

Aboveground Storage Tank Standards: A Tutorial

HEALTH AND ENVIRONMENTAL AFFAIRS DEPARTMENT

API PUBLICATION No. 327

SEPTEMBER 1994



American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005



Documents

Document Sharing Hub



One of the most significant long-term trends affecting the future vitality of the petroleum industry is the public's concerns about the environment. Recognizing this trend, API member companies have developed a positive, forward looking strategy called STEP: Strategies for Today's Environmental Partnership. This program aims to address public concerns by improving our industry's environmental, health and safety performance; documenting performance improvements; and communicating them to the public. The foundation of STEP is the API Environmental Mission and Guiding Environmental Principles.

API ENVIRONMENTAL MISSION AND GUIDING ENVIRONMENTAL PRINCIPLES

The members of the American Petroleum Institute are dedicated to continuous efforts to improve the compatibility of our operations with the environment while economically developing energy resources and supplying high quality products and services to consumers. The members recognize the importance of efficiently meeting society's needs and our responsibility to work with the public, the government, and others to develop and to use natural resources in an environmentally sound manner while protecting the health and safety of our employees and the public. To meet these responsibilities, API members pledge to manage our businesses according to these principles:

- To recognize and to respond to community concerns about our raw materials, products and operations.
- To operate our plants and facilities, and to handle our raw materials and products in a manner that protects the environment, and the safety and health of our employees and the public.
- To make safety, health and environmental considerations a priority in our planning, and our development of new products and processes.
- To advise promptly, appropriate officials, employees, customers and the public of information on significant industry-related safety, health and environmental hazards, and to recommend protective measures.
- To counsel customers, transporters and others in the safe use, transportation and disposal of our raw materials, products and waste materials.
- To economically develop and produce natural resources and to conserve those resources by using energy efficiently.
- To extend knowledge by conducting or supporting research on the safety, health and environmental effects of our raw materials, products, processes and waste materials.
- To commit to reduce overall emission and waste generation.
- To work with others to resolve problems created by handling and disposal of hazardous substances from our operations.
- To participate with government and others in creating responsible laws, regulations and standards to safeguard the community, workplace and environment.
- To promote these principles and practices by sharing experiences and offering assistance to others who produce, handle, use, transport or dispose of similar raw materials, petroleum products and wastes.

Aboveground Storage Tank Standards: A Tutorial

Health and Environmental Affairs Department

API PUBLICATION NO. 327

SEPTEMBER 1994

**American
Petroleum
Institute**



ACKNOWLEDGEMENTS

This project was undertaken by the American Petroleum Institute (API) through the combined efforts of consultants, company representatives, and API staff. Will Carter of Chevron Oil Company, in conjunction with the API Storage Tank Task Force, developed the concept of the document. Rich Basile of Exxon, Phil Smith of Texaco, Bruce Roberts of Aramco, and Rick Nichols of Pennzoil made substantial contributions to the technical details. Dee Gavora of API's Health and Environmental Affairs Department served as Project Officer. Dana Marinacci, a graduate student in public policy at Duke University, assisted in technical editing and production of this report. The API Refining Department and Office of General Counsel provided essential review of the technical information to facilitate completion of this document.

Copyright 2003 by American Petroleum Institute



FOREWORD

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

API is not undertaking to meet the duties of employers, manufacturers, or suppliers to warn and properly train and equip their employees, and others exposed, concerning health and safety risks and precautions, nor undertaking their obligations under local, state, or federal laws.

Nothing contained in any API publications is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

API makes no recommendations regarding the course of conduct that should be followed, and the reader is in no way bound to the findings of this study. The reader should exercise independent judgment that suits individual needs and must negotiate independently with the suppliers of any technology.

API makes no promises, claims, or recommendations as to the site specific applicability, performance, or economics of any technology described herein. The reader is cautioned regarding the interpretation of any references to "costs" or "cost effectiveness" as these references may not be applicable to his/her specific application.

This tutorial may be used by anyone desiring to do so. Every effort has been made by the American Petroleum Institute to assure the accuracy and reliability of the material contained in it at the time in which it was written. However, API makes no representation, warranty, or guarantee in connection with the publications of this tutorial and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any federal, state or municipal regulation with which this tutorial may conflict, nor does API undertake any duty to ensure its continued accuracy.

PREFACE

The American Petroleum Institute (API) sponsored the preparation of this document, "Aboveground Storage Tank Standards: A Tutorial," which presents procedures and examples to aid in understanding and complying with API's Recommended Practices (RPs), Standards (STDs), and Specifications (SPECS) regarding the prevention of leaks caused by bottom or shell corrosion, brittle fracture, and excessive settlement. It also shows how the API inspection and maintenance requirements influence the initial design of tanks. This tutorial is not meant to be used by itself; rather it is meant to be used as an aid in understanding the relevant RPs, STDs, and SPECS and to be used in conjunction with those documents.



