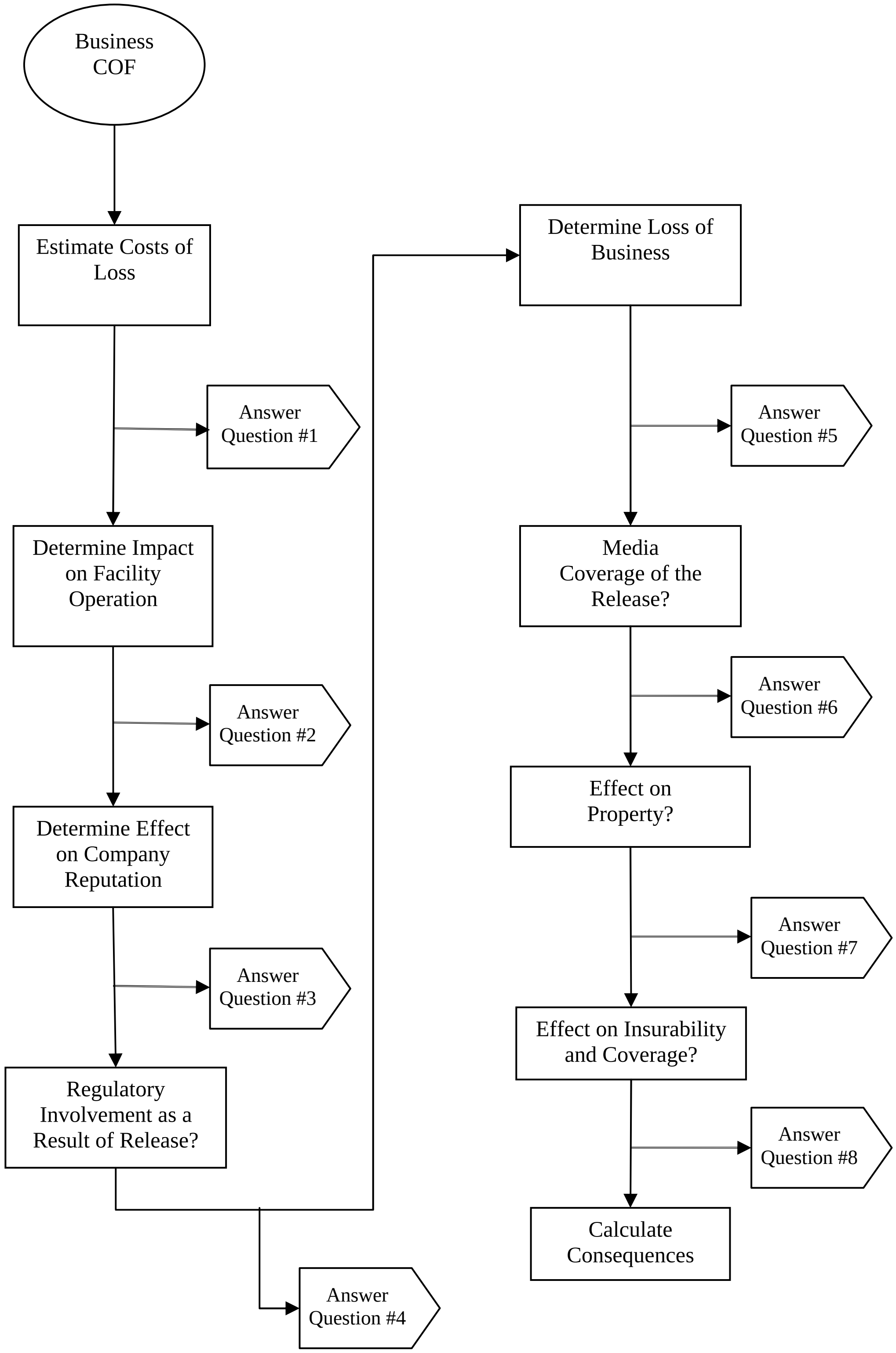


Figure A.3.3.1: Business Consequences Process Flow Diagram

A.3.4 Consequence Scoring System

The user will compute a consequence score for each LRS. The consequence score represents the total COF.

$$\text{COF}_{\text{for event (i)}} = \text{Environmental Consequences}_{\text{for event (i)}} + \text{Population Consequences}_{\text{for event (i)}} + \text{Business Consequences}_{\text{for event (i)}} \qquad \text{(Equation A.47)}$$

$$\text{COF} = (\text{WF}_{\text{Environmental}} \times \text{ECOF}) + (\text{WF}_{\text{Population}} \times \text{PCOF}) + (\text{WF}_{\text{Business}} \times \text{BCOF}) \qquad \text{(Equation A.48)}$$

For the example, the COF is:

COF = <u>0.5</u> x <u>27.5</u> + <u>0.3</u> x <u>200</u> + <u>0.2</u> x <u>12.5</u> for a total COF = <u>76.25</u>

<u>Method 1—Risk Score Approach</u>
The consequence score can then be used directly to compute a total risk score for the specific LRS from Equation A.49.

Risk = Likelihood of Failure (LOF) for LRS event (i) x Consequence of Failure (COF) for LRS event (i)

(Equation A.49)

This will provide a total numerical risk number for the specific LRS event. The risk scores for different LRSs can then be compared or ranked to establish a prioritized list of risks.

<u>Method 2—Risk Matrix Approach</u>
A risk matrix can be developed as an alternative to computing a total risk score for each specific LRS. The consequence score can then be plotted on a risk ranking matrix to determine the different risk categories. The user needs to establish the data ranges for the different risk categories. An example scoring matrix is included in Table A.3.4.1.

Table A.3.4.1: Example Consequence Scoring Matrix

Consequence Category	Consequence Score
Catastrophic	> 100,001
Severe	75,001 to 100,000
Major	50,001 to 75,000
Moderate	25,001 to 50,000
Minor	0 to 25,000

Environmental Consequences of Failure (ECOF) Result: *Minor*

A.3.5 Consequence Examples

The following examples have been developed to aid the user in understanding key concepts in the development of LRS consequences.

Example 1—Storage Tank Consequence Analysis

- AST 25,000 bbl, 30-feet tall, storing gasoline with an external floating roof
- Earthen secondary containment consisting of silt with groundwater 10 feet below ground surface
- Groundwater not used as a drinking water source
- Located in a commercial/light industrial area
- Not an ecologically sensitive area, but surface water in proximity to the site
- Restrictive regulatory atmosphere
- Written response plan in place
- Portable suppression system for firefighting

Step 1—Small Bottom Leak Consequences

<u>Determine Volume of a Small Leak from the Storage Tank Bottom.</u>

From Figure A.3.1.4, for a 30-foot product height and silty soil, the flow out of the tank bottom is approximately between $3x10^{-3}$ bbl/hr and $2x10^{-2}$ bbl/hr for an average flow of 0.0115 bbl/hr. Based on the tank foundation configuration and experience, it is assumed that a release from the tank bottom could conservatively go undetected and unmitigated for 120 days. The released volume would therefore be:

$V_{\text{tank bottom}}$ = 0.0115 bbl/hr x 120 days x 24 hrs/day
$V_{\text{tank bottom}}$ = 33 bbl

<u>Determine the Media Impacted by the Bottom Leak</u>

From Figure A.3.1.5, “Vertical Fluid Velocity,” for a silt soil with gasoline, the spill will vertically migrate 0.015 feet/day to 0.15 feet/day. If the higher vertical flow rate is conservatively assumed, the spill will migrate vertically:

$D_{\text{penetration}}$ = 0.15 ft/day x 120 days
$D_{\text{penetration}}$ = 18 ft

Because the groundwater is 10 feet below the ground surface, it is now known that the groundwater will be impacted.

The costs of the leak and resulting environmental cleanup are estimated to be $90,000.

The first consequences evaluated are the environmental consequences. The user assigns an environmental consequence variable weighting factor:

ECOF = <u>*50%*</u>

Then the user completes the questionnaire for ECOF.

EVENT<u>: *Small Bottom Release*</u>   UNIT Operation: <u>*Tank 11*</u>

Question #1

1.	Product Type	Score
A	Heavy oil (heavy crudes, #6 FO, asphalt, and motor oil)	0.5
B	Medium oil (most crudes)	0.75
C	Light oil (diesel, #2, light crudes)	1.0
D	Very light oil (gasoline and jet fuels)	1.5

ANSWER Q $_1$=__*1.5*_

Question #2

2.	Anticipated Volume of Released Liquid Petroleum	Score
A	< 25 bbl (~ 1,000 gal)	1
B	25 bbl to 250 bbl	5
C	251 bbl to 2,500 bbl	10
D	2,501 bbl to 25,000 bbl	45
E	>25,001 bbl	90

ANSWER Q $_2$=__*5*_

Question #3

3.	Primary Area Impacted by Release	Score
A	Release contained in an impermeable diked area	1
B	Release impacts onsite soils only	5
C	Release impacts offsite soils	25
D	Release impacts subsurface soils	40
E	Release impacts groundwater	60
F	Release impacts surface waters	50
G	Release impacts drinking waters (surface or groundwater)	100

ANSWER Q $_3$=__*60*_

Question #4

4.	Surrounding Ecology Sensitivity (Site Conditions)	Score
A	Not an ecologically sensitive area	1
B	Close proximity to aquatic habitats or regulated wetlands	25
C	Sensitive biological, species, or ecologic receptors	50
D	Unusually sensitive biological species	100

ANSWER Q $_4$=__*25*__

Question #5

5.	Pathway Assessment to Sensitive Ecology	Score
A	Unlikely, limited, or negligible impact to surrounding ecology	0.5
B	Likely impact to surrounding ecology	2

ANSWER Q $_5$ =___*0.5*__

Question #6

6.	Environmental Regulatory Atmosphere	Score
A	Low regulatory environment	0.5
B	Moderate regulatory environment	1
C	Restrictive regulatory and enforcement environment	2

ANSWER Q_6=___*2*__

Question #7

7.	Duration of Environmental Impact (Ecology or Surrounding Offsite Environment)	Score
A	No or negligible impact	0.5
B	Short-term impact up to 1 week	1
C	Moderate impact up to 1 month	5
D	Long-term impact > 1 month	10

ANSWER Q_7= ___*10*__

Question #8

8.	Response Plans and Response Effectiveness	Score
A	Written spill response plan, drills, and OSRO in place with ability to perform a rapid effective response to the incident	1
B	No response plan in place or response contingency plan of limited effectiveness due to the nature of the incident	1.5

ANSWER Q_8 = __*1*___

ECOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = Q1 $_{\text{Product}}$ x Q2 $_{\text{Volume}}$ x (Q3 $_{\text{Media}}$ + Q4 $_{\text{Ecology}}$ x Q5 $_{\text{Pathway}}$) x Q6 $_{\text{Regulatory}}$ x Q7 $_{\text{Duration}}$ x Q8 $_{\text{Response}}$

ECOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = *1.5*__ $_{\text{Product}}$ x *5* $_{\text{Vol}}$ x (*60* $_{\text{Media}}$ + *25* $_{\text{Ecology}}$ x _*0.5*_ $_{\text{Pathway}}$) x _*2.0*__ $_{\text{Regulatory}}$ x __*10*__ $_{\text{Duration}}$ x __*1*__ $_{\text{Response}}$

ECOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = ____*10875*___

Next, the user assigns a population consequence variable weighting factor:

PCOF = *30%*

Then the user completes the questionnaire for PCOF.

EVENT: *Small Bottom Release* UNIT Operation: *Tank 11*

Question #1

1.	Anticipated Volume of Released Liquid Petroleum	Score
A	< 25 bbl (~ 1,000 gal)	1
B	25 bbl to 250 bbl	5
C	251 bbl to 2,500 bbl	10
D	2,501 bbl to 25,000 bbl	45
E	>25,001 bbl	90

ANSWER Q_1=__*5*_

Question #2

2.	**Stored Product Flammability/Combustibility**	**Score**
A	Combustible liquids including motor oils, lubricants, hydraulic oils	0.5
B	Combustible liquids including #2, #1, Kero, diesel, Jet A, JP-8	1
C	Flammable liquids including most crude oils	5
D	Flammable liquids including gasoline all grades, ethanol	10

ANSWER Q_2 =__*10*__

Question #3

3.	**Fire Response Capabilities (Fire Suppression or Spill Dispersant Capabilities)**	**Score**
A	Fixed fire suppression systems in place on flammable loading areas and flammable storage tanks	0.2
B	Local or portable fire suppression systems available for flammable and combustible liquids	1.0
C	No local or sufficient portable firefighting or spill dispersant capabilities on site; local response available but response time anticipated to be greater than 30 minutes	2.0

ANSWER Q_3 :____*1*__

Question #4

4.	**Health and Safety Impact to Personnel, Contractors, or the Public**	**Score**
A	No injury or near miss	1
B	Minor injury	15
C	Serious injury or fatality	100

ANSWER Q_4 :_*1*__

Question #5

5.	**Dispersion of Released Product (Area of Impact)**	**Score**
A	Release contained in an impermeable diked area	1
B	Release contained on site	5
C	Release impacts off site property	25
D	Release impacts recreational surface waters	50
E	Release impacts drinking waters (surface or groundwater)	100

ANSWER Q_5 :___*5*__

Question #6

6.	**Surrounding Community Impact Duration**	**Score**
A	No or negligible community impact	1
B	Short-term community impact up to 1 week	2
C	Medium-term community impact up to 1 month	5
D	Long-term community impact > 1 month	14

ANSWER Q_6 :_*1*__

Question #7

7.	Adjacent Human Use/Population Sensitive Areas	Score
A	Limited or negligible human use in the affected area	0.5
B	Light commercial/industrial	1.0
C	School, hospital, stadium, church, residential area, heavy commercial in the affected area	2.5
D	Historical, recreational, transportation, or water resource sensitive area	5

ANSWER Q $_7$:_*1*__

Question #8

8.	Response Plans and Response Effectiveness	Score
A	Written spill response plan, drills, and OSRO in place with ability to perform a rapid effective response to the incident	1
B	No response plan in place or response contingency plan of limited effectiveness due to the nature of the incident	1.5

ANSWER Q $_8$:_*1*___

PCOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = Q1 $_{\text{Volume}}$ x (Q2 $_{\text{Product}}$ x Q3 $_{\text{Response Capabilities}}$ x Q4 $_{\text{Health /Safety}}$ + Q5 $_{\text{Dispersion}}$ x Q6 $_{\text{Community}}$ x Q7 $_{\text{Adjacent Use}}$) x Q8 $_{\text{Response Plans}}$

PCOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = *5* $_{\text{Volume}}$ x (10 $_{\text{Product}}$ x 1 $_{\text{Response Capabilities}}$ x 1 $_{\text{Health /Safety}}$ + 5 $_{\text{Dispersion}}$ x 1 $_{\text{Community}}$ x 1 $_{\text{Adjacent Use}}$) x 1 $_{\text{Response Plans}}$

PCOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = ____*75*____

Finally, the user assigns a business consequence variable weighting factor:

BCOF = *20%*

Then the user completes the questionnaire for BCOF.

EVENT: *Small Bottom Release* UNIT Operation: *Tank 11*

Question #1

1.	Estimated Cost of Loss	Score
A	< $10,000	1
B	$10,000 to $100,000	5
C	$100,000 to $1,000,000	10
D	$1,000,000 to $10,000,000	25
E	> $10,000,000	49

ANSWER Q $_1$:_*5*__

Question #2

2.	Impact on Facility Operation	Score
A	No facility or equipment loss of service	0.1
B	Equipment out of service for < 1 month	1
C	Equipment out of service for > 1 month	1.5
D	Facility out of service for < 1 month	2.5
E	Effectively shuts down facility operation for > 1 month	5

ANSWER Q $_2$: __*1*__

Question #3

3.	Effect on Company Reputation or Standing in Community	Score
A	No or minimal public complaint	1
B	Only local public complaints	1.5
C	Significant local and some regional public complaints	2.5
D	Widespread national or regional public complaints	5

ANSWER Q $_3$: __*1*_

Question #4

4.	Regulatory Involvement as a Result of the LSR	Score
A	No regulatory involvement	0.5
B	Only local regulatory oversight	1
C	Local and state regulatory involvement with cleanup, inspection, or startup of the facility after the incident	2.5
D	Will most likely lead to additional enforcement at other facilities or for the industry as a whole	5

ANSWER Q $_4$: _*1*__

Question #5

5.	Loss of Business	Score
A	No loss of business	1
B	Results in short-term loss of business (< 1 month)	1.5
C	Results in long-term loss of business (1 to 12 months)	2
D	Results in nearly permanent loss of business (>1 year)	5

ANSWER Q $_5$: _*1*__

Question #6

6.	Media Coverage	Score
A	No media coverage, local officials and response personnel only	1
B	Only local media coverage	1.5
C	Significant local and some national coverage of event	5
D	Extended local and national coverage of event	8

ANSWER Q $_6$: _*1*__

Question #7

7.	Effect on Property	Score
A	No change in property or equipment value	1
B	Some diminishment of the property and equipment	1.5
C	Significant diminishment of the value of the facility	2

ANSWER Q $_7$: __*1*__

Question #8

8.	Insurability and Coverage	Score
A	No effect on insurance	1
B	Event fully insured but claim will affect company rating	1.5
C	Event has insurable portions but will affect future costs and coverage	2
D	Self-insured up to event costs	2.5

ANSWER Q_8 : *1*

BCOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = Q1 $_{\text{Cost}}$ x Q2 $_{\text{Impact on Operation}}$ x Q3 $_{\text{Community Reputation}}$ x Q4 $_{\text{Regulatory}}$ x Q5 $_{\text{Loss of Business}}$ x Q6 $_{\text{Media}}$ x Q7 $_{\text{Effect on Property}}$ x Q8 $_{\text{Insurability}}$

BCOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = 5 $_{\text{Cost}}$ x 1 $_{\text{Impact on Operation}}$ x 1 $_{\text{Community Reputation}}$ x 1 $_{\text{Regulatory}}$ x 1 $_{\text{Loss of Business}}$ x 1 $_{\text{Media}}$ x 1 $_{\text{Effect on Property}}$ x 1 $_{\text{Insurability}}$

BCOF $_{\text{Score(for Tank 11 Small Bottom Leak)}}$ = *5*

The total COF is then calculated:

COF $_{\text{Tank 11 Small Bottom Leak}}$ = (WF $_{\text{Environmental}}$ x ECOF)+(WF $_{\text{Population}}$ x PCOF)+(WF $_{\text{Business}}$ x BCOF)

COF $_{\text{Tank 11 Small Bottom Leak}}$ = (0.5 x 10,875) + (0.3 x 75) + (0.2 x 5) = 5461

Step 2—Tank Rapid Bottom Failure

Determine Volume of a Rapid Bottom Failure

The released volume would be the entire tank safe fill contents:

$V_{\text{tank rapid bottom failure}}$ = 25,000 bbl

Determine the Media Impacted by the Bottom Failure

Because the secondary containment soil has moderately low permeability, the spill will not vertically migrate very far in a short period of time (0.15 feet/day from the previous analysis). It is assumed the failure will be detected quickly, so impact to the groundwater below the dike is not believed to be an issue. The rapid bottom failure will result in some percentage of the release going over the dikes. A total of 20 percent of the release is estimated to go over the dikes based on the ratio of the volume of the tank to the volume of the dike. Because the release goes beyond the secondary containment, it will impact the surface water, but it is assumed that the cleanup will occur quickly enough that groundwater outside of the dike will not be impacted. Although the facility is not located in an ecologically sensitive area, it is assumed that an offsite ecological receptor (surface water) will be impacted. The water body is not used for recreational activities nor as a drinking water source.

The cost of the leak and resulting environmental cleanup is estimated to be between \$250,000 and \$300,000.

The COF analysis is completed as follows:

EVENT: *Rapid Bottom Release*　　UNIT Operation: *Tank 11*

ECOF = *50%*

Question #1

1.	Product Type	Score
A	Heavy oil (heavy crudes, #6 FO, asphalt, and motor oil)	0.5
B	Medium oil (most crudes)	0.75
C	Light oil (diesel, #2, light crudes)	1.0
D	Very light oil (gasoline and jet fuels)	1.5

ANSWER Q_1=__*1.5*_

Question #2

2.	Anticipated Volume of Released Liquid Petroleum	Score
A	< 25 bbl (~ 1,000 gal)	1
B	25 bbl to 250 bbl	5
C	251 bbl to 2,500 bbl	10
D	2,501 bbl to 25,000 bbl	45
E	>25,001 bbl	90

ANSWER Q_2 =__*45*_

Question #3

3.	Primary Area Impacted by Release	Score
A	Release contained in an impermeable diked area	1
B	Release impacts onsite soils only	5
C	Release impacts offsite soils	25
D	Release impacts subsurface soils	40
E	Release impacts groundwater	60
F	Release impacts surface waters	50
G	Release impacts drinking waters (surface or groundwater)	100

ANSWER Q_3=__*50*_

Question #4

4.	Surrounding Ecology Sensitivity (Site Conditions)	Score
A	Not an ecologically sensitive area	1
B	Close proximity to aquatic habitats or regulated wetlands	25
C	Sensitive biological, species, or ecologic receptors	50
D	Unusually sensitive biological species	100

ANSWER Q_4=__*1*__

Question #5

5.	Pathway Assessment to Sensitive Ecology	Score
A	Unlikely, limited, or negligible impact to surrounding ecology	0.5
B	Likely impact to surrounding ecology	2

ANSWER Q_5 =___*2*__

Question #6

6.	Environmental Regulatory Atmosphere	Score
A	Low regulatory environment	0.5
B	Moderate regulatory environment	1
C	Restrictive regulatory and enforcement environment	2

ANSWER Q_6=___*2*__

Question #7

7.	**Duration of Environmental Impact (Ecology or Surrounding Offsite Environment)**	**Score**
A	No or negligible impact	0.5
B	Short-term impact up to 1 week	1
C	Moderate impact up to 1 month	5
D	Long-term impact > 1 month	10

ANSWER Q_7= ___5__

Question #8

8.	**Response Plans and Response Effectiveness**	**Score**
A	Written spill response plan, drills, and OSRO in place with ability to perform a rapid effective response to the incident	1
B	No response plan in place or response contingency plan of limited effectiveness due to the nature of the incident	1.5

ANSWER Q_8 = __1___

$ECOF_{\text{Score(for Tank 11 Rapid Bottom Failure)}} = Q1_{\text{Product}} \times Q2_{\text{Volume}} \times (Q3_{\text{Media}} + Q4_{\text{Ecology}} \times Q5_{\text{Pathway}}) \times Q6_{\text{Regulatory}} \times Q7_{\text{Duration}} \times Q8_{\text{Response}}$

$ECOF_{\text{Score(for Tank 11 Rapid Bottom Failure)}} = \underline{1.5}_{\text{ Product}} \times \underline{45}_{\text{ Vol}} \times (\underline{50}_{\text{ Media}} + \underline{1}_{\text{ Ecology}} \times \underline{2}_{\text{ Pathway}}) \times \underline{2}_{\text{ Regulatory}} \times \underline{5}_{\text{ Duration}} \times \underline{1}_{\text{ Response}}$

$ECOF_{\text{Score(for Tank 11 Small Bottom Leak)}} =$ ____35,100____

PCOF = _30%_

Question #1

1.	**Anticipated Volume of Released Liquid Petroleum**	**Score**
A	< 25 bbl (~ 1,000 gal)	1
B	25 bbl to 250 bbl	5
C	251 bbl to 2,500 bbl	10
D	2,501 bbl to 25,000 bbl	45
E	>25,001 bbl	90

ANSWER Q_1=__45_

Question #2

2.	**Stored Product Flammability/Combustibility**	**Score**
A	Combustible liquids including motor oils, lubricants, hydraulic oils	0.5
B	Combustible liquids including #2, #1, Kero, diesel, Jet A, JP-8	1
C	Flammable liquids including most crude oils	5
D	Flammable liquids including gasoline all grades, ethanol	10

ANSWER Q_2 =__10_

Question #3

3.	**Fire Response Capabilities (Fire Suppression or Spill Dispersant Capabilities)**	**Score**
A	Fixed fire suppression systems in place on flammable loading areas and flammable storage tanks	0.2
B	Local or portable fire suppression systems available for flammable and combustible liquids	1.0
C	No local or sufficient portable firefighting or spill dispersant capabilities on site; local response available but response time anticipated to be greater than 30 minutes	2.0

ANSWER Q $_3$:__*1*__

Question #4

4.	**Health and Safety Impact to Personnel, Contractors, or the Public:**	**Score**
A	No injury or near miss	1
B	Minor injury	15
C	Serious injury or fatality	100

ANSWER Q $_4$:_*1*__

Question #5

5.	**Dispersion of Released Product (Area of Impact)**	**Score**
A	Release contained in an impermeable diked area	1
B	Release contained on site	5
C	Release impacts off site property	25
D	Release impacts recreational surface waters	50
E	Release impacts drinking waters (surface or groundwater)	100

ANSWER Q $_5$:__*25*__

Question #6

6.	**Surrounding Community Impact Duration**	**Score**
A	No or negligible community impact	1
B	Short-term community impact up to 1 week	2
C	Medium-term community impact up to 1 month	5
D	Long-term community impact > 1 month	14

ANSWER Q $_6$:_*5*__

Question #7

7.	**Adjacent Human Use/Population Sensitive Areas**	**Score**
A	Limited or negligible human use in the affected area	0.5
B	Light commercial/industrial	1
C	School, hospital, stadium, church, residential area, heavy commercial in the affected area	2.5
D	Historical, recreational, transportation, or water resource sensitive area	5

ANSWER Q $_7$:_*1*__

Question #8

8.	Response Plans and Response Effectiveness	Score
A	Written spill response plan, drills, and OSRO in place with ability to perform a rapid effective response to the incident	1
B	No response plan in place, or response contingency plan of limited effectiveness due to the nature of the incident	1.5

