# CHAPTER 4

# OIL AND HAZARDOUS SUBSTANCE STORAGE

## 4.1. INTRODUCTION

The Navy uses several types of storage areas to satisfy a variety of needs and mission requirements. Bulk storage areas normally store oil and hazardous substances (HS) in large aboveground storage tanks (ASTs) and underground storage tanks (USTs). Non-bulk storage areas include hazardous substance storage areas, hazardous waste (HW) accumulation storage points, and other container storage sites for oils and HS. This chapter provides specific guidance for identifying and evaluating deficiencies in oil and HS storage areas relative to spill prevention and recommends corrective measures to insure compliance with applicable requirements. Area related guidance is a general SPCC guidance that addresses multiple regulations, not just 40 CFR 112. This chapter also discusses the use of storage tanks and other types of storage containers (i.e., drums, cylinders, cans, etc.). Bulk transfer and pipeline areas are discussed in Chapter 5.

Bulk oil storage areas use large ASTs and USTs for storing millions of gallons of oil to support aircraft operations or to drive a power plant. These areas commonly consist of several large (200,000 gallon and greater) ASTs or USTs or a farm of smaller tanks. Smaller oil storage tanks, 1,000 to 5,000 gallon capacity, are commonly used such as day tanks to fire boilers or fuel tanks to support equipment such as emergency generators. Portable oil storage units of 3,000 gallons and below, called bowsers or buffaloes, store lubricants or fuels for field operations. Bulk ASTs are also used to store process chemicals for several operations including wastewater treatment plants, metal plating, metal finishing, paint stripping, degreasing, and fire fighting practice areas.

Bulk storage areas, due to the quantity of material stored, have the highest potential for significant spills. Common spill problems associated with bulk storage areas include overfilling, hose or pipeline ruptures, leaks from worn or corroded parts, damage to tanks and pipes from inadequate supports or vehicle collisions, and improper identification of fill ports, leading to mixing of hazardous and incompatible substances.

Significant spills from non-bulk storage areas are unusual. However, small spills are common; spills can occur from leaking containers, accidental releases from container handling, improper storage procedures, poor housekeeping, and inadequate containment structures.

## 4.2. STORAGE TANKS

Tanks are generally classified by the internal vapor pressure they are designed to sustain (atmospheric, low pressure, and high pressure). Naval activities use these tanks in a variety of ways to meet the specific storage requirements of the substances used.

Atmospheric tanks operate near atmospheric pressure and are used for the storage of low-volatility materials such as heavy oils, hydraulic fluids, antifreeze (ethylene glycol) and metal plating wastes. Common construction materials include welded and riveted mild steel, stainless steel, plastic, fiberglass-reinforced plastic (FRP), and concrete. The Federal Occupational Safety and Health Administration (OSHA) (29 CFR 1910.106) requires that atmospheric tanks be designed to operate at pressures from atmospheric through 0.5 psig. In many instances, these tanks are protected by pressure vacuum vents to maintain the pressure differential between the tank interior and the atmosphere.

Low-pressure tanks are designed to operate at pressures between 0 and 15 psig and are preferred over atmospheric tanks for storing volatile products (vapor pressure <15 psig) such as benzene, acetone, and light napthas. These tanks are normally constructed of steel and are equipped with pressure relief valves or ruptured disks to prevent pressure buildup. Vapor control devices may be required for low-pressure tanks to prevent hazardous gases from venting to the atmosphere. In practice, atmospheric tanks can be used in lieu of low-pressure tanks at the expense of significant vapor losses. However, local air quality requirements and product losses may restrict their use.

High-pressure tanks are used where the operating pressure exceeds 15 psig. The Navy uses high-pressure tanks primarily for the storage of compressed gases such as Freon®, chlorine, and propane.

The following tank operation and system parameters are identified and discussed in this chapter.

- Tank Construction and Materials
- Material Strength
- Storage Compatibility
- Corrosion Protection
- Grounding
- Internal Tank Heating Coils
- Level Controls
- Automatic Controls
- Secondary Containment
- Tank Testing

- Tank Inspection
- Leak Detection and Monitoring
- Certification

### 4.2.1. Tank Construction and Materials

A primary concern is that the tank type is adequate for the storage conditions (material stored, pressure, and temperature). A discussion of the numerous types of tanks available is beyond the scope of this manual. What is important is that by knowing the vapor pressure of a chemical at a given temperature, you can determine if the type of tank is appropriate to withstand the pressure. In actual conditions, temperatures may vary considerably along with other factors, such as excessive pressures occurring during filling operations. As a consequence, the approach presented in this section should be used only to identify chemicals that warrant pressure storage considerations.

Table 4-1 gives typical storage requirements for selected chemicals at standard conditions (25$^{o}$C, atmospheric pressure).

**Table 4-1**
**Storage Tank Type for Liquid Chemicals at Standard Conditions**

| Chemical | Tank Type | | Chemical | Tank Type |
|---|---|---|---|---|
| Acetaldehyde | H | | Ethylene diamine | A |
| Acetamide | A | | Ethylene dichloride | L |
| Acetic acid | A | | Ethylene glycol | A |
| Acetone | L | | Ethylene glycol monoethyl ether | A |
| Acetonitrile | L | | Formic acid | L |
| Acetaphenone | A | | Freons® | H |
| Acrolein | L | | Furfural | A |
| Acrylonitrile | L | | Gasoline | A |
| Allyl alcohol | L | | Glycerin | A |
| Ammonia | H | | Hydrocyanic acid | L |
| Benzene | L | | Isoprene | L |
| Benzoic acid | A | | Methyl acrylate | L |
| Butane | H | | Methyl amine | H |

**Table 4-1 Cont.**
**Storage Tank Type for Liquid Chemicals at Standard Conditions**

| Chemical | Tank Type | | Chemical | Tank Type |
|---|---|---|---|---|
| Carbon disulfide | L | | Methylchloride | H |
| Carbon tetrachloride | L | | Methyl ethyl ketone | L |
| Chlorobenzene | L | | Methyl formate | L |
| Chloroethanol | A | | Naptha | A |
| Chloroform | L | | Nitrobenzene | A |
| Chloropicrin | L | | Nitrophenol | A |
| Chlorosulfonic acid | A | | Nitrotoluene | A |
| Cumene | A | | Pentane | L |
| Cyclohexane | L | | Petroleum oil | A |
| Cyclohexanone | A | | Propane | H |
| Dichloromethane | L | | Pyridine | A |
| Diesel oil | A | | Styrene | A |
| Diethyl ether | L | | Sulfuric acid | A |
| Dimethylformamide | A | | Sulfur trioxide | L |
| Dimethyl phthalate | A | | Tetrachloroethane | A |
| Dioxane | L | | Tetrahydrofuran | L |
| Epichlorohydrin | A | | Toluene | A |
| Ethanol | L | | Trichloroethylene | L |
| Ethyl acetate | L | | Xylene | A |
| Ethyl benzene | A | | | |

Key: A = Atmospheric, less than 0.5 psig
L = Low Pressure, less than 15 psig but greater than 0.5 psig
H = High Pressure, greater than 15 psig
Source: Ecology and Environment, 1982.

Most tanks are stable and properly designed for the intended operation. Structural elements must withstand the mechanical, hydrostatic, and thermal forces transmitted during normal operation; but tank systems are normally assumed to be designed properly. A review of design specifications and drawings is warranted only if inadequate design or adverse soil conditions is strongly suspected. Spill prevention requirements are intended to question whether the tank's structural elements are adequate for its normal operating conditions.

The National Fire Protection Association, Inc. (NFPA) Code 30 addresses the design, construction, operation, testing, and maintenance of ASTs, USTs, and portable tanks whose capacity exceed 660 gallons and are used to store flammable and combustible liquids. The code covers tanks with low-pressure or high-pressure operating conditions. NFPA Code 30A, The Automotive and Marine Service Station Code, is also relevant for fuel storage tanks, piping, and ancillary equipment that are used at service stations. It is particularly useful as guidance for preventing spills from fuel dispensing units. NFPA Code 31, Oil Burning Equipment, contains guidance on fuel storage tanks that are used in conjunction with boilers and other oil burning equipment. NFPA Code 31 contains requirements for tanks that are less than 660 gallons in size and for day tanks that are installed inside of buildings. Specific NFPA spill prevention requirements are noted in each corresponding tank system discussed in the following sections.

RCRA regulations, 40 CFR 264.191, require the owner to determine that a HW tank system is not leaking or is unfit for use. This assessment must determine that the tank system is adequately designed, has sufficient structural strength, and is compatible with the waste(s) to be stored or treated. The purpose of this assessment is to ensure that the tank will not collapse, rupture, or fail. At a minimum, this assessment must consider the following: design standard(s); hazardous characteristics of the waste(s) that have been and will be handled; existing corrosion protection measures; documented age of the tank system; and results of a leak test, internal inspection, or other tank integrity examination.

The following guidelines are intended to give a better understanding of potential structural problems with tanks and to determine requirements to reduce the likelihood of spills. Unless a major structural problem is apparent (i.e., visible settlement of tank), corrective action is usually not warranted.

#### 4.2.1.1. Aboveground Tanks

Aboveground tanks may be horizontal, vertical, partially buried (base and foundation), or totally elevated from the ground by column or supports. It is important to note that if more than 10% of the volume of the tank and associated piping is below the surface grade then the tank is regulated as an underground tank and must meet the requirements in 40 CFR 280 (see section 2.6.4 of this Guidance Manual for a full definition of regulated underground tanks). The SPCC should address field-constructed tanks even though they are deferred under 40 CFR 280. To assure the stability of aboveground tanks, it is necessary that the tank rests on a level, sound foundation. Small elevated horizontal tanks supported by small steel posts and tall, small-diameter vertical tanks are more susceptible to stability and anchorage problems than horizontal tanks that are not elevated. Figure 4-1 shows several types of typical above ground storage tanks.

Vertical tanks are almost always installed directly on a concrete pad. Figure 4-2 shows a typical tank foundation on a concrete pad. Figure 4-3 shows a schematic of a ringwall foundation for a large outdoor vertical tank. The ringwall distributes the tank load and creates a more uniform soil loading condition and structural support. The outer wall of the tank is supported by the concrete ring, but inside of this ring, the floor of the tank may be underlain by compacted gravel or fill dirt. Due to this type of construction a leak may not be detected as it may seep straight down into the gravel or fill dirt. A foundation sealer and adequate drainage grading are important to prevent the accumulation of rainwater and minimize moisture under and around the tank to minimize spill risk.

Horizontal tanks are usually installed on legs or saddle supports; the legs or saddle supports should then rest on a level foundation. Figure 4-4 shows a horizontal tank resting on a saddle support. For adequate support, horizontal cylindrical tanks should rest on saddles that make contact on at least 120° of their circumference. To minimize potential point sources of corrosion, the ends and edges of these saddles should be angled to allow drainage of precipitation or spillage away from the tank surface. Ideally, contact should consist of a metal reinforcing wear plate hermetically sealed to the tank and a metal saddle resting on a concrete pier. An alternative, though less desirable, is resting the sealed plate directly on a concrete saddle. Decomposable material such as tar-saturated felt paper should never be used as a wear plate, since this provides a moist surface to encourage corrosion.

An EPA memorandum entitled "Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Prevention Regulation (40 CFR 112)" states that in order for double walled aboveground tanks to provide substantially equivalent protection of navigable waters, they must meet the secondary containment requirement listed in 40 CFR 112.7(c) or:

- individual tanks must have capacities less than 12,000 gallons
- inner tank constructed of Underwriters' Laboratory-listed steel tank
- outer wall constructed in accordance with nationally accepted industry standards
- tank has overfill prevention measures that include an overfill alarm and an automatic flow restrictor or flow shut-off
- constant monitoring of all product transfers
- manifolded tanks or other piping arrangements that would permit a volume of oil greater than the capacity of one tank to be spilled as a result of a single system failure must have a combined capacity less than 40,000 gallons

NFPA Code 30 also requires anti-siphon protection on double walled aboveground tanks. Without anti-siphon protection, a break in the delivery piping could cause the entire contents of a tank to siphon out onto the ground. Anti-siphon protection is also critical for all aboveground tanks that have delivery piping that extends outside of diked areas whenever any portion of the piping is lower than the liquid level in the tank.