TABLE OF CONTENTS

1.0 INTRODUCTION AND SCOPE	1
2.0 SUMMARY OF PROCEDURES	3
FIGURE 2.1: LOGIC DIAGRAM FOR TANK DESIGN & EVALUATION	4
FIGURE 2.2: LOGIC DIAGRAM FOR BOTTOM EVALUATION	6
FIGURE 2.3: LOGIC DIAGRAM FOR SHELL EVALUATIONS	8
3.0 BASIC DATA REQUIREMENTS	9
FIGURE 3.0 - HIGH PRIORITY DATA	9
4.0 BOTTOM SELECTION	11
Case 1 - Basic Design Data for 150,000 BARREL API STD 650 Tank	13
Case 2 - Basic Design Data for 10,000 BARREL Gasoline Storage Tank	13
Case 3 - Basic Design Data for 500 BARREL Production Fluid Tank	14
Example 4.1 - Ground/Bottom Contact - 150,000 Barrel Tank	15
Example 4.2 - Ground/Bottom Contact - 10,000 Barrel Gasoline Tank	16
Example 4.3 - Ground/Bottom Contact - 500 Barrel Production Tank	17
Example 4.4 - Cathodically Protected Bottom	18
Example 4.5 - Leak Detection/Containment System	19
Example 4.6 - Leak Detection/Containment System	20
Example 4.7 - Internal Bottom Lining	21
Example 4.8 - Internal Bottom Lining and Cathodic Protection	23
5.0 INSPECTION	25
FIGURE 5.1	25
FIGURE 5.2	26
6.0 BOTTOM FLAWS	27
FIGURE 6.1	27
Example 6.1 - Bottom Settlement	28
Example 6.2 - Bottom Corrosion	29
7.0 SHELL EVALUATION	31
Example 7.1 - Minimum Shell or Ring Thickness	31
Example 7.2 - Risk of Brittle Fracture	32
Appendix A	35
Appendix B	39
Appendix C	43
Appendix D	47
Appendix E	55
Appendix F	63
Appendix G	69
Appendix H	75

1.0 INTRODUCTION AND SCOPE

1.1 Introduction

This document is published to help owner/operators of aboveground storage tanks (ASTs) maintain ASTs in an environmentally safe manner.

API maintains several comprehensive documents that address the design, fabrication, operation, inspection, and maintenance of ASTs. Based on the combined industry experience of tank designers, fabricators and owners, the API documents provide guidelines designed to minimize the risk of an environmental hazard caused by spills or leaks.

This tutorial presents a set of procedures and examples to aid in understanding and complying with API Recommended Practices (RPs), Specifications (SPECs) and Standards (STDs).

1.2 Scope

The procedures contained in this tutorial address the prevention of leaks or catastrophic loss caused by corrosion of the tank bottom or shell, brittle fracture, and excessive settlement. And, most importantly, they show how the API inspection and maintenance documents influence the design of new or proposed tanks.

This document is applicable to ASTs fabricated and/or maintained per the following standards:

- API SPEC 12B: Bolted Tanks for Storage of Production Liquids;
- API SPEC 12D: Field Welded Tanks for Storage of Production Liquids;
- API SPEC 12F: Shop Welded Tanks for Storage of Production Liquids;
- API RP 12R1: Setting, Maintenance, Operation, and Repair of Tanks in Production Service;
- API STD 650: Welded Steel Tanks for Oil Storage;
- API RP 651: Cathodic Protection of Aboveground Storage Tanks;
- API RP 652: Lining of Aboveground Petroleum Storage Tank Bottoms;
- API STD 653: Tank Inspection, Repair, Alteration, and Reconstruction.

Application of the principles discussed in this tutorial to ASTs constructed to differing design criteria should be based on sound engineering judgements. This tutorial does not attempt to address additional rules and requirements that may be imposed by individual jurisdictions or states.

2.0 SUMMARY OF PROCEDURES

Figures 2.1, 2.2, and 2.3 are logic diagrams that provide a picture of the process used to minimize the risk of bottom or shell leaks from a proposed or existing tank. The discussion below briefly summarizes each diagram.

2.1 Proposed Tanks

Figure 2.1 shows that the first decision relates to whether the tank is proposed or existing. While the evaluation steps for a proposed or existing tank may be similar or in some cases identical, the results for a proposed tank provide options that influence design and construction decisions. Results associated with existing tanks may lead to repairs or a change of service conditions.

If the tank is proposed, then how does one comply with the API in-service AST inspection STD 653 and RP 12R1? (Note: These two documents will be referred to collectively as the API Standard). The logic diagram shows that the API Standard does influence the proposed design, especially in the important area of bottom selection.