ANSWER Q_8 : *1*

PCOF $_{\text{Score(for Tank 11 Rapid Bottom Failure)}}$ = Q1 $_{\text{Volume}}$ x (Q2 $_{\text{Product}}$ x Q3 $_{\text{Response Capabilities}}$ x Q4 $_{\text{Health /Safety}}$ + Q5 $_{\text{Dispersion}}$ x Q6 $_{\text{Community}}$ x Q7 $_{\text{Adjacent Use}}$) x Q8 $_{\text{Response Plans}}$

PCOF $_{\text{Score(for Tank 11 Rapid Bottom Failure)}}$ = *45* $_{\text{Volume}}$ x (*10* $_{\text{Product}}$ x *1* $_{\text{Response Capabilities}}$ x *1* $_{\text{Health /Safety}}$ + *25* $_{\text{Dispersion}}$ x *5* $_{\text{Community}}$ x *1* $_{\text{Adjacent Use}}$) x *1* $_{\text{Response Plans}}$

PCOF $_{\text{Score(for Tank 11 Rapid Bottom Failure)}}$ = *6075*

BCOF = *20%*

Question #1

1.	Estimated Cost of Loss	Score
A	< $10,000	1
B	$10,000 to $100,000	5
C	$100,000 to $1,000,000	10
D	$1,000,000 to $10,000,000	25
E	> $10,000,000	49

ANSWER Q_1 : *10*

Question #2

2.	Impact on Facility Operation	Score
A	No facility or equipment loss of service	0.1
B	Equipment out of service for < 1 month	1
C	Equipment out of service for > 1 month	1.5
D	Facility out of service for < 1 month	2.5
E	Effectively shuts down facility operation for > 1 month	5

ANSWER Q_2 : *1.5*

Question #3

3.	Effect on Company Reputation or Standing in Community	Score
A	No or minimal public complaint	1
B	Only local public complaints	1.5
C	Significant local and some regional public complaints	2.5
D	Widespread national or regional public complaints	5

ANSWER Q_3 : *1.5*

Question #4

4.	Regulatory Involvement as a Result of the LSR	Score
A	No regulatory involvement	0.5
B	Local regulatory oversight only	1
C	Local and state regulatory involvement with cleanup, inspection, or startup of the facility after the incident	2.5
D	Will most likely lead to additional enforcement at other facilities or for the industry as a whole.	5

ANSWER Q_4 : _*2.5*__

Question #5

5.	Loss of Business	Score
A	No loss of business	1
B	Results in short-term loss of business (< 1 month)	1.5
C	Results in long-term loss of business (1 to 12 months)	2
D	Results in nearly permanent loss of business (>1 year)	5

ANSWER Q_5 : _*1.5*__

Question #6

6.	Media Coverage	Score
A	No media coverage, local officials and response personnel only	1
B	Only local media coverage	1.5
C	Significant local and some national coverage of event	5
D	Extended local and national coverage of event	8

ANSWER Q_6 : _*1.5*__

Question #7

7.	Effect on Property	Score
A	No change in property or equipment value	1
B	Some diminishment of the property and equipment	1.5
C	Significant diminishment of the value of the facility	2

ANSWER Q_7 : __*1*__

Question #8

8.	Insurability and Coverage	Score
A	No effect on insurance	1
B	Event fully insured but claim will affect company rating	1.5
C	Event has insurable portions but will affect future costs and coverage	2
D	Self-insured up to event costs	2.5

ANSWER Q_8 : _*1.5*___

BCOF $_{\text{Score(for Tank 11 Rapid Bottom Failure)}}$ = Q1 $_{\text{Cost}}$ x Q2 $_{\text{Impact on Operation}}$ x Q3 $_{\text{Community Reputation}}$ x Q4 $_{\text{Regulatory}}$ x Q5 $_{\text{Loss of Business}}$ x Q6 $_{\text{Media}}$ x Q7 $_{\text{Effect on Property}}$ x Q8 $_{\text{Insurability}}$

BCOF $_{\text{Score(for Tank 11 Rapid Bottom Failure)}}$ = *10* $_{\text{Cost}}$ x *1.5* $_{\text{Impact on Operation}}$ x *1.5* $_{\text{Community Reputation}}$ x *2.5* $_{\text{Regulatory}}$ x *1.5* $_{\text{Loss of Business}}$ x *1.5* $_{\text{Media}}$ x *1* $_{\text{Effect on Property}}$ x *1.5* $_{\text{Insurability}}$

BCOF $_{\text{Score(for Tank 11 Rapid Bottom Failure)}}$ = ____190___

The total COF is then calculated:

$COF_{\text{Tank 11 Rapid Bottom Failure}}$ = ($WF_{\text{Environmental}}$ x ECOF)+($WF_{\text{Population}}$ x PCOF)+(WF_{Business} x BCOF)

$COF_{\text{Tank 11 Rapid Bottom Failure}}$ = (*0.5* x *35,100*) + (*0.3* x *6075*) + (*0.2* x *190*) = *19,411*

The user would continue by evaluating a small shell leak, as well as leaks from overfill, fittings leaks, etc.

Evaluation of Risk

Once the COF for each scenario are calculated, they can be combined with the previously determined LOF and the overall risk can be calculated. Using the LOF from Example 2 of the tank examples in Section A.2.8.4, the leak frequencies for the tank bottom are as follows:

Leak Frequencies for Tank Bottom

Leak Type	Frequency (per year)
Small Bottom Leak	7.2×10^{-7}
Rapid Bottom Failure	4.0×10^{-6}
Total	4.7×10^{-6}

A risk score is calculated from Equation A.49:

$Risk_{\text{Tank 11 Small Bottom Leak}} = LOF_{\text{Tank 11 Small Bottom Leak}} \text{ x } COF_{\text{Tank 11 Small Bottom Leak}}$
$= 7.2 \times 10^{-7}$ x 5461 = 0.0039

$Risk_{\text{Tank 11 Rapid Bottom Failure}} = LOF_{\text{Tank 11 Rapid Bottom Failure}} \text{ x } COF_{\text{Tank 11 Rapid Bottom Failure}}$
$= 4.0 \times 10^{-6}$ x 19,411 = 0.0776

A.4 Normalization of Risk Data

For the Appendix A risk assessment method, the likelihood and consequence values will fall into the following general data ranges:

Likelihood 0.01 to 0.0000001
Consequences 0 to 1,200,000

It should be noted that the consequence value can never be zero, but only close to zero. The data ranges were developed such that likelihood values would have values up to seven orders of magnitude to the right of the decimal place. Similarly, the consequence values were selected to have up to seven orders of magnitude to the left of the decimal place. The reason behind this development was twofold. The data ranges are more meaningful in a logarithmic analysis (comparing relative risk in orders of magnitude), and the product of the likelihood and consequences would yield a result of less than1.0. So that the user does not have to deal with the large span of numbers in the above data range, the following data normalization method may be employed. The approach allows a rationalization or normalization of the data with loss of perceived accuracy or precision. The analysis of risk in the risk assessment is to develop a metric which allows the user to weigh relative risks, rank different risks, and determine the improvement in risk after mitigation. Therefore, there is no loss in the analysis if the data are normalized to begin with.

The users may elect to work with the raw data values, or they may choose to normalize the data range into categories between zero (0) and one (1). Normalization of the data provides the user with an easier method for comparing different risk scenarios, easier plotting of the data, and a more transparent understanding of what the value really means. The user may determine the product of the two data points or easily plot the data in a matrix. The user may choose whether to utilize the actual data values or the normalized data, and the choice will not affect the outcome or accuracy of the approach.

Normalization of the data still allows the user to determine risk as the product of likelihood and consequences or to plot the normalized data on a risk matrix. The normalized data ranges are presented below for the likelihood and consequence values which would be determined using the approach in this appendix.

Table A.4.1: Normalized Data Values for Likelihood

Calculated Likelihood Value	**Normalized Value**
<0.00001	0.1
0.00001 to 0.0001	0.3
0.0001 to 0.001	0.5
0.001 to 0.01	0.7
>0.01	0.9

Table A.4.2: Normalized Data Values for Consequences

Consequence Value	**Normalized Value**
<250,000	0.1
250,000 to 500,000	0.3
500,000 to 750,000	0.5
750,000 to 1,000,000	0.7
>1,000,000	0.9

For example, if the user calculated a likelihood of 0.00005, then the normalized value, from Table A.4.1, would be 0.3. If the user calculated a consequence value of 650,000, then from Table A.4.2, the normalized value would be 0.5. The user can then plot these two values on a risk matrix or determine the total risk for this release scenario by multiplying the product of 0.3 times 0.5 for a normalized risk value of 0.15.

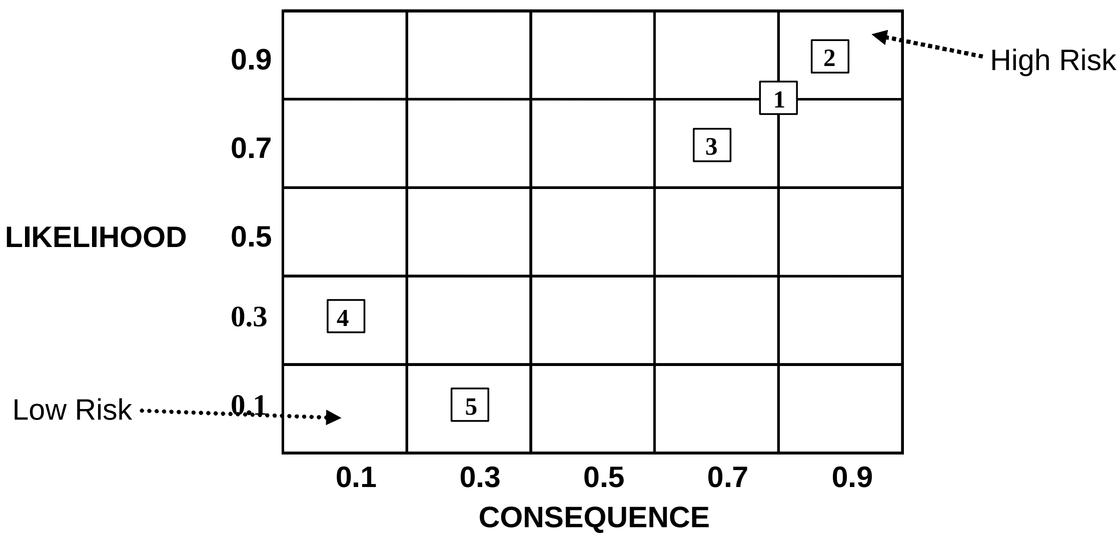
To determine the risk associated with each of the remaining likelihood and consequence numbers, the user repeats the process of assigning a likelihood number (between 0.1 and 0.9) and assigning a consequence number (again between 0.1 and 0.9). The product of these two numbers will yield a data range of risks between 0.01 and 0.81, with 0.01 considered an extremely low-risk event and 0.9 an extremely high-risk event. The user can decide whether to view risk as a product of the two numbers or as a plot on a risk matrix. The establishment of this data range allows the user to view the risks of each scenario either way. It is up to the user to develop criteria for determining the acceptability of the risk(s).

Approach 1 compares the total risk for each event and ranks the risks from highest to lowest. The user defines what risk score is unacceptable and requires further review or mitigation, as shown in the example.

Liquid Release Scenario	Risk Score	Risk Ranking Priority
Event #1	0.63	2
Event #2	0.81	1
Event #3	0.49	3
Event #4	0.03	4
Event #5	0.03	4

In Approach 2, the user plots the risk score individually for consequences and likelihood on a matrix. The user defines where on the matrix the low-, medium-, and high-risk cutoffs are located on the matrix.

NORMALIZED RISK MATRIX APPROACH



For further discussion of the risk scoring and risk matrix system, refer to Sections 6.7.2 and 6.7.3 of the main text of this document.

For the risks determined by the user to require further evaluation or establishment of a risk mitigation strategy, the same approach can be used in the evaluation and selection of mitigation measures.

A.5 Comprehensive Risk Method I Examples

The following examples have been developed to aid the user in applying the overall risk method. The examples illustrate the development and approaches available when applying the risk methodology detailed in this appendix.

The example below[1] illustrates how to compare relative risks of failure for aboveground storage tanks at a specific facility. The tank risks compared in this example are the total relative risk score for the following items:

- Tank bottom failure
- Tank shell failure

- Tank overfill failure
- Tank external floating roof hose failure

The facility is composed of 24 steel ASTs with external floating roofs. The illustration begins with the computed relative risk score for bottom failure of each of the 24 tanks. The relative risk score of tank bottom failure (rapid bottom failure + bottom corrosion failure) for each AST is illustrated in Figure A.5.1.

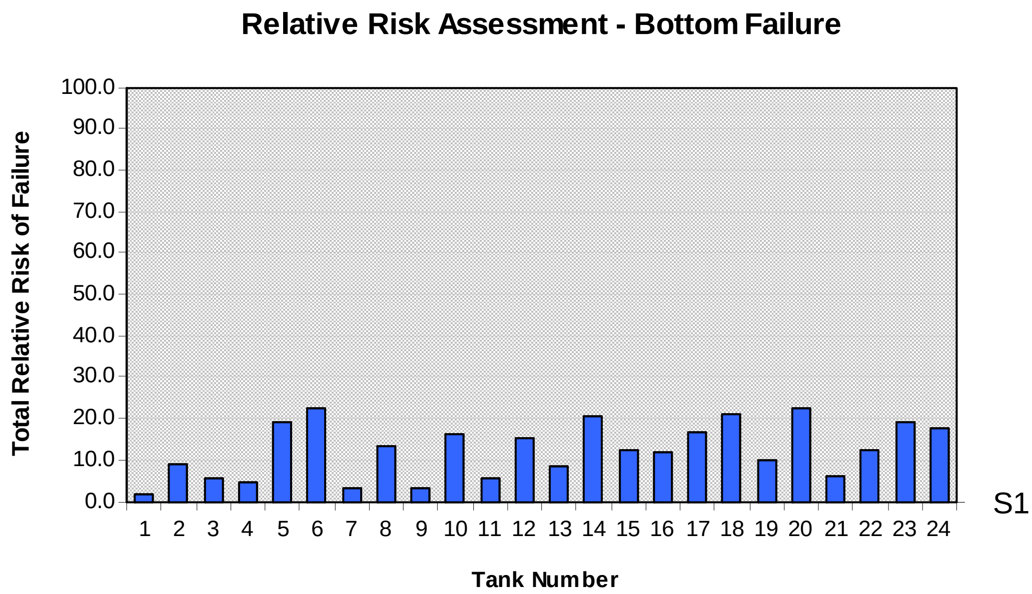


Figure A.5.1: Relative Risk Assessment—Bottom Failure

The example next looks at the computed relative risk score for tank shell failure for each of the 24 ASTs. The relative risk score of tank shell failure (rapid shell failure + shell corrosion failure) for each tank is illustrated in Figure A.5.2.

[1] For reference information regarding this example, contact SPEC Consulting, LLC in Albany, NY.

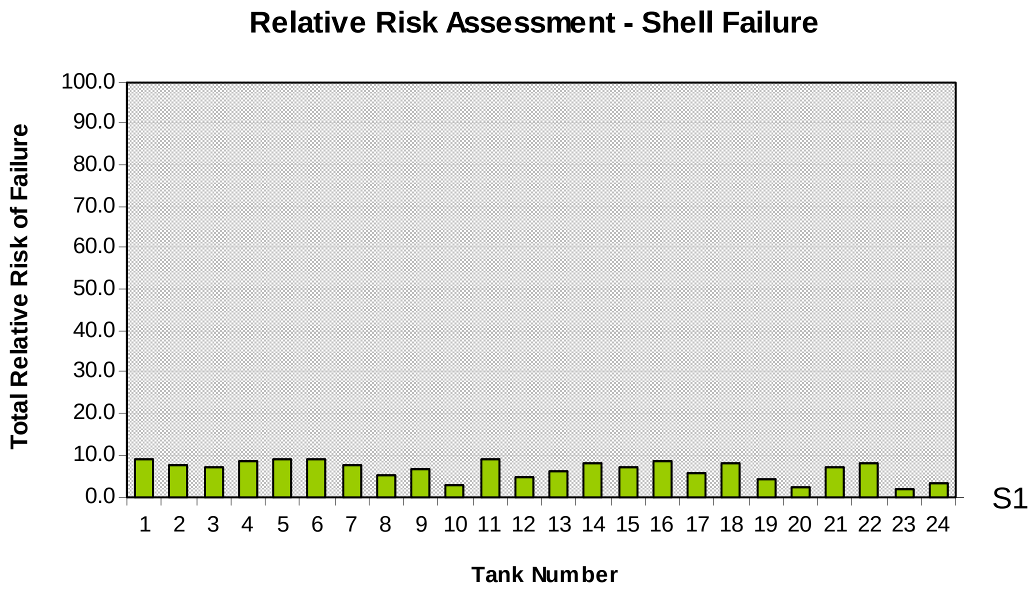


Figure A.5.2: Relative Risk Assessment—Shell Failure

The example then examines the computed relative risk score for a tank overfill for each of the 24 ASTs. The relative risk score of a tank overfill for each tank is illustrated in Figure A.5.3.

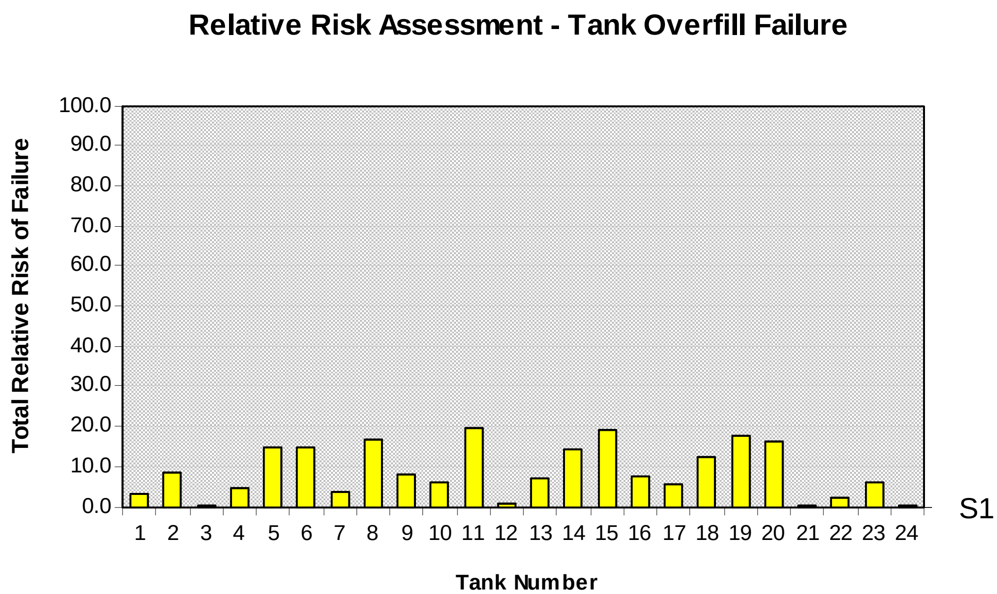


Figure A.5.3: Relative Risk Assessment—Tank Overfill Failure

The example looks last at the computed relative risk score for tank external floating roof drain failure for each of the 24 ASTs. The relative risk score of external tank roof hose failure for each tank is illustrated in Figure A.5.4.

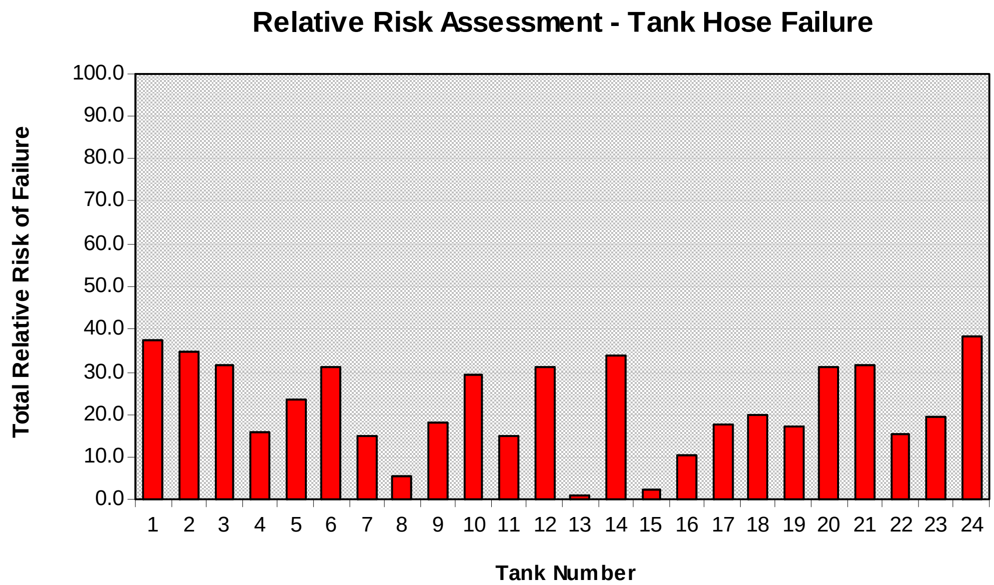


Figure A.5.4: Relative Risk Assessment—Tank Hose Failure

The risk score for each AST at the terminal can now be combined into a total risk score that is illustrated as a stacked bar chart in Figure A.5.5. The total risk score illustrates the combined relative risk of bottom failure, shell failure, overfill failure, and external floating roof hose failure for each tank at the facility.

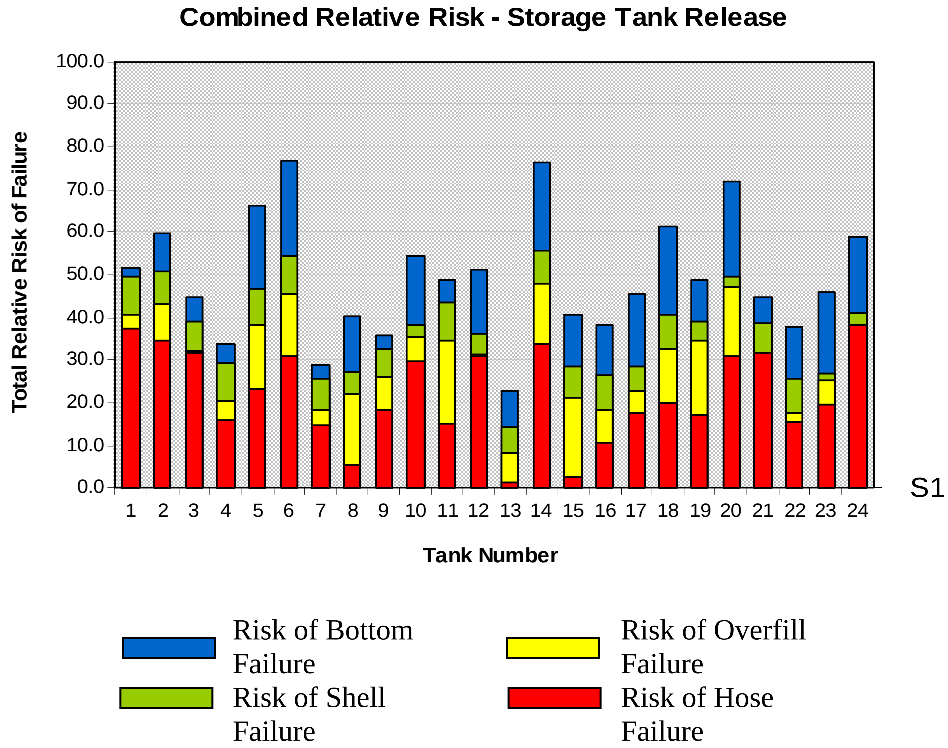


Figure A.5.5: Combined Relative Risk—Storage Tank Release

The data can be further sorted to illustrate the ranked risks from highest to lowest, as in Figure A.5.6. This illustration clearly shows which tanks have the highest relative risk of failure. Tank 6, for example, has the highest overall risk score, while Tank 13 has the lowest risk score.

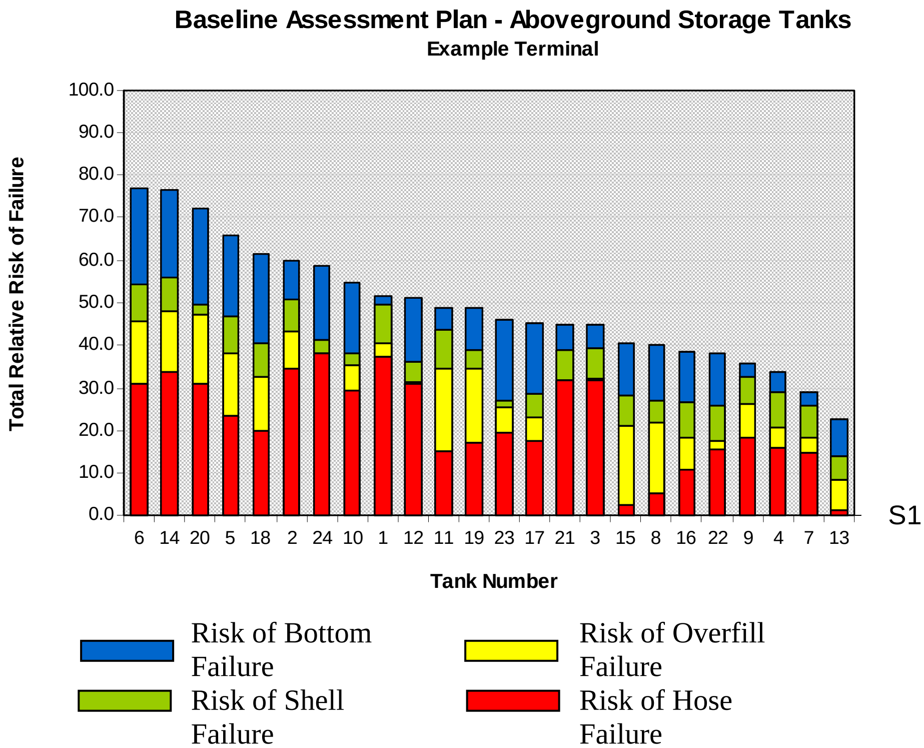


Figure A.5.6: Baseline Assessment Plan for ASTs

The same tank risk assessment data can be evaluated in a risk matrix, as in Figure A.5.7. The data were plotted in the matrix with consequences of failure plotted on the vertical axis and the likelihood of failure plotted on the horizontal axis.

