Public Final Report

Project Title:

Developing Periodic External/Internal Inspection Requirements to Assess Low Temperature and Cryogenic Storage Tanks

Contract Number: **693JK32110006POTA**

Date Issued: **February 2, 2024**

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This research was funded in part under the Department of Transportation, Pipeline and Hazardous Materials Safety Administration's Pipeline Safety Research and Development Program. The views and conclusions contained in this document are those of the authors and should not be interpreted as representing the official policies, either expressed or implied, of the Pipeline and Hazardous Materials Safety Administration, or the U.S. Government.

Contents

1. Introduction and Project Summary

1.1 Background

1.1.1 Project Context

This report provides a starting point for Standards Development Organizations (SDOs) such as the American Petroleum Institute (API) or other international SDOs to develop an inspection and repair Recommended Practice, Standard, or Guideline for LNG and cryogenic tanks. This report gathers all the widely differing existing practices and consolidating them into a uniform set of best practices with oversight supplied by the Technical Advisory Panel (TAP) which consisted of a broad spectrum of stakeholders representing the LNG industry.

The infrastructure of the United States is critically dependent on the reliable supply of natural gas and petroleum liquids transported through pipelines. However, that infrastructure is aging, with a significant fraction being more than fifty years old. While new facilities and pipelines are being planned and constructed, the phasing out of old facilities does not occur consistently with their originally planned equipment design lives, and for many, continued operations are planned well beyond the original design life. Assuring the long-term integrity and security of these existing pipelines and storage facilities is essential.

Recognizing these facts, the U.S. Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) have designed a process to emphasize the importance of continuing pipeline-related Research and Development (R&D). States, industry, and other federal agencies strongly support PHMSA's initiative.

A Pipeline Research and Development Forum was held by PHMSA. The workshop resulted in a common understanding of current research efforts, a listing of key challenges facing government and industry, and a compilation of potential research areas whose exploration will assist with meeting these challenges and should therefore be considered in the development of new research and development applications.

PHMSA pipeline safety representatives determined that the following major research areas need to be addressed:

- Threat/Damage Prevention
- Anomaly Detection & Characterization
- Remote Sensing/Leak Detection
- <u>Liquefied Natural Gas</u>
- Other – Materials

On March 05, 2021, PHMSA issued a Research Announcement, # 693JK3211RA01, to address the Liquefied Natural Gas research area. *The research work was aimed to address the need for and the types of inspection necessary to maintain the ongoing integrity of cryogenic liquefied gases including LNG.*

1.1.2 Project Execution

PEMY Consulting, LLC. was awarded this work on September 30, 2021. This report provides tank inspection guidelines and checklists that can be used directly or modified as needed by Owner/Operators of LNG and cryogenic tank facilities or developed further by SDOs such as the

American Petroleum Institute (API) or any other American National Standards Institute (ANSI) accredited SDO.

This project was originally scheduled to be completed in 8 quarters (2 years) but extended to 10 quarters or about 2 ½ years and the work was completed at the end of 2023. The delay involved the difficulty of the formation of the TAP which was a critically important function of the research project. As used in this report, the term “Project” refers to this research project “Developing Periodic External/Internal Inspection Requirements to Assess Low Temperature and Cryogenic Storage Tanks” under PEMY Contract 693JK32110006POTA with PHMSA.

1.1.3 Technical Advisory Panel

To ensure stakeholders were involved, a Technical Advisory Panel (TAP) was formed. The membership consisted of representatives from PHMSA, FERC, inspection companies, storage tank manufacturers, repair companies, consultants, and owners and operators of LNG storage facilities. Balance across companies, sectors, and disciplines was a goal achieved by wide solicitation of the activity across the U.S. industry. In addition to the PEMY team members, seven Owner/Operators and six other stakeholders (as mentioned above) comprised the TAP membership.

One of the most important aspects of TAP was to ensure consensus involving all stakeholders. Also significant was the importance of having TAP committee members who are responsible for and knowledgeable in the operation of LNG tanks. This was achieved by selecting members of TAP consistent with objectives, by holding quarterly meetings of 2-hour duration each to discuss written material as it was developed, and by ensuring that each TAP member had ample time to review, comment, and improve all technical aspects of the work as it developed over the Project’s life. Each component of the work was stated, prepared, and sent to the TAP where it was discussed at the next meeting. All comments were reviewed and incorporated into the report tasks as they developed. All revisions and modifications were sent to TAP for final approval. An open invitation to challenge and ask for revisions applied to any portion of the Project tasks and reiterated at each TAP meeting.

1.2 Objectives of the Work

1.2.1 Primary Objective

The primary objective of the research project was the development of guidelines, checklists, and considerations for inspection and repair of large, flat-bottom, vertical, cylindrical cryogenic and LNG storage tanks based on industry experience, supported by stakeholders which reflects the current state of the art. This included considering the best available technologies as well as consideration of emerging and potentially new technologies to support the goals of the Project. The inspection and repair guidelines addressed by this report could be the source information for an ANSI accredited SDO such as API to develop a Recommended Practice or Standard aimed specifically at these types of tanks. Such documents could be included in federal regulations or other industry standards such as NFPA. The regulatory and industry bodies would benefit in terms of standardization and reshaping the inspection processes relevant to these types of tanks. Over time, well written standards foster a strong, healthy market for cryogenic tank inspections as well as public confidence in the safe and environmentally sound operation of LNG tanks.

1.2.2 Organization of the Final Report

This report is divided into the following main sections:

1. Introduction and Project Summary
2. Regulations and Industry Standards
3. Incidents and Survey Data
4. Repairs
5. Damage Mechanisms, Inspection, and Risk
6. Corrosion and Fatigue Damage
7. Inspection Technology
8. LNG Tank Reliability
9. Tank Inspection Guidelines (TIG)
10. Conclusions and Recommendations

1.3 Project Summary

The purpose, structure, and background of this Project is provided by this Project summary. The report has been reviewed and approved by all stakeholders, including regulatory stakeholders and the public domain as represented by TAP.

The current state of inspection practices for cryogenic liquefied gas tanks is a disparate mix of regulations by different authorities throughout the world, individual corporate policies and procedures, and various industry standards. The result is that there is a wide variety of practices within the industry and no standardized approach or set of best practices that can be advertised as such or applied uniformly across the industry. Many of the industry standards appear to be copied versions of each other. While regulatory and industry standards focusing on new construction are standardized by documents such as API 620 and API 625, the inspection and repair practices are not comprehensively or consistently addressed. The result is major gaps in those areas that need development such as inspection and repair protocols. There is little content that deals with equipment degradation from age-related deterioration, fatigue, or other damage mechanisms that occur over time.

Addressing the problem of deterioration mechanism and repair processes requires related data and experience. Unfortunately, there are very few official databases that contain information about LNG tank incidents. However, one such official dataset in the public domain is mandated by PHMSA regulations. It requires that LNG tank Owners/Operators provide standardized details of incidents that are in scope and that they are recorded and documented. While incidents drive changes in industry standards, it is insufficient to look only to industry standards and regulations to determine how urgently the consolidation of best practices is needed. So that more applicable information could be acquired, surveys of TAP members were conducted to acquire baseline data on existing practices and experiences related to deteriorating equipment directly from the industry. Two surveys were developed to provide this data. The results are compiled and summarized in Section 3 of this report. They serve as a basis for the following sections of the final report. Because the survey participants represented about 30-35% of the U.S. tank population, they can be considered representative of the entire tank population and the Owner/Operators who participate in the U.S. LNG markets.

Additional deficits with respect to publicly available standards, guidelines, and practices related to LNG tanks are the repair processes that are applied to them. Repairs are an integral part of any tank integrity program and are an integral part of any inspection/integrity program that aims to preserve tank integrity with time. Section 4 served as a basis for determining what general types of repair issues are associated with the tank population. The PHMSA Safety-Related Condition Reports (SRCR) were also used to ensure broad coverage of the types of repairs that were involved with leak prevention. The PHMSA tank incident database was also useful in understanding the damage occurring in these tanks and how they were addressed. As expected, most repairs are related to weather exposure damage such as corrosion on the outer metallic components of the tanks. However, there were repairs that involved cracking of external steel tank due to spillage of cryogenic liquid on the roof or shells of steel tanks. Section 4 includes some general recommendations related to repairs that steer back to guidance provided by the original standard of construction (i.e., API 620 or ACI 376). However, the development of any guideline or standards that relate to inspection of LNG tank repairs and how they should be implemented is a monumental task generally outside the scope of this study. Any SDO that writes the inspection and repair standard will have to perform a significant amount of work directly related to repairs.

The inspection process is highly dependent on age-related damage mechanisms. The damage mechanism elements listed and described in API 571 were used as a starting point for development of a comprehensive damage mechanism list for cryogenic liquefied gas storage tanks. API 571 was found to be lacking in those elements that are specific to cryogenic equipment. Therefore, the list of general damage mechanisms was supplemented by including cryogenic damage mechanisms which is documented in Section 5. The list also includes what might not be considered damage mechanisms, but instead, initiating events such as loss of power, roll-over, and even human factors. A discussion of managing risks through safety management systems is briefly discussed because human factors always play a significant role in risk exposure. While a modernistic approach to inspecting equipment is referred to as “risk-based inspection,” there are limitations to its applicability and effectiveness. Therefore, the relevance of risk to inspection processes was examined. A simple ordinal risk ranking matrix is demonstrated along with hypothetical application to cryogenic LNG storage tanks in the Tables of Section 5. The process used to develop inspection effectiveness against various damage mechanisms shown in the tables of this section must, in general, be individualized by specific Owner/Operators. This is because the qualitative risk assessments of risk are not repeatable across different business entities. The sample risk ranking matrix shows how an Owner/Operator can conduct group exercises within the organization to identify and categorize the impact of inspection on risk as well as other risks that are not controllable through inspections. This assists Owner/Operators tailoring integrity management programs including the inspection and repair elements to make these tasks as efficient as possible. More advanced risk assessment and management methods are outside the scope of this study.

Corrosion and fatigue are two well-known damage mechanisms. These damage mechanisms are associated with the inner tank of an API 625 tank system. The inner tanks are usually constructed of 9% nickel steel alloys which remain ductile to low temperatures. Corrosion was shown to be nil because of multiple reasons: the hermetically sealed environment that can act on the inner tank, that cryogenic temperatures minimize corrosion rates, and industry experiences supporting this claim. The remaining important damage mechanism may potentially be fatigue due to repeated fill-empty cycles. Appendix 5 Fatigue Analysis contains fatigue analyses on 2 different size tanks. The analyses showed that the fatigue life is well over 100 years of operation for the two tanks considered. It must be recognized that the analyses did not consider inner tanks constructed of aluminum or stainless steels and did not consider unique designs, all of which may be important factors in determination of the fatigue life, especially for the very oldest of the LNG tank population.

One important aspect of this Project was to review state-of-the-art technologies directly applicable to LNG storage tanks which is provided in Section 7. This section also identified gaps in technology as well as potential emerging technologies that may eventually help the industry with the monitoring and inspection processes.

One of the most significant and controversial aspects of the Project was the issue of the periodicity of and the use of external and internal inspections. The impact of external and internal inspections on the industry was examined. The external inspection impacts were shown to be insignificant on business operations. However, the internal inspections have significant impacts. The tradeoffs of taking a tank out of service for an internal inspection has many important issues associated with it and these are discussed in Section 8 which concerns tank reliability over time. Essentially, taking a tank out of service for an internal inspection when not needed may cause unnecessary damage and increases the number of tanks that must be built and maintained because the duty cycle of the existing tanks is reduced. Tank lifetime data sets for conventional tanks are considered along with the LNG tank lifecycles and subjected to reliability engineering principles. Although tank life data are extremely hard to acquire, parametric and probabilistic Weibull reliability analyses were applied using conventional petroleum tanks as a baseline. Estimates of the probability of failure of the inner tanks were postulated and then used to show that internal inspections for LNG tanks are not necessary for at least 100 years of operation. Suggestions for further research are provided to improve the accuracy of this estimate.

The most important deliverable outcome for this Project is the development of an LNG tank inspection guideline and checklist. These are in Section 9. The guidelines for the inspection of LNG tanks were developed far enough that they can either be used directly by an Owner/Operator with some further detailing; or, better yet, they can be further developed by an SDO, such as the API, to write specific, detailed standards or recommended practices. Section 9 also includes a detailed checklist as part of the tank inspection guidelines.

Section 10 is a listing of conclusions and recommendations. They are primarily aimed at the regulatory industries as well as the SDOs that will take this Project as an input to the process of developing publicly available ANSI-accredited recommended practices, guidelines, and standards.

1.4 Miscellaneous

The term *LNG Tank* primarily applies to LNG tanks which are large (over 5000 bbl), flat-bottom, vertical, cylindrical storage containers. However, most of the work in this report also applies to other cryogenic liquefied gas storage tanks including oxygen, nitrogen, and others. The term *tank system* has been used to distinguish the system of components such as both containers, liners, insulation systems, instrumentation, relief systems, and any other component that comprises the LNG tank. By contrast, conventional oil storage tanks which are much simpler, are not referred to as a tank system.

1.5 Summary of Project Final Financial Contributions

The financial contributions to the Project were consistent with contract 693JK32110006POTA. The Project remained on budget to the end of the Project duration.

2. Regulations and Industry Standards

2.1 Introduction

A literature search and review of domestic and international regulations and industry standards on maintaining the integrity of LNG and cryogenic tanks was conducted. The scope of review was limited to large, flat bottom, vertical cylindrical LNG and Cryogenic Storage Tanks used by industry for LNG import and export terminals as well as other liquefied gases stored at cryogenic temperatures. Excluded were non-cryogenic refrigerated tank systems such as those storing butane or propane.

The primary focus of existing regulations and industry standards is on new constructions and ensuring safety in designs as well as appropriate safety distances and zoning requirements. Little content is available in both the regulatory and industry domains regarding formal and specific processes for external or internal inspections or programs for the inspection of LNG storage tanks.

The purpose of the regulatory and industry review and assessment was to consider the current state of LNG Storage Tank standards worldwide including:

a. Identify and review United States (API), European (EN, EEMUA), Japanese (JSA), Korean (KATS) and other national and international regulations or standards that address low temperature and cryogenic storage tank inspection, evaluation, fitness-for-service-determination, and rerating.
b. Determine potential gaps in applicable standards such as API 620, API 625, NFPA 59A and other standards that identify areas of concern where inspection is not possible due to design, construction and operational reasons and provide recommendations for focus areas of inspection.

Item a is discussed in 2.2 Regulatory Survey and 2.3 Industry Standards Survey. Item b is addressed in 2.4 Gaps in Regulatory and Industry Standards.

2.2 Regulatory Survey

2.2.1 Overview

The purpose of the regulatory review was to consider the current best practices for inspection, repairs, and maintenance of LNG tanks that could be a basis for future industry and regulatory rules for inspection and best practices related to operating cryogenic tanks. Regulations and standards were examined to determine which specifically address the issue of maintaining the ongoing integrity of LNG tanks through inspection practices, maintenance, repairs, and testing as well as to determine the sufficiency of such requirements as they currently exist in regulations and industry standards or practices. These practices and regulations are best developed by a consensus process involving practitioners, subject matter experts, policy makers, and owners/operators.

2.2.2 Abbreviated Names of Governmental and Standards Development Organizations

Table 1 lists the abbreviated names of organizations referred to throughout this report.

Table 1 Abbreviated names of Regulatory and Standards Development Organizations

Abbreviation	*Meaning*
DOT	Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration

FERC	Federal Energy Regulatory Commission
USCG	United States Coast Guard
ACI	American Concrete Institute
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
NFPA	National Fire Protection Association
BS	British Standards
EEMUA	Engineering Equipment and Materials Users Association
EN	European Standards (European Norm)
ISO	International Organization for Standardization
JSA	Japanese Standards Association
KATS	Korean Agency for Technology and Standards

2.2.3 Regulations in the US

Several federal agencies may regulate LNG facilities depending on use and location. These include the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard (USCG), and PHMSA, and by state utility regulatory agencies. U.S. LNG import and export terminals are inspected for safe operations by the FERC, the USCG, and PHMSA. Peak-shaving, LNG satellite, and vehicular fuel LNG plants connected to the interstate gas transmission system are inspected by both FERC and PHMSA. Peak-shaving, LNG satellite, and vehicular fuel LNG plants connected to intrastate gas transmission pipelines or gas distribution systems are typically inspected by a state agency through an agreement with PHMSA.

PHMSA has the authority to establish and enforce safety regulations for onshore LNG facilities. PHMSA LNG safety regulations are codified in 49 CFR Part 193.

The comments in this section of the survey are limited to the LNG storage tanks within the scope of 49 CFR Part 193. Although Part 193 is primarily for new LNG construction for facilities in scope, there is little content directed to inspection, maintenance, repairs, and testing. However, if there are existing facilities under construction before March 31, 2000, which are replaced, relocated, or significantly altered after March 31, 2000, the facility must comply with the applicable provisions of Part 193 requirements. If there are major changes such as alterations for capacity or relocation of the tank, then siting requirements may apply.

The survey was focused on regulations concerned with maintaining the ongoing integrity of the LNG storage tanks through inspection, maintenance, repairs, alterations, procedures, and testing. It did not cover new construction or siting of facilities or equipment spacing rules. The survey also did not cover the many other components of an LNG facility such as piping, instrumentation, vaporizers, or other components that comprise these complex processing facilities.

2.2.4 Survey of PHMSA Regulations

The reference documents cited in 49 CFR 193.2013 are primarily for new construction so that there is little guidance related to maintaining storage tank integrity through inspections other than as outlined below.

Recordkeeping (193.2119) does not cover maintaining records for inspections, repairs, or maintenance.

Corrosion control (193.2304) does address operation after tank construction stating that

> *. . . components may not be constructed, repaired, replaced, or significantly altered until a person qualified under § 193.2707(c) reviews the applicable design drawings and materials specifications from a corrosion control viewpoint and determines that the materials involved will not impair the safety or reliability of the component or any associated components.*

Investigation of failures (193.2515) is addressed but is focused on serious incidents for which it could be interpreted that leaks, corrosion, and other detected failures that may or may not be covered depending on the severity. Reporting of failures is a retrospective process and does not establish safety margins against failure or produce predictive failure capabilities for use with inspection information.

Subpart G covers maintenance, however, it is general and applicable to numerous systems within an LNG facility. There is no specific guidance for storage tanks. It should be noted that:

> *(193.2603 (d)) If a safety device is taken out of service for maintenance, the component being served by the device must be taken out of service unless the same safety function is provided by an alternate means.*

Although this subpart has a protocol for maintenance procedures there is no direct tie to industry standards related to maintenance of these tanks. However, operators must maintain periodic inspections and tests consistent with generally accepted engineering practice.

Repairs (193.2617) is very broad and generic, so no guidance specifically related to LNG storage tanks is provided.

Control Systems (193.2619) requires inspection of control devices such as internal shutoff valves and relief venting devices annually. No specific guidance on how to evaluate or interpret changes in the equipment is provided.

Inspection LNG Storage Tanks (193.2623) states that

> *Each LNG storage tank must be inspected or tested to verify that each of the following conditions does not impair the structural integrity or safety of the tank:*
> *(a) Foundation and tank movement during normal operation and after a major meteorological or geophysical disturbance.*
> *(b) Inner tank leakage.*
> *(c) Effectiveness of insulation.*
> *(d) Frost heave.*

The interpretation of this rule implies applicability to both new and existing tanks.

No specific guidance is provided for the specific damage mechanisms listed. For example, for settlement of the foundation, specific types of surveys can be done that indicate rigid body, planar, or differential settlement mechanisms acting on the tank. The rule establishes the need for settlement monitoring, but no guidance for assessing the damage mechanisms analyses is provided.

Corrosion deterioration is addressed by 193.2625, 193.2627, 193.2628, and 193.2631. Interference current (193.2633) and corrosion monitoring (193.2635) are addressed. Maintenance of the corrosion protection systems is addressed by 193.2639. All of the corrosion rules are too general to be specifically applicable to the various components of the storage tanks and it would be difficult to have criteria based on these rules that give a clear indication as to whether a facility is or is not in a safe state, or whether it is or is not in compliance with the rule objectives.

Although the title of 193.2705, *Construction, Installation, Inspection, and Testing*, would appear to address inspection, it is clearly aimed at new construction and thus, does not address periodic integrity testing through time as age-related damage mechanism probabilities accumulate.

2.3 Industry Standards Survey

The American Gas Association has published the "LNG Plant Preventive Maintenance Guide." The last published version of this document was in 1984 and it apparently is not maintained or used. The Guide uses a series of checklists for visual inspection of various equipment used in LNG facilities which it covers comprehensively. However, there is little that is quantitative, and few auxiliary standards are referenced. This document has limited value in providing criteria for maintaining LNG storage tank integrity through inspection, repairs, maintenance, or testing.

API Standard 620 "Design and Construction of Large, Welded, Low-pressure Storage Tanks" and API Standard 625 "Tank Systems for Refrigerated Liquefied Gas Storage" are the two most important US standards that are applied to large flat bottom LNG tanks including single containment, double containment, and full containment tanks. API 620 governs the use of steel tanks applicable to LNG storage as well as other cryogenic and non-cryogenic tanks. Annex Q of API 620 is the appropriate component of the standard to follow since it covers the primary and secondary liquid containers, the roofs, warm product vapor containers, purge gas containers, and relevant appurtenances. Annex Q allows design temperature of liquid storage tanks to -325F. It provides information about the required materials and fabrications rules applicable to these tanks. Annex L covers the design of tanks to resist acceleration and seismic forces. API 620 states that applicable standards are 49CFR 193, ASCE 7, and NFPA 59A. API 625 lays out the basic storage concepts for LNG tanks and categorizes them into various types of containment.

NFPA 59A "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)" covers the design, siting, and general criteria for LNG tank construction. It includes Chapter 18 *Operating, Maintenance, and Personnel Training* to address operational topics including maintenance, inspection, and testing. Like the 49 CFR 193, these topics are addressed in a very general nonspecific way. For example, 18.10.10.2 states "Each operating company shall ensure that the inspections and tests in this section are carried out at the intervals specified." But no detail is provided related to what types of inspections should be done or how to carry them out or even at what interval. The requirements for maintenance, tests, and inspections are like those listed in 49 CFR 193. As with 49 CFR 193, existing facilities are “grandfathered” except in limited cases. The important API standards that are mandatory by reference are API 650 and API 620. API 650 is also relevant as the seismic provisions of API 620 Annex L depend foundationally on the requirements for seismic in API 650. Other standards that are applicable are ACI 376 “Code Requirements for Design and Construction of Concrete Structures for the containment of Refrigerated Liquefied Gases” and ASCE 7-16 “Minimum Design loads for Building and other Structures.”

EN 14620-1 and EN 14620-2 “Design and manufacture of site built, vertical, cylindrical, flat-bottomed steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0 °C and –165 °C” is a publication by the European Community. The scope of the standard has been limited to steel tanks used for the storage of refrigerated, liquefied gases. This European Standard is a specification for vertical, cylindrical tanks, built on site, above ground and of which the primary liquid container is made of steel. The secondary container, if applicable, may be of steel or of concrete or a combination of both. An inner tank made only of pre-stressed concrete is excluded from the scope of this European Standard. Other parts of this standard include:

- Part 3: Concrete components
- Part 4: Insulation components
- Part 5: Testing, drying, purging and cool-down

The maximum design pressure of the tanks covered by this European Standard is limited to 500 mbar (7.25 psi). For higher pressures, reference can be made to EN 13445, Parts 1 to 5. The operating range of the liquefied gases to be stored is between 0 °C and –165 °C. The tanks for the storage of liquefied oxygen, nitrogen, and argon are excluded. The standard has figures similar to those in API 625. The standard is for new construction and does not address ongoing inspection, testing, or maintenance.

BS EN 1473:2021 “Design, construction and operation of all onshore liquefied natural gas (LNG) installations for the liquefaction, storage, vaporization, transfer and handling of LNG and natural gas (NG)” focuses on siting, design, risk management and has appendices that cover topics such as pumps, vaporizers, piping, and odorant systems. It has no inspection or maintenance rules or criteria.

Technical Specification ISO/TS 16901 “Risk Assessment In The Design Of Onshore LNG Installations Including The Ship/Shore Interface” addresses risk assessments for onshore export and import LNG facilities. There is a lot of information about risk which is tutorial in nature covering concepts and methodologies such as ALARP, FN curves, and methods such as HAZID, FMEA, ETA, HAZOP, and so on. These standards and regulations mention protection through procedures and analysis against accident scenarios such as ship collisions, tank overfills, earthquakes, and natural hazards. But there is little to no information on corrosion, coatings, foundation warming or settlement, fitness for service, or other age-related damage mechanisms.

ISO/TS 16901 has a section on regulations in various countries including Australia, Canada, France, Hong Kong, Japan, Malaysia, Netherlands, Singapore, and the United Kingdom. However, the citations are limited to heat radiation hazards and thermal flux limits at specific distances.

With respect to the US standards for LNG and cryogenic tanks, there is little contributory value offered by these standards.

2.3.1 Applicability of API 653 to LNG Storage Tanks

API Standard 653 "Tank Inspection, Repair, Alteration, and Construction" is commonly used for the inspection and repair of conventional petroleum storage tanks constructed to API 650. A fundamental question arises: is API 653 applicable to the inspection of cryogenic and LNG tanks? In fact, API 653 states, *"1.1.3 This standard employs the principles of API 650; however, storage tank Owner/Operators, based on consideration of specific construction and operating details, may apply this standard to any steel tank constructed in accordance with a tank specification."* Although API 653 is primarily aimed at API 650 tanks, a common application of API 653 is to API 620 tanks as well. While this approach has been applied in the past, a cryogenic tank is not just an API 620 tank; rather, it is a tank system consisting of many parts. Notably, the tank system includes at least 2 tanks, of which one is usually an API 620 tank, with many of the provisions applicable to it split between API 620 and API 625. Despite this, API 653 provides general good practices for tank inspection, and there is benefit to maintaining consistency with API 653 where reasonable.

When inspecting an LNG tank, each inspection company uses their own experience and judgment to fill in the gaps related to API 653 caused by the differences between typical oil storage tanks and LNG tanks. Although inspection contractors have employed robust inspection programs of their own using industry publications such as API 653, the small number of LNG tanks relative to the tank population as a whole combined with the lack of industry standardized practices means that their LNG inspection experience is minimal, and the inspection practices between different agencies can be highly variable. This can be seen by the observation that only a very small percentage of certified API 653 inspectors have ever inspected LNG tanks[1]. As an example of how experience facilitates LNG tank inspection, consider the act of opening the outer tank of a steel LNG tank system. Inspection of an interstice filled with perlite takes an advanced and rather complex procedure typically unknown to an API 653 inspector. This process requires a high degree of specific knowledge and skills as well as direct prior experience with LNG tank inspection.

While it would be possible for an inspection agency to review many disparate industry standards and compile the appropriate inspection criteria and provisions into the inspection agency's own internal standard, as a practical matter this does not occur. It is far more efficient for an SDO to develop the best practices and guidance for inspection of these tanks and compile them into a standard. This is the basic motivation for writing an LNG tank inspection and repair standard.

2.4 Gaps in Regulatory and Industry Standards

It is clear that the regulatory and industry requirements for LNG tank inspection:

- Lack independence and are highly duplicative. The same problem exists between and among international standards and organizations.
- Are too abstract and performance-based in some cases, and yet in other cases can be extremely prescriptive. The result is that enforcing or auditing these facilities for inspection and repair activities with repeatability is difficult or impossible.
- Would not provide sufficient guidance or details for managing effective owner and/or contractor-conducted inspections.

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[1] Informal surveys conducted at API SCAST meetings.

- Do not provide standardized methodologies for the various types of inspection that may be needed.

Though some requirements for maintenance are specified in relevant industry codes and standards, those most widely applied in the United States are the requirements that are included in 49 CFR 193 and its reference to applicable industry standards, such as NFPA 59A. While many Owner/Operators have attempted to incorporate robust inspection programs, many have simply attempted to comply with what they believe are the applicable jurisdictional rules. Because there is not a specific and focused inspection and repair standard for LNG tanks, the body of literature, regulations, standards, and publications leaves the Owner/Operators of their facilities to a large domain of interpretation. The details of exactly how to conduct such tasks are also minimal or missing.

Section 9 of this report, Tank Inspection Guidelines, provides a strawman outline of the proposed methodology for inspecting LNG tanks. The industry and regulatory stakeholders can use best practices to develop consensus on the methodology that is optimized for LNG tank inspections.

3. Incidents and Survey Data

3.1 Introduction

The occurrence of incidents, in large part, drives changes for improvements in standards and best practices. LNG tanks are no exception. However, in the current legal and regulatory structures that underlie most industrial operations, including LNG handling, there is corporate incentive to *not* share details. To assess the potential to reduce incidents and increase tank system reliability for LNG tanks, publicly available information about LNG incidents was examined. While there are many informal and anecdotal reports, however, there were few official reports that could be relied on for facts or conclusions.

One of the goals of the survey conducted with Technical Advisory Panel (TAP) member LNG tank Owner/Operators was to expand information about how incidents evolve from conditions to a threat with as much detail as possible. Therefore, the TAP survey asked questions about damage mechanisms to investigate tank degradation, its progression, and whether inspections could have prevented these problems.

In this section, the trends in tank incidents and in tank construction, design, and inspection practice were identified. This was accomplished by a review of:

a. Past incidents associated with LNG storage tanks.
b. Survey of the Owner/Operators within the TAP, detailing:
    - Historical tank designs and categories of equipment types.
    - Commonalities and differences in inspection practices across the industry.

3.2 Review of Past Incidents

The US DOT prescribes the requirements for the reporting of LNG incidents which must be created by the Owner/Operator and submitted to the DOT on the form "Incident Report - Liquefied Natural Gas

(LNG) Facilities." This form must be filled in when an LNG incident is reported to PHMSA. The form can be obtained from the PHSMA website[2].

49 CFR 191.3 provides the definition of an incident for which reporting is required. PHMSA records these incidents in a database.

> *Incident means any of the following events:*
>
> *(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:*
> *(i) A death, or personal injury necessitating in-patient hospitalization;*
> *(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.*
> *(iii) Unintentional estimated gas loss of three million cubic feet or more.*
>
> *(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.*
>
> *(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.*

This definition means that incidents that have resulted in releases must be reported. Although a shutdown of an LNG facility is reportable, many incidents that do not meet the strict definition will be unrecorded in the PHMSA public domain database. An example of an incident type that may go unrecorded is a corrosion hole that is discovered during an inspection and is nearly ready to penetrate the outer tank.

A list of incidents may be downloaded from the PHMSA website[3]:

Information about LNG tank incidents is given in Appendix 1 which has been extracted from the PHSMA incident database. Those parts which are relevant information for this Project are contained within Appendix 1 Table 1. The remaining 25 incidents, described in Appendix 1 Table 2, are not directly related to tanks or tank inspection.

[2] https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data, "Liquefied Natural Gas (LNG) Incident Data – January 2011 to present (ZIP)"
[3] See previous link.

3.2.1 Discussion

A review of the data in Appendix 1 showed that thirty-two LNG facility incidents were reported from November 28, 2012, to February 28 ,2022, a period of 3379 days, giving a point estimate for the LNG tank incident mean recurrence interval (MRI) of 105.6 days. Of the 32 reported incidents, 7 were considered relevant to this Project (i.e., they were tank-related incidents), or, slightly over 20 percent of the total LNG facility incidents. The MRI for LNG tank-specific incidents is therefore 482 days or about 5 quarters. The number of incidents is too low to conduct formal statistical analyses for causation or for determining the contribution of the individual reasons or scenarios to the incident rate with significant confidence. However, it does suggest input for inspection guideline development. Annotations are provided for Appendix 1 Table 1 to comment on the relevance of each incident to this project.

Noteworthy is the fact that there were no catastrophic failures of the LNG tanks as a result of inner tank failures recorded in the PHMSA incident database for this time period. There were some cases of cracked outer tanks and LNG spillage.

3.2.2 Other Incidents

Although other incidents information was reviewed via internet and literature searches, most of the reports available in the public domain appeared to be unofficial. For this reason, the descriptions and data in these unofficial reports were not deemed to be sufficiently authoritative. With that in mind, the review of domestic and international incidents showed that there have been no large-scale failures of the inner tanks since the 1960s. For example, the 1944 Cleveland East Ohio Gas Company incident resulted in an explosion that killed 131 people and destroyed a one-square-mile area on the East side of Cleveland, Ohio. At that time, due to war efforts, stainless steel was in short supply and a nickel-steel alloy of insufficient low-temperature toughness was used, and the tank shell failed. In addition to other engineering problems, there was no secondary containment, which allowed LNG to flow into municipal drainage systems in city streets, form a vapor cloud, and explode. The lessons learned from this incident have been applied in the industry and for this reason there has never again been this type of incident.

A sample of some other serious LNG tank incidents since the 1960s are:

- 1969 Portland, Oregon. An explosion occurred in an LNG tank under construction. No LNG had ever been introduced into the tank. The cause of the accident was attributed to the accidental removal of blinds from natural gas pipelines which were connected to the tank. This led to the flow of natural gas into the tank while it was being constructed.
- 1971 La Spezia, Italy. This accident was caused by “rollover” where two layers of LNG with different densities and heat content form. The sudden mixing of these two layers results in the release of large volumes of vapor. In this case, about 2,000 tons of LNG vapor discharged from the tank safety valves and vents over a period of a few hours, damaging the roof of the tank.
- 1973 Staten Island, NY. A fire started while repairing the interior of an empty storage tank at Staten Island. The resulting increase in pressure inside the tank was so fast that the concrete dome on the tank lifted and then collapsed down inside the tank, killing the 37 construction workers inside.
- 2004 Skikda, Algeria. A steam boiler that was part of an LNG production plant exploded, triggering a second, more massive vapor-cloud explosion and fire. The explosions and fire destroyed a portion of the LNG plant and caused 27 deaths, 74 injuries, and material damage outside the plant’s boundaries.

- 2014, Plymouth, Washington. The Plymouth-Liquefied Natural Gas (LNG) Peak Shaving Plant experienced a catastrophic failure and a resulting explosion on a portion of the facility's purification and regeneration system. Debris from the adsorber and associated piping caused extensive damage to the surrounding plant facilities, including penetration of the outer shell of the LNG storage tank, a dent to the inner shell of the LNG-1 storage tank and other equipment. There were no fatalities but there were 5 injuries.

What is clear is that external events such as nearby explosions from adjacent LNG plant units, terrorism, and natural hazards (i.e., seismic, tsunamic, flooding) may pose a threat to the overall integrity of these tanks.

3.3 TAP Owner/Operator Survey

A survey was conducted to collect baseline data for assessing the ways LNG tanks are inspected and maintained in the industry and to determine the types of tank system degradation that occurs. More specifically, the survey was intended to collect data and survey owner and operator companies regarding specific standard practices, operational methods, experience, issues, and critical storage tank components that are affected by the aging and operational aspects of the facilities. This data, along with TAP meeting discussions, provided the basis for identifying practices regarding inspection types and methods, frequency of inspections, and how such programs are managed. Implementing the survey required soliciting interest from US based LNG Owner/Operators, the development of focused and appropriate questionnaires, and discussions with the Owner/Operators. The survey focused questions in these areas:

- Susceptibility to degradation.
- Identify practices regarding inspection methods and frequency of inspections.
- How analysis of data received was done and discussion and summarization of the findings with members of TAP.

3.3.1 Baseline Data

Two surveys were sent to participants. The initial survey questionnaire was developed to collect data from Owner/Operator companies on their tank population, inspection practices, repair practices, and opinion/recommendations on existing and future LNG storage-related issues.

The initial survey questionnaire was developed and sent out to survey participants on June 6, 2022. This version of the survey covered these topics:

- Tank Data, information on each of the participants' tanks, e.g., age, dimensions, capacity, construction, materials, inspection history.
- Inspection Type and Frequency
- Inspection Questions (general)
- Inspection Policy
- Repairs
- Components
- Opinions, e.g., on existing regulations, standards, desired changes.

Following discussion in the second TAP meeting (July 11, 2022), a second survey was sent out to participants on July 28, 2022. This revised survey included an extra section on inspection processes, some clarifications in language, and separation of the tank data survey and inspection survey into two separate files.

The survey was sent out to seven TAP members owning LNG facilities. The results of the survey were collected and summarized. Specific findings regarding the practices of the surveyed owners and operators regarding inspection methods and frequency are discussed below.

3.3.2 Survey Findings.

The received survey response submissions were anonymized and are summarized with some commentary in Appendix 2 TAP Tank Survey Summary and Appendix 3 TAP Inspection Survey Summary.

The tank information and inspection practices described in the survey responses informed the scope of much of the work done for this Project.

3.4 Review of Current and Historical Tank Designs and Equipment Categories

3.4.1 Types of Tank Configurations

Prior to 2010, API Standard 620 was the sole U.S. standard for the primary containment of LNG and cryogenic storage tanks constructed of metal alloys. When the first edition of API 625 was published in 2010, the new standard expanded the domain of API 620 to address complete tank systems, including the various containment options for storage of cryogenic liquids as well as other concepts. These options can relate to the different materials for pressure and containment within the same tank system, foundation requirements, and accessories and appurtenances. API 620 and API 625 are comparable to standards around the world for cryogenic storage and they are considered world class standards.

API 625 shows 10 configurations grouped into three categories:

1. Single containment. The primary cryogenic liquid container is liquid-tight itself, whether or not there are additional outer containers. A secondary containment impoundment using dikes or berms is required to retain the contents of the container, should it fail.
2. Double containment. The primary container is vapor and liquid tight. Outer liquid containers are designed to hold all liquid contents but not intended to control the vapor.
3. Full containment. Both primary and secondary containers are liquid and vapor-tight.

There are 10 configurations from API 625, as shown in Figure 1. API 625 configurations 5.1, 5.2, 5.3 and 5.4 are single containment. Configurations 5.5 and 5.6 are double containment. Configurations 5.7, 5.8, 5.9, and 5.10 are full containment.

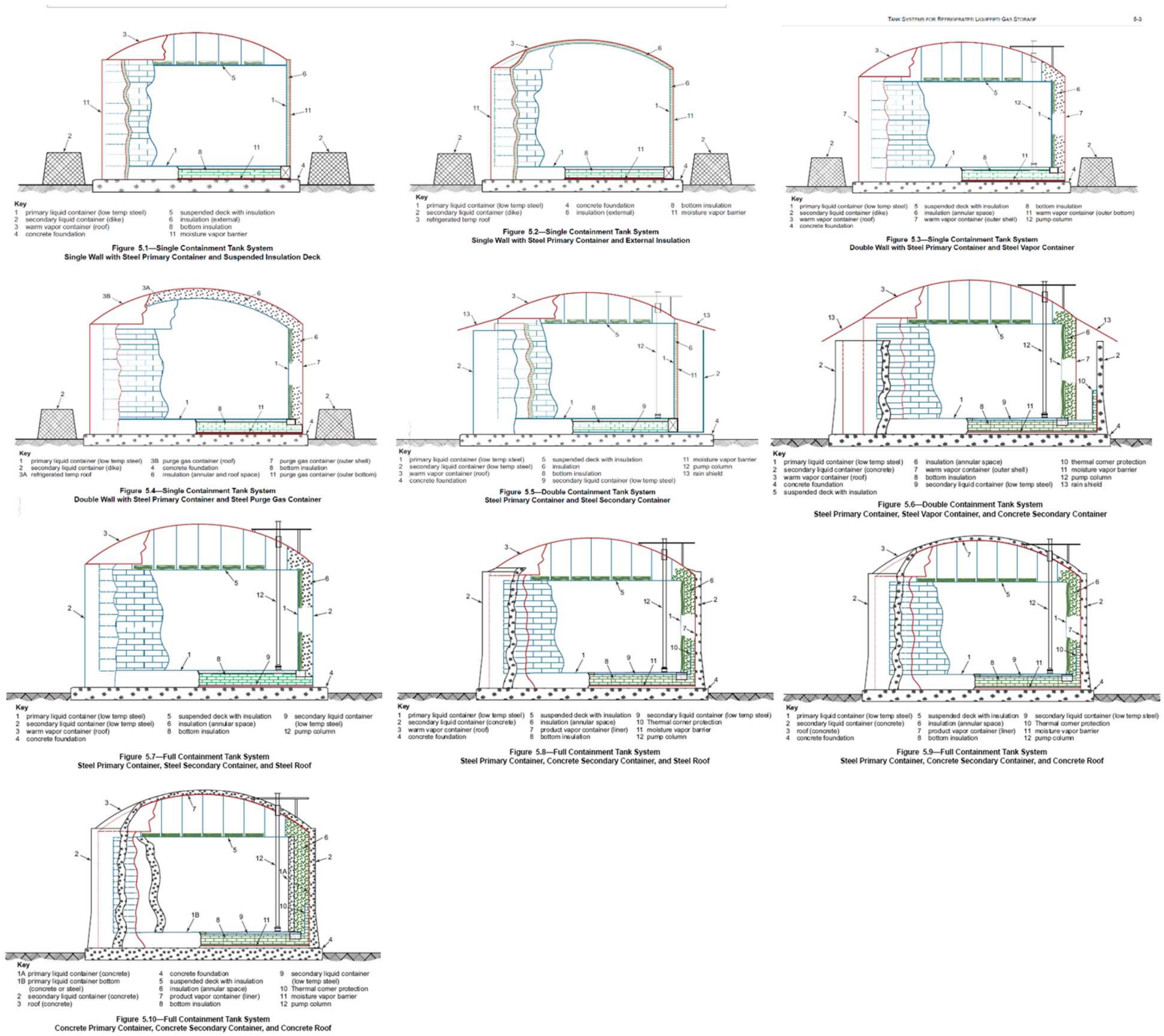
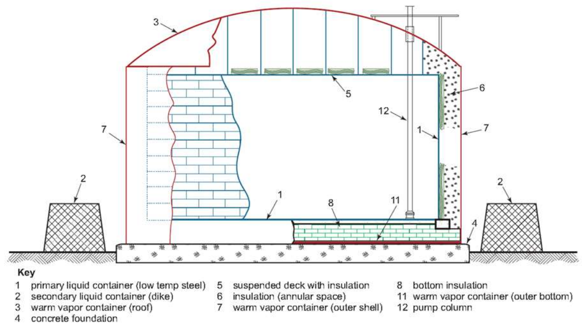
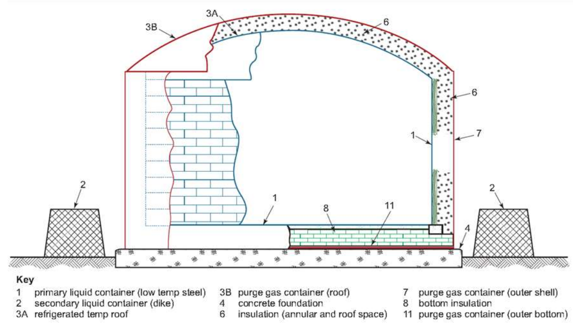
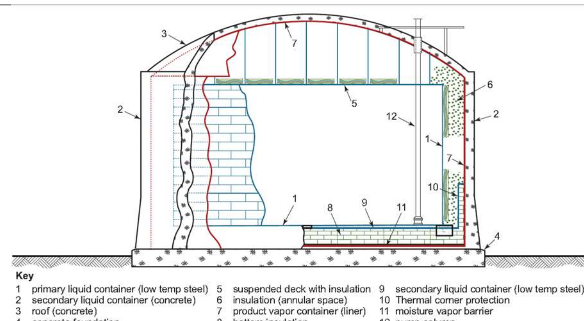


Figure 1 Ten tank system configuration from API 625 used in the TAP Industry Survey.

API tank systems 5.3, 5.4 and 5.9 were the tank systems represented in the survey. These are shown in Table 2. For other configurations see API 625.

Table 2 TAP survey tank configurations

API 625 Figure Number	Schematics	Comment
Figure 3—Single Containment Tank System Double Wall with Steel Primary Liquid Container and Steel Vapor Container		Listed in survey as 5.3
Figure 4—Single Containment Tank System Double Wall with Steel Primary Liquid Container and Steel Purge Gas Container		Listed in survey as 5.4
Figure 9—Full Containment Tank System Steel Primary Liquid Container, Concrete Secondary Liquid Container, and Concrete Roof		Listed in survey as 5.9

3.4.2 Membrane Tanks

While "membrane tanks" have been in NFPA 59A since the 2013 edition and have been in use for at least 30 years, they have not been used in the U.S. See Figure 3 for an interior view of a large LNG membrane tank. The primary reason for this is that PHMSA regulations in 49 CFR 193 only recognizes an out-of-date, older edition of NFPA 59A (the 2001 edition), "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)." There have been many newer editions of NFPA 59A published since the 2001 edition. Because PHSMA referenced the 2001 edition of NFPA 59A, which does not include membrane tanks, they cannot be used in the U.S.

However, they are widely used for shipping of LNG (see Figure 4) as well as for storage in other countries, just like the conventional API 625 tanks. Their safety record is comparable to that of the LNG tanks allowed by API 625. The later editions of NFPA 59A do indeed include LNG tanks constructed as membrane tanks.

Figure 5 is a schematic of how the full containment tank per API 625 compares with a comparable membrane tank. The API 625 full containment tank is a conventional tank in that the tank shell carries all of the hydrostatic forces. In the membrane tank, the hydrostatic stresses are transferred to the outer tank. The membrane system is applied along the walls and the base. The membrane is stainless steel (304L) about 1mm thick, and it incorporates a double network of orthogonal corrugations allowing free contraction/expansion under thermal loads in two directions. A view of a membrane liner section is shown in Figure 2. Other important differences are summarized by the following table:

Function	API 625 Design	Membrane Tank Design	Comment
Insulation	Perlite	Layered insulating panels	Heat transfer rates are comparable
Interstice gas	LNG vapor	Nitrogen	May be dependent on leak detection
Thermal shock	Susceptible	Non susceptible	The corrugations absorb thermal shock

Figure 2 Thin stainless steel membrane in contact with LNG uses corrugations to handle thermal expansion.

When PHSMA updates their industry standard references to include the current version of NFPA 59A, it is likely that this important class of tank and these tanks will eventually be a construction option in the U.S. for LNG storage.

Figure 3 View of Membrane Tank Interior. The liner is stainless steel with membrane corrugations forming a square pattern.

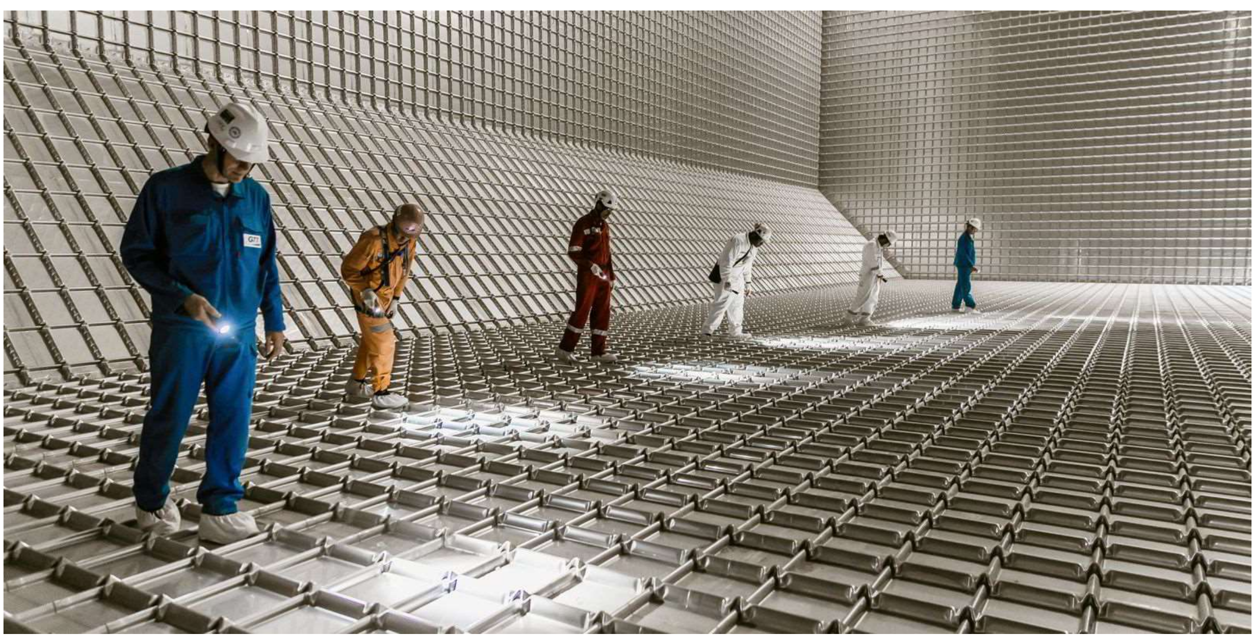


Figure 4 Membrane tank used cargo ship for LNG transport; note membrane and corrugations that allow for thermal expansion.

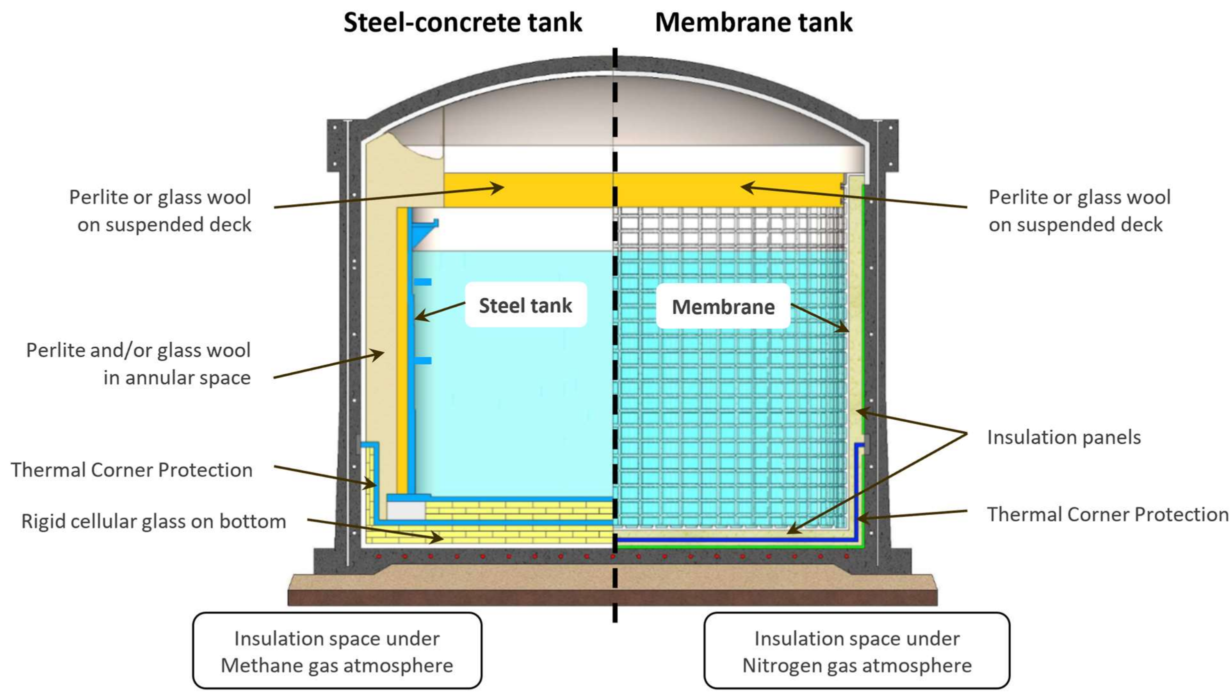


Figure 5 Comparison of full containment API 625 tanks and Full Containment Membrane Tank

3.4.3 Tank Design Trends

The plot in Figure 6 show two periods of time where the LNG tanks from the TAP survey (see Appendix 2) were constructed; the first period started in the late sixties and ended before 1980. There was little building during the period from 1980 to 2000. Then a resurgence of construction started in the early 2000s and continues through today. The plot also shows the tank configuration for each constructed tank. Configuration 5.3 (single tank with steel inner and outer tank) is the most common tank design and spanned the period from 1960 through the present. There is not enough data to definitively establish any trends, except that there was a noticeable increase in Configuration 5.9 (full containment steel and concrete outer tank) occurring in the period after 2000.

In Figure 7, the survey tanks are plotted with the capacity in barrels (bbl) and the diameter and height in feet, varying with time. There is a clear increase in capacity and thus diameter and height. Although both have increased, the diameter has increased more substantially than the height.

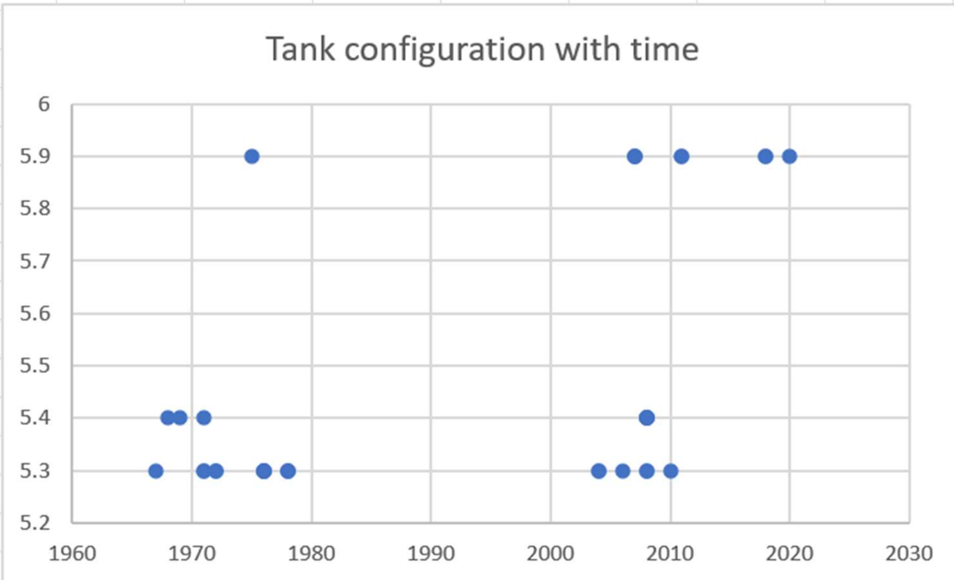
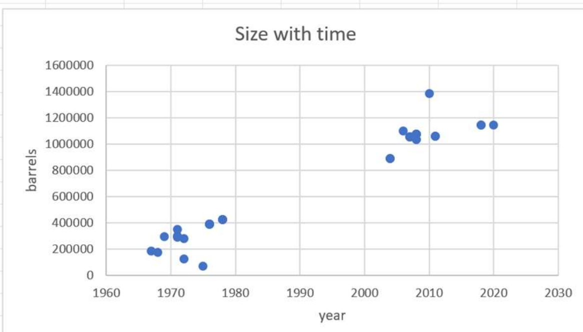


Figure 6 Survey tank configurations with time. 5.3 is the single containment steel inner and outer tank system. 5.4 is the single containment steel inner and concrete outer tank system. 5.9 is the full containment steel inner and concrete outer tank system.



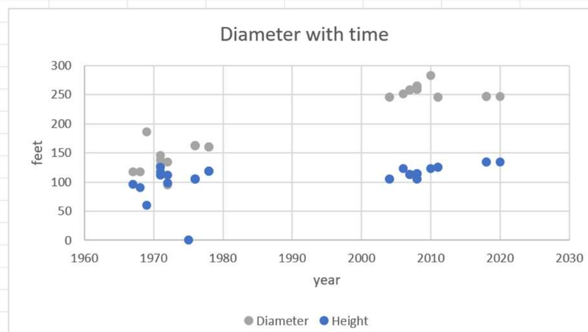


Figure 7 Capacities, diameter, and height of tanks with time

3.4.4 Major component materials

The survey data in Appendix 2 indicates that the predominant material of construction for the shell is 9% nickel steel (9Ni) which has adequate toughness for cryogenic temperature. However, aluminum has been used on the shell and roof domes as well. Concrete domes as well as shells are not uncommon.

3.4.5 Observations

A review of publicly available PHMSA data showed that the 36 tanks in the TAP Survey comprised approximately 35% percent of the existing population of medium or larger LNG storage tanks (the 2021 PHMSA LNG tank terminal data includes around 92 tanks with a 10,000+ bbl capacity). The survey population can therefore be considered representative of the existing LNG tank population. From this, it is reasonable to conclude that the tank configurations of Table 2 well represent the existing tank population configurations. The Project can therefore focus on these configurations.

3.5 Inspection Practices

TAP survey responses regarding inspection methods and practices are summarized from Appendix 3 and described here. These responses provide insights into the practices of the industry as a whole.

A selection of survey responses from the survey participants is presented here:

- Inspection History
    - 4/6 of the participants have only ever performed in-service inspections of their LNG tanks. The remaining 2/6 of participants have performed both in- and out-of-service inspections.
- Inspection Intervals
    - 3/5 of the participants base their inspection intervals on prescriptive periods; 1/5 of the participants use risk-based methods to determine inspection intervals; the remaining 1/5 of participants stated they used “many different reasons.”
    - 3/6 of the participants responded that their top motivation for inspection was regulatory; the other 3/6 stated they were concerned with corrosion or the status of equipment.
    - The participants differed greatly on the stated frequency of their in-service inspection frequencies: 1/5 responded monthly, 1/5 quarterly, 1/5 annually, 2/5 stated “it varies.”
    - Nearly all participants (5/6) stated that they did not have a set out-of-service inspection frequency. It is likely the participants only perform out-of-service inspections if there is some concern, e.g., signs of an inner tank leak, equipment failure.
- Inspections (general)
    - Nearly all participants (5/6) have never conducted hydrotests for their tanks after they are commissioned (i.e., after the tank first put into operation).
    - Nearly all participants (5/6) have a corrosion-under-insulation program for piping or are in the process of implementing one.

4. Repairs

4.1 Introduction

This section takes a closer look at the available data on LNG and cryogenic tank repairs, with the following goals:

a. Perform data acquisition and analysis regarding repairs performed available in public domain with support from PHMSA and other entities.
b. Solicit, survey, compile, review and analyze historical data regarding cryogenic storage tank repair projects that have been:
    - Identified in the public domain.
    - Have data supplied to the PHMSA organization and
    - Could be shared with the analysis team with emphasis on the following:
        - The size of the tank,
        - Service life (years)
        - The type of the tank (single containment, double or full containment)
        - The location of tank
        - Subjected environmental conditions over the service life such as: coastal/proximity to coastline or inland
        - The repairs, if any, performed on the tank, containment, and/or its appurtenances
        - Identification if the repairs were an operational preference or performed due to the aging of the facility (if known).
        - Definition of the source for the repair.
c. Identify common areas of susceptibility.

4.2 Repairs

4.2.1 Inspection and Repair Data Acquisition

This task was based on relatively sparse data sets involving inspection and repair issues. The information for this task was collected from three sources: the tank operator TAP survey, PHMSA Safety-Related Condition Reports, and PHMSA Incident Reports.

- A subset of the PHMSA incident database (see Appendix 1) includes information on incidents involving LNG tanks. Narratives of what happened, what equipment was involved, and causal details are provided. However, these reports are issued relatively soon after the incident and do not necessarily represent formal causes and up-to-date responses for the purpose of prevention in the future. Interpretation and speculation are needed to fill in the link between cause and result and indicated repair.
- The tank Owner/Operator TAP survey (see Appendix 3) included questions relating to repairs based not only on prior history of repairs, but also inspection practices, repair practices, and potential conditions that would require repairs. The data collected from the survey provided insight into the conditions that operators are concerned with and the overall repairs they perform. However, the data lacked specific information that would be required for a formal data analysis.