If the tank is proposed, then one proceeds along the left side of Figure 2.1. After compiling basic data, the major benefit of the procedure is to provide tank bottom design options. This is an important step. If the owner/operator expects a reasonable onstream time, then the influence of cathodic protection, leak detection, linings, etc., on inspection frequency must be explored.

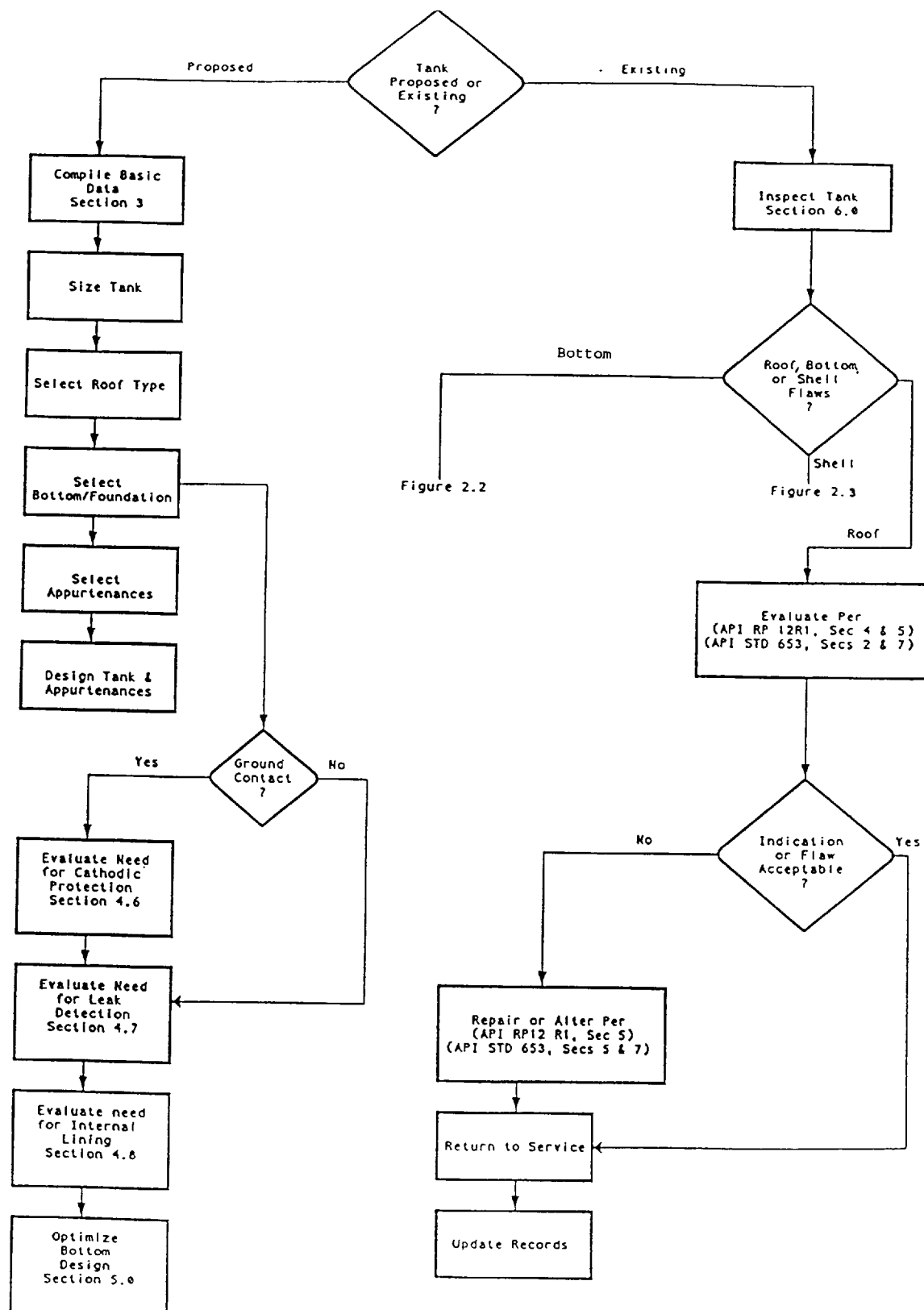
Tank bottom design is based on standards and engineering and economic data. The last box on Figure 2.1 provides a method for selecting a bottom design when several configurations satisfy the API Standard.

2.2 Existing Tanks

The right side of Figure 2.1 shows that the evaluation process for existing tanks is separated into three paths. Tank Bottom and Shell are the two paths which are addressed in this tutorial, and are shown in Figures 2.2 and 2.3, respectively.