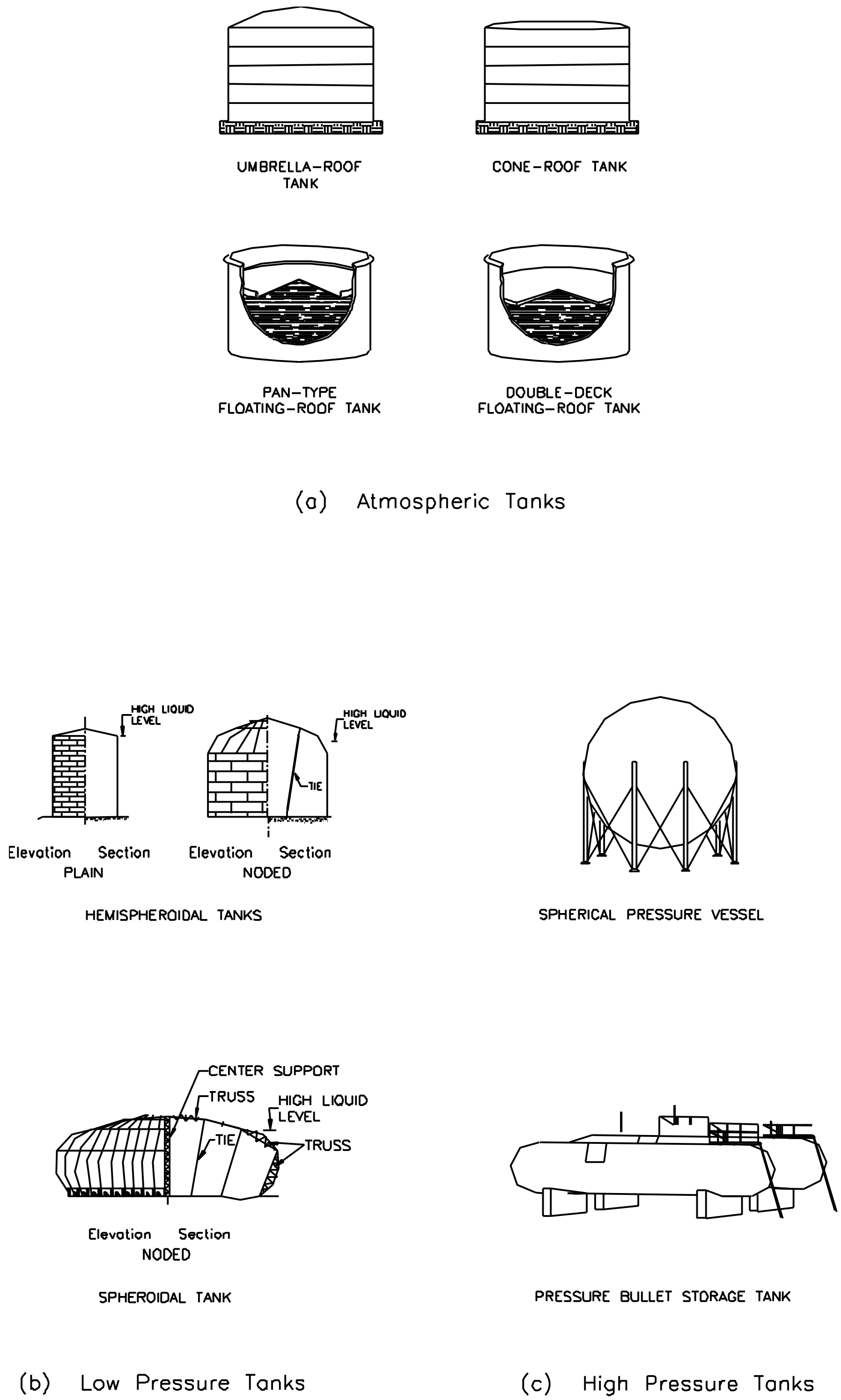



**Figure 4-1**
**Typical Aboveground Storage Tanks**

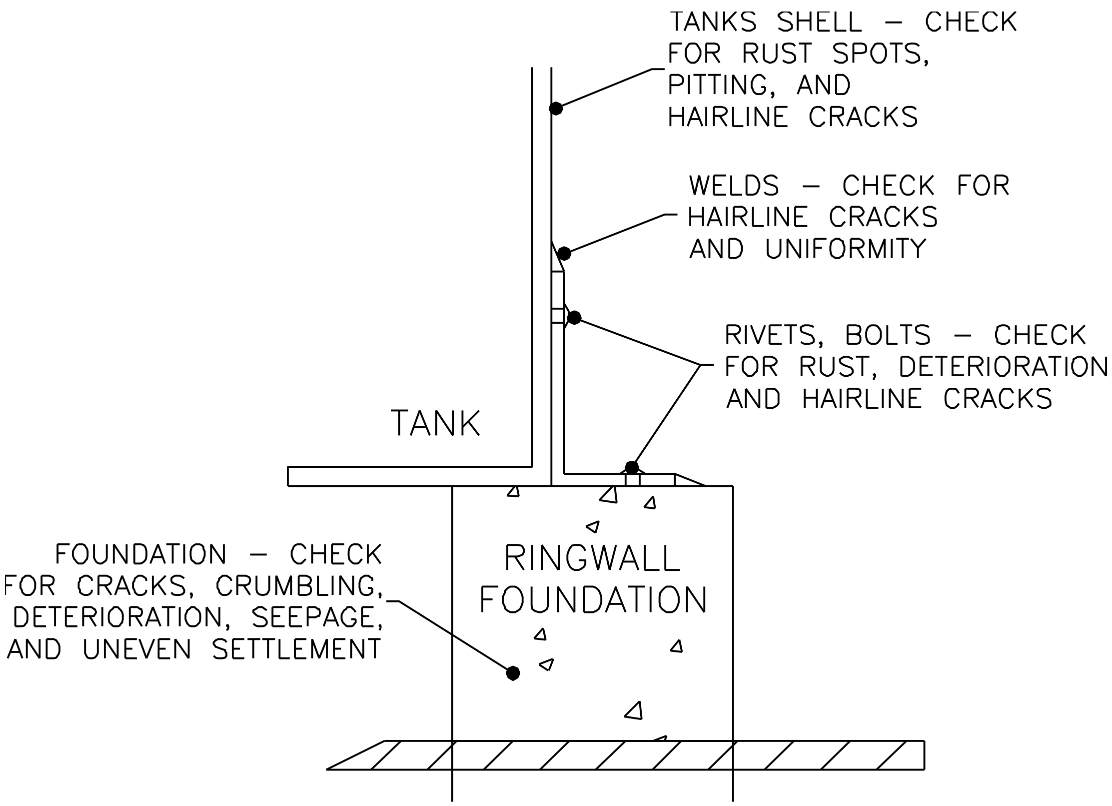



**Figure 4-2**
**Typical Tank Foundation - Areas of Concern**

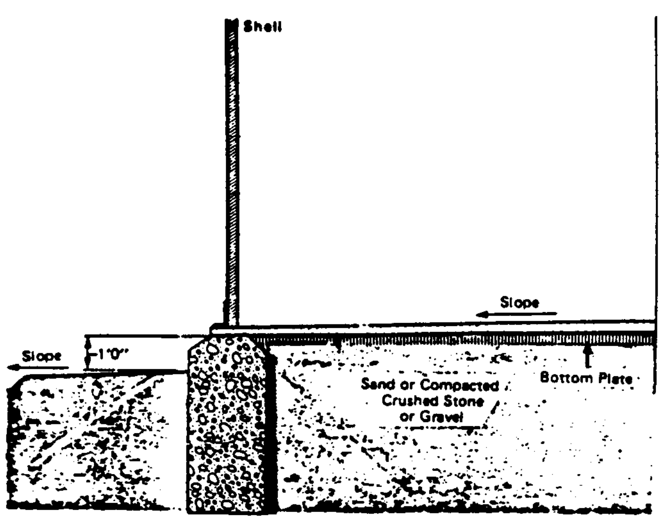



**Figure 4-3**
**Illustrative Ringwall Foundation**

Whether the tank rests directly on a concrete pad or on legs or saddle supports, the foundation must be free of cracks and deterioration. A crumbling or uneven foundation can lead to corrosion or can result in added stresses to the tank. This can result in tank failure and release of stored material; therefore, a cracked, crumbling, or otherwise deteriorating foundation must be repaired. Tank legs or stands should also be inspected for integrity and deterioration or corrosion. In addition, anchor bolts should be checked for tightness. Unstable, wobbly tank legs are cause for replacement. Saddle supports should be checked for cracks, buckling, or crumbling and should be repaired as necessary.

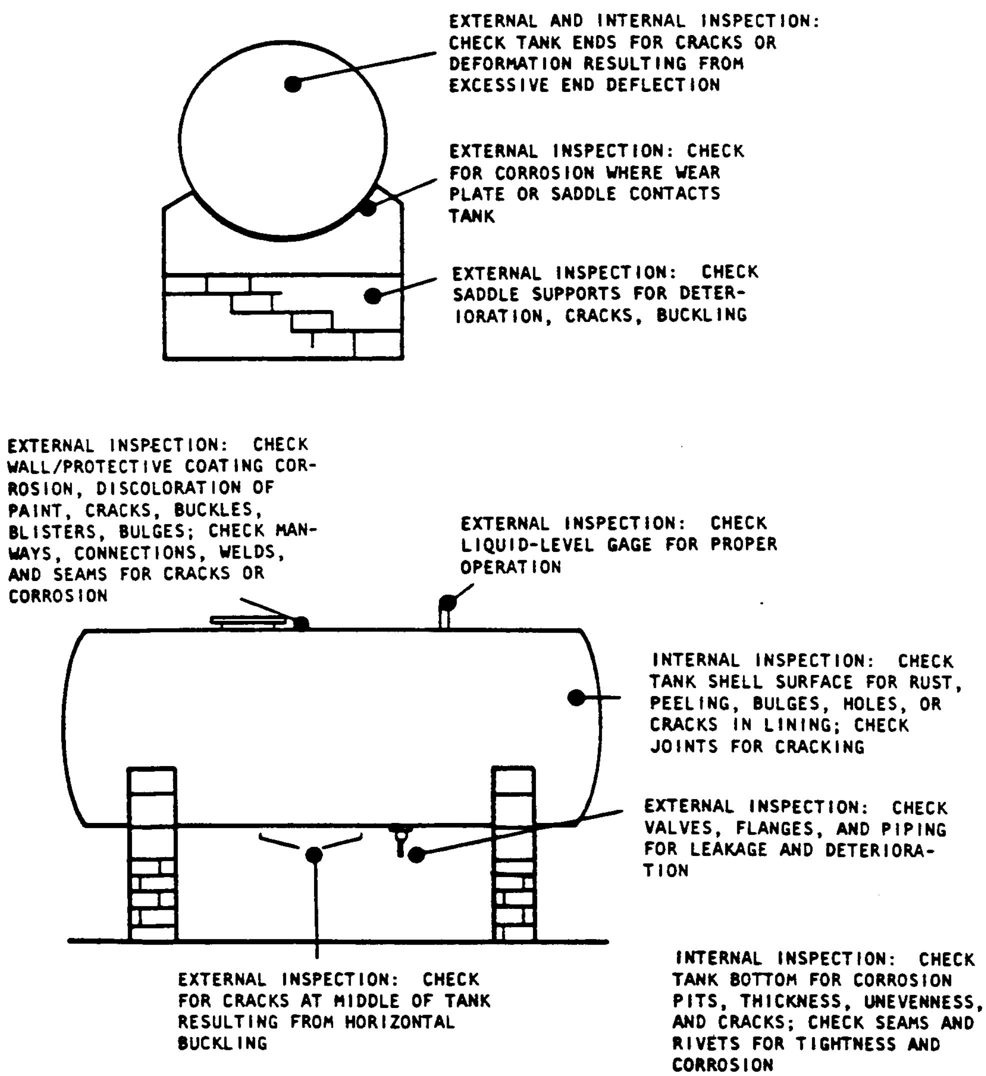



**Figure 4-4**
**Typical Saddle Supports - Areas of concern**

#### 4.2.1.2. Underground Tanks

Underground tanks are typically horizontal since more uniform support can be achieved. This uniform support eliminates the structural support problem encountered with horizontal aboveground tanks.

USTs located in areas with a high water table or flooding are subject to floating. Several methods are used to prevent flotation:

- Placing the tank at a sufficient depth;
- Adding a thicker slab at grade;
- Anchoring the tank using deadmen anchors, (see Figure 4-5);
- Anchoring the tank using a hold-down pad ; and
- Anchoring the tank using mid-anchoring (this is to be used on a limited basis only after consulting the tank manufacturer).

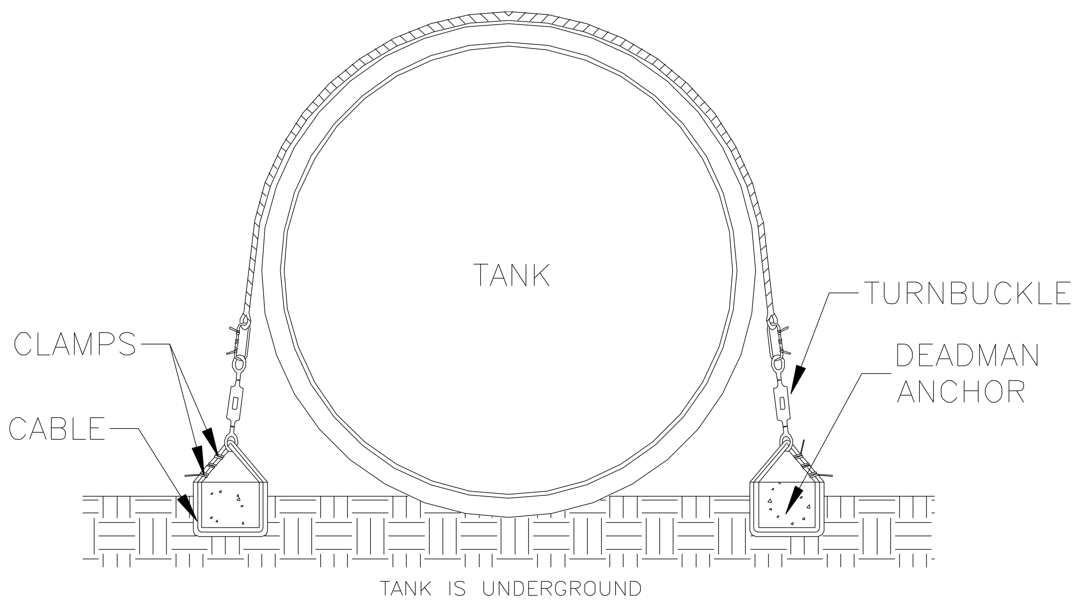



**Figure 4-5**

**Deadman Anchor**

Placing the tank at a sufficient depth with adequate backfill is the most common method used to prevent floatation. Increasing the thickness of the at grade concrete pavement also helps. Mid-anchoring is used infrequently, since improper installation may damage protective coatings or the shell of the tank or violate the electrical isolation of cathodically protected steel tanks.

A major problem with underground tanks is that due to their inaccessibility, structural stability problems can not be readily identified. New UST requirements (40CFR 280) establish very stringent design and installation requirements geared towards eliminating these problems.

Double walled underground storage tanks are required to follow the requirements of USTs as listed in 40 CFR 280. The use of double walled tanks as a means of secondary containment is discussed in 40 CFR 280.42(b)(1), and regulations on interstitial monitoring are written in 40 CFR 280.43(g). The major requirements for regulated USTs are provided in section 2.6.4 of this document.

#### 4.2.1.3. New Tank Construction 280.20

New underground storage tanks must be constructed and installed in compliance with 40 CFR 280. New tanks can be constructed of fiberglass-reinforced plastic (FRP), cathodically protected steel, or steel FRP composite. Metal tanks without corrosion protection can be used if a corrosion expert determines that the soil is not sufficiently corrosive to cause the tank to fail during the operating life. The owners and operators must maintain records for the operating life of the tank showing that unprotected tanks are not subject to corrosion.

