Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service

API RECOMMENDED PRACTICE 12R1
FIFTH EDITION, AUGUST 1997

EFFECTIVE DATE: OCTOBER 1, 1997

American
Petroleum
Institute

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Exploration and Production Department

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FOREWORD

This API recommended practice is under the jurisdiction of the API Subcommittee on Standardization of Field Operating Equipment. This fifth edition is a reformatted reissue of the 1991 fourth edition, which was reaffirmed by 1996 letter ballot.

This recommended practice provides guidelines for (a) setting and connecting of lease tanks at new tank battery installations and in other production and treating service, (b) maintaining and operating lease tanks, and (c) inspecting and repairing tanks constructed in accordance with API 12 series (B, D, F and P) standards.

Changes adopted in the fourth edition of this recommended practice address both technical and environmental/safety issues. Major technical revisions included (a) development of tank inspection criteria and scheduling intervals, (b) adoption of repair recommendations, and (c) inclusion of a section addressing spill prevention control and countermeasures (SPCC).

A number of federal, state, and local environmental and safety regulations affect the design and the operation of storage tanks utilized in production operations. In preparing this recommended practice, the following safety and environmental concerns were addressed:

a. Personal safety assurance.
b. Prevention of catastrophic failure.
c. Prevention of operational mishaps, such as tank overflows.
d. Minimization of the potential for leaks.

The environmental statutes and regulations affecting the operation of lease facilities are constantly evolving. Individuals utilizing this document should review federal, state, and local regulations to determine whether the practices recommended in this document are consistent with current laws and regulations.

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Suggested revisions are invited and should be submitted to the director of the Exploration and Production Department, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005-4070.

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Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service

1 Scope

1.1 This recommended practice should be considered as a guide on new tank installations and maintenance of existing tanks. It contains recommendations for good practices in (a) the collection of well or lease production, (b) gauging, (c) delivery to pipeline carriers for transportation, and (d) other production storage and treatment operations. In particular, the spill prevention and examination/inspection provisions of this recommended practice should be companion to the spill prevention control and countermeasures (SPCC) to prevent environmental damage.

This recommended practice is intended primarily for application to tanks fabricated to API Specifications 12B, D, F, and P (sometimes called the API 12 series in this document) when employed in on-land production service; but its basic principles are applicable to atmospheric tanks of other dimensions and specifications when they are employed in similar oil and gas production, treating, and processing services. It is not applicable to refineries, petrochemical plants, marketing bulk stations, or pipeline storage facilities operated by carriers. Tanks fabricated to API Standard 650 or its predecessor (API Standard 12C) should be maintained in accordance with API Standard 653.

1.2 This document recommends maintenance practices based on the estimated corrosion rate life of various tank components. Corrosion rate life of tank components will vary widely with location, environment, service, type of fluid, and corrosion mitigation techniques elected by the owner/operator. Recommendations for specific corrosion mitigation techniques are not within the scope of this document. For such recommendations, see publications of the National Association of Corrosion Engineers (NACE) (see Section 2).

1.3 This document contains some specific safety recommendations applicable to tanks. For complete safety recommendations, see publications of the API Committee on Safety and Fire Protection.

1.4 The schematic drawings included in this publication are examples only of some features described in the document. Numerous variations in piping systems and tank components are known to give satisfactory service. Unusual grades of crude, particularly heavier grades, may cause the owner/operator to elect other equally satisfactory practices.

1.5 Lease automatic custody transfer (LACT) operations are covered in API Specification 11N, and in the API *Manual of Petroleum Measurement Standards,* Chapter 6.1.

2 References

This recommended practice includes by reference, either in total or in part, the most recent editions of the following standards, unless a specific edition is listed:

API

Spec 11N	*Lease Automatic Custody Transfer (LACT) Equipment*
Spec 12B	*Bolted Tanks for Storage of Production Liquids*
Spec 12D	*Field Welded Tanks for Storage of Production Liquids*
Spec 12F	*Shop Welded Tanks for Storage of Production Liquids*
Spec 12P	*Fiberglass Reinforced Plastic Tanks*
Bull D16-1974	*Suggested Procedure for Development of Spill Prevention Control and Countermeasures Plans*
RP 500	*Classification of Locations for Electrical Installations at Petroleum Facilities*
RP 520	*Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries,* Part 1, "Sizing and Selection"
Std 650	*Welded Steel Tanks for Oil Storage*
Std 653	*Tank Inspection, Repair, Alteration, and Reconstruction*
Std 2000	*Venting Atmospheric and Low-Pressure Storage Tanks: Nonrefrigerated and Refrigerated*
Std 2003	*Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*
Publ 2009	*Safe Welding and Cutting Practices in Refineries, Gasoline Plants, and Petrochemical Plants*
RP 2015	*Safe Entry and Cleaning of Petroleum Storage Tanks, Planning and Managing Tank Entry From Decommissioning Through Recommissioning*
Publ 2207	*Preparing Tank Bottoms for Hot Work*
Publ 2210-1982	*Flame Arresters for Vents of Tank Petroleum Products*
	Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations
	MPMS, Chapter 6.1—"Lease Automatic Custody Transfer (LACT) Systems"
	MPMS, Chapter 8.1—"Manual Sampling of Petroleum and Petroleum Products"

NACE[1]

RP-01-78 *Design. Fabrication. and Surface Finish of Metal Tanks and Vessels to be Lined for Chemical Immersion Service*

RP-05-75 *Design, Installation, Operation, and Maintenance of Internal Cathodic Protection System in Oil Treating Vessels*

SPE[2]

Petroleum Handbook

3 Definitions

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

3.1 alteration: Any work done on a tank which departs from the original design and includes changes in size, shape, or structural members.

3.2 applicable standard for alteration: The applicable standard for alteration is the latest revision of the original API specification.

3.3 applicable standard for inspection or rating: Any tank covered by this recommended practice may be rated or inspected either by the original specification under which it was built or, at the option of the owner/operator, the latest revision of the same specification.

3.4 applicable standard for repair: For design, materials, workmanship, and testing of any new piece or part added to the tank, the applicable standard is the latest revision of the original API specification. For original parts, see applicable standard for inspection or rating.

3.5 atmospheric pressure tank: A tank designed for internal pressures up to, but not exceeding, 2½ pounds per square inch gauge in the vapor space above the contained liquid.

3.6 change in location: Any relocation within or between fields, units, or plants.

3.7 change in service: A change from previous operating conditions involving different properties of the stored product, such as specific gravity, corrosivity, temperature, or pressure.

3.8 class of tank: Classification for a group of tanks according to service, coatings, corrosion mitigation techniques, locale, and setting.

3.9 competent person: A responsible individual, designated by the owner/operator, who is capable of recognizing existing and predictable hazards. Recommended qualifications for a competent person are given in Appendix A of this document.

[1]NACE International, P.O. Box 218340, Houston, Texas 77218.
[2]Society of Petroleum Engineers, P.O. Box 833836, Richardson, Texas 75083-3836.

3.10 condition examination (internal/external): A review of history and physical observation of a tank and its adjacent equipment by a competent person.

3.11 corrosion rate: Estimated or measured rate of metal loss due to corrosion.

3.12 corrosion rate life: The corrosion rate life of a tank is defined as follows:

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

Where:

$T_{current}$ = the thickness, in inches, measured at the time of inspection for the limiting section used in the determination.

$T_{minimum}$ = the minimum allowable thickness, in inches, for the limiting section or zone.

3.13 frangible deck: A tank in which the roof deck is designed to fail under pressure loading. For design criteria, see API Specification 12D. Frangible decks may also be called *weak seam construction*.

3.14 hot tap: A procedure for installing appurtenances penetrating the shell or deck of a tank that is in service.

3.15 inspection (internal/external): A detailed inspection to appraise the suitability for service of a tank including sufficient measurements to estimate its remaining corrosion rate life. Inspections shall be done only by a qualified inspector. Inspections are categorized in the following four ways:

a. Scheduled inspections: Routine inspections performed at intervals specified by the owner/operator based on the corrosion rate life of the class of tanks.
b. Unscheduled inspections: Inspections prompted by results obtained from a condition examination or by an operational alert.
c. External inspections: Inspections made without human entry or visual inspection of internal parts.
d. Internal inspections: Inspections which require human entry or visual inspection of internal parts.

3.16 operational alert: Any operational malfunction of a tank which may signal a potential deterioration.

3.17 owner/operator: The legal entity having both control of and/or responsibility for operation and maintenance of an existing storage tank.

3.18 potential deterioration: Potential deterioration is indicated by a warning sign of deterioration. This warning may be obtained from corrosion coupons or fluid analysis and may indicate the need for a condition examination of a tank.

3.19 qualified inspector: An individual designated by the owner/operator who has the technical ability to read and understand API specifications and employ measurement tools required to evaluate technical compliance with the specifications. Recommended qualifications are presented in Appendix A.

3.20 reconstruction: The work necessary to reassemble a tank that has been dismantled and relocated to a new site.

3.21 routine operational examination: A visual examination made by operators or technicians during their routine attendance at a facility to determine the occurrence of an equipment malfunction or a tank leak. No written record of a routine operational examination need be kept unless an equipment malfunction or tank leak is detected.

4 Recommended Practice for Setting and Connecting Tanks

4.1 SETTING OF NEW OR RELOCATED TANKS

4.1.1 The location of tanks should be selected after considering operational needs, carrier requirements, prevailing winds, environmental and safety conditions, and all local, state, and federal regulations governing such locations.

4.1.2 Tanks should be constructed in accordance with the following:

a. API Specification 12B.
b. API Specification 12D.
c. API Specification 12F.
d. API Specification 12P.

4.1.3 Tank spacing should comply with local, state, and federal regulations. In general, tanks should be located in a straight line as shown in Appendix I, Figure 1. The minimum shell-to-shell spacing for personnel access between tanks is 3 feet (91 centimeters) with spacing adjusted so that pipe headers can be prefabricated to standard patterns. If tanks are set with pipeline connections facing one another, sufficient space should be provided between tank shells to safely afford proper inspection and operation of valves and other appurtenances. Personnel access to all piping connections for operations, inspection, and maintenance should be considered in the design. Appendix I, Figure 2 shows examples of small shop welded tanks with foundation and connection configurations. Appendix I, Figures 3A and 3B show examples of battery installations with piping configurations when dikes/firewalls are used. The recommendations for barriers, valves, drains, vents, and the like shown in these figures are discussed in more detail in the remainder of this recommended practice.

4.1.4 The foundation of a tank should be designed and installed to do the following:

a. Support the tank so that it will remain level and elevated.
b. Drain rainwater away from the base and bottom of the tank so as to keep the underside as dry as possible.
c. Ensure that any fluids leaking through the bottom of the tank will drain to the perimeter of the tank rather than penetrate the soil and/or groundwater.