The decision path for evaluation of a tank roof is beyond the scope of this tutorial. However, Figure 2.1 shows that existing tank roofs may be evaluated per the methods in the API Standard and repaired, altered, or returned to service.

FIGURE 2.1: LOGIC DIAGRAM FOR TANK DESIGN & EVALUATION



2.3 Tank Bottom

Figure 2.2 shows the process for evaluating an existing tank bottom. The first decision is to identify concerns associated with either settlement, corrosion, or both. This identification is determined by a tank inspection and evaluation of the inspection data.

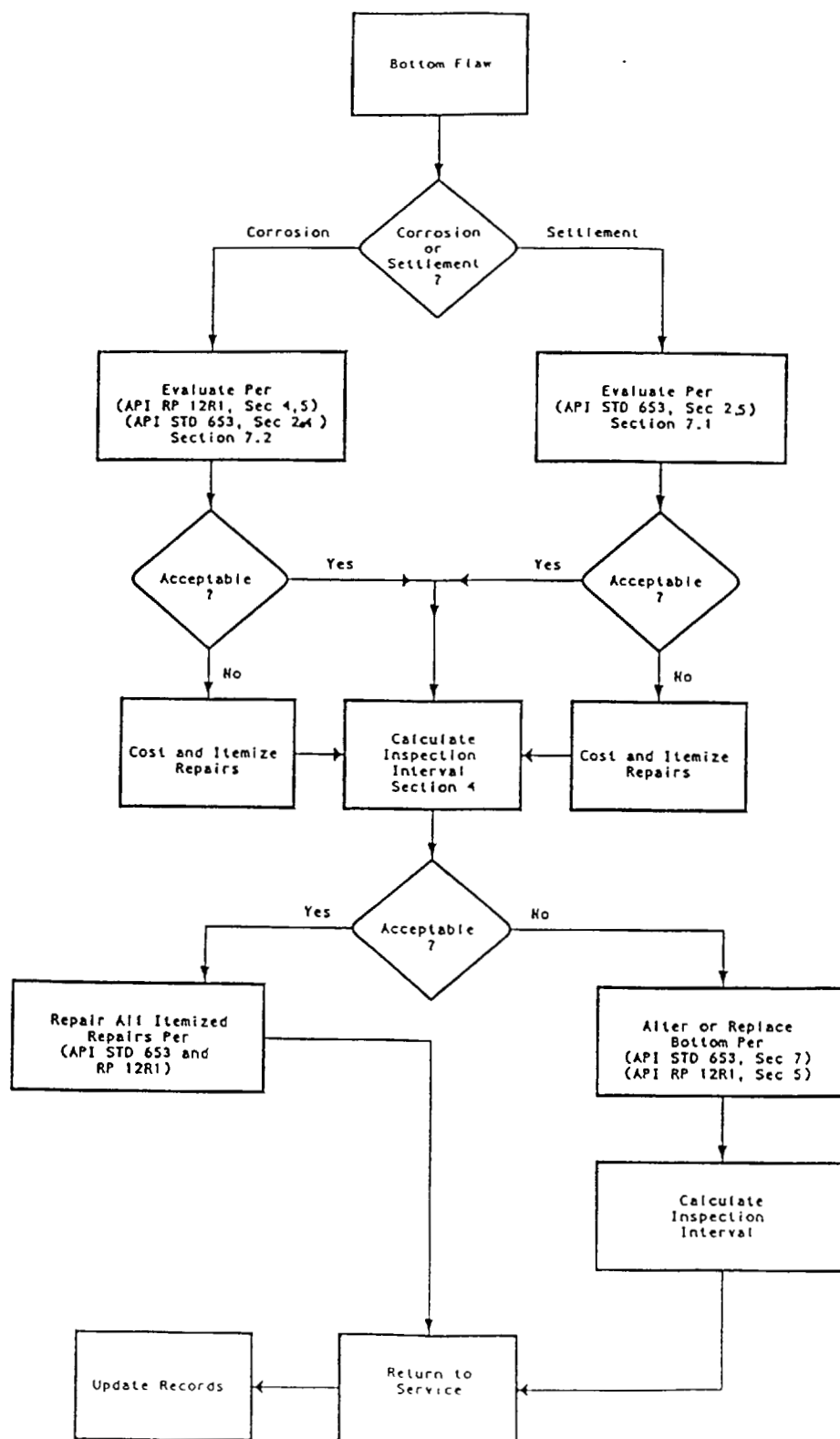
If a settlement problem is identified, then it should be evaluated as shown in Section 6.1. If found unacceptable, the problem should be added to the list of repair items.

The left side of Figure 2.2 shows the process for evaluating bottom corrosion. The referenced sections of API RP 12R1 and API STD 653, and Section 6.2 of this document provide guidance for this evaluation. When the damaged areas are found to be unacceptable, they should be added to the list of repair items.