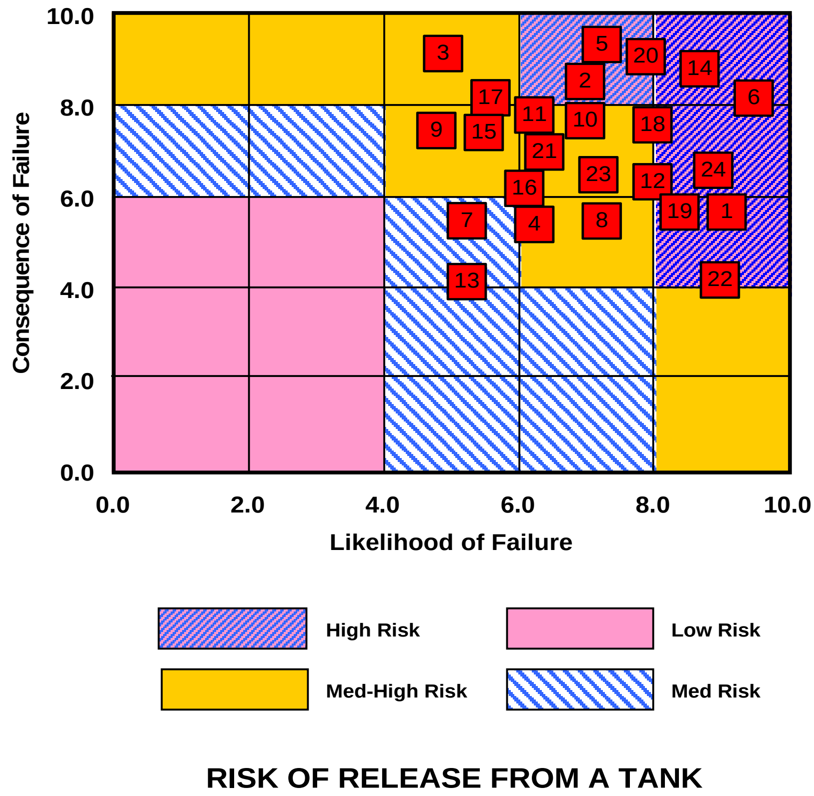


Figure A.5.7: Risk of Release from a Tank

A.6 Document Base Resources

Det Norske Veritas U.S.A., Inc., Process North America (DNV) was contracted by the American Petroleum Institute to develop a risk assessment methodology that was defensible, based on practical methodology, and could be used by facility engineers and operators to perform risk assessment. The risk assessment method was envisioned as a screening tool to evaluate API Publ 340 control measures that can aid AST facilities in risk management and risk reduction associated with liquid releases only. The culmination of DNV's work was a report titled *Risk Assessment System for Aboveground Storage Tank Facilities,* dated March 2003. A major portion of DNV's work was the development of the frequency or likelihood of occurrence for each of the major release scenarios (tanks, piping, transfer areas) at petroleum storage terminal facilities. DNV's basis for the development of the leak frequencies is described below.

A.6.1 Tank Bottom Leak Frequency

The base failure frequency for the leak of a tank bottom was derived primarily from an analysis of a portion of the API publication *A Survey of API Members' Aboveground Storage Tank Facilities*, published in July 1994. The survey included refining, marketing, and transportation storage tanks, each compiled separately.

The survey included the years 1983 to 1993. Table A.6.1 shows the highlights of the survey results. One of the most significant findings of the survey was that tank bottom leaks contributing to soil contamination had been cut in half in the last 5 years compared to the first 5 years covered by the survey. This was attributed to an increased awareness of the seriousness of the problem and to the issuance of the API 653 standard for AST inspection.

Table A.6.1: Summary of Survey Results

Population Description	Number of tanks	Percent with bottom leaks in last 5 years	Number with bottom leaks in last 5 years	Tank years*	Bottom leak frequency (1988–1993)
Tanks < 5 years old	466	0.9%	4	2330	1.7×10^{-3}
Tanks 6–15 years old	628	3.8%	24	3140	7.6×10^{-3}
Tanks > 15 years old	9204	3.8%	345	46020	7.5×10^{-3}
All tanks in survey	**10298**	**3.6%**	**373**	**51490**	$\mathbf{7.2 \times 10^{-3}}$

* Tank years = number of tanks × average number of years in service

An AST bottom leak frequency of 7.2×10^{-3} leaks per year was chosen as the base leak frequency by the publication committee team members. Although the leak frequency data in Table A.6.1 indicate that tanks less than 5 years old had a much lower leak frequency, it was decided to use the whole survey population in setting the base leak frequency. The age of the tank was accounted for elsewhere in the model since the percent wall loss in the model is a function of the tank age, corrosion rate, and original wall thickness. The percent wall loss was selected as the basis of the modifier on the base leak frequency; thus, a very young tank with minimal corrosion would have a frequency modifier less than 1, which lowers the leak frequency accordingly.

The survey did not report the size of leaks, but a survey of the sponsors for the aboveground storage tank risk assessment project indicated that leak sizes of ≤½ inch in diameter would adequately describe the vast majority of tank bottom leaks.

A.6.2 Tank Shell Leak Frequency

Only two categories of leaks were considered for shell leaks: (1) small shell leaks of $^{1}/_{8}$ inch or larger that reach the ground and (2) rapid shell failures. The base leak frequency for small shell leaks used in this document is based on the experience of one of the major operating companies. All of this company's shell leaks were of the variety that wet the outside of the tank; however, the vast majority of the leaks did not reach the ground before they were cleaned up and the tank repaired. The small shell leak frequency reflects the fact that the majority of shell leaks did not reach the ground. A failure rate for rapid shell failures was determined separately, based on actual incidents as noted below.

A review of the literature produced reports of two rapid shell failures in the petroleum industry in the United States in the last 30 years:

1. 1971 (location unknown), brittle fracture caused loss of 66,000 bbl crude oil
2. 1988, Ashland Oil, PA, brittle fracture caused loss of 96,000 bbl diesel

The number of tanks that provided the basis for the two failures was estimated from the literature to be about 33,300 large storage tanks. This value was based on a 1989 study carried out for API by Entropy Ltd (Christensen, 1989). In this case, "large" is defined as having a tank capacity greater than 10,000 barrels. The number of tanks represents the total in the United States for the refining, marketing, transportation, and production sectors; thus, the total number of tank years was found to be approximately 1,000,000.

Dividing the number of failures by the number of tank years yields a rapid shell failure frequency of 2×10^{-6} per tank year. API Standard 653 requires an evaluation of tanks for susceptibility to brittle fracture, and hydrostatic testing or re-rating of the tank may be required for continued service; thus, API 653 provides considerable protection against brittle fracture. Assuming that one-half of the tanks are not maintained to API 653, then the base leak frequencies for rapid shell failures would be 4×10^{-6} per tank year. Because the committee team members found no documented cases of rapid shell failure for a tank that was operated, maintained, inspected, and altered in accordance with API 653, the failure frequency was believed to be significantly better than the calculated average result, and the committee selected a frequency of 1×10^{-7} per tank year.

A.6.3 Tank External Floating Roof Drain Leak Frequency

The hose failure rate for tank external floating roof drains was derived from the base unloading hose failure rate as indicated in Section A.6.7. Since storage and handling are not factors with roof drain hoses, the leak rate was adjusted downward accordingly. The articulated pipe failure rate was obtained from a major European risk assessment (COVO, 1982). These rates represent the frequency for the roof drain valve being always left open. In the case of a roof drain valve that is generally closed, a second conditional probability was applied to account for human error that may leave the roof drain valve in the open position. In order to account for this possibility, DNV used information from the U.S. Nuclear Regulatory Commission that suggests a human error rate of 1.0×10^{-2} for "general human error of omission where there is no display in the control room of the status of the item omitted (e.g., failure to return manually operated test valve to proper configuration after maintenance" (U.S. NRC, 1975, and Kletz, 1991).

A.6.4 AST Overfill Frequency

The base probability of overfilling aboveground storage tanks was taken from the history of one of the major operating companies. This company experienced four overfills in 25,000 tank fillings. This equates to a base probability of overfill of 1×10^{-4}/tank filling.

A.6.5 Underground Piping Leak Frequency

Underground piping leak frequencies are based on a distribution of underground piping leaks by cause. Table A.6.5.1 provides that distribution as determined by the sponsor members.

Table A.6.5.1: Distribution of Underground Piping Failures by Cause

Cause	**Percentage**
Corrosion	41%
External Forces	21%
Material	15%
Operation/Equip. Malfunction	18%
Other	5%
Total	**100%**

Data from the U.S. Department of Transportation suggested, at the time this report was prepared, that the likelihood of leaks due to external forces is 1.1×10^{-4} for pipelines in general. This value was adjusted (reduced by 50 percent) based on the experience of the publication committee team which suggested that leaks due to external impacts at terminals would be approximately half that of less controlled underground piping located beyond the fenced limits of petroleum terminals. Thus, the frequency of external forces was assumed to be 5.5×10^{-5}. The frequencies of failures from other causes were calculated from that value and based on the distribution in Table A.6.5.1. Table A.6.5.2 shows the resulting frequencies.

Table A.6.5.2: Distribution of Underground Piping Failures by Cause with Frequencies

Cause	Percentage	Leak Frequency (per mile-year)
Corrosion	41%	1.1E-04
External Forces	21%	5.5E-05
Material	15%	3.9E-05
Operation/Equip. Malfunction	18%	4.7E-05
Other	5%	1.3E-05
Total	**100%**	**2.6E-04**

The expected frequency distribution of each leak size (after converting frequency to per 100 ft-year basis) is presented in Table A.6.5.3.

Table A.6.5.3: Base Leak Frequencies for Underground Piping

Hole Sizes	Percentage	Frequency (per 100 ft-year)
Small Leak (≤ ¼")	99%	4.9E-06
1"	1%	5.0E-08
Total	**100%**	**5.0E-06**

External Corrosion Rate for Underground Piping

The categories in Table A.6.5.1 were selected based on a classification presented in ASTM publication STP 741. The adjustment factors were calibrated using corrosion data available in the literature (Romanoff, 1997). For example, the average corrosion rate measured for carbon steel was 12 mpy for soils with resistivities around 325 ohm-cm, while for those with resistivities of 7500 ohm-cm, the carbon steel corrosion rate was 3.5 mpy. Very corrosive soils will increase the corrosion rate by 100 percent. Moderately corrosive soils are assumed to be the norm, and the corrosion rate is left unchanged. Soils with low corrosivity actually show a decrease in the base corrosion rate of more than one-half.

Underground Piping Location Modifying Factor

Table A.6.5.1 indicates that 21 percent of underground piping failures are due to external forces. Assuming that the location of underground piping is accurately known, it is estimated this would reduce piping leaks caused by external forces by 70 percent. The overall leak frequency (due to all causes) would then be reduced from 2.4×10^{-4} per mile-year to 2.04×10^{-4} per mile-year. This is a reduction of 15 percent in the overall underground piping leak frequency.

A.6.6 Aboveground Piping Leak Frequency

The leak frequencies for aboveground piping were also based on U.S. Department of Transportation pipeline failure rate data for the years 1984–1994 (see Section A.6.5). The frequencies for aboveground piping failures were assumed to be the same as those used for underground piping systems, except that the contributions from corrosion and external forces were reduced. This adjustment was made because, for buried piping, the external corrosion typically constitutes 80 percent of the total, and internal corrosion accounts for the remaining 20 percent. For aboveground piping, however, the external corrosion is much less than that for buried piping; accordingly, leaks due to corrosion for aboveground piping are assumed to be 20 percent of those for buried piping. Additionally, leaks due to external forces are less likely for aboveground piping in a terminal or tank farm than for buried piping. A 60-percent reduction is assumed based on the expert opinion of the publication committee members. Thus, the base leak frequency for aboveground piping systems was determined to be 1.4×10^{-4} per mile-year or 2.7×10^{-6} per 100 ft-year. Table A.6.6.1 shows the distribution of aboveground piping failures by cause.

Table A.6.6.1: Distribution of Aboveground Piping Failures by Cause

Cause	Percentage	Leak Frequency (per mile-year)
Corrosion	15%	2.1E-05
External Forces	15%	2.2E-05
Material	27%	3.9E-05
Operation/Equip. Malfunction	33%	4.7E-05
Other	9%	1.3E-05
Total	**100%**	**1.4E-04**

The frequency distribution of each leak size (after converting frequency to per 100 ft-year basis) was developed and is presented in Table A.6.6.2.

Table A.6.6.2: Base Leak Frequencies for Aboveground Piping

Hole Sizes	Percentage	Frequency (per 100 ft-year)
Small Leak (≤ ¼")	99%	2.7E-06
1"	1%	2.7E-08
Total		2.7E-06

Flange Leaks

The experience of the workgroup was used to develop the leak frequency of $1\text{x}10^{-4}$ flange leaks/year/flange.

A.6.7 Transfer Equipment Leak Frequencies

Tank Truck and Rail

Tank trucks and rail cars generally use flexible hoses to transfer product. DNV determined the frequency of a flexible hose failure based on data from an unrelated (non-petroleum) industry. DNV found these data to be more comprehensive than any data readily available from the petroleum industry at the time its report was prepared. These data were from the paper “Accidental Releases of Ammonia: An Analysis of Reported Incidents” by P.J. Baldock, which was quoted by Lees in *Loss Prevention in the Process Industries* (Appendix 14, p.23). These sources reported a hose rupture rate of 1.0×10^{-3} per transfer point per year. The causes of failure were usually mechanical failure during storage or handling of the hose or corrosion. Other causes of failure included over-pressuring the hose and using the wrong material. Massive connection failures were included in the reported rupture rate. Table A.6.7.1 presents the failure rates developed by DNV for flexible hoses.

Table A.6.7.1: Flexible Hose Failure Rates

Transfers per Transfer Point	Rupture Rate (/yr)	$^1/8$" Leak Rate (/yr)*
≤ 20/week	6.0×10^{-4}	2.0×10^{-2}
21–40/week	1.0×10^{-3}	3.3×10^{-2}
41–80/week	1.5×10^{-3}	5.0×10^{-2}
> 80/week	2.0×10^{-3}	6.6×10^{-2}

Note: These leak rates are inferred from the data for hose ruptures.

Other releases due to drive-offs and other transport movement while still connected lead to a rupture rate of 2.5×10^{-4} as reported by Baldock. This value also includes connection failures; Baldock reported a leak rate of 6.7×10^{-4} per transfer point year due to “transport movement while still connected.” Table A.6.7.2 presents flexible hose rupture and leak rates for drive-offs.

Table A.6.7.2: Flexible Hose Failure Rates Due to Drive-offs

Transfers per Transfer Point	Rupture Rate (/yr)	¼" Leak Rate (/yr)
≤ 20/week	1.0×10^{-4}	2.7×10^{-4}
21–40/week	2.5×10^{-4}	6.7×10^{-4}
41–80/week	5.0×10^{-4}	1.3×10^{-3}
> 80/week	1.0×10^{-3}	2.7×10^{-3}

If an articulated arm was used to transfer the product instead of a flexible hose, the leak frequencies were reduced by 60 percent, according to DNV.

Marine Vessel

The leak frequencies for ship-to-shore transfers in port were determined by DNV based on in-house RiskNet data. The leak frequency data were for leaks exceeding 1 ton.

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APPENDIX B
OPTIONAL
QUALITATIVE RISK
ASSESSMENT, METHOD II

LIKELIHOOD & CONSEQUENCE ANALYSIS

APPENDIX B TABLE OF CONTENTS

B.1 Introduction

This appendix presents a simplified qualitative approach to performing a risk assessment at liquid petroleum storage terminals. It uses a "what if/check list" that is similar to the format used in a process hazard analysis. Although the approach detailed below is significantly easier than the method detailed in Appendix A, it requires users to be more knowledgeable about the types of risk scenarios, the likelihood of the user-developed scenarios, and the consequences if the specific scenario were to occur. Therefore, the method is best performed by skilled and knowledgeable individuals in a group setting and should not be performed by inexperienced users. API suggests that the optimum approach is to assemble a group of knowledgeable and experienced persons, in an approach similar to that used for the performance of a process hazard analysis.

The risk assessment method presented here can be used to address all possible risks at a terminal; however, it relies on the users to develop a list of appropriate terminal risks and then assign values to the likelihood and consequence variables. The users must then apply the likelihood and consequence ranking consistently for each event, each piece of equipment, and each facility. The users should focus on the most credible and severe risks at the facility and not analyze trivial or non-credible risks. The attached example will help users by illustrating the application of the approach used in this method. If the users are interested in a more rigorous model for terminal risk assessment, they should refer to Appendix A for a comprehensive, quantitative approach.

This appendix presents optional methods for conducting a risk assessment if a facility decides to do so. Other methods are available outside the scope of this appendix, or a company can decide to create its own method. The optional method presented here is for demonstration purposes only.

B.2 Release Secenarios

As indicated in the main body of this document, the scope is limited to the risks associated with terminal liquid releases. However, users can analyze the risks associated with vapor releases using the method presented in this appendix. The particular risk assessment model is also not limited to addressing the specific liquid release scenarios detailed in Appendix A. Users are required, however, to develop their own list of release scenarios for the risk assessment analysis. For convenience, a basic list of release scenarios is given below, and users may also refer to API Publ 340 for a detailed list of release scenarios addressed in that document. As discussed above, it is important that the list of release scenarios represents the most credible and severe risks typically associated with liquid petroleum storage facilities. Users need to develop this list based on their specific facility configuration and operation. As a starting point, the following list contains the major risks associated with petroleum terminals:

- Aboveground storage tank releases
  - Tank bottom, tank shell, rapid bottom failure, and rapid shell failure
- Piping system releases
  - Underground or aboveground piping system damage, corrosion, and flange failure
- Transfer area releases
  - Loading, unloading, and transfer/pumping equipment releases
  - Truck, rail, and marine areas
- Underground storage tank releases
- Vapor emission control device failure releases

In this method, the user can look at both liquid releases and vapor releases. Vapor releases are usually viewed in terms of their potential for causing a fire or explosion associated with the vapor emission.

B.3 Overview of Likelihood Estimation

For each user-established release scenario (e.g., bottom failure), the users need to assign a likelihood number. The likelihood number represents the users' best estimate of the likelihood, probability, or frequency at which an event could be expected to occur. In general, the users must rely on their own experience and the group's experience to determine this number, which is why it is suggested that this method be performed by a group of knowledgeable individuals. The assigned likelihood number is between 1 and 5, with 1 being "extremely unlikely to occur" and 5 being "extremely likely to occur." For the benefit of the users, the following descriptions were developed for each of the numbers used in the likelihood determination. Users can follow these definitions or establish their own data ranges.

1 Extremely unlikely to occur
2 Very unlikely to occur
3 Average likelihood of occurrence when compared to other scenarios
4 Very likely to occur
5 Extremely likely to occur

Some users may wish to provide a more detailed or comprehensive range for these values, such as "a rating of 2 means that the event is anticipated to occur once in 10 years." Establishment and definition of this range is up to the users, but the assigned number can never be zero because there is always some probability that any event can occur. Once the users establish the definitions, they should use them consistently throughout the analysis.

B.4 Overview of Consequence Estimation

As with the likelihood approach, the users need to assign a consequence number for each user-established release scenario (e.g., bottom failure). The consequence number represents the users' best estimate of the adverse impact of an event if the release scenario were to occur. In general, the users must rely on their experience and the group's experience to determine this number. Again, that is why it is recommended that this method be performed by a group of knowledgeable individuals. The assigned consequence number is between 1 and 5, with 1 being "extremely low consequences" and 5 being "extremely high consequences." For the benefit of the users, the following descriptions have been developed for each of the numbers used in the consequence determination. The users can follow these definitions or establish their own data ranges.

1 Extremely low consequences
2 Low consequences
3 Moderate consequences when compared to the consequences of other scenarios
4 High consequences
5 Extremely high consequences

Some users may wish to provide a more detailed or comprehensive range for these values, such as "a rating of 2 means that the event is anticipated to impact onsite surficial soils only." Additionally, the users need to define what consequences they are considering in assigning this value. They can look at environmental, population, or business consequences or all three. Establishment and definition of this range is up to the users. Once the users have established the definitions, they should use them consistently throughout the analysis.

B.5 Determination of Risk

As in the Appendix A risk assessment method, risk is based on the following premise:

$$\text{Risk} = \text{Likelihood} \times \text{Consequence}$$

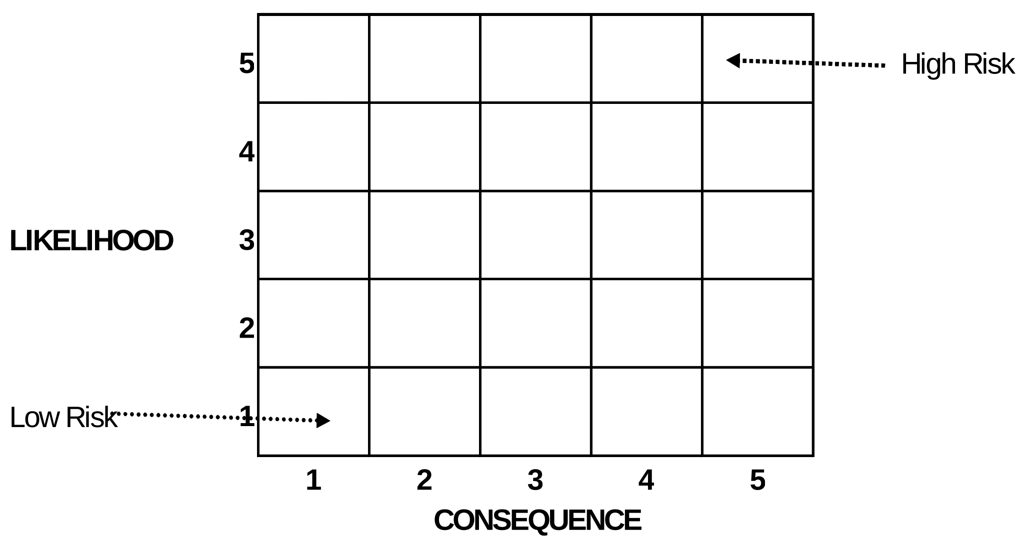
To determine the risk associated with each user-established release scenario, the users multiply the assigned likelihood number (between 1 and 5) by the assigned consequence number (again between 1 and 5). The product of these two numbers yields a data range of risks between 1 and 25, where 1 would be considered an extremely low risk event and 25 would be considered an extremely high risk event. The users can choose whether to view risk as a product of the two numbers or as a plot on a risk matrix. Establishing this data range allows the users to view the risks for each scenario both ways. The users must also develop criteria for determining the acceptability of the risk(s).

Approach #1 compares the total risk for each event and ranks the risks from highest to lowest. The users define what risk score is unacceptable and requires further review or mitigation, as shown in the example below.

Liquid Release Scenario	**Risk Score**	**Risk Ranking Priority**
Event #1	12	2
Event #2	16	1
Event #3	9	3
Event #4	3	4
Event #5	3	4

Approach #2 plots the risk score individually for consequences and likelihood on a matrix and defines where on the matrix the low, medium, and high risk ranges are located.

RISK MATRIX APPROACH



For further discussion of the risk scoring and risk matrix system, refer to Sections 6.7.2 and 6.7.3 of the main text of this document.

For those risks that users determine to require further evaluation or establishment of a risk mitigation strategy, the same approach can be used to evaluate and select mitigation measures.

B.6 Simplified Qualitative Risk Assessment Form

The approach discussed above is presented in the form in Section B.7. The form was developed for the performance of a simplified qualitative risk assessment as outlined in this appendix. Users can easily computerize the form in a spreadsheet format. Again, it is recommended that a team of experienced personnel develop a list of release scenarios and consistently evaluate the likelihood and consequences of occurrence for each scenario. Table B.1 provides a description of the column headings used in the form.