The associated piping of underground storage tanks must meet the same material and corrosion requirements as the tanks. Corrosion protection is discussed in Section 4.2.4.

#### 4.2.1.4. Upgrading of Existing UST Systems 280.21(a)

By December 22, 1998, all USTs must comply with the following requirements as specified in 40 CFR 280:

a) same performance standards as new tanks

b) upgrade requirements

c) closure requirements

The upgrade requirements include lining the tank or providing cathodic protection, or a combination of both. If the tank is lined, it must be installed in accordance with 40 CFR 280.33. Cathodic protection in required to be in accordance with 40 CFR 280.21 (b)(2).

### 4.2.2. Material Strength

Another consideration is the material strength of the tank. Mild (carbon) steel is widely used for both aboveground and underground tanks and appurtenances due to its strength, durability, and low cost, but it is very vulnerable to corrosion. Proper corrosion control techniques can significantly enhance mild steel's resistance to severe internal and external conditions. Stainless steel offers superior corrosion resistance to chlorinated organics and acids compared to mild steel, but it is more expensive. FRP tanks have high-corrosion resistance but lack the structural strength, performance at elevated temperatures (above 200°), and impact resistance of steel tanks. These constraints limit their use to operating pressures close to atmospheric and conditions of minimal structural demands. OSHA regulations prohibit the use of FRP tanks for above ground storage of flammable or combustible liquids.

### 4.2.3. Storage Compatibility

Another consideration in evaluating the adequacy of storage tanks is the degree to which the construction material of the tank and appurtenances are compatible with the stored material. The variety of chemicals used in the Navy have different physical and chemical characteristics and specific storage requirements. Many materials may undergo corrosion, loss of structural integrity, or total destruction when in contact with certain chemicals or combination of chemicals. Storing materials in an inappropriate tank can result in a leak, or worse, an explosive condition. This is a great concern when dealing with underground tanks or aboveground tanks with concrete bottoms, since leaks can go undetected.

40 CFR 264.172 also requires that tanks not contain hazardous substance or waste that are incompatible with the tank's construction. If a tank stores the material it was originally designed to contain, then it probably satisfies this requirement. However, tanks used to store HW and substances other than which they were intended may be inappropriate and should be carefully evaluated for compatibility. A typical example of incompatible storage is the storage of corrosive waste liquids in bare steel tanks.

A qualified professional should evaluate and certify the adequacy of any proposed chemical and material combination prior to actual storage. Chemical products should be removed promptly from incompatible tanks and pipes. This is particularly important for underground and partially buried tanks and pipes where leaks could go undetected for long periods of time. Appendix F contains a compatibility matrix between specific chemicals and a variety of construction materials. The chemicals listed are representative of materials commonly encountered at Navy activities. Because corrosion and reaction rates also depend upon other factors such as concentration, temperature, and humidity, the matrix presents only the general suitability of a chemical or material combination over a broad range of conditions. Therefore, the matrix should be used as a tool for preliminary screening of a material and chemical combination and for identifying gross incompatibilities between chemicals and tank materials.

The interior of some existing tanks can be lined with an appropriate material and reused. The cost-effectiveness of relining a tank will depend upon tank age, structural integrity, and how well the tank has been maintained. If a tank is too old or deteriorated, replacing it with a new tank may be more economical. Incompatible tank appurtenances such as access manholes, pipes, and valves, should be promptly repaired or replaced.

Another storage compatibility concern is the aboveground storage of oil with a true vapor pressure of 1.5 psia or more. Some examples are gasoline at any storage temperature or JP-4 where the temperature exceeds 70° F. In these cases, the tanks should be equipped with an internal floating pan to control the presence of explosive vapors.

### 4.2.4. Corrosion Protection

Suitable methods of corrosion protection include: a coating with a suitable dielectric material; field-installed cathodic protection systems designed by a corrosion expert; impressed current systems designed to allow determination of current operating status; or cathodic protection systems operated and maintained in accordance with 40 CFR 280.31 or according to guidelines established by the implementing agency.

Increasing problems with chronic UST leaks due to corrosion have resulted in design requirements for new USTs. Federal guidelines for implementation of SPCC plans (40 CFR 112.7(e)(2)(iv)) state that new buried metallic storage tanks and piping should be protected from corrosion by coatings, cathodic protection or other effective methods, and should at least be subjected to regular pressure testing. Partially buried tanks for the storage of oil are not recommended unless the buried section is adequately protected (40 CFR 112.7(e)(2)(v)). New tank SPCC construction requirements are also in DM 22.

The corrosion prevention requirements of 40 CFR 280 address primarily new underground tank construction. However, 40 CFR 280.20 (a) requires that by December 22, 1998, all buried tanks be protected from corrosion by coatings, cathodic protection, or other effective methods compatible with local soil conditions. Since applying an exterior coating to a buried tank is seldom practical, installing a cathodic protection system can be an effective and practical corrective action.

Corrosion of the tank supports on aboveground horizontal tanks can be a problem. Horizontal tanks often come from the factory mounted on skids. If water is allowed in contact with these steel skids, then corrosion of the skids can be a significant problem. If possible, steel tank supports should be on elevated concrete pads which are angled so that precipitation drains away from the steel support structure. This is particularly important when the tank is surrounded by concrete curbing such that rainwater routinely accumulates around the tank. Another factor to be aware of is the floors of vertical aboveground tanks which may also be subject to corrosion.

RCRA hazardous waste regulation 40 CFR 264.192 also requires that all new ASTs and USTs used to store or treat HW be provided with an accepted form of corrosion protection such as fiberglass, protective coatings, double-walled tanks with continuous monitoring, and vaulted tanks equipped with man-ways for access to inspection and maintenance.

NFPA 30 also requires application of corrosion protection systems to flammable and combustible liquid USTs and associated piping.

#### 4.2.4.1. Fundamental Concepts

Corrosion is the deterioration of a material because of a reaction with its environment. Plastics and other non-metallic materials may deteriorate rapidly when exposed to certain corrosive chemicals. This is a chemical reaction that can be easily eliminated through proper selection (See Section 4.2.3) and careful handling of tank and piping materials.

The reaction is usually an electrochemical process wherein the metal tank reacts with its environment and oxidizes giving off electrons into the environment or into a different type of metal. Steel aboveground tanks in contact with the earth, steel underground tanks, and buried steel piping are all susceptible to corrosion. Corrosion can occur over the entire tank, piping, or in small-localized spots. When localized, corrosion may occur much more quickly, resulting in deeper holes. Corrosion control in metals is therefore more complicated and more strictly regulated. The American Petroleum Institute has tabulated steel tank and pipe failure data; corrosion is the major cause of all leaks.

The characteristics of soil, water, and air surrounding a tank or pipeline directly influence the rate of corrosion. Although corrosion of non-buried aboveground tanks and pipes is a concern, its presence can be easily detected and mitigated through routine inspections and maintenance. Partially buried and underground steel tank systems require special considerations to minimize corrosion from adverse soil conditions such as corrosive elements, poor soil aeration, high or low pH, high moisture or organic content, and low or non-uniform resistivity. Soils with a resistivity (resistance to direct current within the material) of 10,000 ohm-cm or less usually require corrosion protection. Many states are even more stringent and you should consult applicable state and local requirements. Table 4-2 provides relative corrosivities based on the different resistivities of soils.

**Table 4-2**
**Soil Resistivity Classification**

| Resistivity - ohm-cm | Category |
|---|---|
| 0-1,000 | Very corrosive |
| 1,000-5,000 | Aggressive |
| 5,000-10,000 | Mildly corrosive |
| 10,000-25,000 | Slightly corrosive |
| Over 25,000 | Progressively less corrosive |

Source: Steel Tank Institute, R892-91, page 4

Corrosion may be eliminated by the proper application of protection methods. Table 4-3 lists several common corrosion control methods. One way to avoid corrosion damage from environmental conditions is to install tanks and piping constructed of fiberglass and PVC. Coating tanks and piping is another method of preventing corrosion, since the metal of the tank or piping is no longer in direct contact with the corrosive soil. Coating aboveground tanks and piping for corrosion protection is common since the coating can be inspected. However, coatings can easily become damaged, and severe localized corrosion (pitting or pinhole corrosion) can occur where the damage occurs.

The most common corrosion protection methods applied to tanks are the application of protective coatings and/or installation of cathodic protection systems. A complete evaluation of the corrosion protection systems in existing tanks and pipes is beyond the scope of a SPCC plan. However, one should be able to tell if these areas are afforded adequate corrosion protection, if the systems operate properly, and if they are inspected and maintained. Use the following guidelines to identify and evaluate the adequacy of existing corrosion protection systems. If a system needs further evaluation, a corrosion control expert should be consulted.

**Table 4-3**
**Corrosion Control Methods**

| Type of Corrosion | Control Methods |
|---|---|
| Uniform Corrosion | • Inhibitors<br>• Protective coating<br>• Anodic protection |
| Intergranular Corrosion | • Avoiding temperatures that can cause contaminant precipitation during heat treatment or welding |
| Pitting Corrosion | • Protective coating<br>• Allowing for corrosion in wall thickness |
| Stress-Corrosion Cracking | • Reducing residual or applied stresses<br>• Redistributing stresses<br>• Avoiding misalignment of sections joined by bolts, rivets, or welds<br>• Materials of similar expansion coefficients in one structure<br>• Protective coating<br>• Cathodic protection |
| Corrosion Fatigue | • Minimizing cyclic stresses and vibrations<br>• Reinforcing critical areas<br>• Redistributing stresses<br>• Avoiding rapid changes in load, temperature, or pressure<br>• Inducing compressive stresses through swaging, rolling, vapor blasting, chain tumbling, etc. |
| Galvanic Corrosion | • Avoiding galvanic couples<br>• Completely insulating dissimilar metals (paint alone is insufficient)<br>• Using filler rods of same chemical composition as metal surface during welding<br>• Avoiding unfavorable area relationships<br>• Using replaceable parts of the anodic metal<br>• Cathodic protection<br>• Inhibitors |

## Table 4-3 Cont.
## Corrosion Control Methods

| Type of Corrosion | Control Methods |
|---|---|
| Thermogalvanic Corrosion | • Avoiding non-uniform heating and cooling<br>• Maintaining uniform coating or insulation thickness |
| Crevice Corrosion; Concentration Cells | • Minimizing sharp corners and other stagnant areas<br>• Minimizing crevices to a minimum, especially in heat transfer areas and in aqueous environments containing inorganic solutions or dissolved oxygen<br>• Enveloping or sealing crevices<br>• Protective coating<br>• Removing dirt and mill-scale during cleaning and surface preparation<br>• Welded butt joints with continuous welds instead of bolts or rivets<br>• Inhibitors |
| Erosion; Impingement Attack | • Decreasing fluid stream velocity to approach laminar flow<br>• Minimizing abrupt changes in flow direction<br>• Streamlining flow where possible<br>• Installing replaceable impingement plates at critical points in flowlines<br>• Filters and steam traps to remove suspended solids and water vapor<br>• Protective coating<br>• Cathodic protection |
| Cavitation Damage | • Maintaining pressure above liquid vapor pressure<br>• Minimizing hydrodynamic pressure differences<br>• Protective Coating<br>• Cathodic protection<br>• Injecting or generating larger bubbles |
| Fretting Corrosion | • Installing barriers which allow for slip between metals<br>• Increasing load to stop motion, but not above load capacity<br>• Porous protective coating<br>• Lubricant |
| Hydrogen Embrittlement | • Low-hydrogen welding electrodes<br>• Avoiding incorrect pickling, surface preparation, and treatment methods<br>• Inducing compressive stresses<br>• Baking metal at 200-300° F to remove hydrogen<br>• Impervious coating such as rubber or plastic |
| Stray-Current Corrosion | • Providing good insulation on electrical cables and components<br>• Grounding exposed components of electrical equipment<br>• Draining off stray currents with another conducting material<br>• Electrically bonding metallic structures |

| Type of Corrosion | Control Methods |
| --- | --- |
| | • Cathodic protection |

**Table 4-3 Cont.**
**Corrosion Control Methods**

| Type of Corrosion | Control Methods |
|---|---|
| Differential-Environment Cells | • Underlying and backfill underground pipelines and tanks with the same material<br>• Avoiding partially buried structures<br>• Protective coating<br>• Cathodic protection |

### 4.2.4.2. Protective Coating Systems.

Protective coatings work by creating a barrier to moisture, oxygen, and electrical current, thus, sealing the metal tank from the corrosive environment. Protective coatings are applied to protect both exterior and interior surfaces. To stop corrosion completely, coatings and linings (interior surface) must provide the following:

- Form a uniform high-resistance to electrical current,
- Be pore free,
- Have excellent adhesion to the tank,
- Be resistant to damage due to impact and abrasion,
- Be resistant to moisture absorption,
- Be splash resistant to product spills,
- Resist degradation with time and exposure to the environment, and
- Be compatible with cathodic protection systems.

For the best results, coating materials should have high dielectric properties and should be applied to properly prepared surfaces. Some of the common coating materials used include polyurethanes, epoxies, and reinforced plastics. Coatings that are applied by the manufacturer generally perform better than coatings applied in the field. Normally, a good coating system decreases the size and cost of the cathodic protection system, as well as increases the life of the protection system.

Chemical compatibility and operating temperature are the prime considerations in coating evaluation or selection. Comparative resistances of typical coatings are provided in Table 4-4. However, these should be used for general information only, and manufacturers should be consulted for more detail.