4.1.5 The foundation sub-base should be well-graded, compacted soil. If the soil is not sufficiently impermeable to prevent migration of fluids into soils below the tank, a plastic sheet or other barrier to liquid should be placed over the sub-base to provide an impermeable barrier. The sub-base should be raised at the center of the tank to facilitate drainage toward the perimeter. Drainage should be provided away from the tank.

4.1.6 The foundation base should be made of gravel, shell, sand, concrete, or other material that facilitates drainage and provides structural support. A retainer ring may be used to confine loose material and to facilitate detection of liquid drainage from below the tank.

4.1.7 The foundation should be level at the circumference of the tank and greater than the tank diameter unless a retainer ring is used. Level bases are required for tanks which are used for measurement of produced liquids.

4.1.8 If a retainer ring is used and it does not extend beyond the diameter of the tank, small seep holes or tell-tale devices should be provided as a means for visible leak detection and drainage.

4.2 PROPER MEASUREMENT AND SAMPLING OF OIL IN TANKS USED FOR MEASUREMENT AND PROVIDING FOR STORAGE EFFICIENCY

4.2.1 All lease tanks should be set and maintained as level and as free of distortion as possible. Inlet and outlet connections should be located so as to cause level settlement of basic sediment during filling or draining.

4.2.2 The main hatch (thief or gauge) should be of standard size as shown in API 12 Series tank specifications, and should be located in the roof deck adjacent to the top chime directly above the pipeline outlet except in the following situations:

a. Where a connection is provided with an upturned ell or other appurtenance inside the shell of the tank.
b. Where wet-oil (oil with basic sediment and water content above pipeline specifications) is encountered.
c. Where sample cocks or LACT units are used for sampling.

In the cases described in 4.2.2, Items a, b, and c, a minimum of 6 feet (1.8 meters) circumferentially should separate the main hatch and the pipe outlet. If an auxiliary hatch is necessary as a second point to measure the settled basic sediment and water content, it should be located diametrically across from the main hatch.

Gauging or striking plates should be installed at or near the bottom chime, directly below the gauging hatch, if the innage method of gauging is used. These plates should be attached to the tank shell and must be set level and anchored.

4.2.3 The pipeline connection should be located in the tank shell at a height so that the bottom of the pipe ell (firmly anchored) or other fitting on the inside of the tank is a minimum of 12 inches (31 centimeters) above the tank bottom. In cone-bottom tanks, the connection may be 6 inches (15 centimeters) above the bottom chime of the tank. A valve equipped with a tamper-proof sealing device should be installed in this line immediately adjacent to the tank.

4.2.4 Except for tanks having frangible decks, the fill line may be located either through the deck near the tank shell or may be introduced into the side of the tank at, or about, the height of the pipeline outlet. Downcomer inlet lines may be selected as an option by the operator to reduce rolling or agitation of the stored liquids and may be required by some carriers. When installed, such lines should extend down to below the nominal low-liquid level. They should be vented with at least two ½-inch (1.27-centimeter) holes directly below the roof deck to permit gas to escape and to act as siphon breakers.

4.2.5 For cylindrical tanks, the drain line should be located in the tank shell adjacent to the bottom chime and not be less than 2 inches (5.1 centimeters) in nominal pipe size. For cone bottom tanks, it may be located either in the bottom adjacent to the tank shell or in the center of a cone bottom. When placed adjacent to the shell, it should be located a minimum of 6 feet (1.8 meters) and preferably 180 degrees from the main hatch. This line should have a valve equipped for sealing and be installed adjacent to the tank.

4.2.6 The equalizer connection, if any, should be located in the shell no closer than 12 inches (31 centimeters) from the top chime. This line should have a valve equipped for sealing, which is readily accessible from the walkway.

4.2.7 Steam coils or hot water coils, if used, should be installed inside the tank in a manner which will not interfere with measurements taken through the main or the auxiliary hatch, and the inlet and the outlet lines should have valves installed adjacent to the tank shell.

4.2.8 Sample cocks, if used, should be installed in accordance with API *Manual of Petroleum Measurement Standards*, Chapter 8.1. Test cocks should be installed 4 inches (10 centimeters) below the bottom of the pipeline connections. They should be located a minimum of 6 feet (1.8 meters) distance circumferentially from the pipeline outlet and the drain line connections and 8 feet (2.4 meters) from the fill line connection. All sample cocks should be equipped with non-leaking valves, plugged inspection tees and tamper-proof sealing devices. Lines from all cocks should extend a minimum of 4 inches (10 centimeters) inside the tank.

4.3 DELIVERY OF MEASURED QUANTITIES TO PIPELINE IN TANKS USED FOR MEASUREMENT

4.3.1 The carrier's gauger should be able, through observation and sealing, to assure that the carrier has complete control of the tank contents, while same are being run to the pipeline.

4.3.2 The valves on the pipeline outlet, the drain line, the filling line, and the equalizer line should be of a reliable type and design and equipped with adequate sealing devices.

4.3.3 The drain line, if it does not empty directly into an open drain or draw-off trough, should be provided with a means for assuring inspection that its valve does not leak. Such a visible check usually consists of a tee with bullplug located adjacent to the valve. It should be accessible at all times, in other words, it should be kept permanently free from dirt, rock, and other obstructions.

4.3.4 All pipeline valves should be provided with an independent means, such as a block-and-bleed system, to insure that they seal properly.

4.4 TANK INTEGRITY

4.4.1 Tank integrity is required to provide economy, safety, and environmental protection.

4.4.2 Welded tanks should be liquid and vapor tight.

New API Specification12B bolted tanks should be either hydrostatic or pressure tested on site prior to being put in service to assure that they are pressure tight. If hydrotested, the roof should be pressure tested up to the maximum allowable working pressure.

Welded or fiberglass tanks should be tested in accordance with the procedures outlined in API Specifications 12D. 12F. and 12P.

4.4.3 In low-resistance soils where electrolytic action may be prevalent, the corrosive effect on the tank should be minimized by providing vapor barrier, external coating, cathodic protection, and/or electrical isolation.

4.4.4 In corrosive fluid or sour gas service, corrosion of a tank's interior can be significantly reduced by the proper application of a corrosive resistant material to the surfaces affected and by the installation of sacrificial anodes. The use of sacrificial anodes without internal coating of the tank usually results in a very short anode life and is not recommended. A properly designed cathodic protection system to NACE RP-05-75 that penetrates the water phase should be installed and maintained to prevent corrosion at the coating holidays. Shortened anode life. due to higher operating temperature, should be accounted for in the initial design, and internal inspections should be scheduled accordingly.

A good quality coating such as coal tar, epoxy, polyester, phenolic, or fiberglass-reinforced plastic should be used, and the surface preparation and application should be in accordance with NACE RP-01-78, or Steel Structures Painting Council (SSPC)[3] Standards. Experience has shown that a major key to obtaining good coating protection lies in adequately preparing the underlying surface. Prior to applying any coating material, the surface should be inspected to assure that it is clean and blasted to the proper standard.

Tank decks should be internally coated if the tank is used in sour gas service or whenever oxygen ingress is likely (for example, tanks without a gas blanket or tanks handling oxygenated water). Special construction techniques can be used for reducing tank corrosion in corrosive or sour service. One such technique is the placement of roof/deck beams on the outside of the roof/deck. This technique also facilitates inspection in seismically active areas.

If a tank contains both steam coils and an internal coating, the coils should be located at a sufficient distance from the surface to avoid coating damage.

4.4.5 Protective coatings suitable for the environment at the location should be applied to the exterior of the tank using acceptable surface preparation and application techniques.

4.4.6 All hatches, connections, and other access points should be vapor tight. Connections and cleanout plates should be capable of holding pressure in excess of the pressure-relieving device. If the tank fluids contain hydrogen sulfide or the recommended gas blanket must be maintained, then a spring-action thief hatch with an appropriate envelope gasket such as a Viton® A or B, or equivalent, material should be used.

Normal or primary venting is through the vent connection. Individual tank vents or combined vent systems for multiple tanks may be employed. This connection may be located conveniently in the tank or, except for tanks having dome covers installed with loose fitting long bolts, this connection may be located in the dome cover. Tanks in some installations may require additional pressure relief devices for emergency venting during potential fire exposure against the exterior. Requirements are specified in the appendixes of the API 12 series specifications and API Standard 2000. If required, such devices may take the form of larger or additional vent valves, thief hatches, or dome covers having loose-fitting bolts. All primary and auxiliary venting devices including thief hatches should be kept in good working order.

Thief-hatch-sizing requirements and sample calculations are presented in Appendix B. These are based on the Society of Petroleum Engineers' *Petroleum Handbook*, API Recommended Practice 520, and the requirements of API Specification 12D.

[3]Steel Structures Painting Council, 4400 Fifth Avenue, Pittsburgh, Pennsylvania 15213.

4.4.7 If hydrogen sulfide (H_2S) is present in the system, one should consider using vent piping made from nonferrous materials, special alloys or internally coated steels to help prevent elemental sulfur or iron sulfide (FeS) deposition problems. If fiberglass-reinforced plastic is used, it should be properly supported and a 2-foot (61-centimeter) long section of steel pipe should be installed on the open end. This steel pipe should be electrically connected to the tank shell.

4.4.8 Flame arresters, if installed, should be connected to the venting system and should be installed consistent with the recommendations presented in API Publication 2210.

4.4.9 A vacuum relief valve is recommended for all tanks. However, for tanks over 3000 barrels in volume and other tanks subject to local regulations, a pressure-vacuum valve is required on the vent line or connection. This valve should be large enough to prevent rupture or distortion of the tank due to temperature change or during filling or emptying operations as determined by the API 12 series tank specifications or in API Standard 2000.

Pressure-vacuum valves must be selected to provide for normal inflow and outflow venting at an outlet pressure less than the thief hatch exhaust pressure and at an inlet pressure greater than the thief hatch vacuum setting. Pressure regulators on vapor recovery systems or gas blanket systems, if any, must be set at values consistent with those set for the pressure-vacuum valves and the thief hatches to avoid loss of gas blanket or tank rupture.

4.4.10 Pressure-vacuum valves must be located at the highest point in the vent line, and the line must not contain a liquid trap.

5 Recommended Practice for Safe Operation and Spill Prevention of Tanks

5.1 OPERATING SAFETY

5.1.1 Normal aboveground operations of tanks should be accessible from platforms and walkways. Tank decks, platforms, and walkways and the area around the tanks should be kept cleared of accumulation of oil, basic sediment, and surface water.

5.1.2 The main gauge hatch, valves, and other appurtenances requiring personnel access for operation or maintenance should be made accessible from elevated platforms and walkways which provide clear walking/working surfaces so that personnel do not have to walk on roofs or decks.

5.1.3 Elevated platforms, walkways, and stairways should meet OSHA and API tank standards.

5.1.4 Piping, walkways, platforms, and so forth that must rest on or against the tank shell or deck should be secured to it.

5.1.5 The pipeline valve, the drain valve, and the test or inspection locations should be accessible from a firm nonskid walking surface which is free of obstructions and above normal levels of rainwater accumulation. If a firewall or dike is built, it should be traversed by this walking surface, which should lead to the gauging platform stairway as well as to the lower level valves and check points.