- The PHMSA Safety-Related Condition Reports (SRCR) are reports that PHMSA requires operators to submit for certain conditions that may cause a leak. These conditions include corrosion, unintended movements or loadings, material defects, or any other safety-related conditions. Only the subset of the SRCR data relating to LNG storage was included. The SRCR information provided some insight into the kinds of leak-causing events that LNG tank operators encounter. However, these reports are issued relatively soon after incidents and do not necessarily represent formal causes and up-to-date responses for the purpose of prevention in the future. Interpretation and speculation are needed to fill in the link between cause and result and indicated repair. Also, the data is not exhaustive, as the regulations have many exemptions from reporting.
  Source: *Safety-Related Condition Reports (SRCRs) - 2002 to present.xlsx*
  https://www.phmsa.dot.gov/data-and-statistics/pipeline/leading-indicators-srcr-and-im-notifications

Based on the collected data, there are a number of conditions that have or could lead to the need for repairs. The following grouping of conditions of concern are:

- Leaks
- Cracks in welds, piping, or plate
- Material defects
- Corrosion
- Operational errors
- Physical damage

An attempt to align these conditions of concern with actual TAP survey data has been made. The list below extracts and summarizes the TAP survey data related to repairs.

- Repairs include:
  - Painting
    - Shell, roof
    - Nozzles, pipes, valves, actuators, hoists, supports
    - Handwheels, any other carbon steel appurtenances
  - Insulation repair/replacement
  - Moisture/vapor barrier repairs
  - Full replacement of external pipes, handwheels, etc., due to corrosion
  - Foundation cracking/spalling repair with grout.
  - Foundation heater repair/replacement
  - Bottom patch plates
  - Inner tank anchor
  - Repair leaking piping for internal tank fill
  - Repair of level indicators and relief valves

Some immediate findings include:

- The most common repair common to all operators was external painting/coating.
- All tanks in the TAP survey were coastal or close to the coast, so any correlations between painting repair frequency and coastal/inland location cannot be made.

- It appears no operator has repaired tanks due to settlement conditions.
- No data was provided for calibration of level, temperature, or density measuring equipment.

4.2.1.1 Use of Supplemental Information

There is little public domain data that specifically addresses the types of LNG tank inspection and repairs that regularly occur. Therefore, the repair data collected in the above attachment was supplemented with (a) information from TAP beyond repair data, (b) existing industry standards, (c) vendor input, and (d) PEMY knowledge and experience.

4.2.2 Areas of Susceptibility

It is clear that the most common drivers for repairs were associated with:

- The external tank exposure to atmospheric and external conditions causing:
    - Corrosion of the shell-to-bottom of outer metallic containers
    - Coating failures
    - Projectile damage from high velocity winds (hurricanes, tornadoes, etc.)
- Maintenance activities such as removal of pumps, hoisting objects, replacing valves and operators such as wear out or corrosion or damage of hoists or lifting components.
- Spillage of cryogenic liquid without sufficient protection using drip pans or drains.
- Piping thermal expansion and contraction leading to cracks in welds or expansions joints, or failure of flange gaskets.
- Insulation failure and degradation due to breeches in moisture barriers, mechanical damage, and improper installation.
- Hydraulic transients or "water hammer" based in improper valve closure times in piping systems.
- Operational factors such as:
    - Failure to ensure all segments of piping when blocked in by valves have thermal reliefs to control expansion pressure or to ensure the design cannot allow thermal growth in blocked sections of piping and equipment.
    - Valve line up
    - Instrumentation for operation and shutdown systems testing and calibration

Most of these items are external to the tank system itself and are therefore not addressed. The items that directly impact the tanks are:

- Foundation and concrete tank and roof degradation, cracking, spalling, and internal corrosion of rebar.
- Corrosion of all metallic components exposed to the atmosphere.
- Equipment handling on the tank roof with potential for releases, impact, fires, spills.
- Potential spills of cryogenic liquids through failed valves or piping joints causing damage to metal containment.
- Instrumentation testing and calibration for operation, gas detection, alarm systems, and shutdown systems.

4.3 Summary and Conclusions

With regard to inspections – because of the sparse nature of existing inspection data of LNG tanks and components, it is essential to rely on supplemental data from similar activities on other types of tanks and also expert opinion to develop best practices and recommendations for these activities. This has been done for the Section 9 Tank Inspection Guidelines as well as other sections. However, for repairs, reliance on other industry standards that most closely relate to repairs is necessary instead.

Because the most important domain of repair work involves the primary and additional metallic containment systems within the scope of this Project, this leads discussion of repairs directly to the new construction standard API 620 or ACI 376. Although uncommon, it may be possible that an Owner/Operator wishes to install new shell fittings into existing tanks. In this case, these repairs should be governed by the existing rules and design criteria specified in API 620. Moreover, a formal design analysis along with MOC (management of change) is necessary before attempting any new opening, replacement, or addition of any containment component. The quality control measures that are in API 620 are applicable to repairs, in terms of NDE and acceptance criteria. This includes all of the requirements for welding, dimensional tolerances, and qualification of welders and welding procedures. All materials used in repairs should meet the requirements of API 620. These requirements should be spelled out in the repair contracts and any contractor performing the repairs must be qualified to do the work. Any repairs made that penetrate the container shell should be analyzed with finite element structural and thermal analysis to consider the stresses and fracture potential for both steady state operations as well as warm up and cool down cycles.

The same recommended requirements apply to anchorage system repairs and any penetrations of any of the containers regardless of size.

When thinning by corrosion indicates needed repairs, then a thorough analysis using API 579 Fitness for Service is recommended. This analysis will indicate how close to failure the damaged component is.

It is a major SDO challenge to write standards applicable to repairs of LNG tanks, not only because of the wide variety of designs and materials involved, but because of the materials, joining, and fabrication engineering issues involved. The development of this work will take a substantial effort comparable to or exceeding the development of the standards for inspection. It is possible that the SDO may choose to write separate standards for inspection and repairs of LNG tanks.

5. Damage Mechanisms, Inspection, and Risk

5.1 Damage Mechanisms

The purpose of this section is to identify and describe the types of damage mechanisms and operating practices that affect LNG tanks, with a focus on inspection and inspection effectiveness. Damage mechanisms unique to LNG tanks are also addressed. By examining the damage mechanisms individually, an assessment of causation and susceptibility to failure for the various equipment components in LNG tanks is possible. In addition, the listing of damage mechanisms aids in the consideration of the impact that inspection can or should have on the potential reduction in risk for these damage mechanisms.

The primary reference for fixed equipment damage mechanisms is API RP 571 "Damage Mechanisms Affecting Fixed Equipment in the Refining Industry." This reference was used as a checklist to ensure that most of the common damage mechanisms are identified and addressed. However, API RP 571 is not comprehensive to specialty equipment such as cryogenic tanks, vessels, and piping.

5.2 General Damage Mechanisms

This section is accompanied by Appendix 4 Tables 1-4, which provides details on the relevant damage mechanisms as well as the relationship between inspection and risk. Appendix 4 Table 1 lists general damage mechanisms while Table 2 provides a list of those damage mechanisms that are specific to LNG tanks. Appendix 4 Table 3 and Table 4 provide insight into inspection effectiveness with respect to risk.

5.3 Risk Grading System Used in Appendix 4

Risk is considered a combination of probability (also called likelihood) and consequence. There are many informal methods such as risk matrices or "layers of protection" analyses. There are also advanced methods that are more sophisticated but also more difficult to apply. In this section, a simple ordinal ranking system is used. Ordinal means that the risks are ranked only relative to one another without an underlying numerical scale; that is, one can differentiate whether a given risk is greater or less than another, but not by how much. The ordinal ranking system used will have only 5 levels from lowest to highest represented by 1 through 5, or VL, L, M, H, and VH (very low, low, medium, high, and very high).

This method was used to rank the various damage mechanisms identified and discussed. Likelihood[4] (probability) will use three ordinal probability categories which are low (L), medium (M), and high (H). Similarly, the consequence will have three ordinal categories which are low (L), medium (M), and high (H).

Typically, risk can be considered the combination of likelihood and consequence. To simplify the processing and results for risk assessment, an assumption is that the law of commutativity applies to the pair (likelihood, consequence) pair. For example, (L, M) is treated equivalent to (M, L).

Any consistency problems arising from combining probability and consequence which result in a single rank unique set {X, Y} must be disambiguated, where X is the probability rank and Y is the consequence rank. For example, is (L, H) greater than, less than, or equal to (M, M)? These pairs have been ruled to be equivalent, as they are indeterminate otherwise.

[4] Although likelihood is used to mean probability in risk assessment, it is a term that can be confused with Bayesian probabilistic analysis where likelihood refers to the process of determining the best data distribution given a specific situation in the data.

As a reminder, this assessment process is quantitative but in an ordinal sense only. Very low risk corresponding to "1" and low risk corresponding to "2" does not imply a low risk is twice as severe as a very low risk.

The process of risk ranking is developed as follows:

Step 1. Start with the following template for ranking probability and consequence:

CONSE / PROB	LOW	MEDIUM	HIGH
LOW	(L, L)	(L, M)	(L, H)
MEDIUM	(M, L)	(M, M)	(M, H)
HIGH	(H, L)	(H, M)	(H, H)

Step 2: Apply symmetry of (P, C) pairs where P is the probability rank and C is the consequence rank, assuming the commutativity of P and C – i.e., (L, H) is equal to (H, L). This is reasonable since, without an underlying numerical scale, symmetry must apply.

Assume (L, H) and (M, M) are equivalent. Rank each pair.

CONSE / PROB	LOW	MEDIUM	HIGH
LOW	(L, L) = 1	(L, M) = 2	(L, H) = 3
MEDIUM		(M, M) = 3	(M, H) = 4
HIGH			(H, H) = 5

Step 3: Fill in the missing cells using symmetry. Provide a name for each risk rank.

CONSE / PROB	LOW	MEDIUM	HIGH
LOW	1 Very Low VL	2 Low L	3 Medium M
MEDIUM	2 Low L	3 Medium M	4 High H
HIGH	3 Medium M	4 High H	5 Very High VH

Step 4: Apply to problem. See Table 3 and 4 of Appendix 4 Damage Mechanisms and Risk Tables.

5.4 Human Factors

While human factors are not specifically addressed in the specifications for this section, they are probably the single most important factor governing the potential for failure. Human factor-caused incidents are the result of their direct interaction with facility management and operations. These are typically addressed by *Safety Management Systems* or SMS. For example, a possible human factors-related initiating event is the release of cold liquid onto the external LNG tank components from work on the tank roof. Incidents of external steel shell, roof, and accessories cracking have occurred as the result of liquid spills.

Another common initiating event is the potential for fire incidents when work is being done on the tank, from vapors that are likely to be near the tank roof. In one instance, there was a fire caused when an in-tank pump was being removed. In another instance, while placing perlite into the annular space, a fire ignited on the vent stack of the tank and burned for 2 hours due to failure to install a block valve on the vent stack (a failure to follow maintenance procedures).

These human factors related events may have been preventable by carefully using process safety management principles.

5.5 Conclusions

The relationship between damage mechanisms and inspection effectiveness has been shown to range from low to high effectiveness depending on the specific damage mechanism under consideration. Some damage mechanisms such as excess pressure caused by blocked liquid lines that can warm up are not subject to improvement or even identifiable by periodic inspections. This means this particular damage mechanism-inspection pair is *not* improved by inspection. It is directly related to the system design and the way the system is operated. On the other hand, the corrosion-inspection pair is highly effective in determining the extent of damage and the potential for an incident. Each facility Owner/Operator should periodically review all damage mechanism-inspection pairs to determine how inspection impacts risk and prioritize the type and frequency of specific inspections.

Appendix 4 Tables 3 and 4 should not be considered the last word on the topic of risk or mitigation of risk. Instead, these are simply examples of how one might approach the problem of inspection effectiveness on various damage mechanisms. It should be noted that there is dependence between the management system in place, the types and periodicity of risk assessments, and the quality control over inspection that all interact to result in potentially significantly different levels of risks associated with the storage tanks.

6. Corrosion and Fatigue Damage

6.1 Introduction and Scope

The purpose of this section is to determine if there is a limit to how long LNG tanks should be allowed to operate without an internal out-of-service inspection (OSII, see Section 9) resulting from corrosion and/or fatigue damage. The four elements of this task are:

a. For relevant damage mechanisms, compute expected rates of damage growth. Common growth-based damage mechanisms are corrosion and fatigue.
b. Estimate ranges of growth rates and corresponding inspection intervals.
c. Define inspection parameters including type (internal or external), method and frequency that would address the areas susceptible.
d. Determine timing limits for internal and external inspections that are frequent enough to detect changing conditions.

6.2 Background

6.2.1 Relevant Damage Mechanisms

The two basic age-related damage mechanisms of concern associated with the primary container are (a) corrosion and (b) crack propagation. These are the focus of this section.

6.2.1.1 Corrosion

The interior of the primary container is a clean, dry, oxygen free environment that is cold. Corrosion is an electrochemical oxidation reaction that requires oxygen and an electrolyte, typically moisture, to drive the reaction. Temperature controls the rate of the chemical reaction, and at cryogenic temperatures the rate would be slow, even if the other corrosion requisites were present. Therefore, corrosion damage is nil, and experience bears this out. Outer metallic containers have their outer surfaces exposed to the atmosphere and therefore corrosion can degrade susceptible elements of these outer containers. Because corrosion is a relatively slow process and begins with small holes and subsequent leakage, this type of damage is not catastrophic in nature and is far less hazardous than a sudden breach, such as a brittle fracture. Because the outer surfaces of the outer container can be monitored, inspected, and tested for condition and leakage, the intervals can be driven by the observations on the outer container's condition.

Removing the tank from service to perform internal corrosion inspection should not be driven by fixed periodic intervals. This is consistent with the concept of risk-based inspection. This concept is described by the ETI or Event Triggered Inspection (see Section 9).

6.2.1.2 Fatigue

The damage mechanism of fatigue has been recognized long ago in early editions of API 620. In fact, API 620 states that an allowance for fatigue life of 1000 cycles is built in the construction requirements specified in Annex Q based on design stresses in the first shell course and based on the minimum thickness of the annular plates specified in Table Q-4A of API 620. The API 620 fatigue limits are out-of-date and overly generalized.

Fatigue is a damage mechanism that exhibits crack growth, driven by repeated applied forces over time. Failure stresses can be less than the material yield stress due to the effects of variable loading. Metals are susceptible to fatigue damage to varying degrees, depending on the metal type, construction detail, and equipment lifecycle and load history. Common metals used to build LNG tanks are 9% nickel steels, aluminum, and stainless steels. The Project considered only the nickel steels in this study because they are by far the most common construction today. However, the material fatigue life of aluminum and stainless steel is less than that of carbon and nickel steels.

It is assumed that fatigue is not an issue for the outer containment since it does not cycle as does the inner tank because of fill-empty cycles. Fatigue is typically considered in terms of a fatigue life, the number of load cycles that can safely be expected before failure or the number of years of life given a regular rate of load cycles per year. Higher loads and stresses tend to shorten the fatigue life. Stresses due to thermal load cycles commonly lead to problems with fatigue. In the case of LNG tanks, this is not an issue because they number of cool down and warm up cycles is only a few cycles over the life of a tank system at the most. When assessing LNG tanks for fatigue damage, it is important to understand the number and type of load cycles that the inner container tank has and will experience in its lifetime.

Welds are more susceptible than the rest of the container to fatigue for several reasons. Welds necessarily involve a geometrical discontinuity, which has local stress concentrations typically occurring at the toe of the weld. The zones of peak tensile stress cycling are likely areas for fatigue cracks to initiate. Welding residual stress fields increase fatigue damage. It is interesting to note that unwelded base metals do not fatigue under compressive-only loading, but it is possible to fatigue a weld joint under compressive loading. The welds and nearby areas can normally have a residual tensile stress field that will change and cycle under compressive-only loading. Even welds of high quality have small flaws and discontinuities on the surface and inside of the weld. Crack initiation is believed to initiate from micro-cracks in the material, and larger cracks, weld defects, or notches can accelerate the crack initiation and propagation process. Inspecting all welds and grinding contours perfectly smooth is largely impractical. LNG tanks are welded with the traditional arc welding processes and tend to have normal weld quality compared to other tanks and vessels in the industry.

6.2.2 Areas of Concern for LNG tanks

6.2.2.1 Inner Tank Shell-to-Bottom Weld

The current edition of API 620 (the 12th Edition Addendum 2 at the time of this writing) Annex Q requires improved construction and welding of the shell-to-bottom weld. Thickened, butt-welded annular bottom plates are required. These are stronger and more uniform in geometry compared to lap welded bottom plates found in conventional API 620 flat bottom tanks. The shell-to-bottom weld is to be 100% liquid penetrant tested. Welding is completed with a minimum of two passes per side. These construction details improve the tank fatigue life, and API 620 Annex Q lists a default fatigue life of 1000 fill cycles. It turns out that this is typically far less than the number of cycles actually required to cause a crack that could propagate.

The figures from API 620 compare lap welded bottom plate (Figure 8) on left to butt welded annular plate joint (Figure 9).

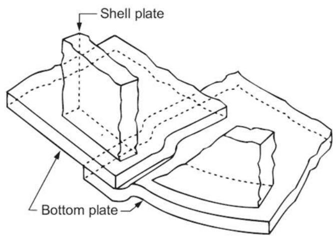


Figure 5-2—Method for Preparing Lap-welded Bottom Plates under the Tank Sidewall

Figure 8 Typical shell to bottom weld plate weld

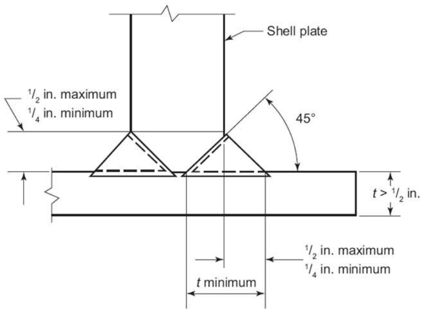


Figure 5-3—Detail of Double Fillet-groove Weld for Bottom Plates with a Nominal Thickness Greater than $^1/2$ in. (See 5.9.5.3)

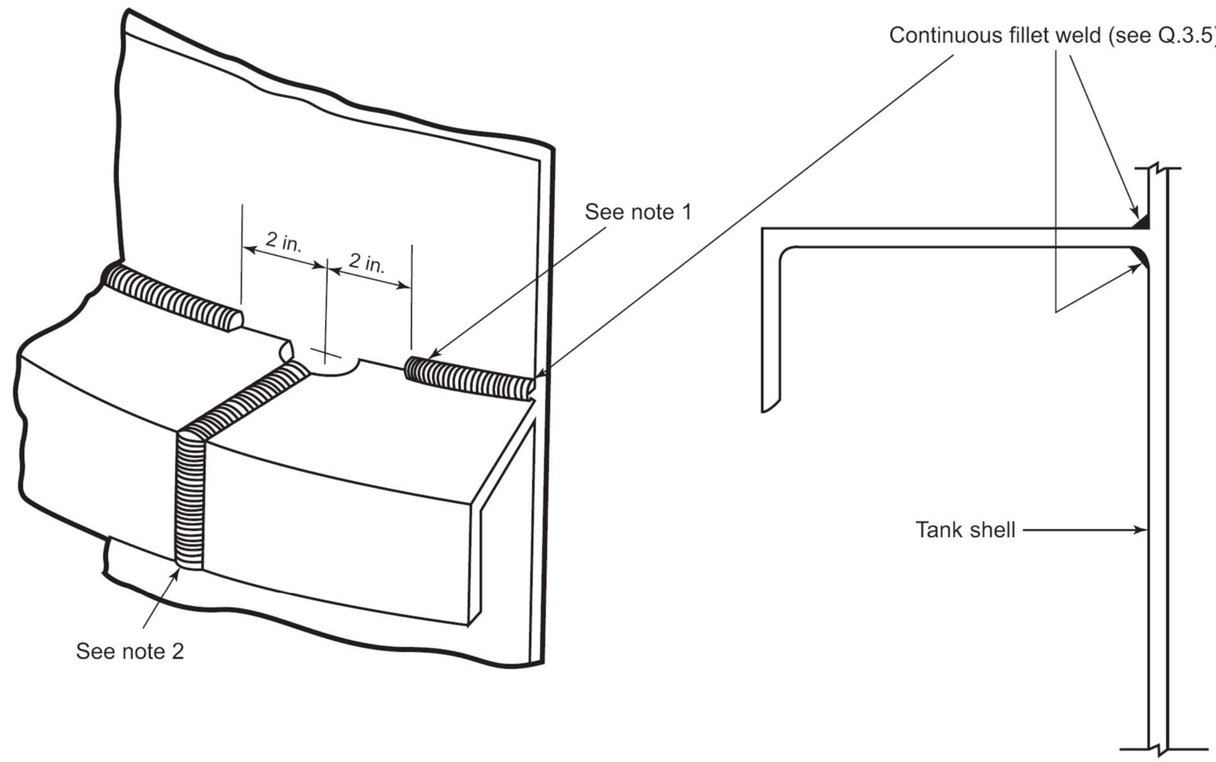
Figure 9 Corner weld joining shell to annular plates

6.2.2.2 Shell Nozzle Welds

It is preferred to build LNG tanks without nozzle or manway penetrations through the shell, but some tanks are in operation with shell penetrations. These areas would experience higher stress and shorter fatigue life. Because of the variety of nozzle designs and reinforcements, fatigue analyses on these components were not performed.

6.2.2.3 Shell Stiffener Welds

Stiffeners are commonly welded to the inner tank shell to resist the external pressure exerted by the perlite insulation pressure loads. The current edition of API 620 Annex Q requires several welding improvements for the shell stiffeners. See Figure 10. Continuous welds are required, except at stiffeners splices and intersections with shell vertical welds, where a small rat-hole is provided to minimize stress interactions between welds. Prior LNG tank construction may have used intermittent welding and may have omitted the rat-holes, and for these cases, the stiffener welds could be a site for fatigue damage.



NOTE 1 See Q.3.5.4 for alternative fillet-weld termination details.

NOTE 2 Backing strips are permitted on stiffening-ring junction welds.

Figure Q-1—Typical Stiffening-ring Weld Details

Figure 10 API 620 Showing Shell Stiffener Ring Details

The analyses that were conducted show that the stresses for the weld stiffeners are low even with discontinuities. This work shows that in general fatigue analyses on shell stiffeners are not necessary.

6.2.3 Compression Ring

The compression ring is the joint where the tank fixed roof meets the shell. Tanks with suspended deck on the inner tank have only one compression ring, on the outer tank. Tanks built with a dome roof inner tank will have two compression rings, one for inner tank and one for the outer tank. Stresses develop in the compression ring area from internal pressure loading. If there were a vacuum event, then the vacuum loads could also generate stress in the compression ring area, but this is not a usual occurrence for LNG tanks. Furthermore, the degree of pressure loading and the number of cycles is not expected to be significant for LNG tanks. These are issues common to all tanks with internal design pressure.

6.2.4 Fatigue Assessment General Methodology

Fatigue assessments of existing LNG tanks can be performed in a straightforward manner. The first and foremost methodology is found in API Standard 579 "Fitness-for-Service", Part 14 "Assessment of Fatigue Damage." The fracture mechanics crack growth model is capable of incorporating variable load combinations as compared to an SN curve, but for predicting design life it is typical to perform a cumulative damage summation over all the types of cycles (so then the results are just the number of each type of cycle, and the order is not important). In the fatigue analysis, full cycles were used, and the evaluation of partial fill cycles was determined to be unnecessary. The fracture mechanics growth model is preferred over SN curves because it incorporates inspection results. The degree of initial inspection and NDE is used to size typical flaws that are small enough that they could have escaped detection. More importantly, the fracture mechanics growth model can extend the tank's service life based on inspection and NDE performed later on during a tank inspection. The SN curves do not account for inspection, and therefore would lack a mechanism to extend fatigue service life.

6.3 Results

6.3.1 Estimation of Growth Rates and Corresponding Inspection Intervals.

See Appendix 5 Fatigue Analysis.

6.3.2 Selection of Inspection Parameters to Address Areas of Susceptibility

The fatigue damage mechanism of concern is fatigue that occurs in the tank bottom inner toe of the fillet weld at the annular plate of the inner tank. This is of concern because the failure mode is not necessarily of a "leak-before-break" type. However, the number of cycles appears to be more than needed for the life of LNG tanks where the life is upwards of 50 to 70 years with a frequent fill/empty rate of 3 to 4 cycles per week. The risk of fatigue failure appears unlikely even in those existing tanks that have high cycle rates and have been operating for many years because it would have to be in excess of 20,000 cycles. Only 2 cases were analyzed, which may not be representative of all types and sizes of LNG tanks constructed, and therefore this report recommends performing a desktop fatigue life study on all new and existing LNG tanks where the anticipated life exceeds the 1000 cycle basis as stated in API 620 (see recommendations in Section 10).

The results of the fatigue study in Appendix 5 Fatigue Analysis indicate that an LNG tank may have significantly longer fatigue service life compared to the default API 620 basis. These recommendations are only valid if there is confidence that the tank welding meets the quality control for welding criteria, since the fracture study was based on reference flaw sizes that are consistent with the requirements of API 620 for weld flaws. Recommendations for removing a tank from service to conduct fatigue crack inspections should be based on the results of the fatigue study and on a case-by-case basis. Tanks should not be removed from service for fatigue crack inspections based solely on the 1000 cycle fatigue basis of API 620.

6.3.3 Timing Limits for Internal and External Inspections

Based on either fatigue or on corrosion of the LNG containers, there is no justification for taking the tank out of service on a routine or scheduled basis. The damage mechanisms that would require a policy of internal inspections based on damage mechanisms are:

1. Fatigue cycles exceeding limits of a desktop fatigue study
2. Event-triggered inspection

6.3.3.1 Corrosion

All surfaces within the outer container are in an environment not subject to corrosion, as these components are subject to the environment. However, inner tanks are not subject to moisture, electrolytes, and oxygen, and the environment is dry and free of foreign substances based on an initial proper installation. Further protection is provided by cryogenic temperatures that slow any corrosion chemical reaction. The only damage that corrosion can cause is on the exterior surfaces of an outer metallic container. The primary corrosion threat would occur under the bottom of this container, as the tank bottom is subject to rain and moisture on the foundation. However, most foundations are constructed with slopes that reduce most of the moisture and the concrete supporting slabs have a basic pH of around 12 when moist with water reducing the corrosion rates. In some cases, corrosion could penetrate the outer tank due to some contamination, improper construction, or presences of salts caused by a marine environment or failure to check and remove them when the tank is under construction. In this case, the tank may leak but routine inspection will detect the potential threat of these leaks quickly. In this case the tank system must be repaired either in-service or shut down if extensive repairs are needed.

Corrosion can affect the metallic outer tank roof, shell, and other exposed components such as anchorage systems, piping supports, stiffening rings, and structural members. These can be easily inspected externally, maintained, and in many cases can be repaired without interrupting tank operation.

6.3.3.2 Fatigue

Appendix 5 Fatigue Analysis shows that fatigue is generally not a problem up to about 20,000 cycles. This is beyond the range of any typical LNG life. Therefore, there is no justification for taking LNG tanks out of service specifically for fatigue.

6.3.3.3 Timing Limits for External Inspections

For LNG tanks with steel outer containment, the components to be inspected and the scope of external inspection are similar in nature to a Standard API 653 external inspection. It is judged that a similar external inspection schedule is appropriate and can be adopted for LNG outer steel tanks. There is further benefit in maintaining uniformity with prevalent and established practices in the industry.

Standard API 653 provides inspection schedules for external inspections as shown below. It is recommended that the same inspection schedules can be applied to LNG tank inspection.

a. Routine In-service Inspections not to exceed one month (API 653 6.3.1)
b. Formal External Inspection not to exceed five years (API 653 6.3.2)

Standard API 653 also schedules ultrasonic thickness (UT) inspections, but this activity is not deemed necessary for LNG steel outer containers. For in-service tanks, corrosion on the external surface of the tank can be detected visually and measured manually, but the inside of the tank is inaccessible for visual inspection. The usual purpose of UT inspection is to detect corrosion loss occurring on the inside of the tank. As discussed previously, there is no active corrosion inside the tank.

The size and complexity of an LNG tank could be reason to inspect them more frequently tank a conventional API 650 tank. The external inspection is primarily designed to detect external corrosion. Unless there is serious neglect of maintenance, the most likely damage mode for an LNG tank would be localized corrosion or pitting that could penetrate through the outer containment wall. That would indeed be problematic as it would release the vapor residing in the interstice, either natural gas or purge gas. As LNG tanks are relatively low pressure, the leakage could most likely be repaired using temporary repair methods while the tank remains in service. Compared to a conventional API 650 tank, the consequences are likely to be higher for the API 650 tanks than for LNG and liquefied cryogenic gases storage tanks for these reasons.

1. The hydrostatic stresses can be higher.
2. Internal corrosion is more likely.

3. Leakage consequences would likely be higher for storage of petroleum or hazardous liquids.
4. It is more difficult to repair a liquid leak.

7. Inspection Technology

7.1 Purpose

The best reasonable and available technologies for cryogenic and LNG tanks for steel outer containers are nearly the same as it is for typical ambient temperature storage tanks constructed to API 650 and API 620. However, cryogenic tanks use additional inspection and testing methodologies that arise from their low temperatures or unique construction details. The challenge of inspection for operating LNG tanks is to detect emerging potential problems on the inner liquid and vapor barrier.

7.2 Inspection Technologies Specific to Cryogenic Applications

Inspection of the cryogenic inner tank and low temperature tank system components is difficult and largely limited by access to the inner tank surfaces. Nonetheless, there are methods that can be applied as indirect measures of potential problems. For example, unusually low temperatures detected on the outer container may indicate an inner tank leak or the presence of cold liquid.

This section addresses both direct and indirect inspection of the inner tank integrity for tanks which are in service – both inspections via conventional methods, which are well established today, and emerging technologies that may become common in the near future. For inspection of the inner tank of an in-service LNG tank, an indirect inspection might involve the detection of a leak in the inner tank by inference, using indirect indications such as by the detection of cold spots on the outer shell or within the interstice, or the acoustic emissions of specific frequencies generated by leaks. Leaks or cracks in inner tanks likely have a low probability of occurrence, given there are no reported incidents. By analogy to other types of tanks, it is probable such cracks or corrosion holes will provide sufficient time to react before the failure threatens overall tank integrity. While some mechanisms are sudden and catastrophic such as fatigue (see Section 6 Corrosion and Fatigue Damage), for LNG and cryogenic tanks to date, these events have not occurred. However, thermal shock resulting from cold liquid on a steel dome constructed of material not suited for cryogenic temperatures has happened. Such incidents have occurred because of direct liquid spills at the top of the tank onto the dome without safeguards such as drip pans.

7.2.1 Overview of Existing Technologies

Direct inspection of the inner cryogenic tank is accomplished by cameras which can observe the vapor space above the liquid such as the suspended roof while operating. Cryogenic cameras can visually inspect the inner tank inside surfaces under or above the liquid surface. As is evident, there are very few direct methods of inspection of the inner tank of double container cryogenic tank systems.

More commonly indirect inspection such as use of temperature measurement, gas detection, or other available technologies make indirect inspection of the inner tank feasible.

The most important inspection techniques unique to cryogenic tank applications are:

- Submersible cryogenic cameras
- Thermal monitoring
- Thermal imaging cameras
- Optical gas imaging (OGI) cameras
- Inclinometers

Other areas where temperature monitoring has high utility are for:

- Tank cool-down
- Leakage monitoring in the tank annulus
- Monitoring of the spill containment area
- Cool-down monitoring on the jetty
- Leakage detection in liquefaction and process areas
- Base slab monitoring

In all of these applications, a baseline is important because the change from a baseline may indicate a potential developing problem area.

7.2.2 Emerging Technologies

Most of the emerging technologies for cryogenic applications are improvements to existing technology. However, some are made available because new equipment is available on the market, such as satellites used for industrial purposes (see Figure 12).

7.2.2.1 Acoustic Imaging

Using an array of more than 50 ultrasonic microphones and beamforming technology, triangulation of the source of leaks mapped on video or photographs is possible. See Figure 11.

While the technology is at least a decade old, the miniaturization of the technology has made the essential portability of such instruments possible.

Figure 11 Acoustic Imaging Showing Leak Location

While acoustic imaging has been useful for flanged connections and small diameter piping connections, it is not well suited to detect leaks from tank bottoms and the inner tank.

7.2.2.2 Satellite Mapping of Methane Plumes[5]

Different satellite missions have recently shown the potential to map methane plumes from space. See Figure 12. An example is the Maxar WorldView-3 (WV-3) satellite mission for methane mapping of LNG facilities. This technology relies on high spatial resolution (up to 3.7 m) data in the shortwave infrared part of the spectrum, which is complemented by a good spectral sampling of the methane absorption feature at 2300 nm and a high signal to noise ratio. The proposed retrieval methodology is based on the calculation of methane concentration enhancements from pixel-wise estimates of methane transmittance at WV-3 SWIR band 7 (2235–2285 nm), which is positioned at a highly-sensitive methane absorption region. A sensitivity analysis based on end-to-end simulations has helped to understand retrieval errors and detection limits. The results have shown the good performance of WV-3 for methane mapping, especially over bright and homogeneous areas.

Today, this technique has limited usefulness for LNG storage facilities because the sensitivity of this type of methodology requires release rates of at least 1000 kg/hr. However, as an emerging technology it is expected that the resolution and sensitivity will improve. So, it may become a candidate for mapping leaks from tanks and piping in cryogenic facilities for routine inspections in the future.

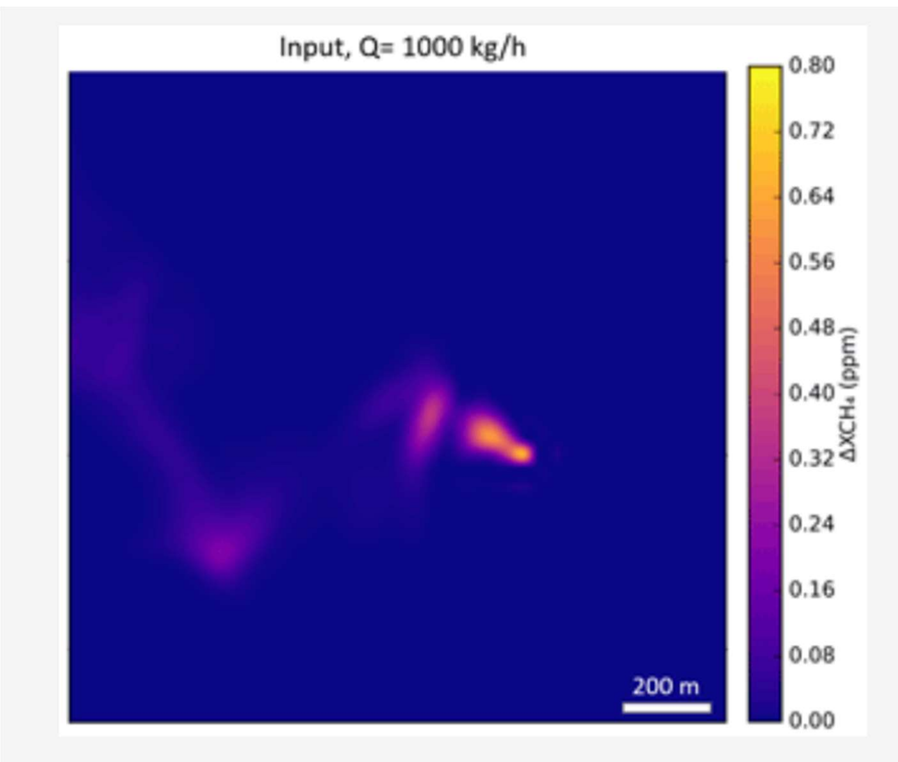


Figure 12 Methane plume with 1000 kg/hr of 1.5x1.5km^2 area

7.2.2.3 Optical Time Domain Reflectometry (OTDR[6]*).*

There are several application approaches to using temperature as a means of detecting leaks and problems with cryogenic tank storage. Because the liquid form of liquefied gases is so much colder than

[5] https://amt.copernicus.org/articles/15/1657/2022/

[6] https://ntrs.nasa.gov/api/citations/20120007653/downloads/20120007653.pdf

ambient, the signal for a leak is the temperature differential between ambient and the low temperature wherever liquid LNG is present. In some systems, RTD arrays are used to collect many temperatures at points on the surface of the inner storage tank, in the insulation, and the bottom. The problem with RTDs is not only the cost of large-scale arrays with many sensor points but complications with the installation and placement of numerous sensors that could create a 3D image of temperatures in the tank areas of interest.

A recent option is to use optical fiber cable to detect temperature changes as shown in Figure 13.

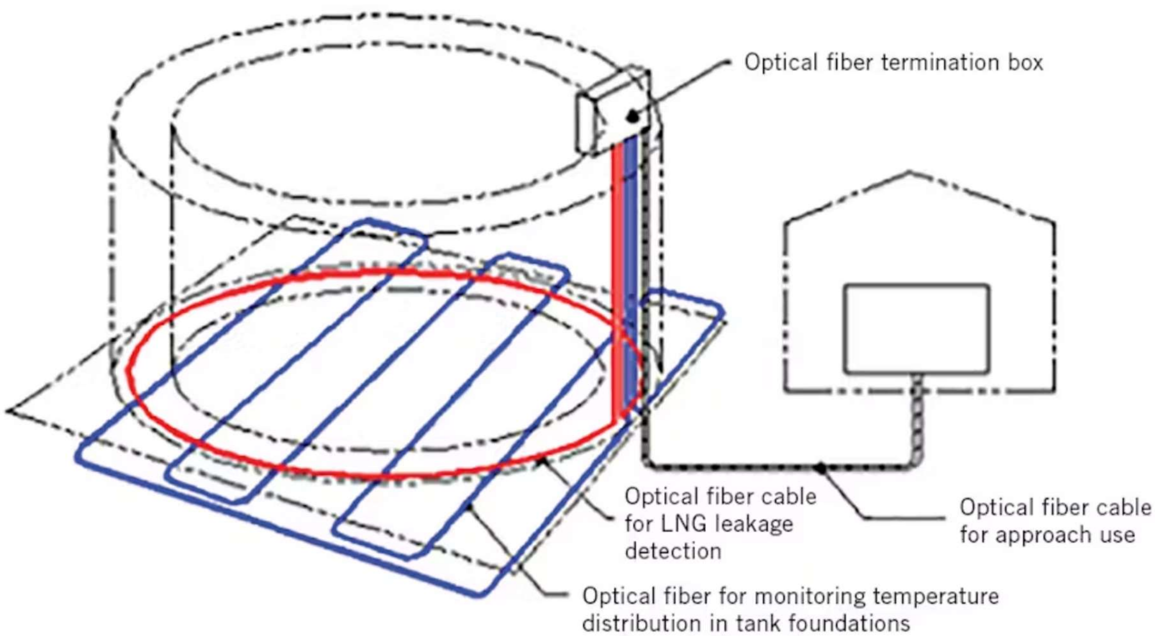


Figure 13 Thermal monitoring with optical fiber cable[7]

Although some fiber-optic thermometers can be single-point, multiple-point or continuous there is one design that sends a 10-nanosecond laser pulse through the glass core of the optical fiber. As the optical pulse propagates through the fiber, it undergoes scattering (called Raman scattering) due to structural defects in the glass fiber. In this way, the fiber itself is the sensor and the scattered radiation carries the information on both the temperature and the location of the cold spot. Some of the scattered radiation travels forward and some back to the source, and their ratio is a well-defined function of temperature. This ratio reveals the average temperature of each 1-meter section of the fiber, while the time of the round-trip flight of the backscattered pulse indicates the location of any cold spots. This method of location detection is called *optical time domain reflectometry* (OTDR).

The current advantages as the technology stands today are insufficient to displace the use of RTD arrays.

[7] https://www.controlglobal.com/protect/physical-security/article/11295886/how-best-to-detect-lng-spills-and-leaks

Fiber optic Distributed Temperature sensing (DTS) technology has been discussed for spillage detection in LNG facilities in section 7.5.4 and 7.5.1.3 of BS EN 1472:2021. These systems can also be applied to:

- Cool-down monitoring on the jetty
- Leakage detection in liquefaction and process areas
- Leakage monitoring in the tank annulus
- Monitoring of the spill containment area
- Base slab monitoring

Visualizing the DTS as applied to an LNG facility is shown in Figure 14.

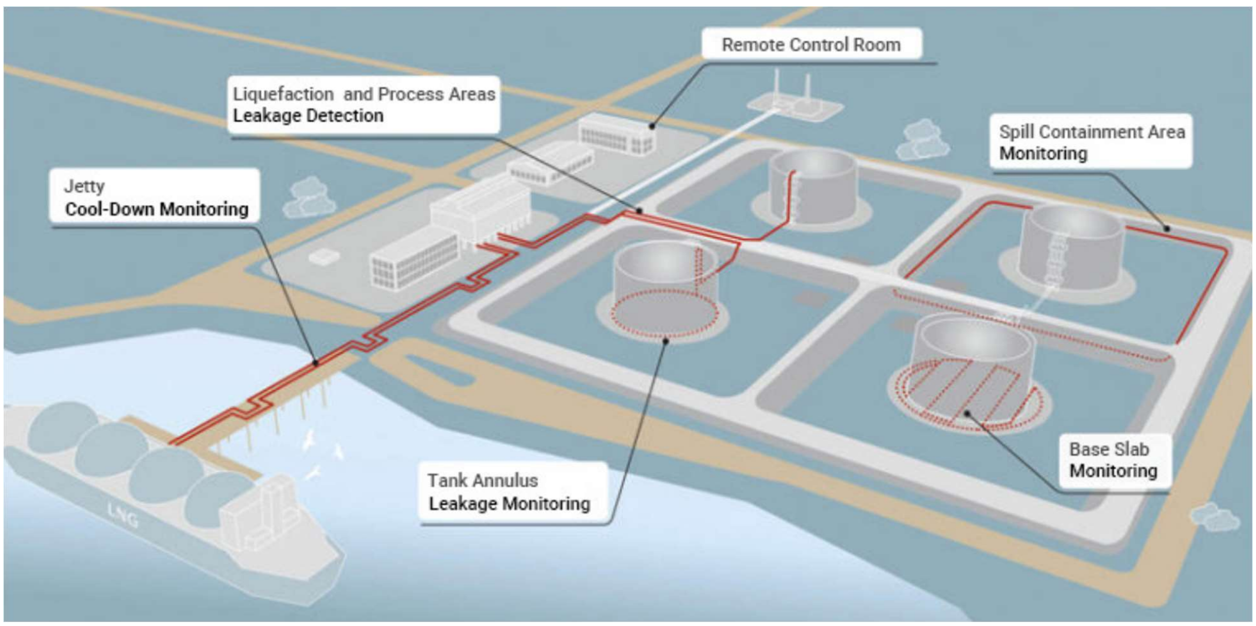


Figure 14 Distributed fiber optic sensors monitoring of LNG facility

7.2.2.4 Drone Assisted Technology

One of the challenges of inspecting large LNG tanks is the sheer height reaching up to 150 feet elevation and the ability to safely access the entire shell area externally. Normally, either scaffolding or rope access techniques would be required which are costly and hazardous to personnel. However, drones are capable of conducting not only visual inspection but thermal imaging quickly and efficiently with little hazard to personnel.

To survey the outer tank surfaces for cold spots, a UAV could be equipped with a thermal imaging scanner or a radiometric thermal camera, which measures surface temperature by interpreting the intensity of the infrared signal reaching the camera. Millions of data points can be combined to create a comprehensive mosaic or model of the tank surface that tracks temperature to a tenth of a degree. The collection process only takes one or two days.

7.3 Identification of Technology Gaps

7.3.1 Insulation Inspection

As is the case with inspection of the inner tank, the inspection of insulation uses indirect measures of changes to the insulation physical characteristics and properties such as the formation of cold spots or changes in temperature. Because insulation such as Perlite used between the shells of the inner and outer tanks can form voids and compact over time, the insulation can have problems that quickly occur right after inspection or gradually over time that reduce its effectiveness. Measures to counteract compaction of insulation such as the use of insulation blankets that have some resiliency to them have been used, but measuring their effectiveness is difficult and there is uncertainty as to their real effectiveness.

Technology that can assist in measuring the uniformity and density of the insulation throughout the annulus would provide a metric for not only assessing the installation but in monitoring insulation effectiveness with time. While this is possible today, better imaging combined with better technology could produce finer images with greater accuracy.

In addition, formal studies showing how insulation densification changes with time, how uniform it is, the effectiveness of insulation blankets, and other properties of insulation could be better understood and quantified by more research.

7.3.2 Tank Bottom Corrosion

7.3.2.1 Sealed Bottoms

Inner tanks where the bottom is completely within the outer tank resting on an insulation layer have very low potential for corrosion damage. This is backed up by the fact that there are no documented cases of inner tank failures caused by corrosion. However, cracks in welds can also be a source of bottom leaks. The best prevention is quality control over welding and careful inspection of the bottom before the tank is commissioned.

The most likely location for corrosion penetration in the tank system would be in the bottom of the outer container of a double walled tank system, since the bottom is potentially exposed to a wet corrosive environment. Although the pressure is low (a few psi at most), some gas leakage will pass through the bottom wall to the foundation and flow to the perimeter where it can be detected. The problem of determining leakage from a bottom to the environment is compounded by the fact that some tank designs attempt to caulk and seal the perimeter to the foundation and others do not. There is no research that shows whether the sealing of the tank bottom perimeter to the foundation promotes or reduces tank bottom underside corrosion. This is a gap that should be studied to determine the truth sealing the shell to bottom projection of the outer tank to the foundation, which is likely dependent on the foundation material, slope, design, and other factors. It is known that the percentage of time that a steel surface is wet or has a thin film of moisture on it that corrosion can occur. Therefore, ensuring that any water which may carry corrosive salts in certain environments that flows down the outer container has good drainage away from the tank bottom. Because of capillary action, water will flow over the bottom edge that extends beyond the shell and onto the underside of the bottom. Currently the most effective prevention is to make sure that the foundation where shell drippage lands is sloped away from the tank bottom.

Inspection of the perimeter on a regular basis by providing inspection ports (installed into the sealed area between the bottom area and the foundation) would help determine if there is a corrosion problem developing at the tank bottom causing gas leakage.

7.3.2.2 Acoustic Emission (AE) Leak Detection

Acoustic emission technology uses frequency domain-based pattern recognition to identify fluid flow through tank bottoms. This technology was introduced by several vendors/suppliers in the last three decades. However, the literature has been biased and not conducted formally with independent research work so that the credibility of vendor claims cannot be verified independently. A review of the literature suggests that the technology does work[8] but that the probability of detection is dependent on:

a. The specific tank configuration as well as the foundation
b. The extent and nature of corrosion
c. Background noise
d. Many other potential factors

Stating that a technology "works" only means that, compared to a random indication or guess of the existence of a leak, the technology is just "better than nothing." So, the probability of detection may range from only slightly better at detecting leaks than random guesses all the way up to highly accurate. Unfortunately, at this time, there is little in the literature to confirm objectively what the performance level of acoustic emission performance is and under what conditions.

However, when two or more independent tests are conducted the true positive rate can be increased substantially. That is, if a test for methane in the interstice is combined with AE testing, then the probability of a true positive is magnified substantially.

The improvement in leak testing results could be substantial by combining multiple tests such as gas detection and acoustic emission testing. Formal studies of AE testing in combination with other test methods could potentially represent a significant improvement in detection of leaks from the inner container should appropriate research be conducted in valid statistical trials.

[8] https://www.osti.gov/etdeweb/servlets/purl/20671861

8. LNG Tank Reliability

8.1 Inspection Program Impacts on Business and Operations

LNG has a key role in the transition from hydrocarbon-based fuels to other forms of energy, in response to societal recognition that carbon dioxide is an important input variable to the climate system. LNG is not only used to support energy needs of industrial operation such as heating, cooling, drying, food production, and many other uses. One of the key advantages of LNG is the reduced level of pollutants per unit of fuel mass consumed for energy generation. For this reason, the business and operational impacts of inspections and maintenance cycles on the LNG industry are important to understand and implement in an optimal manner.

Any discussion of optimal inspection and maintenance cycles depends on system reliability. The next section provides an overview of tank reliability and its interaction with inspections. Particularly important are the impacts of inspection or maintenance cycles that take the tank out of service, even if for only a short time.

This section focuses on the reliability of LNG tanks. Most of the discussion is on internal inspections involving the inner tank of the LNG tank system because these have, by far, the greatest impact on business and operations. While external inspections should be considered a "given," as they do not interrupt business and have relatively lower costs compared to the overall costs of operating LNG tanks, they are nonetheless important to prevent incidents and identify emerging problems.

8.2 Reliability Estimation

The Weibull distribution is used to model the failure rate (also known as hazard rate or force of mortality) in this analysis due to its flexibility and mathematical tractability. The two-parameter (rate, shape) Weibull can model an increasing hazard (shape > 0), constant hazard (shape = 0), or decreasing hazard (shape < 0); the three-parameter version (rate, shape, shift) has an initial period of constant hazard followed by a regime of increasing or decreasing hazard (but not both). The Weibull is probably the most widely used distribution in reliability engineering. The Weibull is capable of modeling a "Bathtub," hazard that involves decreasing, constant, and then increasing hazard rates shown in Figure 15.

.

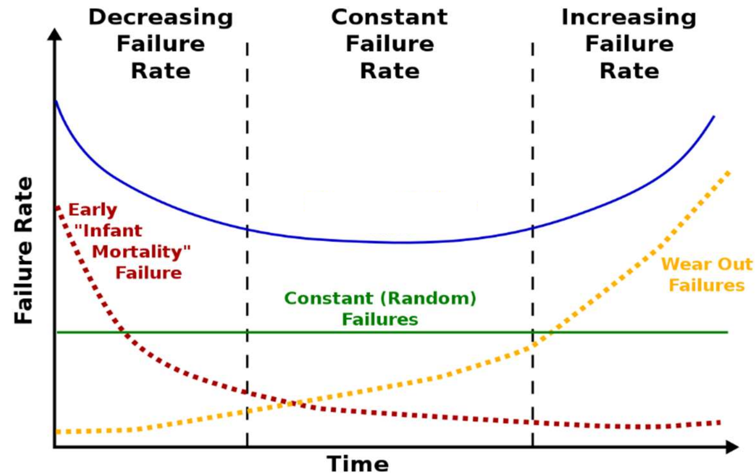


Figure 15 The Weibull can have constant, increasing, or decreasing failure rate, but cannot be "bathtub" shaped.

8.2.1 Hazard Rate and Reliability

To better understand this distribution, consider a power law function for a hazard rate $\lambda(t) = at^b$ (a > 0) which is increasing for $b > 0$, decreasing for $b < 0$, and constant for $b = 0$. The Weibull hazard function is a power function,

$$\lambda(t) = \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1}$$

The reliability (or survival) function *R(t)* can be computed from the hazard function,

$$R(t) = \exp\left[-\int_0^t \lambda(t')dt'\right] \tag{0.1}$$

The Weibull *reliability function* (see Figure 17) is,

$$R(t) = \exp\left(\frac{\beta}{\theta}\int_o^t \left(\frac{t'}{\theta}\right)^{\beta-1} dt'\right) = \exp\left(-\left(\frac{t}{\theta}\right)^{\beta-1}\right) \tag{0.2}$$

The Weibull probability density function (PDF) of the time-to-failure distribution is the negative derivative of the reliability function,

$$f(t) = -\frac{dR(t)}{dt} = \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1} e^{-\left(t/\theta\right)^{\beta-1}}$$

β is called the shape parameter and θ is the scale parameter (see Figure 16).

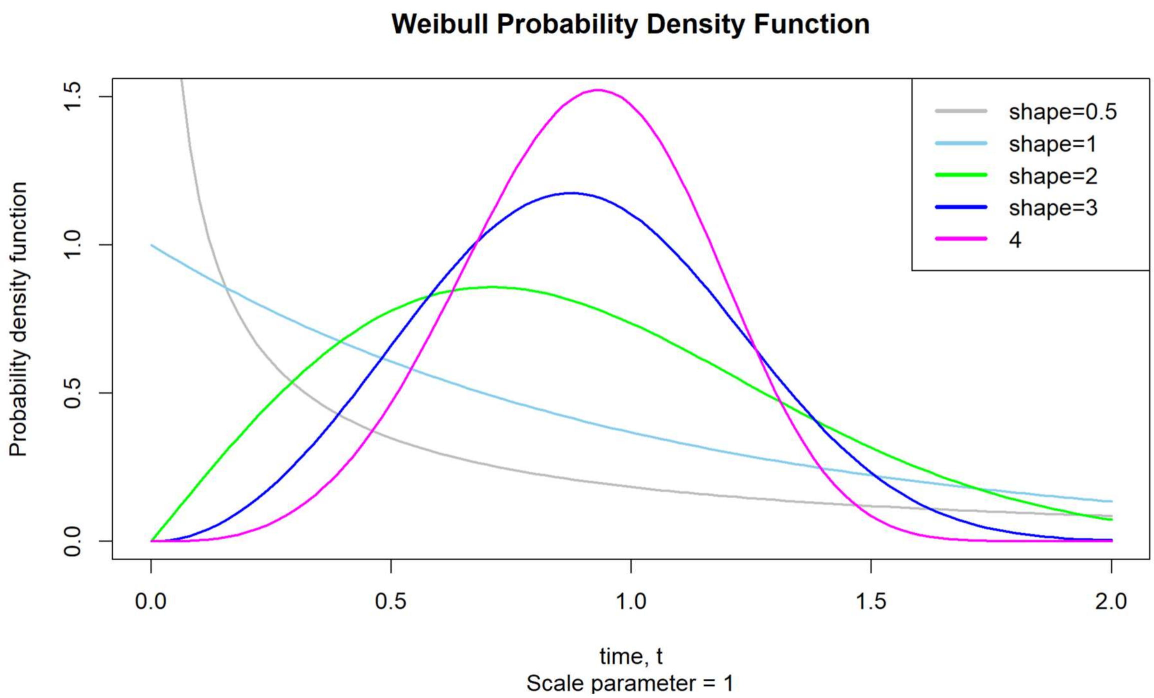


Figure 16 Weibull PDF

Figure 16 shows the PDF of the time-to-failure distribution for various shape parameter values, holding the scale parameter constant at 1.0. The effects that the shape parameter has on the distribution are:

- When $\beta = 1$ the distribution collapses to the exponential distribution and represents a constant hazard rate.
- When $\beta < 1$ the distribution is monotonic decreasing and decays faster than exponential. This form of the hazard function is used to model infant mortality.
- When β is between about 1.5 to 2.5, roughly, the distribution is skewed right.
- When β is about 3 the distribution is symmetrical.
- When β is large the distribution becomes skewed left.

The Weibull cumulative distribution function (CDF) is plotted in Figure 17 using the same parameters as in Figure 16.

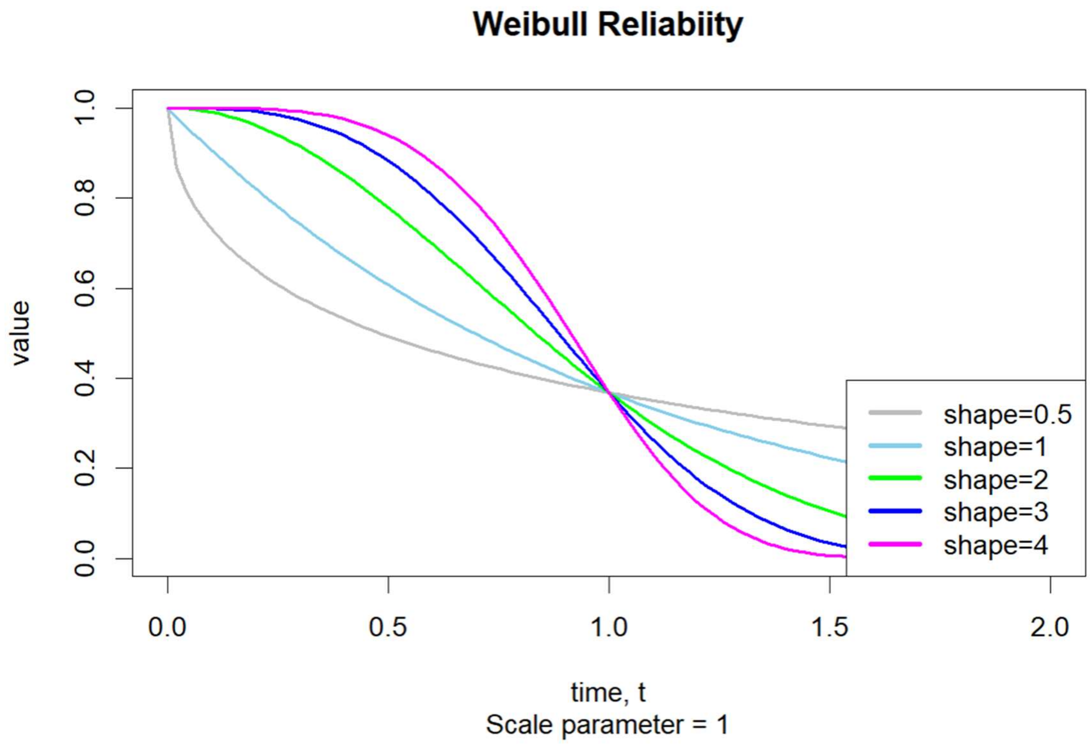


Figure 17 Weibull Reliability Function

When $t = \theta$ all reliability curves pass through the same point, since the reliability for $t = \theta$, the scale parameter, drops to $1 - e^{-1} = 0.636$. About 63% of all Weibull failures occur by time $t = \theta$, regardless of the value of the shape parameter.

8.3 Setting Inspection Intervals

Large flat bottom tanks for conventional oil storage tanks typically have two types of inspections: (a) external inspections which can be conducted while the tank is in service, and (b) internal inspections which require the tank to be out of service and cleaned for entry by personnel. The purpose of tank external and internal inspections and maintenance is to improve tank system reliability compared to an unmaintained tank system. Unmaintained systems were the common practice before the 21st century in the chemical and petroleum industries (i.e., tanks were "run to failure"). Preventive and corrective maintenance and human factors play a major role in the overall rate of occurrence of industry incidents.

The two primary inspection intervals that should be considered for LNG tanks are the external and internal inspection intervals based on a review of API 653. Developing guidelines for these inspections relies on how this problem has been treated in the past by tank inspection SDOs. Therefore, the reliability of typical oil storage tanks is considered along with that of LNG tank systems.

8.3.1 External Intervals

The best practices for the setting of conventional petroleum storage tank external inspection intervals are documented in API Standard 653. The standard gives the definition as "*A formal visual inspection, conducted or supervised by an authorized inspector, to assess all aspects of the tank as possible without* *suspending operations or requiring tank shutdown."* This inspection allows for the examination of all accessible surfaces and any tank component subjected to the weather except for the tank bottom which is, of course, inaccessible. The discussion below assumes an outer tank constructed of steel. For outer tanks that are not constructed of steel, then allowance for the differences should be considered in setting external inspection intervals.

The API 653 rules for an external inspection are governed by *"All tanks shall be given a visual external inspection by an authorized inspector. This inspection shall be called the external inspection and must be conducted at least every five years or RCA/4N years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) whichever is less. Tanks may be in operation during this inspection."* Almost all tank owners/operators use a 5-year interval for conducting external inspections. However, because the tank wall thickness can be measured by technologies such as various forms of ultrasonic testing, the interval may be reduced in cases of active corrosion. This report does not judge active corrosion to be a critical component for setting external inspection intervals for LNG tanks because any active external corrosion can and should be mitigated by cleaning and application of coatings and temporary repairs.

For LNG tanks, internal corrosion is naturally limited by the clean, cold, and oxygen-free internal environment in the space between the tank shells (i.e., the interstice). Even if there were a case of extreme, active corrosion that could not be mitigated, this scenario would be handled by the triggered event protocols in Section 9 Tank Inspection Guidelines.

The costs of an external inspection are not high, relatively; they sometimes require an inspection contractor to mobilize at the site with various inspection tools, and to spend several days to several weeks at a tank, carefully examining and documenting all conditions associated with the tank. Typical damage mechanisms such as foundation settlement, corrosion, and mechanical distortions are the most common age-related damage mechanisms.