**Table 4-4**
**Comparative Resistances of Typical Coatings**

| Coating Type | Acid | Alkali | Salts | Solvents | Water | Oxidation | Sunlight and Water | Stress | Abrasion | Heat |
|---|---|---|---|---|---|---|---|---|---|---|
| Acrylic | 8 | 8 | 9 | 5 | 8 | 9 | 10 | ? | 10 | 8 |
| Alkyd | 6 | 6 | 8 | 4 | 8 | 3 | 10 | 5 | 6 | 8 |
| Asphalt | 10 | 7 | 10 | 2 | 10 | 2 | 7 | 5 | 3 | 4 |
| Chlorinated Rubber | 10 | 10 | 10 | 3 | 10 | 9 | 7 | 7 | 7 | 5 |
| Epoxy | 10 | 9 | 10 | 8 | 10 | 6 | 9 | 3 | 6 | 9 |
| Furan | 10 | 10 | 10 | 10 | 10 | 2 | 8 | 1 | 5 | 9 |
| Inorganic (metallic) | 1 | 1 | 5 | 10 | 5 | 10 | 10 | ? | 10 | 10 |
| Latex | 2 | 1 | 6 | 1 | 2 | 1 | 10 | ? | 6 | 5 |
| Neoprene | 10 | 10 | 10 | 4 | 10 | 6 | 8 | 10 | 10 | 10 |
| Oil Base | 1 | 1 | 6 | 2 | 7 | 1 | 10 | 4 | 4 | 7 |
| Phenolic | 10 | 2 | 10 | 10 | 10 | 7 | 9 | 2 | 5 | 10 |
| Saran | 10 | 8 | 10 | 5 | 10 | 10 | 7 | 7 | 7 | 7 |
| Urethanes | 9 | 10 | 10 | 9 | 10 | 9 | 8 | ? | 10 | 8 |
| Vinyl | 10 | 10 | 10 | 5 | 10 | 10 | 10 | 8 | 7 | 7 |

Scale: 1 = Nonresistant
10 = Extremely resistant
? = Insufficient data

Sources: NACE, 1975, and Steiner, 1959.

It should be noted that buried tanks and piping that do not also have cathodic protection can suffer much faster corrosion damage than bare steel tanks and piping if the coating has been damaged in any way. Small holes in the coating cause corrosion to be greatly accelerated on the surface of the tank or piping exposed by the hole and the steel can corrode clear through much faster than if the coating was not there at all. Whenever possible, coatings should be used in conjunction with cathodic protection on buried tanks and piping. For aboveground piping systems, coating damage on aboveground piping may allow water to seep inside of the coating where it will collect and again cause greater corrosion damage than if the coating was not present.

Eroded coatings or linings are spill prevention deficiencies and should be repaired promptly to avoid the spread of corrosion. If the extent of corrosion can result in failure, or if the tank is already leaking, it should be removed immediately from service for proper replacement or repair.

DM-22 requires that underground steel piping systems be cathodically protected in addition to a coating or wrapping. NFGS 15192 requires that new underground steel pipes have a factory-applied polyethylene coating with an adhesive undercoat for diesel and fuel oil pipes. Fittings, couplings and areas of damaged coating are to be covered with tape conforming to FS L-T-15.

Coatings and linings are economical retrofit alternatives to achieve chemical resistant tanks and pipes, but are not feasible or are highly impractical for inaccessible surfaces (i.e. buried tanks and pipes, pipe interior walls, tanks without manholes, etc.). Recoating and rewrapping of aboveground piping systems is commonly practiced throughout the Navy.

If the existing records do not indicate whether or not a UST has a protective coating, it may be possible to observe a coating through an access manhole or vault. It may also be possible to observe if venting piping has some type of coating that extends above the ground level; if the piping is coated, then it is very probable that the UST also has a coating.

#### 4.2.4.3. Cathodic Protection

Cathodic protection reverses the electrochemical action of corrosion. Instead of allowing electrons to flow away from a steel structure (thereby permitting corrosion to occur), an electron flow toward the structure is induced, thereby protecting the structure. The method has wide application for both aboveground and underground structures and is often the only practical way to stop existing corrosion.

Cathodically protected systems can usually be identified by the presence of test stations, as presented in Figure 4-6. The test stations can be either wall mounted or flush mounted on the ground usually adjacent to walls, curbs, or guard posts. The test stations are usually installed for every tank and 200 lineal feet of piping.

There are two basic types of cathodic protection systems: the sacrificial anode system and the impressed current system. The sacrificial anode (i.e., a metal anode more negative in the galvanic series than the metal to be protected) is electrically connected to the tank or piping and buried in the soil. To prevent corrosion, a sacrificial anode such as magnesium or zinc, releases electrons and corrodes instead of the tank or piping. A typical sacrificial anode system is shown in Figure 4-7.

Some of the drawbacks of a sacrificial anode system include:

- Low-voltage generation. Zinc anodes generate only .25 volts and may be ineffective for soil resistivities of 2,000 ohm-cm or greater. Magnesium anodes produce from .7 to .9 volt driving potential, but are often ineffective for soil resistivities above 10,000 ohm-cm.
- Self-corrosion of sacrificial anodes reduces their usable protective current output efficiency to about 50% for zinc and 90% for magnesium.
- Highly corrosive environments can drastically reduce their useful life. Sacrificial anodes must be replaced frequently.

For these reasons, sacrificial anodes are used to protect relatively small areas, localized "hot spots" in a structure, well-coated structures, and locations where the impressed current method poses a hazard.

The impressed current system employs direct current from an external source to reverse the flow of electrons and prevent corrosion. Current is passed through the system by non-sacrificial anodes such as carbon or graphite, non-corrodible alloys, or platinum. These anodes are buried in the ground and connected to an external power supply. This method is preferably used for large, bare, or poorly coated surfaces. An impressed current system is illustrated in Figure 4-8.

Potential problems associated with this system include:

- Damage to the steel structure and its coating due to excessive voltage.
- Interruption of protection by power failure.
- Stray current interference from adjacent or nearby buried structures

A cathodic protection system does not ensure that a structure is properly protected against corrosion. Faulty cathodic protection constitutes a spill prevention deficiency and must be corrected. Not replacing sacrificial anodes when required, evidence of corrosion (rust spots, spalling, or flaking), or any of the above mentioned problems may indicate the system is not designed, operated, or maintained properly.

As a retrofit method, cathodic protection is particularly effective for underground applications, where it is impractical to excavate and coat buried tanks and pipes. Cathodic protection is more effective and less expensive on coated structures, since the amount of protective current required is proportional to the amount of bare metal exposed to the corrosive media. On bare tanks, cathodic protection may be only 90% effective, due to the existence of active pits into which the protective current cannot penetrate.

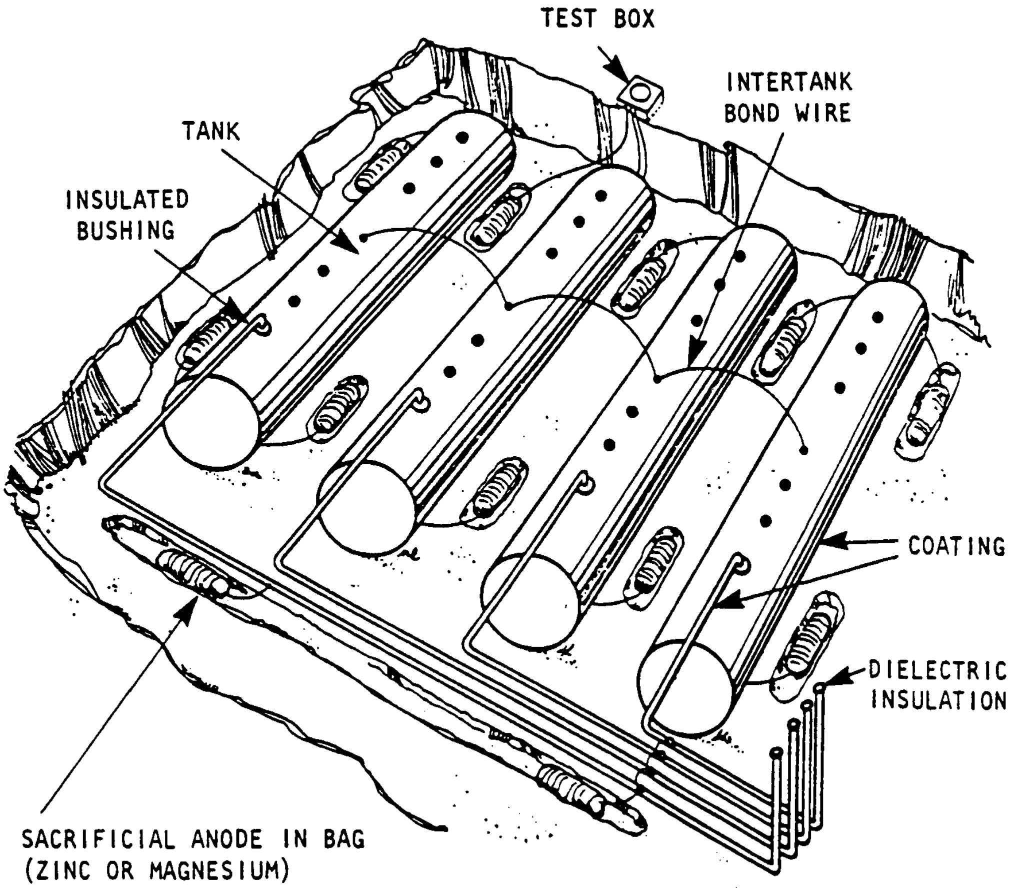



**Figure 4-6**
**Sample Cathodic Protection Test Station Location**

Sacrificial anode systems are generally not effective on bare tanks because of their low volt driving potential. Also, since sacrificial anodes need to be bonded to all system components being protected (in fact, threaded piping does not reliably provide the necessary electrical continuity), retrofitting entails exposing all system components and welding a bonding wire to these components. This can be costly and can require purging the system for safety. Therefore, impressed current systems are probably the best retrofit alternative for buried systems.

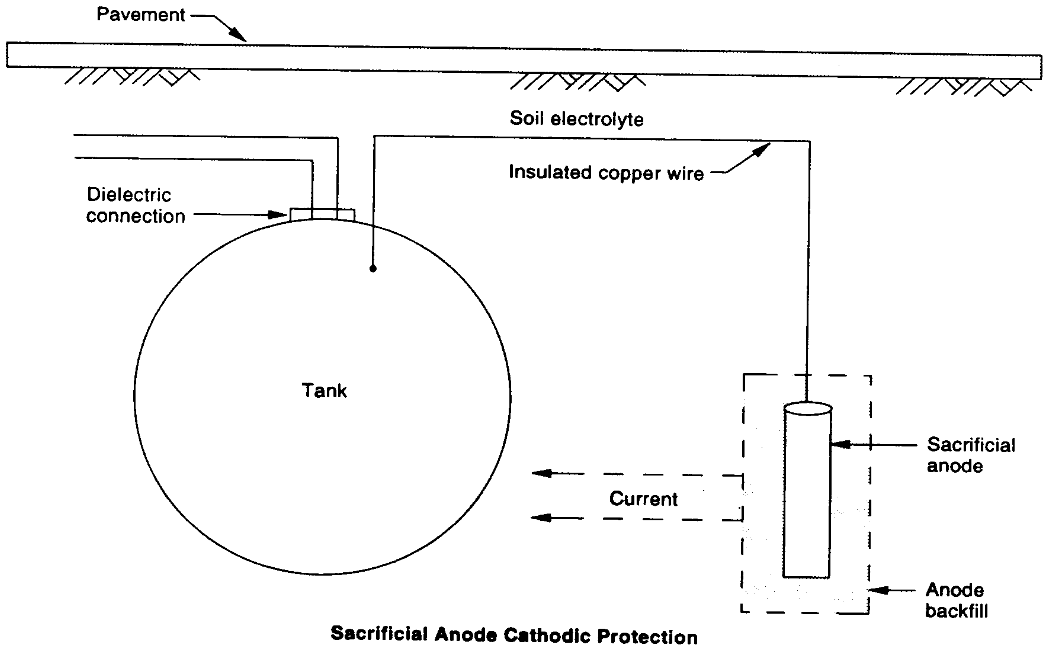



**Figure 4-7**
**Sacrificial Anode System**

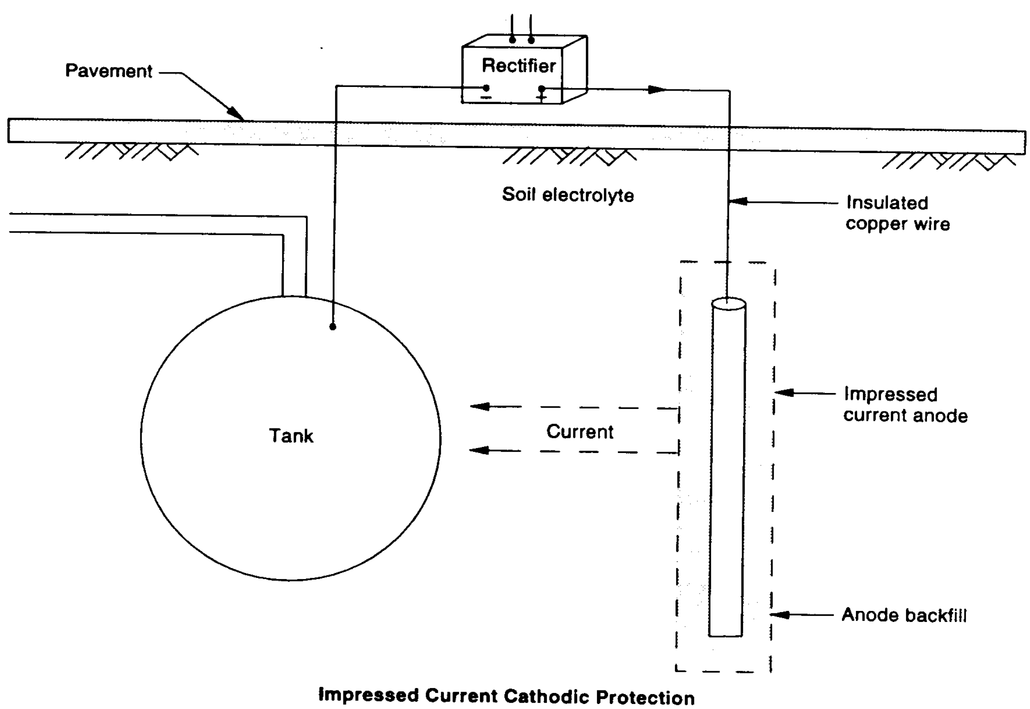



**Figure 4-8**
**Impressed Current System**

### 4.2.4.4. Other Methods

Other corrosion protection methods used include electrical isolation, corrosion inhibitors, and strikeplates. These systems should only be used in concert with cathodic protection or other acceptable method discussed above.