5.1.6 All connections to openings in the roof deck, for example, filling line and vapor vent or breather line, should be located so that they do not interfere with opening and closing of hatch lids or access to thief or gauge hatches.

5.1.7 NO SMOKING signs should be displayed appropriately at points in facilities where there is controlled access or boundary fencing. Where access is not controlled, NO SMOKING signs should be visible from normal road or pathway approach.

5.1.8 Tanks installed for production and storage of crude oil that contains toxic or poisonous gases, such as H_2S, should have signs posted at all entries to the facility and at the bottom entry of all stairways leading up to gauge hatches warning of the presence of toxic or poisonous substances. Approved breathing apparatus should be used in accordance with OSHA regulations.

5.1.9 Tanks are classified as *confined spaces* within the OSHA regulations and warrant special attention before personnel are allowed to enter. A permit system should be established that prohibits personnel (owner/operator and/or contractor) from entering the tank until the atmosphere has been tested for hydrogen sulfide, oxygen deficiency, explosivity, and the presence of any substance, such as benzene, for which an exposure limit has been published. Special procedures should be developed and implemented to assure personnel safety prior to entering any confined space. These procedures should address items such as respiratory protection, standby personnel, and lockout/tag-out procedures.

5.1.10 Atmospheric tanks used in the oil and gas industry present a significant explosion hazard if ignition sources are introduced in an uncontrolled fashion. Operations which temporarily employ open fires, automotive and welding equipment, internal combustion engines, and open drip-proof electric motors should be prohibited inside dikes or firewalls and in any area 50 feet (15.2 meters) from sources of vapor release from undiked tanks or oil accumulations without special permission of the owner/operator. The owner/operator of a tank should establish a hot-work permit system prior to allowing any hot work to be performed on any tank. Hot work should be defined to include the following:

a. Arc welding.
b. Cad welding.
c. Chipping.
d. Flaming.
e. Grinding.
f. Painting around spark-producing equipment.
g. Acetylene cutting.
h. Sandblasting.
i. Soldering.
j. Torching.
k. Any other potentially spark-producing operations.

5.1.11 Fired equipment located within 150 feet (46 meters) of an atmospheric tank or a thief hatch, should be equipped with flame arrestors except where Class III liquids are stored (See API Recommended Practice 500). Location of permanent fired equipment must comply with local, state, and federal regulations.

5.1.12 Rapid removal of liquid from an atmospheric storage tank presents the possibility of tank collapse. This may occur even if a vent or thief hatch is installed but is not properly sized (See Appendix B). The owner/operator should develop safe liquid transfer procedures to prevent any potential filling/emptying problems.

5.1.13 Grounding or bonding of lease tank batteries for crude oil and produced water is not normally required for tanks placed directly on the ground without heavy electrical insulation. For storage and transfer of refined products such as diesel, gasoline, circulating oils, and so forth, at a production facility, grounding should be provided in accordance with API Standard 2003.

Grounding practice and cathodic protection practice must be consistent to avoid corrosion effects.

5.1.14 Downcomer pipes for top fill inlet lines are normally optional in crude oil and salt water tanks. However, they are recommended for tanks storing refined liquids while steel downcomer pipes may be used to reduce the potential for static charge accumulations in API Specification 12P tanks (See API Specification 12P). For additional information see API Standard 2003.

5.1.15 In lightning-prone areas, lightning strikes of massive size are a cause of tank battery fires and explosions. A properly designed and installed lightning protection system may reduce the occurrence of explosions and fires due to lightning strikes in the vicinity of the tank. Personnel should not mount tanks during thunderstorms.

5.1.16 The opening of tanks and equipment that have contained H_2S can result in spontaneous combustion due to the presence of FeS. Recognition of this potential ignition source is important in planning work in gaseous areas. To minimize problems, the use of nonferrous pipe to prevent iron sulfide formation in vent areas may be considered.

5.2 SPILL PREVENTION

5.2.1 A review of local. state. and federal regulations should be made to determine spill prevention requirements. An evaluation of spill prevention requirements and measures should be made on a site-specific basis.

If a formal spill prevention plan is required by regulation, API Bulletin D-16 should be consulted for guidance. Regardless of regulatory requirements, Bulletin D-16 contains recommendations for spill prevention that can be utilized at any facility and includes sections on secondary containment (dikes), facility drainage, high-level alarms, and flowline and facility inspection.

5.2.2 Dikes or firewalls should be constructed to contain, at a minimum, the volume of the largest tank enclosed plus an allowance for rainwater (normally, 10 percent additional tank volume). The diked area should be impervious in order to contain spilled oil until it can be cleaned up. The ground enclosed by the dike should be sloped so as to drain any water away from tanks, and it should be kept cleared of any accumulations of oil, basic sediment, and water.

A pipe drain, if used, should be provided at the lowest point to permit draining accumulations of storm water. This pipe drain should have a locked-closed valve outside the drainage area to ensure proper containment and control of fluids other than storm water. Other substances, such as saltwater, oil, and basic sediment spilled within the diked area should be disposed of properly. API Environmental Guidance Document, *Onshore Solid Waste Management in Exploration and Production Operations,* as well as applicable regulations, should be consulted when disposing of these substances.

5.2.3 In the event dikes are not practical, the area around the tank should be sloped so as to drain into a pit, catch basin, or sump system. This is to reduce the possibility of damage to adjacent properties or pollution of ponds, streams, rivers, bays, and so forth.

5.2.4 The owner/operator should establish operating practices or install level detection alarms to circumvent potential overflow or other operational problems. If this cannot be done consistently, then proper level control systems are recommended.

6 Recommended Practice for Examination, Inspection and Maintenance of Tanks

6.1 GENERAL

6.1.1 The owners or users of tanks should have an ongoing inspection program that will assure their tanks have sufficient integrity for normal service without any undue expectation of endangering workers, the public, or the environment. As a minimum, the program should meet the recommendations and guidelines established in this document. The owner or operator should have the option of employing, within the limitations of the jurisdiction, any appropriate engineering, inspection, and recording systems. The program should include provisions for the safety of the inspector and any other personnel, and should consider the difficulty or impossibility of entry into small tanks.

6.1.2 Many factors must be evaluated when determining the suitability of an existing tank for continued service or for a change of service, or when making decisions involving repairs, alterations, dismantling, relocating, or reconstructing an existing tank. These factors include the following:

a. Internal corrosion due to the product stored or water corroding the bottom.
b. External corrosion due to environmental exposure.
c. Stress levels and allowable stress levels.
d. Properties of the stored product such as specific gravity, temperature, and corrosivity.
e. Metal design temperatures at the service location of the tank.
f. External roof life, wind, snow, and seismic loadings.
g. Tank foundation, soil, and settlement conditions.
h. Chemical analysis and mechanical properties of the construction materials.
i. Distortions of the existing tank.
j. Operating conditions, such as filling or emptying rates and frequency.

Additionally, combinations of any of these factors together with pressure due to fluid static head, internal and external pressure, nozzle loads, attachment loads, and settlement should be included as part of the evaluation.

General industry observations and experience with shell corrosion and brittle fracture are included in Appendix C.

6.1.3 The fitness for purpose and structural integrity of a tank are important to assure its long-term, leak-free condition. As such, both internal and external observations are required. These observations are divided into examinations and inspections. The examinations are conducted by knowledgeable and trained field operations personnel. There are two classifications for examinations. The first is done routinely by the operators of the battery. These are called *routine operational examinations.* The second classification of examinations are called *conditions examinations.* These examinations can be done internally and externally. However, these inspections require a person who is more highly skilled and knowledgeable. This person is called a *competent person.*

Condition inspections are also done internally or externally. These inspections require the most highly skilled and trained personnel. Usually, the condition inspections should need to be done only after the competent person conducts an

Table 1—Internal Tank Examination/Inspection Schedule

Scheduled Type	Frequency	By Whom
Condition examination	When a tank is: a. Cleaned for normal operations. b. Transferred to a new location. c. Service of a tank is changed more than 5 years after an inspection. d. Entered for any type of maintenance or modification.	Competent person or qualified inspector
Condition inspection	At end of ¾ of corrosion rate life.	Qualified inspector
Unscheduled Type	**Frequency**	**By Whom**
Condition examination	When results from an external condition examination warrant it.	Competent person or qualified inspector
Condition inspection	When warranted by results of condition examination.	Qualified inspector

Table 2—External Tank Examination/Inspection Schedule

Scheduled Type	Frequency	By Whom
Routine operational examination	At least once a month.	Field personnel, technicians
Condition examination	Once a year.	Competent person or qualified inspector
Condition inspection	As determined from corrosion rate but not more than 15 years after construction.	Qualified inspector
Unscheduled Type	**Frequency**	**By Whom**
Condition examination	When operational alert, malfunction, shell or deck leak, or potential bottom leak is reported as a result of an operational examination.	Competent person or qualified inspector
Condition inspection	When warranted by results of condition examination.	Qualified inspector

examination, and it is determined that a more detailed assessment of the tank's integrity is required.

Appendix A lists the various qualifications for a competent person and a qualified inspector.

A summary of the types of observations, the frequency, and the associated personnel qualifications are shown in Tables 1 and 2. Table 1 shows the schedule summary for external examinations and inspections. Table 2 shows the schedule summary for internal examinations and inspections. The detailed requirements associated with each one of these examinations/inspections are presented in the remainder of this section.

6.2 MAINTENANCE

The owners/operators of tanks should have a preventive maintenance program to assure tank integrity for normal service without undue expectation of endangering workers, the public, or the environment.

Specific programs are at the option of the owner/operator, but should include draining of bottom water and/or sediment, replacement of gaskets, replacement of seals, inspection of sacrificial anodes, and repair of coatings and linings as required.

6.3 ROUTINE OPERATIONAL EXAMINATION

A proper level of surveillance of all properties is recommended for efficient and prudent operations and for spill prevention control and countermeasures (SPCC) as outlined in API Bulletin D-16.

The owner/operator should establish procedures for visual examination and reporting of equipment malfunctions or leaks (routine operational examination), identified by operational personnel or technicians during their routine attendance at a facility.

At a minimum, routine operational examinations should be made at least once a month for any in-service tank. Written records need not be retained except for leaks or operational alerts.

6.4 EXTERNAL CONDITION EXAMINATION

6.4.1 An external condition examination may be done on either a scheduled or unscheduled basis:

a. Unscheduled: An external condition examination should be made by a competent person when an operational alert, malfunction, shell or deck leak, or potential bottom leak is reported as result of a routine operational examination.

b. Scheduled: An external condition examination should be performed at least once a year by a competent person for any in-service tank.