The main difference between corrosion damage mechanisms affecting the tank bottom for a conventional API 650 tank and for a cryogenic tank can be summarized:

- LNG tank foundations may be less subject to settlement problems in that they are often designed as full slabs elevated on piles. The use of a slab reduces native corrosion rates on steel because when rain contacts the concrete it becomes alkaline to about pH 11-12, which is known to reduce moisture corrosion rates. The elevated foundation prevents local flooding of the tank bottom which would allow for intrusion of salts and other corrodents under the tank bottom. In addition, a concrete slab is far superior to other kinds of foundations for water drainage and removal because the slope of the bottom can be maintained over time. Settlement problems are also reduced as a result.
- LNG tank bottoms and foundations are colder than typical oil storage tanks, reducing the corrosion rates substantially due to reduction of the rate of corrosion as a function of temperature. Like other chemical reactions, the corrosion rate decreases roughly by a factor of two for every 10 °C drop in temperature.
- LNG inner tank bottoms are analogous to the double bottoms of normal oil storage tanks because the inner tank sits on an insulating layer completely isolated from the external environment including corrodents. The outer tank protects the inner tank.

The API Subcommittee on Aboveground Storage Tanks (SCAST) that authored the aboveground storage tank standards did not perform reliability analyses or data analytics to set the external inspection interval for oil storage tanks. Instead, the collective experience and judgement of SCAST members was the basis for establishing these rules. Among these considerations, SCAST included the cost-benefit of preventing incidents including factors such as costs, business interruption, product releases, public good will, reputation, regulatory advances, and other factors.

Given that outer steel tanks of LNG storage systems are subject to the same damage mechanisms that apply to typical oil storage tanks, there is no strong incentive to deviate from the API 653 norm for LNG tank systems with steel outer tanks. It could be argued that because of the potentially better tank design and construction details and the reduced operating temperatures resulting from heat flow into the tank, the external inspection intervals for LNG tank should be extended. However, the TAP consensus was that external inspections for LNG and cryogenic tanks (i.e., EISI) should be parallel to the requirements of API 653 for LNG tanks where the outer tank is constructed of steel and that the maximum external inspection interval of 5 years is satisfactory. This shows the importance of establishing a corporate culture of high reliability, because external defects could precipitate internal failure, and because (whether true or not) LNG tanks are perceived to be more hazardous than ordinary petroleum storage tanks. If there is any inefficiency in terms of an inspection interval that is too short, it is countered by the relatively low costs of external inspections. Having time-based rules also creates a rigor in execution and periodicity of the tank external inspections driving the industry to make such inspections routine and auditable.

8.3.2 Internal Inspection Intervals

Atmospheric oil storage tank internal inspections, under the rules of API 653, are typically limited to 20 years maximum, with some exceptions. The rules for setting the internal inspection interval were, again, set by the judgement and experience of SCAST, accounting for the most common damage mechanism governing failure: corrosion of both the internal and external surfaces of the tank bottom. For a conventional API 650 storage tank, the difficulty and costs associated with an internal inspection are at least an order of magnitude greater than an external inspection because of:

- Hazards of cleaning, entering, and working in confined spaces.
- Removal of large quantities of sludge, bottoms, emulsions, and debris.
- Cleaning of the interior so that effective examination is possible.
- Business interruption.
- Disposal of hazardous waste.

Removal of an LNG tank from service for inspection is entirely different in many ways than that of a conventional API 650 atmospheric storage tank:

- The inner tank of LNG and cryogenic tank systems are isolated from the environment by an inert dry atmosphere, meaning that corrosion of the primary inner tank bottom does not occur.
- Each time the primary tank is taken out for an internal inspection it must go through a thermal warm up cycle and when put back into service it must go through cool down. These cycles accumulate, resulting in thermal fatigue damage. The extent of damage is a complex of interactions between features of the tank's design and rate of cooling.
- The balance between availability of on-line storage tanks and market demand is tuned to minimize the number of required LNG tanks that are in service. Should high numbers of internal tank inspections be required, caused by increasing the frequency over what it is today, the number of LNG tanks required to meet market demand at a given time would have to increase to meet the current demand.

- The number of LNG tank failures caused by corrosion and other damage mechanisms that directly affect the inner tank is negligible compared to failures of typical oil storage tanks.
- If the interior tank failure rate is not increasing over time (see Figure 15) then preventive maintenance has little impact and might even decrease the overall reliability of the tank system. This is the reason that this report does not recommend performing internal inspections of cryogenic and LNG tanks unless there is a compelling specific reason to do so (see Section 9 Tank Inspection Guidelines on event-triggered inspections). Another way of saying this is that the LNG tank should not be taken out of service during its constant failure rate period.
- LNG is a clean service and there is very little to no sludge and debris to be removed.

While ground contamination has been a significant problem for conventional oil storage tanks, this is not the case for LNG or cryogenic liquids. There have been no cases of ground contamination caused by LNG tanks, primarily due to historically robust site investigations and designs that support long-term uninterrupted service. Any liquid that escapes the outer shell, whether as a surface spill or by injection into the ground, will eventually warm and evaporate. While there will be a significant flammable vapor hazard, the risk of ground contamination just does not exist beyond local effects such as freezing of soil and/or water.

Notwithstanding the relatively lower environmental consequences of an LNG release, it is vitally important to avoid a catastrophic failure of the inner tank and therefore vitally important to prevent failure of its protective outer container by regular external inspections.

The following discussions on LNG tank reliability will make the case that the intrinsically lower corrosion rate and the higher cost and risk of metal fatigue and other potential hazards of taking LNG and cryogenic tanks out of service militate against regularly scheduled internal inspections unless there is a specific significant and imminent threat to the integrity of the inner, cryogenic, tank which could lead to a release.

8.4 Maintenance Programs

8.4.1 Introduction

There are many types of maintenance programs and approaches, but this section in particular considers maintenance as consisting of examination, inspection, and repair of tank components based on internal access to the interior surfaces of the storage tank.

In preventive maintenance, parts are replaced prior to failure based on time-in-service. In corrective maintenance, a component is repaired after it has failed or has been severely damaged. In theory these are distinctly different strategies – but in real world practice, the differences between these practices may be blurred.

For this analysis, failure is defined by a loss of containment (of the inner tank shell which contains the cryogenic liquid). Internal inspections involve taking the tank out of service, entering it, executing a comprehensive inspection for corrosion, cracking or other changes that might lead to premature failure, and making repairs.

To optimally schedule internal inspections, a Weibull probabilistic model of the inner-tank time-to-failure distribution was applied using the Mean Time to Failure (MTTF). This analysis considered two cases:

8.4.1.1 Perfect maintenance

Perfect maintenance means that the system is repaired to a state that is “as good as new” which is, naturally, an idealization.

8.4.1.2 Imperfect maintenance

Imperfect maintenance means that, although the system is repaired to as good as new, the maintenance itself injects a small failure probability caused by the maintenance function.

8.4.2 General Tank System Life Cycle Failure Rate Concept

In reliability engineering, the failure rate or, to be more technically correct, the *hazard rate*, is the conditional probability that a component that has survived to time t will fail in the next instant of time, $t + \Delta t$ in the limit as $\Delta t \to 0$.

The epoch on the left side of Figure 15 shows an initial high failure rate that decreases over time. This is called *Infant Mortality*. Infant mortality exists in most systems with high complexity including biological systems and engineering systems. Infant mortality arises from many sources such as defects in design, workmanship, materials, and quality issues. As an example, many electronics systems are operated by their manufacturers for some relatively short time period to “burn in” the components before they are sold (past the infant mortality epoch) to make sure that the warrantees remain profitable.

There is no evidence that large LNG cryogenic storage tanks experience a period of infant mortality, therefore, the analysis only considers the constant rate and wear-out phases of Figure 15. The next interval in the Bathtub Curve is the near-constant failure rate period and is often referred to as the “useful life.” In this epoch the failure or hazard rate is nearly constant. It appears that large cryogenic LNG storage tanks spend many decades in this regime at a nearly constant hazard rate; this is modeled by the exponential distribution of time to failure.

In theory, the third epoch is the wear out or aging phase where the hazard rate increases with time due to wear out or aging effects such as fatigue or corrosion. This is represented with a Weibull time-to failure distribution with a positive shape parameter. For capital-intensive equipment there is an incentive to operate as far into the wear-out epoch as possible, and tanks are no exception.

8.4.3 Statistical Modeling Approaches

Because industry data on cryogenic tank failures is sparse, a parametric survival model approach is taken to estimating the mortality of LNG tanks. There are many probability distributions that can be used to model any one of the three epochs in the Bathtub Curve but the most useful and versatile is the Weibull Distribution. All of these models are based on probability distributions that are well defined and have support for time $T \geq 0$. To model the early failure rate period the specific distributions such as the truncated normal or lognormal are often used, but it is not included this in this analysis’s model of large LNG storage tanks. The constant rate period is modeled by the exponential. The increasing rate is often modeled by the lognormal. The Weibull Distribution with positive shape parameter is used to model the era of increasing hazard at the end of a tank’s life.

To model the observed longevity of LNG tanks, a 3-parameter Weibull distribution was used. The third parameter (the *location* or *threshold* parameter) is an initial period where there is no possibility of failure followed by a time of gradually increasing hazard.

Reliability is defined as the probability that a system survives for some specified period. In terms of the random variable T representing time to failure, the probability of failure in a small increment of time can be written $f(t)\Delta t = P\{t < T \le t + \Delta t\}$, which is the unconditional probability at time 0 that failure will happen at a future time between t and $t+\Delta t$.

Function $f(t),\ 0 \le t < \infty$, is the probability density function (pdf). The cumulative distribution function (CDF) is then $F(t) = P(T \le t) = \int_0^t f(x)\,dx$ is the unconditional probability assessed at time zero that failure will happen at or before a future time t.

The reliability function is the upper tail of the CDF; that is $R(t) = 1 - F(t)$. It is the probability assessed at time zero that the system will operate without failure from time 0 to time t. The reliability function may be written in terms of the probability density function, the cumulative density function, or the hazard function (see Equation (0.2):

$$R(t) = P\{T > t\} = 1 - F(t) = \int_t^{\infty} f(x)dx = \exp\left(-\int_0^t \lambda(x)dx\right),$$

where $\lambda(t)$ is the *hazard rate (failure rate, force of mortality)* at time *t*,

$$\lambda(t) = \frac{f(t)}{1-F(t)} = \frac{f(t)}{R(t)},$$

As expected, there is 100% survival at time 0, $R(0) = 1$, and since no real system can operate forever without failure, $R(\infty) = 0$.

The time to failure distribution is the negative first derivative of reliability and the hazard rate is the derivative of log-reliability, $R(t)$

$$f(t) = -\frac{d}{dt}R(t) \quad and \quad \lambda(t) = -\frac{d}{dt}\ln\left(R(t)\right) \tag{0.3}$$

Integrating Equation (0.3) results in:

$$\int_0^t \lambda(t')dt' = -\ln\left(R(t)\right)$$
$$\exp\left[-\int_0^t \lambda(t')dt'\right] = \exp\left(\ln\left(R(t)\right)\right) = R(t)$$

8.4.4 Preventive Maintenance

In the following discussion there are many components that could fail such as instrumentation, venting systems, insulation systems, and so on. However, the primary focus is on failures of the inner container that could result in loss of contents. As mentioned, the possible failure modes for the inner container are corrosion and mechanical fatigue. Although thermal fatigue is a potential failure mechanism, it is not considered here because LNG tanks are typically only put through cool-down-warm-up cycles a few times in their lifespans and thus thermal fatigue typically does not present a damage mechanism threat. Corrosion is also not considered because the inner tank lives in a “hermetically sealed,” dry, non-corrosive environment. Additionally, LNG tanks and their support systems are typically designed with high levels of redundancies.

8.4.5 Idealized Model

Reliability is defined as the probability that a system survives for some specified period. It may be expressed in terms of the distribution of a random variable T, the time-to-system-failure. Denote the reliability of a tank system without maintenances as $R(t)$. Denote the reliability of a maintained system by $R_M(t)$. Assume that downtime is negligible so that the time that the system is operating (i.e., the tank in service) is t. Assume that maintenance is performed at a fixed time interval t_M ; i.e., at $t_M, 2\cdot t_M, 3\cdot t_M, \ldots$, and that maintenance and repairs upgrade the system to a condition as good as new.

Up to the time of first maintenance, $t < t_M$, there is no effect on reliability since, by definition, maintenance does not happen until t_M and , because maintenance restores the tank to as good as new condition, the various future times are:

$$R_M(t) = \begin{cases} R(t) & 0 \le t < t_M \\ R(t_M)\cdot R(t - t_M) & t_M \le t < 2\cdot t_M \\ R(t_M)^2 \cdot R(t - 2\cdot t_M) & 2\cdot t_M \le t < 3\cdot t_M \\ \vdots & \vdots \end{cases}$$

The logic is this: since it is assumed that when maintenance is performed the system becomes as good as new, it therefore has no memory of its previous state. Therefore, in the second interval $t_M < t \le 2\cdot t_M$ reliability is the product of the probability of surviving to time t_M times the probability that a good as new survivor will last from t_M (when it is as good as new) to time $t_M + t$, when it is equivalent to a brand new tank aged t years. Extending this argument to N intervals results in

$$R_M(t) = R(t_M)^n \cdot R(t - nt_M),\ nt_M \le t < (n+1)t_M,\ n = 0,1,2,\cdots \tag{0.4}$$

Mean time to failure, MTTF, from the point of view of an observer at time $t = 0$ is in general the definite integral of the reliability function, so the MTTF for the unmaintained system is,

$$MTTF = \int_0^\infty R(t)dt \tag{0.5}$$

To find MTTF for the maintained system, substitute Equation (0.4) into expression (0.5),

$$
\begin{aligned}
MTTF_M &= \sum_{n=0}^{\infty}\left[R\left(t_M\right)^n \int_{i\cdot t_M}^{(n+1)\cdot t_M} R\left(t-n\cdot t_M\right)dt\right] \\
&= \int_0^{t_M} R\left(t\right)dt\cdot\left[\sum_{n=0}^{\infty} R\left(t_M\right)^n\right] \\
&= \int_0^{t_M} R\left(t\right)dt\cdot\frac{1}{1-R\left(t_M\right)}
\end{aligned}
$$

Does the maintained system have better reliability than an unmaintained system? The answer depends on the hazard rate function $\lambda\left(t\right)$. For a constant hazard rate such as exhibited by the exponential function the answer is that there is no improvement in reliability. This can be demonstrated by plugging the exponential reliability function into Equation (0.4):

$$
\begin{aligned}
R_M(t) &= (e^{-\lambda t})^n e^{-\lambda(t-n\cdot t_M)} && n\cdot t_M \le t \le \left(n+1\right)\cdot t_M,\ 0\le n<\infty \\
&= e^{-\lambda t} && ditto \\
&= R(t) && 0\le t\le\infty
\end{aligned}
$$

Preventive maintenance on systems subject to random failures has no effect on improving system reliability.

The two other cases for the hazard rate are (a) decreasing and (b) increasing. When the hazard rate decreases with time then maintenance will cause an overall higher failure rate. When the hazard rate increases with time (i.e., aging effects) then there will be a positive effect on maintained systems. This can be examined by applying the Weibull distribution which can model constant, increasing or decreasing hazard rates.

The two parameter Weibull reliability function is

$$
R(t)=\exp\left[-\left(\frac{t}{\theta}\right)^{\beta}\right],0\le t\le\infty
$$

Where θ is the scale parameter and β is the shape parameter.

Substitution of the Weibull reliability into Equation (0.4) gives,

$$
R_M(t)=\exp\left[-n\left(\frac{t_M}{\theta}\right)^{\beta}\right]\exp\left[-\left(\frac{t-n\cdot t_M}{\theta}\right)^{\beta}\right],\ n\cdot t_M\le t\le(n+1)\cdot t_M,\ n=0,1,2,\cdots
$$

Now the following proves that $R\left(t\right)<R_M\left(t\right)\ if\ t>0\ and\ \beta>1$ the overall effect of maintenance:

$$
\begin{aligned}
-\ln\left(R_M(t)\right) &= n\left(\frac{t_M}{\theta}\right)^{\beta}+\left(\frac{t-n\cdot t_M}{\theta}\right)^{\beta} \qquad n\cdot t_M \le t<\left(n+1\right)\cdot t_M \\
&= n\cdot x_M^{\beta}+\left(x-n\cdot x_M\right)^{\beta} \qquad \textit{where } x=t/\theta \\
-\ln\left(R(t)\right) &= n\cdot x^{\beta}
\end{aligned} \tag{0.6}
$$

For positive x and $\beta > 1$, x^{β} is a strictly convex function. Since a strictly convex function $g\left(x\right)$ obeys the triangle inequality, $g\left(x+y\right)>g\left(x\right)+g\left(y\right)$:

$$
x^{\beta}=\left(n\cdot x_M+\left(x-n\cdot x_M\right)\right)^{\beta}>n\cdot x_M^{\beta}+\left(x-n\cdot x_M\right)^{\beta} \tag{0.7}
$$

Which implies that

$$
R_M(t)>R(t)
$$

Thus, for components with a Weibull distribution for time to failure with shape $\beta > 1$, an inspection plan that does an out-of-service internal inspection at regular time intervals, with repair to good as new, will have higher reliability than never inspecting. Conversely, if the Weibull distribution has shape $\beta < 1$ it is better not to inspect. This makes sense because with $\beta < 1$, good as new components have a higher failure rate than do older components.

In the real world, maintenance is subject to human factors and is never perfect and this means that there is a finite probability p that maintenance and repairs may cause failure. A good example is a patch plate that is welded to the tank to repair a defect such as a crack or corrosion hole. An imperfect maintenance repair will lead to early failure. This can be accounted for by modifying the reliability by the imperfect maintenance reliability function,

$$
R_M(t)=R(t_M)^n\cdot(1-p)^n\cdot R(t-n\cdot t_M),\; n\cdot t_M<t<(n+1)\cdot t_M,\; n=0,1,2,\cdots
$$

If only aging effects are considered and other random failures are neglected, then the Weibull shape parameter $\beta > 1$. The ratio of ${R_M}/{R}$ can again be used to examine the effect of preventive maintenance on the overall reliability. The factor $(1-p)^n \simeq e^{-n\cdot p}$ can be used to show that

$$
\begin{aligned}
\ln\left(\frac{R_M(n\cdot t_M)}{R(n\cdot t_M)}\right) &\approx -n\left(\frac{t_M}{\theta}\right)^{\beta}-n\cdot p+\left(\frac{n\cdot t_M}{\theta}\right)^{\beta} \\
&= n\cdot\left[\left(\frac{t_M}{\theta}\right)^{\beta}\left(n^{\beta-1}-1\right)-p\right]
\end{aligned}
$$

So imperfect maintenance is more reliable than no maintenance if

$$
p<(n^{\beta-1}-1)\left(\frac{t_M}{\theta}\right)^{\beta}.
$$

8.5 Tank Reliability

This analysis used data for conventional oil storage tanks, which allowed the fitting the Weibull distribution and determining its parameters. For LNG inner tanks, engineering judgment was used to determine the applicable Weibull distribution.

8.5.1 Conventional Oil Tank Life Data

Oil tank survival is typically governed by the bottom life (i.e., when a tank bottom is penetrated by corrosion). The datasets for conventional oil tank life were taken from real tanks from two major companies: a multinational integrated oil company and a crude oil pipeline distribution company. The data available was for corrosion rates. These were used as a proxy for tank bottom lifespan by taking the bottom thickness of 250 mils and dividing by the corrosion rate, resulting in a proxy for lifetime. Note that the fourth dataset from the pipeline company is based on tanks that are at ambient temperature, unlike refining tanks which are usually heated. These datasets are shown in Table 3.

There is no data to generate a dataset for the inner LNG tanks, so engineering judgement was used to formulate the distribution for LNG tanks for developing a comparison of life distributions (conventional oil tanks versus inner LNG tanks).

Table 3 API 650 and Crude Oil Pipeline Proxy Life Data (years)

cru		GasJet		FO	Crude	
35.71	12.50	83.33	25.00	250.00	10.87	35.71
35.71	12.50	83.33	25.00	83.33	12.50	35.71
31.25	12.50	83.33	25.00	50.00	12.50	41.67
31.25	11.90	62.50	17.86	41.67	14.71	41.67
31.25	11.90	50.00	16.67	35.71	16.67	50.00
27.78	11.36	50.00	14.71	35.71	17.86	50.00
20.83	10.87	41.67	12.50	31.25	25.00	62.50
19.23	10.00	41.67	12.50	27.78	25.00	83.33
19.23	10.00	35.71	10.87	22.73	25.00	83.33
15.63	10.00	35.71		22.73	25.00	83.33
15.63	8.33	31.25		22.73	27.78	125.00
15.63	8.06	31.25		13.89	27.78	
13.16	5.56	27.78		10.00	31.25	
12.50	5.00	27.78		5.00	31.25	
12.50	4.17	25.00				

8.5.2 LNG Inner Tank Distribution Function

For comparing distributions for the inner LNG tanks, the distribution was based on the following assumptions:

- Failures cannot happen before 50 years of operation.
- 3-Parameter Weibull with shape=2.5, scale=200, threshold= 50.

As a check on the reasonableness of a 50-year threshold used in the 3 parameter Weibull distribution, assume that the failure of LNG tanks over time follows a binomial process. The first estimate needed is the individual failure probability per tank. If there have been no failures[9] in a binomial process, that does not mean the failure probability is zero. The *"rule of three[10]"* has been developed for just such a problem.

The rule of three states that if a "success" (incident) did not occur within n trials, then the 95% confidence for the probability of successes is the interval 0 to 3/n. This can be demonstrated by considering Bernoulli trials. Assume the probability of success is p, so that at n trials, the probability of failure is $(1-p)^n$. Since $P(X=0)=0.05$ for the 95% confidence then $(1-p)^n=0.05$ and $n\ln(1-p)=\ln .05\approx -2.996$. From Taylor series approximation, $\ln(1-p)\approx -p$ and rounding -2.996 to -3 to obtain $3/n$.

The general confidence interval is given by $\frac{-\ln(\alpha)}{n}$ where $1-\alpha$ is the confidence level.

Using the rule of three confidence level of 0.75 the rule of three gives an individual tank upper bound on the probability of failure of $p_{75\%}=-\ln(0.25)/5000=0.00028$. Is this probability reasonable?

PHMSA collected accurate data for LNG tanks in the US over a period of 9.25 years where the number of incidents of various types was documented. For this analysis, the US LNG tank population for tanks over 5000 m^3 is conservatively taken as 100 and the world population to be 500 or five times larger than that of the US.

Assuming steady state over 50 years (conservatively) the chance of an incident for the US tank population would be $1\text{-dbinom}(0,100*50,0.00028)=0.7534514$ or about 75%. This is unreasonable since there has not been an LNG inner tank failure within the worldwide population in over 50 years. To get a reasonable probability for a trial-and-error assessment over the 25000 tank years (500 tank worldwide * 50 years of operation), a small probability of about 3 parts in one hundred thousand would be required, which yields an incident probability of about 0.5. For comparison, this is about one half the probability of dying in a skydiving accident. While this probability is not zero, it is negligible, validating the general practice of not internally inspecting inner tanks unless there is a specific reason to do so.

[9] There are no documented cases of a failure of the inner tank of an LNG tank system.

[10] Hanley, J. A.; A. Lippman-Hand (1983). "If nothing goes wrong, is everything alright?" JAMA. 249 (13): 1743–5. doi:10.1001/jama.1983.03330370053031.

To improve the estimates of reliability for both thermal and mechanical fatigue, more research should be conducted to more accurately determine the Weibull failure parameters.

These calculations lead to a reasonable estimate for the Weibull failure distribution, ensuring that it is conservative and applying engineering judgement along with numerous trial-and-error simulations. The pdf is shown in Figure 18. The reliability function is shown in Figure 19. The hazard rate increases slightly faster than linear, as shown in Figure 20.

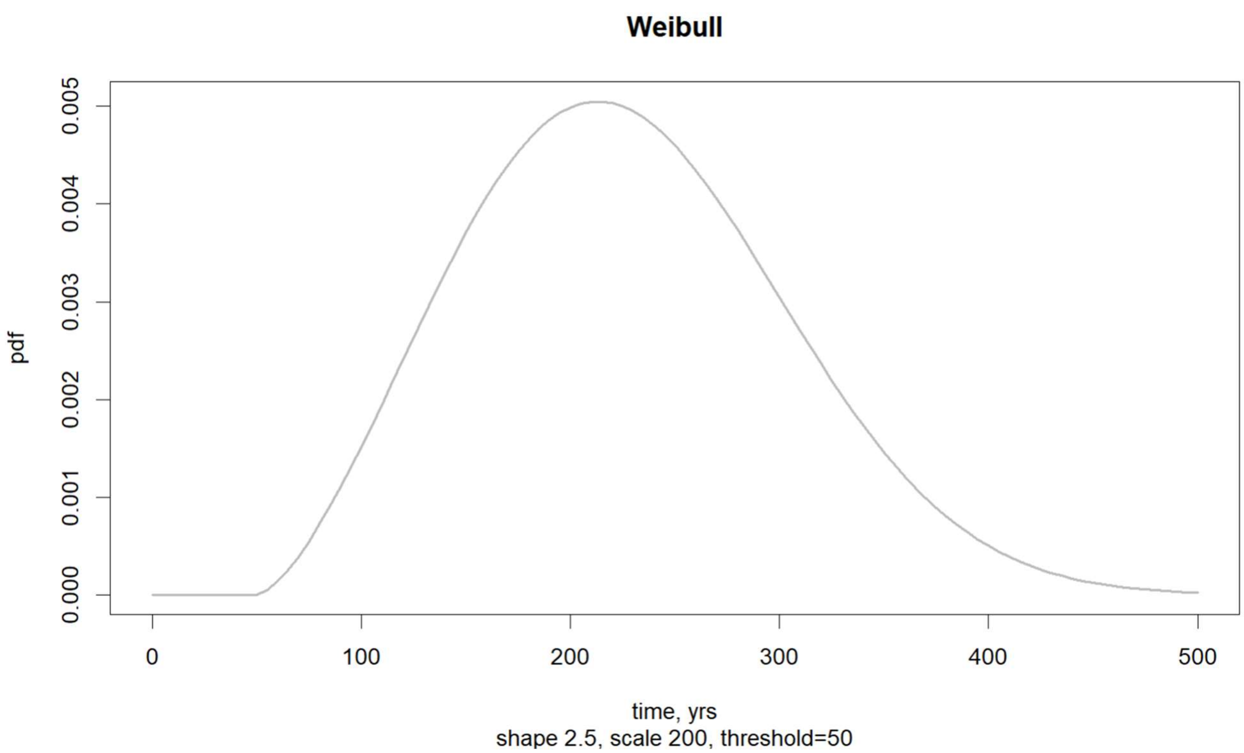


Figure 18 Weibull pdf for LNG inner tanks

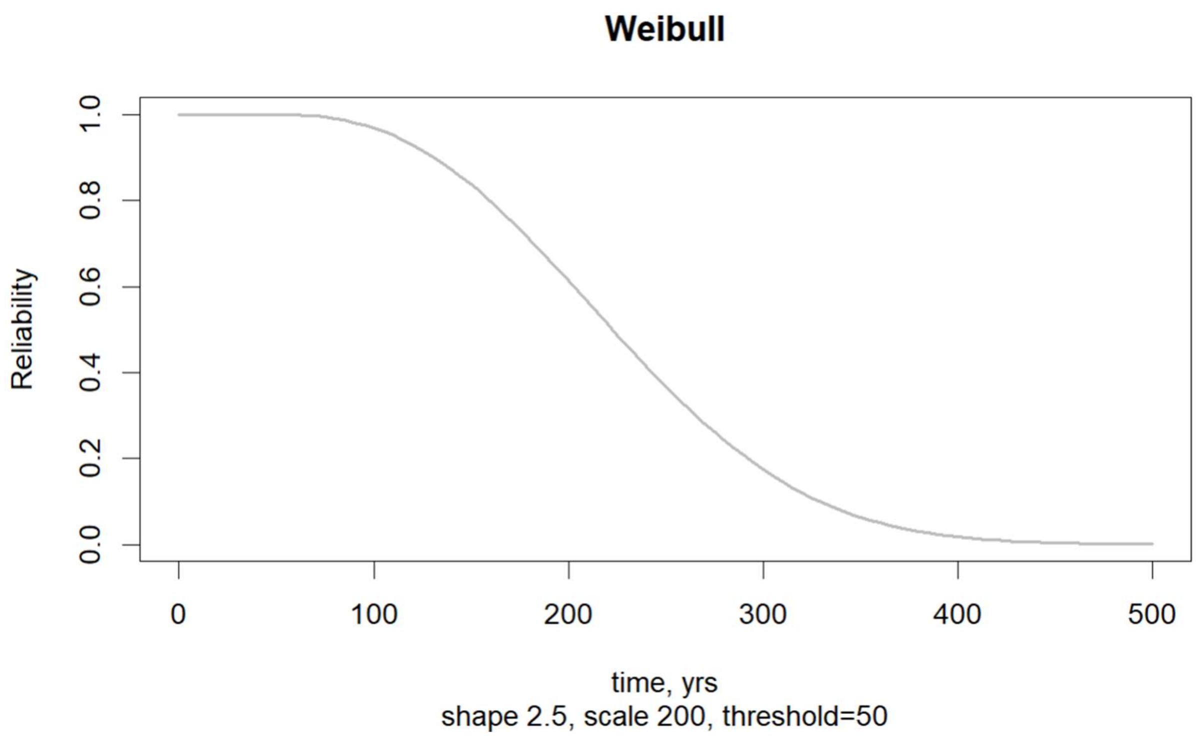


Figure 19 Weibull reliability function for LNG inner tanks

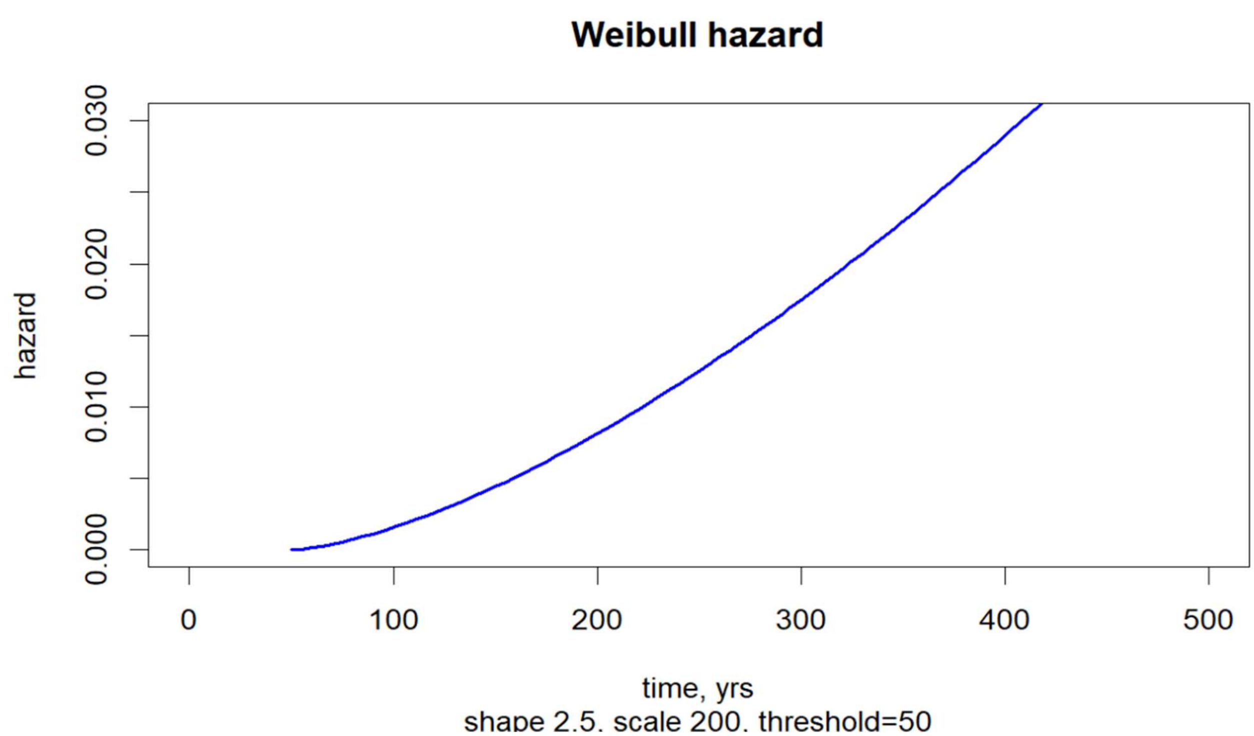


Figure 20 Weibull hazard function for LNG inner tanks

8.5.3 Weibull Analysis

The R[11] Package *WeibullR* was used to fit the conventional oil tank datasets to a Weibull life distribution to determine the shape and scale parameters shown in Table 4 for the 4 conventional oil tank datasets.

Table 4 Five corrosion rate life datasets

Dataset No	Dataset	shape	scale	Comment
1	CRU	2.229	17.75	Refinery tanks
2	GasJet	2.054	39.93	Finished fuel
3	FO	1.31	44.52	Fuel oil
4	Crude	2.0	44.53	Pipeline tanks
	LNG inner tanks	2.5	200	

Table 5 Five number summary of datasets

Dataset	Min	1st quartile	Median	3rd quartile	Max
1	4.17	10.0	12.5	19.23	35.75
2	10.87	21.43	29.515	45.86	83.33
3	5	22.73	29.51	41.67	250
4	12.5	25	31.25	50	125

The general features of Table 5 are consistent with experience. The highest mortality rates are in crude oil tanks. However, there is a noticeably longer life for Dataset 4 (pipeline crude tanks) compared to Dataset 1 (refinery crude tanks). Refinery tanks operate at higher temperatures and therefore higher corrosion rates and shorter tank bottom lives than do pipeline crude oil tanks which in this case operate at ambient temperature. Refinery tanks also tend to have more debris and bottoms than do pipeline crude tanks. These factors explain both differences in the shape and scale parameters of the Weibull fits to these data. Datasets 2 and 3 consist of finished fuel tanks and fuel oil tanks which should be the least corrosive of all the tanks and therefore have the longest lifetimes.

The reliability or survival function for the 4 conventional oil tank datasets and the LNG inner tanks are shown in Figure 21. It clearly distinguishes the survival rate for LNG tanks compared to typical oil tanks.

[11] R is a free software environment for statistical computing and graphics. It compiles and runs on a wide variety of UNIX platforms, Windows and MacOS. https://www.r-project.org/

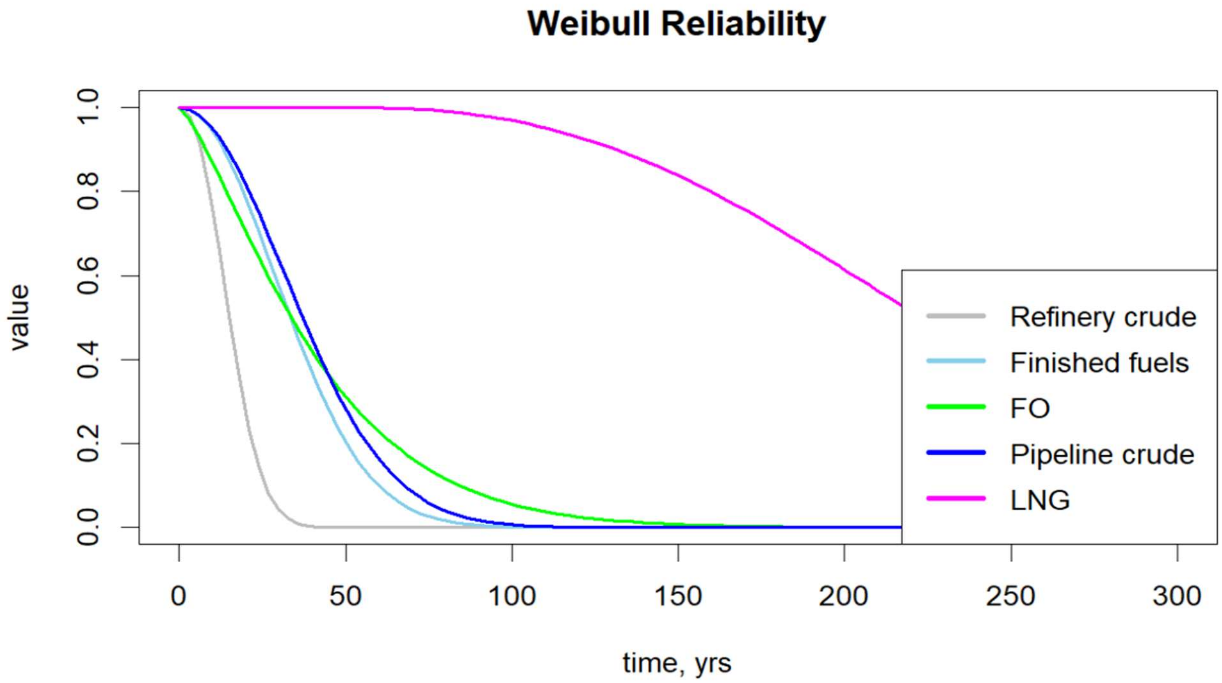


Figure 21 Conventional oil tanks and LNG inner tank reliability

In Figure 22 the probability density functions for the conventional oil tanks are contrasted with that of the LNG inner tanks.

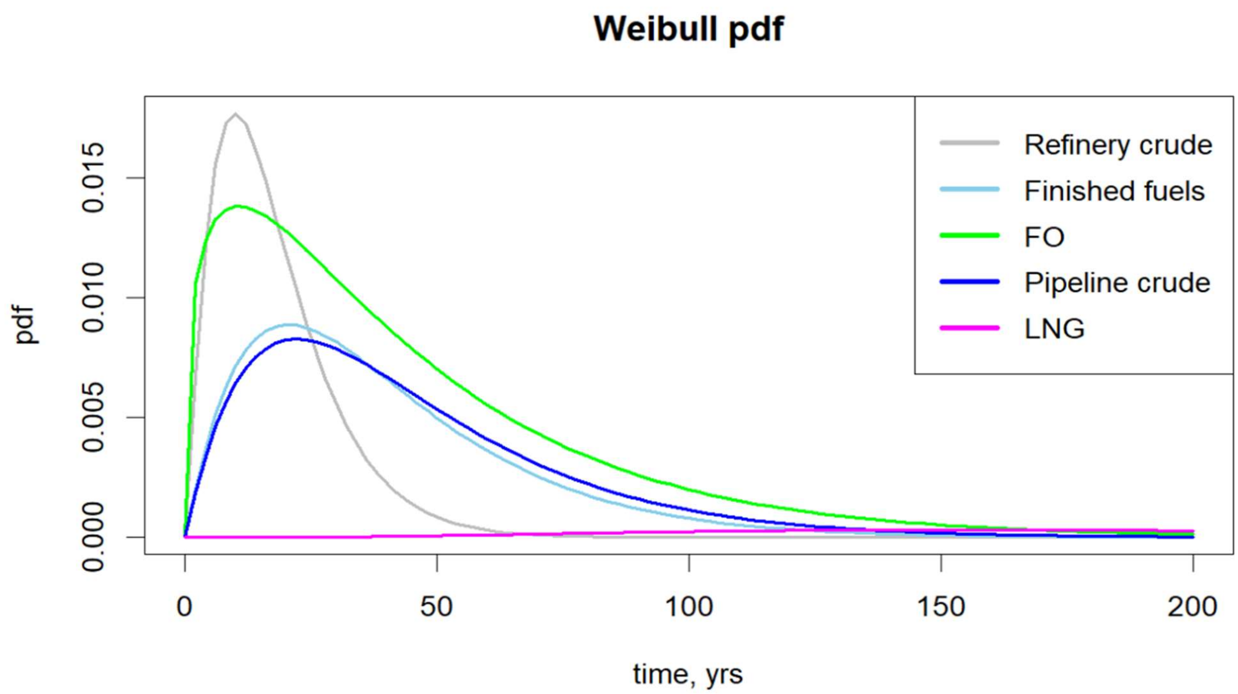


Figure 22 Comparison of probability density functions

The hazard rate for the conventional oil tanks compared to the LNG inner tanks is shown in Figure 23.

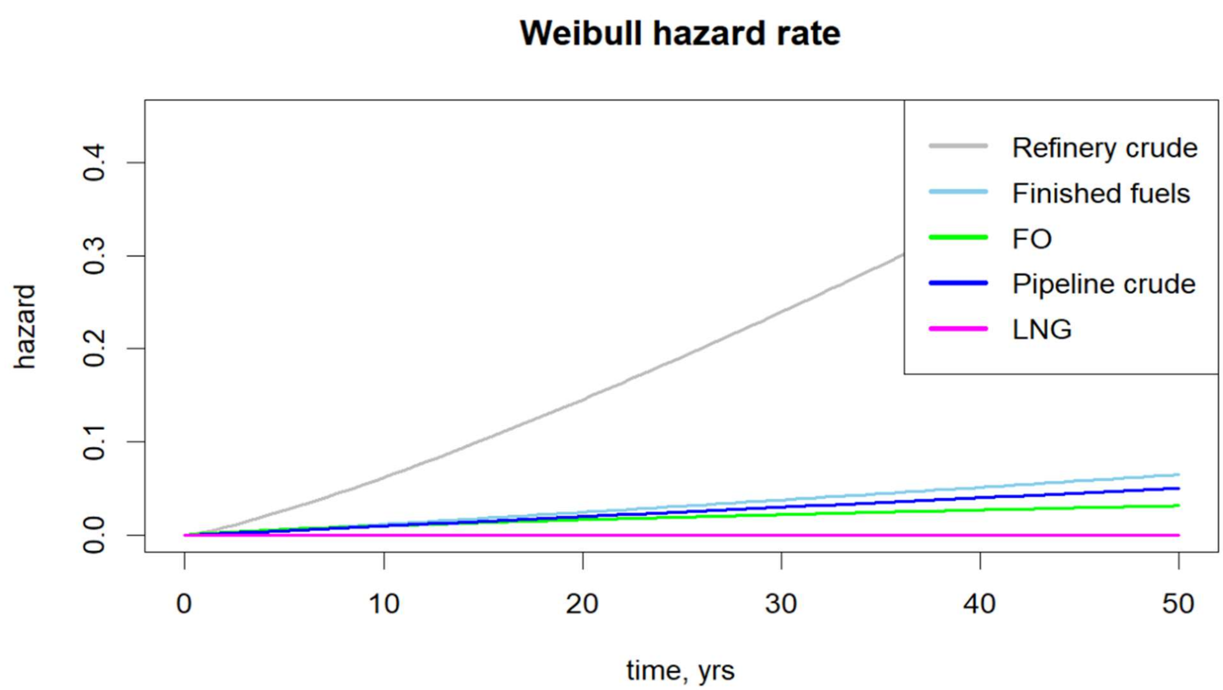


Figure 23 Hazard function for conventional oil tanks and LNG inner tanks

8.5.4 Comparison of Maintenance Programs

The 4 datasets for conventional oil tanks and LNG inner tanks discussed above are compared for reliability of the following maintenance programs and the impact of reliability:

- No maintenance.
- Perfectly maintained systems.
- Imperfectly maintained systems.

"Maintenance" as described above is referring to typical internal inspections for the liquid containing tank whether a conventional tank or an LNG tank.

8.5.5 No Maintenance

When there is no maintenance the failure data show the reliability or survival function as simply the complementary cumulative distribution function (CCDF) of the fitted Weibull distribution. Figure 24 through Figure 27 show the 4 datasets from real tank surveys and the effect of three maintenance programs on tank life. Each plot shows three lines:

- Survival (reliability) with no maintenance
- Survival (reliability) with perfect maintenance
- Survival (reliability) with imperfect maintenance

Perfect maintenance means that at the end of each (internal) inspection interval the tank is restored to "as good as new." *Imperfect maintenance* means that at each inspection interval (internal) there was a 5% probability that a tank failure was caused by the repair/maintenance processes.

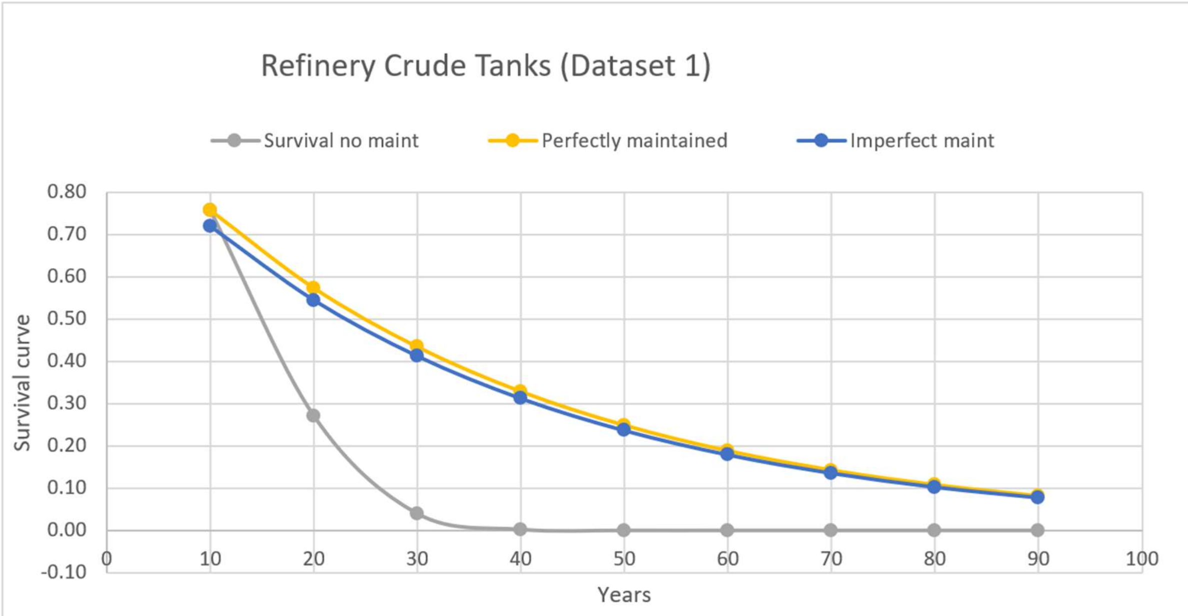


Figure 24 Refinery crude tanks; Survival curve; shape=2.229, scale=17.75

For refinery tanks (Figure 24) the difference between perfect and imperfect maintenance is small. However, a maintenance program does make a significant improvement in reliability as seen by the divergence between the unmaintained and maintained systems. It should be noted that while internal inspections are permitted to extend to 20 years, in the case of this particular dataset, the internal inspection and maintenance should clearly be conducted at a considerably smaller interval since the survival rate at 10 years is about 70%.

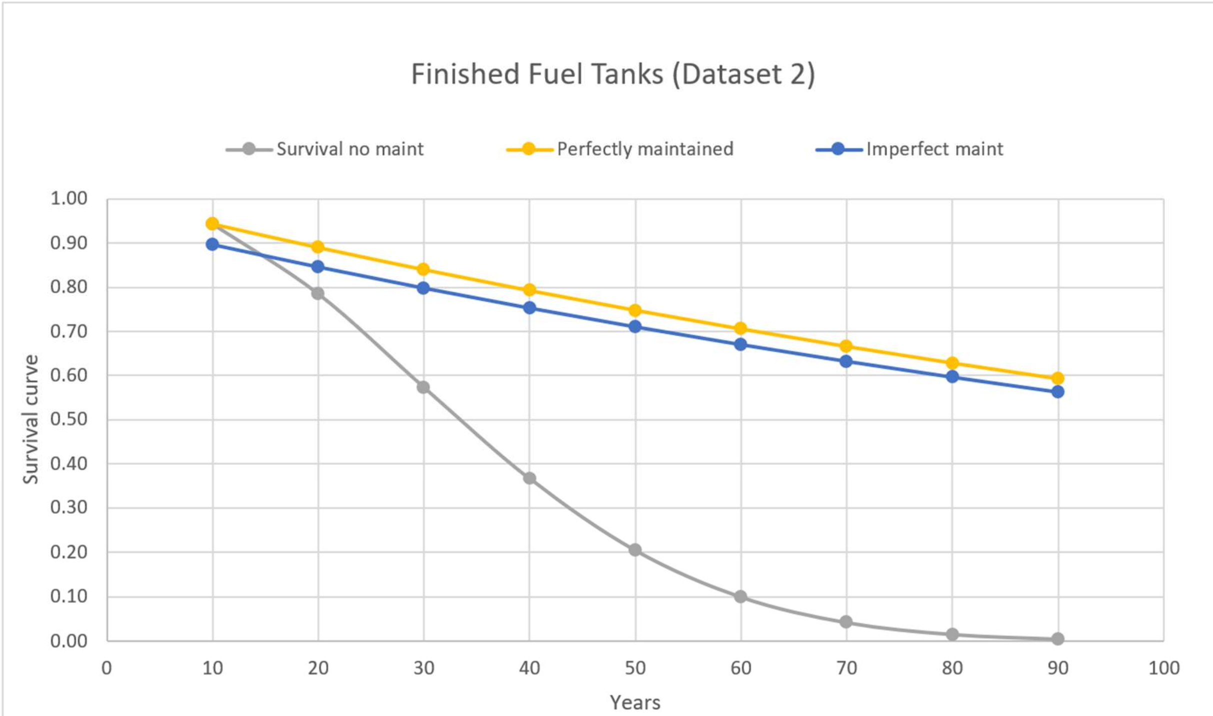


Figure 25 Finished fuel tanks; Survival curve; shape=2.054, scale=39.93

In finished fuel tanks (Figure 25) the slope of the reliability curves for unmaintained tanks is significantly steeper than for maintained tanks indicating a greater force of mortality without maintenance. Maintained refinery tank systems have a significant improvement on reliability after about 20 years. In other words, the increasing divergence between maintained and unmaintained tanks for this dataset supports the API 653 proposition that tanks should be inspected at intervals not exceeding 20 years. Note the similarity of the survival curves for finished fuel tanks compared to pipeline crude tanks (Figure 27), as indicated in Figure 22.

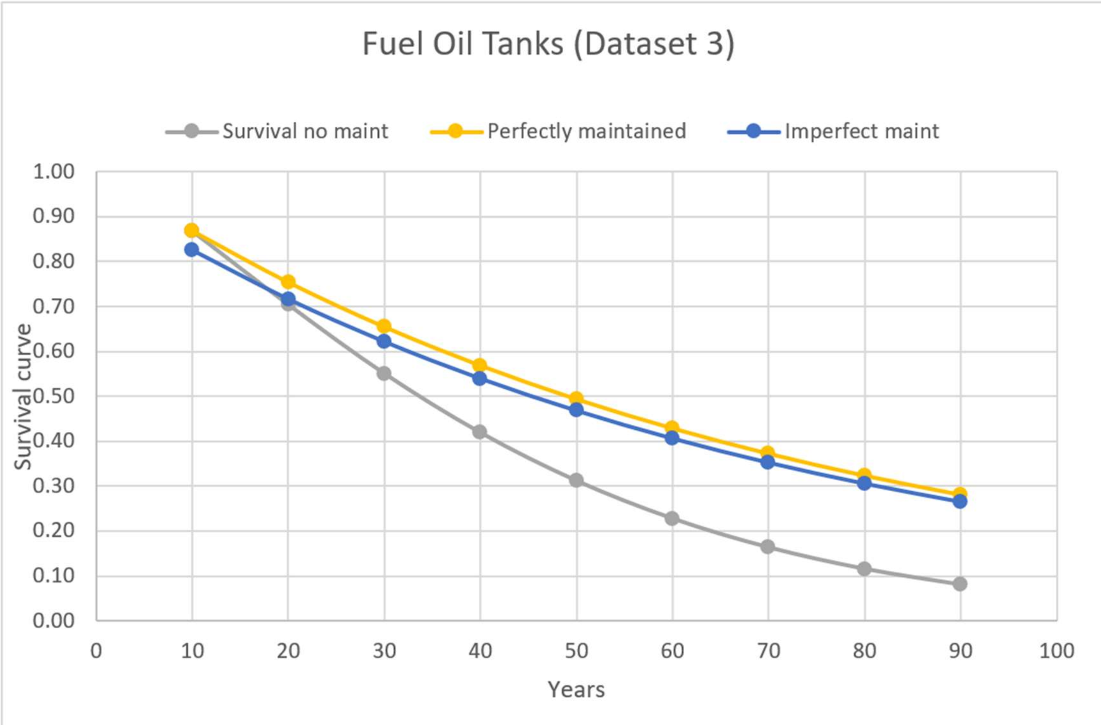


Figure 26 Fuel oil tanks (Dataset 3); Survival curve; shape=1.31, scale =44.52

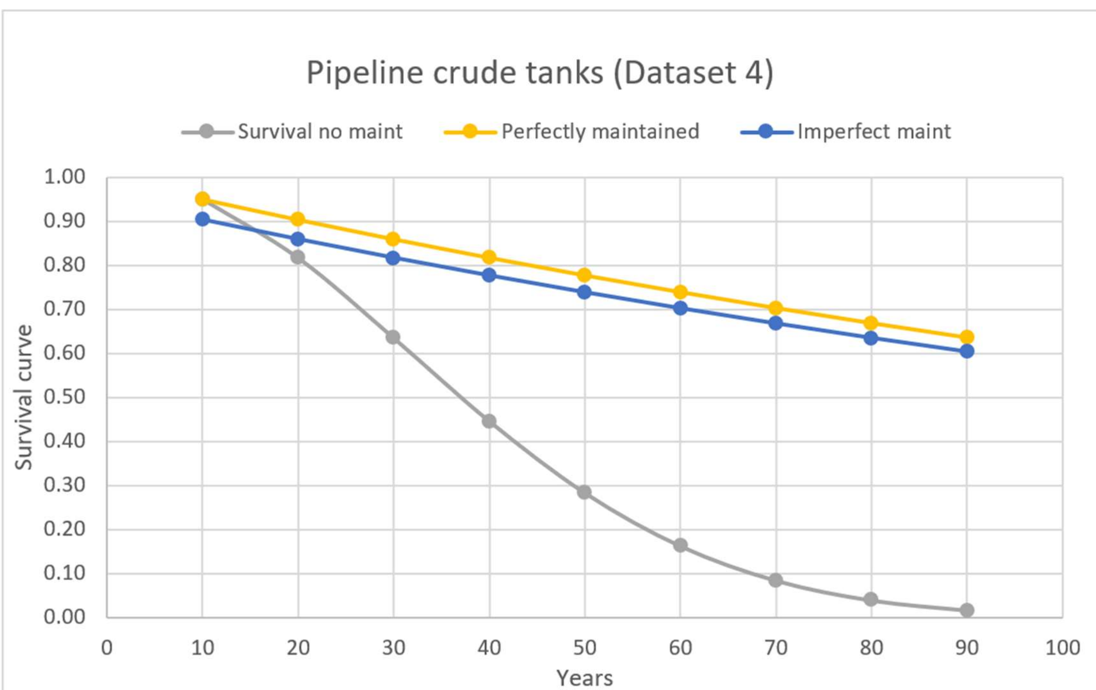


Figure 27 Pipeline crude tanks (Dataset 4); Survival curve; shape=2.0, scale=44.53

The reliability of LNG inner tanks is significantly higher than any conventional oil storage tank. A crude estimate of the failure probability of LNG inner tanks is based on the track record for the last 50 years and is discussed in Section 3. However, for the purpose of comparing LNG inner tank reliability to conventional oil tanks, the distribution can be represented by a 3-parameter Weibull distribution. This is used to compare the reliability of maintained and unmaintained inner tanks shown in Figure 28. The reliability of the LNG tank shows that no maintenance is required until at least 100 years of operation has elapsed. At 150 years, reliability drops only by a small percentage to about 99%. In fact, the point where the imperfectly maintained program actually provides benefit is at about 150 years.

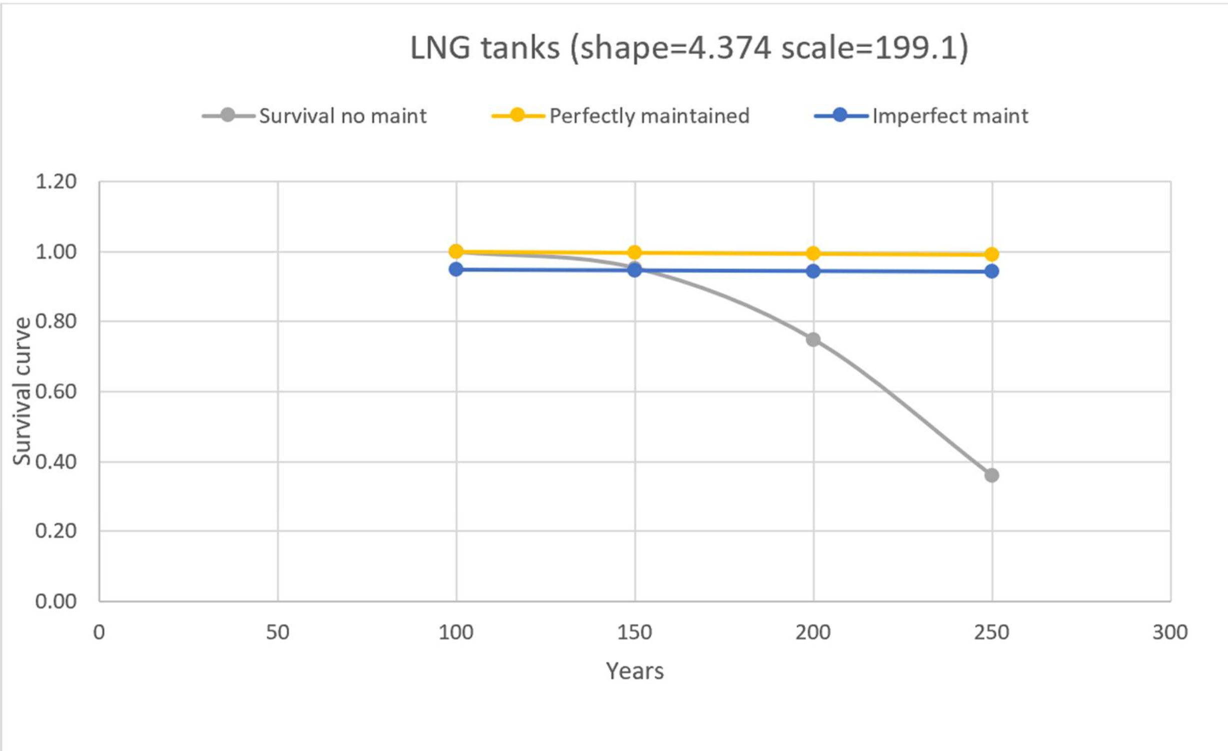


Figure 28 Comparing Maintenance Programs for the Inner LNG Tank Systems

8.6 Conclusions

The reliability analyses conducted in this section depend on publicly available data. Undoubtedly, these analyses do not have access to all the data that exists relevant to LNG tank reliability, and certainly little data outside of the database of incidents that PHMSA has collected. Without more data, the analyses that support these types of conclusions and recommendations can be only of the type provided by this report.

8.6.1 Inspection-Maintenance Intervals

8.6.1.1 Internal Inspection Intervals

The results in this section showed that for LNG tanks, the internal inspections have little value until at least 100 to 150 years has elapsed (subject to conditions determined by external inspection). However, the data was generated by assumptions about the life and our knowledge of the existing tank population. The failure distribution was conservatively selected using a 3-parameter Weibull distribution. If more data is collected and more research is conducted on the fatigue mechanisms for the specific configuration and materials of LNG liquid storage tanks, then more accurate estimates of the Weibull parameters can be deduced and more accurate maximum internal inspection intervals can be established, especially for the oldest of the existing population of LNG storage tanks.

The two primary time-dependent failure mechanisms for LNG tanks are fatigue and corrosion. Given the data that is currently available the conclusions emerge as follows:

Routine internal inspections and internal maintenance cycles for LNG tanks are not required to be conducted for intervals that are less than 100 years. The 100-year marker may be too conservative and be extended. However, since no failures have occurred, a very conservative value is 100 years. The long inspection timeline gives ample opportunity to collect and process new data, and of course this report recommends reanalysis in the future as more information becomes available.