Table B.1: Qualitative Risk Assessment Method II Heading Description

Form Heading	Description & Purpose
#	Release scenario number for the specific release scenario under consideration. The number allows the user to more easily refer to the specific release scenario.
Release Scenario	Description of the specific user-defined release scenario under consideration. The user stipulates the specific release scenario under consideration in the risk assessment (for example, "Overfill of Tank #101").
Experience with Occurrence	The user describes the group's experience with the likelihood of occurrence with the specific release scenario. This section aids the user in documenting the basis for the development of the likelihood number. For example, "tank overfills have occurred in the past at this facility or at other similar facilities and the likelihood of an overfill given the current configuration of the facility is above average."
Anticipated Consequences	The user describes the group's experience with the anticipated consequences if the event were to occur for the specific release scenario. This section aids the user in the documentation of the basis for the development of the consequence number. For example, "tank overfills, when they have occurred, resulted in the contamination of the surface and subsurface soils in the vicinity of the tank and resulted in no impact to the environment outside of the facility."
Likelihood #	A number from 1 to 5 assigned by the user to represent experience with the likelihood (probability or frequency) that the specific event could occur.
Consequence #	A number from 1 to 5 assigned by the user to represent experience with the consequences that would result from the occurrence of the specific event.
Risk Score	A number from 1 to 25 that represents the product of likelihood x consequences. The risk score represents the numerical value assigned to risk for the specific release scenario. The user may wish to plot likelihood and consequences on a risk matrix instead of establishing a risk score.
Is Risk Acceptable without Mitigation (Y or N)	The user selects "Y" for Yes and "N" for No once he determines whether the risk for the specific release scenario is acceptable or not. The definition of acceptable risk is up to the user (see

	Section 8 of the main document for risk evaluation). If the risk is determined to be unacceptable, then mitigation is required, and the user proceeds across the form to evaluate the residual risks associated with specific mitigation strategies.
Possible Mitigation	If the risk is determined to be unacceptable, then possible mitigation measures need to be evaluated. This column provides a space for the user to identify the possible mitigation measures available for reduction of risk (for example, “install high level alarms compliant with API RP 2350”).
Mitigation Measure Improvement	Describes the anticipated effect of a specific mitigation measure on the risk for a specific release scenario. Mitigation measures may decrease likelihood or decrease consequences or both. For example, installation of a high level alarm system will decrease the likelihood of a tank overfill, and it may also decrease the consequences of a release by decreasing the amount of product spilled if the alarm is tied into an automatic shutdown system.
Revised Likelihood	A number from 1 to 5 assigned by the user to represent experience with the revised likelihood (probability or frequency) of occurrence that a specific event is assigned after application of a selected mitigation measure or mitigation strategy.
Revised Consequences	A number from 1 to 5 assigned by the user to represent experience with the revised consequences that would result from the occurrence of a specific event after application of a selected mitigation measure or mitigation strategy.
Residual Risk Score	A number from 1 to 25 that represents the product of the revised likelihood x revised consequences for a selected mitigation measure. The revised risk score represents the numerical value assigned to risk for a specific release scenario after mitigation. The user may wish to plot revised likelihood and consequences on a risk matrix, instead of utilizing the risk score.
Is Risk Acceptable with Mitigation (Y or N)	The user selects “Y” for Yes and “N” for No after he has determined if the risk for the specific release scenario is now acceptable with the application of a specific mitigation measure or strategy. The definition of acceptable risk is up to the user (see Section 8 of the main document for risk acceptability). If the risk is determined to be unacceptable after the application of a specific mitigation measure, then additional mitigation measures or a new mitigation strategy should be evaluated.

B.7 Worked Example

The following example has been prepared to illustrate the application of the simplified risk assessment approach discussed in this appendix.

#	Release Scenario	Experience with Occurrence	Anticipated Consequences	Likelihood 1 to 5	Consequences 1 to 5	Risk Score	Is Risk Acceptable without Mitigation? Y or N
1	Tank Overfill	Has occurred two times a year in tanks without high level alarms	Typically spilled 7000 gallons	4	3	12	N
2	Tank Bottom Release	For the seven facility tanks there have been two tank bottom leaks, but since the API 653 inspection program was implemented 10 years ago, no tank bottom failures have occurred	around 500 to 1000 bbl	2	4	8	Y
3	Tank Shell Leak	In the last 20 yrs no tank shell leaks. API 653 inspection program check tank shell thickness	250 bbl from a corrosion hole	1	3	3	Y
4	Tank Rapid Bottom Failure	Most likely due to edge settlement , which is monitored during API 653 inspection and is within Appendix B tolerance	Loss of entire tank contents—largest tank is 11,000 bbl	1	5	5	Y
5	Tank Rapid Shell Failure	Most likely due to modifications or repairs to older tanks; brittle fracture failure review performed on all tanks per API when altered or repaired	Loss of entire tank contents—largest tank is 11,000 bbl	1	5	5	Y
6	Leak or Spill at Loading Rack from Hose or Piping Flange Leak	Terminal experiences 1 to 2 events per year.	Spill is contained on loading pad and is typically less than 40 gal.	5	1	5	Y

APPENDIX C—COMPREHENSIVE RISK ASSESSMENT MODEL I WORKBOOK FOR AST FACILITIES

The following scenarios are merely examples for illustration purposes only. Each company should develop its own approach. They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document. Users of this document should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein. Work sites and equipment operations may differ. Users are solely responsible for assessing their specific equipment and premises in determining the appropriateness of apply the instructions. At all times users should employ sound business, scientific, engineering, and safety judgment when using this bulletin.

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Purpose of Workbook

The following workbook has been prepared as a supplement to Appendix A of API Publ ####, *Managing Systems Integrity of Aboveground Terminal and Tank Facilities, Managing the Risk of Liquid Petroleum Releases.* The purpose of this workbook is to provide users with structured forms that will aid in the completion of the risk assessment method presented in Appendix A of this document. The forms are divided into Data Collection, Likelihood Analysis, Consequence Analysis, and Analysis Summary. The data collection forms are to assist the user in organizing the data collection and data summary needs for the remainder of the analysis. The workbook is organized as follows:

CHAPTER 1 – DATA COLLECTION

- General Facility Information
- Form 1 – Summary Form

CHAPTER 2 – LIKELIHOOD ANALYSIS

- Tank Likelihood Analysis
- Piping Likelihood Analysis
- Transfer (Loading/Unloading) Likelihood Analysis

CHAPTER 3 – CONSEQUENCE ANALYSIS

- Environmental Consequences
- Tank Consequence Analysis
- Piping Consequence Analysis
- Transfer (Loading/Unloading) Consequence Analysis
- Population Consequences
- Business Consequences

Prior to completing this workbook, the user should collect all available information required to complete these forms. The information to be collected is listed.

Facility	______________________	Date	______________
Completed By	______________________	Page	_____ of _____

- A scaled facility base map showing all major facility features including tanks, dikes, loading and unloading areas, topographic features, property lines, and abutting properties
- Secondary containment systems for loading, unloading, and storage areas
- Operations data including receipt, unloading/loading positions, locations, equipment, control systems, and flow rates
- Latest and previous tank inspection reports
- Environmental facilities data such as monitoring well logs
- Geotechnical and soils information including soil types, depth to groundwater, etc.

The user should be aware that interviews with onsite personnel and a field visit may be necessary to complete this document. The user should identify data gaps and make reasonable approximations using similar service data for the facility being studied or other similar facilities.

Facility ______________________ Date ______________

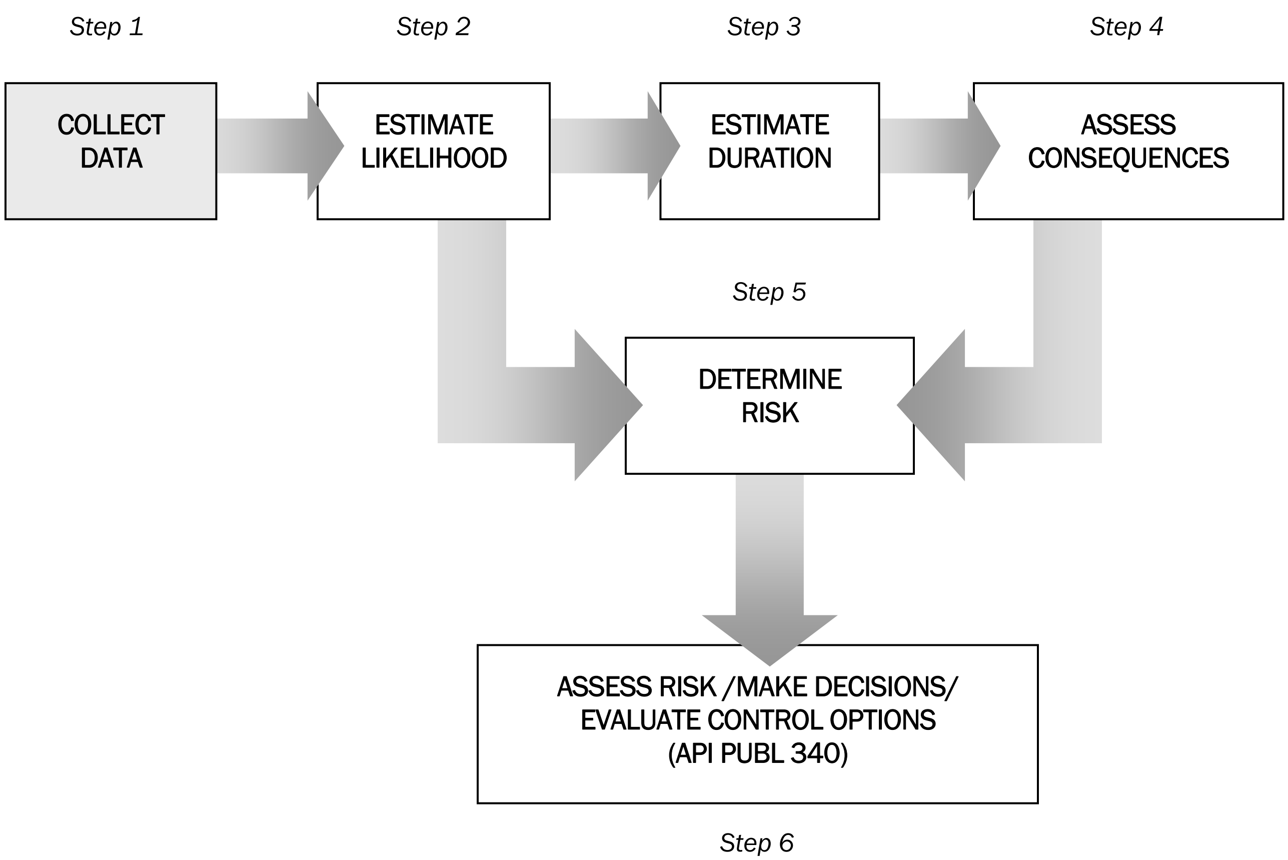
Completed By ______________________ Page ______ of ______

CHAPTER 1

Workbook Forms for Data Collection

The following process flow steps are used in this workbook. The first step is to collect the required facility information which will be needed for each piece of equipment.

FIGURE 1 - DATA COLLECTION, ORGANIZATION, AND ANALYSIS PROCESS FLOW



Facility ______________________ Date ______________

Completed By ______________________ Page _______ of _______

AST PETROLEUM TERMINAL SITE DATA FORM – STEP 1 DATA COLLECTION

ITEM #1 – SITE GENERAL INFORMATION

SITE ______________________ COLLECTED BY ______________________

ADDRESS ______________________ DATE ______________________

CITY, STATE, ZIP ______________________

TERMINAL OPERATOR ______________________ PHONE ______________________

TERMINAL ENGINEER ______________________ FAX ______________________

Product Receipt *(check all that apply)*

1	❑	Barge/Ship	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*
2	❑	Pipeline	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*
3	❑	Rail	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*
4	❑	Truck	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*

(specify the maximum receipt rate for all flow rates)

Product Shipped *(check all that apply)*

5	❑	Barge/Ship	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*
6	❑	Pipeline	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*
7	❑	Rail	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*
8	❑	Truck	Flowrate =		*(bbl/hr)*	No. of Positions:		*(each)*

(specify the maximum receipt rate for all flow rates)

Facility ______________________ Date ______________________

Completed By ______________________ Page ________ of ________

AST PETROLEUM TERMINAL SITE DATA FORM – STEP 1 DATA COLLECTION

ITEM #2 – SITE GENERAL ARRANGEMENT

1 CAN A RELEASE GO OFFSITE? YES NO *(circle one)*

IF **YES**, COMPLETE THE FOLLOWING

2 DISTANCE TO WATER BODY ____________

3 TYPE OF WATER BODY ____________

4 IS SURFACE WATER USED AS A POTABLE SOURCE? YES NO

5 IS GROUNDWATER USED AS A POTABLE WATER SOURCE? YES NO

6 DEPTH TO GROUNDWATER TABLE ____________ (ft below ground surface, bgs)

7 SOIL TYPE ____________

8 IS THERE AN EXISTING REMEDIATION SYSTEM IN PLACE? YES NO

8a IF YES, DESCRIBE ____________

Facility ____________ Date ____________

Completed By ____________ Page ______ of ______

The following scenarios are merely examples for illustration purposes only. Each company should develop its own approach. They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document. Users of this document should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein. Work sites and equipment operations may differ. Users are solely responsible for assessing their specific equipment and premises in determining the appropriateness of apply the instructions. At all times users should employ sound business, scientific, engineering, and safety judgment when using this bulletin.

AST PETROLEUM TERMINAL SITE DATA FORM – STEP 1 DATA COLLECTION

ITEM #3 – SECONDARY CONTAINMENT INFORMATION

12 NUMBER OF INDIVIDUAL CONTAINMENT AREAS ______________________ *(each)*

(For each individual containment complete the following information)

CONTAINMENT AREA #1

13 SIZE OF LARGEST TANK IN DIKED AREA ______________________ *(bbl)*

14 CAPACITY OF DIKED AREA ______________________ *(bbl)*

15 IS DIKED AREA LINED? YES NO *(circle one)*

CONTAINMENT AREA # ______

13 SIZE OF LARGEST TANK IN DIKED AREA ______________________ *(bbl)*

14 CAPACITY OF DIKED AREA ______________________ *(bbl)*

15 IS DIKED AREA LINED? YES NO *(circle one)*

CONTAINMENT AREA # ______

13 SIZE OF LARGEST TANK IN DIKED AREA ______________________ *(bbl)*

14 CAPACITY OF DIKED AREA ______________________ *(bbl)*

15 IS DIKED AREA LINED? YES NO *(circle one)*

CONTAINMENT AREA # ______

13 SIZE OF LARGEST TANK IN DIKED AREA ______________________ *(bbl)*

14 CAPACITY OF DIKED AREA ______________________ *(bbl)*

15 IS DIKED AREA LINED? YES NO *(circle one)*

Facility ______________________ Date ______________________

Completed By ______________________ Page ________ of ________

AST PETROLEUM TERMINAL SITE DATA FORM – STEP 1 DATA COLLECTION

ITEM #4 – LOADING INFORMATION

LOADING RACK #1

16	DETERMINE IF LOADING OPERATIONS IN ACCORDANCE WITH API RP 1004 *(For MC-306 tank trucks only)*	________________
17	LEVEL ALARMS PROVIDED ON LOADING OPERATIONS	________________
18	TYPE OF CONTROL SYSTEMS	________________
19	RATE LEVEL OF ATTENDANCE DURING FILL OPERATIONS	________________

LOADING RACK # _____

16	DETERMINE IF LOADING OPERATIONS IN ACCORDANCE WITH API RP 1004 *(For MC-306 tank trucks only)*	________________
17	LEVEL ALARMS PROVIDED ON LOADING OPERATIONS	________________
18	TYPE OF CONTROL SYSTEMS	________________
19	RATE LEVEL OF ATTENDANCE DURING FILL OPERATIONS	________________

Facility ____ Date ____________________

Completed By ____ Page __________ of __________

CHAPTER 2

LIKELIHOOD ANALYSIS

GENERAL LIKELIHOOD INFORMATION FORMS

The user must now take the information collected in Chapter 1 and determine the likelihood (frequency) that a specific event will occur for a specific piece of equipment. This analysis addresses the following events:

- Small Bottom Leaks (FORM A)
- Rapid Bottom Failure (FORM B)
- Small Shell Release (FORM C)
- Rapid Shell Failures (FORM C)
- Tank Overfills (FORM D)
- Tank Roof Drain Leaks (FORM E)
- Underground Piping Leaks (FORM F)
- Aboveground Piping Leaks (FORM G)
- Transfer Equipment Leaks (FORM H)
- Tank Truck Overfills (FORM I)

The likelihood analysis provides a measure of the frequency that a specific event will occur.

COMPLETION OF FORMS

The tank, piping, and transfer equipment data generated in Chapter 1 will be used to complete the forms listed above. Additional data and information are required as the user completes the forms. The information entered on the sheets should be based on the user's knowledge of the facility's location, general arrangement, site conditions, and configuration.

Facility ______________________ Date ______________

Completed By ______________________ Page ______ of ______

CHAPTER 3

CONSEQUENCE ANALYSIS

GENERAL CONSEQUENCE INFORMATION FORMS

The user must now take the information collected in Chapters 1 and 2 and determine the consequences for each specific event analyzed in Chapter 2 for each specific piece of equipment. This analysis addresses the following events:

- FORM J – Consequence of Failure Summary Form
- FORM K – Environmental Consequence of Failure Model
- FORM L – Small Tank Bottom Leak Volume/Media Determination
- FORM M – Small Tank Shell Leak Volume/Media Determination
- FORM N – Rapid Tank Failure Volume/Media Determination
- FORM O – Tank Overfill Volume/Media Determination
- FORM P – Tank Roof Drain Leaks Volume/Media Determination
- FORM Q – Pressurized Piping Leaks Volume/Media Determination
- FORM R – Underground Suction/Gravity Piping Leak Volume/Media Determination
- FORM S – Aboveground Suction Piping Leak Volume/Media Determination
- FORM T – Transfer Equipment Leak Volume/Media Determination
- FORM U – Population Consequence of Failure Model
- FORM V – Business Consequence of Failure Model
- FORM W – Estimation of Direct Costs of Loss

The consequence analysis provides a measure of the impact to the environment, population, or business from a specific event.

COMPLETION OF FORMS

The tank, piping, and transfer equipment data generated in Chapters 1 and 2 will be used to complete the forms presented above. Some additional data or information may be required as the user attempts to complete the forms. The information entered on the sheets should be based on the user's knowledge of the facility's location, general arrangement, site conditions, and configuration.

Facility ____________________ Date __________

Completed By ____________________ Page _____ of _____

AST PETROLEUM TERMINAL SITE DATA **FORM 1**

DATA SUMMARY FORM (FACILITY RISK)

Make as many copies as needed to accommodate for all Tanks.

Tank #_____

		Likelihood		Consequences[1]	RISK[2]
1.	BOTTOM LEAK FREQUENCY	______	*(FORM **A**)*	______	
2.	RAPID BOTTOM LEAK FREQUENCY	______	*(FORM **B**)*	______	
3.	TANK SHELL LEAK FREQUENCY	______	*(FORM **C**)*	______	
4.	RAPID TANK SHELL LEAK FREQUENCY	______	*(FORM **C**)*	______	
5.	TANK OVERFILL FREQUENCY	______	*(FORM **D**)*	______	
		Rupture ______		______	______
6.	ROOF DRAIN FREQUENCY	1/8" Leak ______	*(FORM **E**)*	______	______

Pipe Section # ______

7.	UNDERGROUND PIPING LINE LEAK FREQUENCY	______	*(FORM **F**)*	______
8.	ABOVEGROUND LINE LEAK FREQUENCY	______	*(FORM **G**)*	______

Transfer Area #_______

9.	TRANSFER LEAK FREQUENCY	______	*(FORM **H**)*	______
10.	TANK TRACK OVERFILL FREQUENCY	______	*(FORM **I**)*	______

[1] Total Consequences of Failure is calculated on Form J
[2] See Equation Below:

RISK = LIKELIHOOD x CONSEQUENCES

Facility ____________________ Date____________
Completed By ____________________ Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM A**

Bottom Small Leak Frequency (If Corrosion Rate Is Known, Skip to Form A Page 2) Tank____

(Make copies of this form for each tank)

1.	*GIVEN*	External Base Corrosion Rate (**$r_{ext\text{-}base}$**) =	5 mpy	*(Ext. Base Rate)*
2.	*DETERMINE*	Soil Resistivity (**AF_{res}**)=	________	*(Table A.2.2.6)*
3.	*DETERMINE*	Tank Pad Adjustment (**AF_{TP}**)=	________	*(Table A.2.2.8)*
4.	*DETERMINE*	Tank Drainage Adjustment (**AF_D**)=	________	*(Table A.2.2.9)*
5.	*DETERMINE*	Cathodic Protection Adjustment (**AF_{CP}**)=	________	*(Table A.2.2.10)*
6.	*DETERMINE*	Fluid Temperature Adjustment (**AF_{FT}**)=	________	*(Table A.2.2.11)*
7.	*CALCULATE*	External Corrosion Rate (**$r_{soil\ side}$**)=	________	*(Equation A.6)*

Equation A.6

Calculation:

External Corrosion Rate (**$r_{soil\ side}$**)= **5 mpy** * **AF_{res}** * **AF_{TP}*** **AF_D*** **AF_{CP}*** **AF_{FT}**

r_{ext} =

8.	*SELECT*	Internal Base Corrosion Rate (**$r_{int\text{-}base}$**)=	________	*WET Condition=5 mpy* *DRY Condition=2 mpy*
9.	*DETERMINE*	Internal Lining Adjustment (**AF_{IL}**)=	________	*(Table A.2.2.14)*
10.	*DETERMINE*	Internal Lining Age Adjustment (**AF_{LA}**)=	________	*(Table A.2.2.15)*
11.	*DETERMINE*	Fluid Temperature Adjustment (**AF_{FT}**)=	________	*(Table A.2.2.11)*
12.	*DETERMINE*	Steam Coil Heater Adjustment (**AF_{SC}**)=	________	*Present = 1.5* *NO = 1.0*
13.	*DETERMINE*	Water Draw Adjustment (**AF_{WD}**)=	________	*Present = 0.7* *NO = 1.0*
14.	*CALCULATE*	Internal Corrosion Rate (**$r_{top\ side}$**)=	________	*Equation A.7*

Equation A.7

Calculation:

Internal Corrosion Rate (**$r_{top\ side}$**)= **$r_{int\text{-}base}$** * **AF_{IL}** * **AF_{LA}*** **AF_{FT}*** **AF_{SC}*** **AF_{WD}**

r_{int} =

Table A.2.2.14: Internal Lining Adjustment

Is internal lining needed for corrosion protection?	AF
YES (but no internal lining or unknown)	1.75
YES (internal lining applied, but not per API 652)	1.15
YES (internal lining applied per API 652)	0.5
NO (and no lining applied)	1
NO (internal lining applied anyway but not per API 652)	0.9
NO (but internal lining applied per API 652)	0.8

Table A.2.2.6: Natural Soil Resistivity Adjustment

Resistivity (ohm-cm)	Potential Corrosion Activity	AF
<500	Very Corrosive	1.5
500 – 1000	Corrosive	1.25
1000 – 2000	Moderately Corrosive	1
2000 – 10000	Mildly Corrosive	0.83
>10000	Progressively Less Corrosive	0.66
Tank with RPB		1

Table A.2.2.8: Tank Pad Adjustment Factors

Type	AF
Soils with high concentrations of salts	1.5
Crushed limestone	1.4
Native soil	1.3
Construction grade sand	1.15
Continuous asphalt	1
Continuous concrete	1
Oil sand	0.7
High resistivity, low chloride sand	0.7

Table A.2.2.9: Tank Drainage Adjustment

Type of Drainage	AF
More than one-third of the bottom edge of the tank is frequently under water	3
Storm water usually collects around the base of the tank	2
Storm water does not usually collect around the base of the tank	1

Table A.2.2.10: Adjustment for Cathodic Protection

Functional Cathodic Protection in Place?	AF
NO	1
YES (not per API 651)	0.66
YES (installed and maintained per API 651)	0.33

Table A.2.2.11: Adjustment for Fluid Temperature

Bulk Fluid Temperature (°F)	AF
≤ 75	1
76 – 150	1.1
151 – 200	1.3
201 – 250	1.4
>250	1

Table A.2.2.15: Lining Age Adjustment

Lining Application and Age	AF
Lining applied per API 652	
> 20 years – limited or no data to assess lining condition	2.5
> 20 years – data to demonstrate that lining is in good condition	1
10 – 20 years	1
< 10 years	0.66
Lining not applied per API 652	
> 10 years – limited or no data to assess lining condition	1.5
> 10 years – data to demonstrate that lining is in good condition	1
5 – 10 years	1
< 5 years	0.87

Facility ______________________
Completed By ______________________

Date______________
Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM A**

Bottom Leak Frequency (Cont.)