6.4.2 This examination should include a visual inspection of the tank exterior surface to check for leaks, shell distortion, and evidence of corrosion and to determine the condition of the foundation pad, drainage, coatings, cathodic protection (if any), and appurtenances and connections. The need for additional detailed inspections and measurements should be determined from the results of this examination. Leaks are not acceptable while the tank is in service. Extensive corrosion and/or pitting should be further evaluated for possible repair.

A suggested checklist for an external condition examination is presented in Appendix D.

Summary results of the general findings from an external condition examination should be retained for a period of not less than five years or until superseded by a newer external condition examination summary report.

6.5 INTERNAL CONDITION EXAMINATION

6.5.1 An internal condition examination may be done on either a scheduled or unscheduled basis. For either examination situation, the tank should be safely isolated, cleaned, and ventilated in accordance with API Recommended Practice 2015:

a. Unscheduled: An unscheduled internal condition examination should be made by a competent person when an operational alert or potential bottom leak is reported as a result of a routine operational examination or an external condition examination.

b. Scheduled: A scheduled internal condition examination should be made, as a minimum, for the following events:

1. When a tank is cleaned for normal operational requirements.
2. When there is a change in location or of a tank.
3. When the service of a tank is changed more than 5 years after a detailed internal inspection.
4. When the tank is entered for any type of maintenance or modification.

6.5.2 Whenever ownership/operatorship of a tank changes, the new owner/operator should obtain the original records and files on the tank. If adequate records are not available, the new owner/operator should consider performing an internal examination.

6.5.3 This visual examination of the tank interior should include checks for leaks, shell distortion, cracks, condition of any coating, evidence of the nature and severity of internal corrosion, evidence of damage to the structural supports and rafters, and condition of cathodic protection system.

Results from this examination may determine the need for an additional detailed internal inspection or it may result in a conclusion to either repair or to replace the tank without further detailed internal inspection (See 6.7 for detailed inspection techniques).

A suggested checklist for internal condition examination is shown in Appendix E. Summary results of the general findings from an internal condition examination should be retained for a period of five years unless superseded by a newer internal condition examination summary report.

6.6 INTERNAL/EXTERNAL INSPECTIONS

External and internal inspections may be scheduled by the owner/operator based on the corrosion rate life of the tank and should be performed by a qualified inspector. Internal inspections should be done by safety isolating, cleaning, and ventilating the tank in accordance with API Recommended Practice 2015; also the tank bottom would be prepared in accordance with API Publication 2207, as applicable.

6.6.1 Development of Corrosion History

6.6.1.1 Tank Classification

Tanks may be divided into classes depending on their physical construction, setting, environment, liquid service, lining, protection coating, type of internal cathodic protection, chemical inhibition, and other factors which impact corrosion rate life.

Experience has shown that tanks can be roughly divided into the following eight generic classes with regard to corrosion protection, and can be further subclassified according to the type of fluid stored (crude oil or produced/water-flood supply water), and geographical location (high plains, wet lands, etc.). The eight generic classes are as follows:

a. Lined with cathodic protection with a gas blanket.
b. Lined with cathodic protection without a gas blanket.
c. Lined without cathodic protection with a gas blanket.
d. Lined without cathodic protection without a gas blanket.
e. Unlined with cathodic protection with a gas blanket.
f. Unlined with cathodic protection without a gas blanket.
g. Unlined without cathodic protection with a gas blanket.
h. Unlined without cathodic protection without a gas blanket.

6.6.1.2 Determination of Corrosion Rate

For a given class of tanks, corrosion rates may be either predicted, based on operational experience, or determined from measurements made from sampling tanks of the same class and similar service.

The following roof deck and shell corrosion rates can be determined from external ultrasonic measurements. Tank bottom corrosion rates can be determined by a variety of methods. These include the following internal and external techniques.

a. Internal:

1. By external ultrasonic measurement on the one-foot-wide annular ring at the shell-bottom connection, at a

minimum of eight areas around the tank (see Appendix I, Figure 4).

2. By results obtained from scheduled internal inspections.

3. By analysis of historical field data.

b. External:

1. By external examination at eight areas on the one-foot-wide annular ring at the shell-bottom connection (see Appendix I, Figure 4).

2. By results obtained from scheduled external inspections.

3. By analysis of historical field data.

6.6.1.3 Whenever possible, field measurements should be used to establish the corrosion rates used for determining inspection intervals. However, in the absence of historical data, published reports by API or other operators may be used to establish or to support initial corrosion rate estimates, but these should be verified or revised as soon as field data becomes available.

6.6.2 Critical Sample Size Necessary to Determine Corrosion Rate

The number of tanks which should be included to determine the corrosion rate for a generic class and subclass corrosion condition should be based on a sufficient number of randomly selected tanks so as to be statistically significant. However, it should be noted that localized corrosion rates at holidays in lining of tanks without cathodic protection may be difficult to predict.

6.6.3 Extent of Physical Measurements

For the purposes of this document, a measurement of at least 2 percent of the critical area will be considered the minimum physical coverage necessary to determine corrosion rates. Individual rates should be determined for individual construction members (bottom, shell chimes, roof deck, and so forth). These measurements can be done by a variety of ways. These ways include, at a minimum, dividing the area into a square grid and making at least one measurement at each grid point or inspection of the critical one-foot-wide annular ring by dividing this into grids and inspecting a sufficient number of locations to equal the minimum of two percent of the total area.

6.6.4 Inspection Schedule

Recommended schedules for tank inspections are as follows:

a. *Unscheduled inspections:* Inspections are required if a leak, near a through-wall pit, or severe roof deck corrosion is observed during a condition examination (internal/external). The inspection may be either external or internal depending on the location of the suspected flaw.

b. Scheduled inspections:

1. The timing of scheduled external or internal inspections should be based on the predicted corrosion rate life of the tank as given by the formula:

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

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

2. Minimum required thicknesses for various tank elements are shown in Appendix F. These are based on structural integrity considerations and a remaining 5-year tank life. Thus, the calculated minimums are based on the corrosion rate for the tank. The minimum acceptable thickness is the critical element thickness before the tank is scrapped or repaired.

These criteria are suggested for individual lease tank batteries, but the owner/operator may elect to modify these criteria for other services or environments. These minimum values are suggested for purposes of inspection. They should not be construed as limit values for either acceptance or rejection of a tank in any specific service.

3. Following a scheduled inspection, adjustments in corrosion rate life predictions should be made based on the new findings.

4. External inspection intervals should not exceed three-fourths of the predicted shell/roof deck corrosion rate life for any class of tanks or a maximum of 15 years.

5. Internal inspection intervals should not exceed three-fourths of the predicted corrosion rate life of any class of tanks.

6.7 INSPECTION TECHNIQUES

6.7.1 External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements should be determined by the owner/operator based on the corrosive environment and previous known corrosion rates at the location.

A suggested external condition inspection checklist is included in Appendix G.

6.7.2 Internal inspection is primarily required to do the following:

a. Ensure that the tank bottom and internal piping are not severely corroded and leaking.

b. Gather the data necessary for the minimum bottom and shell thickness assessments. As applicable, these data should

also take into account internal and external ultrasonic thickness measurements made during in-service inspection.
c. Identify and evaluate any tank bottom settlement for tanks that are used for fluid measurement.
d. Evaluate tanks for stresses associated with bottom settlement.
e. Evaluate rate of corrosion of the roof and the corrosion rate associated with the tank structural supports such as rafters and center poles.
f. Evaluate the degree of corrosion protection provided by cathodic protection and/or internal coatings.

A suggested Internal Condition Inspection checklist is included in Appendix H.

6.8 SHELL WELDS

The corrosion condition of the tank shell welds should be visually evaluated to determine their suitability for continued service, the requirement for the use of other nondestructive inspection, or for their need for repair.

6.9 RECORDS

Records should be maintained by the owner or user of tanks from the date of adoption of this recommended practice by the owner/operator. These records should contain pertinent data reports, tank identification, relief equipment test information, and documents recording the results of inspection and repairs. Information relative to the tank integrity, such as corrosion for associated or similar systems, should be included. Records should demonstrate that repairs are consistent with the service and appropriate codes. All basic data may, at the option of the owner/operator, be maintained by the class of tank rather than on an individual basis. After the adoption of this recommended practice, repairs and inspections should be recorded on an individual basis. Inspection records should be retained with permanent equipment records.

7 Recommended Practice for Alteration or Repair of Tanks

7.1 TYPES OF REPAIRS

Alteration or repair of tanks should be made whenever the results of inspection indicate alteration or repairs are necessary. Thus, leaks, structural damage, or minimum thickness criteria shown in Appendix F summary table not being met should require repair unless the projected service life is less than the remaining tank life.

7.1.1 Storage tanks may be repaired without welding or hot work by various forms of patching and reinforcement including the following:

a. Epoxy or fiberglass-reinforced plastic liners for bottom and shell leak repair.
b. Epoxy or fiberglass-reinforced plastic for limited areas of roof deck holes or thin sections in non-highly stressed structural areas.
c. Bolted patches, steel, or plastic plugs of permanent connection type.
d. Bolted or threaded-type tank flanges with bull-plugs or blinds.
e. Various types of commercial devices which feature mechanical connections of sufficient strength consistent with tank structural requirements.

7.1.2 Selection of a particular repair method consistent with anticipated tank requirements is an owner/operator option.

7.1.3 Temporary repairs should be corrected, at owner's/operator's convenience, to permanent repairs within a two-year time period unless the tank is removed from service.

Note: Fiberglass or epoxy-reinforced plastic patches are not an accepted structural repair for steel tanks.

7.2 PREPARATION OF TANK FOR REPAIRS

Prior to performing any interior tank repairs, the tank should be safely isolated, cleaned, and ventilated in accordance with API Recommended Practice 2015. If hot work is required, tank bottoms should be prepared in accordance with API Publication 2207.

7.3 MINIMUM THICKNESS AND MATERIAL REQUIREMENT OF REPLACEMENT SHELL PLATE

The minimum thickness and material of the replacement shell plate should meet the minimum requirements of the original standard used for construction and should not be less than the greatest nominal thickness of any plate in the same course adjoining the replacement plate, except where the adjoining plate is a thickened insert plate.

7.4 WELD JOINTS

7.4.1 Welding and Inspection Requirements

The following welding and inspection requirements apply:

a. Welding on API Specification12B bolted tanks is not recommended.
b. Welding consumables should conform to the American Welding Society (AWS)[4] Classification applicable to the intended use.
c. New weld joint details should meet the welding requirements of the current revision of the applicable standard.
d. All welding and inspection should be done by qualified personnel.

[4]American Welding Society, 550 N.W. LeJeune Road, Miami, Florida 33135.

7.4.2 Repair of Welds

The following applies to weld repairs:

a. Cavities resulting from gouging or grinding operations to remove weld defects should be examined by visual and magnetic particle or liquid penetration methods.
b. Completed repairs of butt-welds should be examined over their full length by visual and radiographic or ultrasonic methods.
c. Completed repairs of fillet welds should be examined over their full length by visual and magnetic particle or liquid penetration methods.