Aggregating data not only from LNG tanks but similarly constructed liquefied gas tanks would provide an opportunity to improve these estimates. Until better data is available, the precaution holds because internal inspection cycles have a finite and negative impact by creating early failures what would not have occurred otherwise and for other negative population impacts discussed earlier. TAP discussions have made it clear that those tanks that have been taken out of service and internally inspected at the end of their design lives showed in all cases that there was no corrosion and no other recognizable damage mechanism found. However, it is not clear that inspection for fatigue was conducted.

8.6.1.2 External Intervals

The costs of external inspections are relatively low compared to internal inspections, so the issue of how frequently to conduct them is not typically governed by costs. External inspections can be conducted in accordance with a standard similar to API 653, since the steel outer container of LNG tanks is similar to conventional oil tanks, with the exception of materials of construction and typically better foundations. Thus, it is recommended that they can be inspected every 5 years where the precedent (i.e., API Standard 653) has already been established. There is no sound basis for deviating from the precedent already set by API 653 for external inspection of tanks, with the exception that the maximum interval should be five years. Although an argument could be made that the construction of LNG external tanks is "better" than conventional oil tanks and "deserve" a longer interval, other factors such as establishing simple rules that ensure corporate management systems clearly can incorporate and ensure compliance can be made which suggest reasonable time frames such as those already established. Although API 653 can serve as a model for developing a standard or recommended practice for external inspections, there are many differences (such as a concrete external tank) that should be addressed, perhaps differently. However, the TAP consensus was that the 5-year periodic external inspections (EISI) are reasonable benchmark goals for SDOs to apply to any inspection standard or recommended practices for LNG and cryogenic tanks.

8.6.2 Research

A comprehensive study on fatigue is needed to address not only the existing LNG tank populations but the tanks currently being constructed. The population has significant variety such as materials variability and detailed designs. Only through such studies will the known damage mechanisms for both fill-empty cycles and thermal warm-up and cool-down be understood sufficiently to develop accurate life tables and mortality rates for the LNG tank population. Another driver for this work is that the failure mode of a fatigue crack as discussed in Section 6 raised questions about whether the failure would be sudden and without warning ("break before leak") or with warning ("leak before break"). It is possible that depending on tank size, configuration, and materials, either failure mode could occur. For those tanks that have no "warning" of failure, it would be useful to understand which of the tanks in the existing tank population yield the highest levels of risk.

9. LNG Storage Tank Inspection Guidelines (TIG)

This document provides guidelines for LNG Tank Inspections. These guidelines capture the industry's best practices and methodologies for inspection of flat-bottom, vertical cylindrical LNG storage tanks. They are intended to ensure the ongoing integrity of cryogenic liquefied gases storage tanks for cryogenic liquefied gases including LNG by application of inspections, repairs, maintenance, testing, and data management systems applicable to these tanks. The TIG was compiled using industry consensus through meetings with TAP and serves as a basis for documenting, consolidating, unifying, and improving how the industry currently manages tank integrity.

The TIG may be used as a guide for further standards development through official standards development organizations, regulatory authorities, or corporate policy makers. It is the joint responsibility of the tank owners/operators, tank manufacturers, inspection agencies, and regulators to develop consensus standards applicable to the cryogenic tank industry and to determine how, when, and if tank inspections should be conducted.

The intent of this roadmap is to outline the consensus of best practices for the inspection, maintenance, and repair of storage tanks. On publication in the public domain, these guidelines may be immediately incorporated in part or in whole by LNG facility owners or may be used as a roadmap for inclusion of more specific detail that would occur if an SDO chooses to write standards for these facilities.

Effectively managing tank inspections depends on managing information and data over time. While not a part of the TIG, the first section of this document addresses considerations for a Tank Data and Document Management System (TDDM) that could assist in the efficiency and accuracy of conducting inspections over time. Please note that TDDM is not a requirement but a compilation of considerations for LNG facility owners/operators.

9.1 Tank Data and Document Management (TDDM)

The term TDDM is used to mean the data and document management systems specific to a given facility, owner, or operator with reference to the information that will be used to manage the integrity of LNG tanks over time.

Because of myriad and disparate data collection, management, recordkeeping, and document control systems currently used by the industry, TAP felt that it would not be appropriate to develop standardization of the data and documentation system discussed here. Each Owner/Operator does have such systems, but they are all different, highly complex, jointly mixed with other functions such as systems to track as-built drawings and embedded with other document management systems. Attempting to force companies into a template approach for TDDM would result in significant costs, inefficiencies, without necessarily making an improvement.

As a result, it is not appropriate to attempt to specify details of how TDDM should be constructed, operated or work. Instead, the discussion of TDDM below serves as a checklist for considering those aspects of data management that may not be included in a given facilities practices so that it may be considered and incorporated into their TDDM.

TDDM can be used by owners/operators or others as a checklist to determine if the data management systems they use have gaps or can be improved. A TDDM system is useful for effective management of operations and inspections. This data can assist facility owners/operators manage tank integrity when upsets occur, security issues arise, natural disasters happen, and whenever any event including age related damage potentially causes damage to the tank systems. TDDM can be thought of as an information management system and should be checked for effectiveness and efficiency periodically by the Owner/Operator. It should not be delegated to a contractor because of access to security and proprietary information and for many other reasons. A TDDM system is ideally fully electronic which makes for quick retrieval and comparison of data related to the data below retrievable with maximum efficiency. TDDM is ideally an electronic documentation system that contains data for easy retrieval of information such as:

- Tank physical properties including date of commissioning, date of construction, size, construction materials, tank classification according to API 625, type of roof, suspended deck, leak detection types and monitoring, secondary containment type and construction, size of isolation zone, foundation, heating system, primary tank penetrated or not, data such as welding records (including welding procedure specifications, if possible), and traceability records of the materials for inner tank as well as the outer tank.
- Initial records for the tank, including but not limited to:
    - NCRs (non-conformance reports) documented during construction
    - Hydrotesting procedure, methods, and results
    - First cooldown procedure and rates achieved
    - Any issues during start up
- A complete list of engineering data[12] available including but not limited to:
    - Inner and outer tank basis of design
    - Process engineering
    - Mechanical engineering
    - Geotechnical and civil engineering
    - Electrical and instrumentation engineering information
    - Materials and corrosion engineering information
    - Fire protection and safety engineering information
    - Anticipated cool down and warm up cycles as well as historical cycle records
- Records may include a list of failures caused by:
    - Improper or inadequate design
    - Original component failures
    - Corrosion
    - Insulation failure
    - Loss of containment (regardless of size)
    - Significant deterioration of any component
    - Compliance documents for PHMSA incident reporting requirements
- The following records[13], which may be segregated by inner container, outer container, or accessories as applicable:

[12] Although much of this information likely exists in Owner/Operator-controlled documents, that is often not the case for the mechanical, geotechnical, and civil engineering data. Mechanical, geotechnical, and civil engineering data can be incorporated into the construction contracts as mandatory information supplied by contractors and subcontractors.
[13] In addition to the information displayed or recorded in the control room.

    - Piping and instrumentation diagrams
    - Plot plans showing tank layout and impoundment areas
    - Plot plans showing electrical area classifications in and around the storage facilities
    - Plot plans showing storm water drainage, tank spill drainage, locations of sumps, traps, and sewers identifying whether open or closed systems
    - Electrical one-line drawings
    - Spill containment, hazard detection, hazard control, and firewater layout and coverage drawings
    - Plans showing exclusion zones (e.g., vapor dispersion, thermal radiation, etc.)
    - Plans showing local or remote impounding with sizing calculations
    - Plans showing all areas covered by fire detection systems
    - Records of alarm testing and calibration of level and pressure measuring devices if possible.
    - Records of testing high liquid level and pressure measuring shut down devices
    - Records of testing pressure relieving devices (over- and underpressure)
    - Records of foundation heating systems tests
    - All thermal surveys conducted on the foundation, the tank, or the piping connected to the tank
    - A list of all ESD systems, cause and effect matrices, test records, and locations on a plot plan
    - A list of all gas detection systems and fire detectors, calibrations, and locations on a plot plan
    - A plot plan showing the fire water loops, pumps, tests, locations of hydrants, monitors or other delivery points with nominal flow rates listed under various scenarios.
    - Fire water system testing records.
    - All inspection procedures related to storage tank inspection protocols, training, and qualifications required
    - Operating and Maintenance manual
    - History of any repairs conducted on the tank
    - Cumulative and complete photographic record of all deteriorated components with progressive photos and assessments at each inspection
- Hazards and risk analyses
    - Distances to nearest potential ignition sources (shown on plan)
    - Hazard distances computed according to NFPA 59A
    - Vapor dispersion models based on release scenarios with assumptions and showing probable concentrations of vapors at property lines, potential ignition sources.
    - Criteria and data defining exclusion zones per PHMSA requirements 49CFR193.2057 and 193.259.
    - Hazard Identification (HazID) and Hazard and Operability Studies (HazOp) completed, including records of attendance and validations in accordance with the regulation.
    - Reports done on hazard analyses, PHAs, risk assessments, etc.
- Any incidents associated with the storage tanks including but not limited to leaks, spills, directly connected piping, valves, or pumps, mechanical failures, significant corrosion issues, coatings, foundation, and cathodic protection events, roll over events, status of insulation.

- A list of all regulatory noncompliance events and events that trigger regulatory intervention.
- Inclusion of a guideline to verify that the record keeping requirements in 49CFR193, NFPA 59A, API 620, and API 625 are up to date and consolidated and electronically available including a document index. Include a provision to specify which documents are electronic and when the goal of the company is to be fully electronic in terms of data records.
- A list of minimum documents that may be kept up to date for the life of facilities.
- A list of all damage mechanisms that have been assessed for fitness for service methods by API 579 or other equivalent methods, including but not limited to:
    - Mechanical impact
    - Thinning
    - Gouging
    - Excessive pressure
    - Excessive vacuum
    - Fatigue
    - Tank distortions
    - Settlement
    - Excessive external loads
    - Fire damage
- Repair Procedures
    - Welding repairs scope
        - By material carbon steel, nickel steel, stainless steel, concrete
        - New nozzles and reinforcement
        - Pit repairs
        - Larger corroded areas and weld filling vs patch plates
    - Documents showing all historical repair
    - Documentation of temporary repairs made when they are due for a permanent repair
    - Related ASME or API requirements for each repair such as WPS, PQR, etc.
    - Verification of proper materials used
- Metallic component repairs
    - Stainless steel (fill in details for typical repairs: input from TAP)
    - Nickel steel
    - Carbon steel
    - Aluminum
    - Concrete
- Foundation repairs
    - Heating systems
    - Concrete or other component repairs
- Monitoring and Testing
    - Cathodic protection systems
    - Leak detection
    - Bottom plate thickness
    - Anchorage
    - Outer steel tank annular plate (similar principles to API653)
- TDDM Management system elements

- A management system may be applied to ensure that TDDM remains current, that changes may be addressed by MOC, and that there is accountability for maintaining the system with continuous improvement in mind. Typical elements of the management system include:
    - Contractors and contractor management compliant with API 2220 and API 2221
    - MOC
    - System of lessons learned
    - Process safety information (i.e., tank data, and information listed above)
    - Leadership accountability for ensuring that budgeting and continuing support for ensuring the system is robust
    - Employee involvement
    - Written procedures for ensuring TDDM and continual improvement
    - Training for employees and contractors
    - System of permitting for various data collection processes
    - System to investigate and improve faults in the implemented version of TDDM
    - A system to audit the implemented version of TDDM
    - Leadership accountability

Carefully planning the type of data and the way the data can/will be used to ensure the ongoing integrity of the tank systems has high value in any type of tank integrity or inspection program.

9.2 Tank Inspection Guidelines (TIG)

9.2.1 Scope

- Flat bottom, vertical, cylindrical LNG tanks > 5000 m^3 including other liquefied cryogenic gas storage tanks.
- LNG tanks constructed and commissioned on or after 1965.
- Tanks systems compliant with API 625. If noncompliant, then an evaluation to determine if older noncompliant tanks pose new issues that must be dealt with.
- Tank systems, including foundation, container, containment, secondary containment, piping integral and up to the first block valve of the tank system, attached conduits, control systems, alarms, detectors, and all tank topworks.
- Type of tank configurations:
    - Single containment
    - Double containment
    - Full containment
    - Membrane tanks
- Materials: any combination of inner and outer tanks constructed of concrete, steel, aluminum, or stainless steel, and membrane tanks.
- Periodic and aperiodic inspections of different types that are conducted by the Owner/Operator or by contractors and inspection agencies.
- Aperiodic (or event triggered) inspections after sudden threats to a facility such as earthquake, flood, natural disasters, or abnormal operations, such as fires, explosions, or sabotage.

- Internal inspections are not required except when facility management calls for them considering the results of the *Event Triggered Inspection* or any other reason it deems necessary.
- Periodic revalidation and assessment based on evolving regulatory or industry code changes.

Note: TIG is intended to cover tanks that are in service. However, that means that many tanks may precede the appearance of standards such as API 620 or may have been constructed to older editions of API 620. This raises the issue of "grandfathering." The general approach of industry standards to grandfathering is that existing equipment or structures do not need to be updated unless the changes in applicable standards have substantially reduced risks to health and human safety. This is an engineering evaluation that the Owner/Operator should consider, make a decision, and document the rationale for either upgrading or not.

9.2.2 Inspection Types

There are 5 possible different inspection types covered by 3 categories as follows:

(1) Periodic: Self Inspection by Owner (SIO) and External In-service Inspection (EISI)
(2) Event triggered: Event-Triggered Inspection (ETI) and Repair Inspection (RI)
(3) Out-of-Service Internal Inspection (OSII)

The specifics of these kinds of inspections are detailed below and in the Inspection Overview Checklists, which are a guide for Owner/Operators or SDOs to develop their own internal inspection checklists.

9.2.3 Periodic Inspections

9.2.3.1 Self Inspection by Owner (SIO)

Periodic inspections ensure that:

- Tank is inspected and maintained to ensure that tank integrity is maintained per design basis.
- Facility regulatory and industry requirements are compliant.
- Documentation and recordkeeping are being updated and managed.
- Ensure appropriate security, safety controls, and requirements are in effect.
- Any change detected by visual examination to the tank system is identified and tracked for possible further analysis.

The SIO should be conducted by the Owner/Operator since confidential data may be involved and the efficiency of conducting these inspections is far greater than by attempting to use a contractor. This inspection does not require taking the tank out of service.

It is good practice to document and log these inspections and this inspection requires the formal completion of records, checklist, and/or documentation. It is a quick review by knowledgeable operators to look for changes in the system that may indicate the evolution of future problems. Changes in condition shall be documented for tracking over time.

A record of who conducted the SIO, the date it was done, and any major findings documented on a checklist developed for this purpose is required.

This type of inspection is designated ***SIO or Self Inspection by Owner***.

9.2.3.2 External In-Service Inspection (EISI)

Another periodic inspection that investigates all exposed equipment and systems that can be examined in detail without shutting down the tank operations is the EISI. This may be conducted by the Owner/Operator or by a contracted service. The purpose of the EISI is to determine:

- Assessment of age-related deterioration mechanisms
- Determination of the need for further inspections or repairs
- The need to take the tank out of service
- Provide a formal and documented record of findings that may impact the condition or integrity of the tank, and which indicate the degree of change occurring as a result of age-related damage (i.e., coating failures, corrosion, small instrumentation leaks, etc.)

This type of inspection is designated **EISI** or **External In-service Inspection.**

9.2.4 Event Triggered Inspections

9.2.4.1 Event Triggered Inspection (ETI)

When natural events such as earthquakes, high winds, and floods occur, they may or may not damage any component of the tank system. An assessment, defined as the *Event Triggered Inspection*, determines the nature and extent of follow-up inspections. This inspection is an external inspection, however, it may lead to an OSII, if the damage is considered sufficient to warrant it. Examples of damage that initiate the ETI are:

- Sloshing waves impacting suspended roofs
- Shell buckling, denting, or distortion
- Severe cracking of the outer tank
- Piping damage
- Displacement of tank system on foundation
- Introduction of corrodants into critical instrumentation, electrical systems, or other tank components
- Leaks and spills
- Fires or explosions
- Materials or fabrication defects becoming evident and arising from improper construction and fabrication.

The ETI is an external inspection which may be used to establish possible damage mechanisms resulting from the event. The decision whether to conduct an ETI shall be made by the Owner/Operator or the Authority Having Jurisdiction (AHJ). This inspection may lead to recommendations for a series of future focused inspections to learn more about exactly what damage, if any, has been incurred and how critical that damage is to ongoing operations. The output of the ETI should include a recommendation that the tank either should or should not be taken out of service for further investigation. Thus, the ETI may result in an EISI or an OSII.

This type of inspection is designated ***ETI** or **Event Triggered Inspection***.

9.2.4.2 Repair Inspection (RI)

When repairs are required that involve cutting, welding, or other significant repairs to the inner or outer tank system, specialized inspections requiring control of the welding procedures, NDE, and quality controls are necessary.

This type of inspection is designated ***RI*** *or* ***Repair Inspection***.

9.2.5 Out of Service Internal Inspection (OSII)

For this inspection, the tank must be taken out of service and put through a warm-up cycle. Note that there is no period-driven basis for conducting an internal inspection. A OSII could be event driven or may never occur in the lifetime of the tank.

When an OSII occurs, the interstice or internal container may be cleaned and gas freed as necessary so that inspection can access the interstice or the inside of the inner container as required. In addition, it is imperative that the Owner/Operator develop and have procedures ready to implement should the tank system require warming up. These procedures should comply with NFPA 59A as well as any other regulatory requirements. They are critical to minimizing the damage by thermal gradients affecting the tank system components.

It should be noted that an OSII is comprehensive and that the EISI is a component of the OSII in addition to OSII-specific inspection tasks.

This type of inspection is designated ***OSII*** *or* ***Out of Service Inspection***.

9.2.6 Summary and Comparison of Inspection Types

A description of the inspection type, symbol, who conducts the inspection, the purpose, and frequency is given in Table 6, Table 7, and Table 8. For the inspection activities that make up the SIO, EISI, and OSII, see the inspection checklists in the following section.

Table 6 Periodic Inspections

Type Inspection	Who conducts inspection	Function	Frequency
Owner Self Inspection SIO	Owner/operator	Walk around inspection by Owner/Operator to determine if any significant changes are occurring in the tank systems with time. It provides opportunity to log concerns and potential issues needed further reviews in the future.	Once per month
External In-service Inspection EISI	Owner/operator or contractor	Periodic 5-year inspection General inspection of all components that can be inspected without interrupting tank service. Requires extensive use of NDE and documentation. Assessment of changes that may impact integrity. Extensive use of NDE, diagnostic tools, lasers scanning, photography, recordkeeping.	Every 5 years

Note 1: Inspector qualifications may be added to the table

Note 2: The SIO requires minimal disruption and should be conducted by those personnel most familiar with the tank systems. There are no formal qualification requirements other than familiarity with the tank system. In contrast, the EISI should be conducted by professional inspectors experienced in tank inspection.

Table 7 Event Triggered Inspections ETI

Type Inspection	Who conducts inspection	Function	Frequency

Event Triggered Inspection ETI	Owner/operator or contractor	External events may indicate potential damage. Determine extent of damage. Triggering events such as seismic, flood, wind, formation of icing and cold spots, mechanical damage or other event that is cause for concern on tank integrity. Also, any indication of an abnormal condition triggers this inspection to determine causation and potential remedies. The result of this inspection will determine the need for an OSII.	External event
Repair Inspection RI	Owner/operator or contractor	Inspections involving cutting or welding of any pressure containing part of the tank, the anchorage system, foundation repairs, any tank structural steel such as platforms, pump systems. May be done concurrent with other inspections (e.g., OSII)	Whenever repairs are made affecting any pressure containing component. May cause service interruption of tank depending on location of potential damage.

Note 1: The Owner/Operator or SDO writing inspection standards shall determine the qualifications for those conducting this type of inspection. Formal reporting is required to document the findings of this inspection.

Table 8 Out of Service Internal Inspection (OSII)

Out of Service Internal Inspection OSII	Owner/operator or contractor	An inspection conducted when the tank must come out of service, go through a warm-up cycle, and either the interstice or internal tank inspected.	Indeterminate unless ETI establishes need for this inspection.

Note 1: Professional inspectors with expertise in the required disciplines shall be used to conduct these inspections. Their work shall be documented, and findings and recommendations developed in concert with the facility Owner/Operator.

9.2.7 Considerations for Inclusion in the LNG Inspection Standard

Any standard or recommended practice developed by the tank Owner/Operator or by a standards development organization shall consider these statements in the development of a TIG:

- NFPA 59A-2023 18.10.12.1 LNG storage facilities and, in particular, the storage container and its foundation shall be externally inspected after each major meteorological disturbance to ensure that the structural integrity of the LNG facility is intact.
- NFPA 59A-2023 18.10.13.6.2 Each component that is protected from atmospheric corrosion shall be inspected at intervals not exceeding three years.
- NFPA 59A-2023 18.10.10.7.2 Set-point testing intervals shall be in accordance with either of the following:
  (1) At intervals not exceeding five years, plus three months
  (2) At a frequency in accordance with API RP 576, Inspection of Pressure-Relieving Devices
- NFPA 59A-23 18.10.13.8.3.3 The following procedures for external corrosion control of buried or submerged components shall be met within five years of the issuance of this standard:
  - Install cathodic protection system in accordance with 18.10.13.1.2, 18.10.13.3.3, 18.10.13.3.4, 18.10.13.3.5, and 18.10.13.5
  - Monitoring in accordance with 18.10.13.6.1
  - Remedial measures in accordance with 18.10.13.7
  - Record keeping

See Section 10 for further recommendations related to the next evolutionary step of this guideline which is for an ANSI accredited SDO to write a standard or recommended practices based on this work.

9.3 Introduction to Inspection Overview Checklists

The following checklists are intended to be used in conjunction with the Tank Inspection Guidelines (TIG). This checklist is not intended to be applied as is. It is intended as a guide for those responsible for development of informal or formal checklists that are applicable to a specific facility, set of tanks at a facility, tanks within a corporation, or by the scope set by those authorities or SDOs developing formal standards or recommended practices for cryogenic and LNG tanks. Much of the checklist is based on API Standard 653, but it has been modified to include supplemental items unique to cryogenic tanks. Wherever there is a discrepancy, if any, between industry standards and regulation, the more stringent of the two should govern.

The inspection checklists should be modified as appropriate by considering the risks and cost-benefits of the possible inspection items listed here. The development can be done either by an Owner/Operator or by a standards development organization. In many cases, API 653 may be used as a starting point. Another reason that regulatory, corporate, site, or tank-specific checklists may be developed is to consider the impact of grandfathered tank systems and components. The decision to upgrade to current codes and standards is based on many considerations of which risk to the public, costs-benefits, and other factors play an important role.

TIG specifies 3 Inspection frequency categories with 5 different inspection types:

(1) Periodic (SIO, EISI)
(2) Event triggered (ETI, RI)
(3) Internal out-of-service inspection (OSII)

The following checklists are conceptual in nature and show the major and minor components that should be inspected under a formal inspection program. Consideration should be given to categorizing the checklist findings categories:

(1) Checked or tested with no concern.
(2) Should be monitoring for change (such as during the SIOs).
(3) If a more in-depth follow-up inspection is recommended.
(4) If an engineering evaluation is recommended for the purpose of making further decisions about this item.
(5) Requires internal inspection to be conducted within 3 months.

The manufacturer for all equipment and components should be identified, and Owner/Operators should be ready to contact manufacturers for recommendations on the repair, inspection and maintenance of these equipment and components.

9.4 SIO Periodic Self Inspection by Owner

Who: The most qualified personnel for this task are the Owner/Operator personnel because they are most familiar with the tank system and can detect changes in its condition. However, others may conduct this inspection and the Owner/Operator shall determine who does this inspection and what the job qualifications are. The SIO should include careful observation of the external tank system and tank system components which are accessible while the tank is in service so that any changes can be documented and reported to management.

How: A photographic record of any anomalies or findings is useful for detecting changes.

When: Monthly frequency

SIO Checklist: Observations by visual examination:

- Leaks or hissing sounds
- Formation of icing or cold spots
- Corrosion of fasteners, structural, connected piping, or shell material
- Cracking, spalling, deterioration of concrete, grout, piles
- Surrounding foundation soil erosion, subsidence or significant changes including rodent burrows
- Cold or ice spots
- Deterioration of conduits, controls, cables, and fasteners
- Changes to shell, roof, or other components such as buckling, warping, or distortion
- Damage or changes to anchor bolts or straps, corrosion, or any cracking especially in welds
- Nozzles, penetration, and piping insulation and conditions for change or damage and breech of moisture barriers
- Cracking, spalling, changes to any thermal coatings or barriers
- Tank top lifting equipment condition and degradation changes such as corrosion, loose fasteners, hooks, frayed cabling
- Condition of stairs, walkways, and platforms
- Detectors and sensors (gas, fire, or others)
- Tests of alarms, ESDs, or other safety critical functions on the tank system according to 49 CFR Part 193.
- Security cameras working to observe tanks and areas around the tank, clean optics, mirrors, etc.
- During significant rainfall events examine drainage, check proper operation of sumps, secondary container drainage valves and operation.
- Owner/Operator should conduct leak detection on all tank components, fitting, valves, and piping systems at least quarterly by a walkdown using FLIR hydrocarbon and VOC optical imaging cameras.
- Owner/Operator may choose to conduct leak detection on the circumference of the outer tank bottom at the foundation to detect vapor leaks using FLIR hydrocarbon and VOC optical imaging cameras.

In addition, temperature data from sensors in the tank system, including the foundation, should be collected and recorded.

Documentation: Checklist that these items were inspected, date, and by whom (including signature).

9.5 EISI Periodic External In-Service Inspection

Who: If the EISI involves thickness measurements or flaw detection, then the recommended qualified persons to conduct this inspection should be knowledgeable in NDE methods and qualified according to industry organization credentialing such as ASNT-1A. The general qualification requirements may be developed internally by the facility Owner/Operator.

When: At least every 5 years

What: Everything that is within the scope of the tank system including but not limited to the foundation, piles, heating systems, observable components of the tank while it is in operation or in a state of isolation ready to be operated on short notice, the walkways, ladders, platforms, first connection from any piping, fire water or foam connection, instrumentation or electrical.

Possible Data Collection: Construction and as built drawings, process flow diagrams for tanks, past testing, inspection and maintenance records, past incident reports, tank design criteria, details on all tank internal valves, all external block valves, design of ESD systems related to tank, location and function of all sensors and detectors including type and function as well as manufacturer, volume calculations of the secondary containment, exclusions zones, storm drainage systems, the design and operation of storm water removal systems, plans showing all underground piping, conduits, trenches, raceways, plans showing critical instrumentation, alarms, and control systems routing paths to and from the tank, plans showing electrical area classification for anything inside the secondary containment areas, manufacturer datasheets and instructions for any control, heating, alarm, detection or other instrumented systems.

This inspection may require some operational testing of components and therefore requires coordination between the testing and inspection company and the Owner/Operator.

- Complete photographic record showing all findings, documentation of the locations, recommendations for further, more in-depth inspections or examinations, all survey or laser scan data to be delivered to Owner/Operator.
- Operation of specific components such as vent valves, internal valves, or others to determine if performance meets criteria.
- Inspection of pumps or pipe columns is not within the scope of this inspection.

An * after each component group below indicates that the main inspection contractor (if used) for tank inspection is not required to do this inspection but should validate that it has been or will be done. For example, inspection of electrical components, or the cathodic protection, or other specialty areas may be individually contracted for by the Owner/Operator. However, the tank inspection report should include the inspection findings and checklists for all such inspections listed in this document. Therefore, coordination and cooperation between contractors as managed by the Owner/Operator will be necessary and should be managed by the facility Owner/Operator.

9.5.1 EISI Checklist

9.5.1.1 Foundation and Tank System Support

- Survey the elevation of the top of the shell-to-bottom joint at the top of the projection of the bottom, using either laser scanning or surveying techniques or the techniques outlined in API

Standard 653. Compare with original surveys when tank was constructed and document the data. Alternatively, conduct a foundation survey based on the top of concrete just outside of the projection of the bottom beyond the shell.

- Collate information from inclinometers all in one place showing changes with time.
- Conduct a laser scan of tank exterior and roof including the foundation.
- Condition of grout around the outer tank shell at the bottom projection beyond the shell.
- Condition and function of caulking around the outer tank shell at the bottom projection beyond the shell.
- Drainage of ground on which tank rests ensuring water drains away from tank bottom and does not pool near the tank bottom.
- Inspection of foundations, ringwalls, slabs, foundation pile caps, piles for cracking, spalling, evidence of rebar corrosion, or other changes from a new condition that warrant possible further examinations.
- Check for frost heave around tank.
- Natural drainage in, around and under elevated foundations for signs of subsidence, erosion, animal borrows, debris, discoloration, or evidence of emerging problems. Compare against previous data from construction or past inspection as well as against the OSIIs.
- Grout and sealants on tank bottom for degradation, cracking, shrinkage, or potential problems.
- For elevated piled tanks, check the underside of the pile cap for icing. The junction of the pile to cap should be examined for spalling, cracking, and traces of corrosive product from the reinforcing bar. Check for foundation spalling or cracking, corrosion stains or products from internally corroding rebar.
- Check all concrete for the presences of stains most likely caused by corrosion of internal rebar. Get photos that can be checked with passing inspections to monitor progress of concrete damage.
- Verify large tank release of contents flow paths, drainage away from tank and potential damage of equipment control cables, conduits, and lines above the potential fires for possible incapacitation of control systems.
- Verify no enclosed drainage systems. If there are, then procure the detailed engineering analyses explaining why they are justified per NFPA 59A.
- Check seismic isolators for wear, damage, or deterioration.

*9.5.1.2 *Foundation Heating Systems*

The following items should be inspected per manufacturer instructions.

- Junction boxes for damage, degradation
- Fuses
- Heating controls
- Amperage and voltage readings
- Thermocouple
- Switchgear

- Record flow rates and temperatures for the fluid heating system

- Compare current to past measurements
- Verify all field readings consistent with control room readings
- Check records of power consumption of heating system and compare with past readings.
- Check that seals are isolating gas flow between electrical area classifications. This may be done on a random basis. If any conduit seals are found not to be properly isolating, then all such seals around the entire tank classified area should be opened and inspected.
- Collate all historical data on heating systems so that there is a record of changes, failures, and repairs over time.

9.5.1.3 External Tank, Connected piping, Nozzles

- Check outer tank and nozzle paint surface condition including all external appurtenances.
- Check spring hangers/cans on piping connected to the tanks to ensure they are operating in the correct range.
- Visually inspect shell stiffeners, any attachments, and any pads for signs of corrosion.
- Check for corrosion or mechanical damage at the bottom plate extension beyond the shell, and at the anchor bolts and chairs. Perform NDE on anchor components and on welds including straps (if they exist).
- Visually inspect for frost or cold spots, ice spots on the outer shell or roof. Determine if normal or new. Make sure to note that this item may require further work by Owner/Operator to resolve the issues.
- Use thermography to scan surfaces of external tank and document findings.
- Check paint condition on shell stiffeners, stairways, structural members, and nozzles. Document locations and findings with written records and photography.
- Any buckling, warping, distortion from past natural events, buckling, or other causes affecting shell, bottom, or roof regions. Confirm with Owner/Operator that reports exist to support continued operation. If not, specify further engineering analysis required to support continued operation.
- Check for signs of wet insulation on shell, roof, or piping.
- Perform NDE thickness readings for any severely corroded pressure containing elements of the tank system.
- Perform NDE on randomly (or risk based) selected pipe and nozzle welds connecting to the tank and on expansion joints. This includes thickness measurements as well as detection of linear indications. Record locations of measurements.
- Check that all exposed steel repads, plates to support roof columns, or other appurtenances are either seal welded or determine if moisture and corrosion is occurring under these plates and provide a way to monitor or repair these accelerated corrosion areas.
- Check pipe and nozzle insulation, cover, moisture barriers if conditions warrant.
- Check piping alignment with nozzles. Large misalignment should be evaluated according to general engineering practices.
- Visually inspect pipe supports on piping within scope (i.e., up to first block valve)
- Determine location of supports documented on plan and piping drawings covering a distance of to at least the secondary containment and exclusion zone boundaries on drawings so that piping analyses can be done if excess stress is suspected.

- Check on the condition of all bolting and fasteners on all nozzles and valves within scope
- Carry out a thermographic survey on the outer tank to verify the general condition of the insulation and compare to previous surveys. It is preferable to do the surveys with a high liquid level and when the surveys are repeated the liquid level should be as close as possible to previous surveys for repeatability and pattern recognition.
- Verify the condition and integrity of cladding, cover, or moisture barriers.
- Check the condition of any expansion bellows regarding corrosion, unusual distortions, ice buildup or other damage.
- Check for rotation of nozzles. Movement would indicate frost heave on the inner tank or deterioration of the foundation.
- Check pipe supports connections to roof or shell.
- Check condition and settings of spring supports and compare with data sheet settings.
- Trace heated nozzles and adjacent piping for localized corrosion.
- Inspect the intersection of the outer bottom plates, anchor straps, and the concrete ring wall where water can collect, corroding the carbon steel footer plates and the anchor straps.
- Use gas monitors to check for escaping methane from the interstice through the bottom by checking around the perimeter at the bottom of the external tank where vapors are normally present under slight pressure.
- Inspect pre-stressing tendons on internally prestressed concrete tanks for loss of seals which would significantly compromise the tank. These circumferential and vertical pre-stressing tendons are located in fully grouted metallic conduit whose function is to protect these highly stressed components from corrosion.
- Inspect for the loss of environmental protection covering or corrosion of the very-high-strength steel music wire exterior wrapping on externally circumferentially prestressed concrete tanks. This should be immediately corrected since the wrapping is critical to maintaining the outer shell in a compressive state.
- Infrared survey of the piping for evidence of water, indicative of the failure of the environmental sealing associated with the insulation.
- Check that all sections of piping that can be blocked are thermally relieved.
- Check which sections of piping have been analyzed for hydraulic transients caused by valve closure, pump start and stop, or substantial elevation changes.

9.5.1.4 External First Block Valves Isolating Tank from Piping Systems

- Check for cold frost, which are indications of failure of the moisture barrier covering the insulation or failures of the valve insulation box and may indicate that repairs are required.
- Check valve stems or other penetrations to ensure that the vapor barrier and insulation is properly working.

9.5.1.5 Internal Shut Off Valves

- Check all mechanisms that operate internal valves including but not limited to corrosion, fasteners, cables, controls, pneumatic systems, instrumentation, etc., as well as documenting the pneumatic system pressures both supply and regulated.

- Ensure the valve reseats after use.
- Operate all block valves to verify performance.
- Use cryogenic cameras to determine if enough bottom debris such as finely unremoved CO2 solids can build up and block or interfere with internal valves or the pump well inlet.

9.5.1.6 Valve Operators

- Check lubrication records and verify completed.
- Check operation.
- Verify control signals and connections.
- Operate all block valves and verify performance of operator using manufacturer instructions.

9.5.1.7 Structural Steel

- Check the condition of protective coatings on handrails, treads, platforms, and walkways.
- Inspect all surfaces where water can collect on or adjacent to the steel outer tank or components. This is especially important for areas that are not accessible such as pads or structures that are stitch welded or not completely seal welded to any pressure containing shells or roof components.
- Perform random visual examination of bolting, welding, and fastening of structural systems.
- Check lifting systems for pump removal and other purpose on tanktop, including random NDE of welds, wrench testing of any suspected loose bolting, examination of all lifting components including hooks, cables, fasteners, clips for integrity (NDE may be used as needed).
  Verify maximum loads handled and validate availability of engineering analyses that support structural calculations made for these systems.
- Check for compliance with OSHA requirements for ramps, ladders, handrails, stairs.
- Check for hot-dip galvanized steel structures above stainless steel components in case of potential liquid metal embrittlement during a fire.

9.5.1.8 Vent Valves

- Check for icing, corrosion, mechanical damage, or leakage.
- Check car seal and locked open vents.
- Check all control pneumatic tubing, fittings, supply gas for proper connection, leaks, mechanical damage, or other problems.
- Block vents using block valves and conduct visual examination of seals and seats with time window for tests approved and managed by Owner/Operator. Verify car seal open when test completed.
- Verify that pilot operated utility systems are available and function at a set point causing intended operation. For vacuum vent testing, the condition or modification for the testing should be such that causing an excess internal pressure vacuum inside the tank cannot occur.
- Test any steam nozzles used for the purpose of warming up venting system if applicable.
- Verify appropriate use of drip pans, proper design, and installation.

*9.5.1.9 *Emergency Shutdown Systems Related to Sensors on Tank*

- Owner/operator to demonstrate and trigger ESD with the various ESD sensors. Inspector to verify that intended actions whether valve closure or alarm functions as intended. If ESD systems are tested prior to each loading, then this satisfies the proper operation of these systems.
- Check operation of remote operated shutoff valves by observation of closure.
- Test alarm or shutdown by inputting sensor values to trigger final element.

9.5.1.10 Spill and Drip Pans

- Visually inspect all such pans for condition, leak tightness, and integrity.
- Check sources of possible liquid escape which could impinge on the tank and check condition of any protection devices provided, e.g., mats, catch-trays. Review with Owner/Operator.

*9.5.1.11 *Tank Instrumentation and Controls*

- Verify calibrations completed and documented according to plans.
- Check fittings and tubing for pneumatic controls and leak test with soap solutions.
- Check connections to electrical sensors and detectors including tubing, leads, and condition.
- Check signal and electrical connections condition.
- Consider operating proximity and limit switches to verify function.
- Motive power (i.e., pneumatic, electrical, etc.) for all control systems on the tank and identify the acceptable ranges of these sources such as psi, voltage, etc.
- Determine the current supply gas pressure for control systems for instrumentation and control valve actuators. Determine the state of failure (i.e., failure on loss of pressure, current, etc.) so that the safe state is clearly identified.
- Test instrumentation used for the monitoring of LNG stratification and rollover and inspect the software used for this instrumentation to ensure its functioning and accuracy.

*9.5.1.12 *Thermocouples and Temperature Measuring Arrays*

- Consider applying inputs and observe if outputs are as expected.
- Review the thermal system records to determine what changes have occurred and why.
- Identify and note any failed sensor arrays and document for future review.

9.5.1.13 Liquid Level Measurement

- Liquid level calibration on all level switches or level measurement devices.
- Review documentation for past calibrations.
- Validate sensor triggers correct level specified in operating documents as well as operation of alarms and control devices.
- Review the procedures that are required when each critical level alarm point or action point for control to determine exactly what must be done by the operations.

*9.5.1.14 *Electrical*

- Examine randomly selected conduit junction boxes for damage, etc. Check fuse condition.
- Check lighting levels at areas around critical ladders, ramps and platforms and record levels.
- Check that electrical boxes, assemblies, covers, and components have the proper explosion proof ratings appropriate to the area in and around the tank as well as on the tank roof.
- Periodically test the emergency lighting system in and around the tank for proper operation.
- Check that the lighting system activates according to design intent.
- Inspect overhead lines, insulators, guys, line say, hardware and poles.
- Inspect any manholes for conditions, cleanliness, excessive heat
- Inspect conduits for corrosion, loose fittings, covers, and conditions of drains
- Inspect ratings of electrical boxes for proper area classification
- Consider applying tests and inspections specified by NFPA 70B[14] for electrical maintenance and document results.

*9.5.1.15 *Fire Protection Devices on Tank*[15]

- Check condition and test devices on tank.
- Check and test the condition of fire protection devices on the tank.

*9.5.1.16 *Cathodic Protection*

- Cathodic protection system components
- Current draws and comparison to past records
- Incorporate API 651[16] and NACE RP0193[17] for the inspection of CP systems.

9.6 Out of Service Internal Inspection (OSII) Checklist

No technical justification for conducting routine time-based internal inspections of LNG tanks can be provided. The basis for this is provided in Section 8 LNG Tank Reliability. However, external inspections, or other inspections that may reveal degradation or damage with loss or potential loss of containment may call for an inspection that requires shutting down the tank, emptying it, and making it available for an internal inspection. The final decision is up to the Owner/Operator.

The OSII may be required based on the results of ETI inspections or any condition or concern that the Owner/Operator deems appropriate.

From the roof manway, visually examine the surface of the deck and supporting rods for signs of damage or degradation. From the inner tank bottom, examine the entire underside of the suspended deck for any unusual distortion or potential problems. When it has been established that the suspended deck is intact the full inspection of the deck may proceed.

[14] NFPA 70B: Standard for Electrical Equipment Maintenance, 2023 Edition

[15] The qualifications and requirements for personnel doing this inspection are based on the Owner/Operator specifications as well as local fire code authorities having jurisdiction.

[16] API-651 - Cathodic Protection of Aboveground Petroleum Storage Tanks

[17] NACE RP0193-2001 - External Cathodic Protection of OnGrade Carbon Steel Storage Tank Bottoms

However, when conducted, the OSII includes inspecting all items under the EISI but includes in addition these items:

9.6.1 Suspended Deck

- Check that support rods are not slack.
- Examine roof structure visually for any distortion or separation of roof plates from support frames.
- Examine undersides of roof plates around roof nozzles and other roof attachments.
- Examine the deck insulation for damage or depressed areas indicative of movement. Measure depth and compare with original.
- Visually examine all piping between roof and suspended deck. Particular attention should be paid to distorted or bent pipes.
- Where pipe is insulated, check the insulation attachment to the pipe.
- Check perlite level in the annular space between inner and outer shell for signs of compacting (where relevant).
- Check the integrity of the seal between suspended deck and inner shell.
- Check all vent openings located in the deck to ensure that they are not blocked.

9.6.2 Inner Tank Inspection

- Check for the presence of deck insulation or any other foreign matter on the bottom.
- Check chloride concentrations in the interstice and record levels found.
- Examine the bottom plate surface and internal piping and supports for damage.
- Examine visually the bottom lap welds, annular plate butt welds, shell to bottom welds, and any attachments welded to the bottom plates.
- Visually examine shell welds and shell plate surfaces for any signs of corrosion.
- Examine the shell surface for any unusual buckling or distortion. Crack-detect any shell nozzle welds.
- Make a level survey across four diameters. Also survey any raised or depressed areas to determine whether settlement or heave has occurred. If the installation temperature and survey temperatures are substantially different then significant bowing and warping of the bottom is likely. Record data from any existing inclinometers.
- Survey the level of the annular plates at the shell-to-bottom junction to determine whether the shell support foundation is intact.
- Leak-test the bottom and shell-to-bottom welds with a vacuum box.
- Carry out ultrasonic thickness survey of the shell plates, the annular plates, and the other bottom plates.

9.7 Important Safety Note

This guideline does not include any safety considerations for conducting inspections. The provisions of API Standard 2015, NFPA 59A Section 11.3.6.2, and ACI 376-11 Section 12.8.7 are useful starting points for the development of such guidelines either by a standards development organization, the Owner/Operator, or contractor. The important differences such as the lighter than air density of methane as well as the operation aspects such as nitrogen purging to remove flammable vapors, causing conventional gas detection meters to not work, properly must be considered.

10. Conclusions and Recommendations

10.1 Conclusions

This work brought together the expertise of consultants, inspectors, manufacturers, government regulatory agencies, and owners and operators of LNG storage tanks to consider the issues and problems associated with developing widely accepted standards and practices applicable to maintaining the integrity of flat-bottom, vertical, cylindrical cryogenic and LNG storage tanks. The application of a Technical Advisory Panel (TAP) provided representation on behalf of the LNG industry and the relevant stakeholders listed above. TAP consensus can be stated in the following points:

- There is little standardized guidance for inspection, maintenance, and repairs of storage tanks beyond that specified by federal regulations 49 CFR 193 as well as industry standards such as API 625, API 653, and NFPA 59A.
- The inspection and repair practices currently vary widely from one Owner/Operator to the next.
- Fatigue life from fill-empty cycles on inner steel, aluminum, or stainless construction is not well understood and needs more analyses to support specific guidelines for setting internal inspection intervals.
- Unless there are specific reasons for internally inspecting tanks, it is better not to do so because of the negative tradeoffs of damage (such as thermal shock) and business interruption. In addition, the value of internal inspections is not yet well enough understood to provide a rational basis for periodic internal inspections. (External inspections should still be regularly conducted, as they are relatively inexpensive and there is no strong incentive to deviate from precedent with other aboveground storage tanks.)
- The inspection and repair guidelines and the checklist provided in this report will be useful and appropriate for most companies to adopt, and ultimately, develop a recommended practice or standard for inspection of cryogenic liquefied gas tanks.
- While the principles of the guidelines included in this final report were developed in the context of LNG, the principles and guidelines can be applied to other liquefied gases such as oxygen, nitrogen, hydrogen, and others with the understanding that the chemical and physical properties of the liquid and gas as well as the hazards need to be thoroughly incorporated into any practice or standard that is applicable.

10.2 Recommendations

The following recommendations arise most directly from the conclusions outlined in Section 8 but include other recommendations based on the contents of the whole report.

10.2.1 Notify and Engage an SDO[18] to Develop an LNG Tank Inspection and Repair Standard

The work in this research report has been developed sufficiently for an accredited US standards development organization (SDO) to prepare either Recommended Practices (RP)[19], guidelines, or

[18] Standards development organization such as the American Petroleum Institute

[19] A standard or an RP are virtually the same kind of document and either may be enforceable if the authority having jurisdiction requires compliance with the RP or Standard.

standards on the inspection and repair of LNG and cryogenic storage tanks. This report recommends that the American Petroleum Institute be the preferred SDO for this activity because:

- API is a consensus based, ANSI accreditation SDO which embodies the principles of such organizations including due process, absence of dominance by any one group, consensus, balance of interests, and a mechanism to handle disputes.
- API may be the most knowledgeable SDO for the purpose of this development work.
- API already has a very efficient, standing subcommittee set up for this type of work. It is called the Subcommittee on Aboveground Storage Tanks (SCAST) and is a branch of the Committee on Refinery Equipment (CRE).

10.2.2 Improve Record-Keeping for LNG Incidents

Government agencies should ensure that a database of incidents and causation are living documents and growing with time as new events occur. Such data provides the most efficient way to reduce incidents and their associated liabilities through knowledge that can flow from the databases to the SDOs and regulatory oversight bodies. Government agencies should solicit research proposals for development of data collection processes to support better estimates of reliability as illustrated by the work of Section 8. Specifically, to support improved failure and incident data processes to support higher reliabilities, this report recommends that a request for proposal be issued by PHMSA or FERC for research aimed to:

- Specify a *minimum dataset*[20] collection process and analysis protocol to support the reliability estimates that support maximum internal inspection intervals as well as allow better grading of individual tank risk. It is likely that several different intervals may be appropriate depending on the age, construction, materials, and design of the storage tanks based on analysis of the minimum dataset.
- Review the requirements for modifying the PHMSA 49 CFR Part 193 rules applicable to incident reporting. The opportunity to improve performance, operability, and safety of LNG tanks is based on the record keeping systems used by PHMSA to require incident reporting. Such studies would aggregate additional sources of data and improve the recordkeeping and reporting processes so that analyses such as those conducted in this Section 8 LNG Tank Reliability or future studies can better depend on the available information about LNG incidents.

10.2.3 Apply Findings and Existing Best Practices Where Relevant

While the current practices in the LNG industry are excellent, there may be a high degree of variability in how tank integrity programs are executed and interpreted. An ANSI-accredited industry RP or standard would help to consolidate the very best practices and allow for easier monitoring and control of these programs not only by facility management but also by regulatory stakeholders. Some important recommendations arising from Section 8 are:

[20] A minimum dataset is a statistical term used in the medical industry to establish the critical data necessary to study issues of mortality and health status over the long-term.

- External inspection should be standardized to 5-year intervals and be consistent with API 653 but include changes to account for differences between external LNG tanks and conventional oil storage tanks.
- Internal inspections should not be conducted without a sound rationale and only done when triggered by an ETI or any condition or concern that the Owner/Operator deems appropriate. Note that when the fatigue research is completed, the standard can impose maximum limits on operational time of LNG tanks before internal inspections are required. The time limits most likely will exceed 100 years for internal inspection that are not triggered by imminent failure. It is possible that tanks constructed before 2000 may have different inspection criteria than tanks constructed after 2000 based on the findings of the research.

10.2.4 Include LNG Tank Repairs in the Standard

LNG tank repairs should be included in the proposed LNG tank inspection standard because the risks of LNG tank failures may be based on improper or inadequate repairs. The work in this Project shows that, while new construction standards can be applied for repairs that attempt to ensure that welding and joining methods are safe, the topic is much more involved than the scope of this Project and requires development of details that would be provided for by an SDO chartered to write the LNG and cryogenic tank inspection standards.

10.2.5 PHMSA and API Should Conduct Needed Research

PHMSA and API should conduct needed research, including but not limited to various materials and configurations of LNG tanks for both thermal and mechanical fatigue. This work should determine the best approach (i.e., either fracture mechanics-based or SN curve-based methods) to find the fatigue lives of both existing and new LNG tanks and systems, including the variability in the way they are operated. When this research is completed, it can be used to support the LNG industry standard to set maximum lifetime limits on fill-empty cycles, especially relevant to some of the older designs and with other materials that may be arising as risk levels increase over the next decades of operations.

10.2.6 Update API Standards

API should update existing applicable standards:

- API 620, which may have overly conservative fatigue life assessment information built into the standard. API should fund research to revise the fatigue requirements specified therein.
- API 2015 for safe entry into LNG tanks should be supplemented to include LNG storage tanks which have safety and environmental mechanisms not currently addressed. There are potentially other relevant standards relating to working in conditions found during an LNG internal inspection that should be considered.
- API 571 could be expanded to include cryogenic damage mechanisms, although this recommended practice primarily applies to refining operations in the petroleum industry.

10.2.7 Update 49 CFR 193 to Include the Latest Edition of NFPA 59A

PHMSA should, as soon as possible, update 49 CFR Part 193 to incorporate the latest edition of NFPA 59A because it represents the latest technology. Use of very old editions locks in out-of-date technology and does not include the newer provisions based on experience from past incidents.

10.2.8 Alignment of API and Other Relevant Standards

API should ensure that the details specified in any new API standard or recommended practices are aligned, consistent, and non-duplicative with those found in NFPA 59A. API should collaborate with ACI to address concrete LNG tank containers and foundations.

11. Appendices

Appendix 1 PHMSA LNG Incident Data

Table 1 Incident Data Considered Relevant for the Project

Report Number	Relevant to Project?	Narrative	Item Involved	Cause Details	PEMY Comment
20220002	Y	An unintentional discharge of natural gas occurred during nitrogen displacement activities associated with commissioning of the south lng tank. Nitrogen must be removed from the tank, prior to the initial start-up, by flowing natural gas into the tank in order to displace the nitrogen. The facility and its primary contractor developed a procedure for carrying out the nitrogen displacement activities that initially included directing the vent stream to the lp flare. Later, the procedure was amended to provide for venting of the nitrogen via a roof vent on the lng tank. The facility completed a management of change ("moc") evaluation for the amended procedure, which was approved by operations, commissioning, and engineering. According to the amended procedure, the venting would be monitored to determine when the nitrogen displacement would be complete and the remainder of the tank contents would be switched to the lp flare. Venting of nitrogen from the tank began on january 15, 2022 at approximately 0300 and ended on january 17, 2022 at approximately 1000 hours when facility environmental personnel became aware of the venting and potential for natural gas to be present in the vent stream. Operations were protectively ceased prior to confirmation of the presence and/or quantity of any natural gas in the vent. Later, it was determined that natural gas mixed with nitrogen was in fact emitted. The primary root cause of the incident was the exclusion of an environmental specialist/ air permitting specialist in the sign-off approval of the moc. If that individual was included in the moc process, the moc would have never been executed since the lng tank is not an approved emission source. To prevent any recurrence, any nitrogen displacement activity using natural gas will either direct any vent stream purged from the lng storage tanks to a flare or such activity will be permitted pursuant to the regulatory permit in lac 33:iii.309 or other appropriate authorization from the louisiana department of environmental quality. In addition, the facility will ensure that any venting procedure and any changes thereto are thoroughly reviewed during the moc process and are approved by appropriate and relevant staff, including environmental staff, in addition to operations and engineering staff. Finally, any personnel involved in nitrogen purging operations for the lng storage tanks will receive additional training on the procedures and regulatory requirements prior to any future nitrogen displacement operations.	other	other incorrect operation	Pre-start up safety reviews could be standardized to include this. A standardized checklist for this start up activity could be included.
20210003	Y	On thursday, february 4, 2021 a plant operator was working on the roof of the lng tank and audibly and visually discovered a non-hazardous leak. The non-hazardous leak is under a steel backing plate that is welded to the roof of the lng tank. The backing plate is part of the support system for the walking platform. Because the backing plate is not fully welded, water accumulated between the backing plate and the lng tank roof, ultimately leading to a non-hazardous corrosion leak. An estimated 300 cfh is venting to the atmosphere. Intermountain gas company (igc) hired an engineering consultant on february 11, 2021 to evaluate repair options. On february 17, 2021 at 11:10 a.m. mst, using data provided by the engineering consultant, igc determined the lng tank will be taken out of service to make repairs, which is expected to exceed $50,000, at which time igc notified the nrc. As of february 17, 2021, the lng tank had 3,093,114 gallons of lng. To allow for the offload and vaporization of the lng, the lng tank will be taken out of service in june 2021. The estimated volume of commodity released unintentionally (part a, question 9) is 201.6 mcf as of march 4, 2021. This quantity will be revised for the final report. Estimated cost of operator's property damage & repairs (part c, question 1.b.) Is $500,000. This cost will be revised for the final report. Intermountain gas company received a quote for repairs on june 23, 2021. The operator's property damage & repairs (part c, question 1.b.) Has been revised from $500,000 to $1,989,000.	storage tank/vessel	external corrosion	Use of seal welding form attachments and pads. Assume this is outer tank?

20200002	Y	Prior to hurricane landfall, the facility was placed into a safe shutdown mode and evacuated. The flare valve was left in auto with a set-point of 3.0 psig to continue controlling tank pressures as long as possible during the storm. During the storm, power was lost to the facility, causing the diesel standby generator to start. Eventually the generator ran out of fuel and shut down because personnel were unable to access the site as a direct result of damage to the surrounding area caused by hurricane laura, which caused the instrument air compressors to shut down, causing loss of instrument air. This caused the control valves to go to their fail safe position, which is fail close for the flare valve. At that point, tank pressures started climbing until the psv on t-202 lifted per design to control the tank pressures. Based on our investigation, we believe the lift occurred the morning of august 27. An initial incident notification was made to the nrc (#1285850) on august 28 once the facility was assessed by our disaster recovery team. The marine flare was restored in the evening on august 29 and the psv re-seated on its own. A 48-hr follow-up notification was made to the nrc (#1285993) the morning of august 30.	relief valve	other natural force damage	Suggests estimating max time personnel cannot access plant and making sure fuel supply is adequate during various natural hazard events
20190006	Y	On november 6, 2019, kinetrex energy's lng north's storage tank experienced a crack in the carbon steel exterior tank shell. The crack was identified directly below the existing lng pump catwalk/platform and approximately 1 foot above the dome lip/compression edge. The operator on duty notified management of a potential leak on top of the lng storage as evidenced by a vapor cloud. Plant management informed the lng plant mechanic of this potential issue and requested that he investigate it immediately. The lng plant mechanic investigated the issue as requested and informed the director of operations that it appeared there was a crack in the exterior tank shell. The director of operations instructed the operator on duty and the lng plant mechanic to shutdown the liquefaction and trailer loading activities until additional investigations could take place. The director of operations and lng plant engineer visited the site immediately following the notification by the lng plant mechanic to confirm the findings. It was confirmed that a crack had occurred in the carbon steel outer tank at a length of approximately 2.5 feet. Approximately 4 to 5 years ago, with the facility under previous ownership, a leak in an lng liquid valve occurred directly above the location of failure causing discoloration in this area. In addition, kinetrex energy replaced this valve in october 2019 as part of our routine maintenance program to ensure the integrity of our facility. After the valve replacement and subsequent cooldown of the line, the kinetrex energy plant mechanics verified tightness of the newly installed valve and notated a small lng leak (a couple of drops/minute) landing in the existing lng drip pan prior to rectifying this leak. This leak was stopped at this time. With the discoloration it is presumed the carbon steel outer tank's integrity was previously impacted ultimately leading to the failure in 2019. Kinetrex energy began the process of contacting various engineering firms with relevant experience, as well as, matrix pdm, the original tank manufacturer. Matrix pdm recommended that kinetrex energy use an epoxy (belzona product) to temporarily stop the leak. The leak was stopped the evening of november 7, 2019 with boil-off gas normal operation resuming. The indiana utility regulatory commission and a phmsa representative visited the site on november 14, 2019 to discuss the incident. Since this leak was discovered, kinetrex energy has contracted with matrix pdm to conduct a phase i engineering study. The engineering study will include recommendation(s), cost(s), and schedule to test and permanently repair the crack. This report is expected to be provided by matrix pdm within 4 weeks. Matrix pdm has since completed a phase i and ii engineering study outlining the proposed design to permanently repair the crack. Material has been procured for this repair and is currently on standby while kinetrex energy boils off the remaining inventory to purge the tank out of service with n2. The tank n2 and air purge out of service process completed on october 12, 2020 with construction commencing immediately after on october 13, 2020 with a completion date of october 22, 2020. All qa/qc measures were taken to ensure the weld of the tank was satisfactory including a pressure test of the area. The n2 and natural gas purge into service activities started on october 23, 2020 and were complete on november 3, 2020. The tank cooldown was completed on november 15, 2020 concluding the repair project and reinstating lng service.	storage tank/vessel	failure of equipment body (except pump/compressor), vessel plate, or other material	Use of temporary repairs such as belzona; id and logging of them with check schedules and replacement time limits.
20180001	Y	On monday, january 22nd, 2018 a small lng release was observed at the base of the southeast side of tank s-103 by operating field personnel. All lng released from the outer tank shell was contained in the secondary containment. The lng vaporized and dispersed. Tank s-103 was promptly removed from operational lng service. Third-party experts performed a root cause failure analysis (rcfa) of the event. The rcfa determined that transient flow though the bottom fill connection caused lng to enter the tank annular space (space between the inner tank wall and outer tank shell) above the inner tank lip during filling of the inner tank, which resulted in the release of lng from tank s-103 during the incident. None of the transient flows exceeded normal operating flow parameters or tank name plate specifications. A detailed discussion of causes and contributing factors is contained in the rcfa report submitted to phmsa. To address the direct cause of the incident, bottom fill rundown capability to all lng storage tanks was permanently and physically disabled. Sabine pass has acted to address basic/root causes associated with prevention and mitigation barriers. Tank s-103 was removed from service and permanent repairs are underway. Item a.5-nrc 48-hour report # 1202757 item b.1 nominal	storage tank/vessel	other incorrect operation	Obtain "detailed discussion" about this. "Transient" implies a water hammer type event so the cause is not clear at this time.