(Make as many copies as required for each tank)

Tank________

NOTE : If the corrosion rate is known, enter it in Item 15 below. If the corrosion rate is unknown, then use results from Items 7 and 14 from the previous page with the following guidance. If internal corrosion is **widespread**, then the external (Item 7) and internal corrosion (Item 14) rates are ***additive***. If internal corrosion is **localized (pitting), *then use the greater of the two corrosion values (either internal or external). Do not set the corrosion rate at less than 2 mpy.***

15.	*DETERMINE*	The Maximum Corrosion Rate (**r**)=	______________	*See Note*
16.	*DETERMINE*	Age of Tank Bottom (**a**)=	______________	*Years*
17.	*DETERMINE*	Original Thickness of Tank Bottom (**t**)=	______________	*Mils*
18.	*DETERMINE*	Inspection Rating=	______________	*Table A.2.2.2*
19.	*GIVEN*	AST Bottom Small Leak Frequency	$7.2x10^{-3}$	*Leaks/yr/Tank*
20.	*CALCULATE*	"**ar/t**" value=	______________	*Equation A.4*

Equation A.4

Calculation:

"ar/t" value= $\frac{a*r}{t}$

"ar/t" value =

21.	*DETERMINE*	Modifying Factor ($\mathbf{MF_{ar/t}}$)=	______________	*Table A.2.2.3*
22.	*CALCULATE*	Bottom Leak Frequency (Tank-Specific)	______________	*Equation A.5*

Equation A.5

Calculation:

Bottom Leak Frequency = $7.2x10^{-3}$ *leaks/yr/tank* ***** $\mathbf{MF_{ar/t}}$

Bottom Leak Frequency= (Enter Result on Form 1)

Table A.2.2.2: Guidelines for Assigning Inspection Ratings – Tank Bottom

Inspection Rating Category	Soil Side	Top Side
A	• Floor scan 90+% & UT follow-up	• Commercial blast • Effective supplementary light • Visual 100% (API 653) • Pit depth gauge • 100% vacuum box test or tracer gas test
B	• Partial floor scan & UT follow-up OR • EVA or other statistical method with floor scan follow-up if warranted by the result	• Brush blast • Effective supplementary light • Visual 100% (API 653) • Pit depth gauge
C	• Floor scan 5-10% plates; supplement with scanning near shell & UT follow-up • Progressively increase if damage found during scanning • Hammer test	• Broom swept • Effective supplementary light • Visual 100% • Pit depth gauge
D	• Spot UT • Hammer test	• Broom swept • No effective supplementary lighting • Visual 25-50%
E	None	None

Table A.2.2.3: Tank Bottom Modifying Factors

	Inspection Rating				
ar/t	E	D	C	B	A
0.15	0.0210	0.0003	0.0001	0.0001	0.0001
0.20	0.139	0.005	0.0002	0.0001	0.0001
0.25	0.521	0.041	0.0032	0.0001	0.0001
0.30	1.405	0.190	0.025	0.001	0.0001
0.35	3.05	0.62	0.12	0.01	0.0002
0.40	5.71	1.58	0.41	0.05	0.003
0.45	9.59	3.39	1.14	0.22	0.02
0.50	14.82	6.40	2.64	0.72	0.11
0.55	21.50	10.95	5.34	1.92	0.42
0.60	29.64	17.29	9.71	4.34	1.33
0.65	39.23	25.64	16.19	8.67	3.47
0.70	50.2	36.1	25.2	15.6	7.8
0.75	62.5	48.6	37.0	26.0	15.5
0.80	75.9	63.3	51.7	40.2	27.9
0.85	90.4	79.8	69.4	58.6	45.9
0.90	106	98	90	81	70
0.95	122	118	113	108	102
1.00	139	139	139	139	139

Facility ______________________
Completed By ______________________

Date______________
Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM B**

Rapid Bottom Leak Frequency
(Make copies of this form for each tank)

Tank__________

1. *GIVEN* Rapid Bottom Failure Base Frequency = $2.0 * 10^{-5}$ /year *(Base Freq.)*
2. *DETERMINE* Tank Design and Maintenance Adjustment (**AF_{Design}**)= ______________ *Table A.2.2.18*
3. *DETERMINE* Corrosion Adjustment (**$AF_{Corrosion}$**)= ______________ *Equation C-1*

Equation C-1

Calculation: Find the $MF_{ar/t}$ value from Item 20 on page 2. The **$AF_{Corrosion}$** is the $MF_{ar/t}$ value divided by 20 with a minimum value of 0.2, so:

Corrosion Adjustment (**$AF_{Corrosion}$**)= $\frac{MF_{ar/t}}{20} \geq 0.2$

$AF_{Corrosion}$ =

4. *DETERMINE* Tank Settlement MF (**$AF_{Settlement}$**)= ______________ *Table A.2.2.19*
5. *CALCULATE* Rapid Bottom Failure Frequency= ______________ *Equation A.8*

Equation A.8

Calculation:
Rapid Bottom Leak Frequency= **$2.0*10^{-5}$** * **AF_{Design}** * **$AF_{Corrosion}$** * **$AF_{Settlement}$**

Rapid Bottom Leak Frequency= (Enter Result on Form 1)

Table A.2.2.18: Modifying Factor for Tank Design and Maintenance	
Is the tank designed according to a recognized industry standard and maintained according to API 653?	**Modifying Factor**
NO	5
YES	1

Table A.2.2.19: Modifying Factor for Tank Settlement		
API 653 Settlement Inspection?	**Settlement Found?**	
	Yes	**No**
Yes	2	1
No	1.5	

Facility ______________________
Completed By ______________________

Date_____________
Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM C**

Tank Shell Leak Frequency (If Corrosion Rate Is Known, Skip to Form C Page 2)

(Make copies of this form for each tank)

Tank____

1.	*SELECT*	Internal Base Corrosion Rate ($r_{int\text{-}base}$) =	________ mpy	*DRY Condition =2* *WET Condition =5*
2.	*DETERMINE*	Internal Lining Adjustment (AF_{Lining})=	________	*(Table A.2.3.7)*
3.	*DETERMINE*	Internal Lining Age Adjustment (AF_{Age})=	________	*(Table A.2.3.8) 1 if no lining*
4.	*CALCULATE*	Internal Corrosion Rate Adjustment (r_{int})=	________	*Equation A.11*

Equation A.11

Calculation:

Internal Corrosion Rate (r_{int})= $r_{int\text{-}base}$ * AF_{Lining} * AF_{Age}

r_{int} =

5.	*SELECT*	External Base Corrosion Rate ($r_{ext\text{-}base}$)=	________	*(Table A.2.3.9)*
6.	*CALCULATE*	External Coating Adjustment ($AF_{Coating}$)=	________	*Equation A.11*

Equation A.11

Calculation:

External Coating ($AF_{Coating}$)= $$\frac{\#YearsTankUnprotected}{TankAge}$$

Quality: (Table A.2.3.10)
1. Low Quality/No Coating
2. A Medium-Quality Coating > 5yrs
3. A High-Quality Coating > 10yrs

$AF_{Coating}$ =

7.	*CALCULATE*	External Corrosion Rate (r_{ext})=	________	*Equation A.12*

Equation A.12

Calculation:

External Corrosion Rate (r_{ext})= $r_{ext\text{-}base}$ * $AF_{Coating}$

r_{ext} =

Table A.2.3.7: Internal Lining Adjustment

Is internal lining needed for corrosion protection?	AF
YES (but no internal lining or unknown)	1.75
YES (internal lining applied, but not per API 652)	1.15
YES (internal lining applied per API 652)	0.5
NO (and no lining applied)	1
NO (internal lining applied anyway but not per API 652)	0.9
NO (but internal lining applied per API 652)	0.8

Table A.2.3.8: Lining Age Adjustment

Lining Application and Age	AF
Lining applied per API 652	
> 20 years – limited or no data to assess lining condition	2.5
> 20 years – data to demonstrate that lining is in good condition	1
10 – 20 years	1
< 10 years	0.66
Lining not applied per API 652	
> 10 years – limited or no data to assess lining condition	1.5
> 10 years – data to demonstrate that lining is in good condition	1
5 – 10 years	1
< 5 years	0.87

Table A.2.3.9: Base Corrosion Rates for Shell External Corrosion

	Climate (see Page 5)		
Bulk Fluid Temp. (°F)	**Marine or Cooling Tower Drift Area**	**Temperate**	**Arid / Dry**
121 – 200	5 mpy	2 mpy	1 mpy
61 – 120	2 mpy	1 mpy	0 mpy
11 – 60	5 mpy	3 mpy	1 mpy
≤ 10	0 mpy	0 mpy	0 mpy

Table A.2.3.10: Adjustment of Quality Coating

Coating Quality	Adjustment
High	Assume that no corrosion occurs during the first ten years after coating application
Medium	Assume that no corrosion occurs during the first five years after coating application
Low/None	No credit given

Facility ____________________
Completed By ____________________

Date____________
Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM C**

Tank Shell Leak Frequency (Cont.) (Make as many copies of this form as required)

Note: If the corrosion rate is known, enter it in Item 8 below. If the corrosion rate is unknown, then use the results from Items 4 and 7 from the previous page with the following guidance. If the internal corrosion is believed to be widespread, then the external and internal corrosion rates are added together. If the internal corrosion is believed to be localized (pitting), then use the greater of the two corrosion values (either internal or external corrosion rate). ***Do not set the corrosion rate at less than 2 mpy.***

Tank ____

8. *SELECT* Corrosion Rate (**r**) = ____________mpy *See NOTE*

9. *DETERMINE* Age of Tank Shell (**a**)= ______________ *Years*

10. *DETERMINE* Original Thickness of Tank Shell (**t**)= ______________ *Mils*

11. *CALCULATE* “ar/t” Value (**ar/t**) = ______________ *Equation A.9*

Equation A.9

Calculation:

“ar/t” value= $\dfrac{a*r}{t}$

“ar/t” =

Table A.2.3.3: Guidelines for Assigning Inspection Ratings – Tank Shell	
Inspection Rating Category	**Inspection**
A	Intrusive inspection – good visuals with pit depth gage measurements at suspect locations
B	External spot/scanning UT based on visual information from previous internal inspection of this tank or similar service tanks
C	External spot/scanning UT at susceptible locations without benefit of any internal inspection information on tank type/service
D	External spot UT at susceptible locations without benefit of any internal inspection information on tank type/service
E	No inspection

12. *DETERMINE* Inspection Rating = ______________ *(Table A.2.3.3)*

12. *DETERMINE* # of Inspections ______________ *(# of each type of inspection i.e., 2 A's)*

12. *DETERMINE* Ar/t Modifying Factor (**$MF_{ar/t}$**)= ______________ *(Table A.2.3.4) *found on page 3**

13. *SELECT* Base Leak Frequency (**BLF**)= ______________ *(Table A.2.3.1)*

14. *CALCULATE* Tank Shell Leak Frequency (**SLF**)= ______________ *Equation A.10*

Table A.2.3.1: Base Leak Frequencies for Tank Shell	
Hole Sizes	**Frequency (per year)**
Small (Welded) Shell Leak	1.0×10^{-4}
Small (Riveted) Shell Leaks	1.0×10^{-3}

Table A.2.3.11: Base Leak Frequencies for Tank Rapid Shell Failures	
Rapid Shell Failure – Tank is not maintained to API 653	4.0×10^{-6}
Rapid Shell Failure – Tank is maintained to API 653	1.0×10^{-7}

Equation A.10

Calculation:

Tank Shell Leak Frequency (**SLF**)= **Base Leak Freq. * MR $_{art/t}$**

Shell Leak Frequency= (Enter Result on Form 1)

14. *SELECT* Tank Rapid Shell Failure Frequency (RSF) = *(Table A.2.3.11)*

(Enter Result on Form 1)

Facility ______________________

Completed By ______________________

Date_____________

Page ____of____

Table A.2.3.4: Tank Shell Modifying Factors

	Number of Inspections																
	0	**1**				**2**				**3**				**4**			
ar/t	E	D	C	B	A	D	C	B	A	D	C	B	A	D	C	B	A
0.05	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.10	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.15	0.314	0.240	0.165	0.0730	0.0202	0.180	0.0785	0.0121	0.0008	0.132	0.0348	0.0018	0.0001	0.0958	0.0148	0.0003	0.0001
0.20	177	135	92.9	41.1	11.3	101	44.1	6.82	0.435	74.4	19.6	1.01	0.0155	53.9	8.31	0.146	0.0005
0.25	2000	1530	1053	465	128	1146	500	77.2	4.92	843	222	11.5	0.176	610	94.1	1.66	0.0062
0.30	2000	1530	1053	465	129	1146	500	77.3	4.94	843	222	11.5	0.178	610	94.2	1.67	0.0066
0.35	2031	1559	1077	479	136	1172	517	82.0	6.13	866	233	12.9	0.349	631	101	2.07	0.0307
0.40	2265	1777	1262	588	197	1372	649	118	15.3	1046	321	23.7	1.66	790	157	5.17	0.217
0.45	2822	2298	1702	848	340	1849	962	204	37.3	1475	529	49.3	4.79	1170	290	12.6	0.659
0.50	5000	4334	3421	1860	899	3713	2188	541	123	3150	1343.5	149	17.0	2652	809	41.5	2.39
0.55	5000	4334	3421	1861	899	3713	2188	541	123	3150	1343.5	149	17.1	2652	809	41.5	2.44
0.60	5001	4335	3422	1862	901	3714	2189	542	125	3151	1344.8	151	18.6	2654	810	43.0	3.96
0.65	5009	4344	3433	1875	916	3725	2202	558	141	3163	1359.1	167	35.0	2666	825	59.4	20.4
0.70	5051	4392	3489	1944	993	3778	2268	638	224	3221	1432.3	250	119	2728	903	144	105
0.75	5179	4537	3657	2152	1225	3938	2467	879	477	3395	1653.3	502	374	2915	1138	398	360
0.80	5441	4835	4002	2579	1703	4268	2877	1376	995	3755	2108	1019	898	3301	1620	921	885
0.85	5850	5298	4540	3245	2447	4782	3516	2149	1803	4315	2816	1825	1715	3902	2372	1735	1703
0.90	6370	5887	5224	4091	3393	5436	4329	3133	2830	5028	3716	2849	2753	4666	3328	2771	2742
0.95	6940	6533	5974	5019	4431	6153	5219	4211	3955	5808	4702	3972	3891	5503	4375	3906	3882
1.00	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000	10000

Notes

A, *B*, *C*, and *D* refer to the inspection rating category. *E* indicates that there have been no inspections.
A value of “0” in the table indicates that the actual value is less than 0.0001.

Facility ______________________ Date_____________
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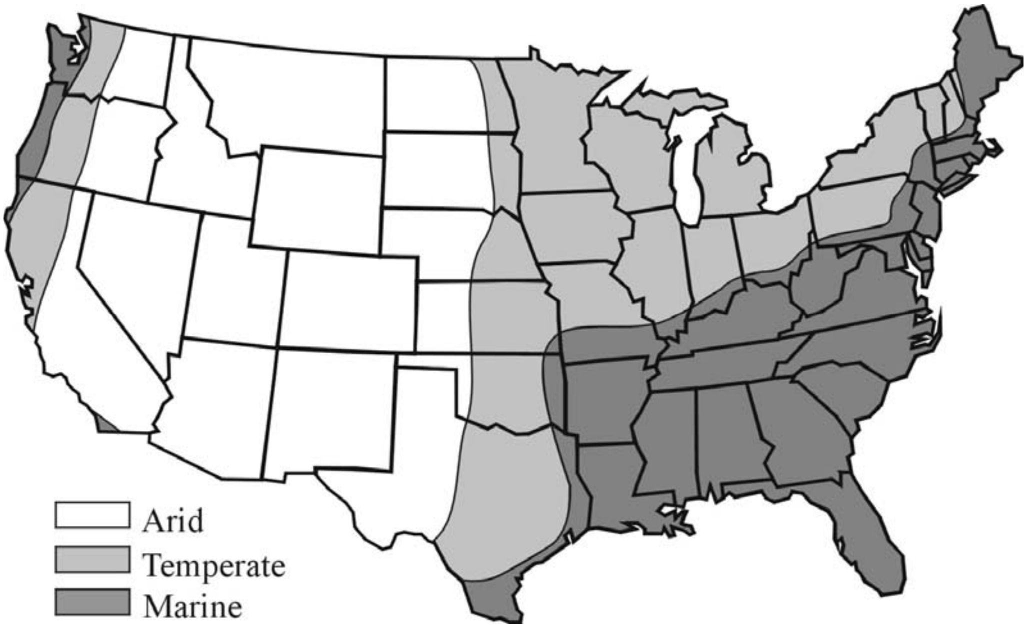

Figure A.2.3.2 Climate Map for the United States

AST PETROLEUM TERMINAL SITE DATA FORM D

Tank Overfill Frequency

(Make as many copies as required)

Tank ___

1.	*GIVEN*	Base Probability of Tank Overfill Frequency ($F_{O\text{-}Base}$)=	$1.0 * 10^{-4}$ / fill / yr	*(Equation A.14)*
2.	*DETERMINE*	How Many Total Fills Per Year Are Completed at This Point	____________	*(Each)*
3.	*DETERMINE*	Quality of Operations ($MF_{Quality}$)=	____________	*(Table A.2.4.2)*
4.	*DETERMINE*	Level Gauging ($MF_{Level\ Gauging}$)=	____________	*(Table A.2.4.3)*
5.	*DETERMINE*	Automatic Shutdown ($MF_{Auto\ Shut}$)=	____________	*Present = 0.1* *NO = 1.0*
6.	*DETERMINE*	Attendance at Fill Operations ($MF_{Attendance}$)=	____________	*(Table A.2.4.4)*
7.	*DETERMINE*	Tank Overfill Frequency (F_O)=		*(Equation A.15)*

Table A.2.4.4: Adjustment for Attendance at Fill Operations

Type of Shutdown	Level of Attendance at Fill Operations	Quality Rating		
		A	B	C
Automatic shutdown	Full time (90 – 100% present)	0.6	1	1.5
	Partial (25 – 90% present)	0.8	1.5	3
	Unattended (0 – 25% present)	1	3	5
Manual shutdown	Full time (90 – 100% present)	0.3	0.7	1
	Partial (25 – 90% present)	0.7	1	2
	Unattended (0 – 25% present)	not considered		

Table A.2.4.3: Adjustment for Level Gauging

Type of Level Gauging	MF
Two-stage independent level gauging	0.5
Instrumented level gauging	0.8
Ground level gauging	1

TABLE A.2.4.2: ASSESSING QUALITY OF OVERFILL MANAGEMENT SYSTEMS

	QUALITY ASSESSMENT QUESTIONS	SCORE
1	What is the quality of your fill procedures? A. Written procedures in accordance with API RP-2350, score =20 B. Written procedures, not in full accordance with API-RP-2350, score = 10 C. no written procedures, score =0	
2	How well do you plan product receipts? A. Planning of product receipt in accordance with API RP-2350, score = 10 B. Planning of product receipt, not in full accordance with API RP-2350, score = 5 C. no planning of product receipt, score = 0	
3	How well do you test electronic systems associated with tank fill operations? A. in accordance with API RP-2350, score =10 B. testing once per month, score = 5 C. no testing or no electronic systems, score =0	
4	How well have you prepared for emergencies? A. in accordance with API RP-2350, score = 10 B. written procedures in place, drills conducted, not in full accordance with API RP-2350, score = 5 C. little or no emergency preparedness, score = 0	
5	How well do you conduct training and performance evaluations? A. in accordance with API RP-2350, score = 10 B. specific training and evaluation occurs for overfill operations, not in full accordance with API RP-2350, score = 5 C. little or no specific training for operators on overfill operations, score =0	
6	How well do you test and inspect the overfill protection system? A. in accordance with API RP-2350, score = 20 B. some testing and inspection occurs, not in full accordance with API RP-2350, score = 10 C. little or no testing or inspection on overfill protection, score =0	
	Add lines 1 through 6. Refer to the table below to assess the overall rating for the quality of overfill management systems: Total Score =	

QUALITY OF OPERATIONS MODIFYING FACTOR

Total Score	Quality	Modifying Factor
50 – 80	A	0.3
30 – 49	B	1
0 – 29	C	3

Equation A.15

Calculation:

Tank Overfill Frequency (F_O) = $1.0 * 10^{-4}$ * (#fills / year) * $MF_{Quality}$ * $MF_{Level\ Gauging}$ * $MF_{Auto\ Shut}$ * $MF_{Attendance}$

Tank Overfill Frequency= (Enter Result on Form 1)

Facility ____________________

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AST PETROLEUM TERMINAL SITE DATA **FORM E**

Tank External Floating Roof Drain Leak Frequency

Tank #____

(Make as many copies as required)

Note: This module applies only to tanks with external floating roofs. *If the facility has several different types and styles of roof draining equipment (e.g., roof drain hose, articulated pipe, valve is left open or closed), the reviewer may elect to analyze several different roof drain operations, one representative operation, the most active operation, or the perceived highest risk operation. Use the figures and tables at the bottom of the page to complete the form. If multiple drain types, styles, and valve normal operations exist at the facility, it is recommended that the analysis be performed on the highest frequency operation.*

1. *SELECT* What Type of Equipment Is Used? Roof Drain Hose or Articulated Pipe *(Circle)*

2. *SELECT* In What Position Is the Roof Drain Valve Kept? Open/Closed *(Circle)*

If the roof drain valve is normally **OPEN,** go to **TABLE A.2.5.2** and select a Rupture Rate (Item 3) and Leak Rate (Item 4) for either a hose or articulated arm.
If the roof drain valve is normally **CLOSED,** go to **TABLE A.2.5.3** and select a Rupture Rate (Item 3) and Leak Rate (Item 4) for either a hose or articulated arm.

3. *SELECT* Rupture Leak Rate Frequency= ________________ *Table A.2.5.2 or Table A.2.5.3*

4. *SELECT* 1/8" Leak Rate Frequency= ________________ *Table A.2.5.2 or Table A.2.5.3*

Table A.2.5.2: External Floating Roof Drain Failure Rates – Valves Normally OPEN		
Equipment Item	**Rupture Rate (/yr)**	**1/8" Leak Rate (/yr)**
Roof drain hose	5×10^{-4}	2×10^{-2}
Articulated pipe	3×10^{-4}	3×10^{-2}

Table A.2.5.3: : External Floating Roof Drain Failure Rates – Valves Normally CLOSED		
Equipment Item	**4" Leak Rate (/yr)**	**1/8" Leak Rate (/yr)**
Roof drain hose	5×10^{-6}	2×10^{-4}
Articulated pipe	3×10^{-6}	3×10^{-4}

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AST PETROLEUM TERMINAL SITE DATA **FORM F**

Underground Piping Input Form

UG#__________

(Make as many copies as required)

The reviewer may elect to analyze one representative piping section, the oldest section, or several sections of piping. Use the figures and tables to the right to complete the form. If only one or two sections of piping are to be analyzed, it is recommended that the analysis be performed on higher risk piping (older, higher pressure, poorly coated or protected, higher temperature, poorly inspected piping).

DATA COLLECTION

1.	Pipe Diameter	______________	*(inches)*
2.	Schedule	______________	*OR*
3.	Thickness	______________	*(inches)*
4.	Pipe Length	______________	*(feet)*
5.	Number of Flanges	______________	*(each)*
6.	Number of Soil-to-Air Interfaces (StA)	______________	*(each)*
7.	Number of Cased Road Crossings (CRC)	______________	*(each)*
8.	Is the Location of Underground Piping Accurately Known?	______________	*Yes / No*
9.	Soil Resistivity	______________	*(ohm-cm)*
10.	Is the Piping Cathodically Protected?	______________	*Yes / No*
11.	Type of Cathodic Protection	______________	
12.	Operating Pressure	______________	*(psi)*
13.	Operating Temperature	______________	*(°F)*
14.	Product	______________	
15.	Is Piping **ACTIVE** or **DEADLEG?**	______________	
16.	Is the Piping Coated?	______________	*Yes / No*
17.	When Was the Piping Coated?	______________	
18.	What Is the Age of the Piping?	______________	*(years)*
19.	Has the Piping Been Inspected?	______________	*Yes / No*
20.	What Type of Inspection Was Performed?	______________	*(Visual, NDT, API 570, etc.)*
21.	When Was the Inspection Performed?	______________	
22.	How Many Previous Inspections Were Performed?	______________	
23.	Is the Inspection Information Available?	______________	*Yes / No*
24.	Establish Base Internal Corrosion Rate from Inspections, if known ($\mathbf{r}_{int\text{-}base}$)=	______________	*Or Assume 2 mils/year*
25.	Establish Base External Corrosion Rate from Inspections, if known ($\mathbf{r}_{ext\text{-}base}$)=	______________	*Or Assume 5 mils/year*

Facility ______________________ Date_____________
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AST PETROLEUM TERMINAL SITE DATA FORM F

Underground Piping Analysis Form

UG#__________

(Make as many copies as required)

Note: If the corrosion rate is known, skip to Item 10 and enter the known value. Continue to the next page using the known corrosion rate.

1.	*GIVEN*	External Base Corrosion Rate ($r_{ext-base}$) =	5 mpy	
2.	*DETERMINE*	Soil Conditions (Resistivity) ($AF_{Soil\ Cond}$)=	______	*(Table A.2.6.9)*
3.	*DETERMINE*	Cathodic Protection (AF_{CP})=	______	*(Table A.2.6.10)*
4.	*DETERMINE*	Exterior Coating/Pipe Wrap (AF_{EC})=	______	*(Table A.2.6.11)*
5.	*DETERMINE*	Exterior Coating Age (AF_{CA})=	______	*(Table A.2.6.12)*
6.	*DETERMINE*	External Corrosion Rate (r_{ext}) =	______	*Equation A.23*

Equation A.23

Calculation:
External Corrosion Rate (r_{ext})= **5 mpy** * AF_{rest} * AF_{CP} * AF_{EC} * AF_{CA}

r_{ext} =

7.	*GIVEN*	Internal Base Corrosion Rate ($r_{int-base}$)=	2 mpy	mpy
8.	*DETERMINE*	Product and Flow Conditions (AF_{PF})=	______	*(Table A.2.6.13)*
9.	*DETERMINE*	Internal Corrosion Rate (r_{int})=	______	*Equation A.24*

Equation A.24

Calculation:
Internal Corrosion Rate (r_{int}) = **2 mpy** * AF_{PF}

r_{int} =

10.	*DETERMINE*	Corrosion Rate (r)=	______	*Equation A.24*

Equation A.24

Calculation:
Corrosion Rate (**r**) = r_{ext} + r_{int}

r=

Table A.2.6.9: Soil Resistivity Adjustment

Resistivity (ohm-cm)	Potential Corrosion Activity	AF
<500	Very Corrosive	2.25
500 – 1000	Corrosive	1.6
1000 – 2000	Moderately Corrosive	1
2000 – 10000	Mildly Corrosive	0.7
>10000	Progressively Less Corrosive	0.46

Table A.2.6.10: Adjustment for Cathodic Protection

Functional Cathodic Protection in Place?	AF
NO CP, With Coating	1.33
NO CP, No Coating	1
YES (not per NACE RP0169 and API 651)	0.66
YES (per NACE RP0169 and API 651)	0.33

Table A.2.6.11: Adjustment for Exterior Coating or Pipe Wrap

Coating Type	AF
No exterior coating or pipe wrap	2
Exterior coating or pipe wrap	1

Table A.2.6.12: Exterior Coating Age Adjustment

Coating Age	AF
> 20 years – limited or no data to assess coating condition	2.0
> 20 years – data to demonstrate that coating is in good condition	0.8
10 – 20 years	0.8
< 10 years	0.5

Table A.2.6.13: Product and Flow Condition Adjustment

Product and Flow Conditions	AF
Refined Product (Gasoline, Diesel, etc.)	
-- Active Line	0.5
-- No Flow (Deadleg)	5
Crude Oil	
-- Active Line	1
-- No Flow (Deadleg)	10

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AST PETROLEUM TERMINAL SITE DATA **FORM F**

Underground Piping Analysis Form (Cont.)