After evaluating all the inspection data, the internal inspection interval must be calculated as described in Section 6.2, (assuming that all repairs are performed). Provided the interval is acceptable, the bottom repairs may proceed.

However, if the interval is not acceptable, the bottom must be altered, repaired, or replaced before the tank is returned to service. The procedure to evaluate these options is explained in Section 4 and includes examples.

FIGURE 2.2: LOGIC DIAGRAM FOR BOTTOM EVALUATION



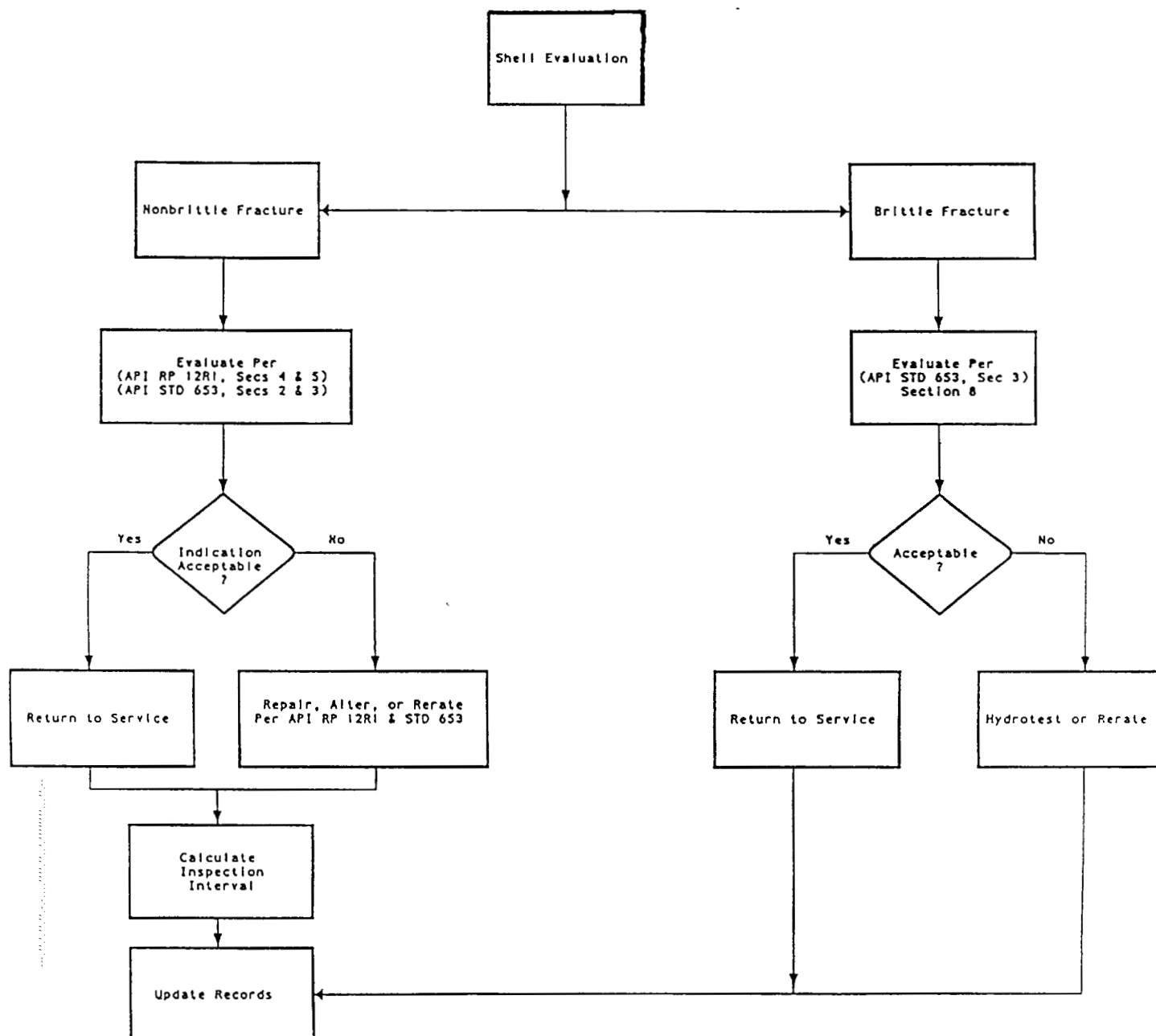
2.4 Tank Shell Evaluation

Figure 2.3 shows two paths for evaluating a tank shell. The right path is for brittle fracture considerations and should be done during the initial evaluation of a tank or when there is a change of service.