20170001	Y	On tuesday, march 7th, 2017 at 15:35:58hrs, lng terminal emergency shutdown #1 was triggered due to the activation of flame detector 1lng-ae-2016c at the top of the lng tank. The event happened while o&m personnel was working in the replacement of lng pump p-101c. While the pump was being removed from the tank column and traveling to its transportation frame, supported by the lng tank top crane, o&m personnel noticed a small fire in the bottom suction notch of the pump. Immediately, ecoelectrica maintenance technicians proceeded to extinguish the fire using portable abc fire extinguishers located at the lng tank top platform. No personnel was injured or equipment damaged during the incident. At 15:37hrs (two minutes later), a lng sendout pump was returned to operation and at 15:41hrs lng vaporization process was reestablished and terminal recovered for normal operation. The root cause of the ignition was a static electricity discharge. After a nitrogen purge of more than 12 hours, the pump was ready to be removed from its well. Due to strong gust of winds, prior to lifting the pump, a polypropylene rope was tied to one of the stands of the bottom suction notch as an aid to control pump movements while being transferred from the well to the transportation frame. During this maneuver the technician attending the pump was using skin gloves while the propylene rope was being controlled with his hands creating friction between the two materials. The gloves' material (leather) in contact with the rope (polypropylene) gave rise to accumulations of electric charge that was released suddenly in electrostatic discharges with sufficient energy to ignite the flammable gas mix present at the pump notch. The first step on the ignition is the production of a spark that instantly generates ir light (corona effect) that was captured by the flame detector which triggered the esd #1.	pump	other incorrect operation	Possible guidelines for static electricity when removing internals from pump. This includes bonding and grounding of isolated metal objects such as pump during removal. The root cause analysis would be helpful as this description does not provide all of the details needed.
20140003	Y	After a tornado disrupted electric power transmission to the east tennessee lng facility in kingsport, tennessee, the generator at the facility did not immediately activate. The compressor stopped which caused pressure to rise in the lng tank and natural gas vented through the associated relief valve until the generator switched on and compressor returned to service.	relief valve	high winds	Consider testing times for generator to go online, Calcs to support how much vapor will evolve is generated does not start, and worst-case planning scenarios

Table 2 Incident Data Considered Not Relevant for the Project

Report Number	Relevant?	Item Involved	Cause Details
20220003	N	other	miscellaneous
20220001	N	relief valve	miscellaneous
20210008	N	vaporizer	valve left or placed in wrong position, but not resulting in a tank, vessel, or sump/separator overflow or facility overpressure
20210007	N	pump	pump/compressor or pump/compressor-related equipment
20210005	N	relief valve	malfunction of control/relief equipment
20210004	N	relief valve	storage tank or pressure vessel allowed or caused to overfill or overpressure
20210001	N	relief valve	malfunction of control/relief equipment
20210002	N	relief valve	malfunction of control/relief equipment
20200004	N	other	pump/compressor or pump/compressor-related equipment
20200005	N	other	miscellaneous
20200001	N	compressor	pump/compressor or pump/compressor-related equipment
20190004	N	flange/gasket	non-threaded connection failure
20190005	N	in-plant piping	other incorrect operation
20190003	N	break-away coupling	miscellaneous
20190002	N	compressor	pump/compressor or pump/compressor-related equipment
20180003	N	cold box	other equipment failure
20180002	N	vaporizer	other equipment failure
20170002	N	other	miscellaneous
20160001	N	in-plant piping	valve left or placed in wrong position, but not resulting in a tank, vessel, or sump/separator overflow or facility overpressure
20150004	N	emergency shut-off valve (esv)	damage by car, truck, or other motorized vehicle/equipment not engaged in excavation
20150002	N	flange/gasket	other equipment failure
20150001	N	weld	construction-, installation-, or fabrication-related
20140002	N	in-plant piping	other incorrect operation
20140001	N	relief valve	malfunction of control/relief equipment
20120001	N	other	other equipment failure

Appendix 2 TAP Tank Survey Summary

General Information		Inner Tank						Outer Tank					Other information				
Year tank commissioned	Tank type	in. D (ft)	in. H (ft)	in. material	suspended?	in. roof	in-tank pumps	out. D (ft)	out. H (ft)	out. material	out. roof	foundation type	ever internally inspected?	ever warmed?	perm. leak monitoring?	internal corros. monitoring?	earthen containment dike?
1967	5.3	118	95.917	aluminum	yes	NA	no	128	98.083	9 nickel	steel dome	pile cap	no	no	yes	no	yes
1968	5.4	118	91	9 nickel	no	9Ni dome	no	128	94.167	stl	steel dome	concrete sl	no	no	no	no	yes
1969	5.4	186	60.5	9 nickel	no	9Ni dome	yes	194.333	65.458	stl	steel dome	concrete ri	yes	yes	no	no	yes
1971	5.3	138.333	112	9 nickel	yes	NA	no	138.333	112	stl	steel dome	Concrete ri	no	no	no	no	yes
1971	5.3	146	117.25	9 nickel	yes	NA	no	152	140	stl	steel dome	concrete ri	yes	yes	no	no	yes
1971	5.4	129	125.666	9 nickel	no	9Ni dome	no	139	127.666	stl	steel dome	concrete ri	no	no	no	no	yes
1972	5.3	95	98.333	aluminum	yes	NA	no	103	107	stl	steel dome	concrete ri	no	no	no	no	yes
1972	5.3	134.333	112	9 nickel	yes	steel dome	no	147.417	139.333	stl	steel dome	concrete ri	yes	yes	no	no	yes
1975	5.9	NA	NA	stainless	yes	NA	yes	100.5	49.5	concrete	concrete d	concrete a	-	-	no	no	yes
1976	5.3	162.333	105.463	aluminum	yes	aluminum	no	168.833	139	stl	other stl	Ringwall	yes	yes	no	no	yes
1976	5.3	162.333	105.463	aluminum	yes	aluminum	no	168.833	139	stl	other stl	Ringwall	yes	yes	no	no	yes
1976	5.3	162.333	105.463	aluminum	yes	aluminum	no	168.833	139	stl	other stl	Ringwall	yes	yes	no	no	yes
1976	5.3	162.333	105.463	aluminum	yes	aluminum	no	168.833	139	stl	other stl	Ringwall	yes	yes	no	no	yes
1976	5.3	162.333	105.463	aluminum	yes	aluminum	no	168.833	139	stl	other stl	Ringwall	yes	yes	no	no	yes
1978	5.3	160	118.5	Aluminum	yes	NA	no	166	129	stl	steel dome	pile suppoi	yes	yes	yes	no	yes
1978	5.3	160	118.5	Aluminum	yes	NA	no	166	129	stl	steel dome	pile suppoi	yes	yes	yes	no	yes
1978	5.3	160	118.5	Aluminum	yes	NA	no	166	129	stl	steel dome	pile suppoi	yes	yes	yes	no	yes
2004	5.3	245.5	105.417	9 nickel	yes	aluminum	no	252	113.167	stl	other stl	Ringwall	no	no	no	no	yes
2004	5.3	245.5	105.417	9 nickel	yes	aluminum	no	252	113.167	stl	other stl	Ringwall	no	no	no	no	yes
2006	5.3	252	123.666	9 nickel	yes	NA	no	258	135.458	stl	steel dome	pile suppoi	no	yes	yes	no	yes
2007	5.9	258.25	112.917	9 nickel	yes	NA	yes	265	113.75	stl	concrete d	pile cap	no	no	yes	no	yes
2007	5.9	258.25	112.917	9 nickel	yes	NA	yes	265	113.75	stl	concrete d	pile cap	no	no	yes	no	yes
2007	5.9	258.25	112.917	9 nickel	yes	NA	yes	265	113.75	stl	concrete d	pile cap	no	no	yes	no	yes
2008	5.3	265	105.417	9 nickel	yes	aluminum	no	271.5	113.75	stl	other stl	Ringwall	no	no	no	no	yes
2008	5.3	265	105.417	9 nickel	yes	aluminum	no	271.5	113.75	stl	other stl	Ringwall	yes	yes	no	no	yes
2008	5.4	259.1667	114.5	9 nickel	yes	NA	yes	265.75	125.4167	stl	steel dome	Concrete s	no	no	yes	no	yes
2008	5.4	259.1667	114.5	9 nickel	yes	NA	yes	265.75	125.4167	stl	steel dome	Concrete s	no	no	yes	no	yes
2008	5.4	259.1667	114.5	9 nickel	yes	NA	yes	265.75	125.4167	stl	steel dome	Concrete s	no	no	yes	no	yes
2008	5.4	259.1667	114.5	9 nickel	yes	NA	yes	265.75	125.4167	stl	steel dome	Concrete s	yes	yes	yes	no	yes
2008	5.4	259.1667	114.5	9 nickel	yes	NA	yes	265.75	125.4167	stl	steel dome	Concrete s	yes	yes	yes	no	yes
2010	5.3	283	123.666	9 nickel	yes	NA	no	289	136.666	stl	steel dome	pile suppoi	no	yes	yes	no	yes
2011	5.9	246	125.354	9 nickel	yes	NA	yes	254	135.771	concrete	concrete d	Concrete s	no	yes	yes	no	yes
2011	5.9	246	125.354	9 nickel	yes	NA	yes	254	135.771	concrete	concrete d	Concrete s	no	yes	yes	no	yes
2018	5.9	247	134	9 nickel	yes	NA	yes	258.5	149.5	stl	concrete d	Concrete s	no	no	yes	no	no
2018	5.9	247	134	9 nickel	yes	NA	yes	258.5	149.5	stl	concrete d	Concrete s	no	no	yes	no	no
2020	5.9	247	134	9 nickel	yes	NA	yes	258.5	149.5	stl	concrete d	Concrete s	no	no	yes	no	no

Appendix 3 TAP Inspection Survey Summary

This document is a summary of the survey responses received from LNG TAP members. 6 out of 8 LNG Owner/Operator TAP members submitted survey responses.

Note:

- When presented in a table, questions are in the left column and answers in the right.
- In the answers column, the number in parentheses is how many survey responses gave that same answer.
- “NA” or “N/A” is shorthand for “not applicable”.
- Irrelevant or unhelpful answers were not recorded in this summary.

Inspection Type and Frequency

What type of inspections are conducted?	both (2) in-service only (4)
Are all of the inspection done by contractors?	no (6)
Basis for setting inspection intervals?	periodic (2) periodic/regulation (1) risk based (1) unsure/many reasons (1)
Top motivation for inspection?	regulation (3) corrosion (1) equipment (2)
In service inspection frequencies?	monthly (1) quarterly (1) annual (1) many different kinds (2)
Out of service inspection frequencies?	none (5) varies (1)
Did the original tank manufacturer assign a "design life" to any of your tanks?	yes (2) no (3)
Have you performed any assessments of remaining life?	no (5)

Inspection Questions

Do you ever conduct hydrotests after the tank commissioned?	no (5) yes (1)
Are there documented inspection checklists that you use? If so, please provide a copy.	yes (4) no (1)
Is there an internal inspection standard that you use? If so, please provide a copy.	no (5)
Are tank inspections unified across business units and countries?	yes (4) no (2)

Have you ever had any stress corrosion cracking issues associated with the tanks or connected piping?	no (5) unsure (1)
Do you have a corrosion under insulation inspection program for piping?	yes (4) undergoing approval (1) no (1)
Is corrosion of the "chime" area a corrosion problem area (the chime is the projection of the bottom beyond the shell)?	yes (1) no (3) unsure (1) NA (1)
Are anchors for the tank inspected by visual means (and how often), by other means (and how often)?	yes, monthly (2) yes, quarterly (1) yes, annually (1) no (1) NA (1)

How do you monitor the effectiveness of tank insulation with time?	visual inspection (3) FLIR camera (2) weekly temp. profile, monitoring boiloff rates (1)
How do you monitor the effectiveness of the tank foundation heating systems with time?	monitor temp from control room (5) NA (1)
For vacuum jacketed piping and connections how do you monitor for the loss of vacuum?	temp sensor (1) NA (5)
If you see a frost spot developing, what protocol is followed?	inspection with thermal camera (4) notify manager (1) document + external firm (1)
How do you inspect ringwalls?	visual + elevation survey (1) visual (3) NA (2)
How do you inspect pile caps?	visual + settlement (2) visual (2) NA (2)
When anomalies in the foundation is detected visually or otherwise how is an evaluation or assessment made, by whom, with what qualifications?	report to engineering, then external firm/SME (5)
If there are problems for insufficient rebar cover or spalling, what is done when detected?	report to engineering, then external firm/SME (4) NA (1) unclear question (1)
Describe major repairs done for renewing or correcting insulation?	install/top with perlite (2) take out of service, remove old insulation, surface prep, install new foam and cladding (1) NA (2)
Describe major repairs done for piping?	repairing hole or small crack, or replacing all insulation major (1)

	replace damaged pipe per spec and new supports installed (1) replace pipe for corrosion (1) none or NA (2)
Describe major repairs done for settlement.	none or NA (6)
Describe major repairs done resulting from corrosion.	coating concrete dome (1) outer tank bottom patch plate (1) none or NA (3)
Describe major repairs to concrete shells or roofs.	none or NA (6)
Have you ever reported any incidents or safety related condition reports under CFR Part 191?	yes (2) no (2) NA (1)
Can you provide incident reports related to LNG tank inspection and repair?	yes (1) no (1) NA (3)
How much time would it take to warm up an empty LNG tank and prepare for an internal inspection?	Approx. 2-3 weeks (3) Approx. 4 months (1) Approx. 5-6+ months (2)
Have you ever retired/decommissioned an LNG tank?	yes (1) no (5)

Inspection Policy

Do you have a corporate policy that requires in-service inspections?	yes (3) no (2)
Do you have a corporate policy that requires out-of-service inspections?	yes (1) no (4)
Does it set maximum intervals?	yes (2) no (2)
Does it require internal entry into the interstice?	no (4)
Does it require internal entry into the inner LNG container?	no (4)
Does it set maximum intervals?	no (2) NA (2)
Are inspection policies in other countries significantly different than from the US?	unsure (3) NA (1)
Are the rules in the US more stringent or less stringent than for other countries?	unsure (3) NA (1)
Can you provide a copy of your LNG tank inspection policy or standard?	yes (2) pending approval (1) no (1)

Repairs

Describe the most common types of repairs done on the tanks.	*total count of responses mentioning each term:* painting/coating (5)

	insulation (1) valves/actuators (1) footer plate seal coating repairs (1) foundation heater repairs/replacement (1) handwheels (1) concrete crack filling (1)
Rank the most common types of repairs by component.	painting (2) piping insulation and surface corrosion (1) valves > actuators, overhead hoists (1) painting > level indicators > relief valves (1) corrosion/painting > handwheel (1)
What are the most common causes of repairs?	corrosion and environmental conditions (5) corrosion and component age (1)
Have foundation repairs been done? Why?	foundation cracks (2) grout replacement (1) no (1) NA (2)

Do you require independent 3rd party inspection for all coating repairs?	yes (2) no (3) not all; large scale coating done by contractors (1)
What components of the tank are coated based on component material?	concrete dome (1) outer tank carbon steel (1) carbon steel piping/equipment (1) outer tank, foundation footer plate (1) anything that can corrode (2)
Are coatings working as intended?	yes (5)
How often do coatings last by component?	3-5 years (2) 7 years (1) 10-15 years (2) Unknown (1)

Do you apply cathodic protection to any part of the tank system or components?	yes (3) no (3)

Components

What components requires the most maintenance?	valves/actuators and hoists (1) foundation heating systems (1) coatings (1) valves, handwheels, outer shell, roof, nozzles (1)
What components are considered critical for inspection due corrosion or other age-related deterioration?	*total count of responses mentioning each term:* carbon steel gas piping (2) pipe hangers and supports (1) hoists (1)

	foundation heating (1) stairs (1) catwalks (1) piping insulation (1) inner wall (1) outer shell (1) "all carbon steel components" (1)
What practice is used to identify leaks from piping?	*total count of responses mentioning each term:* LDAR (5) gas detection (4) visual inspection (2)
What practice is used to identify leaks from inner tank?	*total count of responses mentioning each term:* thermal monitoring of annular space (5) visual inspection (1) boiloff rates and temp profiles (1)
What practice is used to identify leaks from outer tank?	*total count of responses mentioning each term:* thermal monitoring (3) LDAR (3) unusual inert gas usage (2) visual inspection (3) CGIs (1) leak survey (1)
What practice is used to identify leaks from other components?	*total count of responses mentioning each term:* thermal scanning (3) LDAR (1) CGIs/gas detectors (3) visual (1) alarms (1) leak survey (1)
What NDE techniques do you consider the best?	dye penetrant, UT, x-ray (1) visual (1) IR, UT, vacuum/RT/phased array (1) thermal camera (1) depends, UT (1)

Inspection Processes

Q: What elements of visual inspections are used and why? For example, some companies use visual inspection to drive what will be done in follow up inspections.

A:

- "Visual inspections identify areas needing follow-up correction actions. Example: Active corrosion areas require clean and paint."
- "Visual inspection for identifying cold spots and settling before hiring consultants and contractors."
- "Illumination and Magnification, rarely. Hard to access areas sometimes examined with binoculars."

Q: What kinds of detailed inspection and NDE are applied?

A: • "Industry recommended practice API 653. NDE techniques applied are VI and UTT." • "Thermal camera in CCTV always aimed at the tank, licensed surveyors for settling." • "Infrared, Laser settlement and Inclinometer. UT as appropriate."
Q: Are newer technologies such as laser scanning for settlement or distortions being used? A: • "No; we do annual elevation surveys and perform the analysis for settlement as per API 6522 Annex B" • "Consultants are using lasers for measurements." • "Yes/ Currently using conventional surveying and in process of evaluating laser scanning with our 3rd party surveyor."

Opinion

Are US regulations too lax, stringent, or right?	right (3) need to be updated (2)
What regulatory changes would you suggest?	CFR 49 Part 193 (1) RBI/performance-based instead of generic/prescriptive mandatory inspection (2) none (2)
Are industry tank inspection standards adequate?	yes (4) no (1)
Are internal inspections of the inner tank ever warranted without a leak?	case by case (2) yes if warmed, no if cold (1) only if CO_2 is concern and only with cryogenic camera - emptying tank is financially infeasible (1) no (1)
Are there enough LNG tanks to ensure continued operation if internal tank inspections are conducted once per 20 years?	no (4) depends (1)
Should risk based inspections be applied to inspection frequencies?	yes (4) no (1)
Are ASCE7 wind and seismic rules too lax, stringent, or right?	right (4) unfamiliar with ASCE7 (1)
Are there better regulations in other countries for storage of LNG?	maybe/unsure (5)
Are the rules of NFPA 59A for siting of LNG tanks too lax, stringent, or right?	right (4) too lax (1)
What is the best material to construct the inner tank of?	9% ni steel (4) aluminum (1)
What is the best material to construct the outer tank of?	carbon steel (2) reinforced concrete (2) 9% ni but depends (1)
When should concrete outer tanks be used?	dependent on application and region (2) always (1)

	for small LNG site (1) unsure (1)
When should concrete domes be used?	dependent on application and region (2) always, except for high seismicity region (1) for small LNG site (1) unsure (1)
Do you consider API 625 and API 620 to be the best of industry standards for LNG tanks?	yes (3) acceptable (2)
What do you consider to be the best LNG tank standards in the world?	API (1) EN1473 and 14620 (1) unsure/no experience (2)
Are typical tank inspection companies adequately knowledgeable and experienced to conduct LNG tank inspections?	yes (3) they are different and we prefer to work with manufacturer (1) unsure/no experience (1)

Q: Provide your definition of “import terminal”.
A:

- “Large ship delivery of LNG to a terminal for storage and vaporization to interstate pipelines”
- “LNG facility that imports liquefied natural gas via LNG Carrier, stores it or not in permanent LNG Tanks and regasifies it for distribution in the pipeline network. An FSRU is also an import terminal”
- “Terminal optimized for importing/storing product “
- “A plant designed to receive LNG by sea from another country”
- “receive imported LNG”

Q: Provide your definition of “export terminal”.
A:

- “Large liquefiers designed to load/fill large ships of LNG to oversea customers.”
- “LNG facility that process natural gas, liquefies, and stores it in LNG tanks for further loading them into barges or LNG Carriers for local or international distribution.”
- “Terminal optimized for transporting bulk product out.“
- “A plant designed to send LNG by sea to another country.”
- “export lng”

Q: Provide your definition of “base load terminal”.
A:

- “Ship delivery of LNG to be stored and vaporize into interstate pipeline on a daily schedule.”
- “An import or export terminal that does not change production rates based on seasons, and continuously meets market demand.”
- “Terminal optimized for yea-round gas sendout into the local distribution system or transmission system.”
- “An LNG plant designed to vaporize LNG and provide pipeline capacity to meet base firm loads.”
- “Production required to satisfy foundation customers under long term Sales and Purchase Agreements (SPA). Excludes production targeting the spot market.”

Q: Provide your definition of “peak shaving terminal”.
A:

• "Liquidfy domestic natural gas during summer months and re-vaporize during high demand periods." • "A facility that liquefies natural gas and stores it in LNG Tanks, and regasifies it during seasonal demand." • "Terminal optimized for seasonal operation, to augment local or regional gas supply." • "An LNG plant designed to vaporize LNG and augment pipeline capacity when demand exceeds supply." • "Store LNG during low demand and make available during high demand."
Q: Provide your definition of "satellite terminal". A: • "A LNG liquefier Making LNG to load LNG tanker truck for delivery." • "A remote facility that liquefies or regasifies LNG and that is not connected to the general pipeline grid." • "Terminal which may or may not be permanently staffed and can be." • "An LNG plant with no liquefaction equipment with peakshaving capabilities." • "A remote LNG facility placed closer to demand and supplied from a central LNG facility."

Appendix 4 Damage Mechanisms and Risk Tables

Table 1 General Damage Mechanisms

Damage Mechanism	Description	Susceptible tank components	Prevalence or likelihood	Causal factors	Primary inspection techniques	Comment
Outer Concrete Tank Cracking and Spalling.	Foundation, concrete containment structures. A cumulative, historical inspection record of changes is needed to assess the degree of risk and confirm the damage mechanisms in play. Facility management should engage the appropriate experts to assess this type of damage, which tends to be unique and can be related to faults in the original construction or installation processes, settlement, and degradation due to the environment. Guidance on the assessment of cracking in concrete can be found in ACI 376 Section 6 and ACI 224R.	Concrete shells or domes.	Minor spalling common; cracking occurs in domes and shells occasionally; vapor release.	Mostly installation issues, foundation settlement, corrosive atmosphere.	Visual	Damage caused by rebar too close to concrete surfaces and other improper design issues are not within the domain of the inspector except to report and recommend engineering assessments.
Release from inner tank Cracks Outer Steel Tank	When a release of LNG from the inner tank or piping system spills liquid into the interstice, the cold liquid can cool an outer tank sufficiently so that, if it is made of steel designed for a single containment system, it will crack. Leaks from spills from the roof of the tank or from shell components will also crack the tank shell, roof, or other steel components. These types of incidents have occurred in the past. A tank inspection program is unable to address this issue as it is in the realm of engineering design and operations. The piping must be designed so that the likelihood of a liquid release to the interstice does not occur. Operations should ensure that the principles of API 2350 for overfill protection are addressed.	Outer steel tank	Has occurred before	Steel is not suited to cryogenic temperatures Inadequate piping design and/or overfill protection	Not feasible for general in-service inspections. Inspections must be conducted during installation process	
Corrosion (see specific corrosion mechanisms below)	The inner tanks of LNG tanks are not subject to corrosion unless there is a malfunction in the tank system allowing water to enter the interstice. The corrosion of external steel components subject to the weather can be inspected according to the principles of API 653. External metal components. General means that corrosion is relatively uniform. Pitting means that the depth of corrosion is a large percentage of the thin area. Occurrence usually associated with coating failures, pooling of water, soil exposed steel plate. A good example is incident 202110003 (PHMSA Incident database).	Can occur on any external steel component of the outer tank system including the tank bottom underside. One incident occurred because support pads holding up the platform on the roof were not completely seal welded. Moisture retained under the pad cause a hole-through to occur.	Common Localized corrosion is common on external tanks surfaces with exposure to the atmosphere. Extremely uncommon for internal surfaces that are inerted or contain LNG, cryogenic liquids, or their vapors.	Steel exposed to environment is susceptible to corrosion.	Visual	The dominant damage mechanism associated with corrosion is atmospheric corrosion of external steel surfaces and corrosion under the bottom. Visual inspection at suspect areas is the best way for accessible surfaces. There is no way to check for this kind of corrosion under the bottom of these tanks other than the indirect method after corrosion has penetrated the tank bottom by sniffing for leaks.
Atmospheric Corrosion	Typically uniform with potential pitting where there are large, exposed areas of steel without protective coatings. Pitting also occurs such as at areas of coating delamination, unpainted surfaces, or debris areas.	All steel components exposed to environment (underside of tank bottom, shell, roof, piping, valves, platforms, walkways). Does	Rare and uncommon to the extent that failures have not resulted in incidents or releases. No incidents involving	Combination of moisture and mineral salts especially for urban areas with a high degree of	Visual	General corrosion does not generally occur on coated surfaces and where it does, the rate is much smaller than the localized corrosion rate;

		not occur on the inside of outer containers.	primary containers or its components.	pollution or areas near marine environments or those exposed to sea spray		thus, it is not important as a damage mechanism for LNG tanks. Pitting can result in leaks and releases.
Corrosion Under Insulation	If insulation contacting the protected steel surface can be kept dry, corrosion does not occur. Even if the moisture is clean, pure water, the water can cause leaching of salts used in the insulation which tends to accelerate the corrosion. The critical factor for keeping moisture out of the insulation is the proper design and installation of the insulation system. An engineered process should be applied to examine corrosion under insulation for cryogenic applications.	Can occur under any insulated metal surface. However, typically occurs where water can pool or where insulation is breeched to or poorly adhering to the steel surfaces.	Common	Where non-watertight insulation exists and moisture can enter, the corrosion is worse. This includes any areas where water running down the surface of the roof or shell can accumulate and reside for long periods of time.	The insulation must be removed. Usually in a spot-checking manner where amount of insulation removed is based on the amount of corrosion found. Visual inspection of exposed surfaces.	The best means of prevention is through proper specifications and installation with quality controls in place.
Cavitation	Another damage mechanism is cavitation, which is most often observed in pump casings, pump impellers (low pressure side), and in piping downstream of orifices or control valves. Damage can also be found in restricted-flow passages or other areas where turbulent flow is subjected to rapid pressure changes within a localized region. Examples of affected equipment include heat exchanger tubes, venturis, seals, and impellers. There is little that inspection of the tank per se is capable of to reduce cavitation.	Pump casings and impellers; control valves or piping just upstream of pumps.	Not common and no documented failure cases in tanks.	Design issues related to NPSH, piping design, temperature of liquid.	Visual when pumps or valves are removed for inspection.	This damage mechanism is too far removed from typical inspection practices associated with tanks to be included as part of a typical tank inspection program.
Fatigue	Fatigue is classified as either mechanical or thermal. Mechanical can be caused by vibration (usually of small diameter piping or tubing connected to vibration sources such as compressors). This mechanism also covers cyclic service where equipment stresses are cycled from high to low. Thermal fatigue is caused by repeatedly cycling the temperature.	Vibration, mechanical, and thermal fatigue are covered in the next rows.	See below.	See below.	See below.	
Vibration fatigue	Vibration induced fatigue is not uncommon with rotating machinery such as pumps and compressors, it is not common in storage tanks. Small diameter piping for instrumentation and control lines that are attached to vibrating equipment are subject to fatigue cracking. However, this is unlikely on the storage tanks since there is no vibrating or rotating machinery.	Piping and tubing	Vibration fatigue is found in small diameter piping components. Mechanical fatigue is worst at the junction between the shell and the bottom welded joints. Thermal fatigue is found wherever a component is subjected to multiple thermal cycles.	Vibration fatigue is not common on LNG tanks. Mechanical fatigue is not common and so far has not resulted in a cryogenic tank incident. Thermal fatigue is unheard of for cryogenic tanks. Considered inapplicable.	Detection requires knowing where to look and use of crack finding NDE methodologies.	Because vibrating equipment such as compressors are not directly connected to tanks or in proximity to the tank piping, this is not considered a routine inspection issue. If, however, the inspector notices vibration, then it should be reported for further analysis.
Mechanical fatigue	The shell to bottom joint of a tank is subjected to high stresses every time the tank is filled and emptied. The work in Section 8, Fatigue Damage showed that fatigue failure of both existing and new LNG tanks is unlikely over any reasonable life span resulting from numerous fill-empty cycles. However, if the LNG tank's inner steel tank is being internally inspected, then the shell-to-bottom interior weld (which is where fatigue cracking could occur) should always be inspected, especially for older tanks that have seen many fill-empty cycles.	Fatigue cracks can develop on the inner weld of the corner joint of the inner tank.	Fatigue depends on the number of fill-empty cycles over the life of the tank. To date there have been no mechanical fill related incidents. No documented cases of	Never has occurred. See Task 12.	Inspection can only occur when the inner corner weld of a container is available for NDE.	Inspection of fatigue cracks should always be conducted at the inner corner weld of the inner tank when it is available for inspection.

			tank mechanical fatigue failures exist.			
Thermal fatigue	Fatigue cracking caused by large temperature changes and material constraint. Thermal fatigue is not an expected issue since the warmup and cool down cycles occur only a few times, if at all, during the life of the tank. The inspection for mechanical fatigue will also detect thermal fatigue cracking damage. However, more study in the area of thermal cooling is needed to positively rule out this damage mechanism.	Typically not applicable because at most there are only a few warmup/cooldown cycles in the life of an LNG tank	No documented cases exist.		Filling and emptying tank can result in failure of the shell to bottom weld of the inner tank.	Inspection for mechanical fatigue will also pick up thermal fatigue cracks or failures.
Thermal expansions of blocked liquid lines	When a hydrocarbon liquid is trapped or isolated between two valves the change in ambient temperature can cause the pressure rate of change to be 80 psi per deg F, causing rupture of lines and leaks in valves and fittings. Small tubing and piping connected to the tank or long lines connecting to the tank can be blocked such that expansion is impossible. This puts them at risk of over-pressuring the tubing, piping, or fittings. The inspection contractor can work with the owner/operator to determine if it is acceptable to block in any lines or LNG components on or associated with the tank to determine what the risk level is. The inspection agency should document these findings and specify the safeguards to prevent thermal expansion overpressure, such as a "car-sealing" system, locking and tagging procedures, and so on. However, it should be noted that this is often an operational aspect of LNG facilities and would not be delegated to an inspection agency which may have little familiarity with the valve configurations and operations that could result in the problem of thermal expansion in blocked lines.	Where valves can trap liquid volume with no room for thermal growth	Has happened and in one case caused severe damage to an LNG facility and included a fire.	Usually operational error combined with a design that does not have thermal relief valves.	An engineering/operations review in a hazop[1] would likely pick up this kind of problem. However, the entire piping systems would have to be reviewed.	A design review for all plant modification as well as MOC involving piping should always contain a provision to check for liquid thermal relieving capability for all segments of piping.
Hydraulic transient	Sudden filling operation or high velocity flow which are quickly stopped can result in "water hammer" resulting possible rupture of lines. Elevation changes and pumps can aggravate these transients. Hydraulic transients, or "water hammer", occur in piping of long lengths where the flow is suddenly stopped either by valves, loss of power to pumps, unique flow problems associated with elevation changes. Based on physical principles, if the valve closure time is short, then a shock wave rings through the system at the speed of sound in the liquid, with peak pressures that can be above the design pressure. In some cases, the piping can rupture, or gaskets can blow out. In addition, flanges can experience some bolt expansion causing transient loss of liquid. This phenomenon has occurred in one documented incident on the inlet piping to an LNG tank. The mitigative measures are proper design and operation. Inspection has little ability to detect or reduce the likelihood of these types of events.	Inlet filling line or other liquid flowing lines	Not common but has happened (see incident 20190006 in Deliverable 7)	Hydraulic transients, also known as surge or water hammer, occur when flow rates are changed such as by valves or pumps. Longer piping systems increase the probability of damaging surge. Quicker valve closures or sudden power outages that "kill" pumps aggravate surge.	Engineering analysis is required to determine when surge is significant. Inspection is ineffective for this damage mechanism.	The one documented case of a transient that ruptured a piping and caused cracking of the vapor container requires more study and examination to determine exactly how the transient was generated.
Excess Vacuum						
Excess vacuum in out-of-service tanks	Vacuum buckling of tank shell. While this type of failure is rare, it is possible under specific circumstances. For out of service tanks, no LNG collapses due to vacuum developing on either inner or outer tanks were found in the research for this project. However, it happens regularly on normal petroleum tanks due to maintenance workers covering the tank vents. This means that it is possible to occur with LNG tanks. The scenario usually initiates from either an intentional closing or	Buckling occurs on the shell but often damages the roof structure.	Not common and no documented failure cases for LNG tanks but has happened numerous times for petroleum storage tanks.	The most common cause of this damage mechanism occurs when the vents to the out of service tank are blocked for some	This damage mechanism requires that contractors performing any out of service work are aware of	There are no documented cases of this occurring in cryogenic tanks, but this is relatively common for ambient temperature tanks.

[1] Hazard and operability study.

	blocking of the vent valves for maintenance reasons by covering the vent, or closing it off by blinding or by use of blanks. When the ambient temperature cools, the shrinkage of air inside the tank and the sealed-closed vent cause a partial vacuum to develop, which is sufficient to collapse a tank. Owners and inspector should review the owner/operator standards and procedures to determine when and how tank vents are covered and what safeguards exist to prevent excess vacuum, such as continuous monitoring of vacuum by personnel when pressure relief valves for vacuum are out of service for maintenance or not properly operating.			reason due to operational needs.	this phenomenon and have preparedness plans to prevent it.	
Excess vacuum in operational tanks	While the research for this project did not find any LNG tank collapses due to failed vacuum valves that stick closed, it happens regularly on normal petroleum tanks due to sticking vent valve pallets. The sticking of vent components is often due to the nature of the product, which can leave a gummy or sticky residue. Since cryogenic industrial gases have no such residue, the risk is lower. While the problem is worse with dirty or sticky services, it is possible for this to happen with cryogenic tank venting devices due to failed vent valve components. Having multiple redundant vents is a key safeguard to prevent this failure mechanism from damaging the tank. In addition, regular testing and inspection of these devices is an important safeguard. The inspection agency should review the owner/operator procedures for testing and inspection of these devices.	See above.	No documented cases of this occurrence in cryogenic tanks.	Failure to remove car seals, blinds, or blanks after maintenance that requires them to be blocked. Another cause is sticking vent valve components caused by debris or rusting or failure of controls.	Systematic and periodic review of all vents to ensure they are operative.	Routine inspections should include a review of these devices.
Mechanical damage	Damage to internal or external tank caused by construction or by impacts or incidents. Damage caused by terrorism and intentional acts is not covered. Mechanical damage is caused by near or adjacent construction, equipment, or operations that causes mechanical impact damage to the outer tank or the tank piping or roof. One example of this is pulling pumps from tanks either using local davits or external cranes. Responsible operators will assess the potential mechanisms resulting from maintenance, construction or other local activities that can damage the tank either before commissioning or while the tank is in service. Resulting damage should consist of a fitness for service assessment according to API 579, regardless of when the damage occurred (i.e., during construction or in operation). The most likely initiation of this mechanism is tipping over of cranes, dropping crane loads, inadequate crane lifting plans and procedures, or working with heavy equipment too close to tanks. The owner/operator should have procedures that require rigging and lifting plans for all lift operation on or near the tanks.	Any point above the ground on shell or roof.	Not common in industry but does occasionally occur.	Inadequate crane lifting plans, heavy equipment operating too close to tank.	Visual	The common thread is that any damage, no matter how minor, should be subjected to formal analysis and the results documented and kept on file by the owner/operator.
Temporary repairs	Temporary repairs and incorrectly done repairs can lead to cracking, failed gaskets, or other potential scenarios. Temporary repairs should always use MOC in the execution processes. Roof repairs can be in the form of sealants, cold work, or even hotwork under controlled conditions. Most repairs are "temporary) and can fail unexpectedly. Temporary repairs to steel shells and roofs or piping are addressed here. While this research project did not find a documented case of LNG repairs that were "temporary" but which later failed, this kind of damage mechanism occurs regularly with conventional petroleum storage tanks. The extraordinary cost	Shell or dome structure of outer or inner tanks. Sealed, caulked, or puttied joints can leak. An example is a platform roof leg resting on a repad which is not fully sealed to the environment. This can trap water causing a corrosion hole and eventual gas leak.	Uncommon but has occurred (see 20210006 incident in Deliverable 7)	Failure to document repairs and assign a maximum life for the repair.	Visual	All repairs should have a documented MOC and an assessment for integrity over time with an inspection plan identifying when to inspect, how often to inspect and what condition should trigger taking the tank out of service for permanent repairs.

	and business interruption issues associated with taking tanks out of service for repairs dominates the choice of whether or not a temporary repair can or should be made. When it is decided that a temporary repair can be made, the problem is that a time limit on the repair is not usually formally adopted. In addition, temporary repairs that involve small cracks are often sealed with epoxy or by other means and formal fitness for service analyses are not conducted with little to no documentation of the repair. Fitness for service analyses should always be done on any repairs to understand and bracket the possibilities for failure. In addition, a strict monitoring program specifically designed for the repair should be put into place with specified intervals for visual and physical inspection and testing or analysis. The temporary repair is "temporary", and a lifetime limit should be specified clearly at the time of the repair and be assigned to a monitoring/inspection program, which should be available to all involved parties in operations or inspection.					
Improper liquid level	Improperly designed liquid levels or operational errors can allow sloshing waves to impact components above the design maximum liquid level. Normal operations should observe the principles of maximum liquid levels and filling tanks as outlined in API 2350 Overfill Protection for Storage Tanks in Petroleum Facilities. The freeboard requirements of API 625 should be observed to reduce the likelihood of damaged caused by seismic event sloshing waves.	Damage to suspended roofs. Possible damage at the roof to shell junction.	Uncommon. No reported incidents.	Improper overfill prevention measures or standards. Improper operation.	Visual	API 2350 for overfill prevention should be reviewed to ensure that all key principles are incorporated into the equipment and operational aspects of filling cryogenic tanks.
Adjacent structure flexibility	Inadequate design for flexibility between structures connected to or attached to the tank system may be damaged by relative movement. The tank-foundation system can be considered one structure, and anything attached to the ground such as platforms, stair wells, or equipment towers can experience relative movement either from settlement of the tank system or from seismic action and even high winds. Unless designed for these relative displacements, the resulting forces can initiate damage to the structures. These failure initiators are best addressed in the design phases of any of these installations. However, they are relatively easy to spot by an experienced inspector. Therefore, inspection has high value for this damage mechanism.	Attached platforms, ladders, stair systems, piping, etc., if not sufficient flexible for shaking due to wind or seismic may be damaged.	Not common since large forces are required such as seismic to produce these relative movements. More common is relative movement between the foundation and structures connected to both the tank and the ground or other independent structures.	Omissions in engineering to consider these effects.	Visual	
Instrumentation, controls, and electrical	Faults that render final elements to not act properly or ESDs often trigger many final elements to move the systems to a safe state. Improperly reading sensors can cause problems such as overfills. Instrumentation loops consist of sensors, logic solvers, and control through final elements (valves). A single complex logic solver may control many loops and these devices (usually PLCs) can occasionally fail. These systems are generally set up to fail in a safe state. These systems often trigger an emergency shutdown. An inspection company for general tank inspections is unlikely to be able to diagnose and assess these systems. It is up to the operator to develop either in-house or contractors to perform specialized tests for the ESD and other control functions. Several incidents have occurred because conduit fittings were not sealed between electrical area classifications. The sealing prevents flammable	Failure to ensure conduit junction boxes are sealed and gas tight has caused a few incidents, one of them major[2].	Uncommon that incidents occur, but prevalence of failure to seal conduits between various electrical classification areas is unknown.	Migration of flammable vapors through conduits.	Must open conduit fittings and test them both visually and other methods to ensure they do not pass gas.	This verification should be done not only at the end of any major construction project buy anytime any electrical repair work is conducted. It can be done one time if the inspections are documented. Most of the time this is not done rigorously.

[2] Cove Point, MD, 1979.

	gases from flowing through conduits where there are potential ignition sources.					
Wrong materials	Without careful control over materials the wrong material can enter into construction or repairs. This can lead to failure by cracking or inability to obtain a good weld. Wrong materials have caused incidents, such as a valve replacement with the incorrect material that cracked due to exposure to cryogenic temperatures. Wrong materials can creep into new construction but are more likely to enter the scene during repairs. The correct materials are important to prevent initiating events such as cracking, accelerated corrosion, low strength and so on. A robust positive material identification program should be in place for any materials used on the tank. Refer to API 578 for control of materials used in construction and repairs.	Any material in the new construction, but more likely material used in repairs that is not engineered and controlled. One incident in 1977 occurred as a result of wrong aluminum alloy in a replacement valve that releasing LNG but did not initiate ignition[3]	Not common	Inadequate management systems and controls and misdirected motivations.	Can be controlled with a positive material identification program.	
Purging	Procedures to start up a tank system such as a cooldown operation, operation of the flare, and many others require rigorous planning and safety assessments called pre-startup safety review. Some of the worst incidents have been caused by line cleaning of new lines to remove slag and debris, i.e., purging. Purging is the process of blowing natural gas at a high enough velocity to remove weld slag and debris from new lines, which was common until about the 2010s. It may still be used. However, it has led to serious incidents. The rules of thumb for purging safely are (1) use nitrogen or air instead and (2) do not depend on sense of smell to detect dangerous levels of natural gas as it is unreliable; instead used combustible gas indicators. Never purge inside buildings, structures, or closed space using a flammable gas. To our knowledge an incident due to purging has not occurred with LNG tanks.	During startup for line cleaning purging operations to remove weld slag and debris for new lines is a common process. When using LNG purges, a serious result can occur[4]. Any component is susceptible. The Plymouth incident showed that shrapnel ejected from flying debris can puncture the outer tank and break off piping connections to the tank	Uncommon	Failure to ensure that all local ignition sources are contained, estimating of where the purge gas is going, testing for flammability of any purge gas.	The inspection for prevention of this type of incident is specific to the operation involved and must be implemented and enforced by the owner.	There have been enough serious purge gas incidents that a detailed review of all aspects of the operation should be reviewed with safety experts and the controls to minimize risk inspected under the direct supervision and enforcement of the owner/operator.
Loss of power	If a facility loses power for too long, then the tank can warm up and the boiloff gas can vent to the atmosphere, creating a flammable vapor cloud. This has happened in the industry at least twice. Loss of power has led to several incidents. In one case, the power was off long enough for fuel in the backup generator to run out, which led to the tank warming enough to pop the relief valves and emit natural gas. While there is little that can be done to prevent loss of power from an independent source such as a utility, the facility owner/operator can preplan to the extent possible. For example, the anticipation of an extraordinary event where the facility is inaccessible for long periods of time due to a natural disaster might lead to examining the need for larger backup generator fuel tanks for longer service times.	While there are no components that are damaged, the generation of a vapor release is hazardous.	Uncommon	Loss of power	None	Best guidance is to preplan for this scenario and have procedures that address both normal and abnormal operations.
External Events	LNG facilities tend to be large complex facilities where the storage tanks are only one of many LNG engineering systems. If an explosion occurs within an LNG facility, metallic shrapnel can puncture the tanks and break lines and valves[3]. A significant risk for LNG storage tanks is external hazards such as nearby explosion blasts, external fires, terrorist activities, foundation settlements, seismic, and flooding.	Any component on the exterior of the tank is susceptible to impact and potential release of liquid LNG.	Uncommon but has occurred in the industry.	Initiating event is explosion	None	Visual inspection to determine vulnerabilities to ejecta from explosions could be used to determine if additional safeguards would have benefit.

[3] Arzew, Algeria, 1977. https://www.energy.gov/sites/prod/files/2018/11/f57/draft-eis-0531-port-delfin-lng-app-r-2016-07.pdf
[4] Plymouth, WA, 2014, peak shaving plant incident.

	Since LNG tanks are combined with numerous LNG processing and support facilities, explosions which can eject shrapnel that has the potential to damage the LNG tanks are possible. The notable 2014 Plymouth, WA incident propelled debris with sufficient impact to breech the outer container of an LNG tank and dent the inner tank. The loss of Perlite insulation also caused generation of boiloff gas, resulting in the generation of a vapor cloud, leading to the entire facility shutting down. Some debris also damaged an instrumentation pipe associated with the tank causing a release. The release was stopped by shutting off the root valve at the tank. Owners/operators can usually consider these scenarios in PHA or other risk analysis or HAZID meetings and attempt to build some resiliency into the systems that exist. A visual inspection conducted by a specialized team of experts commissioned by the owner/operators might assist in determining the process areas from which explosions are most likely to occur and what the exposure of the tank is to ejected debris. For natural disaster events such as seismic, external fires, flooding events and others, the best practices are to design to the current industry standards. The importance of inspection to ensure compliance with industry standards on new construction cannot be over emphasized. Terrorism is not addressed in this report.				
Flange and gasket failure	Thermal changes cause bolts to unload the stress during cooldown and cause leakage. Improper gasket type and bolt torquing also can result in releases. When there are sudden temperature changes, such as a cooldown, the flange reaches the low temperature quicker than the bolting, and as a result the bolt tension is reduced temporarily. This can cause releases. Gaskets can also fail and generate releases for many reasons, with improper bolt torque being perhaps the most common cause. There is little that inspection can do to mitigate the problem and it is not considered feasible to include flange bolt torques or proper gaskets into an inspection program, since the components are covered with insulation and typical tank inspectors have little expertise in this area. Rather, it is important for the owner/operator to ensure that the controls for piping, component, and gasket selection, including design and installation, are in place and rigorously inspected and controlled at the time of installation to ensure that specifications are met, proper materials used, and that all bolt torquing is done reliably and to specifications.	Flanges, gaskets	Not uncommon	Thermal changes, bolt torque, material selection	Not feasible for general in-service inspections. Inspections must be conducted during installation process
Static electricity	In one incident, the lifting operation of a pump for maintenance generated a static spark, resulting in a small fire on the pump. The most likely location for static to impact the tank is on the roof when work, lifting, maintenance, or repair operations are in progress. All metallic components used in these operations, including tag lines, should be bonded and grounded to reduce the potential for a spark to occur. This type of event is not implemented by tank inspection agencies as this type of event is directly related to the owner/operator maintenance and operations. However, the owner/operator can do a job specific inspection or observation by an independent safety person to ensure that the appropriate static electricity mitigative procedures are being complied with by the maintenance or repair crew.	Pumps	Uncommon but has occurred once	Static	Focused inspection when any work will release small amounts of LNG to ensure that all equipment, lifting lines, and equipment is bonded and grounded.

Table 2 Damage Mechanisms Unique to Cryogenic Tanks

Damage Mechanism	Description	Susceptible tank components	Prevalence or likelihood	Causal factors	Primary inspection techniques	Comment
Rollover in LNG tanks	Rollover occurs when there are layers of LNG with sufficiently different densities that they can stratify within the tank. The large amount of vapor that is quickly generated can damage the roof and generate a dangerous vapor cloud. When evaporation of light ends occurs, or when nitrogen is released from the upper layer, the light layer may trade places with the heavy layers which can rapidly evolve vapors due to the sudden reduction of hydrostatic pressure on what is now the upper layer. The tank must have sufficient venting capacity to handle the vaporization, otherwise an overpressure could result. The typical control is to monitor the temperature, density, and hydrostatic pressure at as many points vertically through the liquid as possible. Different withdrawal points help to prevent layer build up. Additionally, if it is operationally feasible to recirculate LNG, the likelihood of rollover is reduced. This type of event is not implemented by tank inspection agencies as this type of event is directly related to operations. However, the owner/operator should review the physical properties data to assess the danger presented by the rollover. The owner/operator should also review the safeguards that are in place and the procedures aimed at reducing rollover and look for possible improvements and modifications that reduce or mitigate the consequences.	Possible over pressure of tank.	Not common but has happened in industry.	Operations, composition of product received.	Inspection is inapplicable to rollover.	A systematic review of all known rollover events should be conducted at an industry committee or government level to develop the best mitigations. However, this is not an inspection issue.
Thermal shock	Thermal shock can occur when the tank is subjected to a sudden and rapid decrease in temperature such as when first filling a warm (ambient temperature) tank with cryogenic liquid. This damage mechanism can lead to warped steel bottoms and shells and lead to cracking of welds. However, the concern is addressed by both design and operations. The design phase spargers, spray nozzles, or liquid distributors and flow rate control are used to reduce the rate and extent of sudden cooling to non-damaging levels. This type of event is not implemented by tank inspection agencies as this type of event is directly related to the owner/operator maintenance and operations.	Mostly the bottom and bottom to shell joint are affected.	Unlikely given operating procedures are followed and design rules of API standards are complied with.	Uneven thermal contraction and high rates of uneven cooling.	Other than internal inspections to review the cooling control systems there is little that can be done in terms of inspection.	
Insulation compaction	Insulation systems must be thoroughly sealed from the atmosphere to prevent atmospheric moisture from condensing on cold surfaces, expanding and further damaging the insulation. One indicator of failure in the insulation vapor barrier systems is the formation of cold spots that result in an “ice ball” or ice formation which indicates a potential insulation failure. An LNG leak will manifest itself in the same way in some cases. An inspector can visually check the tank for cold spots or ice balls. In addition, the use of thermal imaging is helpful in determining where there are cold spots. Each such location must be individually investigated and considered to determine the cause of the low temperature. In addition, thermocouple networks that are originally installed in the tank system assist with determining insulation failure. Temperature records collected by these networks of sensors establish a baseline from which fluctuations can	Tank shell and attached piping and fittings and valves	Common	Perlite compaction, long term deformation and compression of insulation blankets, original insulation	Thermal imaging of outer container for cold spots.	While finding insulation problems is relatively easy, correcting them is much more difficult. The inspection agency should identify all such

	be tracked through time and which will help to determine if some of the sensors are moving away from the baseline. In this case, the inspector can look further into the potential causes of long-term changes in the thermal sensor records. Thermal imaging of the outer tank is highly effective for determining whether there exists a leak or insulation failure.	filling operation that does not uniformly fill the interstice.	findings, but the owner/operator must further assess the impact of heat leakage into the tank and the associated piping.

Table 3 Component Risk and Inspection Effectiveness and Priority for General Damage Mechanisms

Damage Mechanism	Potential Risk Scenarios	Likelihood L, M, H	Consequence L, M, H	Risk level VL, L, M, H, VH	Inspection Effectiveness L, M, H	Inspection Priority L, M, H	Comment
Concrete cracking and spalling	Repairs required; potential business interruption for severe damage	L	L	VL	M	L	
General and Localized Corrosion							
Atmospheric Corrosion	Small gas release; could escalate to small fire but unlikely to escalate further	M	M	M	M	H	
Corrosion Under Insulation	See above	M	M	M	M	H	
Cavitation	Business interruption for repairs	L	L	VL	L	L	
Fatigue							
Vibration fatigue	Small release; could escalate to fire	L	M	L	H	L	Once ruled out as a mechanism, can be dropped from future inspections
Mechanical fatigue	Major release	L	H	M	L	H	Perform when inner tank inside corner weld available for inspection
Thermal fatigue	Major release	L	H	M	L	H	Perform when inner tank inside corner weld available for inspection
Thermal expansions of blocked liquid lines	Release	M	M	M	L (M) see note 4	L(H)	
Hydraulic transient	Release	L	M	L	L	L	
Excess Vacuum							
Excess vacuum in out-of-service tanks	Business interruption	L	M	L	L (M)	L (M)	Whenever tanks out of service
Excess vacuum in operational tanks	Business interruption	L	M	L	L (M)	L (M)	Should be periodic inspection for tanks in service.

Mechanical damage	L	M	L	L (H)	L (H)	Pre job safety inspections should be effective
Temporary repairs to shell or roof (steel)	M	M	M	L (H)	L(H)	
Improper liquid level	L	M	L	L (H)	L (H)	
Adjacent structure flexibility	L	H	M	L (H)	L (H)	
Instrumentation, controls and electrical	M	M	M	L (H)	L (H)	
Wrong materials	L	H	M	L (H)	L (H)	
Purging	L	M	L	L (H)	L (H)	
Loss of power	M	M	M	L (H)	L (H)	
Projectiles from facility explosions	L	M	L	L	L	
Flange and gasket failure	L	L	VL	L	M	
Release from inner tank cracking outer tank	M	M	M	L	L	
Static electricity on roof operations such as pump removal	L	M	L	L (M)	L (M)	

Notes to table:

1. Five risk levels in increasing order are very low (VL), low (L), medium (M), high (H), and very high (VH).
2. Each owner or user of this system decides on what the inputs are. If a group meeting is used for risk assessment, then the single valued ranks are achieved by consensus. Two different people or organizations do not necessarily have to have repeatable results for a given risk assessment exercise.
3. The inspection effectiveness and priority columns are independent of the risk scoring columns but use judgement based on the risk scores.
4. The dual scores for the inspection effectiveness and priority columns are due to the control the owner/user may exercise of the results and depends on how actively the owner/operator is participating actively in the inspection process. For example, in thermal expansion of blocked lines, a contracted inspector will not know the operations and likely not have P&IDs and will not consider checking for line blockage which is typically not in inspector's domain of work. But an owner can and should do this every time there is an operational change involving changing valve positions. This can be captured by procedures as a one-time exercise. The owner can also walk down the lines searching for potential locations where valve configurations can trap liquid. Therefore, the owner controlled specifically focused inspection for this damage mechanism can be more effective than the general inspection contractor inspection in this damage mechanism. This gives rise to the dual score L (M) for inspection effectiveness and L (H) for inspection priority.

Table 4 Component Risk and Inspection Effectiveness and Priority Unique to Cryogenic Tanks

Damage Mechanism	Potential Risk Scenarios	Likelihood L, M	Consequence L, M	Risk level L, M, H	Inspection Effectiveness L, M, H	Inspection Priority L, M, H
Rollover in LNG tanks	Reversal of LNG layers in tank with differing densities	L	H	M	L	L
Thermal shock	Uncontrolled high-rate filling of cryogenic liquids into a tank can suddenly cause materials to contract with associated damage. Instead, well designed systems apply flow control, design for sprays and spargers, and liquid distributors to keep as large an area of the bottom from cooling certain areas too quickly.	L	M	L	L	L
Insulation compaction	Breaches in insulation vapor barrier and tank shell insulation result in ice buildup.	M	L	L	H	M

Appendix 5 Fatigue Analysis on LNG Primary Containers

1. Analysis overview

The highest stresses relevant for fatigue analysis are shown in Figure 1. Hydrostatic pressures force the angle between the bottom and shell on the liquid side of the tank shell to bend beyond ninety degrees thereby introducing stresses into the corner joint tending to open cracks as shown. Cracks at location 1 or location 2 if large enough can lead to unstable crack propagation. Finite element analysis using the principles of fracture mechanics and conducted under the rules of API 579 and the ASME BPVC were used to determine how many complete fill cycles would be of concern for potentially causing failure.

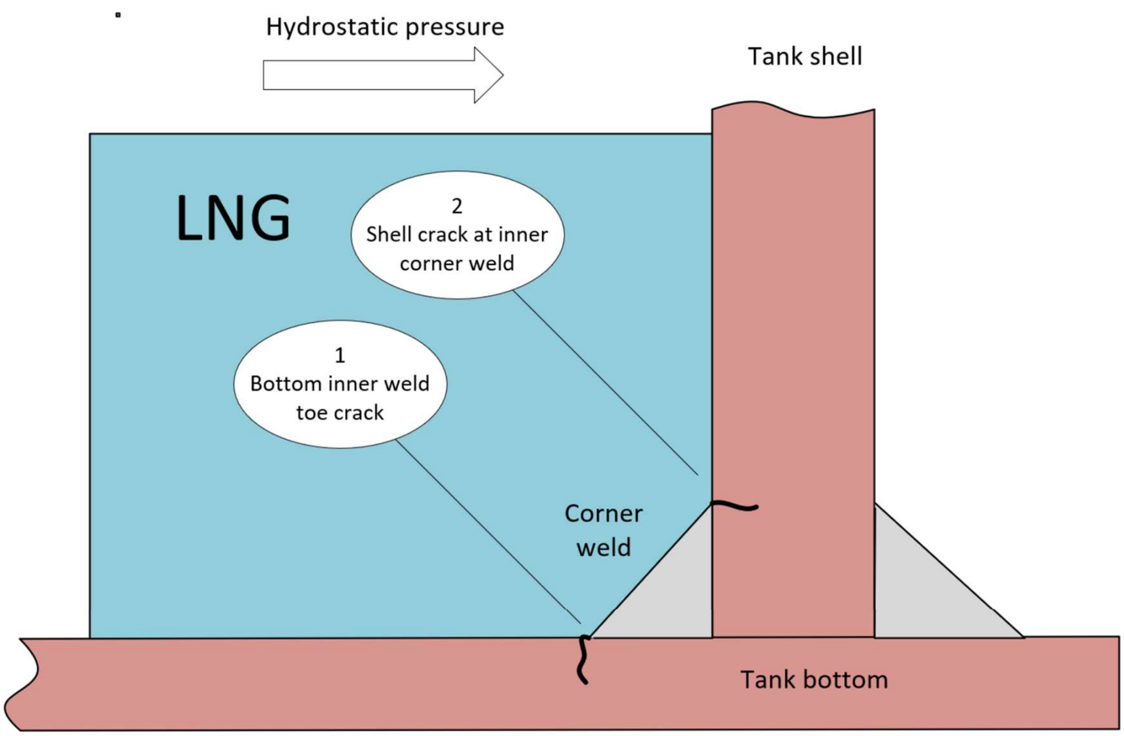


Figure 1 Locations of potential fatigue failure

In an attempt to acquire as general an answer possible to this problem, PEMY performed a fracture mechanics-based fatigue crack growth assessment. This was considered more apt than a typical SN approach because (a) inspection results can be associated where in the fatigue life the tank is based on crack size (b) all welds have indications and the limits of NDE allow for the existence of cracks of a limiting size below which there may be many and (c) the SN curve methodology and test data was originally based on smooth bar fatigue tests that are not representative of welds. While ASME has recently introduced another fatigue methodology for welds, it does not provide fatigue curves for 9% nickel.

2. Two model tanks

A parametric study covering all of the basic sizes of LNG tanks would be the best approach to modeling potential fatigue cracking, however, in this project limited resources required optimization of the models. The two model tanks based on realistic representations of LNG tanks were selected for this analysis. The large tank tends to be representative of the newer post-2000 tank population of high volume and highly cycled storage tanks. The smaller tank is intended to be representative of the older existing population of pre-2000 LNG tanks. The models only considered steel tanks (not considering other material such as aluminum or stainless steel).

Two tank sizes were analyzed:

- 255 ft ID, 1M bbl
- 164 ft ID, 300k bbl

One of the variables was annular plate thickness to determine how thickness affects fatigue life and to determine which of the two flaws (indicated in Figure 1) govern life.

We also considered the fatigue life as a function of sensitivity to the stress profile location (to evaluate the corner weld effect), sensitivity to the foundation stiffness, and sensitivity to the starting crack size which were also evaluated to ensure that the modeling artifacts and assumptions did not significantly impact accuracy.

3. Material properties

- The tank materials were assumed as A553 9Ni steel.
- Elastic modulus, density, and Poisson's ratio were estimated from Table TM-1 and Table TRD of ASME Section II, Part D:
    - Modulus = 29.4×10^6 psi
    - Density = 0.284 lb/in^3
    - Poisson's Ratio = 0.3
- Fracture Toughness
    - 117 ksi-in$^{0.5}$ = 129 MPa-m$^{0.5}$
    - Fatigue Crack Growth Properties
        - ΔK_{th} = 0.0 (no threshold- conservative assumption)
        - Paris Law Coef = 5.07×10^{-10} (in,ksi) = 9.70×10^{-12} (m,MPa)
        - Paris Law Exponent = 3.0
- The stress analyses were performed assuming elastic material behavior.