Electrical Isolation. This method isolates metal components using nonconductive fittings, bushings, flanges, connections, etc. This minimizes the potential for the generation of electrical currents between dissimilar metals, which reduces the likelihood of corrosion. Installation of non-conductive materials normally requires taking the tank system out of service until work is complete.

Strikeplates. These are metal sheets placed inside a tank to prevent corrosion of tank bottoms due to repeated mechanical impingement, such as gage sticks used for inventory control. Strikeplates must be carefully placed to be effective.

Corrosion Inhibitors. Inhibitors added to stored liquids can sometimes help control corrosion on the inside of a tank or pipe. Typical inhibitors include chromates, phosphates, silicates, organic sulfides and amines. Primary considerations and limiting factors include proper inhibitor selection, correct concentration determination and monitoring, and agitation of the liquid.

Corrosion-Resistant Materials. Some applications (e.g., piping for corrosive materials) require the use of corrosion-resistant piping materials. A variety of plastics are used by naval activities for such applications. Table 4-5 provides a summary of piping materials and their corrosion and chemical compatibility characteristics.

**Table 4-5**
**Characteristics of Piping Materials**
**For Aboveground and Underground Service**

| Type of Pipe | Chemical Compatibility | Characteristics |
|---|---|---|
| Carbon Steel | Not compatible with corrosive chemicals such as acids. | Susceptible to corrosion if not coated, galvanized, cathodically protected (for underground service), or otherwise protected against corrosion. |
| Stainless Steel | Compatible with corrosive chemicals such as acids, depending on grade. | Used when product purity is of great concern. Primarily used for corrosion protection in product transfer applications when coated carbon steel will not suffice (e.g., at high operating temperatures). |
| Aluminum | Subject to attack by alkalis, traces of heavy metal ions such as copper, nickel, and mercury, and by prolonged contact with wet insulation. | Limited structural strength as compared to steel. Aluminum does not retain its structural strength at low temperatures. Used in product transfer applications involving substances that cannot be handled by steel, such as organic acids. |

**Table 4-5 Cont.**
**Characteristics of Piping Materials**
**For Aboveground and Underground Service**

| Type of Pipe | Chemical Compatibility | Characteristics |
|---|---|---|
| Nickel and Nickel Alloys | 99% nickel, 0.06% carbonsed for halogen acids at high temperatures. | Useful for handling halogen acids at high temperatures, sodium chloride solutions, and caustic soda. |
| | 99% nickel, 0.01% carbon used for fused caustic soda (sodium hydroxides). | |
| Lead and Lead-Lined Steel | Useful for handling sulfuric acid at moderate temperatures. | Lead has limited structural strength. It is customary to lay lead pipe in steel angles or wood troughs. |
| Copper and Copper Alloys | Has high resistance to industrial and marine atmospheres, seawater, alkalis, and solvents. | Copper has excellent low-temperature properties. |
| | Oxidizing agents rapidly corrode copper. However, alloys have somewhat different properties than commercial copper. | Cupro-nickel is applicable in seawater services. Bronze pipe generally performs well in hydrocarbon service. |
| Plastic Tube and Pipe | Various plastics can be selected for their resistance to specific chemicals | Free from internal and external corrosion. Allowable stresses and temperature limits are low. Low structural strength when compared to steel. Coefficients of thermal expansion are high. Should be protected from fire exposure in accordance with OSHA regulations. |
| | (1) Polyethylene pipe and tubing have excellent resistance to salts, sodium and ammonium hydroxides, and sulfuric, nitric, and hydrochloric acids. | |
| | (2) Polyvinyl chloride pipe and tubing have excellent resistance at room temperatures to salts, alcohol, ammonium hydroxide, and sulfuric, acetic, nitric, and hydrochloric acids; may be damaged by ketones, aromatics, and some chlorinated hydrocarbons. | |
| | (3) Polypropylene pipe and tubing have excellent resistance to most common organic and mineral acids and their salts, strong and weak alkalis, and many organic chemicals. | |

**Table 4-5 Cont.**
**Characteristics of Piping Materials**
**For Aboveground and Underground Service**

| Type of Pipe | Chemical Compatibility | Characteristics |
|---|---|---|
| Plastic-Lined Piping | See plastic pipe. | Combines the chemical resistance of the various plastics and the tensile and structural strength of steel. |
| Fiberglass/ Fiberglass-Reinforced Pipe | Compatible with a wide range of corrosive chemicals, including acids, bases, and hydrocarbon solvents | Less structural strength than steel. High resistance to external and internal corrosion. Should be protected from fire exposure in accordance with OSHA regulations. |

### 4.2.5. Grounding

Because of the possibly explosive environment of fuel tanks, DM-22 requires the grounding or bonding to a grounded network of certain items related to fuel storage. Although the grounding of a tank system is not directly related to spill prevention, it is a requirement of tank design. The SPCC inspector or environmental coordinator should check for proper grounding when inspecting storage tanks. Items such as electrical equipment, aboveground tanks, and pipe support columns are required to be grounded. Refer to DM-22 for details on grounding and bonding of fuel areas.

### 4.2.6. Internal Tank Heating Coils

Standard practice in colder climates is to heat heavier fuel oils, such as No. 6 oil, stored in aboveground tanks. Saturated steam is the preferred heating medium; however, hot oil, hot water, or electric heating is also used where steam is not available. Specific details regarding heating coils are found in DM-22.

Heating coils using steam or hot water that discharge to the environment may be the source of a oil leak. During summer months, when heating coils are idle, condensate lying in the coil internally corrodes the coil metal. Oil enters the coil and is later discharged with the steam or hot water.

In some fuel oil heating systems, the exhaust steam and condensate are returned to the boiler water feed system. If oil enters the boiler feed system, it can insulate and burn the boiler tubes and drums, possibly resulting in metal failure and explosion.

40 CFR 112.7(e)(2)(vii) states that to control leakage through defective internal heating coils, the following factors should be considered and applied, as appropriate.

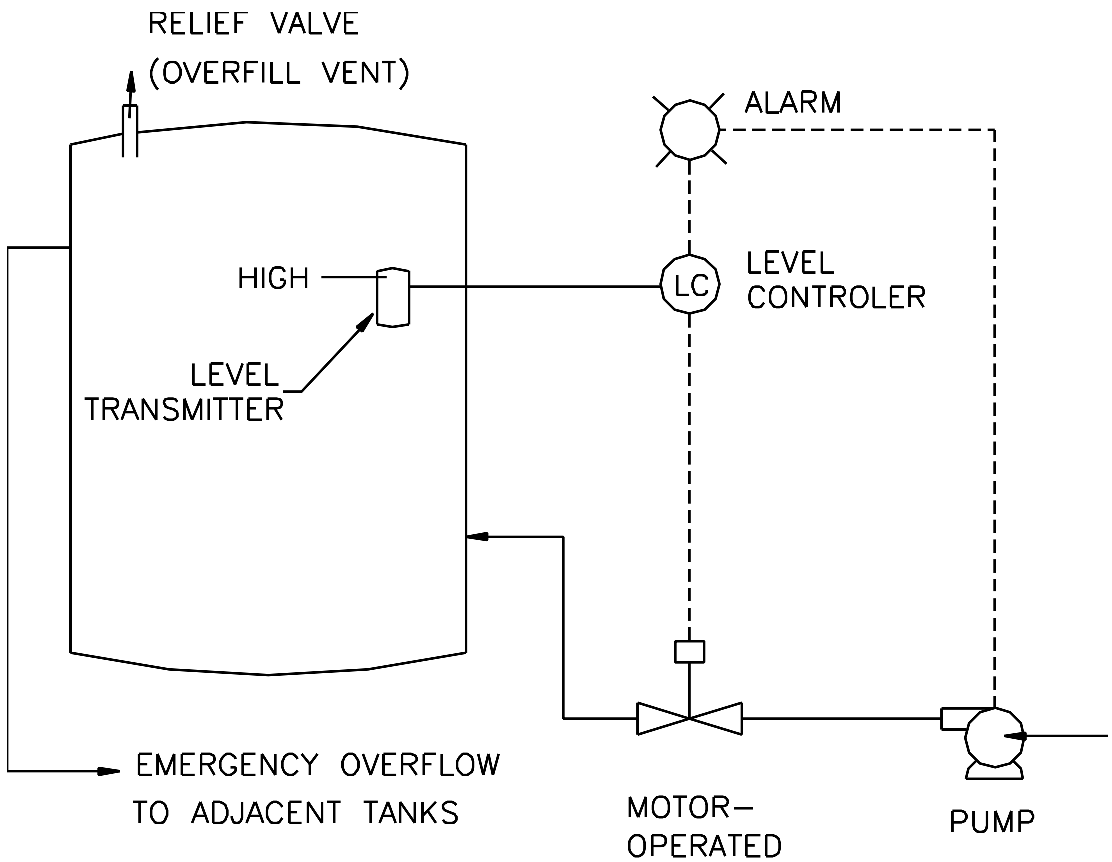
- The steam return or exhaust lines from internal heating coils which discharge into an open water course should be monitored for contamination or passed through a settling tank, skimmer, or other retention system.

- The feasibility of installing an external heating system should also be considered.

### 4.2.7. Level Controls

Tank level controls or detection devices use level sensors and gauges to detect and indicate the liquid level in a tank. They may be used by themselves, connected to audio and/or visual high-level alarms that warn an operator of potential overfill conditions, or interlocked to electronic or mechanical devices that automatically shut down filling operations. Figure 4-9 shows a generalized schematic of an overfill protection system.

40 CFR 112.7(e)(2)(viii) requires new and old oil tank installations to be fail-safe engineered or updated to avoid spills. This includes installation of liquid level sensing devices, high-level alarms, automatic pump cutoff devices, and other automatic controls. NFPA 30 also requires overfill protection of ASTs storing flammable and combustible liquids by utilizing high-level detection devices and automatic controls to shut down or divert flow. Double-walled aboveground tanks are required to have an overfill alarm and a high-level shutoff device by EPA and NFPA Code 30. In addition to the high-level alarm and automatic shutoff device, NPFA Code 30 requires a liquid-level indicating device for double-walled ASTs. The code also states that USTs be equipped with an automatic system to shut down flow when the tank is 95% full or alert the operator when the tank is more than 90% full. Some state and local agencies may also require continuous level sensing equipment as a means of leak detection for the tanks. In addition, level gauging devices and high- and low-level alarms are required for all oil storage tanks by DM-22.




Adapted from Technology for the Storage of Hazardous Liquids; A State–of–the–Art Review, New York State Department of Envirnomental Conservation, 1983.

**Figure 4-9**
**Elements Of Ideal Overfill Prevention System**

Types of level sensing devices include float-actuated devices, displacement systems, electrical capacitance sensors, optical sensors, ultrasonic sensors, thermal conductivity sensors, and pressure sensors. Table 4-6 shows the characteristics of level sensing devices available for aboveground and underground storage tanks and the types of gauges, alarms, and automatic controls that can be applied.

If only high- and low-level conditions need to be monitored rather than a continuous measurement of liquid level, a conductive or capacitance-type probe may be appropriate. However, the type of product being measured must also be considered. For example, conductive level gages (both point probes and continuous measurement) are not effective with fuels such as JP-4 due to low conductance. A mechanical device or capacitance-type gage is more appropriate. Mechanical devices tend to be more reliable and require less maintenance than electrical devices.

**Table 4-6**
**Liquid Level Sensing Devices**

| Type of Device | Applicability | Level Indication | Alarm and Shutoff Response |
|---|---|---|---|
| **Float Actuated Devices** | | | |
| Chain float gauges | A | Gauge | Interfaces with electronic or pneumatic controls |
| Tape float gauges | A&U | Gauge | Interfaces with electronic or pneumatic controls |
| Float vent valves | U | None | Automatic shutoff |
| Drop tube float valve | A&U | None | Automatic shutoff |
| Lever and shaft mechanisms | A | Gauge | Interfaces with electronic mechanisms or pneumatic controls |
| Magnetically coupled floats | A | Gauge | Interfaces with electronic floats or pneumatic controls |
| **Displacer Devices** | | | |
| Torque tube displacer | A | Gauge | Mechanical |
| Magnetically coupled displacers | A | Gauge | Mechanical displacers |
| Flexure-tube displacer | A | Gauge | Interfaces with electronic nor pneumatic controls |
| Pressure Devices | | | |
| Pressure gauge - open vessel | A | Gauge | Interfaces with electronic vessel or pneumatic controls |
| Bubble-type systems (gas bubblers) | A | Gauge | Interfaces with electronic{gas bubblers or pneumatic controls |
| Head systems on pressurized tanks | A | Gauge | Interfaces with electronic pressurized tanks or pneumatic controls |
| Capacitance Devices | A&U | Gauge | Audible alarm and automatic shutoff; electronic controls |
| Thermal Conductivity Devices | A&U | Gauge | Audible alarm and automatic Devices shutoff; electronic controls |
| Ultrasonic Devices | A&U | Gauge | Audible alarm and automatic shutoff; electronic controls |
| Optical Devices | A&U | Gauge | Audible alarm and automatic shutoff; electronic controls |

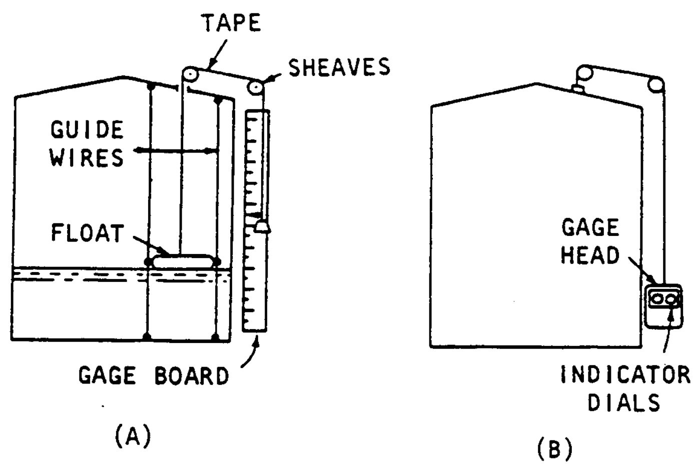
A = Aboveground tanks

U = Underground tanks

### 4.2.7.1. Float-actuated Devices.

Float-actuated devices are characterized by a buoyant member which floats at the surface of the liquid. The float is typically made of a material such as aluminum, stainless steel, or coated steel. This level-sensing device may be used in conjunction with pneumatic or electronic devices to operate valves, pumps, remote alarms, or automatic shutoff systems. Float-actuated devices are classified by the method used to couple the float motion to the indicating system. Examples of classifications include tape float gauges, chain float gauges, float vent valves, lever and shaft float gauges, and magnetically coupled float gauges.