Shell evaluations that are not related to brittle fracture are typically related to corrosion/erosion, shell distortions and/or shell settlement, and these evaluation are shown on the left path. Section 8 of this tutorial identifies the paragraphs in the API Standard associated with these evaluations and illustrates how to apply the requirements.

The evaluation process for an existing tank is the basis for determining acceptability for continued service. If the results are unacceptable, then the tank must be repaired, altered, or considered for a change of service.

FIGURE 2.3: LOGIC DIAGRAM FOR SHELL EVALUATIONS



3.0 BASIC DATA REQUIREMENTS

Before using the API documents listed in Section 1.2, the reader should assemble certain basic data. These data are required before decisions can be made on the most appropriate aboveground storage tank for a given situation. The data listed in the left column below are considered essential, and additional discussion of each requirement can be found in the documents listed in the right column.

FIGURE 3.0 - HIGH PRIORITY DATA

DATA	DOCUMENTS
Foundation and Soil Condition	RP 12R1, Section 2 STD 650, Appendix B RP 651, Section 3 STD 653, Section 2
Corrosion Data	SPECS 12D & 12F, Section 5 RP 12R1, Sections 2, 4 & 5 STD 650, Section 3 RP 651, Sections 2, 3 & 5 RP 652, Section 3 STD 653, Sections 2 & 4
Operating Data which relate to above items	RP 12R1, Sections 2 & 4 STD 650, Appendix M RP 651, Sections 2 & 3 RP 652, Section 4 STD 653, Sections 2, 3, 7 & 10

4.0 BOTTOM SELECTION

This section describes procedures and considerations for selecting a tank-bottom corrosion protection design that conforms to the API Standards.

The necessary site and subsurface investigations are assumed to have been completed, and tank size, corrosion, and type of bottom, (that is cone-up, flat, cone-down, etc.) questions have been resolved.

Selecting the appropriate tank bottom corrosion protection system depends on the type of soil under the tank, expected or actual internal and external corrosion rates, location of the tank field, maintenance program, and design life of the tank.

Requirements for internal inspections have the greatest affect on tank bottom design. Internal inspection can be done only if the tank is taken out of service and entered. Owner/operators work to minimize out-of-service inspections because they are time-consuming, expensive and may generate residual material and emissions.

4.1 Tanks built to API Standard 650 Specifications

API STD 653 links out-of-service internal inspections to the thickness of the tank components including bottom plates. Section 2.4.7.3 of API STD 653 states that the minimum remaining thickness (MRT) of the bottom plates must be equal to or greater than the appropriate thickness shown in API STD 653 Table 4.1 at the end of the in-service period of operation.

The following equations are included in API STD 653 and are considered to be an acceptable method for calculating MRT:

$$MRT_1 = T_o - GC_a - StP_a - UP_m - (StP_r + UP_r + GC_r) O_r$$

$$MRT_2 = T_o - GC_a - StP_m - UP_a - (StP_r + UP_r + GC_r) O_r$$

Where:

MRT₁ = minimum remaining thickness due to average internal pitting and maximum external pitting, in inches.

MRT₂ = minimum remaining thickness due to maximum internal pitting and average external pitting, in inches.

T_o = original plate thickness, in inches.

GC_a = average depth of generally corroded area, in inches.

StP_a = average depth of internal pitting, in inches.

StP_m = maximum depth of internal pitting, in inches.

UP_m = maximum depth of underside pitting, in inches.

- UP_a** = average depth of underside pitting, in inches.
StP_r = maximum internal pitting rate, in inches per year; StP_r = 0 if the tank bottom is internally lined (see API RP 652).
UP_r = maximum underside pitting rate, in inches per year; UP_r = 0 if tank bottom is cathodically protected (see API RP 651).
GC_r = maximum rate of general corrosion, in inches per year.
O_r = anticipated in-service period of operation, in years.

4.2 API 12 Series Production Tanks

Production tanks are usually much smaller than API Standard 650 tanks and their operating conditions and objectives are often substantially different than those used in refining, marketing, and transportation operations. These and other unique characteristics are reflected in API RP 12R1.

API RP 12R1 requires two types of scheduled internal examinations, the scheduled Internal Condition Examination (conducted by appropriate field personnel) and the scheduled Internal Inspection (conducted by a qualified inspector).

At a minimum, a scheduled Internal Condition Examination should be made for the following events:

- When a tank is cleaned for normal operational requirements;
- When there is a change in tank location;
- When the service is changed more than five years after an Internal Inspection; or
- When the tank is entered for any type of maintenance or modification.

Scheduled Internal Inspections should be based on the corrosion rate life of the tank as given by:

$$\text{Corrosion Rate Life (years)} = \frac{(t_{\text{current}} - t_{\text{minimum}})}{\text{corrosion rate (inches/year)}}$$

Where t_{current} is the measured thickness of the bottom plate and where t_{minimum} , for the Critical Annular Ring area, is 0.50 times t_{minimum} of the shell or a minimum of 0.062 inch.