7.4.3 Acceptable Criteria for Existing Shell Plate to New Shell Plate Welds

The following acceptable criteria applies for existing shell plate to new shell plate welds:

a. If the radiograph or ultrasonic inspection results of an intersection between a new and old weld reveals unacceptable welds by current standards, the existing welds may be evaluated according to the original standard of construction.
b. Shell replacement plates should be welded with butt joints with complete penetration and complete fusion. A lap-welded patch plate may be used to repair an individual pit or pin hole-type leak subject to owner/operator approval provided that it meets the following conditions:
   1. It is designed as a reinforcing plate.
   2. The fillet welds join the plate to an existing plate(s) having good structural integrity.

7.5 ALTERATION OF TANK SHELLS TO CHANGE SHELL HEIGHT

Tank shells may be altered by adding new plate material to increase the height of the tank shell. The modified shell height should be in accordance with the requirements of the applicable standard and should take into consideration all anticipated loadings.

7.6 REPAIR OF SHELL PENETRATIONS

7.6.1 Repairs of existing shell penetrations should be in compliance with the applicable API Standard.

7.6.2 Reinforcing plates may be added internally or externally for the repair of unreinforced or leaking nozzles.

7.6.3 Welding performed on plate that has been exposed to H_2S may require special welding procedures.

7.6.4 Welding on tanks which contain flammable fluids is not recommended unless the tank is isolated, drained, and steamed. Also, tests for combustibility should be made prior to welding.

7.7 HOT TAPS

7.7.1 Preparations for hot taps should be made in accordance with API Publication 2009.

7.7.2 Welding on tanks containing flammable liquids or produced water should be restricted to locations below the liquid level unless the tank has been made completely inert. A lower explosion limit (LEL) of zero is required in the welding environment. Tank liquid level should be monitored during welding to assure that welding is below the liquid level. However, before welding below the liquid level of tanks containing flammable liquids, ultrasonic thickness measurements should be made to ensure the welding arc will not burn a hole through a badly corroded area, releasing and igniting a stream of flammable liquid.

7.8 LEAK DETECTION ON BOTTOM REPLACEMENT

When planning a tank bottom replacement, consideration should be given to removing the old bottom or providing a means of preventing galvanic corrosion and/or shielding of cathodic protection. When a tank bottom is replaced from inside the tank, a means for visual leak detection should be included in the refurbished unit. If a second bottom is added to the tank, for example, an impervious barrier (plastic sheet or cement layer) should be installed over the old tank bottom and sloped to drain liquids to the tank perimeter. Holes, spaced no more than 10 feet (3 meters) apart should be drilled into the tank shell immediately above this barrier.

7.9 RECONSTRUCTION OF A DISMANTLED TANK

7.9.1 Prior to reconstruction of a dismantled tank, all internal and external parts should be inspected, and parts found defective should be replaced.

7.9.2 Any reconstructed tank should be in accordance with the latest version of the applicable standard.

7.9.3 After repairs, alterations, and/or reconstruction is completed, any internal or external coatings should be repaired if required for corrosion prevention in the current service.

7.10 REQUIRED HYDROSTATIC TESTING

7.10.1 A full hydrostatic test held for 12 hours should be performed on altered or reconstructed tanks.

7.10.2 A full hydrostatic test held for 4 hours should be performed on a repaired tank.

7.10.3 Hydrostatic testing may be waived by the owner/operator in cases where minor repairs have been made in accordance with the applicable standard and the welds have been nondestructively examined to validate their integrity.

7.11 NAMEPLATES

Welded or fiberglass tanks reconstructed in accordance with this standard should be identified by a corrosion-resistant metal plate. Letters and numerals not less than 5⁄32-inch high should be embossed, engraved, or stamped in the name plate to indicate information as follows:

a. Reconstruction to appropriate API 12 series specification.
b. Reconstruction contractor.
c. Year reconstruction was completed.
d. Nominal diameter.
e. Nominal shell height.
f. Nominal capacity.
g. Bottom thickness.
h. Shell thickness.
i. Design pressure.
j. Shell material.
k. Owner/operator tank designation, if applicable.

The applied nameplate should be consistent in design with that in current use in the latest revision of the applicable standard.

APPENDIX A—RECOMMENDED QUALIFICATIONS FOR QUALIFIED INSPECTORS AND COMPETENT PERSONS

A.1 Qualified Inspectors

Qualified inspectors should have education and experience equal to at least one of the following:

a. A degree in engineering plus 1 year of experience in inspection of tanks or pressure vessels.
b. A 2-year certificate in engineering or technology from a technical college, and 2 years of experience in construction, repair, operation, or inspection, of which one year must be in inspection of tanks or pressure vessels.
c. The equivalent of a high school education plus three years of experience in construction, repair, operation, or inspection, of which one year must be in inspection of tanks or pressure vessels.

In addition to working knowledge of this document and API Specifications 12B, D, F and P, a qualified inspector should have experience in, knowledge of, or training in the following areas:

a. Internal and external inspection.
b. Tank, shell, and bottom evaluation.
c. Brittle fracture.
d. Repair welding.
e. Foundation evaluation and tank settlement.
f. Repair and alteration methods.
g. Material corrosion considerations.
h. Hydrostatic and leak testing.
i. Dismantling and reconstruction.
j. Safety considerations.
k. Structural considerations.
l. Nondestructive inspection techniques such as radiographic, ultrasonic, magnetic particle, liquid penetrant, and acoustic emission.
m. Record keeping.

A.2 Competent Person

Competent personnel for tank condition examinations should have education and experience equal to the following:

a. A high school graduate or equivalent.
b. A minimum of 5 years of oil field production experience.
c. Knowledge and understanding of the requirements and recommendations in this document.

APPENDIX B—EXAMPLE CALCULATION OF VENTING REQUIREMENTS

Required Emergency Venting

Without drainage, when the tank does not have a frangible deck[5] and the wetted surface area is less than or equal to 2800 square feet (260 square meters):

$$Q_v = 1107\,A^{0.82}$$

With drainage, when the tank does not have a frangible deck[a] and the wetted surface area is less than or equal to 2800 square feet (260 square meters):

$$Q_v = 553\,A^{0.82}$$

For wetted surface areas greater than 2800 square feet (260 square meters), set wetted surface, A, equal to 2800 square feet (260 square meters).

Where:

Q_v = required venting rate. SCF/Hr (cubic feet of free air per hour at 60°F and 14.7 psia).
A = wetted surface (square feet).

Reduction Due to Addition of Insulation

Insulation	Required Flow
1 inch	$0.300\,Q_v$
2 inches	$0.150\,Q_v$
4 inches	$0.075\,Q_v$

Thief Hatches

$$Q_v = 833\,A\,(P_{in} - P_{out})^{0.5}$$

Where:

Q_v = required venting rate, SCF/Hr (cubic feet of free air per hour at 60°F and 14.7 psia).
A = hatch area (square inches).
P_{in} = absolute pressure inside tank (inches of water).
P_{out} = absolute pressure outside tank (inches of water).

Maximum Allowable Pressure During Venting

$$P_{max} = 1.5 \times \textit{Design Pressure}\ \text{(Gauge)}$$

[5]Tanks with frangible decks meet emergency venting requirements.

Area of Common Thief Hatches

Size	ID Area (in.^{2})
8-inch round (20 cm)	44 (284 cm^2)
8 inch × 18 inch (20 cm × 46 cm)	130 (839 cm^2)
8 inch × 22 inch (20 cm × 56 cm)	154 (994 cm^2)

Note: cm = centimeters; ID = inside diameter; in. = inches.

Example Problem:

Tank Type	H-500 steel bolted
Diameter	15 feet 4⅜ inches
Height	16 feet 1 inch
Design Conditions	
Pressure	3 ounces
Vacuum	½ ounce

Calculations:

Maximum Venting Pressure:

$$P_{max} = 1.5 \times 3 \text{ ounces} = 4.5 \text{ ounces}$$

Wetted Area:

$$\pi DL = \pi \times 15.385 \times 16.083 = 777.35 \text{ ft}^2$$

Emergency Venting Capacity:

$$Q_v = 1107 \times (777.35)^{0.82} = 259{,}689 \text{ ft}^2$$

Capacity of 8 Inch × 22 Inch Single Thief Hatch:

$$P_{in} - P_{out} = 4\tfrac{5}{16} \times 27.72 = 7.8 \text{ inches of water}$$

$$Q_v = 883 \times 154 \times (7.8)^{0.5} = 379{,}777 \text{ ft}^2$$

Result

Only one thief hatch is required.

Note: These requirements provide for venting during an exposure fire against the lower chime exterior surface. A complete listing of venting requirements for any size tank is included in the appendix of the individual API series 12 specification.

APPENDIX C—INDUSTRY OBSERVATIONS AND EXPERIENCES ON SHELL CORROSION AND BRITTLE FRACTURE

C.1 Shell Corrosion

Shell corrosion occurs in many forms and varying degrees of severity and may result in a generally uniform loss of metal over a large surface area or in a localized area. Pitting may also occur. Each case must be treated as a unique situation and a thorough inspection conducted to determine the nature and extent of corrosion prior to developing a repair procedure. Pitting does not normally represent a significant threat to the overall structural integrity of a shell unless present in a severe form with pits in close proximity to one another. However, pitting corrosion is a primary reason for tank leaks and may result in subsequent underside corrosion. Criteria for evaluating both general corrosion and pitting are defined below.

Widely scattered pits that do not effect the structural integrity of the tank may be ignored provided the following:

a. No pit depth results in the remaining shell thickness being less than one-half the minimum *acceptable* tank shell thickness exclusive of the corrosion allowance.

b. Their dimensions along any line does not exceed 2 inches (5.1 centimeters) in an 8-inch (20-centimeters) length.

C.2 Brittle Fracture

The following applies concerning brittle fracture:

a. For the purpose of this assessment, hydrostatic testing demonstrates that an aboveground atmospheric storage tank in a petroleum or production service is fit for continued use and at minimal risk of failure due to brittle fracture, provided that all governing requirements for repairs, alterations, reconstruction, or change in service are in accordance with this standard (including a need for hydrotesting after major repairs, modifications, or reconstruction). The effectiveness of the hydrostatic test in demonstrating fitness for continued service is shown by industry experience.

b. If a tank shell thickness is no greater than 0.5 inch (1.27 centimeters), the risk of failure due to brittle fracture is minimal, provided that an evaluation for suitability of service has been performed. The original nominal thickness for the thickest tank shell plate should be used for this assessment.

c. The thickest plate for an API 12 series tank is less than the 0.5 inches (1.27 centimeters). which is the necessary thickness to induce brittle fracture. This critical wall thickness is confirmed from actual production experience. Thus, brittle fracture is not a concern for API 12 series tanks unless they are operating in arctic service.

d. An evaluation can be performed to establish a safe operating envelope for a tank based on the past operating history. This evaluation should be based on the most severe combination of temperature and liquid level experienced by the tank during its life. The evaluation may show that the tank needs to be rerated or operated differently; several options exist. These options include the following:

1. Restrict the liquid level.
2. Restrict the minimum metal temperature.
3. Change the service to a stored product with a lower specific gravity.
4. Combinations of the preceding a, b, and c.