Tape and Chain Float Gauges. Chain or tape float gauges consist of a float mechanically connected by a tape or a chain to a board or indicator dial as shown in Figure 4-10. They are commonly used in large atmospheric storage tanks due to low cost and reliability. Their disadvantages include the potential for (1) misalignment of the float or the tape; (2) corrosion of the float material when improperly selected; and (3) jamming and freezing of the float linkage.




Source: Technology for the Storage of Hazardous Liquids: A State-of-the-Art Review, New York State Department of Environmental Conservation, 1983.

**Figure 4-10**
**Chain And Tape Float Gauges Used For Tank Level Control**

Float Vent Valves. Float vent valves are simple, inexpensive devices used to prevent overfilling of underground fuel tanks. These devices, which are shown in Figure 4-11, are installed in the tank's vent line. When a high level is attained, the float closes the vent line, thus blocking the escape of air. This action causes the pressures inside the storage tank to equalize with the discharge head in the tank truck, thereby interrupting the flow of liquid.

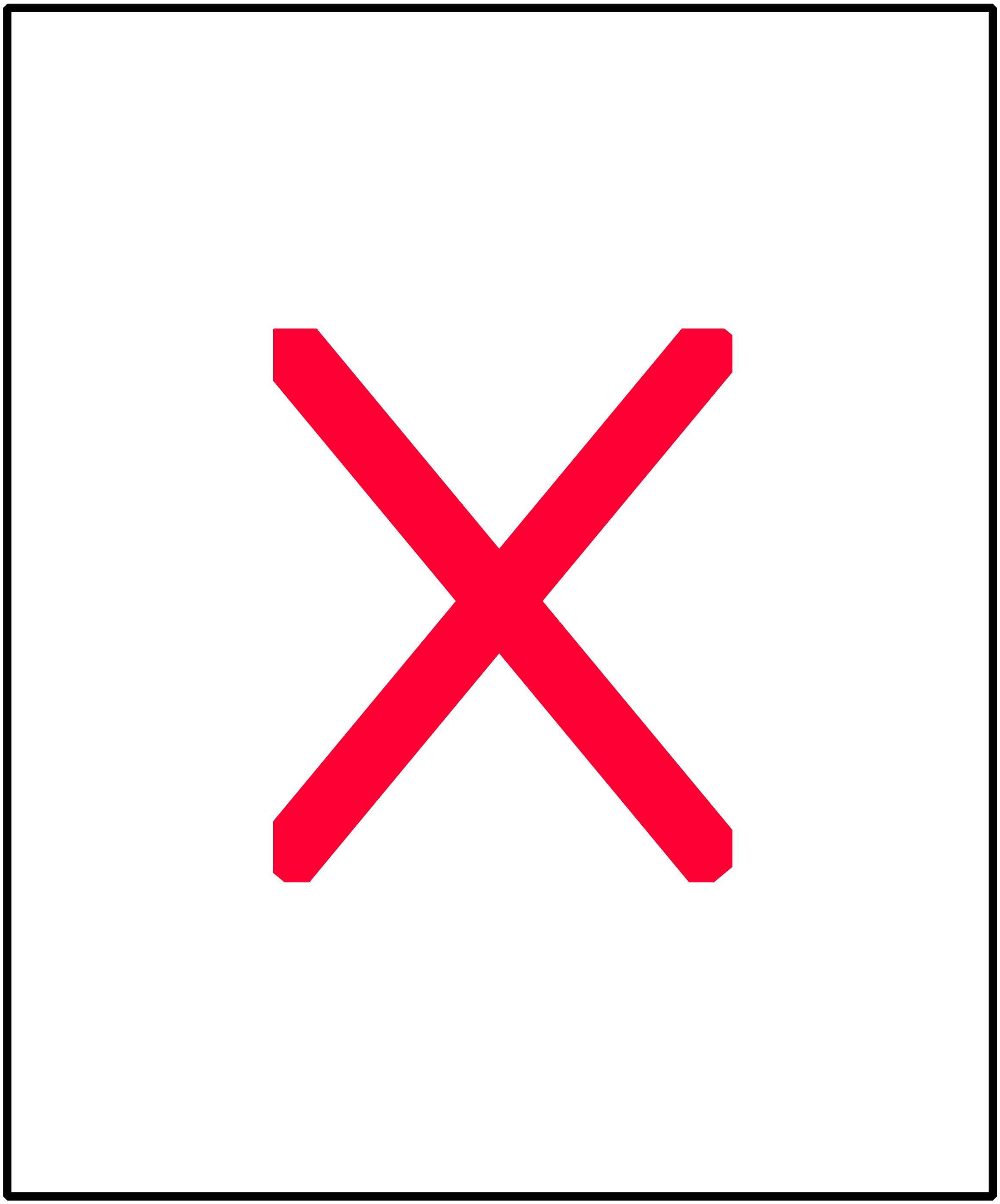


**Figure 4-11**
**Float Vent Valves**

The float vent valve also includes a pressure relief hole. Once flow from the tank truck has ceased due to pressure equalization, the fill line is disconnected. Then, as vapor escapes through the float vent valve relief hole, the liquid remaining in the fill line drains into the tank.

If dry disconnection couples are used, the liquid will be held in the transfer line, thus preventing any spillage of product.

Drop Tube Float Valve. Drop tube float valves are two-stage shut-off valves, as shown in Figure 4-12.

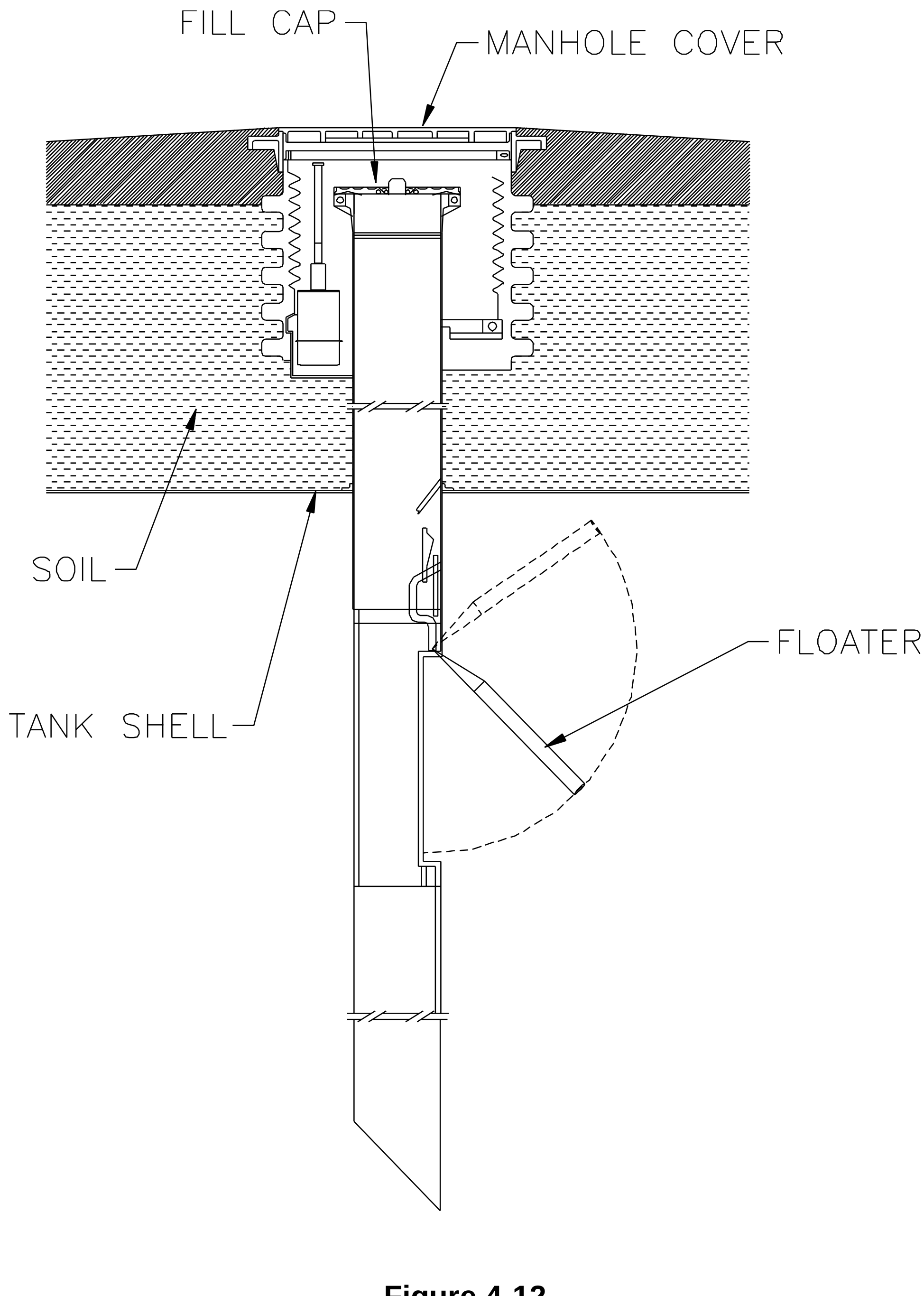
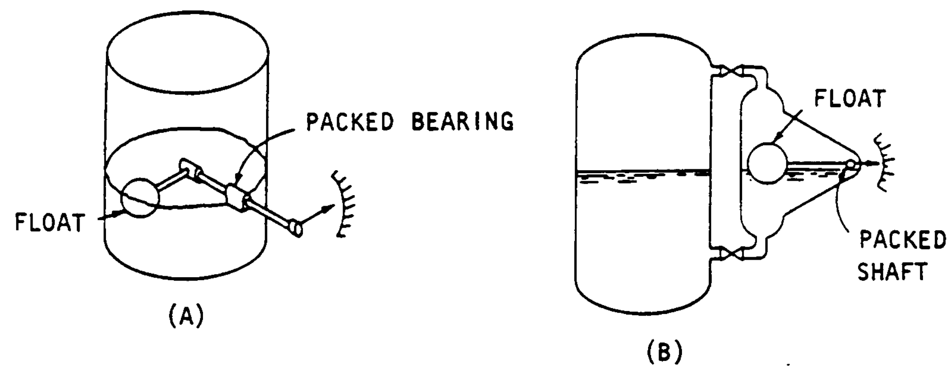



**Figure 4-12**
**Drop Tube Float Valve**

The valve mechanism releases and closes automatically when the liquid level rises to about 95% of tank capacity. This reduces the flow rate through a bypass valve. The operator may then stop filling the tank, disconnect and drain the hose. If the liquid rises to about 98% of tank capacity, indicating an unsafe condition of overfilling, the bypass valve closes. No more liquid will be allowed into the tank until the level drops below a set point.

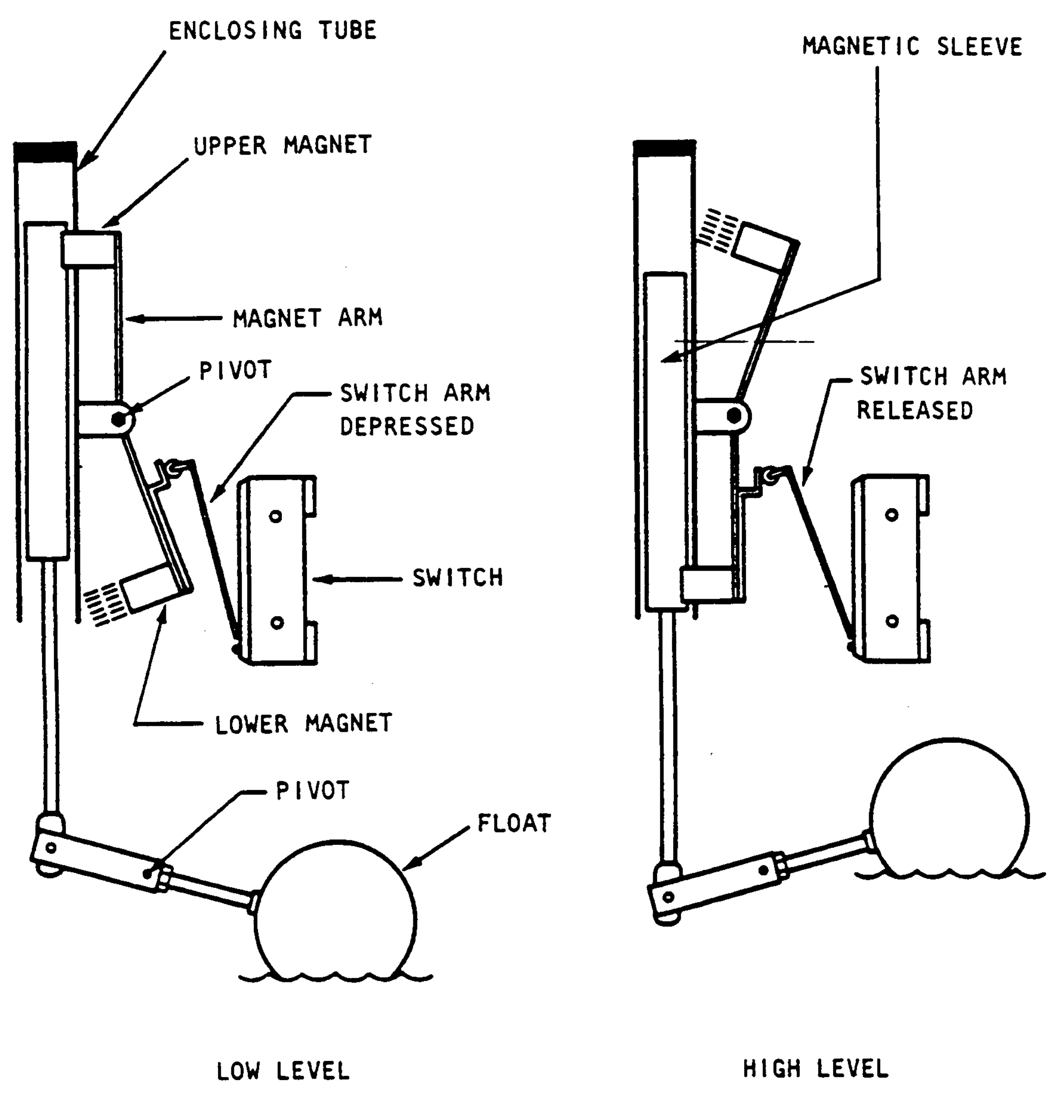
Lever and Shaft Float Gauges. Lever and shaft float gauges consist of a hollow metal sphere, sometimes filled with polyurethane foam, and a lever attached to a rotary shaft that transmits the float motion to the outside of the vessel through a rotary seal as indicated in Figure 4-13. These devices are applicable for atmospheric as well as pressurized tanks.