UG#__________

(Make as many copies as required)

11. *DETERMINE* Inspection Rating= ______________ *(Table A.2.6.2)*

12. *DETERMINE* "ar/t" Value (**ar/t**)= ______________ *Equation A.17*

Equation A.17

Calculation:

"ar/t" value= $\frac{a*r}{t}$

"ar/t" value =

13. *DETERMINE* ar/t Modifying Factor ($\mathbf{MF_{ar/t}}$)= ____________ (Table A.2.6.3— on next page

14. *DETERMINE* Soil to Air Interface ($\mathbf{MF_{StA}}$)= ____________ *Equation A.18*

Equation A.18

Calculation:

Soil to Air Interface

($\mathbf{MF_{Soil\ to\ air}}$) = **1 + 0.5 * (# of Soil to Air Interfaces per 100' piping) * (QF)**

QF is found in Table A.2.6.4
QF is typically < 1

$\mathbf{MF_{Soil\ to\ Air}}$ =

15. *DETERMINE* Cased Road Crossings MF ($\mathbf{MF_{Crossing}}$)= ______________ *Equation A.19*

Equation A.19

Calculation:

Cased Road Crossings

($\mathbf{MF_{Road\ Crossing}}$)= **1 + 0.5 * (# of Cased Road Crossings per 100' piping)**

$\mathbf{MF_{Road\ Crossing}}$=

Table A.2.6.2: Guidelines for Assigning Inspection Ratings – Underground Piping	
Inspection Rating Category	**Method of Underground Piping Inspection**
A	Smart pigging.
B	Visual examination of all air-to-soil interfaces, as well as cased road crossings, and piping at selected excavation areas. **AND** Point thickness measurements supplemented with ultrasonic scanning or profile radiography on these areas.
C	Visual examination of overburden, and piping at selected excavation areas. **AND** Spot thickness measurements using pit gages, ultrasonic scanning or profile radiography on these areas.
D	Spot UT thickness measurements in aboveground sections of the piping and visual examination of overburden and air-to-soil interfaces.
E	No inspection, less than above recommendations or ineffective technique used.

Table A.2.6.4: Quality Factor (QF) for Soil-to-Air Interfaces	
Soil-to-Air Interface Description	**QF**
Applies for high quality soil-to-air interfaces. The coating is wrapped onto the piping and sealed either by a mastic or epoxy and extends aboveground at least 2 feet where the full circumference of the interface of the termination of the section of underground piping is subject to full visual inspection.	0.4
Applies for all bare pipe soil-to-air interfaces, interfaces which terminate through a concrete box, or interfaces where the ability to inspect the coating does not meet the criteria for Q=0.4.	1

Facility ____________________ Date____________

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Table A.2.6.3: Underground Piping Modifying Factors

	Number of Inspections																
	0	1				2				3				4			
ar/t	E	D	C	B	A	D	C	B	A	D	C	B	A	D	C	B	A
0.05	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.10	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.15	0.0241	0.0185	0.0127	0.0056	0.0005	0.0138	0.0060	0.0009	0.0001	0.0102	0.0027	0.0001	0.0001	0.0074	0.0011	0.0001	0.0001
0.20	13.6	10.4	7.15	3.16	0.284	7.78	3.40	0.524	0.0033	5.72	1.51	0.0780	0.0001	4.14	0.639	0.0113	0.0001
0.25	154	118	81	35.8	3.21	88.1	38.5	5.94	0.0378	64.8	17.0	0.884	0.0004	46.9	7.24	0.128	0.0001
0.30	154	118	81	35.8	3.22	88.2	38.5	5.95	0.0385	64.8	17.1	0.885	0.0005	47.0	7.25	0.128	0.0001
0.35	156	120	83	36.9	3.66	90.2	39.8	6.31	0.0848	66.6	17.9	0.992	0.0052	48.5	7.80	0.159	0.0005
0.40	174	137	97	45.3	7.04	106	49.9	9.09	0.443	80.5	24.7	1.82	0.0411	60.8	12.1	0.398	0.0041
0.45	217	177	131	65.2	15.1	142	74.0	15.7	1.30	113	40.7	3.79	0.127	90.0	22.3	0.967	0.0127
0.50	385	333	263	143	46.6	286	168	41.6	4.63	242	103	11.5	0.462	204	62.2	3.19	0.0462
0.55	385	333	263	143	46.6	286	168	41.6	4.63	242	103	11.5	0.465	204	62.2	3.19	0.0499
0.60	385	333	263	143	46.7	286	168	41.7	4.75	242	103	11.6	0.582	204	62.3	3.31	0.167
0.65	385	334	264	144	47.9	287	169	42.9	6.00	243	105	12.9	1.85	205	63.5	4.57	1.43
0.70	389	338	268	150	54.0	291	174	49.0	12.5	248	110	19.3	8.35	210	69.5	11.1	7.94
0.75	398	349	281	166	72.4	303	190	67.6	32.0	261	127	38.6	28.0	224	87.5	30.6	27.6
0.80	419	372	308	198	110	328	221	106	72.1	289	162	78.4	68.3	254	125	70.8	68.0
0.85	450	408	349	250	169	368	270	165	135	332	217	140	131	300	182	133	131
0.90	490	453	402	315	245	418	333	241	214	387	286	219	211	359	256	213	211
0.95	534	503	460	386	327	473	401	324	301	447	362	306	299	423	337	300	299
1.00	769	769	769	769	769	769	769	769	769	769	769	769	769	769	769	769	769

A, B, C, D, and E refer to the inspection rating category (see Table A.2.6.2).

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AST PETROLEUM TERMINAL SITE DATA **FORM F**

Underground Piping Analysis Form (Cont.) UG#__________

(Make as many copies as required)

16.	*DETERMINE*	UG Piping Location MF (**MF_{PL}**)=	______________	*(Table A.2.6.5)*
17.	*GIVEN*	UG Piping Base Leak Frequency (**BLF**)=	$5.0 * 10^{-6}$	*Per 100 foot-year (Standard)*
18.	*DETERMINE*	UG Piping Leak Frequency (**LF**)=	______________	*Equation A.20*

Table A.2.6.5: Modifying Factor for Piping Location	
Is the location of the underground piping accurately identified	**MF**
No	1
Yes	0.85

Equation A.20

Calculation:

Underground Leak Frequency (ULF) = **BLF** * $\mathbf{MF_{ar/t}}$* $\mathbf{MF_{StA}}$* $\mathbf{MF_{Crossing}}$* $\mathbf{MF_{PL}}$ *** (Length (ft)/100)**

Underground Leak Frequency (ULF) =

19. *DETERMINE* Flange Leak Frequency (FLF)= ______________ *Equation A.21*

Equation A.21

Calculation:

Flange Leak Frequency (FLF) = **# of Flanges * ($1*10^{-4}$)**

Flange Leak Frequency (FLF) =

20. *DETERMINE* Total Underground Piping Leak Frequency= ______________ *Equation A.22*

Equation A.22

Calculation:

Total Underground Leak Frequency = **ULF * FLF**

Total Underground Piping Leak Frequency ULF = ***(Enter Result on Form 1)***

Facility ______________________ Date_____________

Completed By ______________________ Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM G**

Aboveground Piping Input Form

(Make as many copies as required)

AG#__________

The reviewer may elect to analyze one representative piping section, the oldest section, or several sections of piping. Use the figures and tables to the right and bottom to complete the form. If only one or two sections of piping are to be analyzed, it is recommended that the analysis be performed on higher risk piping (older, higher pressure, poorly coated or protected, higher temperature, poorly inspected piping).

DATA COLLECTION

1. Pipe Diameter ____________________ *(inches)*
2. Schedule ____________________ *OR*
3. Thickness ____________________ *(inches)*
4. Pipe Length ____________________ *(feet)*
5. Number of Flange Sets in Segment ____________________ *(each)*
6. Operating Pressure ____________________ *(psi)*
7. Operating Temperature ____________________ *(°F)*
8. Product ____________________
9. Is Piping **ACTIVE** or **DEADLEG?** ____________________
10. Is the Piping Coated? ____________________ *Yes / No*
11. When Was the Piping Coated? ____________________
12. What Is the Age of the Piping? ____________________ *(years)*
13. Has the Piping Been Inspected? ____________________ *Yes / No*
14. What Type of Inspection Was Performed? ____________________ *(Visual, NDT, API 570, etc.)*
15. When Was the Inspection Performed? ____________________

16 How Many Previous Inspections Were Performed? ____________________

17 Is the Inspection Information Available? ____________________ *Yes / No*

18. Has Piping Been Left Uncoated or Is Coating in Poor Condition? ______________ *Yes / No*
19. If YES, How Many Years Has the Piping Been Unprotected? ______________ *years*
20. Establish Base Internal Corrosion Rate from Inspections, if Known ($\mathbf{r}_{int\text{-}base}$)= __________ *Or Assume 2 mils/year*
21. Establish Base External Corrosion Rate from Inspections, if Known ($\mathbf{r}_{ext\text{-}base}$)= __________ *Or Assume 5 mils/year*
22. What Is the Coating Quality? __________ *(Table A.2.6.19)*

Table A.2.6.19: Adjustment for Quality of Coating	
Coating Quality	**Adjustment**
High	Assume that no corrosion occurs during the first ten years after coating application
Medium	Assume that no corrosion occurs during the first five years after coating application
Low/None	No credit given
* If the external piping is pitted, no credit should be given for coating the pipe.	

Facility ______________________ Date______________

Completed By ______________________ Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM G**

AG#__________

Aboveground Piping Analysis Form (Corrosion Rate Not Known)

If the corrosion rate of the piping segment under analysis is known, then go to Item 8 on the next sheet. This form is to be completed for each piping segment being analyzed. Make as many copies of these forms as needed.

1. *DETERMINE* External Base Corrosion Rate ($\mathbf{r}_{\text{ext-base}}$) = ________________ *(Table A.2.6.18)*

2. *DETERMINE* # of Years Pipe Unprotected = ________________ *(Table A.2.6.19 & calc below)*

3. *CALCULATE* External Coating ($\mathbf{AF}_{\text{Coating}}$)= ________________ *Equation A.31*

Equation A.31

Calculation:

External Coating ($\mathbf{AF}_{\text{Coating}}$)= $\dfrac{\#YearsPipeUnprotected}{PipingAge}$ =

Quality: (Table A.2.6.19)
1. No pipe coating or low-quality coating: receives no credit, answer = pipe age in yrs
2. A medium-quality Coating: receives up to 5 yrs of credit, answer = pipe age – 5 yrs
3. A high-quality Coating: receives up to 10 yrs of credit, answer = pipe age – 10 yrs
Note that you cannot use a negative number. For example, if the pipe age is 4 yrs and it has a high-quality coating, then the # of yrs that the pipe is unprotected is 4-10 = -6. Instead, use 0 for the answer.

$\mathbf{AF}_{\text{Coating}}$ =

4. *DETERMINE* External Corrosion Rate ($\mathbf{r}_{\text{ext}}$)= ________________ *Equation A.32*

Equation A.32

Calculation:
External Corrosion Rate ($\mathbf{r}_{\text{ext}}$) = $\mathbf{r}_{\text{ext-base}} * \mathbf{AF}_{\text{Coating}}$

$\mathbf{r}_{\text{ext}}$ =

5. *GIVEN* Internal Base Corrosion Rate ($\mathbf{r}_{\text{int-base}}$)= ____2____ mpy (Standard)

6. *DETERMINE* Product and Flow Conditions ($\mathbf{AF}_{\text{PFC}}$)= ________________ *(Table A.2.6.20)*

7. *DETERMINE* Internal Corrosion Rate ($\mathbf{r}_{\text{int}}$)= ________________ *Equation A.33*

Equation A.33

Calculation:
Internal Corrosion Rate ($\mathbf{r}_{\text{int}}$) = $\mathbf{r}_{\text{int-base}} + \mathbf{AF}_{\text{PFC}}$

$\mathbf{r}_{\text{int}}$ =

Table A.2.6.18: Base Corrosion Rates for Aboveground Piping External Corrosion

Bulk Fluid Temp (°F)	Climate: Marine / Cooling Tower Drift Area	Climate: Temperate	Climate: Arid / Dry
121 – 200	5 mpy	2 mpy	1 mpy
61 – 120	2 mpy	1 mpy	0 mpy
11 – 60	5 mpy	3 mpy	1 mpy
≤ 10	0 mpy	0 mpy	0 mpy

Table A.2.6.19: Adjustment for Quality of Coating

Coating Quality	Adjustment
High	Assume that no corrosion occurs during the first ten years after coating application
Medium	Assume that no corrosion occurs during the first five years after coating application
Low/None	No credit given

Table A.2.6.20: Product and Flow Condition Adjustment

Product and Flow Conditions	AF
Refined Product (Gasoline, Diesel, etc.)	
-- Active Line	0.5
-- No Flow (Deadleg)	5
Crude Oil	
-- Active Line	1
-- No Flow (Deadleg)	10

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AST PETROLEUM TERMINAL SITE DATA — FORM G

Aboveground Piping Analysis Form (Cont.) (Make as many copies as required)

Note: If the corrosion rate is known, enter it in Item 10 below. If the corrosion rate is unknown, then use the results from Item 8 from the previous page with the following guidance. If the internal corrosion is believed to be widespread, then add the external and internal corrosion rates area together. If the internal corrosion is believed to be localized (pitting), then use the greater of the two corrosion values (either internal or external corrosion rate).

AG#__________

8. *DETERMINE* Corrosion Rate (**r**)= _______________ *Equation A.34*

Equation A.34

Calculation:
Corrosion Rate (**r**)= $\mathbf{r_{ext} + r_{int}}$

r =

9. *GIVEN* Base Leak Frequency (**BLF**)= $2.7 * 10^{-6}$ *leaks per 100 ft / year (Standard)*

10. *DETERMINE* Inspection Rating= _______________ *(Table A.2.6.15)*

DETERMINE "ar/t" value ($\mathbf{MF_{ar/t}}$)= _______________ *Equation A.27*

Equation A.27

Calculation:
"ar/t" value = $\frac{a * r}{t}$

"ar/t" Value =

11. *DETERMINE* ar/t MF ($\mathbf{MF_{ar/t}}$)= _______________ *(Table A.2.6.16,found on next page)*

12. *DETERMINE* Aboveground Leak Frequency (**ALF**)= _______________ *Equation A.28*

Equation A.28

Calculation:
Aboveground Piping Leak Frequency (**ALF**)= $2.7 * 10^{-6} * MF_{ar/t} * \frac{Length(ft)}{100}$

Aboveground Piping Leak Frequency (**ALF) =**

Table A.2.6.15: Guidelines for Assigning Inspection Ratings – Aboveground Piping	
Inspection Rating Category	**Method of Aboveground Piping Inspection**
A	For the total length of the piping: • Visual examination (API 570) **AND** • Thickness measurements using ultrasonic scanning or profile radiography on selected TML's (API 570) and statistical analysis of the data.
B	For the total length of the piping: • Visual examination (API 570) **AND** • Point thickness measurements supplemented with ultrasonic scanning, or profile radiography on selected TML's (API 570).
C	For the total length of the piping: • Visual examination per API 570 **AND** • Spot UT thickness measurements per API 570.
D	Spot UT thickness measurements.
E	No inspection, less than above recommendations or ineffective technique used.

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Table A.2.6.16: Aboveground Piping Modifying Factors

	Number of Inspections																
	0	**1**				**2**				**3**				**4**			
ar/t	E	D	C	B	A	D	C	B	A	D	C	B	A	D	C	B	A
0.05	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.10	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
0.15	0.0424	0.0324	0.0223	0.0099	0.0009	0.0243	0.0106	0.0016	0.0001	0.0178	0.0047	0.0002	0.0001	0.0129	0.0020	0.0001	0.0001
0.20	23.8	18.2	12.5	5.54	0.498	13.7	5.96	0.920	0.0058	10.0	2.64	0.137	0.0001	7.27	1.12	0.0198	0.0001
0.25	270	206	142	62.8	5.63	155	67.5	10.4	0.0662	114	29.9	1.55	0.0007	82.3	12.7	0.224	0.0001
0.30	270	207	142	62.8	5.65	155	67.5	10.4	0.0675	114	29.9	1.55	0.0009	82.4	12.7	0.225	0.0001
0.35	274	210	145	64.7	6.42	158	69.8	11.1	0.149	117	31.5	1.74	0.0090	85.2	13.7	0.279	0.0008
0.40	306	240	170	79.4	12.4	185	87.6	15.9	0.777	141	43.3	3.19	0.0722	107	21.2	0.698	0.0072
0.45	381	310	230	114	26.5	250	130	27.6	2.27	199	71.4	6.65	0.223	158	39.1	1.70	0.0222
0.50	675	585	462	251	81.7	501	295	72.9	8.11	425	181	20.2	0.810	358	109	5.60	0.0810
0.55	675	585	462	251	81.7	501	295	73.0	8.12	425	181	20.2	0.817	358	109	5.60	0.0876
0.60	675	585	462	251	81.9	501	295	73.1	8.33	425	181	20.4	1.02	358	109	5.81	0.293
0.65	676	586	463	253	84.0	503	297	75.3	10.5	427	183	22.6	3.24	360	111	8.02	2.52
0.70	682	593	471	262	94.7	510	306	86.0	21.9	435	193	33.8	14.7	368	122	19.4	13.9
0.75	699	612	493	290	127	531	333	119	56.1	458	223	67.7	49.1	393	154	53.7	48.4
0.80	734	652	540	348	194	576	388	186	127	507	284	138	120	445	219	124	119
0.85	790	715	613	438	297	645	475	290	236	582	380	246	230	527	320	234	230
0.90	860	794	705	552	429	734	584	423	376	678	501	384	370	630	449	374	370
0.95	937	882	806	677	574	830	704	568	529	784	635	536	524	743	590	527	524
1.00	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350

Notes
A, B, C, D, and E refer to the inspection rating category (see Table A.9.22).
A value of “0” in the table indicates that the actual value is less than 0.0001.

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AST PETROLEUM TERMINAL SITE DATA

FORM G

AG#__________

Aboveground Piping Analysis Form (Cont.)

(Make as many copies as required)

13. *DETERMINE* # of Pipe Segment Flange Connections = ______________ *# of Flanged Connections*

14. *CALCULATE* Flange Leak Frequency (**FLF**) = ______________ *Equation A.29*

Equation A.29

Calculation:

Flange Leak Frequency (**FLF**)= **# of Flanged Connections * $1x10^{-4}$ events/yr/flanged connection**

Flange Leak Frequency (**FLF) =**

15 *CALCULATE* Total Aboveground Piping Leak Frequency= __________________ *Equation A.30*

Equation A.30

Calculation:

Total Aboveground Leak Frequency = **ALF + FLF**

Total Aboveground Leak Frequency = ***(Enter Result on Form 1)***

Facility ______________________

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AST PETROLEUM TERMINAL SITE DATA FORM H

Transfer Leak Frequency

(Make as many copies as required)

LR#____________

The reviewer may elect to analyze several transfer points, one representative transfer point, the most active transfer points, or the perceived highest risk transfer point (risk to the environment). Use the figures and tables on the right to complete the form. If only one or two transfer points are to be analyzed, it is recommended that the analysis be performed on higher risk areas including, if applicable, marine transfer areas and uncontained transfer areas.

Transfer Point #____ *Transfer Point Description:* ________________________________

a. If transfer point is a marine transfer, then complete the following. Otherwise skip to b.
   1 Base marine leak frequency (Base) = _____________ (from Table A.2.7.3)
   2 Average # of marine transfers/year = ______________ (# of marine transfers/yr)
   3 Calculate the marine transfer leak frequency (Ftm) = _______ (leaks/yr) (Equation C.2)

Equation C.2

Calculation:

F_{tm} = Base (from Table A.2.7.3) * # of marine transfers

b. If transfer point is composed of a hose, then complete the following. Otherwise, skip to c.
   1 Average # of hose transfers/week = ______________ (# of hose transfers/wk)
   2 Base hose leak (1/8") frequency ($Base_{\text{hose leak}}$) = ________________(from Table A.2.7.1)
   3 Base hose rupture frequency ($Base_{\text{hose rupture}}$) = ________________(from Table A.2.7.1)

c. If transfer point is an articulated arm, then complete the following:
   1 Average # of articulated arm transfers/week = ______________ (# of transfers/wk)
   2 Base articulated arm (1/8") leak frequency ($Base_{\text{arm leak}}$) = _______________ (from Table A.2.7.2)
   3 Base articulated arm rupture leak frequency ($Base_{\text{arm rupture}}$) = _______________ (from Table A.2.7.2)

Equation C.3

Calculation:

$F_{\text{transfer leaks}} = F_{tm} + Base_{\text{hose leak}} + Base_{\text{hose rupture}} + Base_{\text{arm leak}} + Base_{\text{arm rupture}}$

$F_{\text{transfer leaks}} =$

Transfer Leak Frequency= (Enter Result on Form 1)

Table A.2.7.1: Flexible Hose Failure Rates including Drive-offs		
Transfers per Transfer Point	**$^1/_8$" Leak Rate (/yr)**	**Rupture Rate (/yr)**
≤ 20 / week	2.03×10^{-2}	7.0×10^{-4}
21 – 40 / week	3.37×10^{-2}	1.25×10^{-3}
41 – 80 / week	5.13×10^{-2}	2.0×10^{-3}
> 80 / week	6.87×10^{-2}	3.0×10^{-3}

Table A.2.7.2: Articulated Hose Failure Rates including Drive-offs		
Transfers per Transfer Point	**$^1/_8$" Leak Rate (/yr)**	**Rupture Rate (/yr)**
≤ 20 / week	8.12×10^{-3}	2.8×10^{-4}
21 – 40 / week	1.35×10^{-2}	5.0×10^{-4}
41 – 80 / week	2.05×10^{-2}	8.0×10^{-4}
> 80 / week	2.75×10^{-2}	1.2×10^{-3}

Table A.2.7.3: Marine Transfer Leak Frequencies	
Equipment	**Leak Frequency (per transfer operation)**
Flexible Hose	1.8×10^{-4}
Articulated Arm	7.6×10^{-5}

Facility ______________________ Date_____________

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AST PETROLEUM TERMINAL SITE DATA **FORM I**

Tank Truck Overfill Frequency

(Make as many copies as required)

LR ___

If the facility has several different types and styles of tank truck loading (e.g., different loading racks, differing automation, top loading vs. bottom loading, etc.), the reviewer may elect to analyze several different tank truck overfill operations, one representative operation, the most active operation, or the perceived highest risk operation (risk to the environment). Use the figures and tables to the right to complete the form. If multiple loading types, styles, and automation exist at the facility, it is recommended that the analysis be performed on higher risk operations such as high volume, low automation, and high environmental risk loading areas.

Loading Rack: ______________________________

Tank Truck Loading Description: ______________________________

____

1.	*GIVEN*	Base Probability of Tank Overfill Frequency ($F_{TO\text{-}Base}$)=	$1.0 * 10^{-5}$ / fill	*Standard*
2.	*DETERMINE*	How Many Total Fills Per Year Are Completed at This Point?	________	*(Each)*
3.	*DETERMINE*	Quality of Operations ($MF_{Quality}$)=	________	*(Table A.2.7.4)*
4.	*DETERMINE*	Control Systems ($MF_{Control}$)=	________	*(Table A.2.7.5)*
5.	*DETERMINE*	Tank Truck Overfill Frequency (F_{TO})=	________	*Equation A.35*

Table A.2.7.4: Adjustment for Quality of Operations

Type of Fill Operation	MF
Loading operation in accordance with API RP 1004 (for MC-306 tank trucks only)	1
All others	2

Table A.2.7.5: Adjustment for Control Systems

Type of Fill Operation	MF
None	100
Primary control system (e.g. a preset loading meter and a control valve)	10
Primary plus secondary control systems (e.g. level sensor which activates automatic shutoff)	1

Equation A.35

Calculation:

Tank Truck Overfill Frequency (F_{TO}) = $\mathbf{1.0 * 10^{-5} * (\#\ fills\ /\ year) * MF_{Quality} * MF_{control}}$

Tank Truck Overfill Frequency = (Enter Result on Form 1)

Facility ______________________ Date____________

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AST PETROLEUM TERMINAL SITE DATA FORM J

Consequences of Failure (COF) Summary Form

Make as many copies as needed to accommodate all release scenarios.

EVENT:____

Unit Operation:____

ECOF Weighting Factor (WF) = __________% (1 – 100 %)

ECOF Score = __________________________(Form K)

PCOF Weighting Factor (WF) = __________% (1 – 100 %)

PCOF Score = __________________________(Form U)

BCOF Weighting Factor (WF) = __________% (1 – 100 %)

BCOF Score = __________________________(Form V)

Equation A.38

COF score = (ECOF WF x ECOF) + (PCOF WF x PCOF) + (BCOF WF x BCOF)

COF = _______________

Facility ___________________________ Date_______________

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AST PETROLEUM TERMINAL SITE DATA — FORM K

Environmental Consequences of Failure (ECOF) Model

Make as many copies as needed to accommodate all release scenarios.