The low temperature assumed yield and tensile properties for the nickel steels are stated below and in Figure 2 obtained from manufacturer literature:

- Yield = 105 ksi (@ -260^{o}F)
- Tensile = 155 ksi (@ -260^{o}F)

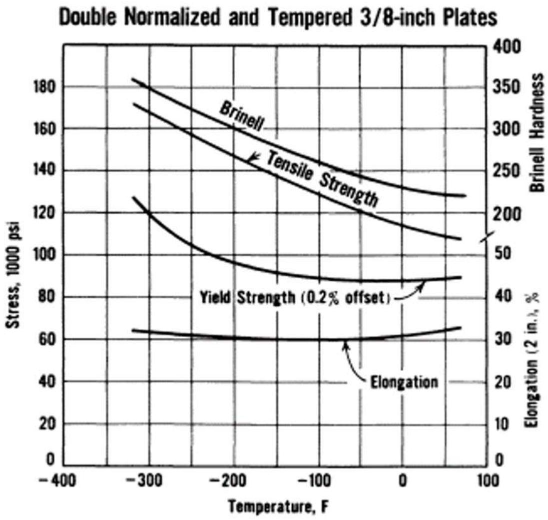


Fig. 22. Effect of temperature on hardness and tensile properties of 9 per cent nickel steel in double normalized and tempered condition.[52]

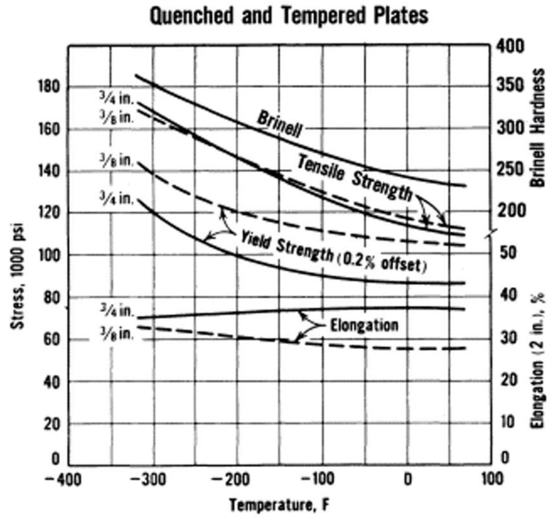


Fig. 23. Effect of temperature on hardness and tensile properties of 9 per cent nickel steel in quenched and tempered condition.[52]

Figure 2 Mechanical Properties of 9% Nickel Steel at Cryogenic Temperatures
From "Low-Temperature Properties of Nickel Alloy Steels" No 1238, INCO, the Nickel Institute.

The material properties associated with fracture toughness are stated below and obtained from the Welding Research Council publication 205 shown in Figure 3:

- 117 ksi-in$^{0.5}$ = 199 MPa-m$^{0.5}$

Table 22—Lower-Bound Fracture Toughness Values 95% Confidence Level, Obtained from Reported Data

Steel	*Location*	*Temp.*	*Criterion*	*Value*[a]
A353	Base metal	−196° C	K_c	112 (125)
		−170° C		150 (165)
		−196° C	COD	0.004 (0.1)
		−170° C		0.007 (0.17)
	HAZ	−190° C	K_c	95 (105)
		−170° C		104 (115)
		−190° C	COD	0.005 (0.13)
		−170° C		0.010 (0.25)
A553	Base metal	−196° C	K_c	126 (140)
		−170° C		146 (160)
		−196° C	COD	0.004+ (0.11)
		−170° C		0.010 (0.25)
	HAZ	−196° C	K_c	117 (130)
		−170° C		121 (135)
		−196° C	COD	0.004 (0.10)
A645	Base metal and HAZ	−170° C	K_c	120 (132)
			COD	0.010 (0.25)
A203	Normalized base metal	−75 (−60)	NDT	. . .
		−75 (−60)	K_{ID} (calc.)[b]	60 (66)
	Q & T base metal	−110 (−80)	NDT	. . .
		−110 (−80)	K_{ID} (calc.)[b]	71 (78)
A203A	Norm. base metal	−90 (−70)	K_{ID} (calc.)[c]	60 (66)
	Q & T base metal	−90 (−70)	K_{ID} (calc.)[c]	72 (79)
A203D	N & SR base metal	−110 (−80)	NDT	. . .
		−150 (−100)	K_{ID}	45 (50)
		−100 (−75)	K_{ID}	65 (72)
	Q & T base metal	−130 (−90)	NDT	. . .
		−150 (−100)	K_{ID}	60 (66)
		−100 (−75)	K_{ID}	100 (110)

[a] K_c in ksi$\sqrt{\text{in.}}$ (MPa$\sqrt{\text{m}^{1/2}}$), COD in inches (mm).
[b] K_{ID} calculated from drop-weight NDT, where $(K_{id}/\sigma_y)^2$ is estimated as 0.5.
[c] K_{ID} calculated from Charpy V-notch value by relation, $K_{id} = 13(C_v)^{1/2}$.

Figure 3 WRC 205 Fracture Toughness and Related Characteristics of the Cryogenic Nickel Steels

Paris' law is a crack growth equation that gives the rate of growth of a fatigue crack. The stress intensity factor K represents the stress field or loading around a crack tip and the rate of crack growth is experimentally shown to be a function of the range of stress intensity ΔK in the loading cycles. The

Paris Law equation is $\frac{da}{dN} = C \cdot \Delta K^{m}$ where a is the crack length, $\frac{da}{dN}$ is the crack growth per cycle N and C and m are determined experimentally. The Paris Law data for 9% nickel steel are based on the data in Figure 4:

- ΔK_{th} = 0.0 (no threshold- conservative assumption)
- Paris Law Coefficient = 5.07×10^{-10} (in,ksi) = 9.70×10^{-12} (m,MPa)
- Paris Law Exponent = 3.0

Figure 9 presents *da/dN*—Δ*K* curves of nickel alloy steel against the design curve suggested by BS 7910 [28]. Material constants for nickel alloy steel are summarized in Table 4. With the fixed slope of 3.0, material constant, *C*, of 9Ni is the highest compared to other nickel alloy steels. However, *C* value of 9Ni has about 58% lower than that in BS 7910 [28]. This implies that the *C* value in BS 7910 is very conservative to reflect the material constant associated FCGR of nickel alloy steels in efficient manner.

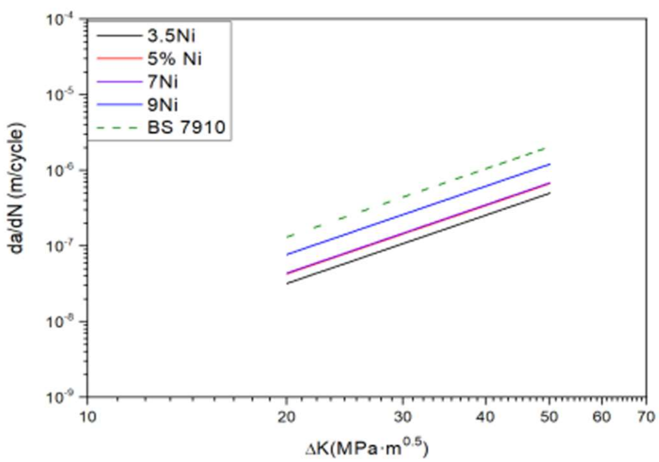


Figure 9. Comparison of FCGR for nickel alloy steels against BS7910 with the fixed slope of 3.0.

Table 4. Comparison of material constants for various nickel alloy steels.

Material	C (m/cycle)	m
3.5Ni	4.01×10^{-12}	
5Ni	5.39×10^{-12}	
7Ni	5.51×10^{-12}	3
9Ni	9.70×10^{-12}	
BS 7910	1.65×10^{-11}	

Figure 4 Effect of Nickel Content on Fatigue Crack Growth Rate and Fracture Toughness for Nickel Alloy Steels

4. Methodology

The analysis of fracture mechanics and fatigue assessments at the shell to plate (chime) weld were conducted per guidelines in API 579 Part 9 "Assessment of Crack-Like Flaws. The internal corner weld was considered for this analysis as it represented the critical location under hydrostatic loading.

- Vertical flaw through plate at chime (opened by radial stress).
- Horizontal flaw through shell at chime (opened by axial stress).

4.1 The analysis applied these steps:

- Extract through-wall radial and axial stresses from FEA results at chime weld.
- Due to elastic material model, artificially high stresses occur at corners of the weld and mesh refinement only increases this stress anomaly. Therefore, stresses were linearized across thickness to mitigate this effect.
- We performed Failure Assessment Diagram (FAD) crack stability analyses (see Figure 5)
  - Reference flaws (1/16 inch depth X 3/16 inch length) were installed at corner weld.
  - As the welds are typically not stress relieved, full residual stresses were assumed based on a yield of 105 ksi.
- We evaluated crack growth of reference flaws and compared the required number of cycles for flaws to grow to critical size to expected number of tank fill cycles.

4.2 Failure assessment diagram (FAD)

The FAD (see Figure 5) evaluates crack stability considering both brittle and ductile failure. The x-axis of the plot is the load ratio (L_r) between the reference stress and the material yield strength. The reference stress is proportional to the far-field stress and is computed based on the loading condition, the component geometry, and the crack size. The y-axis of the plot is the toughness ratio (K_r) which is the ratio of the crack driving force (based on loading and crack size) to the fracture toughness. A point falling under the limiting curve is considered acceptable or safe. A point lying towards the right end of the diagram fails due to plastic collapse. A point lying towards the upper left corner of the diagram fails due to brittle fracture. As an extension to the FAD method, the crack depth and length combinations falling exactly on the limiting FAD curve can be computed. The resulting "Critical Flaw Curve" represents all combinations of flaw length and depth that pose a risk for unstable failure (i.e., are exactly on the FAD curve).

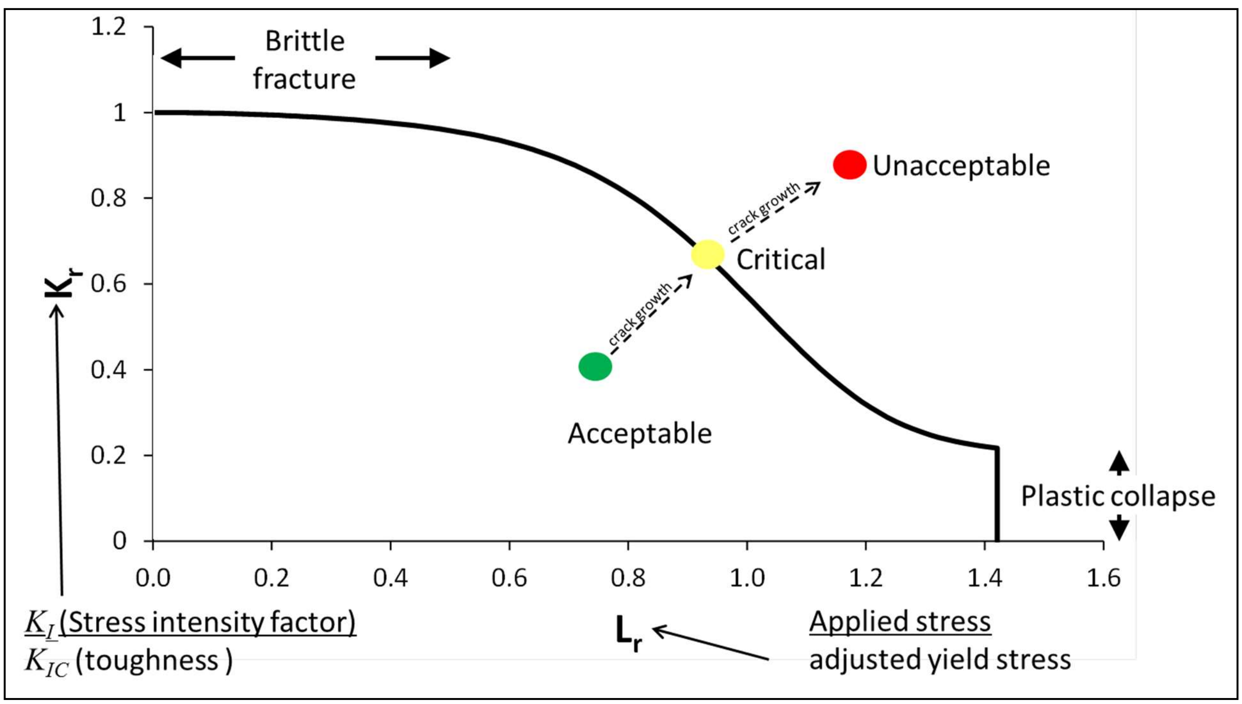


Figure 5 Failure Assessment Diagram (FAD) Concept

4.3 Fatigue Crack Growth

Fatigue crack growth analysis starts with an initial crack and ends when the crack grows to a critical size (as defined by the FAD) or grows through wall (representing a leak condition). Initial crack size is either based on actual detected flaw sizes, or if no flaws are detected, based on a reference flaw. This analysis used the reference flaw size ($^{1}/_{16}$ inch depth X $^{3}/_{16}$ inch length). The result of the crack growth analysis is a plot of crack size versus number of cycles. End of life occurs when the critical crack size is reached. Fatigue crack growth analysis uses the Paris Law with coefficients taken from literature.

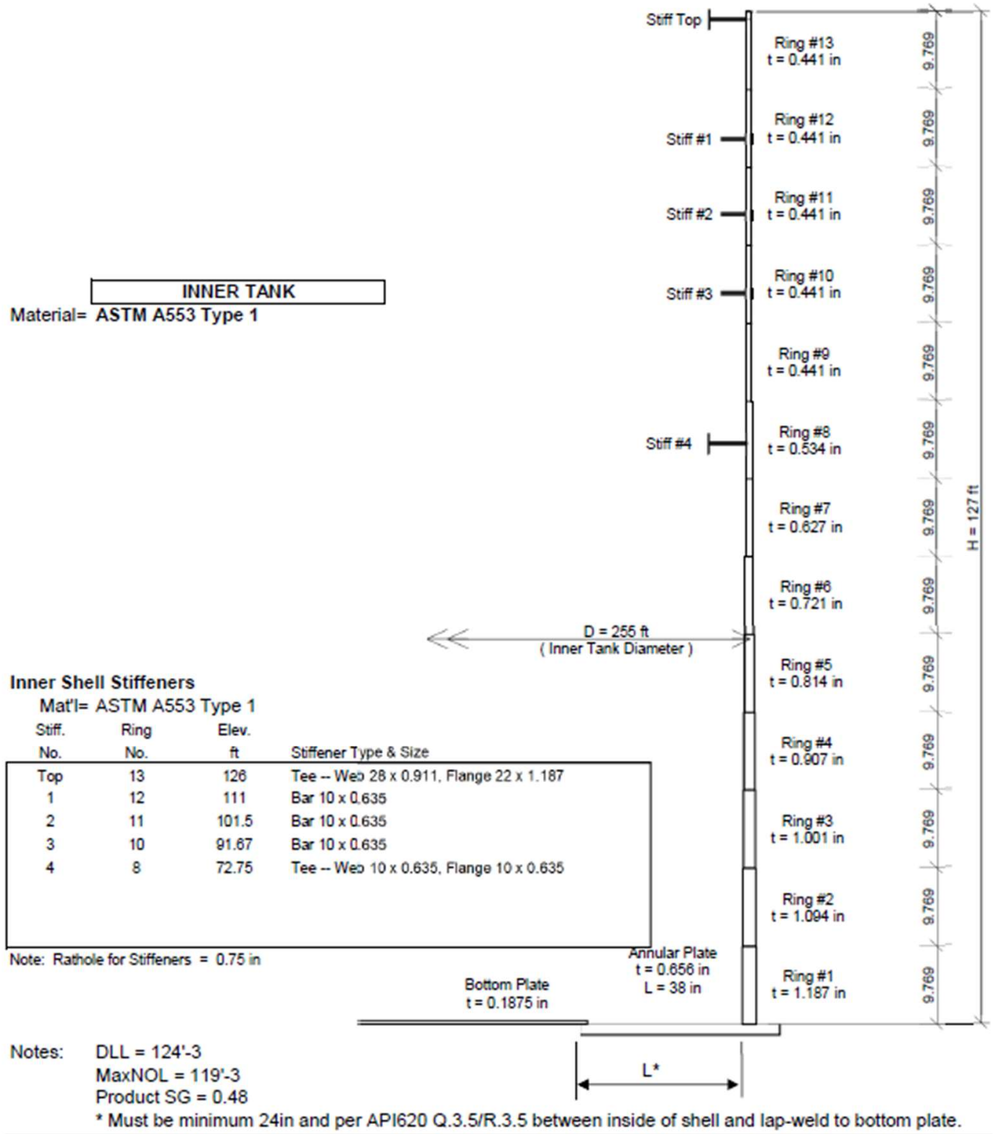
5. Analysis of 1M BBL LNG Tank 1

5.1 Model data

The data for the tank are

- Capacity 160k m3 (approx. 1M bbl)
- Inner Tank Height = 127 ft
- Shell Course Heights = 9.769 ft
- Shell Internal Diameter = 255 ft
- Product Specific Gravity = 0.48
- Design Liquid Level = 124 ft 3 in
- Operating temperature = -260 °F

A cross section drawing of the inner containment tank is shown in Figure 6.



Stiff. No.	Ring No.	Elev. ft	Stiffener Type & Size
Top	13	126	Tee -- Web 28 x 0.911, Flange 22 x 1.187
1	12	111	Bar 10 x 0.635
2	11	101.5	Bar 10 x 0.635
3	10	91.67	Bar 10 x 0.635
4	8	72.75	Tee -- Web 10 x 0.635, Flange 10 x 0.635

Figure 6 1M BBL LNG Tank Cross Section, courtesy of CBI

5.2 Axisymmetric Finite Element Analysis (FEA) Model

The model included shell, annular plate, floor, and stiffening rings with thickness values shown in Table 1 Shell course (ring) thicknesses. Stiffeners are included on shell courses 8, 10, 11, 12, 13. Attachment welds are 0.25 in. The model uses contact with concrete foundation on bottom of annular plate. The lap weld at plate to floor junction is included. The model controls radial constraint at the floor center. Vertical support on the floor extends from the center to the lap weld. (No vertical constraint is applied on annular plate; contact only is used). The full design liquid level gives the maximum hydrostatic load based on a specific gravity of SG=0.48. An 8-node asymmetrical element and 12+ element were applied through the thickness at chime/plate. The model mesh of the annular plate region, welds, and shell as well as crack orientations are shown in Figure 7.

Ring	Thickness (in)	Ring	Thickness (in)	Ring	Thickness (in)
1	1.187	6	0.721	11	0.441
2	1.094	7	0.627	12	0.441
3	1.001	8	0.534	13	0.441
4	0.907	9	0.441	Floor	0.1875
5	0.814	10	0.441	Plate	0.656, 0.75, 1.0

Table 1 Shell course (ring) thicknesses

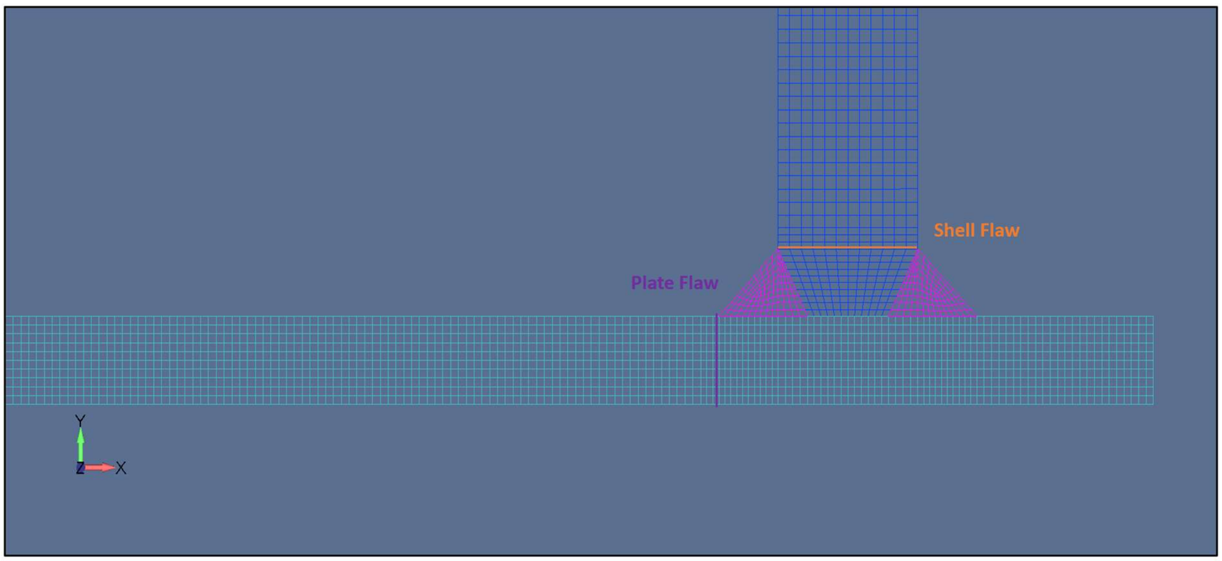


Figure 7 1M bbl: Crack Plane Orientations

The initial annular plate thickness is 0.656 in and a width of 38in. The external plate extension beyond the shell is 2in. The shell ID to the lap weld at the inner side of the annular plates is 33in. The corner weld used was based on 45 degrees with an 0.5 in leg length and a groove depth of 0.25in. These details are shown in Figure 8.

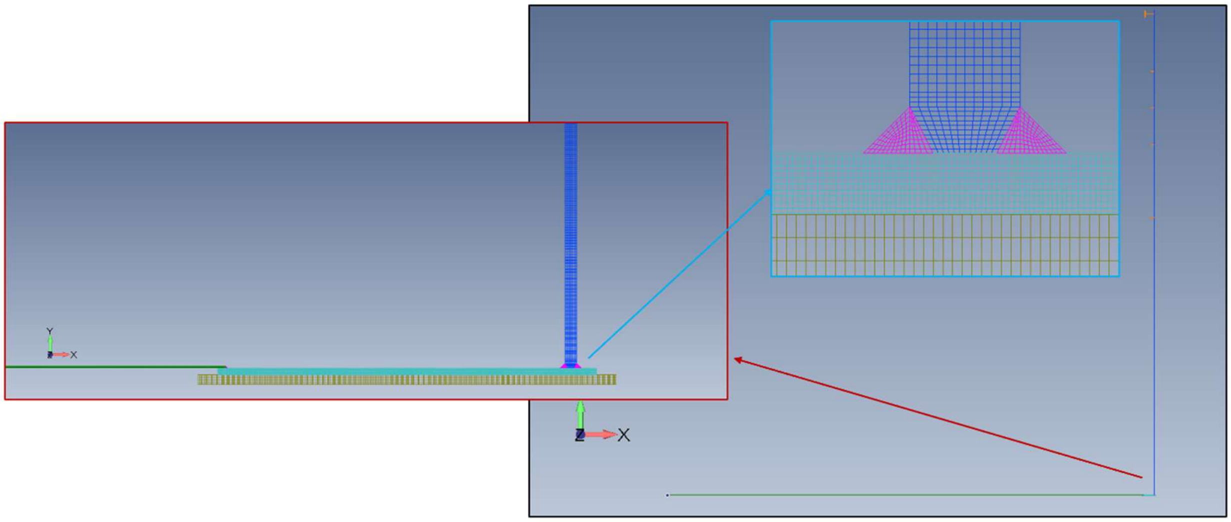


Figure 8 Plate Thickness = 0.656 in

The Von Mises stresses are shown in Figure 9 and the highest stress of 94,493 psi occurs at the inner toe of the inside fillet weld on the bottom.

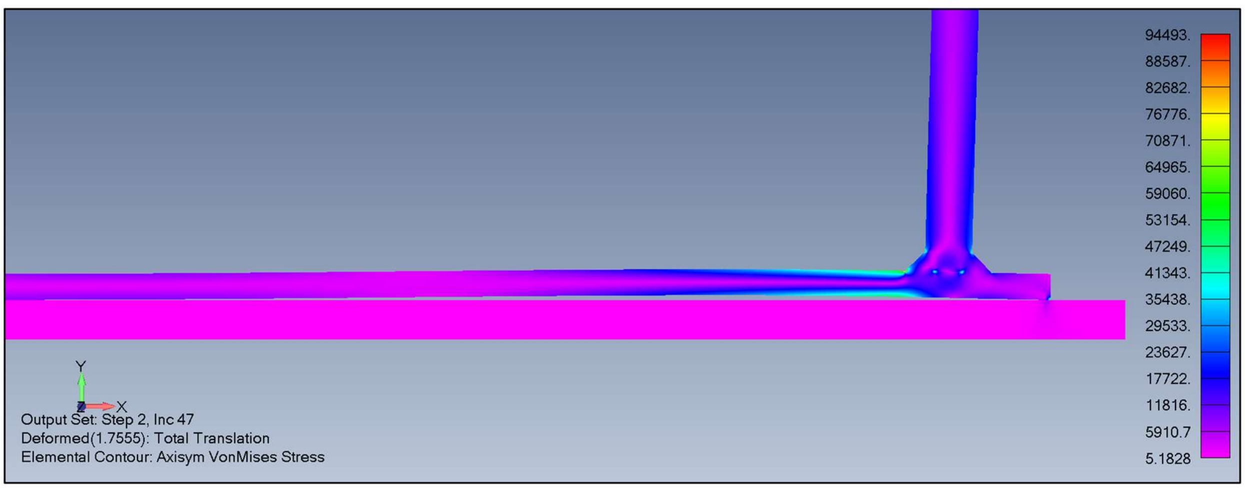


Figure 9 Elastic Results: Plate Thickness = 0.656 in

Radial stresses on the bottom are shown in Figure 10 and the highest stress occurs at the inner toe of the inside fillet weld on the bottom.

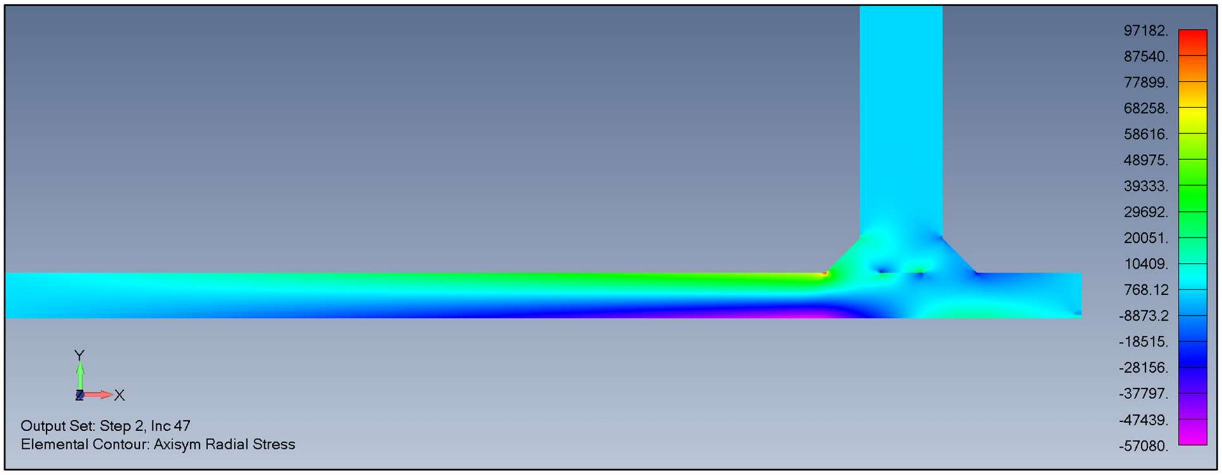


Figure 10 Elastic Results: Plate Thickness = 0.656 in

The axial stresses in the shell are shown in Figure 11. The high stress 52,181 psi occurs at the upper toe of the inside fillet weld.

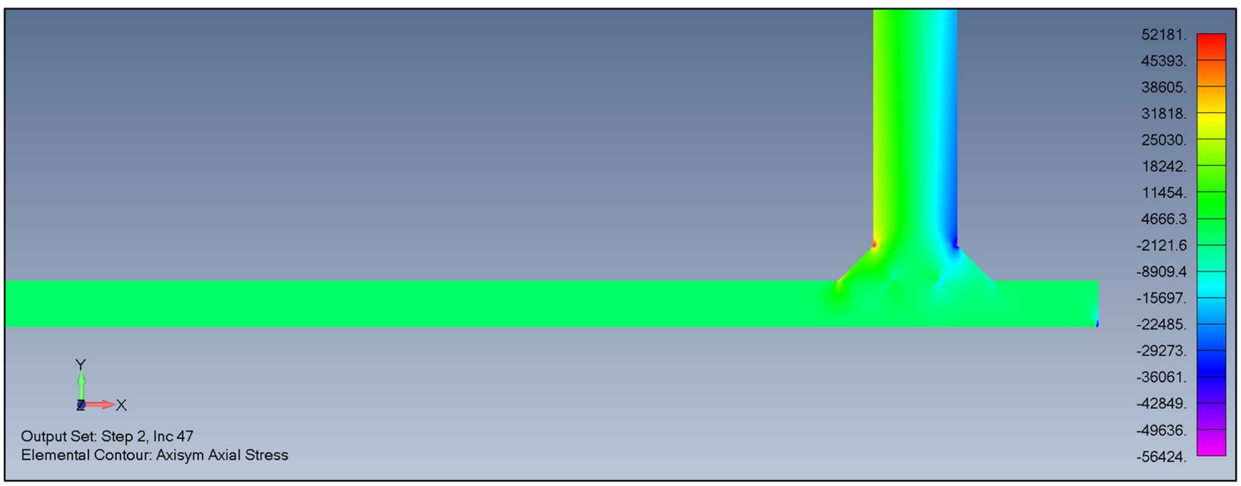


Figure 11 Elastic Results: Plate Thickness = 0.656 in

Stress profiles were extracted and the stresses linearized as shown by the dotted lines in Figure 12.

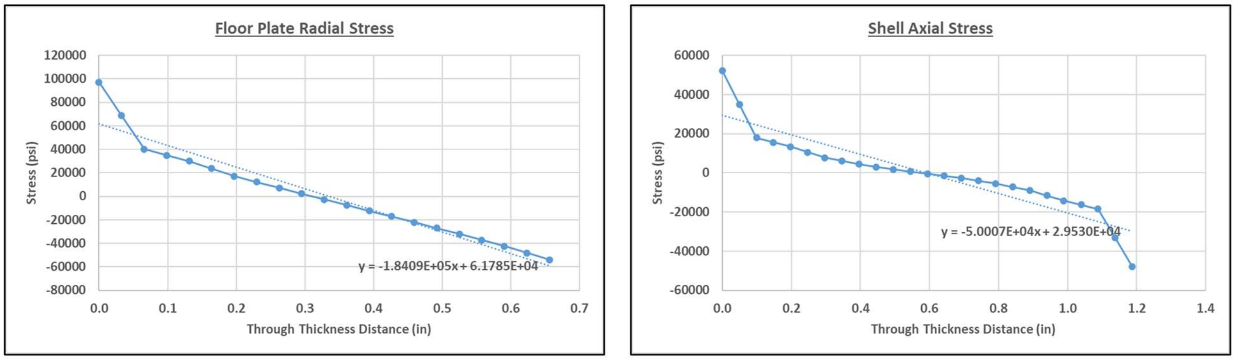


Figure 12 Plate Thickness = 0.656 in: Extracted Stress Profiles

The results of the fracture mechanics analysis using FAD is shown in Figure 13. This indicates that the reference flaws with the orientations most likely to cause fracture are well with the “safe” boundary of the FAD.

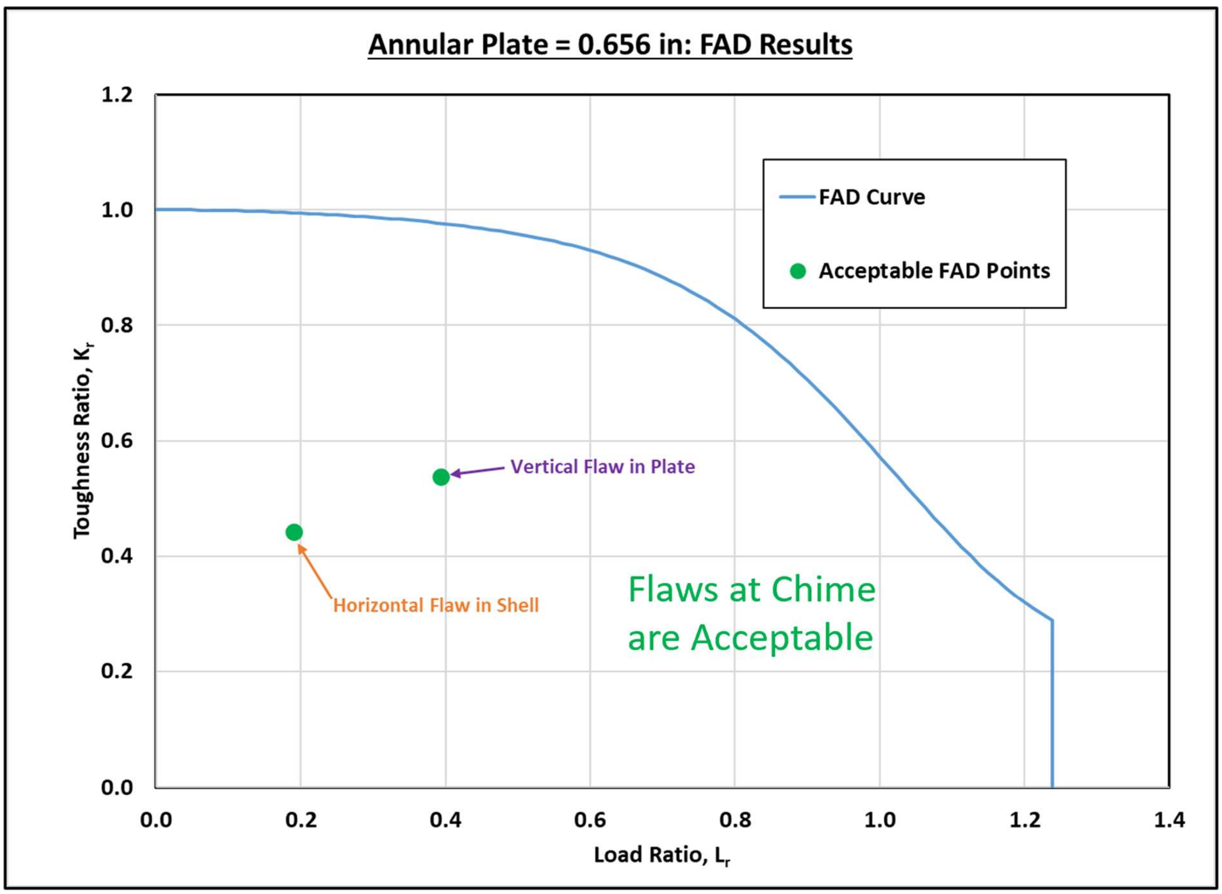


Figure 13 Plate Thickness = 0.656 in: FAD Results

The critical size flaw curves are shown Figure 14. Note that the bottom plate reference flaw is more “critical” than the shell flaw.

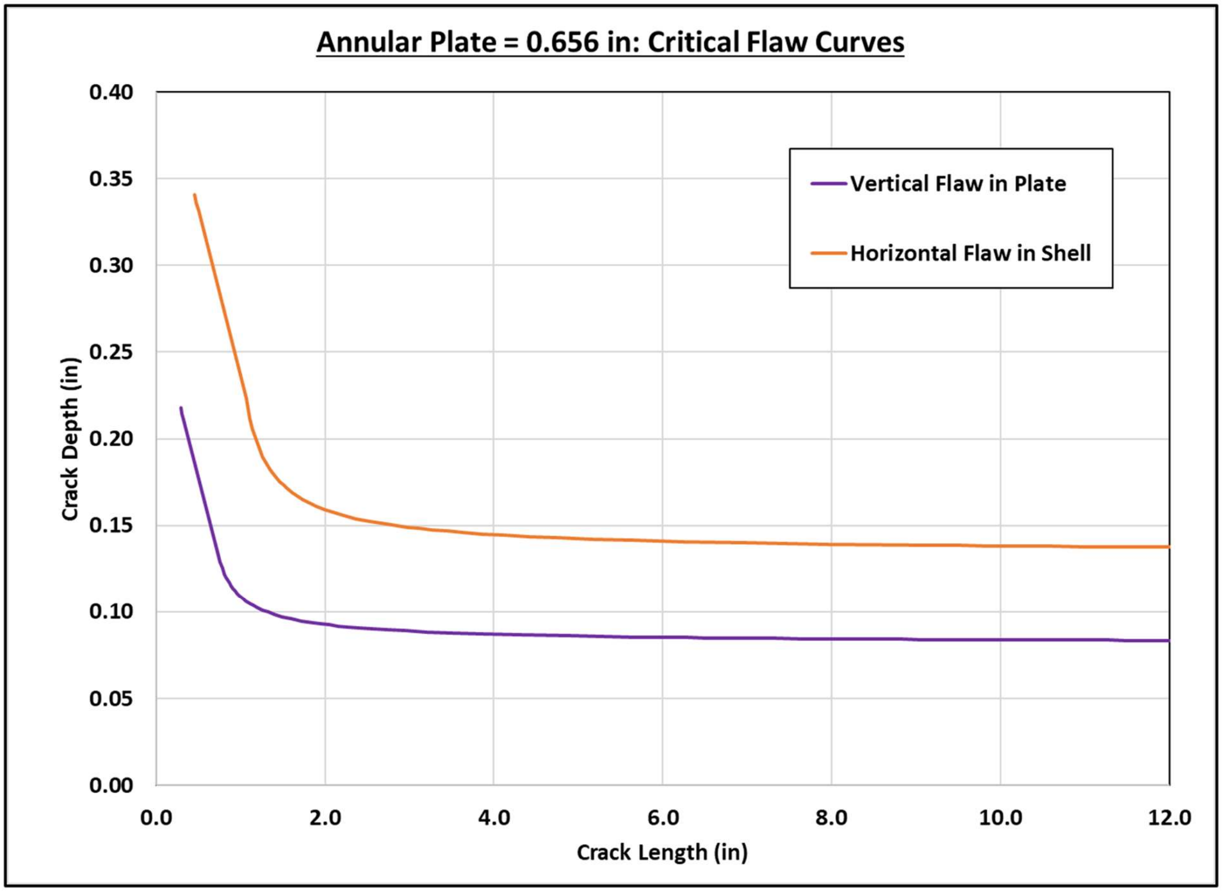


Figure 14 Plate Thickness = 0.656 in: Critical Flaw Curves

The left panel of Figure 15 shows the crack growth depth and length with cycles. Notice that for both the vertical and horizontal flaw the length grows at a much more rapid rate than the depth. This means that failure could not be classified as a "leak before break".

The right panel shows the growth trajectory of the horizontal crack in the shell and the vertical crack in the annular plate. Since the critical points (red points) occur at load ratios L_r below 0.5 the failure can be considered a "brittle failure". For the shell crack this occurs at 181,694 cycles and for the annular plate 22,850 cycles.

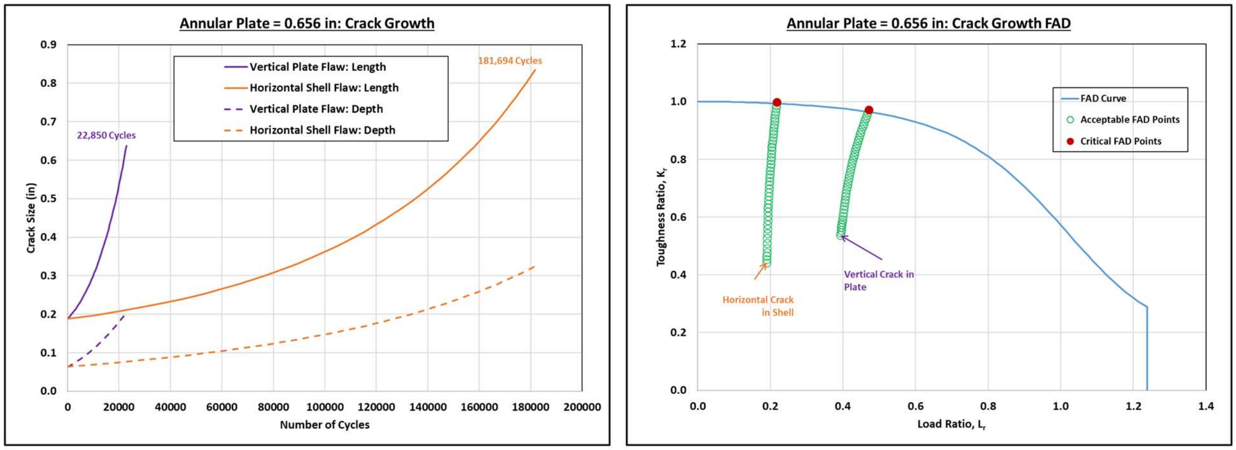


Figure 15 Plate Thickness = 0.656 in:

5.3 Increase Annular Plate Thickness to 0.75 in

The only change in the following figures is the increase in annular plate thickness. Since the discussion follows similarly to the 0.656 Annular plate case, only the figures are shown. Recapping the model data:

- Axisymmetric model with annular plate thickness = 0.75 in.
- Total annular plate length = 38 in.
- External plate overhang at chime = 2 in.
- ID to lap weld distance = 33 in.
- Chime weld: 45 degree, 0.5 in leg length, 0.25 groove.

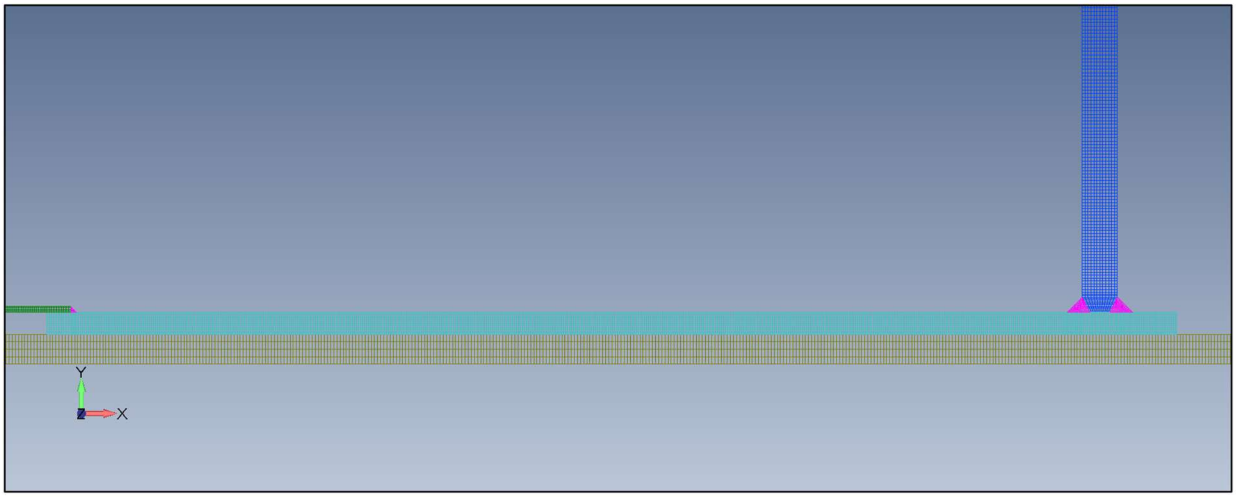


Figure 16 Axisymmetric Model: Plate Thickness = 0.75 in

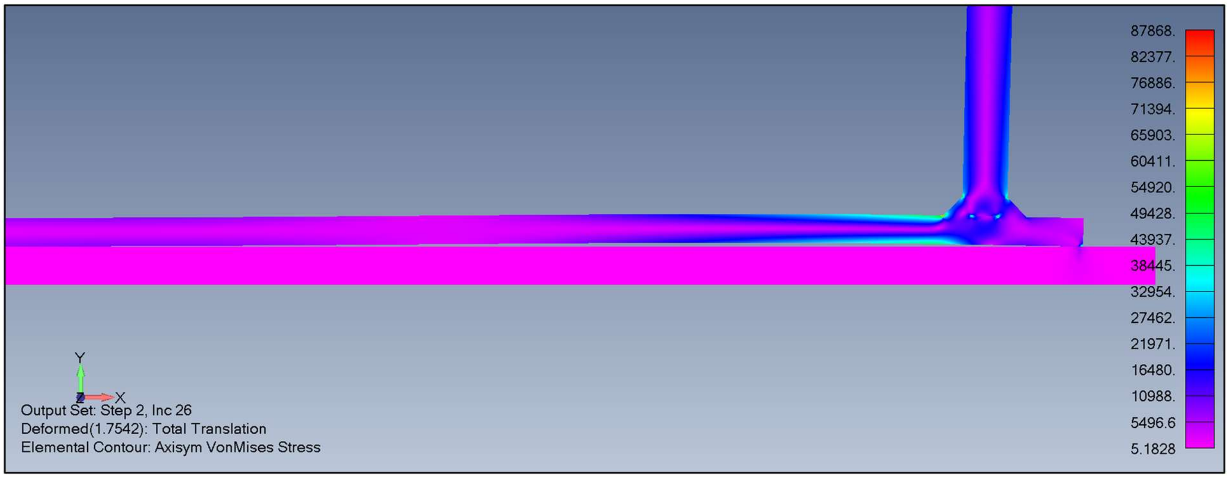


Figure 17 Elastic Results: Plate Thickness = 0.75 in

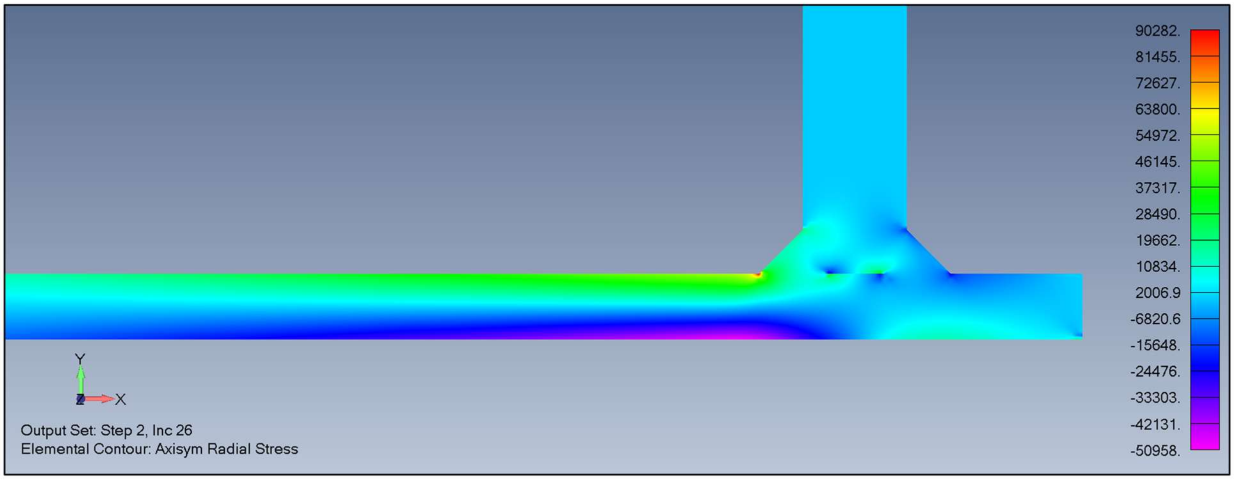


Figure 18 Elastic Results: Plate Thickness = 0.75 in

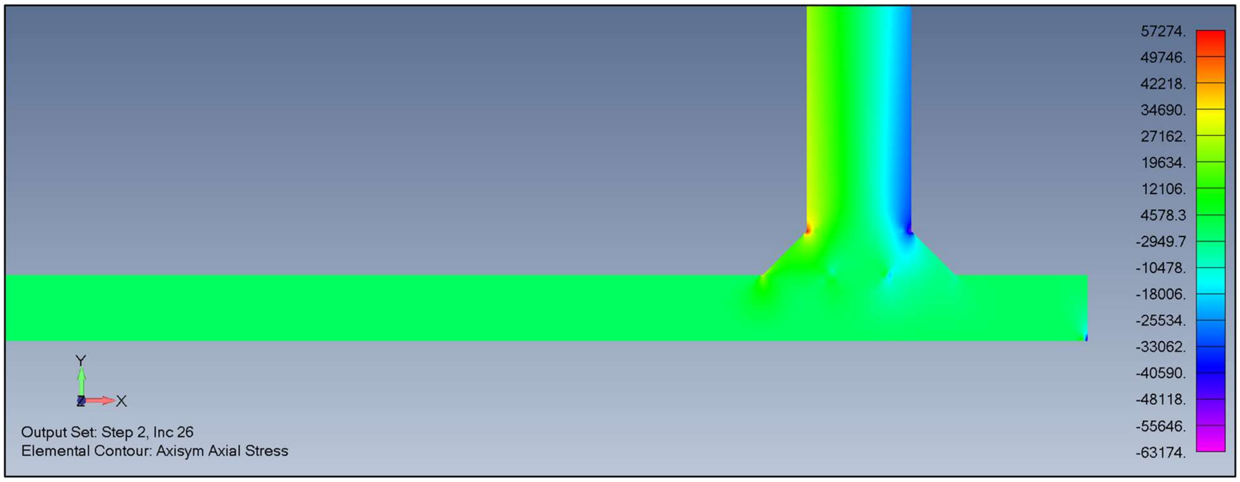
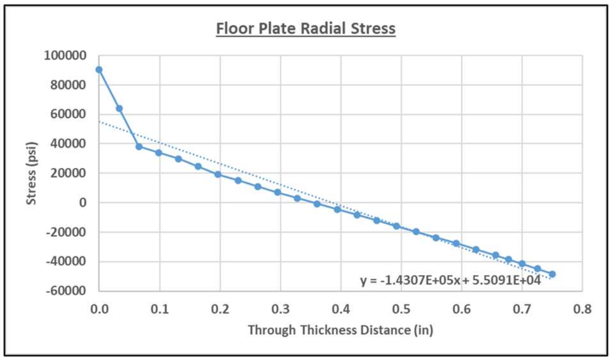


Figure 19 Elastic Results: Plate Thickness = 0.75 in



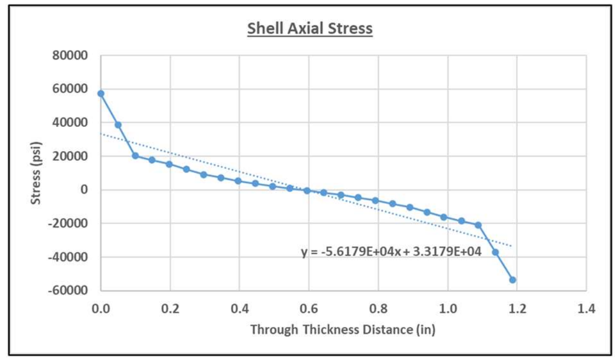


Figure 20 Plate Thickness = 0.75 in: Extracted Stress Profiles

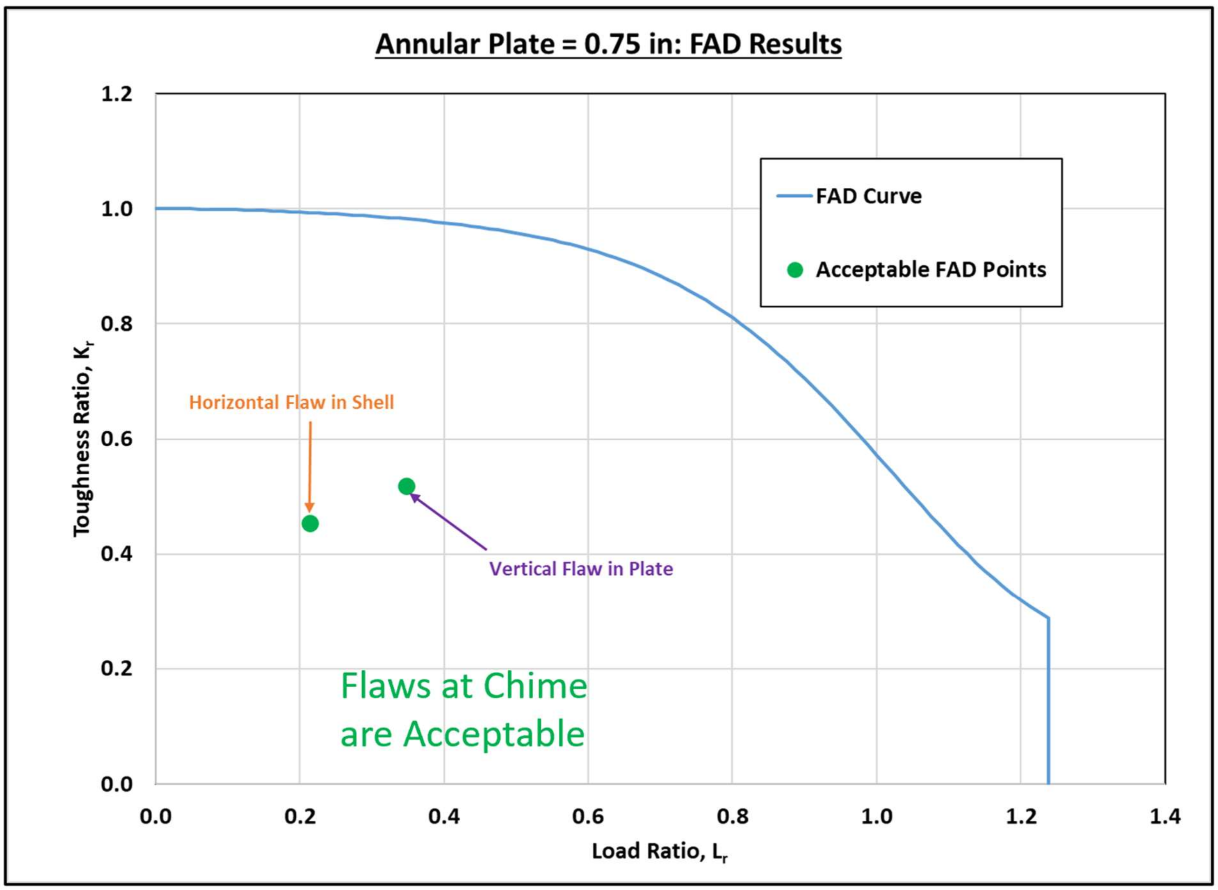


Figure 21 Plate Thickness = 0.75 in: FAD Results

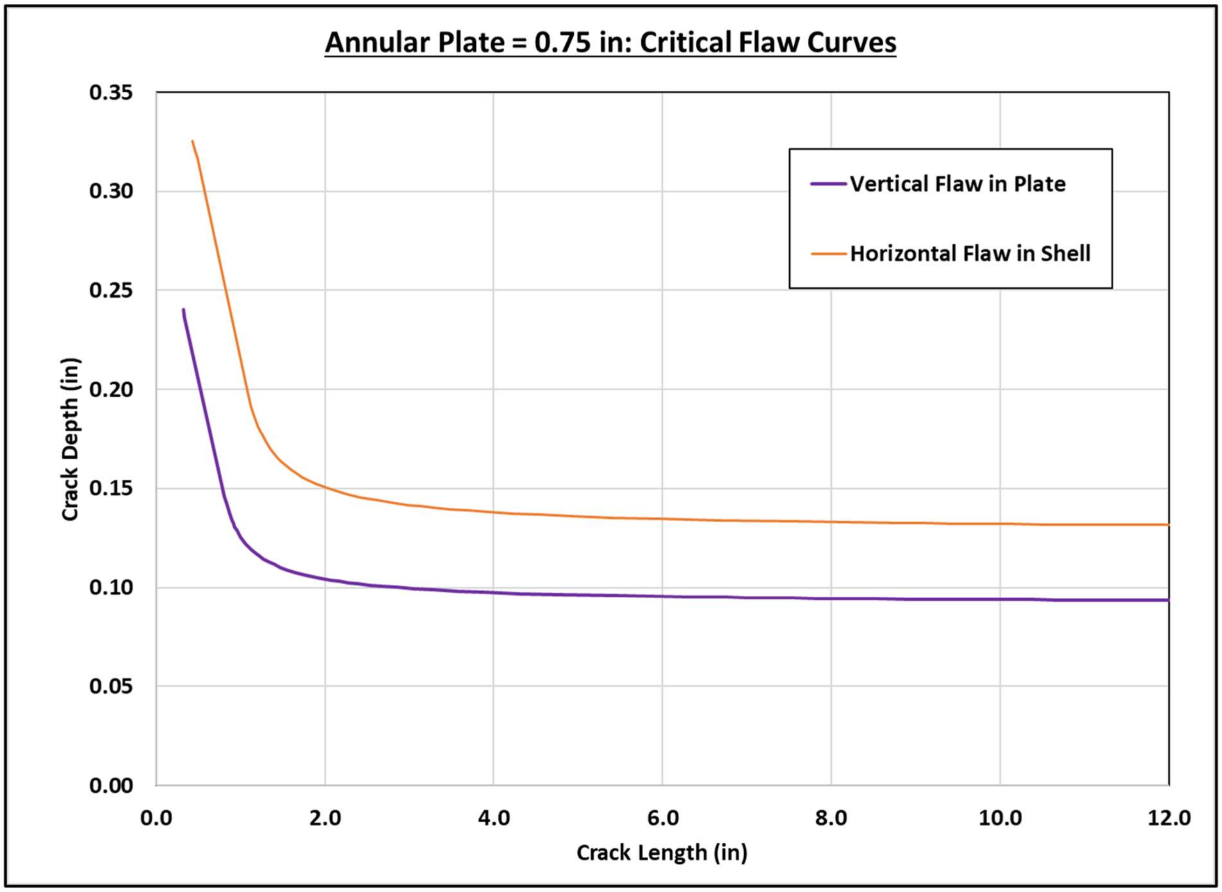


Figure 22 Plate Thickness = 0.75 in: Critical Flaw Curves

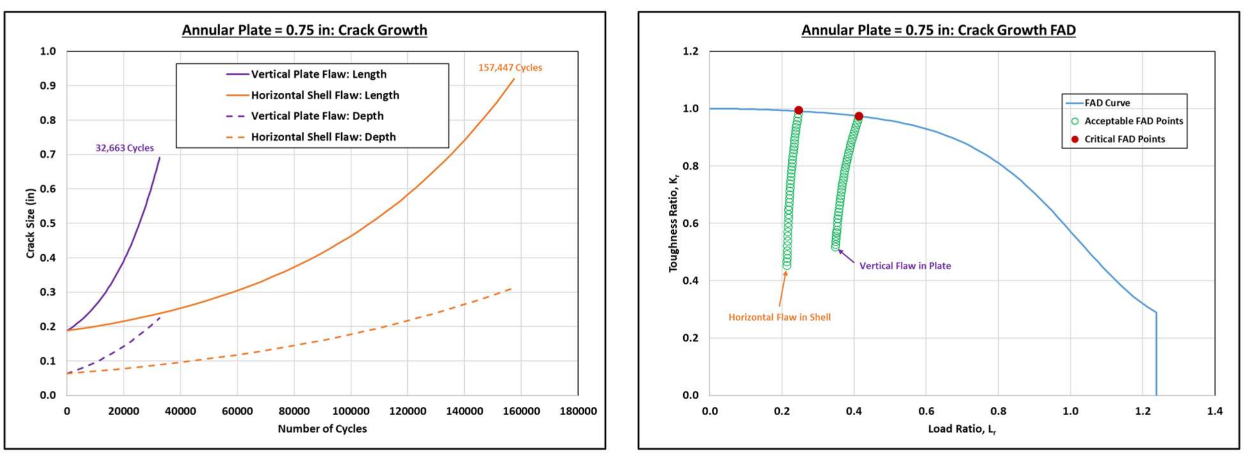


Figure 23 Plate Thickness = 0.75 in:

5.4 Increase Annular Plate Thickness to 1.0 in

The only change in the following figures is the increase in annular plate thickness. Since the discussion follows similarly to the 0.656 Annular plate case, only the figures are shown. Recapping the model data:

- Axisymmetric model with annular plate thickness = 1.0 in.
- Total annular plate length = 38 in.

- External plate overhang at chime = 2 in.
- ID to lap weld distance = 33 in.
- Chime weld: 45 degree, 0.5 in leg length, 0.25 groove.