APPENDIX D—CHECKLIST FOR EXTERNAL CONDITION EXAMINATION

Checklist for External Condition Examination

Identification

Tank Designation: ______________________

Size: ______________________

Date of Inspection: ______________________

Measured or Estimated Liquid Level: ______________________

Contents: ______________________

Foundation

Tank Properly Supported YES/NO

Grade Ring/Foundation Structurally Sound YES/NO

Tank Bottom

Visible Signs of Leakage Around Tank Bottom YES/NO

Adequate Drainage Away From Tank YES/NO

Tank Shell

Active Leaks YES/NO

If Yes, Number & Location

____

____

____

Signs of Past Leakage YES/NO

If Yes, Number & Location

____

____

____

Structural Integrity (Distortions, Warping) YES/NO

If Yes, Type & Location

____

____

____

Coating Condition Satisfactory YES/NO

If No, Type & Location

____

____

____

Severe Corrosion and/or Pits YES/NO

If Yes, Type & Location

____

____

____

Checklist for External Condition Examination (Continued)

Roof Deck

Holes	YES/NO
If Yes, Number & Location	
Adequate Drainage off of Deck	YES/NO
Coating Condition Satisfactory	YES/NO
If No, Type & Location	
Severe Corrosion and/or Pits	YES/NO
If Yes, Type & Location	

Appurtenances/Miscellaneous

Thief Hatch and Vent Valve Seals Air Tight	YES/NO
Gas Blanket System Operational (If Applicable)	YES/NO
Stairways/Walkways Structurally Sound	YES/NO
Proper Warning Signs in Place	YES/NO
Dikes Maintained	YES/NO
If Fiberglass Tank, All Metal Parts Bonded or Gas Blanket Operational	YES/NO
Tank Area Clear of Trash & Vegetation	YES/NO
Cathodic Protection System Operational	YES/NO
Piping Properly Supported	YES/NO

APPENDIX E—CHECKLIST FOR INTERNAL CONDITION EXAMINATION

Checklist for Internal Condition Examination

Identification

Tank Designation: ____________________

Size: ____________________

Date of Inspection: ____________________

Measured or Estimated Liquid Level: ____________________

Contents: ____________________

Tank Shell

Any Visual Leaks or Cracks YES/NO

If Yes, Number & Location

____

____

____

Any Structural Integrity Problems (Distortions or Warping) YES/NO

If Yes, Number & Location

____

____

____

Coating Condition Satisfactory YES/NO

If No, Type & Location

____

____

____

Internal Corrosion (Severe Pits) YES/NO

If Yes, Type & Location

____

____

____

Roof Deck

Holes YES/NO

If Yes, Number & Location

____

____

____

Coating Condition Satisfactory YES/NO

If No, Type & Location

____

____

____

Checklist for Internal Condition Examination (Continued)

Severe Corrosion and/or Pits YES/NO

If Yes, Type & Location

Structural Supports or Rafters Damaged YES/NO

If Yes, Type & Location

Appurtenances/Miscellaneous

Cathodic Protection System Satisfactory YES/NO

If No, Location & Problem

APPENDIX F—MINIMUM THICKNESS FOR TANK ELEMENTS

F.1 Introduction

The following minimum thickness criteria for predicting the corrosion rate life of API Specification12 B, D, and F tank elements is intended to provide a safety factor of at least 5 years of remaining life. See Figure 4 (in Appendix I) for nomenclature.

F.2 Procedure

F.2.1 STEP #1

For steel API 12 series standard tanks, determine an acceptable design thickness at the end of corrosion rate life of the tank using the following equation for Minimum Thickness Calculation for API Standard 653.

$$T_{\min} = \frac{2.6(D)(H-1)(G)}{(S)(E)}$$

Where:

$T_{\min}$ = acceptable minimum thickness in the lowest foot of the shell as used in the prediction of corrosion rate life of the tank in inches.
D = nominal tank diameter in feet.
H = height of high liquid level above bottom in feet.
G = design specific gravity of stored liquid.
E = joint efficiency:
1.00 for corroded plate in bolted tanks and corroded plate away from welds in welded tanks.
0.70 for unknown efficiency of welds.
0.85 or 1.00 for radiographed welds in accord with normal design practice for the class, service, and manufacture of the tanks.
S = 0.80Y.
Y = specified minimum yield strength (A-36 steel plate, or better, is used in most modern API 12 series tanks).

Note: This formula permits calculation of thickness at 80 percent of yield strength, which exceeds normal design practice for mechanical and structural elements in production facilities. It is intended for use in API Recommended Practice 12R1 to predict useful corrosion life. It is NOT intended to serve as a design criteria for new features or as a sole acceptance/rejection criteria.

F.2.2 STEP #2

Obtain estimates for, or whenever possible, data supporting the annual corrosion rate for isolated pits, roof deck, shell, and tank bottom for each class of tanks.

F.2.3 STEP #3

For the tank elements shown on Figure 1 (Appendix I), the suggested corresponding remaining minimum thickness, $T_{\min}$, to be used in the preceding equation are presented in the following:

a. Isolated individual pits:
$T_{\min}$ is equal to 5 years times the corrosion rate.
b. Tank bottom:
1. Critical annular ring area:
T_b^1 is equal to 0.50 $T_{\min}$ or a minimum of 0.062 inches.
2. Primary bottom thickness:
T_b^2 is equal to 5 times the corrosion rate or a minimum of 0.05 inches.
c. Tank shell:
1. Ring #1:
T_s^1 is equal to 0.75 $T_{\min}$ or a minimum of 0.062 inches.
2. Rings #2 and #3:
T_s^2 and T_s^3 values are equal to 0.50 $T_{\min}$ or a minimum of 0.062 inches.
d. Tank roof deck:
1. Areas where personnel access is permitted only with walkboards or reinforcement.
T_r^1 is equal to 5 years times the corrosion rate or a minimum of 0.05 inches.
2. Areas where personnel access is permitted without walkboards, or reinforcement.
T_r^2 is equal to 0.090 inches.
Any area of 100 square inches with a thickness of less than 0.090 inches should be repaired.
e. Center pole and rafters. These members must retain sufficient structural integrity to support dead and live loads of 20 pounds/square foot.

Except for major foundation failure or major seismic activity failure, API design center poles and rafters rarely fail prior to roof or bottom failure. However, frequently rafter bolting failures (with subsequent falling rafters) occur concurrently with, or prior to, roof or bottom failure. Inspection intervals based on roof deck, shell, and bottom failure should normally provide adequate information to assure the structural integrity of these members.

F.2.4 STEP #4

The working equation for computing the corrosion rate life of a given tank element is as follows:

$$\textit{Corrosion rate life}\ \text{(years)} = \frac{(T_{\text{current}} - T_{\text{minimum}})}{\textit{Corrosion rate}\ \text{(inches/year)}}$$

The resultant corrosion rate life is used to establish the remaining life and recommending inspection interval for the tank.

Table F-1—Summary of Minimum Thickness for Tank Elements

Element	T_{min}	Calculated Minimum	Absolute Minimum
Isolated pits		$5 \times CR$[a]	0.050 inch
Bottom			
Critical annulus	T_b^1	0.50 T	0.062 inch
Primary section	T_b^2	$5 \times CR$[a]	0.050 inch
Shell			
Ring #1	T_s^1	T	0.062 inch
Rings #2–#3	T_s^2, T_s^3	0.50 T	0.062 inch
Roof deck			
No access	T_r^1	$5 \times CR$[a]	0.050 inch
With access	T_r^2	$5 \times CR$[a]	0.090 inch

[a]Applicable corrosion rate.

APPENDIX G—CHECKLIST FOR EXTERNAL INSPECTION

Checklist for External Inspection

Identification

Tank Designation: ______________________

Size: ______________________

Date of Inspection: ______________________

Measured or Estimated Liquid Level: ______________________

Contents: ______________________

Foundation

Tank Shell Adequately Supported	YES/NO
Tank Floor Level (No Differential Settlement)	YES/NO
Signs of Soil or Foundation Failure (Major Tank Settlement)	YES/NO
Grade Ring/Foundation Structurally Sound	YES/NO
Adequate Drainage Away from Tank	YES/NO

Tank Bottom

Visible Signs of Leakage Around Tank Bottom	YES/NO
Bottom/Shell Connection Free of Cracks & Leaks	YES/NO

Tank Shell

Tank Shell Patches — YES/NO

If Yes, Number & Location

____

____

Tank Shell Abnormalities/Distortions — YES/NO

If Yes, Number & Location

____

____

Visible Signs of Holes/Leaks — YES/NO

If Yes, Number & Location

____

____

Cracks or Seepage in Seam — YES/NO

If Yes, Number & Location

____

____

Cracks in Shell/Roof Seam — YES/NO

If Yes, Number & Location

____

____

Condition of External Coating of Uninsulated Tanks, Holes, Disbonding, Deterioration, Discoloration

Number & Location

____

____

Checklist for External Inspection (Continued)

Condition of Insulation Protection of Insulated Tanks, Shell Material (Holes/Tears). Number & Location

Seal Around Roof/Shell Joint (Separations). Number & Location

Seal Around Appurtenances (Separations). Number & Location

External Corrosion YES/NO

Tank Bolt/Rivets Corrosion YES/NO/NA

If Yes, Number & Location

Tank Fiberglass Delaminated YES/NO/NA

If Yes, Number & Location

Results of Ultrasonic Measurements

In Vapor Zone

In Liquid Zone

Tank Roof Deck

Hatches Securely Closed YES/NO/NA

Roof Patches YES/NO

If Yes, Number & Location

Roof Deck Abnormalities/Distortions YES/NO

If Yes, Number & Location

Visible Signs of Holes/Leaks YES/NO

If Yes, Number & Location

Checklist for External Inspection (Continued)

Deck External Corrosion

None, Minimal, Moderate, Severe

Adequate Drainage Off of Deck YES/NO

Condition of External Coating of Uninsulated Deck, Holes, Disbonding, Deterioration, Discoloration

Number & Location

Condition of Insulation Protection of Insulated Deck

Roof Material (Holes/Tears). Number & Location

Seal Around Appurtenances (Separations). Number & Location

Results of Ultrasonic Thickness Measurements. (Compare to Original Values)

Results of Hammer Tests

Appurtenances

Thief Hatch & Vent Valves Seal Properly	YES/NO
Thief Hatch Opens Freely W/O Plugging	YES/NO
Vent Valve Operational	YES/NO
Sample & Drain Valves Leak	YES/NO
Inspect Nozzle Seams for Cracks	YES/NO
Piping, and the like, Properly Supported Off of Tank	YES/NO
Tank Shell Dimpling at Connections	YES/NO
Metal Appurtenance Bonded OR Gas Blanket Operational on Fiberglass Tank	YES/NO/NA
Stairways & Walkways Structurally Sound	YES/NO