EVENT:____

Unit Operation:____

ECOF Weighting Factor (WF) = ________% (1 – 100 %)

1. Product Type

		Score
a	Heavy Oil (heavy crudes, #6 FO, asphalt, and motor oil)	0.5
b	Medium Oil (most crudes)	0.75
c	Light Oil (diesel, #2, light crudes)	1
d	Very Light Oil (gasoline and jet fuels)	1.5

ANSWER Q1

2. Anticipated Volume of Released Liquid Petroleum

(complete applicable forms L – T to calculate volume)

		Score
a	< 25 bbl (~ 1,000 gal)	1
b	25 bbl to 250 bbl	5
c	251 bbl to 2,500 bbl	10
d	2,501 bbl to 25,000 bbl	45
e	> 25,000 bbl	90

ANSWER Q2

3. Primary Area Impacted by Release

(complete applicable forms L – T to determine media impacted)

		Score
a	Release Contained in an Impermeable Diked Area	1
b	Release Impacts Onsite Soils only	5
c	Release Impacts Offsite Soils	25
d	Release Impacts Subsurface soils	40
e	Release Impacts Groundwater	60
f	Release Impacts Surface Waters	50
g	Release Impacts Drinking Waters (surface or groundwater)	100

ANSWER Q3

4. Surrounding Ecology Sensitivity (Site Conditions)

		Score
a	Not an Ecologically Sensitive Area	1
b	Close Proximity to Aquatic Habitats or Regulated Wetlands	25
c	Sensitive Biological, Species or Ecologic Receptors	50
d	Unusually Sensitive Biological Species	100

ANSWER Q4

Facility ______________________ Date______________

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AST PETROLEUM TERMINAL SITE DATA **FORM K**

Environmental Consequence of Failure (ECOF) Model (Cont.)

Make as many copies as needed to accommodate all tanks and failure scenarios.

	5. Pathway Assessment to Sensitive Ecology	Score	
a	Unlikely, Limited, or Negligible Impact to Surrounding Ecology	0.5	ANSWER Q5
b	Likely Impact to Surrounding Ecology	2	

	6. Environmental Regulatory Atmostphere	Score	
a	Efficient, Timely, and Pragmatic Regulatory Environment	0.5	ANSWER Q6
b	Moderate Regulatory Environment	1	
c	Strict Proscriptive Regulatory and Enforcement Action	2	

	7. Duration of Environmental Impact (Ecology or Surrounding Offsite Environment)	Score	
a	No or Negligible Impact (less than 1 week)	0.5	
b	Short-Term Impact up to 1 Month	1	ANSWER Q7
c	Moderate Impact up to 1 Year	5	
d	Long-Term Impact > 1 Year	10	

	8. Response Plans and Response Effectiveness	Score	
a	Written Spill Response Plan, Drills, & OSRO in Place with Ability to Perform a Rapid Effective Response to the Incident	1	ANSWER Q8
b	No Response Plan in Place or Response Contingency Plan of Limited Effectiveness Due to the Nature of the Incident	1.5	

ECOF Equation

ECOF score (i) = Q1 Product x Q2 Volume x (Q3 Media + Q4 Ecology x Q5 Pathway) x Q6 Regulatory x Q7 Duration x Q8 Response

= ______ x ______ x (______ + ______ x ______) x ______ x ______ x ______
Q1 Q2 Q3 Q4 Q5 Q6 Q7 Q8

ECOF score (i) = ____________

WF (ECOF) = ___________%

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AST PETROLEUM TERMINAL SITE DATA FORM L

Small Tank Bottom Leak Volume/Media Determination

TANK #______________

1.	DETERMINE	Time to Detect and Stop Lleak	______ days	(Estimate or Table A.3.1.1)
2.	DETERMINE	Depth to Groundwater	______ feet	
3.	DETERMINE	Soil Type	______	
4.	CALCULATE	Leak Rate	______ Bbls/hr	(Equation A.40 and Figure A.3.1.4, Table A.3.1.2)

Equation A.40

$q = C\ h^{0.9}\ a^{0.1}\ k^{0.74}$

q = flow rate, (m^3/sec);
C = adjustment factor for degree of contact with soil:
0.21 for good contact, 1.15 for poor contact;
h = depth of liquid (m);
a = area of hole (m^2) (≤1/2"); and
k = hydraulic conductivity of soil (m/sec).

q =

q = ____________________ m^3/sec

Leak rate (Rr) = q (m^3/sec) x 6.29 bbls/m^3 x 3600 sec/hr

Rr = __________________ barrels/hr
(Or from Figure A.3.1.4 or Table A.3.1.2)

Table A.3.1.1: Small Bottom Leak Duration Times	
Site Conditions	**Leak Duration Time**
RPB or Sand Pad over Clay	5 to 15 days
Impervious Soil Layer Under Tank Sand Pad	15 to 30days
Semi-Impervious Under Tank Soil	30 to 90 days
Pervious Soil	90 plus days

Table A.3.1.2 Release (Leak) rate from small bottom leaks (bbl/hr)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	1	0.5	0.03
Very Fine Sand	0.08	0.03	0.002
Silt	0.006	0.003	0.0002
Sandy Clay	0.001	0.0005	0.00003
Clay	0.0002	0.00008	0.000005

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

5. CALCULATE Leak Volume ______________ bbls (Equation A.42)

Equation A.42

Small Bottom Leak Volume = Leak Rate **Rr** (bbls/day) x Duration of Leak (days)

Leak Volume = _______________ bbls

Facility ______________________ Date_____________
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AST PETROLEUM TERMINAL SITE DATA **FORM L**

Small Tank Bottom Leak Volume/Media Determination (Cont'd)

6.	DETERMINE	Hydraulic Conductivity	____________	cm/s	(Known or Figure A.3.1.4)
7.	DETERMINE	Vertical Fluid Velocity	____________	ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	CALCULATE	Time to Reach Groundwater	____________	day	(Equation C.2)

<u>Equation C.2</u>

Time to Reach Groundwater = Distance to groundwater (feet) / Vertical Fluid Velocity (feet/day)

= ____________________________day

If Leak Duration > Time to Reach Groundwater, then groundwater is affected.

9. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.4 Flow Through Soil at Hydraulic Gradient = 1

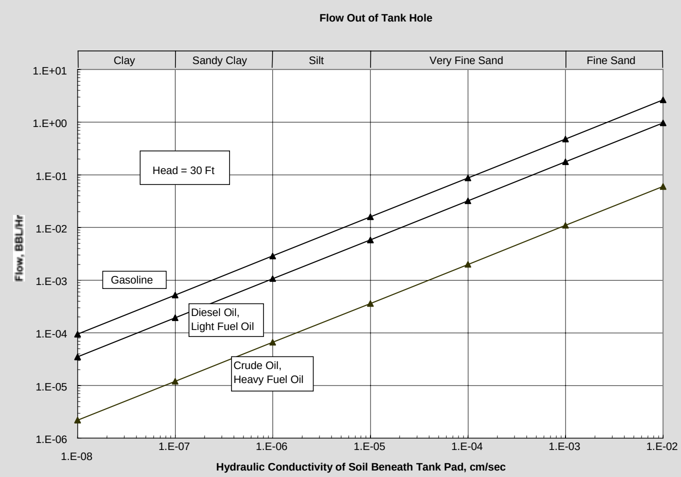


Figure A.3.1.2 Environmental Media

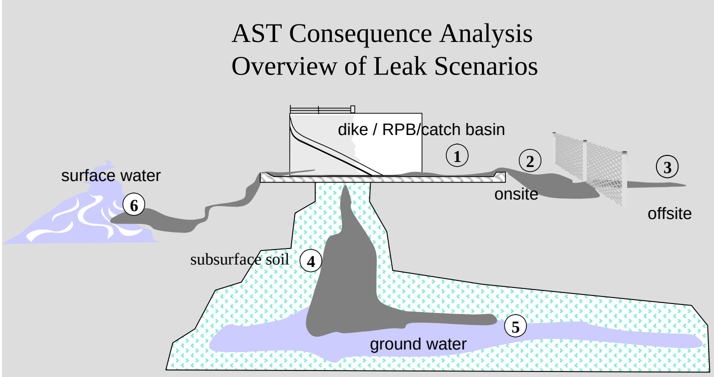
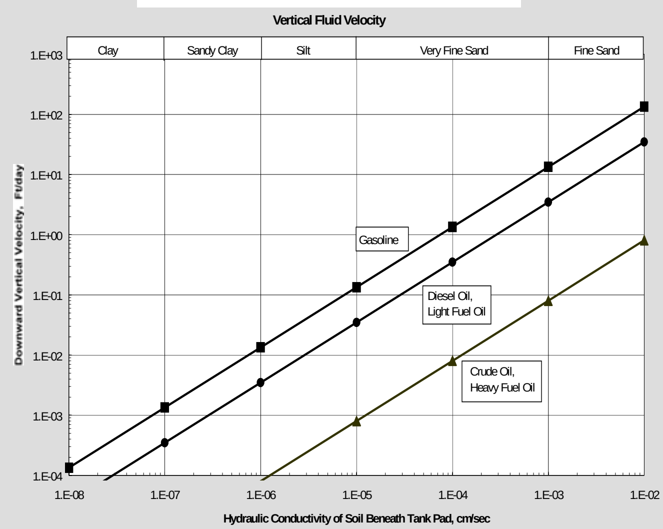


Figure A.3.1.5 Vertical Fluid Velocity



Facility ______________________ Date_____________

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AST PETROLEUM TERMINAL SITE DATA **FORM M**

Small Tank Shell Leak Volume/Media Determination

TANK #_______________ Hole Size______________

1.	DETERMINE	Time to detect and stop leak	______ days	(Estimate)
2.	DETERMINE	Depth to groundwater	______ feet	
3.	DETERMINE	Soil Type	______	
4.	CALCULATE	Leak Rate	______ bbls/hr	(Equation A.41 or Table A.3.1.5)

Equation A.41

$$R_r = C_d \frac{\pi d^2}{4} \sqrt{2g\Delta h} * 4.45$$

R_r = volumetric flow rate (bbl/hour);
C_d = discharge coefficient (dimensionless, suggested value of 0.61 for hydrocarbon liquids);
d = hole diameter (inches, suggest a 1/8" hole);
g = gravitational acceleration (32.2 ft/sec^2);
Δh = liquid head at the leak (ft); and
4.45 = factor used to convert to bbl/hr.

R_r = ________________bbl/hour

Table A.3.1.5 Release rates for fluid to atmosphere (all fluid types)

Head (ft)	R_r (bbl/hr)		
	1/8" hole	½" hole	2" hole
10	0.85	13.5	216.4
15	1.04	16.6	265.1
20	1.20	19.1	306.1
25	1.34	21.4	342.2
30	1.46	23.4	374.8
35	1.58	25.3	404.9
40	1.69	27.1	432.8

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

5. CALCULATE Leak Volume ______________ bbls (Equation A.43)

Equation A.43

Small Shell Leak Volume = Release Rate **Rr** (bbls/hrs) x Duration of Leak (hours)

Leak Volume = _______________bbls

Facility ________________________ Date______________
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AST PETROLEUM TERMINAL SITE DATA **FORM M**

Small Tank Shell Leak Volume/Media Determination (Cont.)

6.	DETERMINE	Hydraulic Conductivity	______________ cm/s	(Known or Estimate Based on Soil Type)
7.	DETERMINE	Vertical Fluid Velocity	______________ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	CALCULATE	Time to Reach Groundwater	______________ day	(Equation C.2)

Equation C.2

Time to Reach Groundwater = Distance to groundwater (feet) / Vertical Fluid Velocity (feet/day)

= ____________________________day

If Leak Duration > Time to Reach Groundwater, then groundwater is affected.

9. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.2 Environmental Media

AST Consequence Analysis
Overview of Leak Scenarios

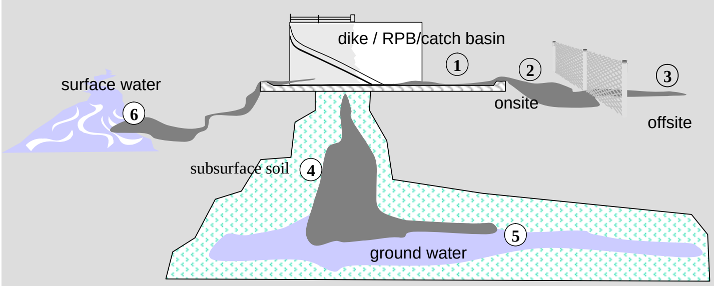
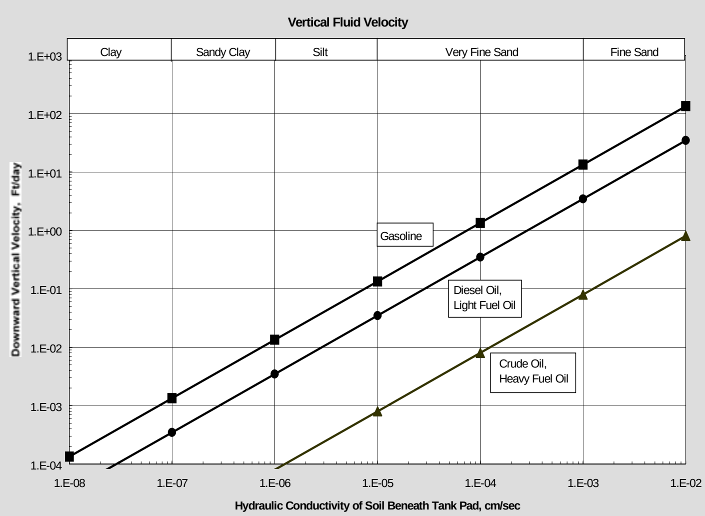


Figure A.3.1.5 Vertical Fluid Velocity



Facility ______________________
Completed By ______________________

Date______________
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AST PETROLEUM TERMINAL SITE DATA — FORM N

Rapid Tank Failure Volume/Media Determination

TANK #______________

1.	DETERMINE	Safe Fill Capacity	______ bbls	(This is the volume released)
2.	DETERMINE	Volume of Dike	______ bbls	
3.	DETERMINE	Time to Detect and Stop Leak	______ days	(Estimate)
4.	DETERMINE	Depth to Groundwater	______ feet	
5.	DETERMINE	Soil Type (within dike)	______	
6.	DETERMINE	Soil Type (outside dike)	______	
7.	CALCULATE	Fraction Lost over Dike	______ bbls/hr	(Equation C.3 & Table A.3.1.6)

Equation C.3

Volume Tank Contents / Volume of Dike = ________

=______________

Fraction lost over dike = _________
(See Table A.3.1.6)

If brittle fracture, and shell within 20 feet of exterior dike, assume 100% lost over dike.

Table A.3.1.6 Rapid Failure Dike Overflow

$V_{Tank\ Contents}$ / V_{Dike}	Fraction of Tank Contents Overflowing Dike
0.4	0.05
0.5	0.2
0.6	0.35
0.7	0.5
0.8	0.6
0.9	0.7

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

8.	DETERMINE	Hydraulic Conductivity for Soils within Dike	______ cm/s	(Known or estimate based on soil type)
9.	DETERMINE	Vertical Fluid Velocity for Soils within Dike	______ cm/s or ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	DETERMINE	Hydraulic Conductivity for Soils outside Dike	______ cm/s	(Known or estimate based on soil type)
9.	DETERMINE	Vertical Fluid Velocity for Soils outside Dike	______ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
10.	CALCULATE	Time to Reach Groundwater within Dike	______ day	(Equation C.2)
10.	CALCULATE	Time to Reach Groundwater outside Dike	______ day	(Equation C.2)

Facility ______________________ Date______________
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AST PETROLEUM TERMINAL SITE DATA FORM N

Rapid Tank Failure Volume/Media Determination (Cont.)

Equation C.2

Time to Reach Groundwater = Distance to groundwater (feet) / Vertical Fluid Velocity (feet/day)

= ___________________day (Inside Dike)

=___________________day (Outside Dike)

If Time to Remediate > Time to Reach Groundwater, then groundwater is affected.

11. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.2 Environmental Media

AST Consequence Analysis
Overview of Leak Scenarios

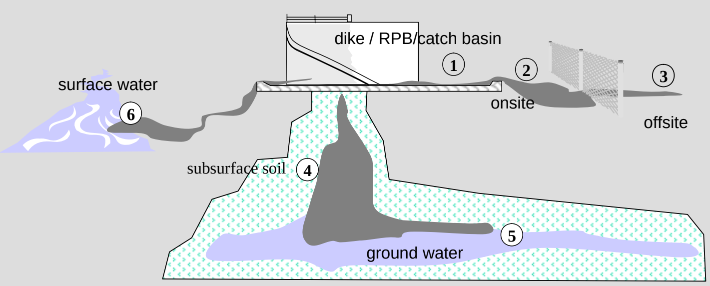
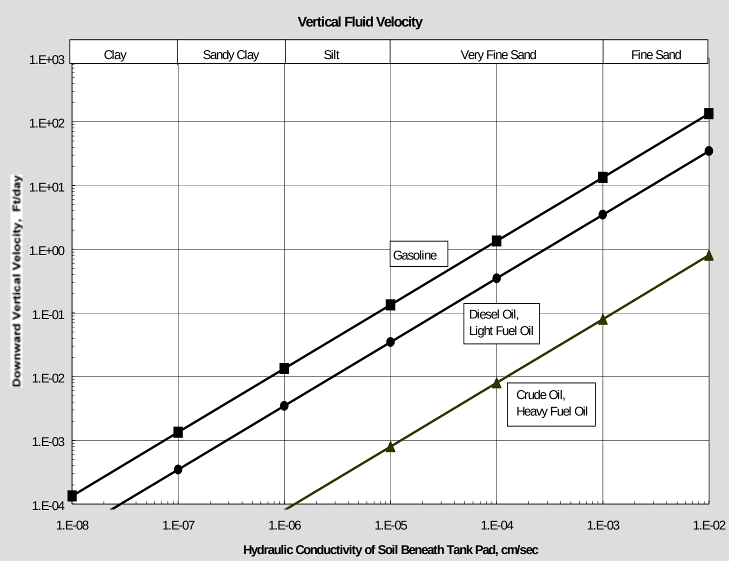


Figure A.3.1.5 Vertical Fluid Velocity



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AST PETROLEUM TERMINAL SITE DATA FORM O

Tank Overfill Volume/Media Determination

TANK #______________

1.	DETERMINE	Tank Fill Rate	______ bbls/hr	
2.	DETERMINE	Time to Detect and Stop Overfill (Duration of Overfill)	______ days	(Estimate)
3.	DETERMINE	Depth to Groundwater	______ feet	
4.	DETERMINE	Soil Type	______	
5.	CALCULATE	Leak Rate	______ bbls/hr	(Equation A.44)

Equation A.44

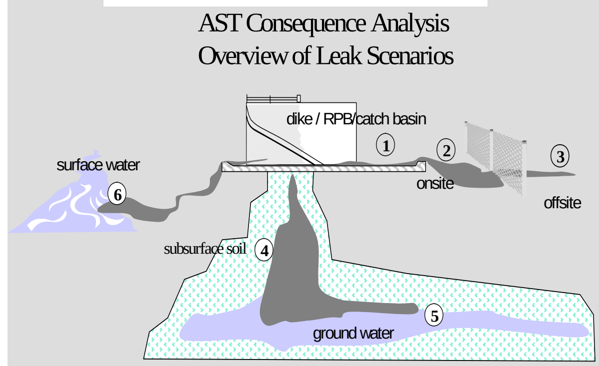
Overfill Volume = Fill Rate (bbls/hr) x Duration of Overfill (hrs)

Volume of Release = _________________bbls

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

Figure A.3.1.2 Environmental Media



6.	DETERMINE	Hydraulic Conductivity	______ cm/s	(Known or estimate based on soil type)
7.	DETERMINE	Vertical Fluid Velocity	______ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	CALCULATE	Time to Reach Groundwater	______ day	(Equation C.2)
9.	DETERMINE	Media Impacted	______	(Figure A.3.1.2)

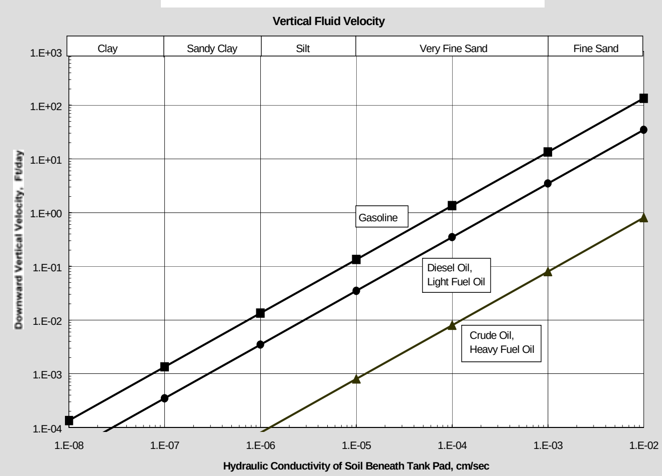
Equation C.2

Time to Reach Groundwater = Distance to groundwater (feet) / Vertical Fluid Velocity (feet/day)

= ____________________________day

If Leak Duration > Time to Reach Groundwater, then groundwater is affected.

Figure A.3.1.5 Vertical Fluid Velocity



Facility ______________________ Date_____________

Completed By ______________________ Page ____of____

AST PETROLEUM TERMINAL SITE DATA **FORM P**

Tank Drain Leak Volume/Media Determination (External Floating Roofs)

TANK #______________

1.	DETERMINE	Time to Detect and Stop Leak	______ days	(Estimate)
2.	DETERMINE	Depth to Groundwater	______ feet	
3.	DETERMINE	Soil Type	______	
4.	CALCULATE	Leak Rate	______ bbls/hr	(Equation A.41)

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

Equation A.41

$$R_r = C_d \frac{\pi d^2}{4} \sqrt{2g\Delta h} * 4.45$$

R_r = volumetric flow rate (bbl/hour);
C_d = discharge coefficient (dimensionless, suggested value of 0.61 for hydrocarbon liquids);
d = hole diameter (inches, for hole in drain pipe suggest a 1/8" hole, for hose failure suggest full internal diameter of hose);
g = gravitational acceleration (32.2 ft/sec^2);
Δh = liquid head at the leak (ft); and
4.45 = factor used to convert to bbl/hr.

R_r = ___________________bbl/hour

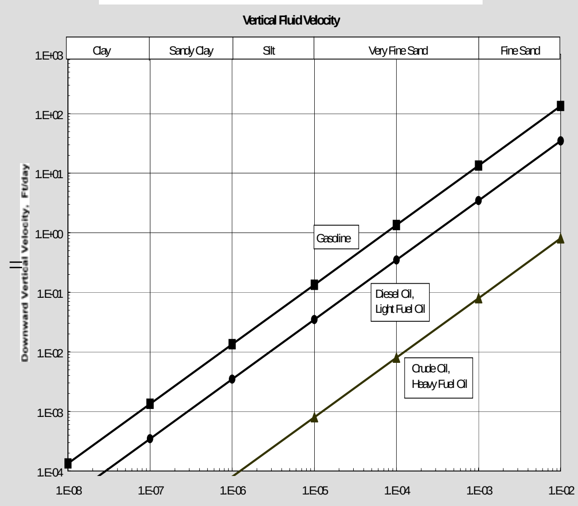
5. CALCULATE Leak Volume ______ bbls (Equation A.43)

Equation A.43

Small Shell Leak Volume = Release Rate **Rr** (bbls/hrs) x Duration of Leak (hours)

Leak Volume = _______________bbls

Figure A.3.1.5 Vertical Fluid Velocity



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AST PETROLEUM TERMINAL SITE DATA **FORM P**

Tank Drain Leak Volume/Media Determination (External Floating Roofs) (Cont.)

6.	DETERMINE	Hydraulic Conductivity	______ cm/s	(Known or estimate based on soil type)
7.	DETERMINE	Vertical Fluid Velocity	______ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	CALCULATE	Time to Reach Groundwater	______ day	(Equation C.2)

<u>Equation C.2</u>

Time to Reach Groundwater = Distance to Groundwater (feet) / Vertical Fluid Velocity (feet/day)

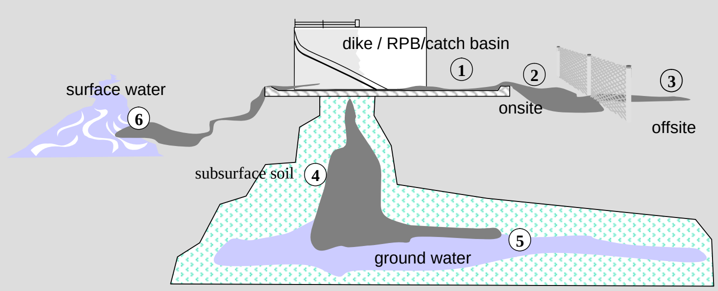
= ___________________________day

If Leak Duration > Time to Reach Groundwater, then groundwater is affected.

9. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.2 Environmental Media

AST Consequence Analysis
Overview of Leak Scenarios



Facility _______________________
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Date_____________
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AST PETROLEUM TERMINAL SITE DATA **FORM Q**

Pressurized Piping Leak Volume/Media Determination

Piping Type (Aboveground/Underground) ______________________________

1.	DETERMINE	Time to Detect and Stop Leak (AG/UG)	________ days	(Estimate)
2.	DETERMINE	Depth to Groundwater	________ feet	
3.	DETERMINE	Soil Type	________	
4.	CALCULATE	Leak Rate	________ bbls/hr	(Equation A.41 or Table A.3.1.8)

Table A.3.1.8: Piping Leak Rates During Pumping (100 psig)

Product	Small Leak Rate (bbl/hr)
Gasoline	6.2
Diesel oil/ light fuel oil	5.7
Crude oil/ heavy fuel oil	5.5

Equation A.41

$$R_r = C_d \frac{\pi d^2}{4} \sqrt{2g\Delta h} * 4.45$$

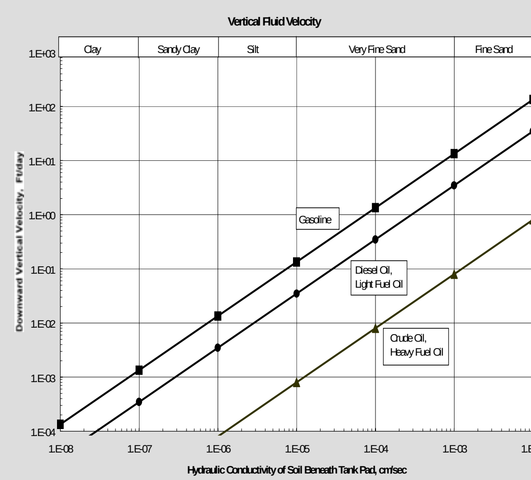
R_r = volumetric flow rate (bbl/hour);
C_d = discharge coefficient (dimensionless, suggested value of 0.61 for hydrocarbon liquids);
d = hole diameter (inches, suggest a 1/8" hole);
g = gravitational acceleration (32.2 ft/sec^2);
Δh = liquid head at the leak (ft); and
4.45 = factor used to convert to bbl/hr.