For small production tanks, the calculation is based on the structural consideration of the annular ring.

At a minimum, inspections should occur at the beginning of the last quarter of the predicted life when a minimum required plate thickness is still in place.

4.3 Case Studies

Three cases are shown below, with basic design data provided for each. These cases are used as the basis for the examples in this section.

Case 1 - Basic Design Data for 150,000 BARREL API STD 650 Tank

A 150,000 barrel API STD 650 tank is in the design stage. The design data are:

Capacity	150,000 barrels
Soil Condition	Firm, little settlement and good drainage
Stored Product	Petroleum crude
Frequency of Internal Inspection	10 years
General Corrosion	3 mpy
Internal Bottom Pitting	20 mpy
External Bottom Pitting	25 mpy bare steel 3 mpy on concrete slab 3 mpy if cathodically protected
Design Life	40 years
Size	Height 48 feet, Diameter 150 feet
Bottom Plates	0.25 inch

Case 2 - Basic Design Data for 10,000 BARREL Gasoline Storage Tank

A 10,000 barrel gasoline storage tank is proposed. The underside corrosion is based on replacing the native soil below the tank. The following design information is available:

Capacity	10,000 barrels
Soil Condition	Good drainage, moderate settlement
Stored Product	Gasoline
Frequency of Internal Inspection	10 years
General Corrosion	4 mils per year (mpy)
Internal Bottom Pitting	6 mpy
External Bottom Pitting	9 mpy
Design Life	40 years
Size	Height 24 feet, Diameter 55 feet
Bottom Plates	0.25 inch

Case 3 - Basic Design Data for 500 BARREL Production Fluid Tank

A 500 barrel production fluid tank is set up at a new site. The tank is internally lined and placed on a crushed stone foundation. The design data are:

Capacity	500 barrels
Soil Condition	Crushed stone with retainer ring over loose fine sand
Stored Product	Production fluids
Frequency of Internal Inspection	Per API RP 12R1
General Corrosion	0
Internal Bottom Pitting	5 mpy
External Bottom Pitting	0
Design Life	40 years
Size	Height 16 feet, Diameter 15 feet, 6 inches
Bottom Plates	0.25 inch
Minimum for Shell	0.036

4.4 Ground Contact

Tank bottoms in contact with the ground will experience some degree of corrosion even when the native material is removed (see RP 651, Section 3). Paragraph 4.4.2.2 of API STD 653 states that when there is no means for detection and containment of bottom leaks, MRT must be equal to or greater than 0.10 inch.

Example 4.1 illustrates this requirement for the 150,000 barrel tank in Case 2. The example assumes that the tank bottom is in contact with the ground. It is evident in the example that some form of external, and perhaps internal, corrosion protection will be needed to satisfy API STD 653 requirements.

Example 4.1 - Ground/Bottom Contact - 150,000 Barrel Tank

Consider the 150,000 barrel tank in Case 1. Using API STD 653 requirements, determine the MRT at the end of the initial 10 year period assuming no corrosion protection. Quantities for the MRT equations are:

T_o	= 0.25 inch.
GC_a	= 0.0 for a new tank.
StP_a & StP_m	= 0.0 for a new tank.
UP_a & UP_m	= 0.0 for a new tank.
StP_r	= 0.020 inch per year.
UP_r	= 0.025 inch per year.
GC_r	= 0.003 inch per year.
O_r	= 10 years.

$$MRT_1 = T_o - GC_a - StP_a - UP_m - (StP_r + UP_r + GC_r) O_r$$

$$MRT_2 = T_o - GC_a - StP_m - UP_a - (StP_r + UP_r + GC_r) O_r$$

Substituting into the equations yields:

$$MRT_1 = MRT_2 = 0.25 - 0 - 0 - 0 - (0.020 + 0.025 + 0.003) 10$$

$$MRT_1 = MRT_2 = -0.23 \text{ inch}$$

The results of Example 4.1 indicate that a hole will be produced in the bottom before the next scheduled inspection at the end of 10 years; therefore, additional protection must be provided. Using a value of 0.10 inches for MRT, the equation can be solved for O_r — or the anticipated in-service period of operation. In fact, if the tank is placed in service without corrosion protection, API STD 653 would require an out-of-service internal inspection in about 3 years.

Example 4.2 applies paragraph 4.4.2.2 of API STD 653 to the 10,000 barrel gasoline tank in Case 1.