Checklist for External Inspection (Continued)

Miscellaneous

Cathodic Protection Operational/Potential Adequate	YES/NO/NA
Vapor Recovery System Operational	YES/NO/NA
Gas Blanket System Operational	YES/NO/NA
Containment Dikes and/or Liner Maintained & Adequate Size	YES/NO/NA
Proper Warning Signs in Place	YES/NO
Automatic Level Indicator Operational & Accurate (Compare to Hand Gauge Level)	YES/NO/NA
Tank Area Clean of Trash & Vegetation	YES/NO

Recommended Future Action

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____

____

____

APPENDIX H—CHECKLIST FOR INTERNAL INSPECTION

Checklist for Internal Inspection

Identification

Tank Designation: ____________________

Size: ____________________

Date of Inspection: ____________________

Measured or Estimated Liquid Level: ____________________

Contents:

Pre-Inspection

Tank Properly Cleaned YES/NO

Tank Atmosphere Properly Tested YES/NO

Tank Properly Isolated YES/NO

Tank Structurally Sound YES/NO

Confined Space Entry Procedure Implemented YES/NO

Tank Bottom

Floor Adequately Supported (Limited Voids Under Floor Plate) YES/NO

Floor Sloped for Adequate Drainage. If Low Spots Exist, Number & Location YES/NO

____

____

____

Plate Buckling/Deflection Acceptable YES/NO

Visually Inspect & Record Plate & Weld Condition

____

____

____

Inspect Shell/Bottom Seam

____

____

____

Condition of Internal Coating (Holes, Disbonding, Deterioration). Number & Location

____

____

____

Inspect & Describe Pitting Appearance (Depth, Sharp Edged, Lake Type, Dense, Scattered)

____

____

____

Results of Ultrasonic Thickness Measurement

____

____

____

Checklist for Internal Inspection (Continued)

Results of Vacuum Tests

Results of Penetrant Dye Tests

Results of Hammer Tests

Results of Other Testing (Magnetic Flux Leakage, Acoustical Emission, and so forth)

In Earthquake Zones 3 & 4, Roof Supports Restrained From Horizontal Movement Only (Not Welded to Floor) YES/NO

Identify Areas to Be Repaired. Number & Location

Tank Shell

Visually Inspect & Record Plate & Weld Conditions. Number & Location

Inspect & Describe Pitting Appearance. (Depth, Sharp Edged, Lake Type, Dense, Scattered, and so on)

Condition of Internal Coating (Holes, Disbonding, Deterioration). Number & Location

Survey Shell to Check Plumb & Roundness

Results of Ultrasonic Thickness Measurements in Vapor Zone

Checklist for Internal Inspection (Continued)

In Liquid Zone

Identify Areas to Be Repaired. Number & Location

Tank Roof

Inspect & Describe Pitting Appearance (Depth, Sharp Edged, Lake Type, Dense, Scattered)

Conditions of Internal Coating. (Holes, Disbonding, Deterioration) Number & Location

Visually Inspect & Record Plate & Weld Conditions. Number & Location

Results of Ultrasonic Thickness Measurements

Check Roof Support Columns for:

Thinning in Vapor Zone

Thinning in Liquid Zone

Drain Opening in Bottom of Pipe or Concrete Filled

Proper Attachment to Roof & Bottom

Inspect Girders & Rafters for Thinning

Girders & Rafters Properly Secured YES/NO

Identify Areas to Be Repaired. Number & Location

Checklist for Internal Inspection (Continued)

Appurtenances

Visually Inspect All Seals & Gaskets

Inspect & Service Pressure/Vacuum Hatches/Valves

Inspect Gauge Well (if Existing)

Inspect Internal Reinforcing Pads (if Existing) for Cracks

Inspect Internal Nozzle Seams for Cracks, Corrosion, and the like

Inspect Diffusers & Rolling Systems

Inspect Swing Lines

Inspect Wear Plates

Recommended Future Action

APPENDIX I—FIGURES AND DIAGRAMS

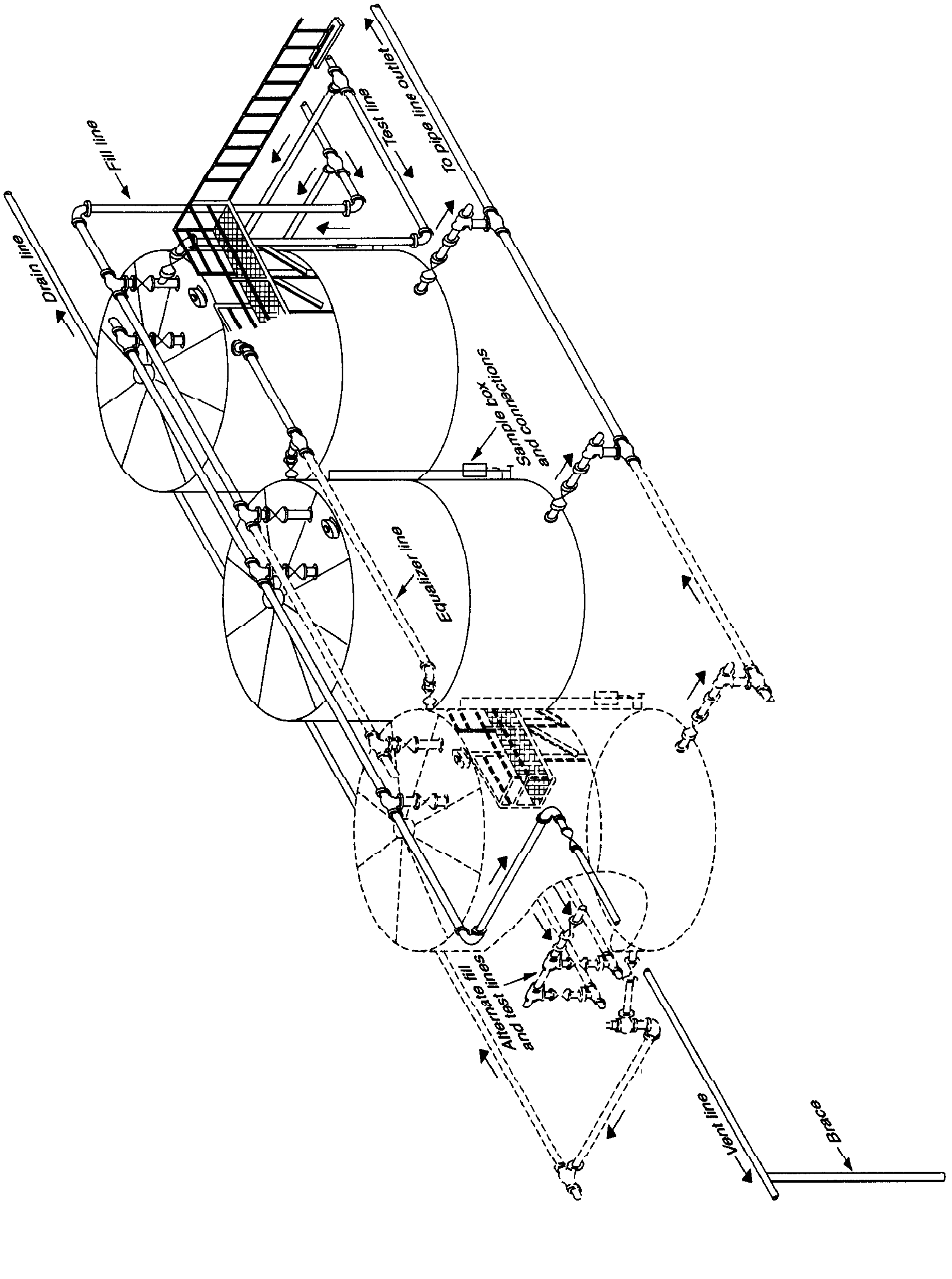
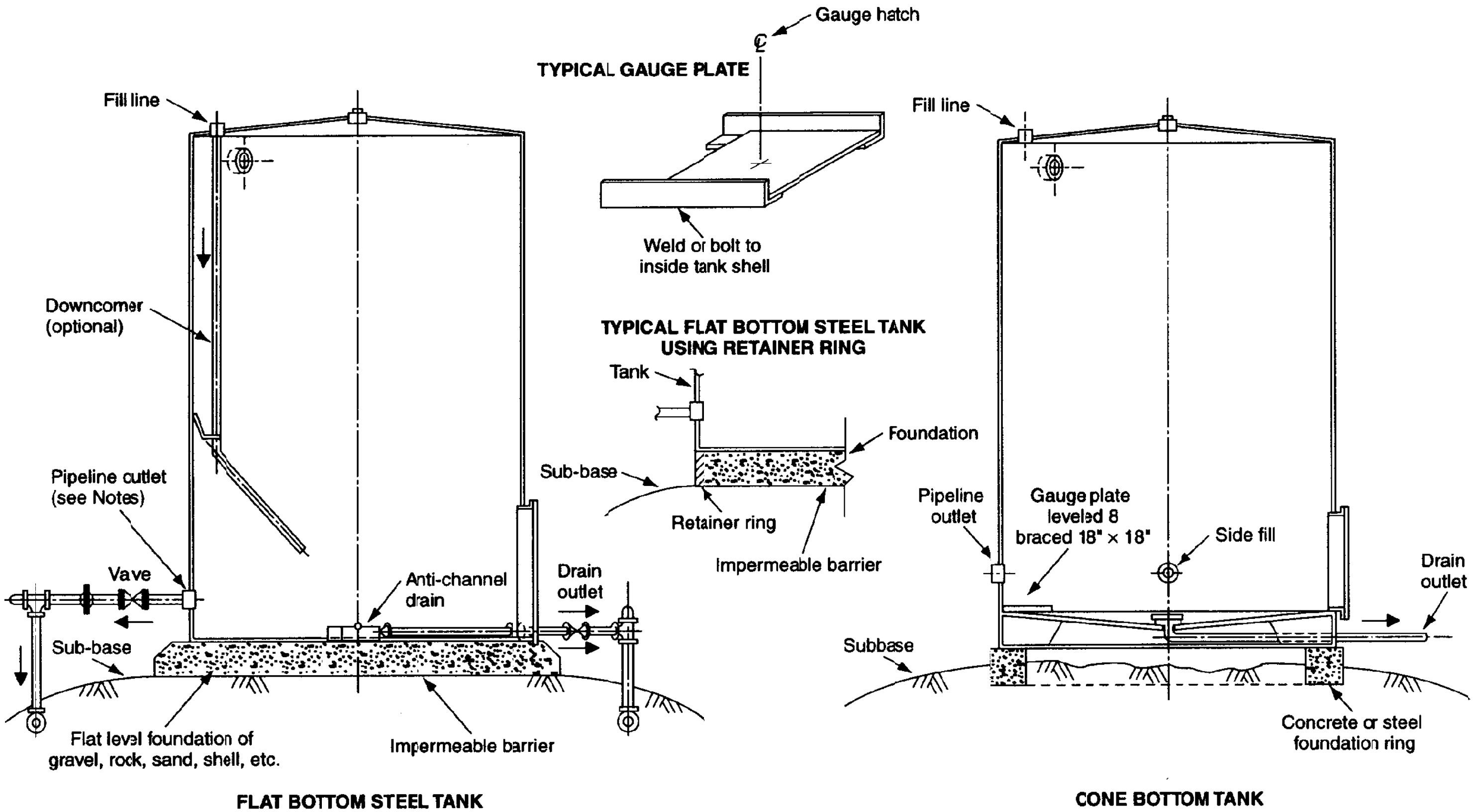
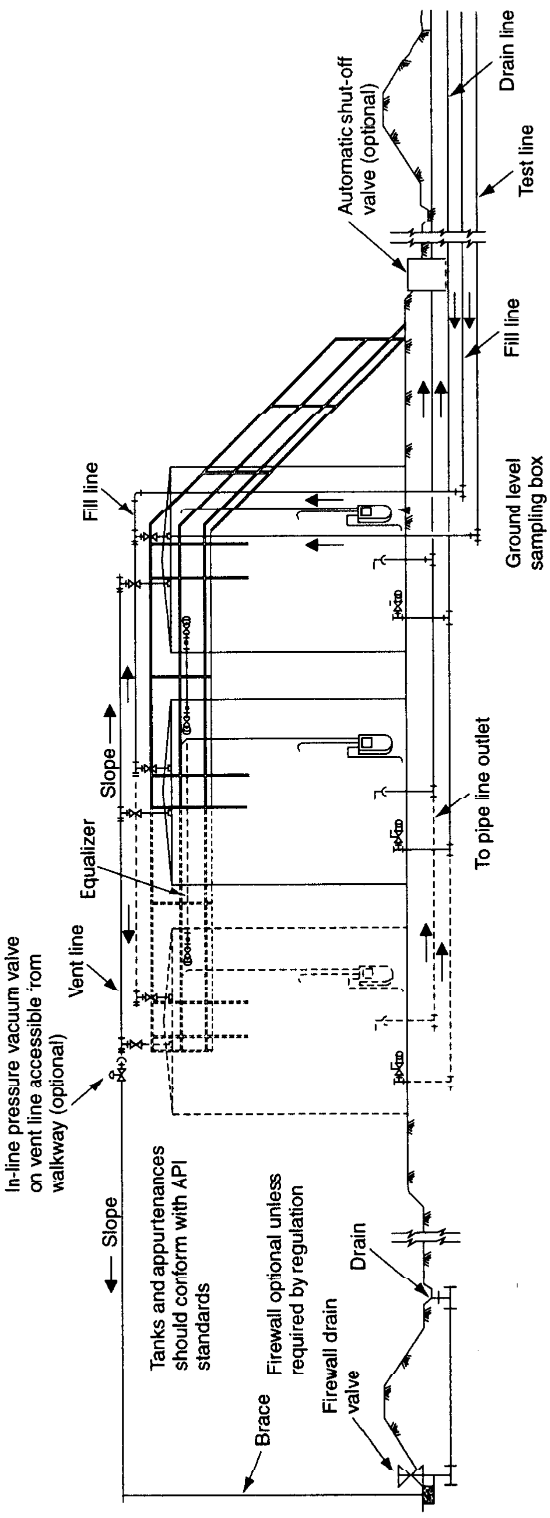