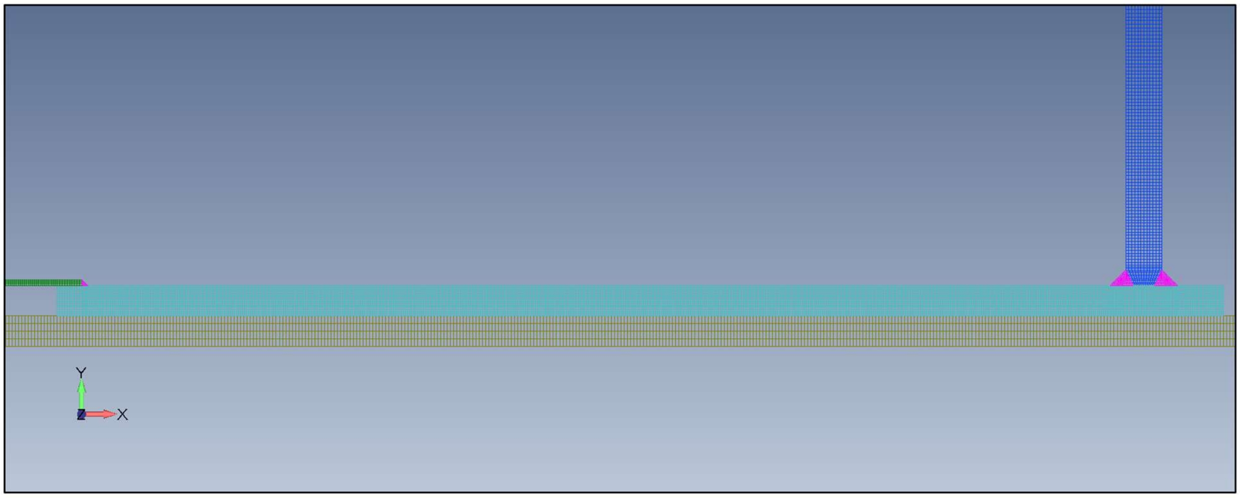


Figure 24 Axisymmetric Model: Plate Thickness = 1.0 in

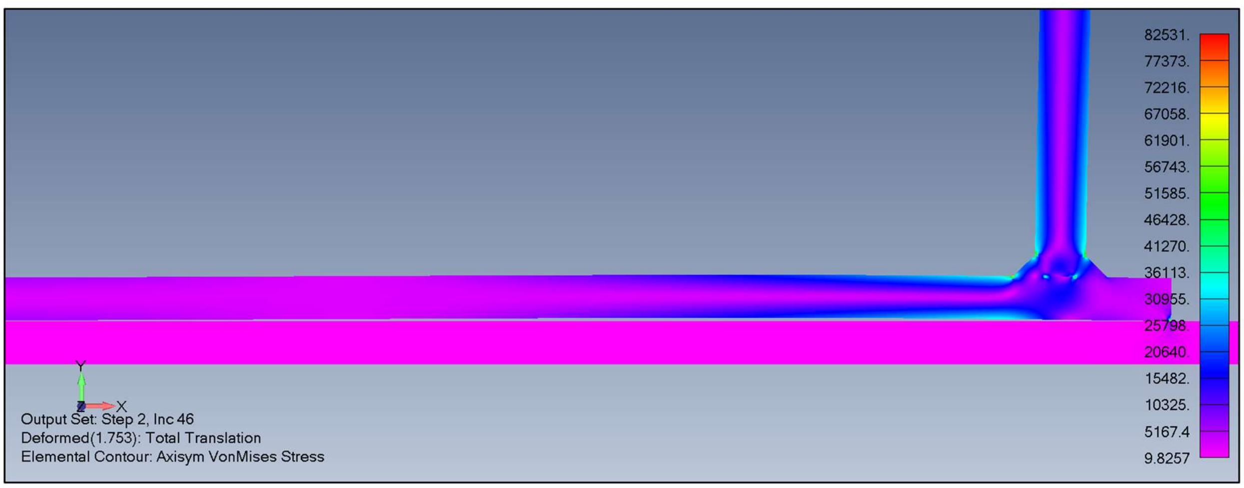


Figure 25 Elastic Results: Plate Thickness = 1.0 in Full Fill SG=0.48. Von Mises stress (psi)

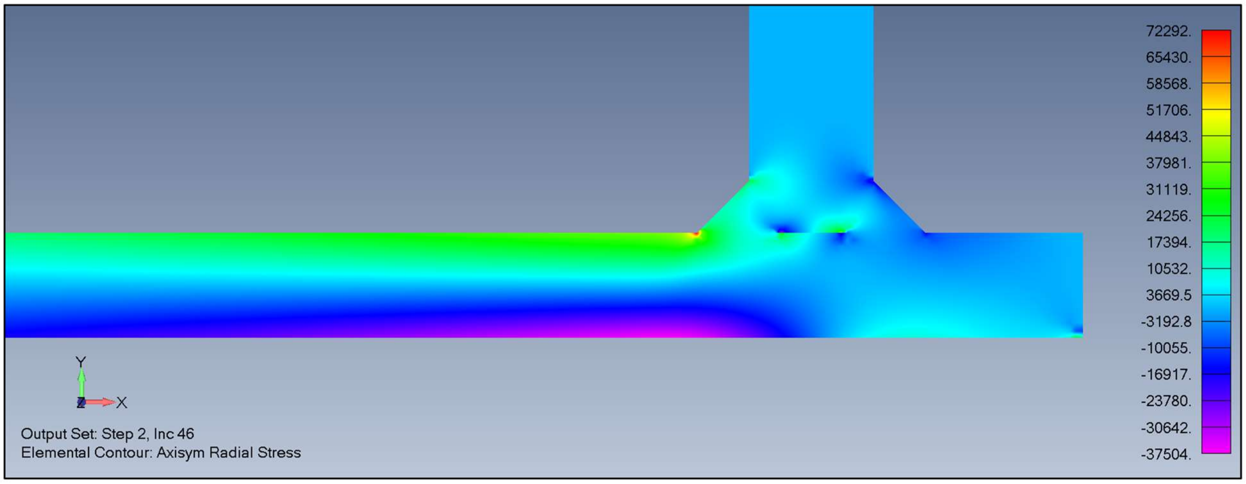


Figure 26 Elastic Results: Plate Thickness = 1.0 in Full Fill SG=0.48. Radial stress (psi)

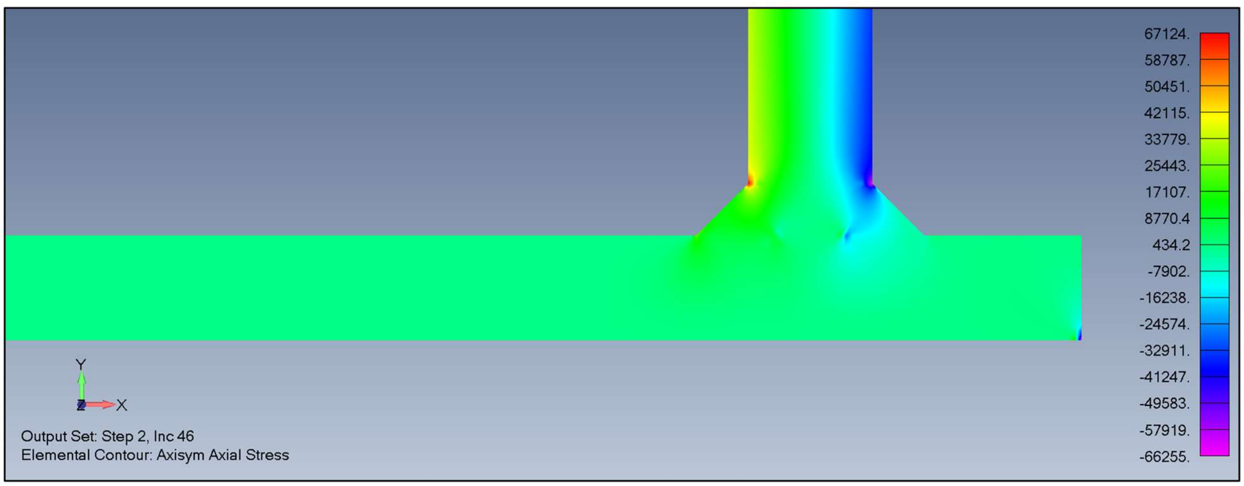


Figure 27 Elastic Results: Plate Thickness = 1.0 in Full Fill SG=0.48. Axial stress (psi)

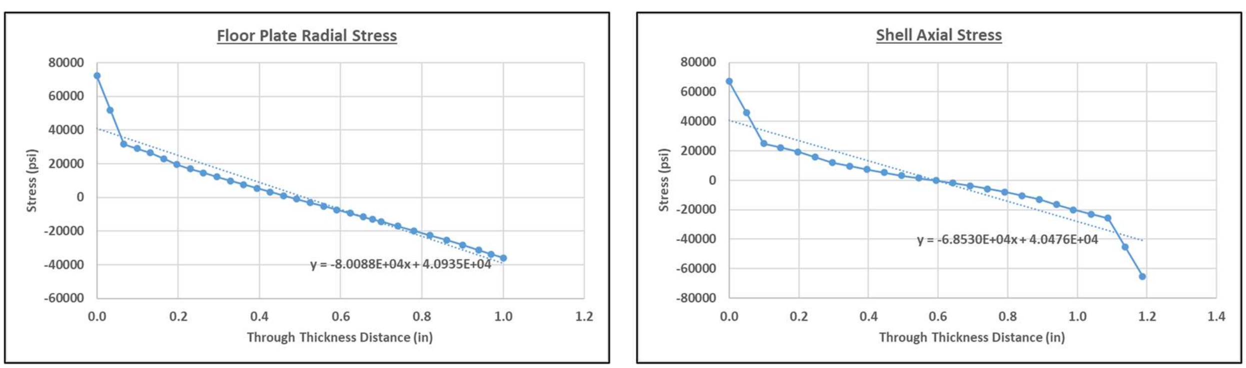


Figure 28 Plate Thickness = 1.0 in: Extracted Stress Profiles

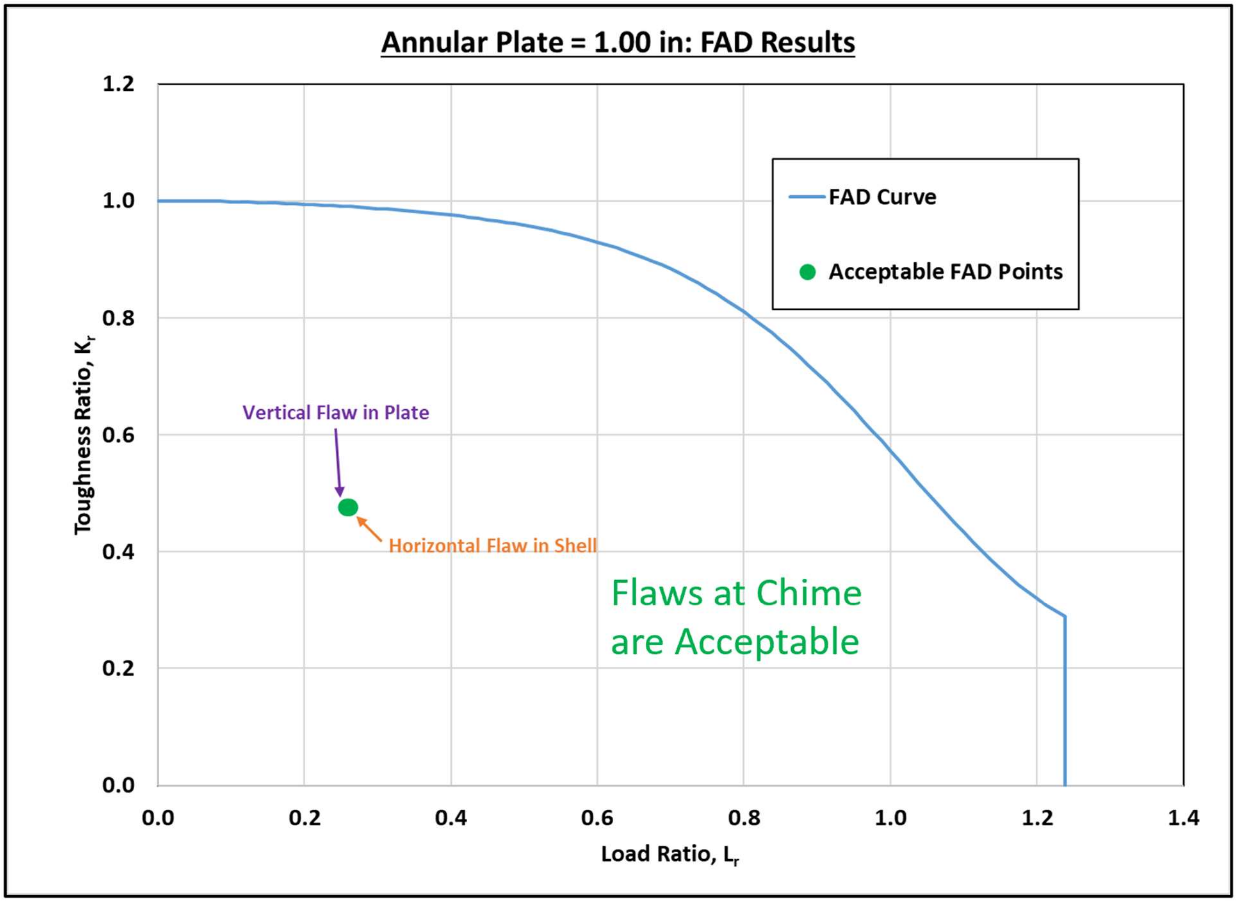


Figure 29 Plate Thickness = 1.0 in: FAD Results

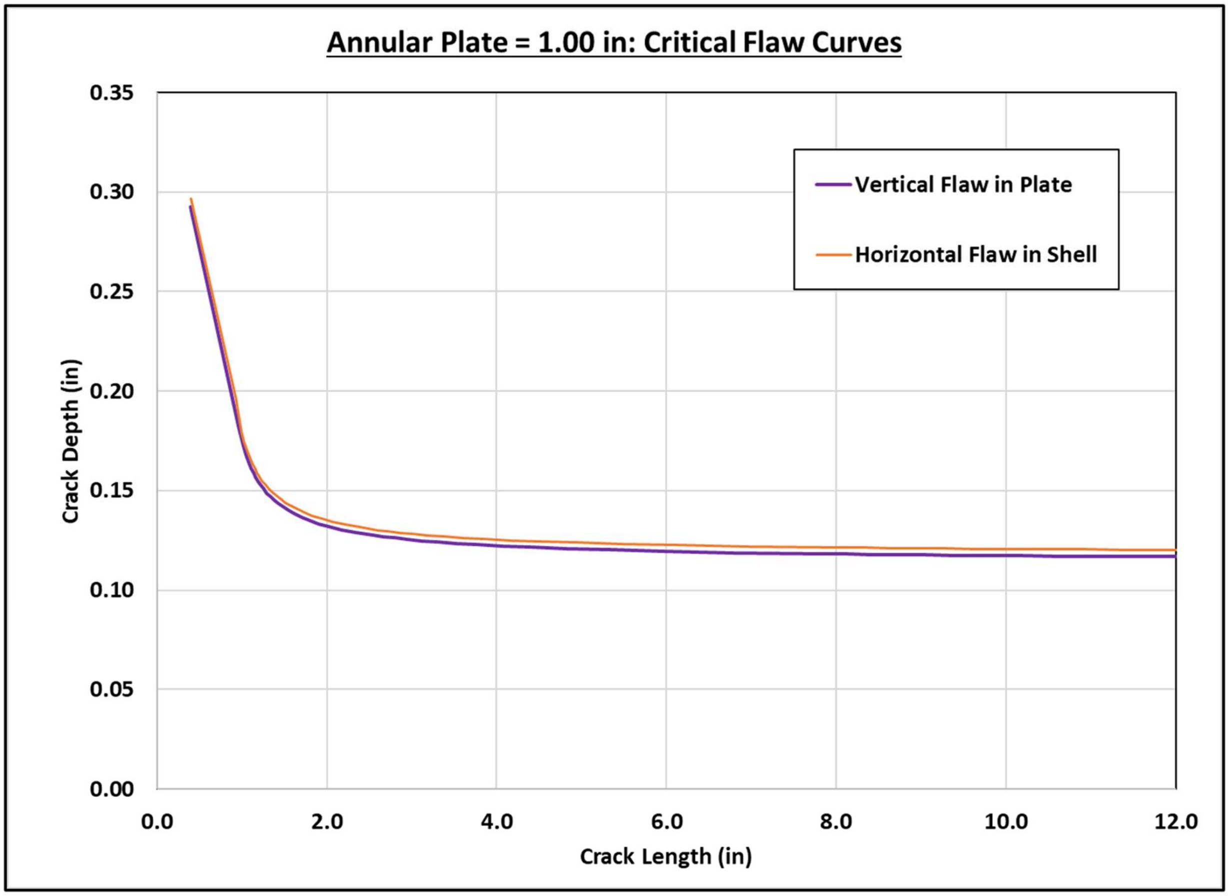


Figure 30 Plate Thickness = 1.0 in: Critical Flaw Curves

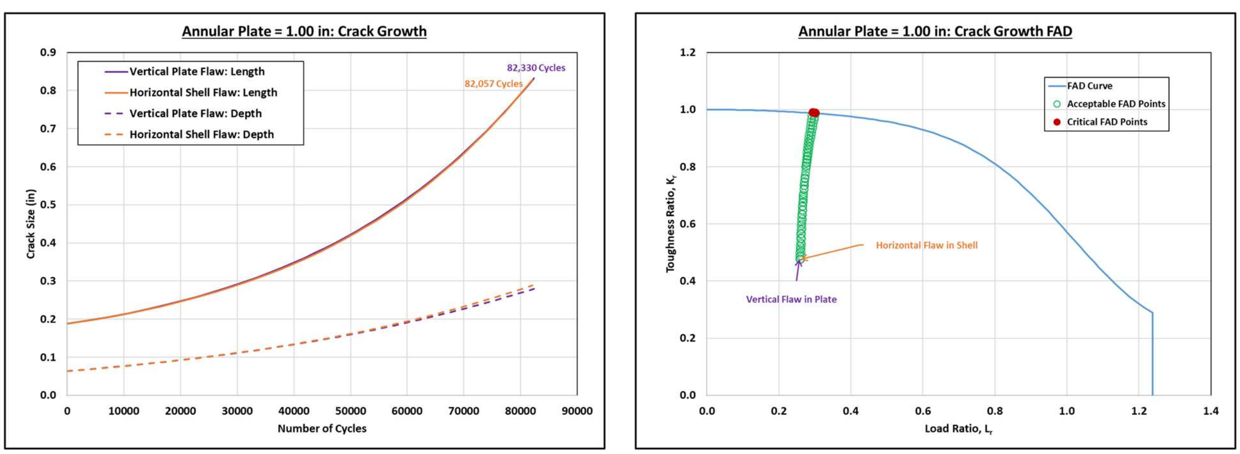


Figure 31 Plate Thickness = 1.0 in: Fatigue Crack Growth Results

5.5 Fatigue Crack Growth Results

Summarizing the analyses for the 3 annular plate thicknesses for the 1M BBL LNG container the results are shown in Table 2. The results demonstrate that a standard annular plate thickness would typically have a satisfactory service life. The standard annular plate thickness of 0.656 in this case is thinner compared to the shell, and for this reason, the annular plate has more stress and lower fatigue cycles compared to the shell. The design can be balanced and optimized by increasing the thickness of the annular plate. An annular plate thickness of 1.0” is the ideal design case, where the fatigue life of the annular has been improved, and at the same point the shell fatigue life is not reduced below the fatigue life of the annular plate. This is where the curves of Figure 32 meet. It is an optimal design point. It would be expected that increasing the annular plate thickness above the optimum point would reduce fatigue life. From a business perspective, the benefit of additional tank life would have to be weighed against the upfront cost of installing a thicker annular plate. In this case, a 50% increase in annular plate thickness yielded a 250% increase in fatigue life.

Annular Plate Thickness (in)	Vertical Flaw in Plate Allowable Cycles	Horizontal Flaw in Shell Allowable Cycles
0.656	22,850	181,694
0.75	32,663	157,447
1.0	82,330	82,057

Table 2 Fatigue Crack Growth Results

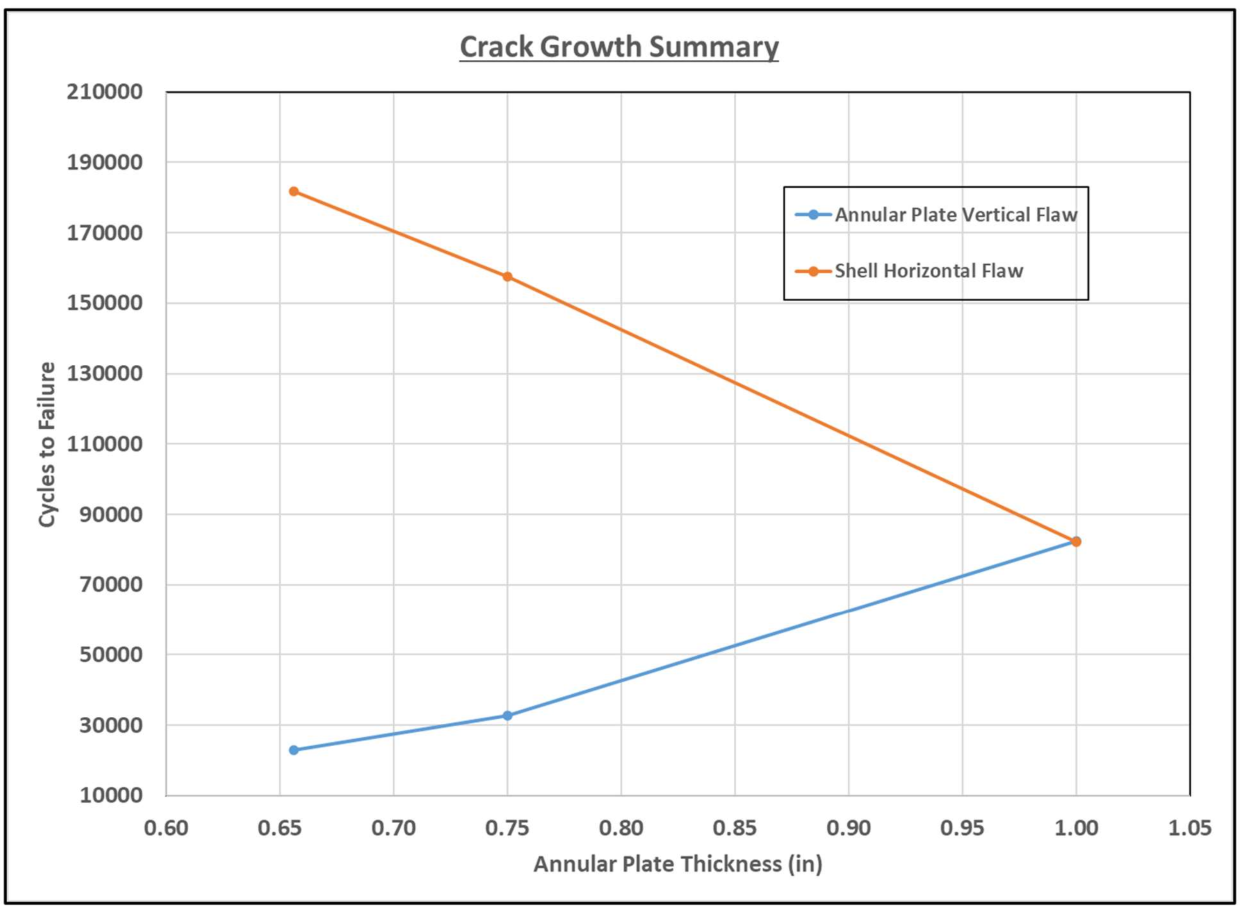


Figure 32 Fatigue Allowable Cycles versus Annular Plate Thickness

5.6 Weld Corner Stress Sensitivity

The sharp toe of the chime weld causes localized high stresses. Note that unlike SN based fatigue assessments, the fracture mechanics assessment uses the entire stress profile through the thickness, rather than being governed by a single high stress value. However, the local high stresses can still have some effect on the FAD and fatigue growth analyses, though this effect is mostly mitigated by the stress linearization.

The effect of the weld toe corner high stresses was evaluated by recomputing fatigue lives for the following cases (all using a vertical crack in the thinnest 0.656 inch annular plate):

- Stresses extracted 0.1 inch from weld toe then linearized.
- Plasticity effects included (limiting peak stresses) and stresses extracted 0.1 inch from weld toe.
- Small radius added to weld toe and stresses extracted 0.1 inch from weld toe.

Extracting stresses a small distance away from the singular point at the corner of the toe of the weld (0.1”) reduces the impact of model anomalies. The elastic analysis through the line shown in Figure 33 provides the stress profile.

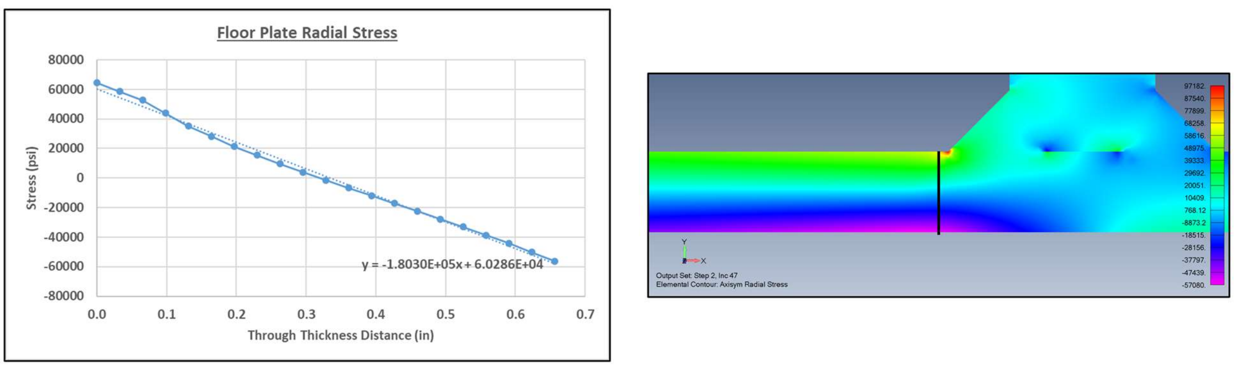


Figure 33 Plate Thickness = 0.656 in: Extracted Stress Profiles 0.1” From Weld Toe

If plasticity effects are included then the results are shown in Figure 34.

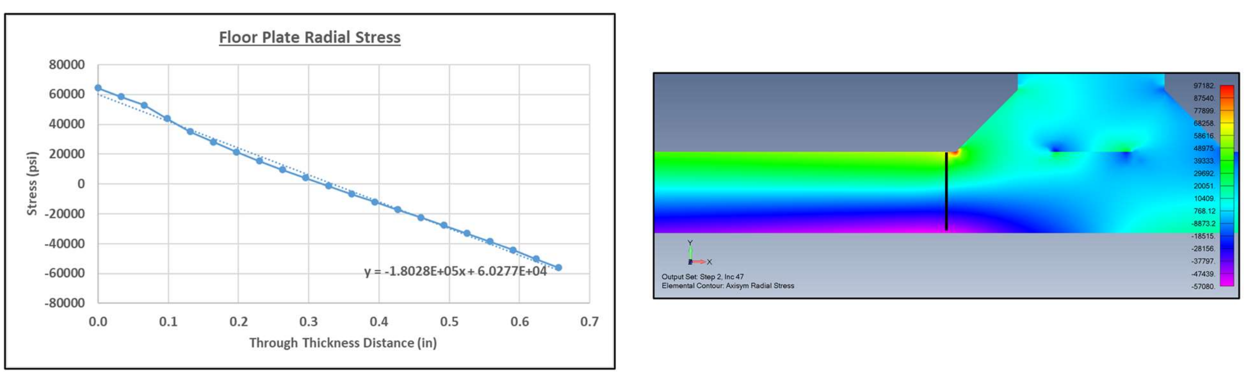


Figure 34 Plate Thickness = 0.656 in: Extracted Stress Profiles 0.1” From Weld Toe, Elastic-Plastic

Finally, using a radius to eliminate the effects of the singularity give results shown in Figure 35.

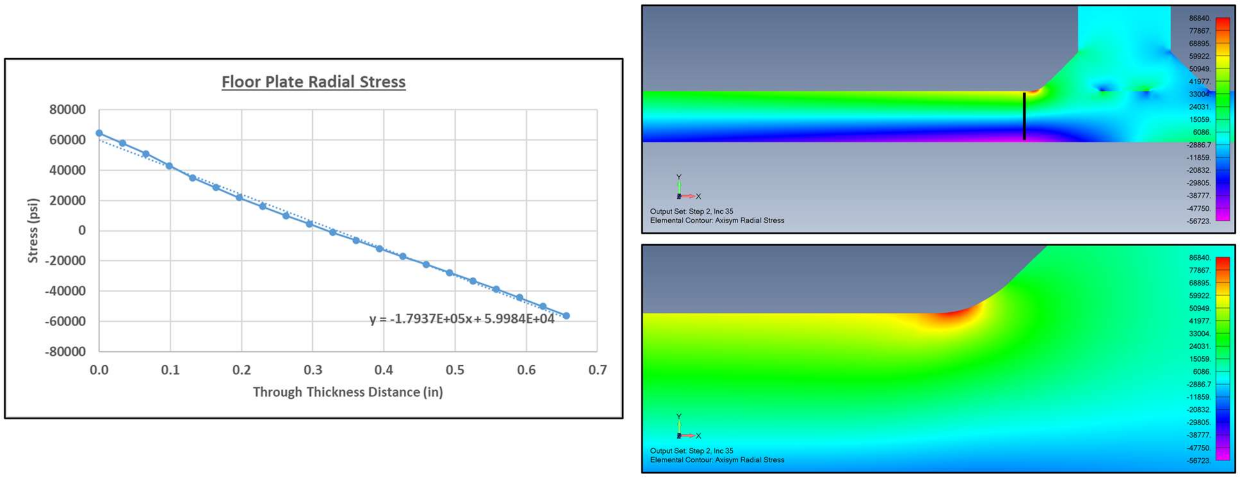


Figure 35 Plate Thickness = 0.656 in: Extracted Stress Profiles 0.1" From Weld Toe, Add Toe Radius

There is barely any perceptible difference between the three cases and the results are summarized in Table 3.

Extracted Stresses	Annular Plate Thickness (in)	Vertical Flaw in Plate Allowable Cycles
Original Profile at Toe	0.656	22,850
Profile 0.1 inch From Toe	0.656	24,747
Elastic-Plastic, Profile 0.1 inch From Toe	0.656	24,760
0.25 inch Toe Radius, Profile 0.1 inch From Toe	0.656	25,458

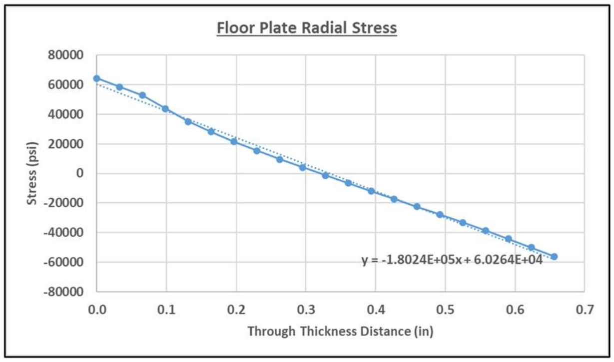
Table 3 Weld Corner Sensitivity: Fatigue Results

The following conclusions about sensitivity of stresses to the weld corner geometry are:

- Plate stresses, even at the corner are near linear. The peak tensile and compressive stresses on the top and bottom surfaces are primarily the result of pure bending of the annular plate (i.e. are physical stresses) and are not solely due to a numeric singularity (corner).
- Avoiding the high corner stresses by moving the profile or using a toe radius only causes slight changes in the resulting fatigue lives. This is likely due to the previous linearization already mitigating the effect of the weld toe corner. Including plasticity makes no significant difference in fatigue life, as stresses are below the temperature dependent yield of 105ksi.
- Based on the results, it is concluded that the estimated fatigue lives are not due to corner effects, but rather due to the physical plate bending stresses.

5.7 Foundation Sensitivity

During the analysis, the annular plate was not constrained, rather contact with a concrete foundation was simulated. This allowed the plate to lift off the foundation due to bending. The concrete elastic modulus assumed a typical value of hardened concrete of 4,000 ksi. To evaluate the effect of a softer foundation, the analysis was repeated reducing the modulus by half, using a soft 2,000 ksi elastic modulus. The fatigue life was recomputed for a vertical crack in the thinnest 0.656 inch annular plate. Stresses were extracted through the plate thickness at a distance of 0.1 inch from the weld toe.



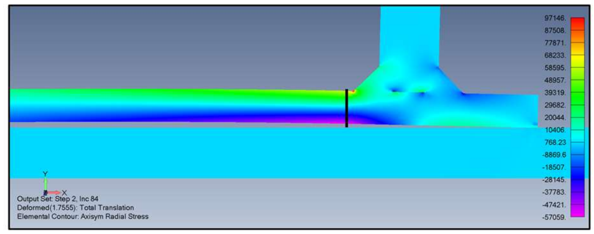


Figure 36 Plate Thickness = 0.656 in: Extracted Stress Profiles 0.1 From Weld Toe, 2000ksi Foundation

The foundation hardness impacted the fatigue results as shown in Table 4.

Extracted Stresses	Annular Plate Thickness (in)	Vertical Flaw in Plate Allowable Cycles
Profile 0.1 inch From Toe, 4000 ksi Foundation	0.656	24,747
Profile 0.1 inch From Toe, 2000 ksi Foundation	0.656	17,510

Table 4 Foundation Sensitivity: Fatigue Results

Reducing the concrete modulus by half to a softer value of 2,000 ksi causes a slight increase in stresses, and thus a corresponding reduction in fatigue life. This likely occurs due to the softer foundation allowing slightly more rotation of the chime weld, and thus increasing bending in the annular plate. Based on the results, it is concluded that the computed fatigue lives are not significantly affected by the foundation stiffness. While changing the foundation stiffness could affect the resulting fatigue lives, significant variation is not expected for typical concrete modulus values.

5.8 Initial Crack Size Sensitivity

One of the key inputs to a fracture mechanics and fatigue crack growth assessment is the assumed initial flaw size. The previous analysis assumed a relatively large reference flaw (1/16 inch deep by 3/16 inch long). This value is typically used in fitness-for-service assessments and hydrotest exemptions, as it is the common acceptance criteria for weld non-destructive examinations such as liquid penetrant examination, which is performed on LNG tank corner welds. Decreasing the assumed initial flaw size can make a significant impact in the resulting fatigue lives. Depending on the inspection conducted, a smaller initial flaw size may be warranted.

To evaluate the effect of a smaller assumed initial flaw, the fatigue crack growth analysis was repeated varying the initial flaw depth and length.

- Compute fatigue lives for vertical flaws in annular plate.

- Radial stresses extracted at weld toe.
- Consider plate thicknesses of 0.656, 0.75, and 1.0 inch.
- Keep same 3:1 aspect ratio (length to depth).
- Vary crack depth / length:
    - 0.0625 / 0.1875 in
    - 0.0300 / 0.0900 in
    - 0.0200 / 0.0600 in
    - 0.0100 / 0.0300 in

Annular Plate Thickness (in)	Initial Crack Depth (in)	Initial Crack Length (in)	Vertical Flaw in Plate Allowable Cycles
0.656	0.0625	0.1875	22,850
	0.03	0.09	39,732
	0.02	0.06	51,050
	0.01	0.03	75,587
0.75	0.0625	0.1875	32,663
	0.03	0.09	56,346
	0.02	0.06	72,110
	0.01	0.03	106,469
1.0	0.0625	0.1875	82,330
	0.03	0.09	137,112
	0.02	0.06	175,567
	0.01	0.03	258,195

Table 5 Initial Crack Size Sensitivity: Fatigue Results

Reducing the initial flaw size greatly increases the fatigue life as shown in Table 5 and Figure 37.

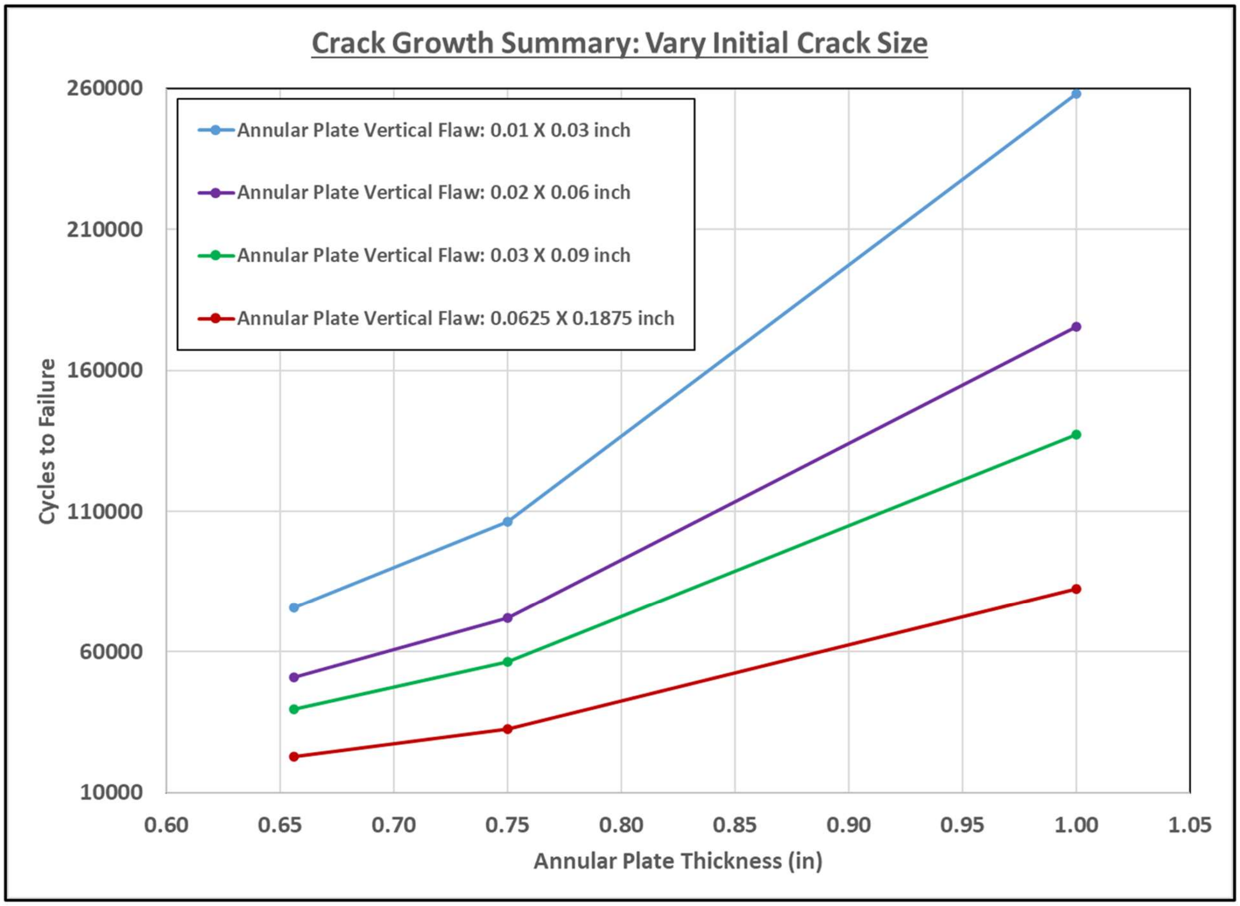


Figure 37 Initial Crack Size Sensitivity: Fatigue Results

6. Analysis of 300k BBL LNG Tank

6.1 Model Data

- Capacity 300k bbl
- Inner Tank Height = 84 ft 8 in
- Shell Course Heights = 8 ft 9.5 in, 8 ft 3 in
- Shell Internal Diameter = 164 ft
- Product Specific Gravity = 0.48
- Design Liquid Level = 80 ft 4 in
- Operating temperature = -260 °F

A drawing of the tank is shown in Figure 38.

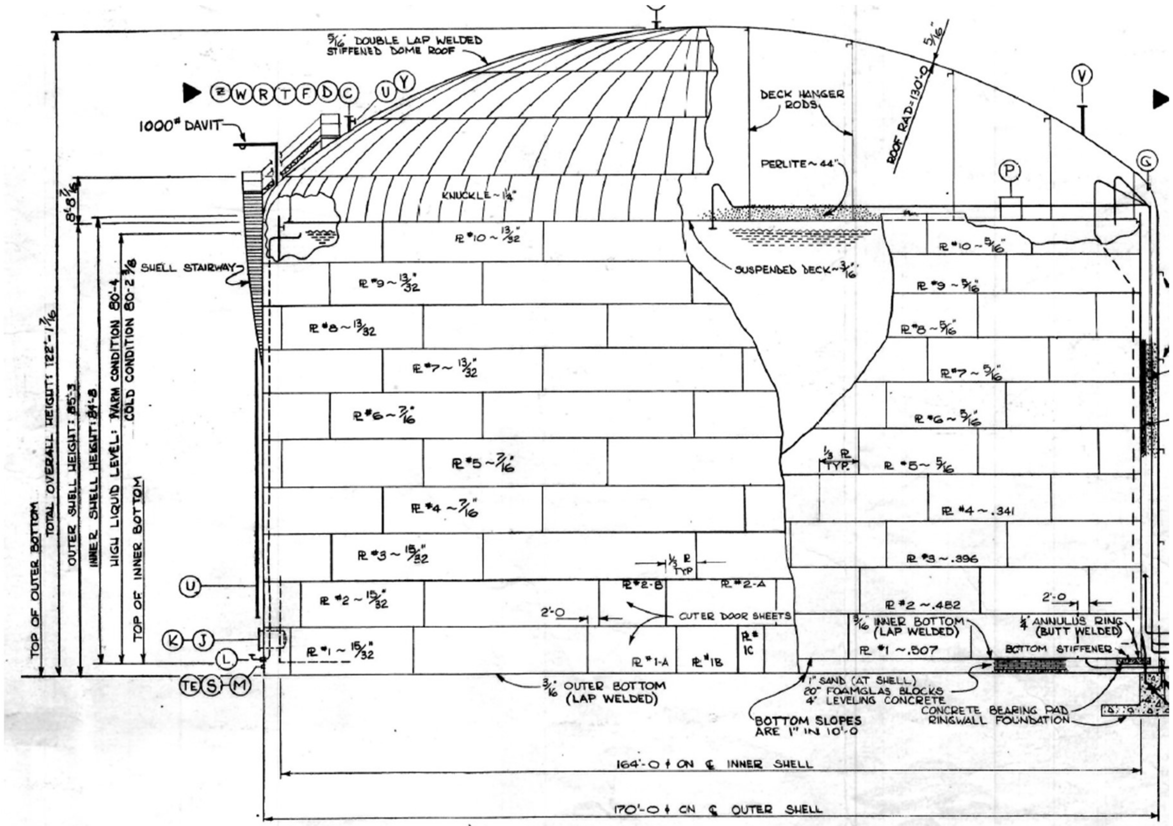


Figure 38 300k BBL LNG Tank

6.2 Model Details

The model included shell, annular plate, floor, and stiffening rings.
Shell course thicknesses are per Table 6.

Ring	Thickness (in)		Thickness (in)
1	0.507	Floor	0.1875
2	0.452	Plate	0.25, 0.375, 0.5
3	0.396		
4	0.341		
5-10	0.3125		

Table 6 Shell Course Thicknesses

- Stiffeners included on Rings 3, 5, 7, 9, 10. Attachment welds = 0.1875 in.
- Contact with concrete foundation on bottom of annular plate.

- Lap weld at plate to floor junction.
- Radial constraint at floor center. Vertical support on floor from center to lap weld. (No vertical constraint on annular plate- contact only).
- Full design liquid level; SG=0.48.
- 8 node asymmetrical elements. 12+ element through thickness at chime/plate.

Figure 39 shows the details of the corner welds.

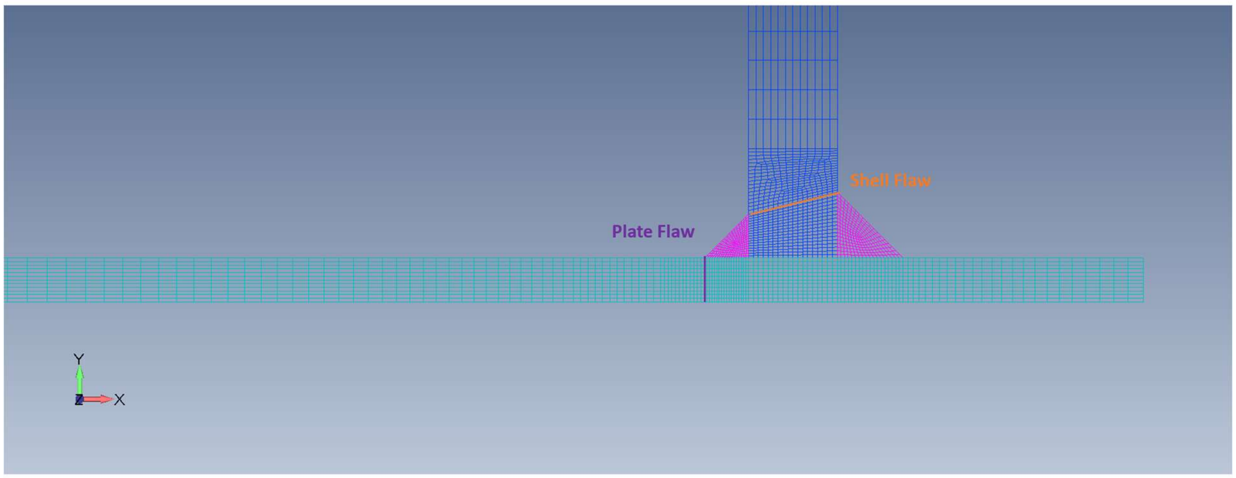


Figure 39 Crack Plane Orientations

6.3 Axisymmetric FEA - Annular Plate 0.25in

- Axisymmetric model with annular plate thickness = 0.25 in.
- Total annular plate length = 22 in.
- External plate overhang at chime = 2 in.
- Chime weld:
  - 45 degree
  - 0.25 in leg length (internal)
  - 0.375 in leg length (external)
  - No weld groove.

The corner details and mesh are shown in Figure 40.

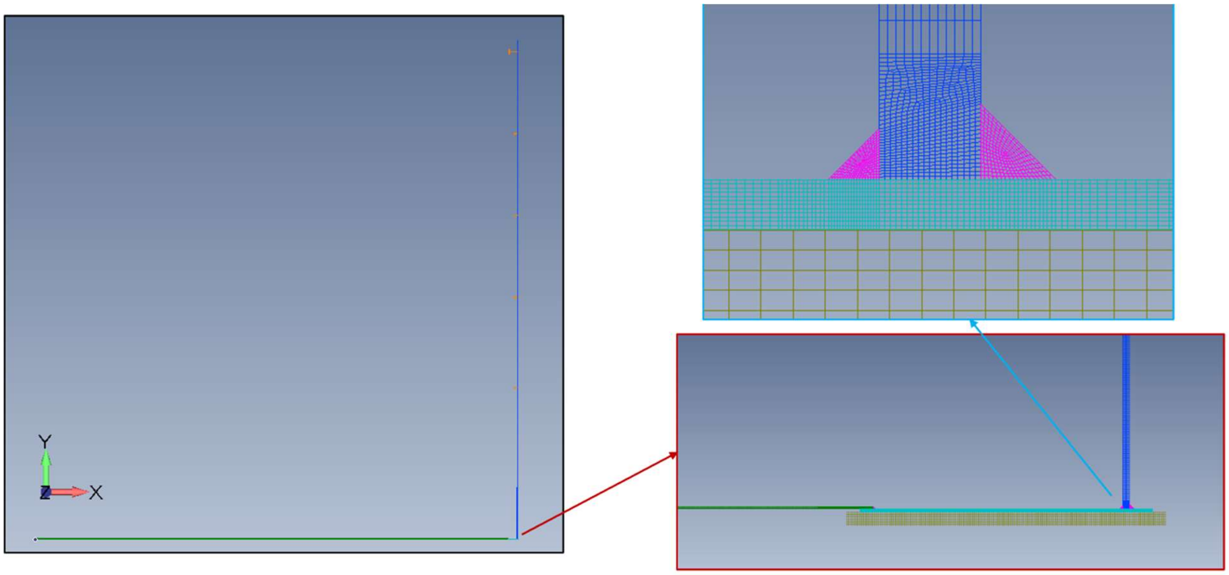


Figure 40 Axisymmetric Model: Plate Thickness = 0.25 in

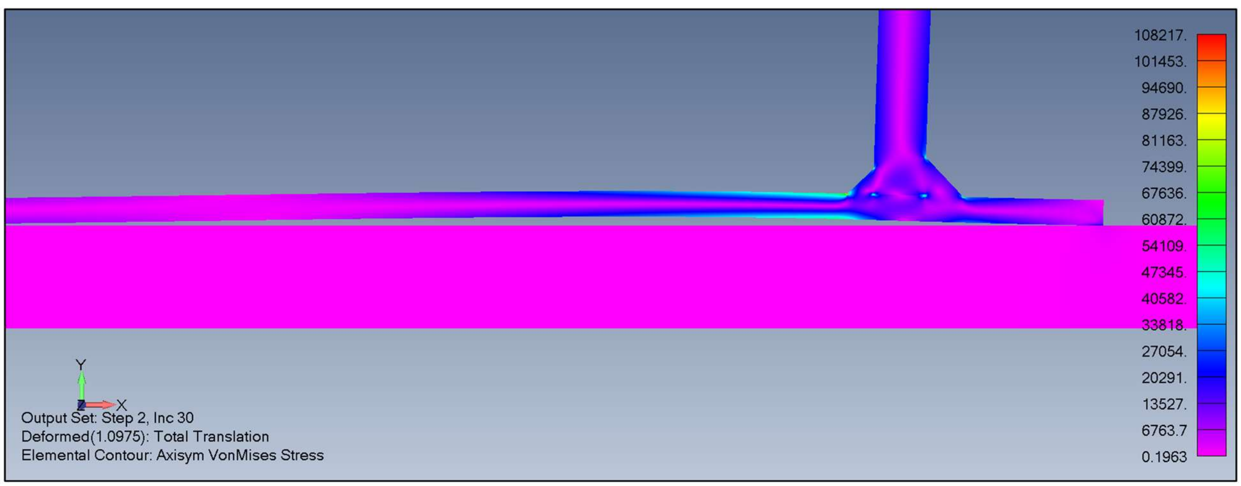


Figure 41 bbl Elastic Results: Plate Thickness = 0.25 in Full Fill SG=0.48. Von Mises stress (psi)

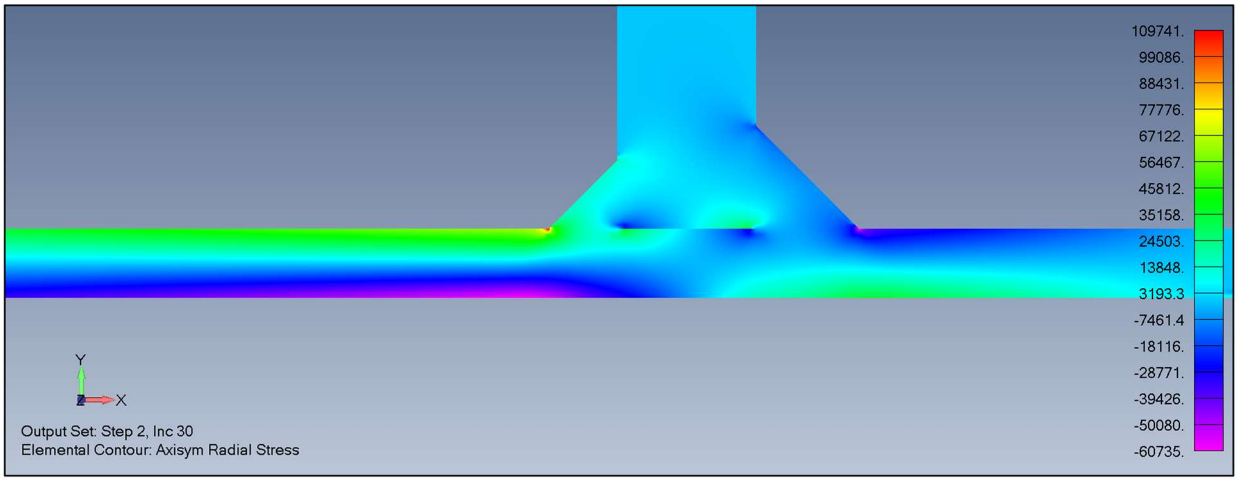


Figure 42 Elastic Results: Plate Thickness = 0.25 in Full Fill SG=0.48. Radial stress (psi)

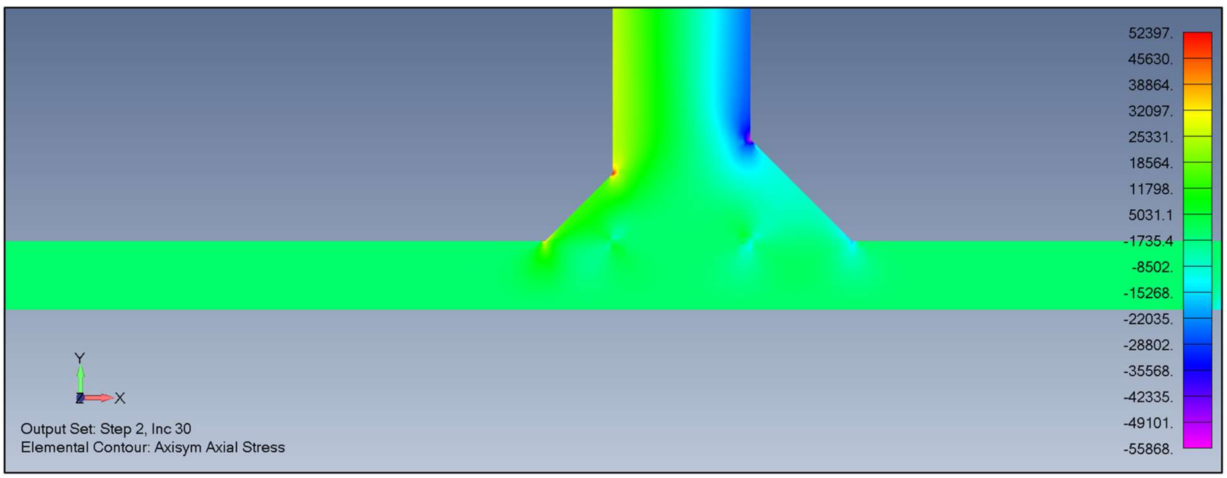


Figure 43 Elastic Results: Plate Thickness = 0.25 in Full Fill SG=0.48. Axial stress (psi)

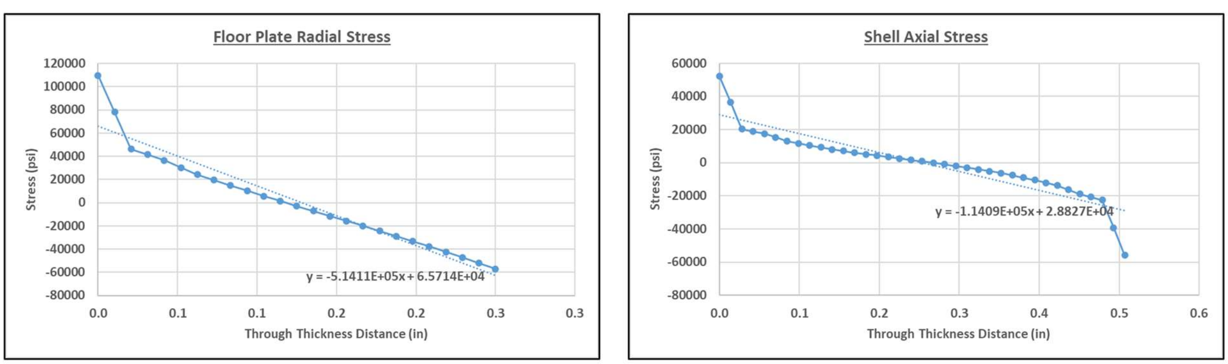


Figure 44 Plate Thickness = 0.25 in: Extracted Stress Profiles

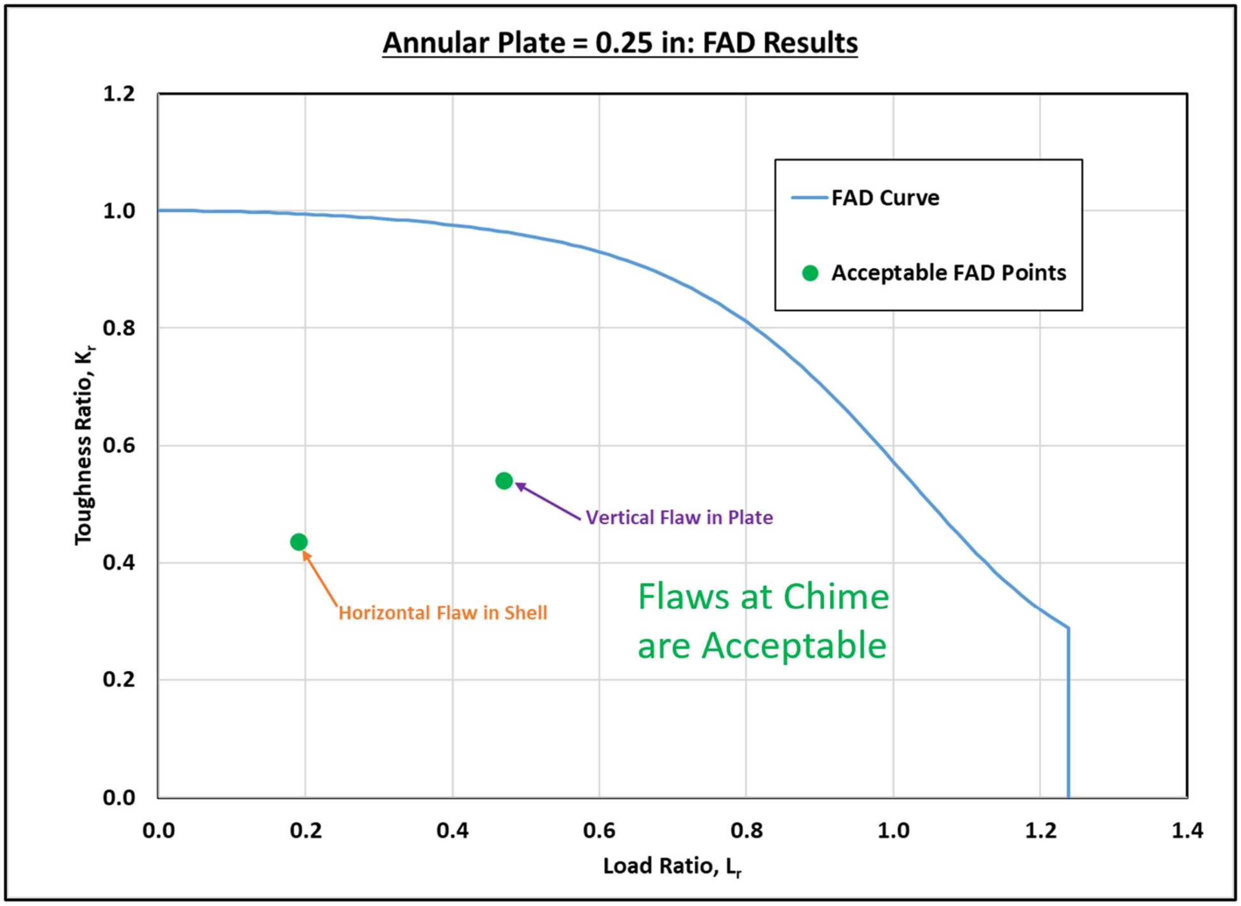


Figure 45 Plate Thickness = 0.25 in: FAD Results

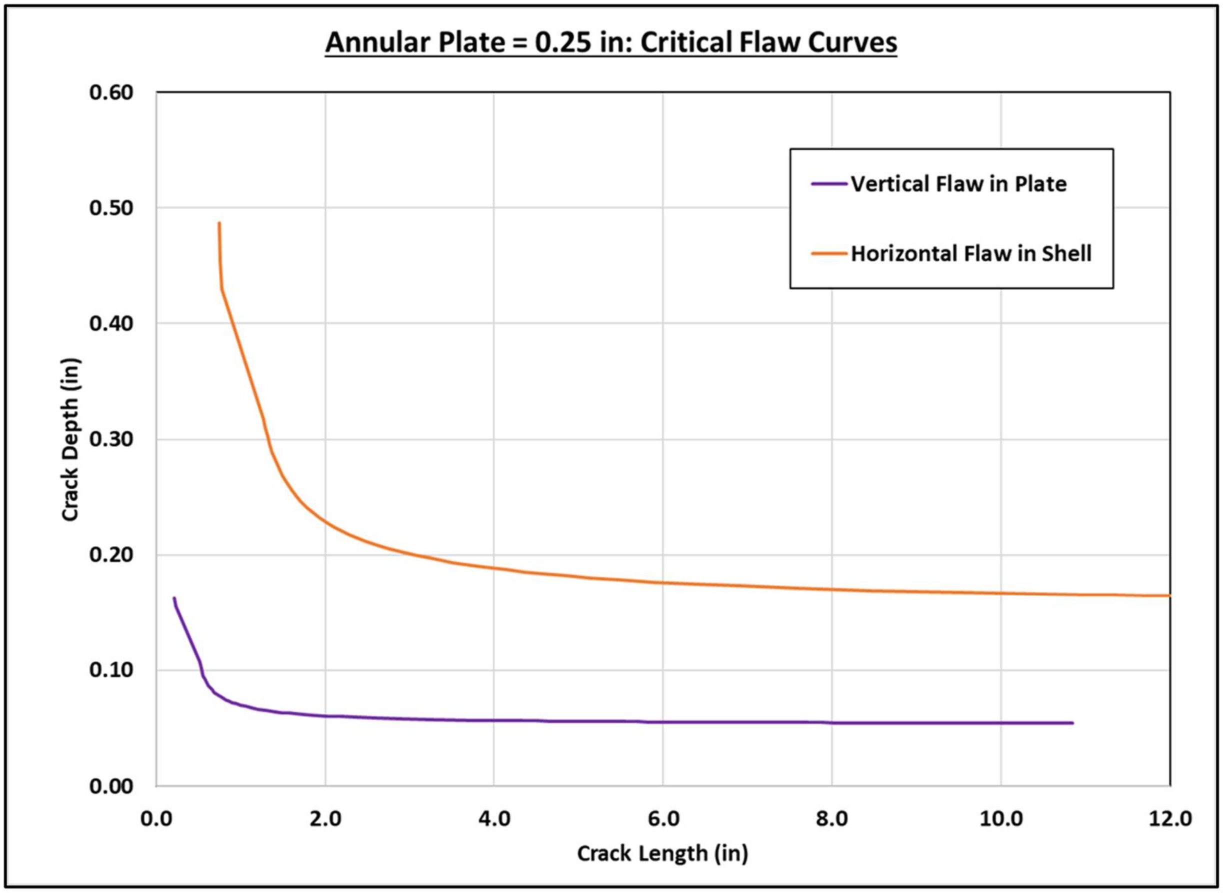


Figure 46 Plate Thickness = 0.25 in: Critical Flaw Curves

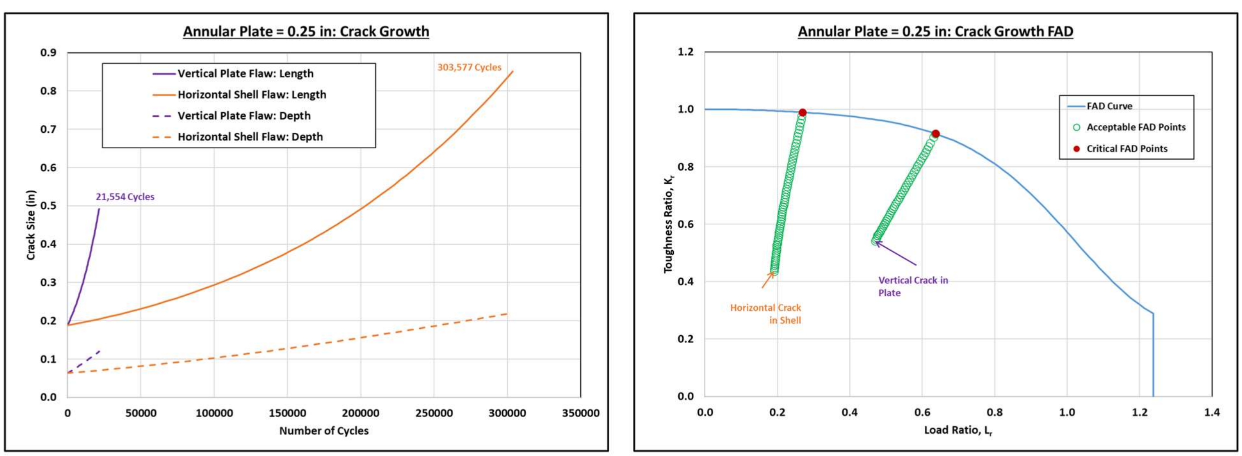


Figure 47 Plate Thickness = 0.25 in: Fatigue Crack Growth Results

6.4 Increase Annular Plate Thickness to 0.375

The model data are:

- Axisymmetric model with annular plate thickness = 0.375 in.
- Total annular plate length = 22 in.