Source: Technology for the Storage of Hazardous Liquids: A State-of-the-Art Review, New York State Department of Environmental Conservation, 1983.

**Figure 4-13**
**Lever and Shaft Float Gauge**

Magnetically Coupled Float Gauges. Magnetically coupled float gauges consist of a permanent magnet attached to a pivoted switch as shown in Figure 4-14. As the float rises, following the liquid level, it raises a magnet attractor into the field of the magnet, which in turn snaps against the non-magnetic barrier tube to tilt a switch. When the liquid level falls, the float draws the magnet attractor below the magnetic field. The magnet swings out and tilts the switch to the reverse position, causing actuation of the low-level switch. The float and guide tube that come in contact with the measured liquid are available in a variety of materials for resistance to corrosion and chemical attack. Magnetically coupled float gauges may be used in conjunction with pneumatic and electronic controls to operate pumps, valves, alarms, and other external systems.




Source: Technology for the Storage of Hazardous Liquids: A State-of-the-Art Review, New York State Department of Environmental Conservation, 1983.

**Figure 4-14**
**Magnetically Coupled Float Gauge**

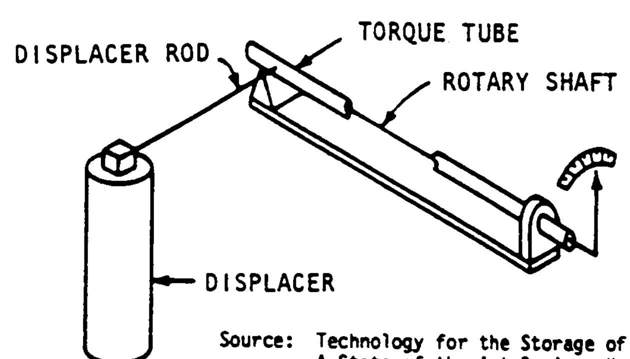
### 4.2.7.2. Displacer Systems.

Displacer-actuated devices use the buoyant force of a partially submerged float or displacer as a measure of liquid level. The vertical motion of the displacer is directly proportional to the buoyant force, which correlates to the level of the liquid. Accurate level measurement with displacement devices is a function of the liquid and vapor densities. Displacer devices can be used in top cage mountings or side mountings in aboveground tanks (atmospheric, pressurized, or vacuum tanks). The following are several types of displacer-actuated level sensing devices.

Torque Tube Displacer. Figure 4-15 depicts a torque tube displacer, which is one of the most frequently used level-measuring devices. The displacer is suspended on a rod attached to a torque tube. This is fixed at its outer end and supported on a knife-edge bearing at its inner end. The torque tube, in addition to being the elastic member, also constitutes a packless, pressure-tight barrier. Inside the torque tube is a shaft fixed to the torque tube at its inner end. The rotation of the outer end of the shaft through a range of 5 to 10 degrees is proportional to the buoyant force exerted on the displacer by the stored liquid.

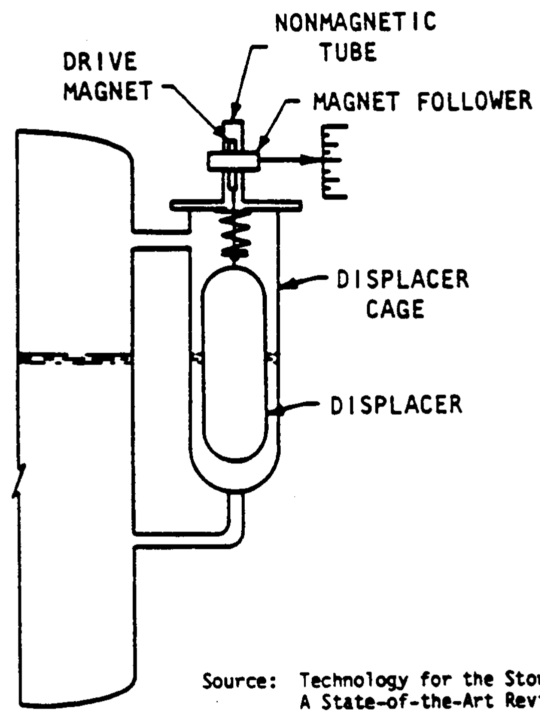
Magnetically Coupled Displacer. The magnetically coupled displacer, illustrated in Figure 4-16, is constrained by a spring and moves a drive magnet enclosed in a protecting tube. Motion of the drive magnet is transmitted to the indicating mechanism by a magnetic follower outside the protecting tube. Devices of this type are almost always mounted in external displacer cages and require two tank connections, one above and one below the liquid level. The magnetically coupled displacers are compatible with both pneumatic and electronic controls.

Flexure Tube Displacer. The flexure tube displacer, as shown in Figure 4-17, is a comparatively simple displacer device. It consists of an elliptical or cylindrical float mounted on a short arm. The arm is connected to the free end of a flexible tube; the fixed end is attached to a mounting flange. Motion of the float end of the tube is transmitted outside the float chamber by means of a rod extending through the tube. These devices are side-mounted and are commonly used to activate either an electrical level switch or a pneumatic pilot.



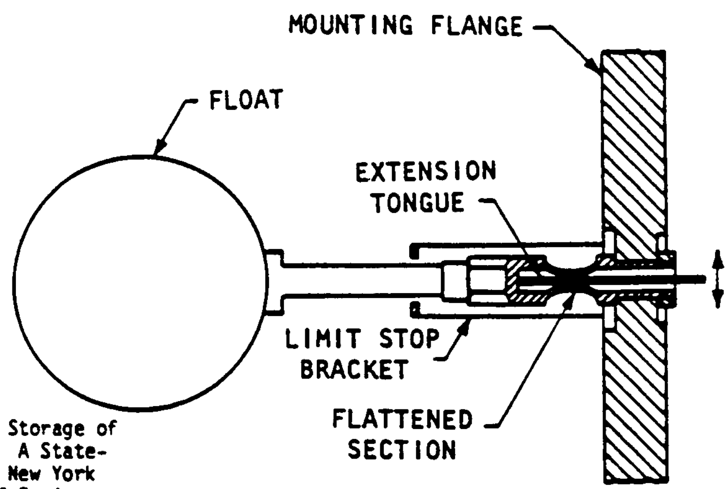

Source: Technology for the Storage of Hazardous Liquids: A State-of-the-Art Review, New York State Department of Environmental Conservation, 1983.

**Figure 4-15**
**Torque Tube Displacer**




Source: Technology for the Storage of Hazardous Liquids: A State-of-the-Art Review, New York State Department of Environmental Conservation, 1983.

**Figure 4-16**
**Magnetically Coupled Displacer**




Source: Technology for the Storage of Hazardous Liquids: A State-of-the-Art Review, New York State Department of Environmental Conservation, 1983.

**Figure 4-17**
**Flexure Tube Displacer**

#### 4.2.7.3. Hydrostatic Head (Pressure) Devices.

A variety of devices utilize hydrostatic head as a measure of level in aboveground tanks. As in displacer devices, accurate level measurement by hydrostatic head is a function of the densities of both the liquid and the vapor-air mixture inside the tank. Therefore, the tank should be used to store the type of product for which it was designed. The majority of these types of level sensing devices use standard pressure or differential pressure measuring devices. They are compatible with either pneumatic or electronic controls. The following are examples of hydrostatic head level sensing devices.

Open-Vessel Pressure Gauge System. The pressure gauge system on open vessels is the simplest application of head level measurement. The pressure-measuring element is located at or below the minimum operating level in the tank. Pressure piping between the vessel and the measuring element must be sloped upward toward the vessel to prevent errors due to entrapped air or other gases. A drain valve at the measuring element allows sediment to be flushed from the piping. These types of level sensing devices are compatible with both pneumatic and electronic controls, although electropneumatic converters may be required when electronic controls are used.

Bubble Tube System. Bubble tube systems consist of a tube inserted in the tank through which an air stream is maintained. The pressure required to keep the liquid out of the tube is proportional to the liquid level in the tank. The higher the liquid level, the higher the air pressure must be to keep the tube evacuated. A flow regulator maintains a constant supply of air into the tube. A pressure indicator is located downstream of the flow regulator to measure the liquid level by measuring the pressure head exerted by the liquid. Bubble tube systems are particularly applicable to corrosive and viscous liquids, liquids subject to freezing, and liquids containing entrained solids. They are generally used in conjunction with pneumatic controls if electropneumatic converters are provided. Bubble tube systems are usually more expensive than float or displacer systems, since they require a constant supply of clean and dry instrument air. This system is shown in Figure 4-18.

Pressurized Tank System. Head systems on pressurized tanks measure liquid level by means of hydrostatic head; this system differs from the system in open vessels in that a differential pressure measurement is made. Applications of this technique may employ almost any of the conventional differential pressure measuring devices.

Careful attention to the details of the installation is important. The density and vapor pressure of the liquid must be known; therefore, the tank should store the product for which it was designed. Hydrostatic heads that are not pertinent to the desired measurement must be compensated for or eliminated. The level above the lower tank connection is measured by the differential pressure across the measuring element. This measurement is accurate only if the following conditions are met: (1) compensation is made for any deviation in the density of the liquid; (2) the connection to the low-pressure side of the measuring element contains no liquid that has accumulated due to

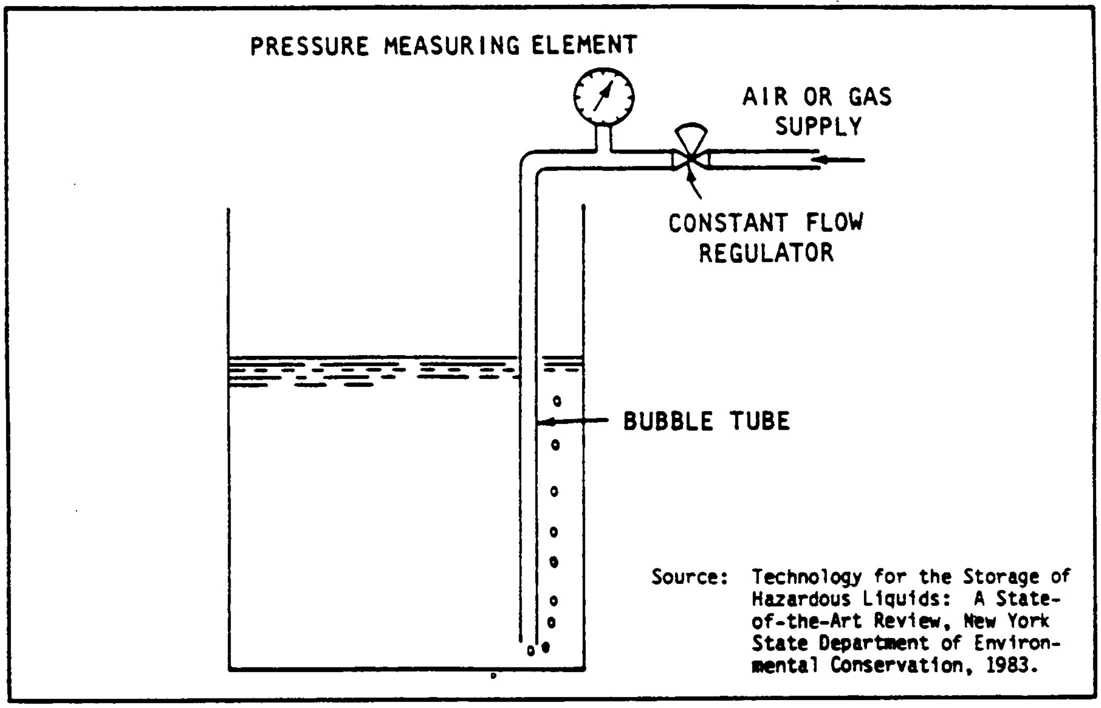



**Figure 4-18**
**Bubble Tube System**

overflow or condensation; (3) the density of the air-vapor mixture above the liquid is either negligible or compensated for; and (4) the measuring element is located at the same elevation as the minimum level to be measured, or suitable compensation is made. Either pneumatic or electronic controls may be used with these devices.

### 4.2.7.4. Capacitance Sensors.

Capacitance sensors measure the difference in capacitance between the liquid product and its vapor to monitor liquid level. A typical device consists of a rod electrode positioned vertically in a vessel; the other electrode is usually the metallic tank wall. The electrical capacitance between the electrodes is a measure of the height of the interface along the rod electrode. The rod is usually electrically insulated from the liquid in the tank by a coating of plastic.

Capacitance devices are used in conjunction with electronic controls to operate pumps, valves, alarms, or other external control systems.