Figure 1—Example of Straight Line Tank Battery Installation and Piping Configurations



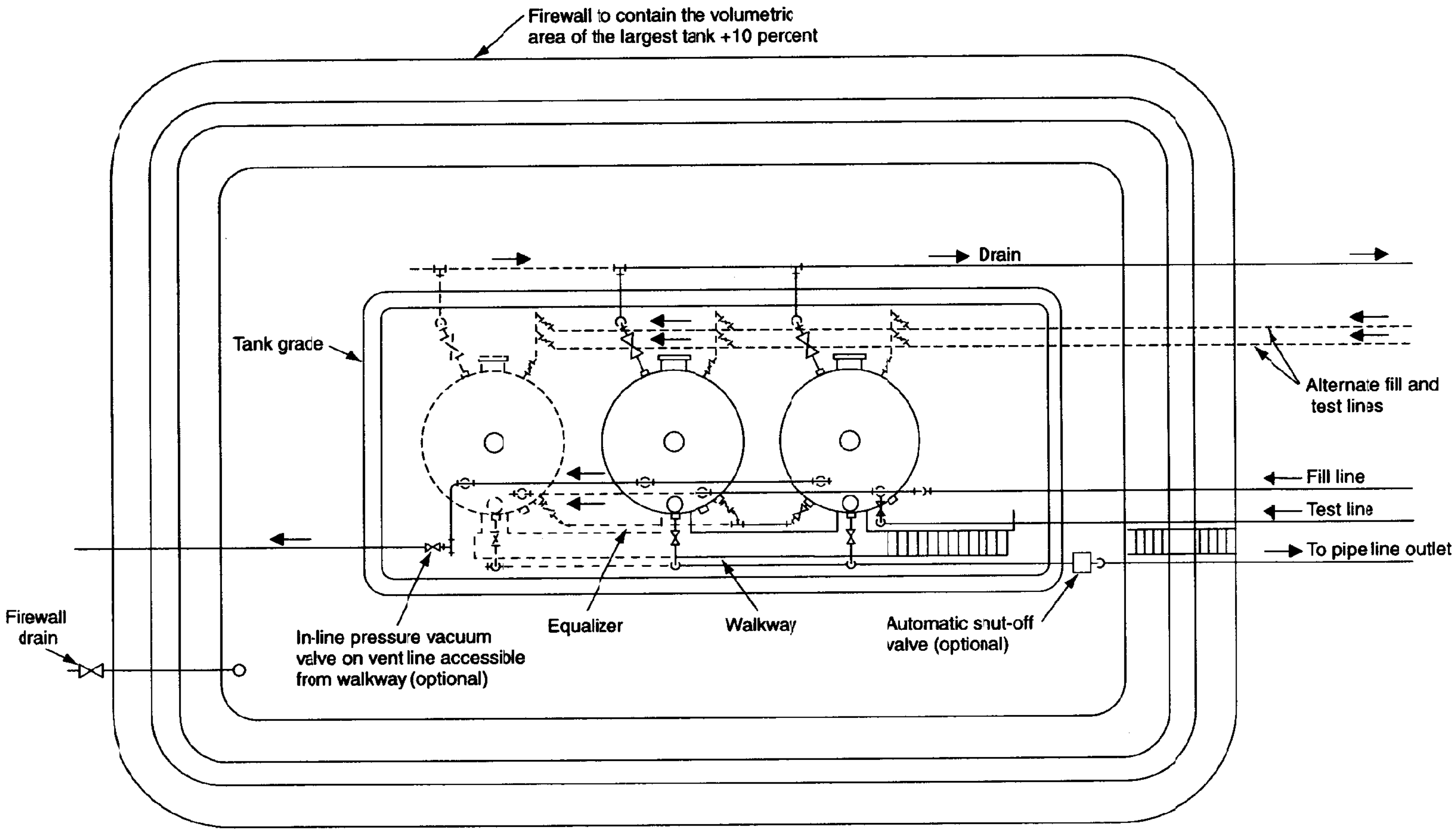
Notes:
1. Fill lines as shown in Figure 2 may be placed in the side of tank.
2. Downcomers should be perforated with 0.5-inch diameter holes above high oil level so as to prevent siphoning.
3. Pipeline connections may be as shown in Figure 2. The bottom of the pipeline outlet should be at least 12 inches above tank bottom.
4. The retainer ring, when used, should be equal to or greater than the diameter of the tank so as to provide the proper structural support.
5. Cleanout plates may be one or two piece. The split cover allows backside inspection at low gauge without oil spill.

Figure 2—Example of Small Volume Shop-Welded Tanks Foundation and Connection Configurations



Notes:
1. Distance between tanks—3 feet or 0.9 meters minimum.
2. All lines may be welded and may also be aboveground.

Figure 3A— Example Tank Battery Installation Showing Dike/Firewall and Example Piping Configuration



Notes:

1. Drawoffs may empty into drain trough or tie-in to drain line—each to have valve adjacent to tank and accessible for sealing.
2. Tank spaced minimum 3 feet or 0.9 meters.
3. Tanks and appurtenances should conform with API standards.
4. Equalizer and pipe line outlet tank connectors to have valve adjacent to each tank and accessible for sealing.

Figure 3B— Example Tank Battery Installation Top View Showing Dike/Firewall and Example Piping Configuration

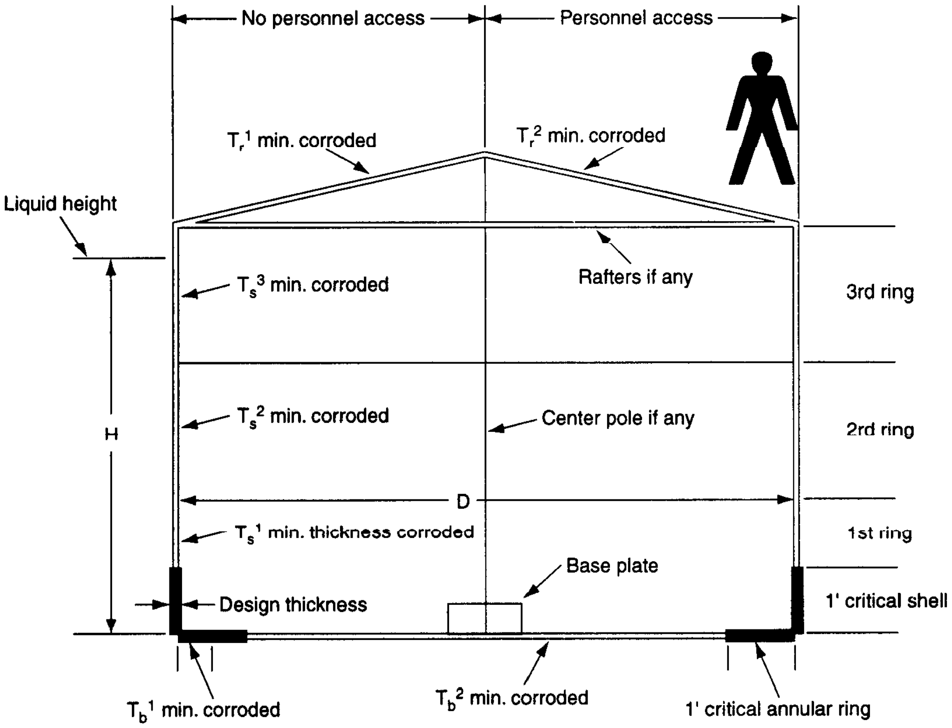


Figure 4—Corrosion Calculation Nomenclature