- External plate overhang at chime = 2 in.
- Chime weld:
  - 45 degree
  - 0.25 in leg length (internal)
  - 0.375 in leg length (external)
  - No weld groove.

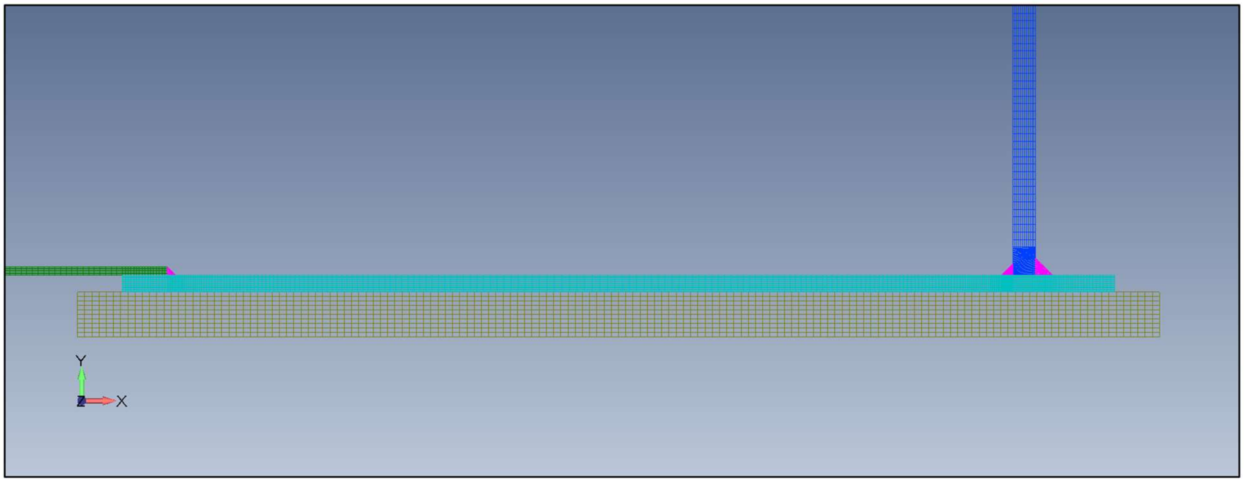


Figure 48 Axisymmetric Model: Plate Thickness = 0.375 in

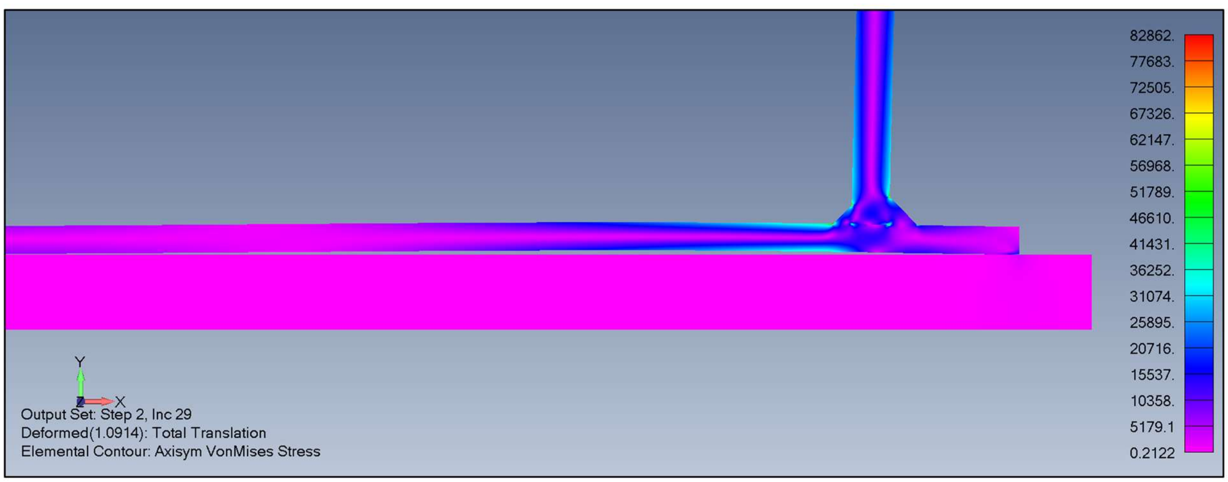


Figure 49 Elastic Results: Plate Thickness = 0.375 in Full Fill SG=0.48. Von Mises stress (psi)

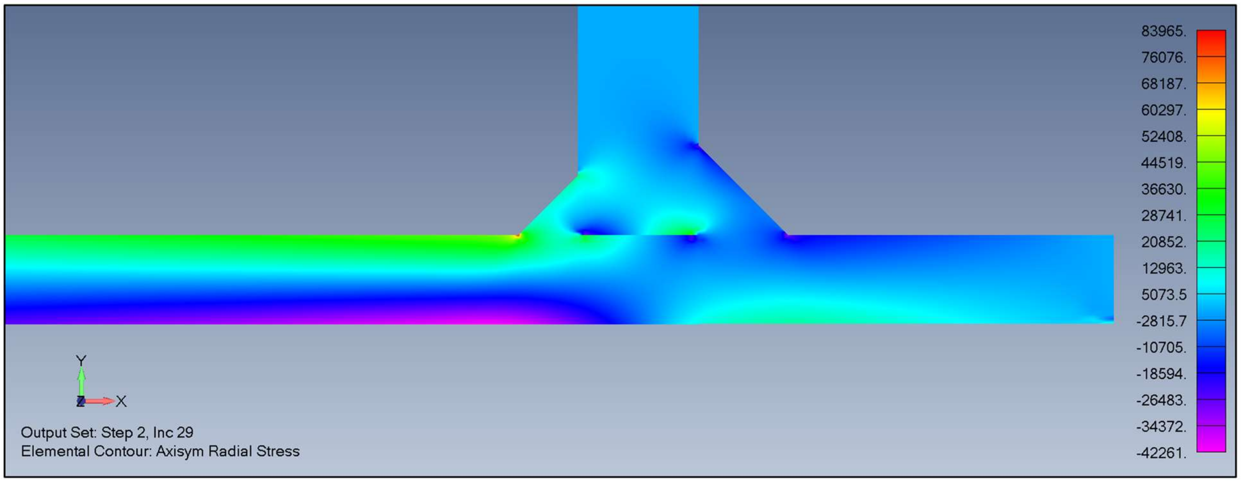


Figure 50 Elastic Results: Plate Thickness = 0.375 in Full Fill SG=0.48. Radial stress (psi)

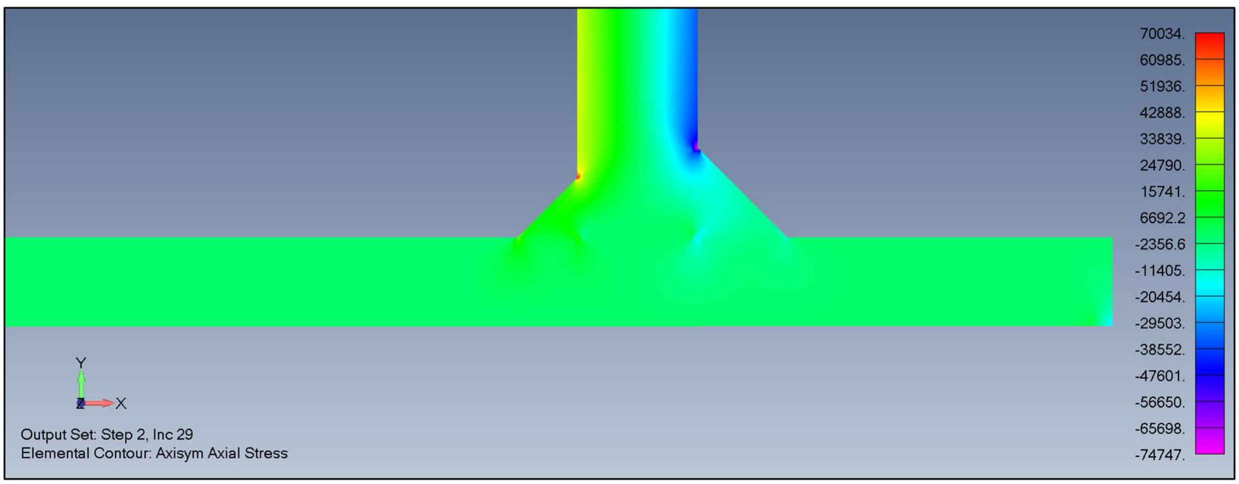


Figure 51 bbl Elastic Results: Plate Thickness = 0.375 in Full Fill SG=0.48. Axial stress (psi)

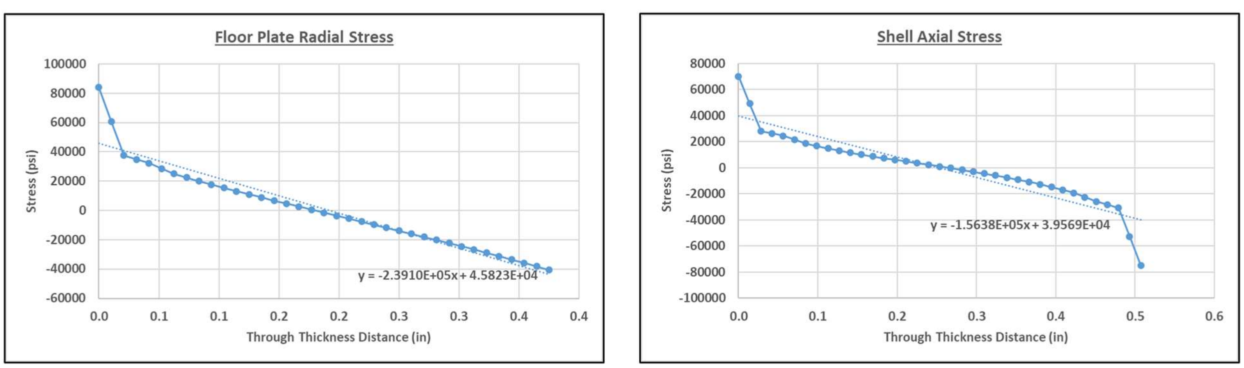


Figure 52 Plate Thickness = 0.375 in: Extracted Stress Profiles

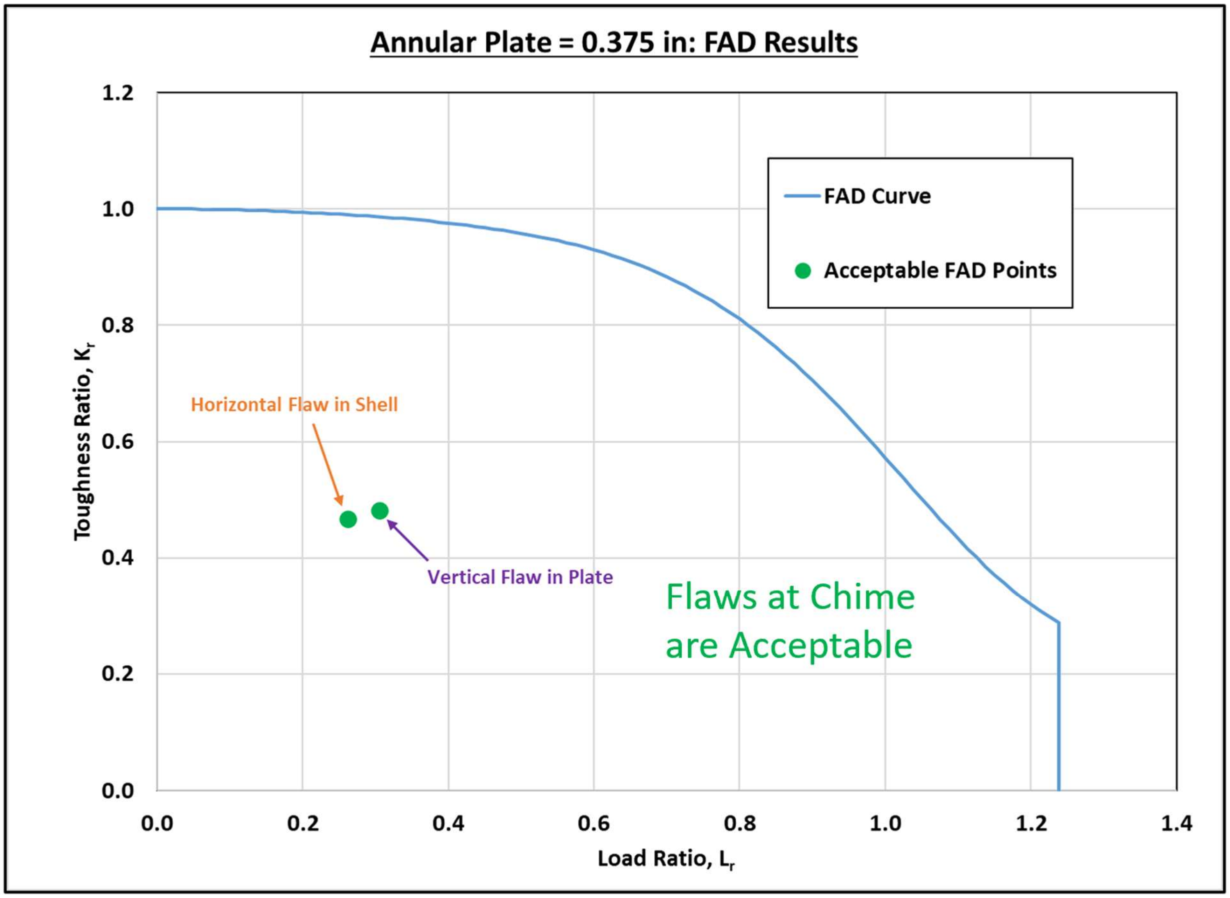


Figure 53 Plate Thickness = 0.375 in: FAD Results

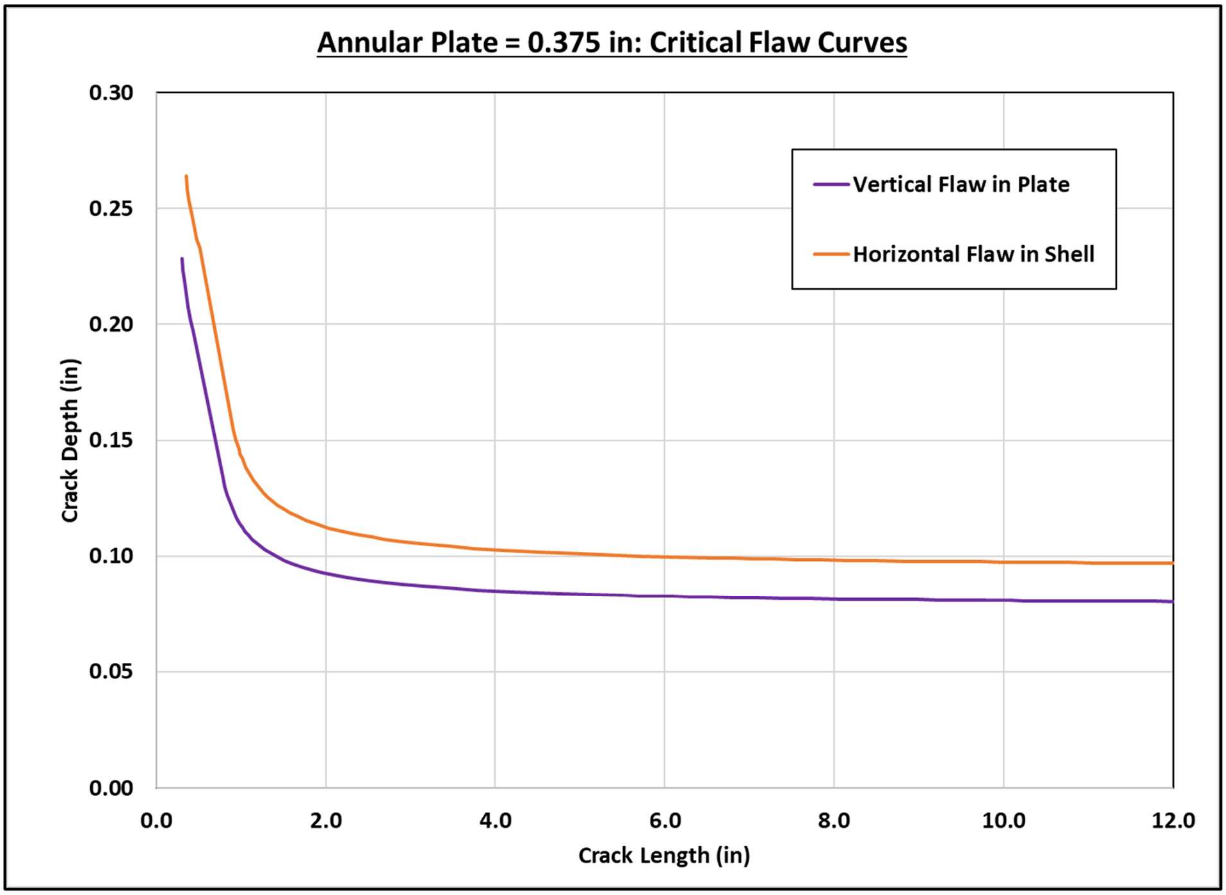
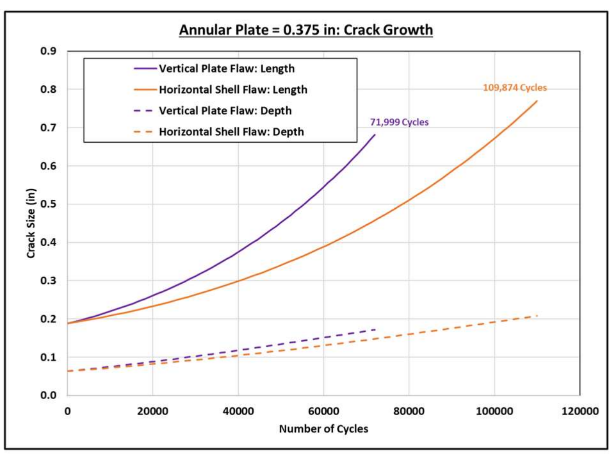


Figure 54 Plate Thickness = 0.375 in: Critical Flaw Curves



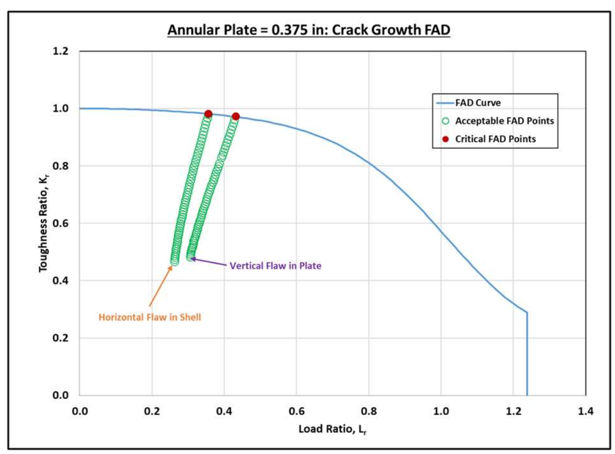


Figure 55 Plate Thickness = 0.375 in: Fatigue Crack Growth Results

6.5 Increase Annular Plate Thickness to 0.5 in

- Axisymmetric model with annular plate thickness = 0.5 in.
- Total annular plate length = 22 in.
- External plate overhang at chime = 2 in.

- Chime weld:
  - 45 degree
  - 0.25 in leg length (internal)
  - 0.375 in leg length (external)
  - No weld groove.

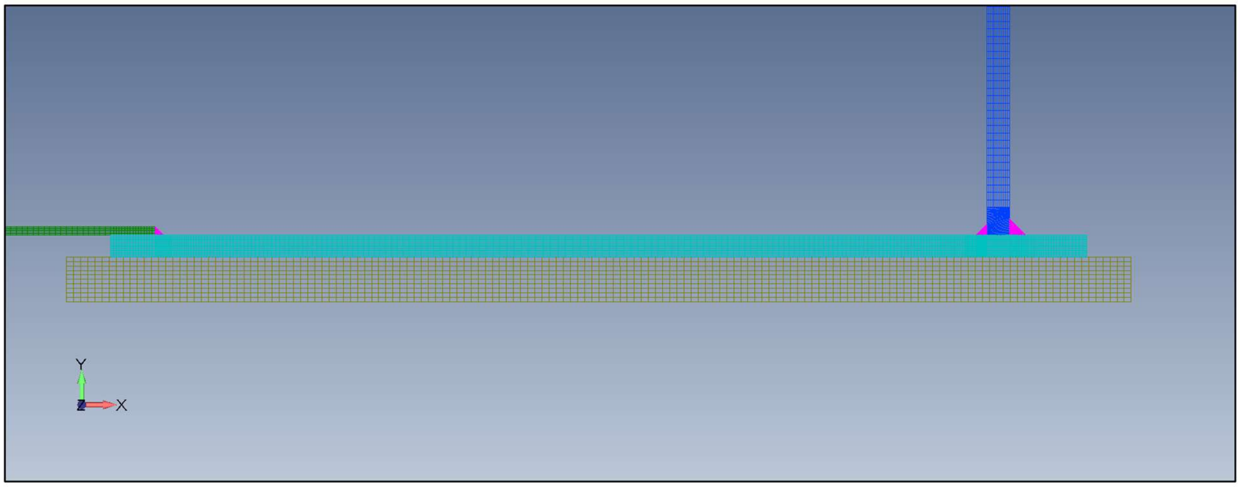


Figure 56 Axisymmetric Model: Plate Thickness = 0.5 in

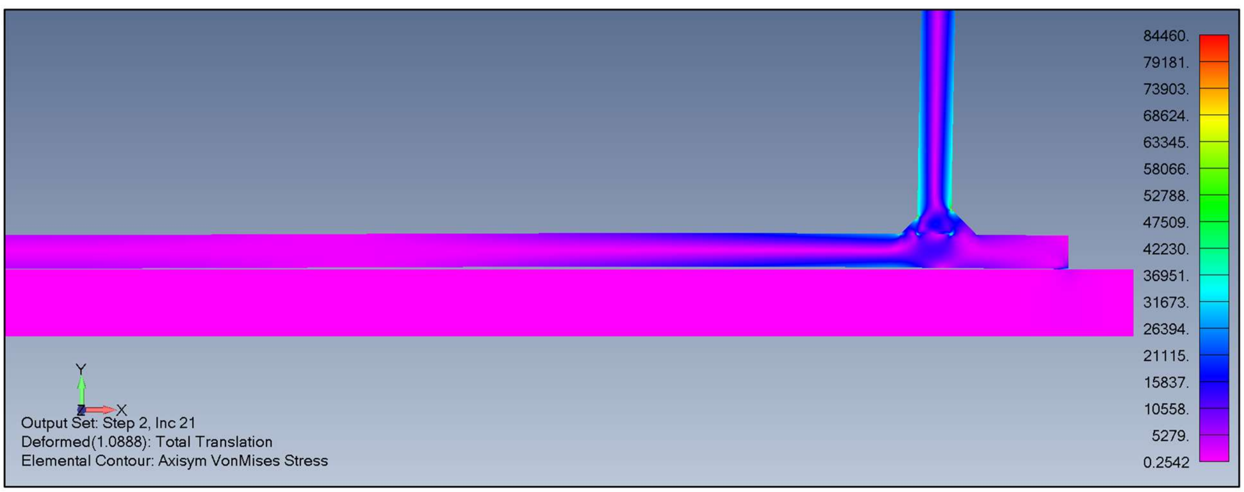


Figure 57 Elastic Results: Plate Thickness = 0.5 in Full Fill SG=0.48. Von Mises stress (psi)

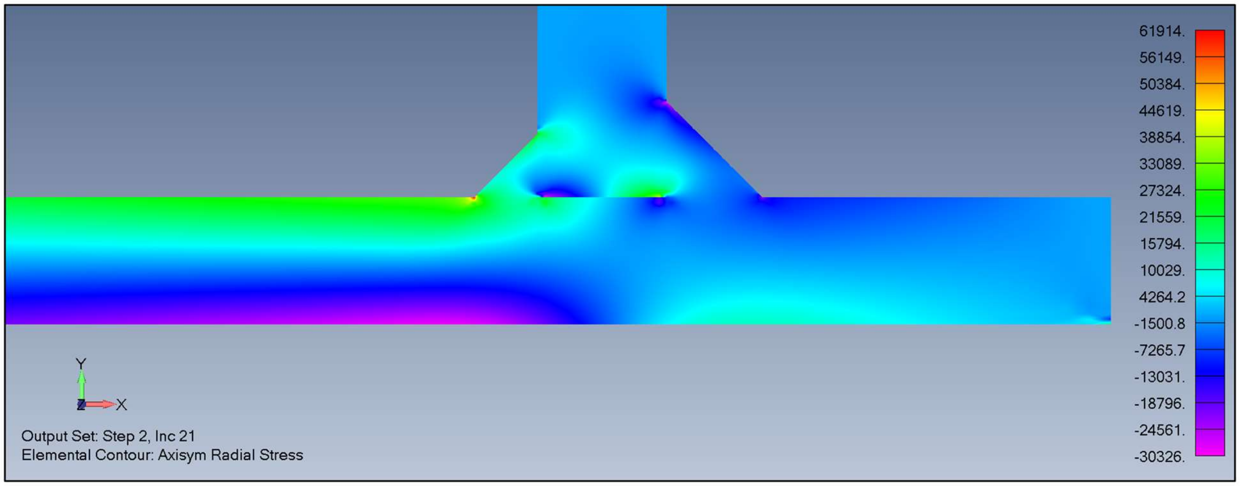


Figure 58 Elastic Results: Plate Thickness = 0.5 in Full Fill SG=0.48. Radial stress (psi)

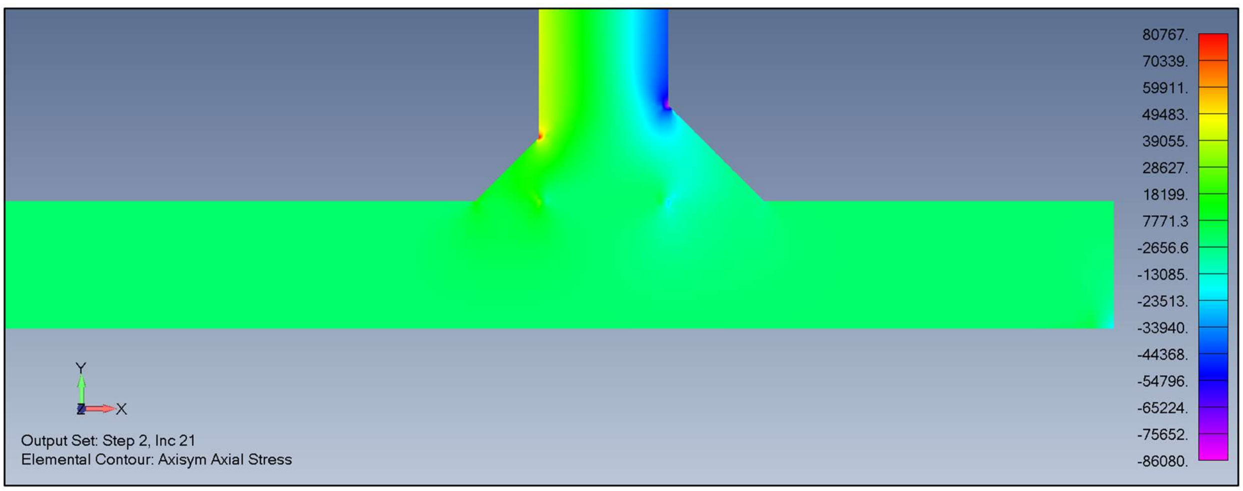


Figure 59 Elastic Results: Plate Thickness = 0.5 in Full Fill SG=0.48. Axial stress (psi)

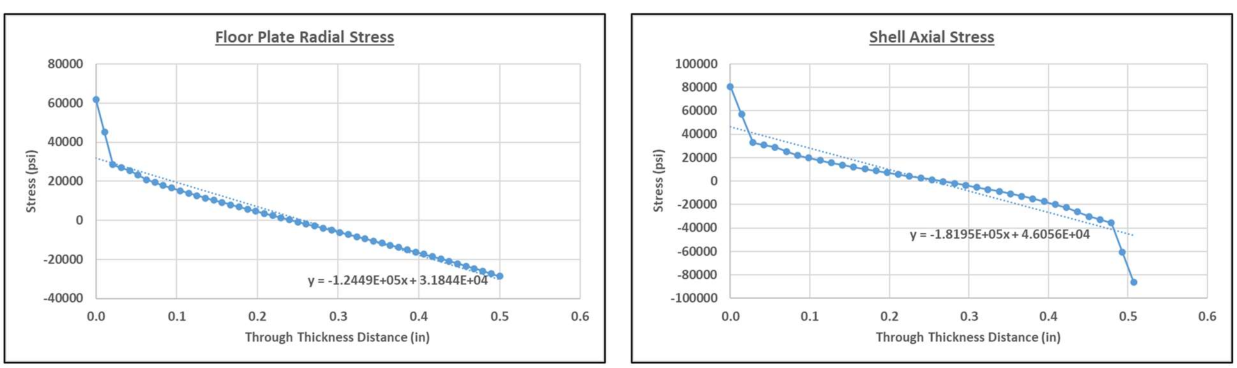


Figure 60 Plate Thickness = 0.5 in: Extracted Stress Profiles

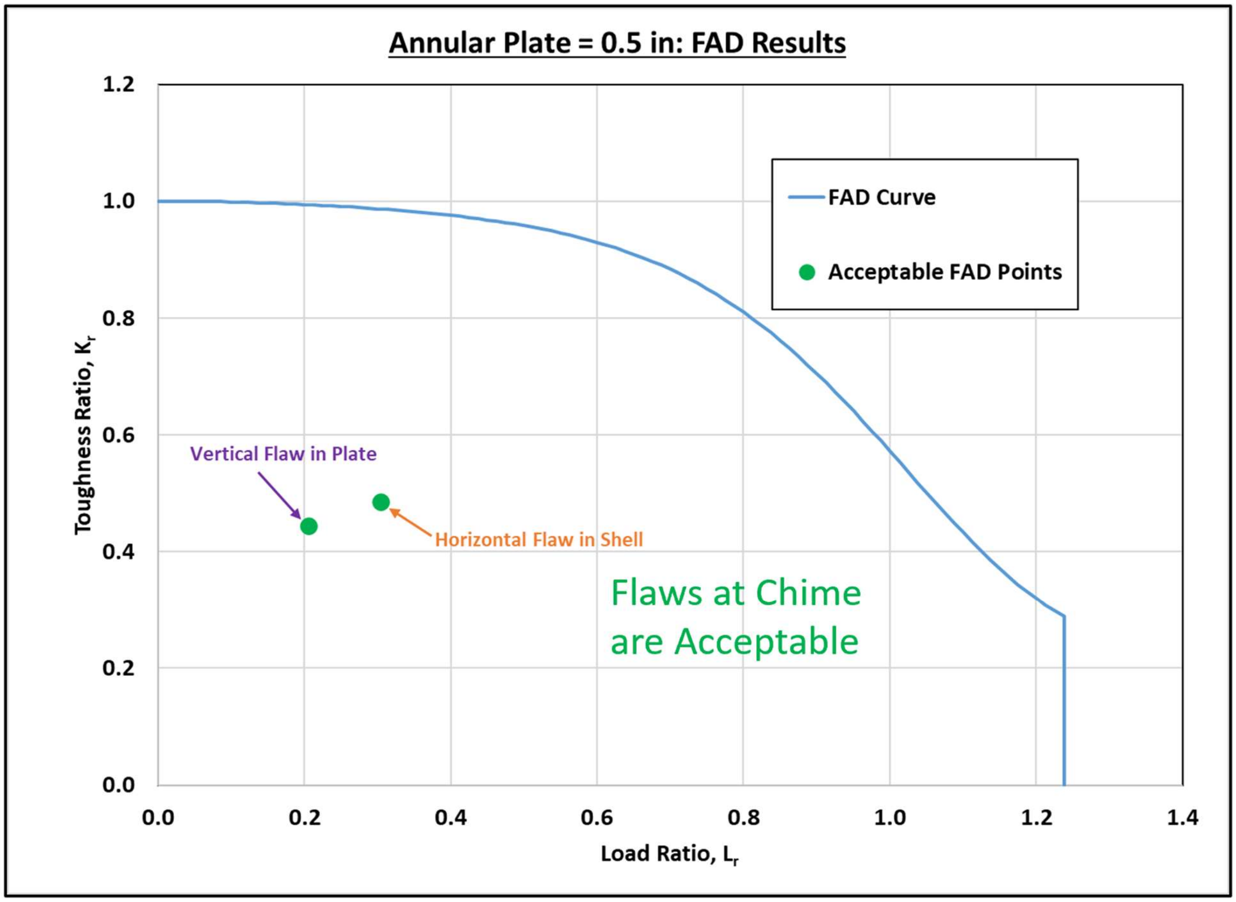


Figure 61 Plate Thickness = 0.5 in: FAD Results

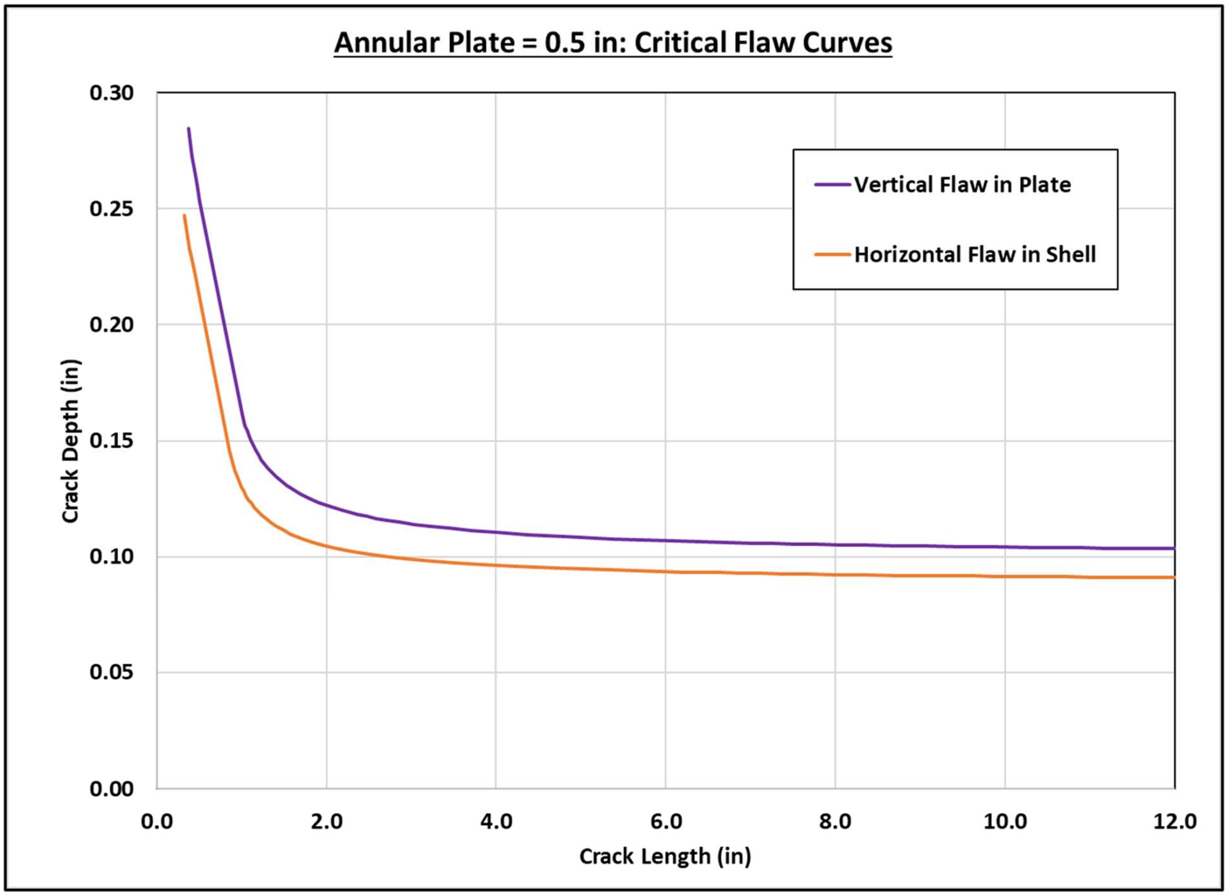
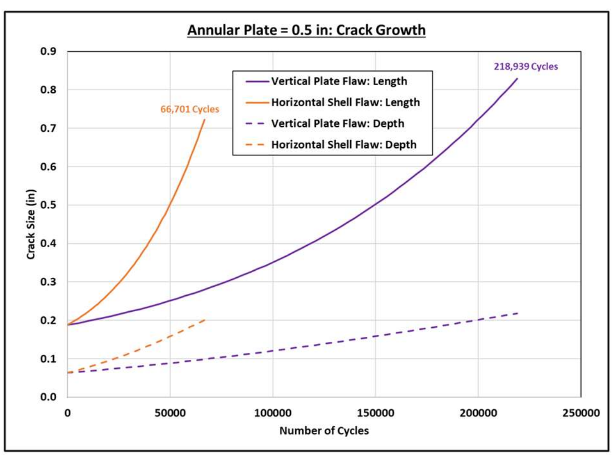


Figure 62 Plate Thickness = 0.5 in: Critical Flaw Curves



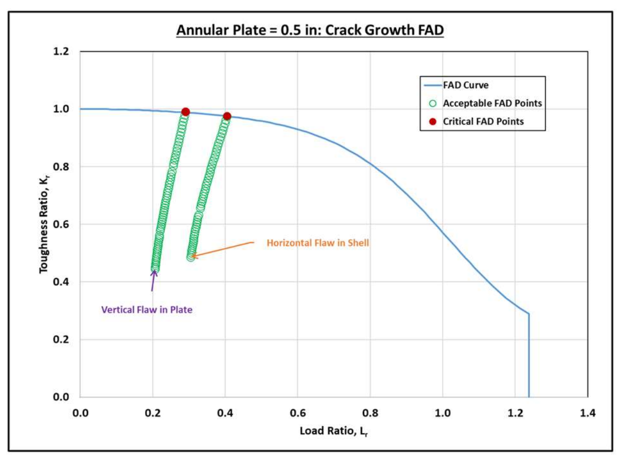


Figure 63 Plate Thickness = 0.5 in: Fatigue Crack Growth Results

6.6 Fatigue Crack Growth Results

Annular Plate Thickness (in)	Vertical Flaw in Plate Allowable Cycles	Horizontal Flaw in Shell Allowable Cycles
0.25	21,554	303,577
0.375	71,999	109,874
0.5	218,939	66,701

Table 7 Fatigue Crack Growth Results

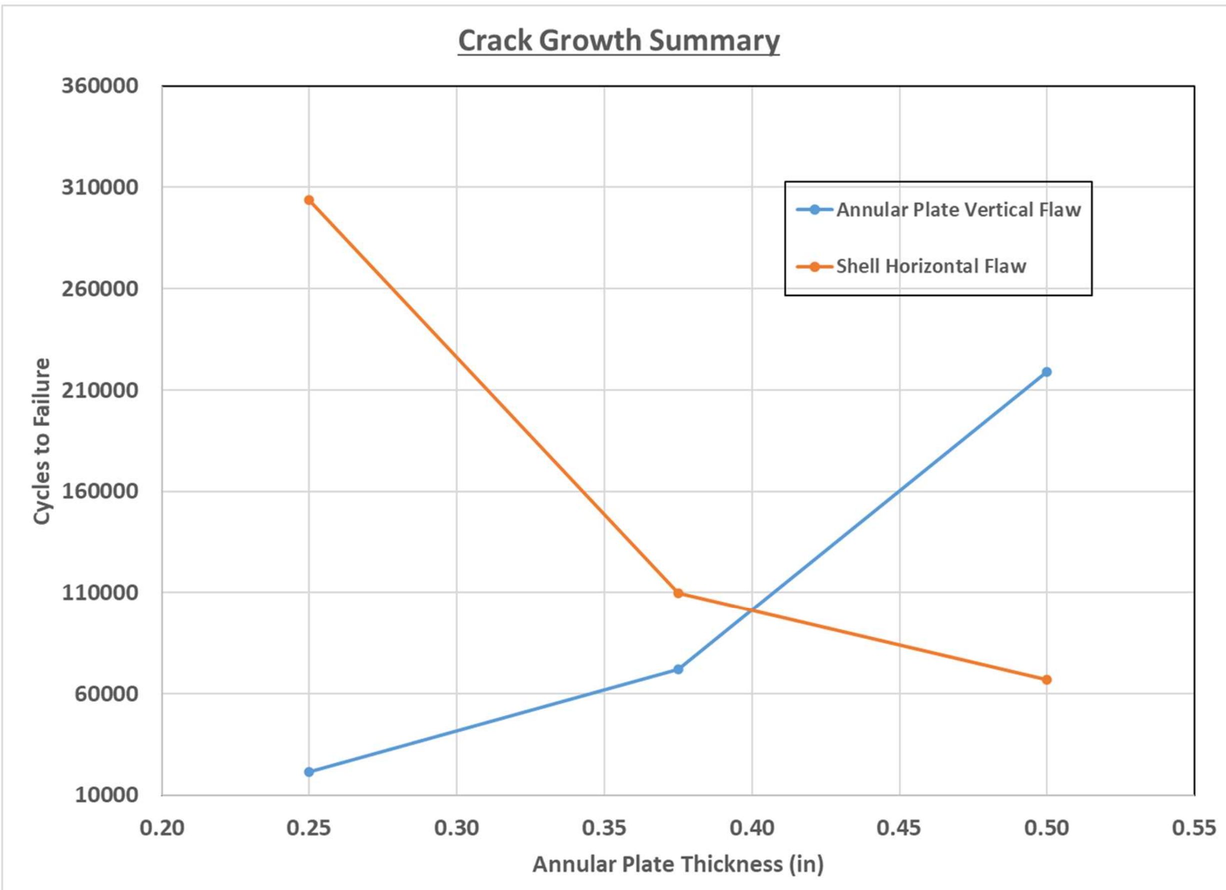


Figure 64 Fatigue Allowable Cycles versus Annular Plate Thickness

6.7 Weld Corner Crack Size Sensitivity

One of the key inputs to a fracture mechanics and fatigue crack growth assessment is the assumed initial flaw size. The previous analysis assumed a relatively large reference flaw (1/16 inch deep by 3/16 inch long). This value is typically used in fitness-for-service assessments and hydrotest exemptions, as it is the common acceptance criteria for weld non-destructive examinations such as liquid penetrant examination, which is performed on LNG tank corner welds. Decreasing the assumed initial flaw size can make a significant impact in the resulting fatigue lives. Depending on the inspection conducted, a smaller initial flaw size may be warranted.

To evaluate the effect of a smaller assumed initial flaw, the fatigue crack growth analysis was repeated varying the initial flaw depth and length.

- Compute fatigue lives for vertical flaws in annular plate.
- Radial stresses extracted at weld toe.
- Consider plate thicknesses of 0.25, 0.375, and 0.5 inch.
- Keep same 3:1 aspect ratio (length to depth).
- Vary crack depth / length:
  - 0.0625 / 0.1875 in
  - 0.0300 / 0.0900 in
  - 0.0200 / 0.0600 in
  - 0.0100 / 0.0300 in

Annular Plate Thickness (in)	Initial Crack Depth (in)	Initial Crack Length (in)	Vertical Flaw in Plate Allowable Cycles
0.25	0.0625	0.1875	21,554
	0.03	0.09	40,385
	0.02	0.06	51,590
	0.01	0.03	74,062
0.375	0.0625	0.1875	71,999
	0.03	0.09	119,939
	0.02	0.06	149,860
	0.01	0.03	213,090
0.5	0.0625	0.1875	218,939
	0.03	0.09	350,118
	0.02	0.06	437,636
	0.01	0.03	620,511

Table 8 Initial Crack Size Sensitivity: Fatigue Results

Reducing the initial flaw size greatly increases the fatigue life as shown in Figure 65.

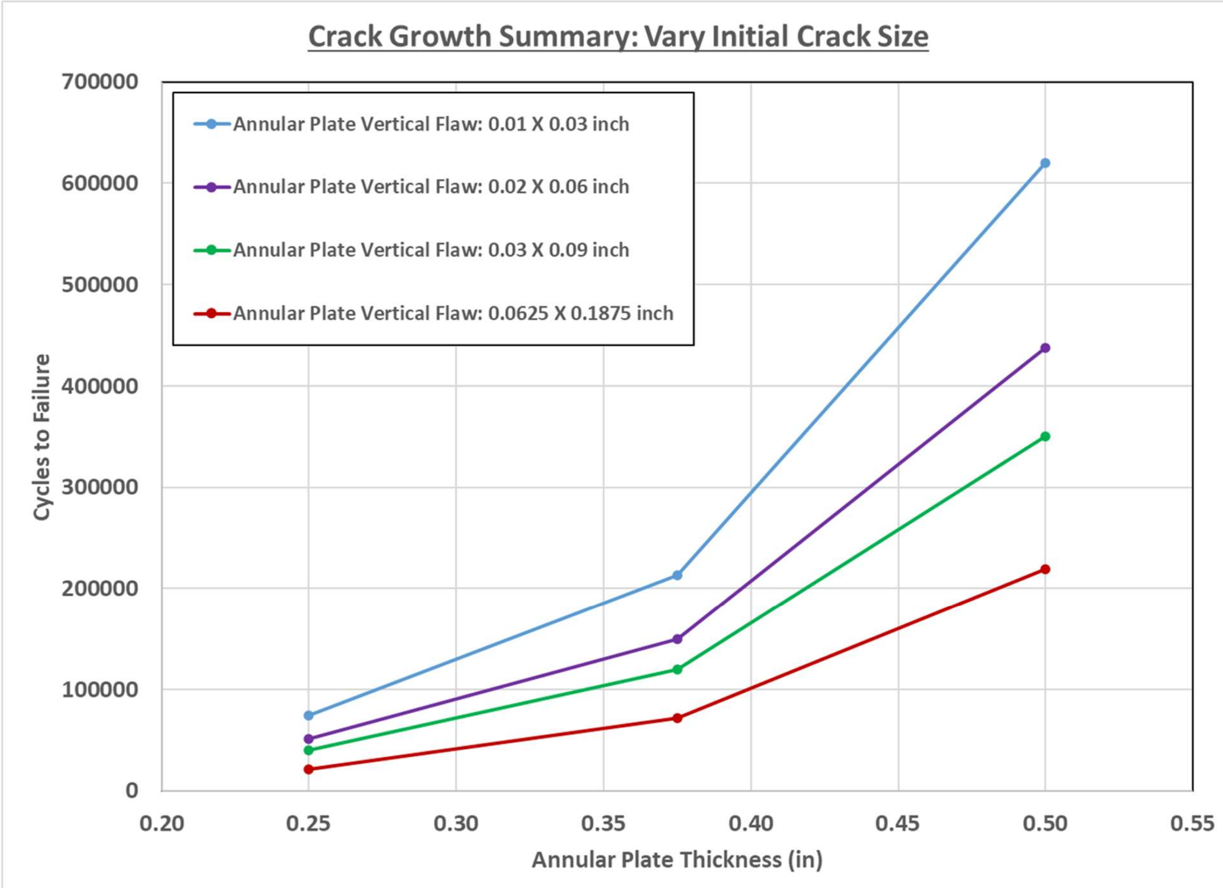


Figure 65 Initial Crack Size Sensitivity: Fatigue Results

6.8 SN Fatigue Curves

Traditionally, fatigue design has been based on the SN curve methodology. It is founded on material test data of applied stress (S) and cycles to failure (N). The stress and cycle datapoints are plotted to form a design curve. The tests are typically performed on specific material specifications using a smooth bar, polished to remove effects of surface quality (surface defects and roughness). The test data may not account for the effects of welded joints, so weld quality factors are applied based on the weld quality, in consideration of the weld joint type, finishing, and examinations. Key disadvantages of using SN curve methodology are that fatigue life cannot be renewed by performing examinations on the welds and that only peak stress at the surface is considered.

To more fully understand the fatigue life of the two tanks, we also analyzed them using SN fatigue methods of API 579 Section 14.4.3.2 Method A – Fatigue Assessment Using Elastic Stress Analysis and Equivalent Stresses, which is based on ASME BPVC Section VIII Div. 2 Part 5.5.3 Fatigue Assessment – Elastic Stress Analysis and Equivalent Stress. Material data for the SN curve analysis was difficult to find, and the best available data is taken from NIST publication LNG Materials and Fluids, as shown in Figure 66. We faced several challenges using the SN curve. It is unclear what stress range should be used with the curve. Standard API 579 and the BPVC use an alternating stress, which is half the total stress range, but then they have penalty factors as well. The SN curve says “Flexural Fatigue Strength” which typically refers to the total bending load, though on this graph its converted to stress. So it is unclear if the total stress or half the stress should be used. This analysis assumed full stress range. The stress direction is unclear. Typically, SN fatigue uses von Mises stress, but flexural would suggest bending stress. The curve only covers a narrow range, and extrapolation on SN curves is usually ill advised. It is unknown whether the curve is from smooth bar or welded joints or whether it is intended to be used with weld joint penalty factors or with any particular code basis. We assumed a weld joint strength reduction factor of 4.0 based on the API Standard 579. For these reasons we do not advise to rely upon the results from the SN curve assessment.

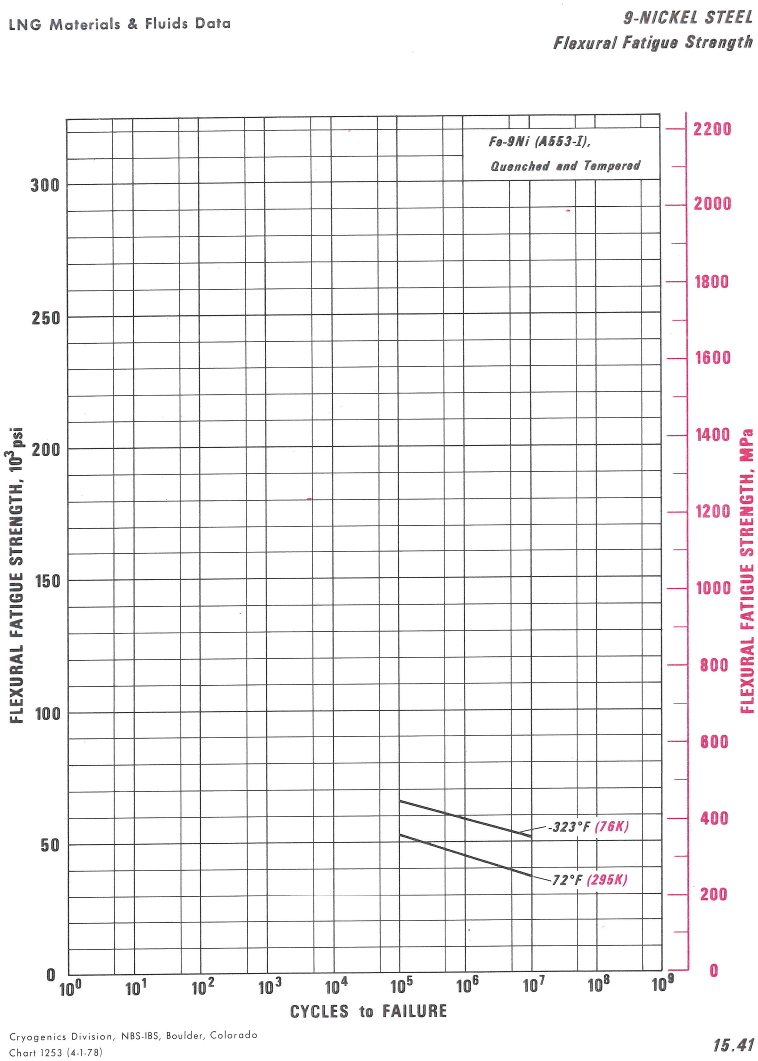


Figure 66 Fatigue Curve from NIST publication LNG Materials and Fluids

Results of the SN curve fatigue assessment are presented and compared to the results of the fracture mechanics fatigue analysis in Table 2. The SN curve assessment generally predicts higher cycle counts. There are multiple sources of uncertainty associated with the SN curve assessment, so that we don't consider it reliable. The SN curve approach may be unconservative for LNG tanks and 9% nickel steel.

		SN Fatigue		Fracture Mechanics	
		Weld Quality 4			
	Floor	Allowable	Allowable	Allowable	Allowable
ID	Plate Thick	Cycles	Cycles	Cycles	Cycles
(ft)	(in)	@72F	@-323F	Depth=1/16"	Depth=0.02"
225	0.656	5.26E+04	3.93E+06	2.28E+04	5.10E+04
	0.750	6.59E+05	5.57E+07	3.27E+04	7.21E+04
	1.000	6.79E+07	7.18E+09	8.23E+04	1.76E+05
164	0.250	1.01E+04	6.95E+05	2.16E+04	5.16E+04
	0.375	1.10E+07	1.06E+09	7.20E+04	1.50E+05
	0.500	7.32E+08	8.70E+10	2.19E+05	6.21E+05

Table 2 SN Curve and Fracture Mechanics Fatigue Results Comparison

6.9 Fatigue Life Summary

FEA indicated significant bending stresses in the plate at the chime weld. However, estimated allowable fatigue cycles are still reasonable for the expected number of fill cycles. The fatigue lives are governed by cracking in the annular plate at the chime weld. Increasing the annular plate thickness beyond the minimum 0.25 inch value results in a corresponding increase in fatigue lives. At a thickness at or beyond approximately 0.4 inch, cracking in the shell at the chime becomes the governing location (as opposed to the plate). The initial analyses assumed a relatively large reference flaw. If justified by inspection of the relevant welds, a smaller flaw size could be considered, resulting in significant increases in the estimated fatigue lives. Note that this analysis conservatively assumed completely empty to completely full cycles. Reduced variation in fill height would result in increased fatigue life.

Appendix 6 Bibliography

The following references were evaluated for relevancy to this Project.

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5. ACI, *Code Requirements for Design and Construction of Concrete Structures for the containment of Refrigerated Liquefied Gases*, 376, 2011 Edition, American Concrete Institute 2011.
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7. EN, *Design and manufacture of site built, vertical, cylindrical, flat-bottomed steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0 °C and –165 °C*, 14620, Sixth Edition, European Committee for Standardization, 2014.
8. EN, *Design, construction and operation of all onshore liquefied natural gas (LNG) installations for the liquefaction, storage, vaporization, transfer and handling of LNG and natural gas (NG)*, 1473, 2021 Edition, European Committee for Standardization, 2021.
9. ISO/TS, *Risk Assessment In The Design Of Onshore LNG Installations Including The Ship/Shore Interface*, Technical Specification 16901, First Edition, International Organization for Standardization, 2015.
10. API, *Tank Inspection, Repair, Alteration, and Construction*, Standard 653, Fifth Edition, American Petroleum Institute, 2014.
11. API, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Recommended Practice 571, Third Edition, American Petroleum Institute, 2020.