R_r = ____________________bbl/hour
(Or from Table A.3.1.8)

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

Figure A.3.1.5 Vertical Fluid Velocity



5. CALCULATE Leak Volume ________ bbls (Equation C.4)

Equation C.4

Piping Leak Volume = Release Rate **Rr** (bbls/hrs) x Duration of Leak (hours)

Leak Volume = ________________bbls

Facility ______________________
Completed By ______________________

Date_____________
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AST PETROLEUM TERMINAL SITE DATA **FORM Q**

Pressurized Piping Leak Volume/Media Determination

6.	DETERMINE	Hydraulic Conductivity	______ cm/s	(Known or estimate based on soil type)
7.	DETERMINE	Vertical Fluid Velocity	______ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	CALCULATE	Time to Reach Groundwater	______ day	(Equation C.2)

Equation C.2

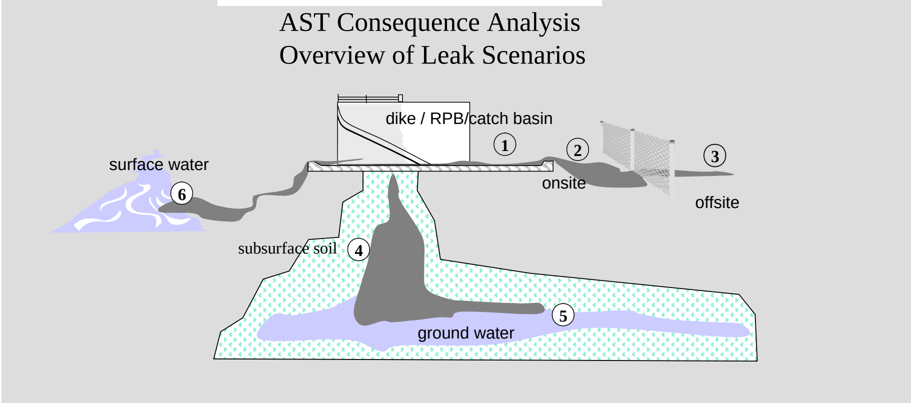
Time to Reach Groundwater = Distance to Groundwater (feet) / Vertical Fluid Velocity (feet/day)

= ___________________________day

If Leak Duration > Time to Reach Groundwater, then groundwater is affected.

9. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.2 Environmental Media



Facility ______________________ Date_____________

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AST PETROLEUM TERMINAL SITE DATA **FORM R**

Underground Suction/Gravity Piping Leak Volume/Media Determination

Piping Type (Suction or Gravity) ______________________________

1.	DETERMINE	Time to Detect and Stop Leak	____________ days	(Estimate)
2.	DETERMINE	Depth to Groundwater	____________ feet	
3.	DETERMINE	Soil Type	____________	
4.	CALCULATE	Leak Rate	____________ bbls/hr	(Equation A.40 or Table A.3.1.9/10)

Equation A.40

$q = C\, h^{0.9} a^{0.1} k^{0.74}$

q = flow rate, (m^3/sec);
C = adjustment factor for degree of contact with soil:
0.21 for good contact, 1.15 for poor contact;
h = depth of liquid (m);
a = area of hole (m^2) (≤1/2"); and
k = hydraulic conductivity of soil (m/sec).

q = ____________________ m^3/sec

Leak rate Rr = q (m^3/sec) x 6.29 barrels/m^3 x 3600 sec/hr

Rr = __________________ barrels/hr
(Or from Figure A.3.1.4 or Table A.3.1.9/10)

Table A.3.1.9: Small Leak Rates for Underground Suction Piping (20 psig)

Soil Type	Leak Rate (bbl/hr) Gasoline	Leak Rate (bbl/hr) Diesel Oil Light Fuel Oil	Leak Rate (bbl/hr) Crude Oil Heavy Fuel Oil
Fine Sand	2	1	0.04
Very Fine Sand	0.2	0.06	0.004
Silt	0.01	0.006	0.0004
Sandy Clay	0.002	0.001	6×10^{-5}
Clay	0.0004	0.0002	1×10^{-5}

Table A.3.1.10: Small Leak Rates for Underground Gravity Flow Piping (0.5 psig)

Soil Type	Leak Rate (bbl/hr) Gasoline	Leak Rate (bbl/hr) Diesel Oil Light Fuel Oil	Leak Rate (bbl/hr) Crude Oil Heavy Fuel Oil
Fine Sand	0.07	0.03	0.001
Very Fine Sand	0.005	0.002	0.0001
Silt	0.0004	0.0002	1×10^{-5}
Sandy Clay	7×10^{-5}	3×10^{-5}	2×10^{-6}
Clay	1×10^{-5}	5×10^{-6}	3×10^{-7}

5. CALCULATE Leak Volume ____________ bbls (Equation C.4)

Equation C.4

Piping Leak Volume = Release Rate **Rr** (bbls/hrs) x Duration of Leak (hours)

Leak Volume = ________________ bbls

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

Facility ______________________ Date______________
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AST PETROLEUM TERMINAL SITE DATA **FORM R**

Underground Suction/Gravity Piping Leak Volume/Media Determination (Cont'd)

6.	DETERMINE	Hydraulic Conductivity	____________ cm/s	(Known or Figure A.3.1.4)
7.	DETERMINE	Vertical Fluid Velocity	____________ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	CALCULATE	Time to Reach Groundwater	____________ day	(Equation C.2)

Equation C.2

Time to Reach Groundwater = Distance to Groundwater (feet) / Vertical Fluid Velocity (feet/day)

= ___________________________day

If Leak Duration > Time to Reach Groundwater, then groundwater is affected.

9. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.2 Environmental Media

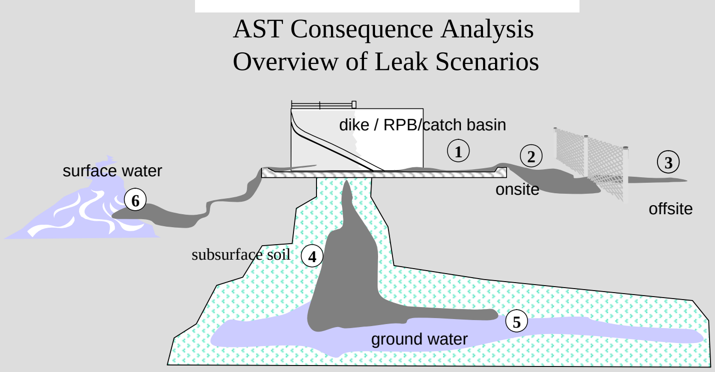


Figure A.3.1.4 Flow through Soil at Hydraulic Gradient = 1

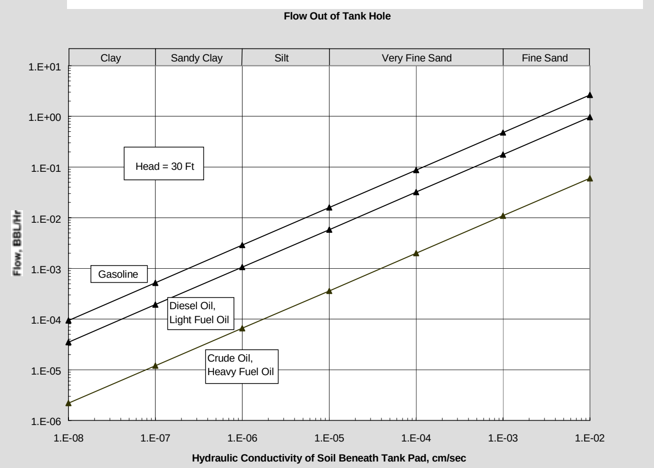
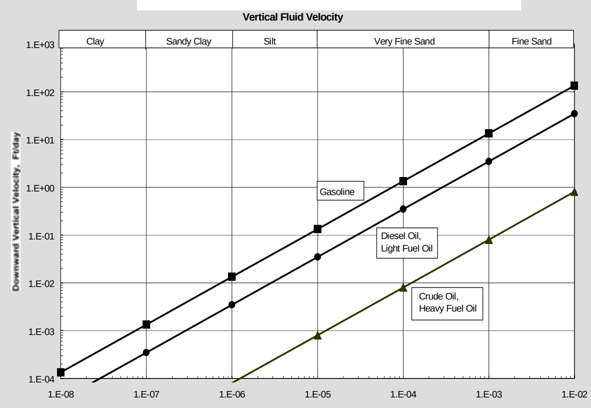


Figure A.3.1.5 Vertical Fluid Velocity



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AST PETROLEUM TERMINAL SITE DATA — FORM S

Aboveground Suction Piping Leak Volume/Media Determination

1. DETERMINE Time to Detect and Stop Leak ______ days (Estimate)
2. DETERMINE Depth to Groundwater ______ feet
3. DETERMINE Soil Type ______
4. CALCULATE Leak Rate ______ bbls/hr (Equation A.41 or Table A.3.1.11)

Equation A.41

$$R_r = C_d \frac{\pi d^2}{4}\sqrt{2g\Delta h} * 4.45$$

R_r = volumetric flow rate (bbl/hour);
C_d = discharge coefficient (dimensionless, suggested value of 0.61 for hydrocarbon liquids);
d = hole diameter (inches, suggest a 1/8" hole);
g = gravitational acceleration (32.2 ft/sec^2);
Δh = liquid head at the leak (ft); and
4.45 = factor used to convert to bbl/hr.

R_r = ______ bbl/hour
(Or from Table A.3.1.11)

Table A.3.1.11: Leak Rates for Aboveground Suction Ping (20 psig)	
Product	**Small Leak Rate (bbl/hr)**
Gasoline	2.7
Diesel oil/ light fuel oil	2.6
Crude oil/ heavy fuel oil	2.5

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

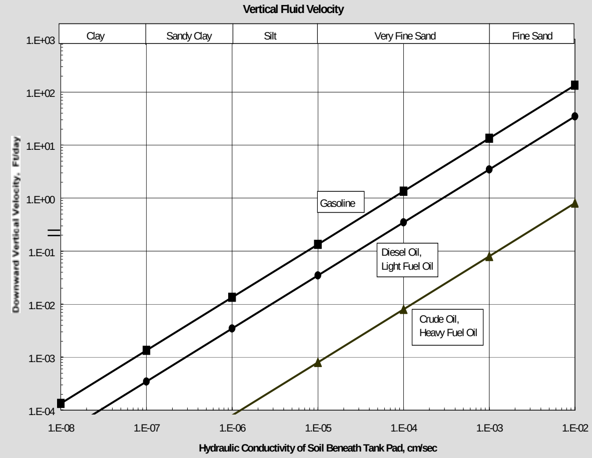
5. CALCULATE Leak Volume ______ bbls (Equation C.4)

Equation C.4

Piping Leak Volume = Release Rate **Rr** (bbls/hrs) x Duration of Leak (hours)

Leak Volume = ______ bbls

Figure A.3.1.5 Vertical Fluid Velocity



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Date ______
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AST PETROLEUM TERMINAL SITE DATA **FORM S**

Aboveground Suction Piping Leak Volume/Media Determination (Cont.)

6.	DETERMINE	Hydraulic Conductivity	______ cm/s	(Known or Estimate based on soil type)
7.	DETERMINE	Vertical Fluid Velocity	______ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
8.	CALCULATE	Time to Reach Groundwater	______ day	(Equation C.2)

Equation C.2

Time to Reach Groundwater = Distance to Groundwater (feet) / Vertical Fluid Velocity (feet/day)

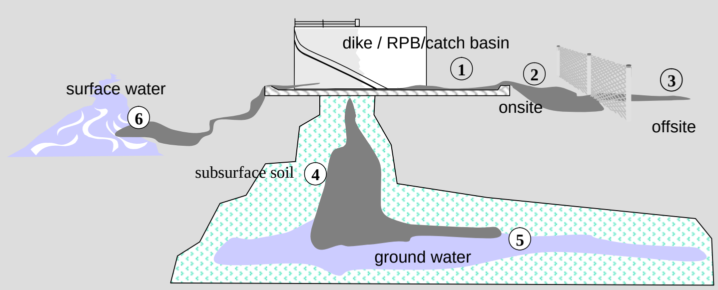
= ____________________________day

If Leak Duration > Time to Reach Groundwater, then groundwater is affected.

9. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.2 Environmental Media

AST Consequence Analysis
Overview of Leak Scenarios



Facility ______________________
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Date______________
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AST PETROLEUM TERMINAL SITE DATA **FORM T**

Transfer Equipment Leak Volume/Media Determination

Transfer Equipment (Overfill Leak or Leak/Rupture)______________________________

1.	DETERMINE	Fill Rate (for overfill)	________ bbls/hr	
2.	DETERMINE	Time to Detect and Stop Cverfill (Duration of Overfill)	________ days	(Estimate)
3.	DETERMINE	Time to Detect Leak/Rupture	________ hours	(Estimate)
4.	DETERMINE	Depth to Groundwater	________ feet	
5.	DETERMINE	Soil Type (at Location of Leak/Overfill)	________	
6.	CALCULATE	Overfill Volume or Leak Rate	________ bbls/hr	(Equation C.5 or Equation A.41)

Equation C.5

Overfill Volume = Fill Rate (bbls/hr) x Duration of Overfill (hrs)

= ________________bbls

Equation A.41 (for leak/rupture)

$$R_r = C_d \frac{\pi d^2}{4} \sqrt{2g\Delta h} * 4.45$$

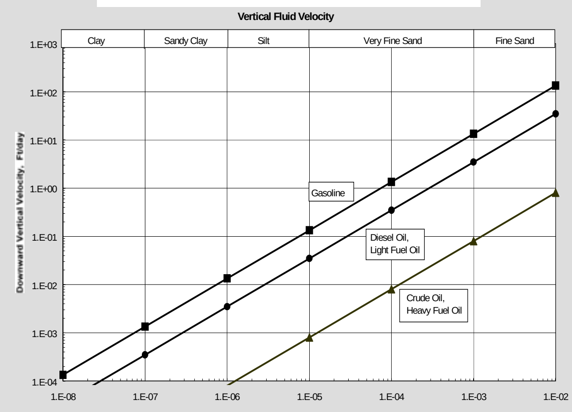
R_r = volumetric flow rate (bbl/hour);
C_d = discharge coefficient (dimensionless, suggested value of 0.61 for hydrocarbon liquids);
d = hole diameter (inches, for hole in hose/pipe suggest a 1/8" hole, for hose/pipe failure suggest full internal diameter of hose/pipe);
g = gravitational acceleration (32.2 ft/sec^2);
Δh = liquid head at the leak (ft); and
4.45 = factor used to convert to bbl/hr.

R_r = ____________________bbl/hour

Table A.3.1.3 Vertical Fluid Velocity through Soil for Leaks from Tanks (ft/day)

Soil Type	Gasoline	Diesel Oil Light Fuel Oil	Crude Oil Heavy Fuel Oil
Fine Sand	40	10	0.3
Very Fine Sand	1	0.3	0.01
Silt	0.04	0.01	0.0003
Sandy Clay	0.004	0.001	0.00003
Clay	0.0004	0.0001	0.000003

Figure A.3.1.5 Vertical Fluid Velocity



7.	CALCULATE	Leak Volume	________ bbls	(Equation C.6)

Facility ________________________ Date______________
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AST PETROLEUM TERMINAL SITE DATA **FORM T**

Transfer Equipment Leak Volume/Media Determination (Cont.)

Equation C.6

Transfer Eqt. Leak Volume = Release Rate **Rr** (bbls/hrs) x Duration of Leak (hours)

Leak Volume = _______________bbls

8.	DETERMINE	Hydraulic Conductivity for Soils in Area of Release	_______________ cm/s	(Known or estimate based on soil type)
9.	DETERMINE	Vertical Fluid Velocity for Soils in Area of Release	_______________ ft/day	(Figure A.3.1.5 or Table A.3.1.3)
10.	CALCULATE	Time to Reach Groundwater	_______________ day	(Equation C.2)

Equation C.2

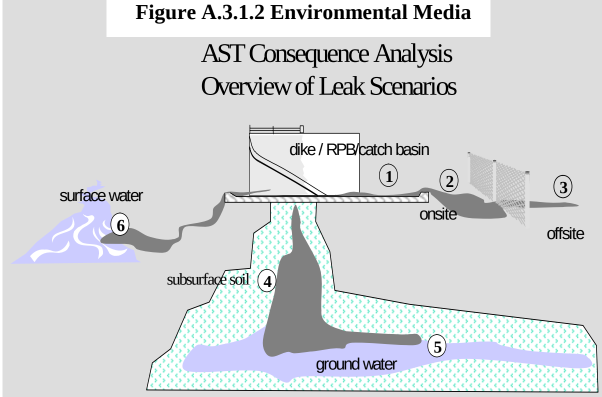
Time to Reach Groundwater = Distance to Groundwater (feet)/Vertical Fluid Velocity (feet/day)

= ___________________day

If Time to Remediate > Time to Reach Groundwater, then groundwater is affected.

9. DETERMINE Media Impacted (Figure A.3.1.2)

Figure A.3.1.2 Environmental Media



Facility _______________________

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Date______________

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AST PETROLEUM TERMINAL SITE DATA **FORM U**

Population Consequences of Failure (PCOF) Model

Make as many copies as needed to accommodate all release scenarios.

EVENT:____

Unit Operation:____

PCOF Weighting Factor (WF) = _________% (1 – 100 %)

1. Anciticipated Volume of Released Liquid Petroleum
(complete applicable forms L – T to calculate volume)

		Score
a	< 25 bbl (~ 1,000 gal)	1
b	25 bbl to 250 bbl	5
c	251 bbl to 2,500 bbl	10
d	2,501 bbl to 25,000 bbl	45
e	> 25,000 bbl	90

ANSWER Q1

2. Stored Product Flammability/Combustibility

		Score
a	Combustible Liquids Including Motor Oils, Lubricatnts, Hydraulic Oils	0.5
b	Combustible Liquids Including #2, #1, Kero, Diesel, Jet A, JP-8	1
c	Flommable Liquids Including Most Crude Oils	5
d	Flammable Liquids Including Gasoline All Grades, Ethanol	10

ANSWER Q2

3. Fire Response Capabilities (Fire Suppression or Spill Dispersant Capabilities)

		Score
a	Fixed Fire Suppression Systems in Place on Flammable Loading Area and Flammable Storage Tanks	0.2
b	Local or Portable Fire Suppression Systems Available for Flammable and Combustible Liquids	1.0
c	No Local or Sufficient Portable Firefighting or Spill Dispersant Capabilities on Site. Local Response Available But Response Anticipated to Be Greater Than 30 Minutes.	2.0

ANSWER Q3

4. Health and Safety Impact to Personnel, Contractors, or the Public

		Score
a	No Injury or Near Miss	1
b	Minor Injury	15
c	Serious Injury or Fatalility	100

ANSWER Q4

Facility ______________________ Date______________

Completed By ______________________ Page _____of____

AST PETROLEUM TERMINAL SITE DATA **FORM U**

Population Consequence of Failure (PCOF) Model (Cont.)

5. Dispersion of Released Product (Area of Impact)
(complete applicable forms L – T to calculate volume)

		Score
a	Release Contained in an Impermeable Diked Area	1
b	Release Contained on Site	5
c	Release Impacts Offsite Property	25
d	Release Impacts Recreational Surface Waters	50
e	Release Impacts Drinking Waters (surface or groundwater)	100

ANSWER Q5

6. Surrounding Community Impact Duration

		Score
a	No or Negligible Community Impact	1
b	Short-Term Community Impact up to 1 Week	2
c	Medium-Term Community Impact up to 1 Month	5
d	Long-Term Community Impact > 1 Month	14

ANSWER Q6

7. Adjacent Human Use/Population Sensitive Areas

		Score
a	Limited or Negligible Human Use in the Affected Area	0.5
b	Light Commercial/Industrial	1.0
c	School, Hospital, Stadium, Church, Residential Area, Heavy Commercial in the Affected Area	2.5
d	Historial, Recreational, Transportation, or Water Resource Sensitive Area	5

ANSWER Q7

8. Response Plans and Response Effectiveness

		Score
a	Written Spill Response Plan, Drills, and OSRO in Place with Ability to Perform a Rapid Effective Response to the Incident	1
b	No Response Plan in Place or Response Contingency Plan of Limited Effectiveness Due to the Nature of the Incident	1.5

ANSWER Q8

PCOF Equation

PCOF score (i) = Q1 Volume x (Q2 Product x Q3 Response Capabilities x Q4 Health/Safety x Q5 Dispersion x Q6 Community Impacts x Q7 Adjacent Use) x Q8 Response Plans

= ______ x (______ x ________ x ________ x _______ x ________ x ______) x ______
Q1 Q2 Q3 Q4 Q5 Q6 Q7 Q8

PCOF score (i) = _____________ WF (PCoF) = _________%

Facility ________________________ Date______________

Completed By ________________________ Page ____of____

AST PETROLEUM TERMINAL SITE DATA — FORM V

Business Consequences of Failure (BCOF) Model

Make as many copies as needed to accommodate all release scenarios.

EVENT:____

Unit Operation:____

BCOF Weighting Factor (WF) = _________% (1 – 100 %)

1. Estimated Cost of Loss (complete form W to calculate costs)

		Score
a	< $10,000	1
b	$10,000 to $100,000	5
c	$100,000 to $1,000,000	10
d	$1,000,000 to $10,000,000	25
e	> $10,000,000	49

ANSWER Q1

2. Impact on Facility Operation

		Score
a	No Facility or Equipment Loss of Service	0.1
b	Equipment out of Service for < 1 Month	1
c	Equipment out of Service for > 1 Month	1.5
d	Facility out of Service for < 1 Month	2.5
e	Effectively Shuts Down Facility Operation for > 1 Month	5

ANSWER Q2

3. Effect on Company Reputation or Standing in Community

		Score
a	No or Minimal Public Complaint	1
b	Only Local Public Complaints	1.5
c	Significant Local and Some Regional Public Complaints	2.5
d	Widespread National or Regional Public Complaints	5

ANSWER Q3

4. Regulatory Involvement as a Result of the LRS

		Score
a	No Regulatory Involvement	0.5
b	Local Regulatory Oversight Only	1
c	Local and State Regulatory Involvement with Cleanup, Inspection, or Startup of the Facility after the Incident	2.5
d	Will Most Likely Lead to Additional Enforcement at Other Facilities or for the Industry as a Whole	5

ANSWER Q4

Facility ______________________ Date______________

Completed By ______________________ Page _____of_____

AST PETROLEUM TERMINAL SITE DATA **FORM V**

Business Consequence of Failure (BCOF) Model (Cont.)

Make as many copies as needed to accommodate all tanks.

5. Loss of Business

		Score
a	No Loss of Business	1
b	Short-Term Loss of Business (<1 month)	1.5
c	Long-Term Loss of Business (1 to 12 months)	2
d	Nearly Permanent Loss of Business (>1 year)	5

ANSWER Q5

6. Media Coverage

		Score
a	No Media Coverage, Local Officials and Response Personnel Only	1
b	Only Local Media Coverage	1.5
c	Significant Local and Some National Coverage of Event	5
d	Extended Local and National Coverage of Event	8

ANSWER Q6

7. Effect on Property

		Score
a	No Change in Property or Equipment Value	1
b	Some Diminishment of the Property and Equipment	1.5
c	Significant Diminishment of the Value of the Facility	2

ANSWER Q7

8. Insurability and Coverage

		Score
a	No Effect on Insurance	1
b	Event Fully Insured But Claim Will Affect Company Rating	1.5
c	Event has Insurable Portions but Will Affect Futures Costs and Coverage	2
d	Self-Insured up to Event Costs	2.5

ANSWER Q8

Equation

BCOF score (i) = Q1 Cost of Loss x Q2 Impact on Operation x Q3 Community Reputation x Q4 Regulatory Involvement x Q5 Loss of Business x Q6 Media Coverage x Q7 Effect on Property x Q8 Insurability

= ______ x _______ x _______ + _______ x _______ x ________ x _______x _______
Q1 Q2 Q3 Q4 Q5 Q6 Q7 Q8

BCOF score (i) = ____________

WF (BCOF) = ___________%

Facility ______________________
Completed By ______________________

Date_____________
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AST PETROLEUM TERMINAL SITE DATA **FORM W**

Estimation of Direct Costs of Loss

Make as many copies as needed to accommodate all scenarios.

EVENT:____

Unit Operation:____

Direct Costs of Loss		**Estimated Amount**
a.	Cost of Cleanup/Remediation • Surface cleanup • Subsurface soil removal • Groudwater remediation • Engineering costs • Contractor/heavy equipment costs • Other (reporting requirements, etc)	$
b.	Equipment Costs • Equipment repair (tank, piping, dike, area outside of dike, etc.) • Equipment replacement • Maintenance cost • Inspection costs/back-in-service costs • Other equipment-related costs	$
c.	Business Interruption Costs • Cost per day x days out of business • Interruption of business • Overtime costs for employee response • Other business-related/profit loss costs	$
d.	Cost of lost product • Cost per unit x units lost • Cost to replace lost product • Other associated lost product costs	$
e.	Diminution of property/facility value • Loss to property value • Loss to facility value • Other property-related costs	$
f.	Costs of insurance/liability coverage • Increased costs for worker's compensation (workers hurt, etc.) • Increased costs for environmental liability • Increased costs for general liability • Other costs associated with insurance/liability	$
g.	Other • Other costs not included in items a through f directly related to release	$
	Total Direct Costs (sum of a through g)	$

Facility Completed By ______________________ Date______________

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