Example 4.2 - Ground/Bottom Contact - 10,000 Barrel Gasoline Tank

Given the tank in Case 2, determine the MRT at the end of an initial 10 year period assuming no corrosion protection. Quantities for the MRT equations are:

T_o	= 0.25 inch.
GC_a	= 0.0 for a new tank.
StP_a & StP_m	= 0.0 for a new tank.
UP_a & UP_m	= 0.0 for a new tank.
StP_r	= 0.006 inch per year.
UP_r	= 0.009 inch per year.
GC_r	= 0.004 inch per year.
O_r	= 10 years.

$$MRT_1 = T_o - GC_a - StP_a - UP_m - (StP_r + UP_r + GC_r) O_r$$

$$MRT_2 = T_o - GC_a - StP_m - UP_a - (StP_r + UP_r + GC_r) O_r$$

Substituting into the equations yields:

$$MRT_1 = MRT_2 = 0.25 - 0 - 0 - 0 - (0.006 + 0.009 + 0.004) 10$$

$$MRT_1 = MRT_2 = 0.06 \text{ inch}$$

API STD 653 requires a minimum thickness of 0.10 inch; therefore, additional corrosion protection must be provided in order to maintain the 10 year inspection interval.

An anticipated in-service-period of 7.9 years results from the MRT value of 0.10 inch.

4.5 Production Tanks

Example 4.3 applies the criteria of RP 12R1 to the proposed tank in Case 3.

While the example shows a calculated out-of-service internal inspection interval of 28 years, it is highly likely that an Internal Conditional Examination will be triggered by one of the four items listed in paragraph 4.2 before the time period has elapsed.

It is important to note that many production tanks will not be at the same location for the period of time that is calculated for the internal inspection interval. Tanks that are relocated should have an Internal Condition Examination and, if warranted, a Condition Inspection when relocated.

Example 4.3 - Ground/Bottom Contact - 500 Barrel Production Tank

Determine the out-of-service internal inspection interval for Case 3, using the procedure given in API 12R1. The corrosion rate is 0.005 inches per year.

Determine t_{minimum} where t_{minimum} is based on the structural considerations of the annular ring.

Annular Ring

For the critical annular ring area, t_{minimum} is 0.5 times t_{minimum} of the shell (0.036 inch) or a minimum of 0.062 inches.

Or, t_{minimum} is the larger of $0.5 (0.036) = 0.018$ inches or 0.062 inches

Therefore $t_{\text{minimum}}(a) = 0.062$ inch.

$$\text{Corrosion Life (years)} = \frac{(t_{\text{current thickness}} - t_{\text{minimum}})}{\text{corrosion rate (inches/year)}}$$

$$\text{Corrosion Life}_a = (0.25 - 0.062)/(0.005) = 37.6 \text{ years.}$$

$$\text{Last quarter begins } 0.75 (37.6 \text{ years}) = 28.2 \text{ years.}$$

Therefore, the calculated interval is 28 years.

4.6 Cathodic Protection

Paragraph 4.4.2.2 of API STD 653 does not allow a reduction in MRT if the tank bottom is cathodically protected. However, Section 2.4.7.1 of the standard will allow a value of zero for external pitting if the tank bottom is protected by a properly designed and maintained cathodic protection system.

Example 4.4 shows the calculations for the 150,000 barrel tank (Case 1) assuming the bottom is cathodically protected.

Example 4.4 - Cathodically Protected Bottom

Using the data given in Case 1, determine the MRT at end of an initial 10 year period assuming the bottom is cathodically protected. Quantities for the MRT calculations are:

T_o	= 0.25 inch.
GC_a	= 0.0 for a new tank.
StP_a & StP_m	= 0.0 for a new tank.
UP_a & UP_m	= 0.0 for a new tank.
StP_r	= 0.020 inch per year.
UP_r	= 0.0 inch per year.
GC_r	= 0.003 inch per year.
O_r	= 10 years.

$$MRT_1 = T_o - GC_a - StP_a - UP_m - (StP_r + UP_r + GC_r) O_r$$

$$MRT_2 = T_o - GC_a - StP_m - UP_a - (StP_r + UP_r + GC_r) O_r$$

Substituting into the equations yields:

$$MRT_1 = MRT_2 = 0.25 - 0 - 0 - 0 - (0.020 + 0.0 + 0.003) 10$$

$$MRT_1 = MRT_2 = 0.02 \text{ inch}$$

Additional protection is needed in order to prevent leaks before the next shutdown. The example can also be worked using a nominal external pitting rate of 0.001 inches per year. Using this nominal rate will provide a more conservative estimate for MRT. This tutorial does not work through the example for cathodic protection on the tank in Case 2. The reader is encouraged to evaluate this option on their own. (Hint: To be conservative, set the external pitting rate to a nominal value. What answer did you get? Using a $UP_r = 0.001$, $MRT_1 = MRT_2 = 0.14 \text{ inch.}$)