### 4.2.7.5. Thermal Conductivity Sensors.

Thermal conductivity sensors measure the difference between the thermal conductivity of the stored liquid and its vapor to monitor liquid levels. A typical device consists of two temperature controlled, temperature sensitive probes connected in a Wheatstone bridge (a type of electrical circuit configuration). When the probes are in air or gas, a maximum temperature differential exists between the active and reference sensors, which results in a great imbalance in the bridge circuit and a correspondingly high bridge voltage. When the probes are submerged in a liquid, the temperature between the sensors is equalized and the bridge is brought more closely into balance. The probes may be installed through the sidewall of a tank or pipe, or assembled together on a self-supporting mounting and suspended through a top connection on the tank.

Thermal conductivity devices may be used to control level with great accuracy. They may be used with any liquid, regardless of viscosity or density. They may also be used in conjunction with electronic controls to operate pumps, valves, alarms, or other external control systems.

#### 4.2.7.6. Ultrasonic Sensors.

Ultrasonic sensors use sonic-wave propagation in fluids to monitor liquid level. These devices use a piezoelectric transmitter and receiver, separated by a short gap. When the gap is filled with liquid, ultrasonic energy is transmitted across the gap to a receiving element, thereby indicating the liquid level. These devices may be used in conjunction with electronic controls to operate pumps, valves, alarms, or other external control systems.

Another sonic technique used for level measurement is a sonar device. A pulsed sound wave, generated by a transmitting element, is reflected from the interface between the liquid and the vapor-gas mixture and returned to the receiver element. The level is measured in terms of the time required for the sound pulse to travel from the transmitter to the vapor/liquid interface and return.

#### 4.2.7.7. Optical Sensors.

An optical sensor uses the refraction of a light beam in fluids to monitor liquid level. An optical liquid level monitoring system consists of sensors and an electronic control device. A specific electronic signal is generated and aimed at the tank-mounted sensors. The sensors convert the electronic signal to a light pulse. This light pulse is transmitted into the tank via fiber optics, through a prism, and out again via fiber optics. The light pulse is then converted to a specific electronic signal to indicate the liquid level. If the level is too high, the controller activates the shutoff valve or the level alarm. A distinct advantage of this type of system is that it is self-checking. Any interruption will sound the alarm, so if equipment is damaged or malfunctions, the operator is alerted.

### 4.2.8. Automatic Controls

In more complex situations such as large, continually fed tanks, level-sensing devices may be interlocked to electronic or mechanical devices that automatically shut down filling operations. These interlocking controls normally work by closing tank inlet valves, shutting off pumps, or diverting flow to emergency overflow tanks when a high-level condition is reached. This practice is recommended for tanks filled by pumps.

Interlocking devices reduce the possibility of human error, the primary cause of spills. The need for interlocking will depend upon tank type, size and configuration, tank inlet flow rates (i.e., gravity or pump), and secondary containment provisions. The tank parameters determine the rate at which the fluid level in the tank rises and the response time available to the operator to shut down operations when a high-level condition is reached. Interlocking devices are particularly desirable for tanks without secondary containment.

For gravity filled tanks, an automatic valve on the inlet side of the tank, which closes at the high-level condition, is recommended.

Interlocking high-level alarm and pump controls are generally less expensive and provide the same degree of protection as an interlocking high-level alarm with tank inlet valves.

Selection of automated overfill prevention systems should be based upon a careful study of the particular application, taking into account economic justification, operational, and security requirements.

#### 4.2.8.1. High-Level Alarm

40 CFR 112.7(e)(2)(viii)(A) states that consideration should be given to high liquid level alarms with an audible or visual signal. A visual signal may be used at a constantly manned operation or surveillance station, while in smaller or unmanned areas an audible alarm may be more appropriate.

High-level alarms should be mechanically and electrically independent of the gauging device. Two alarm levels must be provided, as required in DM-22 for petroleum fuel tanks. One alarm level should be at approximately 95 percent of the safe tank filling height. The alarm should actuate an audible signal located at or near the person controlling the operation. The second alarm should be set at approximately 98 percent of the safe filling height. It should continue the audible alarm, actuate a visual alarm, and close an electrically-actuated valve to stop the flow or to stop product supply pumps if they are controlled solely from within the terminal.

#### 4.2.8.2. Direct Gauger/Pumping Station Communication

Direct audible or code signal communication between the tank gauger and the pumping station are also to be considered according to 40 CFR 112.7(e)(2)(viii)(C). This control arrangement requires the least hardware, but is the most labor intensive. The tank gauger is stationed near the tank being loaded, while the pumper would be at the pump cutoff switch. The tank gauger uses a gauge or alarm to monitor the liquid level and then signals to the pumper to stop pumping.

#### 4.2.8.3. Pump Cutoff Devices

Pump cutoff devices stop flow at a predetermined tank product level. A pump cut-off system is a function of tank size, tank configuration, inlet flow rates, and response time of an operator or inlet motor control valve to stop the flow.

Pump cutoff devices are interlocking devices between tank high-level alarms and the inlet control valves and/or pumps. They are most appropriate at areas without secondary containment.

The high-level alarm is interlocked with the pump and the inlet control valve. This arrangement provides an immediate shutoff of flow to the tank. However, interlocking the tank high-level alarm and the pump controls only is generally less expensive and can provide the same degree of protection. In this case, however, the high-level alarm position must be set low enough to prevent tank overfill due to a short period of continued pump operation.

#### 4.2.8.4. Other Automatic Control Considerations

For pumping areas (non-gravity loading or unloading operations), a positive means should be provided for emergency shutoff of fuel transfer operations. This is especially crucial for tanker truck or tanker car loading operations, where the product is coming from storage to a mobile delivery vehicle.

Options for emergency shutoff include: (1) installing a butterfly or ball valve at the product transfer point which can be accessed and closed in an emergency; (2) automatic, electrically controlled shutoff valves which can be actuated by an emergency control switch; or (3) an emergency pump stop switch at the loading or unloading point. Butterfly or ball valves should be used for emergency shutoff valves; gate valves take longer to close. However, a mechanical engineer or hydraulic engineer should perform a hydraulic analysis of the piping system prior to installing quick-closing valves to determine the impact of hydraulic surges on the system.

Electrically operated valves are expensive and should be used only where environmental conditions warrant such protection or where the valve is located far from the loading/unloading area. A product transfer line will need to be removed from service for up to a week to complete the retrofit process.

### 4.2.9. Secondary Containment

Bulk oil storage tank installations are required under SPCC regulations, 40 CFR 112.7(e)(2)(ii), to have a secondary means of containment for the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation. Where experience indicates a reasonable potential for equipment failure, 40 CFR 112.7(c) requires appropriate containment and/or diversionary structures or equipment to prevent discharged oil from reaching a navigable water course.

The April 29, 1992 EPA memorandum (Appendix K) states that in order for double walled aboveground tanks to provide substantially equivalent protection of navigable waters, they must meet the secondary containment requirement listed in 40 CFR 112.7(c) or:

- individual tanks must have capacities less than 12,000 gallons
- inner tank constructed of Underwriters' Laboratory-listed steel tank

- outer wall constructed in accordance with nationally accepted industry standards
- tank has overfill prevention measures that include an overfill alarm and an automatic flow restrictor or flow shut-off
- constant monitoring of all product transfers
- manifolded tanks or other piping arrangements that would permit a volume of oil greater than the capacity of one tank to be spilled as a result of a single system failure must have a combined capacity less than 40,000 gallons

The use of vaulted tanks does not exempt the requirements of secondary containment. A vaulted tank is considered secondarily contained if no oil is capable of leaving the vault.

Secondary containment is required of USTs if they contain hazardous substances or a mixture of hazardous substances and petroleum, but is not required for USTs containing only petroleum. However, it is important to note that certain states, such as California, require USTs to have secondary containment.

Secondary containment is also required under RCRA (40 CFR 264.193) for new hazardous waste storage tanks and ancillary equipment. For existing hazardous waste tank systems (40 CFR 264.191), if the age of the tanks is known, it was required to have secondary containment by January 12, 1989, or before the tank is 15 years old. If the age of the tank is unknown, it was required to have secondary containment by January 12, 1992; however, if it is over seven years old, it must have secondary containment before it is 15 years old. Requirements for spill control structures and drainage systems are addressed in Chapters 7 and 8 of this manual, respectively.

All hazardous waste container storage areas, where liquid wastes and certain non-liquid wastes (specified in 40 CFR 264.175(d)) are stored, are required by 40 CFR 264.175 to have secondary containment. The secondary containment must have sufficient capacity to contain 10% of the volume of containers or the volume of the largest container, whichever is greater.

NFPA 30 states that ASTs storing flammable and combustible liquids shall have secondary containment such as remote impounding or impounding around the tank using a dike or curb to prevent accidental discharge. NFPA 30 allows for an exception with double-walled ASTs less than 12,000 gallons in capacity. This exception is subject to meeting the requirements stated under 2-3.4.1 of this code.

There are no national regulatory requirements for secondary containment for HS storage other than what is specified above. However, it is considered a best management practice to have secondary containment for all HS storage areas. State and local regulatory requirements should be checked for additional HS storage requirements.

### 4.2.10.Tank System Testing

Integrity or nondestructive testing is the testing of a tank system through applied measuring methods without the tank being altered, modified, or disassembled. Regular testing can prevent leaks or detect them in early stages. Testing is also used on components of tank systems, such as corrosion protection systems, to verify proper operational status.

40 CFR 112.7(e)(2)(vi) states that aboveground tanks should be subjected to periodic integrity testing, using such techniques as hydrostatic testing, visual inspection, or non-destructive shell thickness testing. Comparison records should be kept. Tanks should be inspected for such things as tank supports, foundations, exterior corrosion, leaks, and accumulation of oil inside diked areas.

To prevent underground tank leaks, 40 CFR 112.7(e)(2)(iv) states that underground metallic oil tank areas should be subjected to regular pressure testing. 40 CFR 280 also places stringent requirements for owners to test or monitor their USTs. 40 CFR 280.21(b)(1)(ii) requires that interior inspections of tanks which were retrofitted with interior liners be conducted every 5 years. Tanks upgraded by cathodic protection may require integrity testing in accordance with 40 CFR 280.21(b)(2). Corrosion protection systems must be inspected in accordance with 40 CFR 280.31. 40 CFR 280.33 requires tightness testing after repairs of tanks and piping. Additional, specific testing requirements may be required by 40 CFR 280. The applicability of 40 CFR 280 to any specific UST should be fully assessed by a qualified professional.

Integrity testing is required for all RCRA-regulated HW tanks without secondary containment. Testing is required at one-year intervals for non-enterable underground tanks and ancillary equipment (40 CFR 264.193(i)). For other than non-enterable underground tanks, a leak test must be conducted or a scheduled assessment of tank integrity must be implemented. The frequency of these assessments must be based on the material of construction of the tank and its ancillary equipment, the age of the system, the type of corrosion or erosion protection used, the rate of corrosion or erosion observed during the previous inspection, and the characteristics of the waste being stored or treated. For ancillary equipment, a leak test or other integrity assessment must be conducted at least annually.

NFPA 30 requires that all tanks used to store flammable and combustible liquid be maintained liquid-tight. Leaking tanks have to be emptied, repaired, and tested in a manner approved by the local authority having jurisdiction.

A number of testing methods exist, each with its particular application and limitations. Although most methods can be applied to both aboveground and underground systems, the method used for a particular application will depend upon the accessibility of the equipment to be tested, method reliability and adaptability, and above all, practicality, and cost. Common methods used for aboveground and underground tanks and pipelines are presented below.

Although this section discusses tank testing, it should also be noted that other tank system components including leak detectors and alarms, level sensing devices, level alarms, emergency shutdown switches, and other automatic controls must be operationally tested in accordance with the manufacturer's instructions.

#### 4.2.10.1. Aboveground Tank Testing

**Non-Destructive Shell Thickness Tests.**

The following are several methods of testing storage tanks for shell thickness. The methods discussed below are preferred over common pressure testing methods, since they are easy to apply to exposed areas and do not expose tanks to potentially damaging pressures.

Acoustic Emissions. Acoustic emissions tests use piezoelectric transducers to monitor or "listen to" the acoustic emissions generated by flaws when the system is placed under certain stress conditions. These sounds are recorded and related to the basic material characteristics to determine the relative stability of the equipment being tested. Acoustic emissions tests can be used to determine tank wall thickness, flaws, leaks, and corrosion.

Eddy Currents. Eddy currents are electrical currents induced within the body of a conductor when the conductor moves through a non-uniform magnetic field or is in a region where there is a change in magnetic flux. In the eddy current test, a test coil indicates defects within the tank shell. The method is effective for spot checks of surface and subsurface cracks, wall thickness, and coating thickness.

Hammering. Hammering is a simple and effective method that relies on sound, vibration, denting, and movement to detect defects and flaws in the tank and also reduced wall thickness. This method requires an experienced inspector to be effective. Care must be taken to prevent damaging weak areas or coatings, particularly when testing in-service equipment. For this reason, more accurate, stressless methods, such as radiography or ultrasonics, are recommended for determining wall thickness in areas around a leak or suspected to be extremely thin. Hammering can damage the following:

- Enameled, ceramic, or glass-lined pieces, where the lining may be injured.
- Brittle materials, such as cast iron, some high-steel alloys and nonferrous materials such as brass and bronze. Light tapping with a hammer may be permissible on some of these materials.
- Other locations where hammering might result in stress corrosion or cracking, such as equipment in caustic service.

**Non-Destructive Surface Damage Tests.**

Magnetic (Dry) Particle. Magnetic particle inspection is used to detect surface cracks or flaws. Fine magnetic particles are applied to a magnetized surface and are attracted to regions of magnetic non-uniformity associated with cracks or discontinuities. The tank inspector can visually observe patterns which are indicative of tank flaws. The testing equipment is portable and well suited to fieldwork, and is applicable to large surface areas, such as tank shells.

Magnetic (Wet) Particle. The wet particle testing method is similar in principle to the dry particle testing method. It is less sensitive than the dry method in the detection of fine surface discontinuities, but more sensitive in detecting near-surface discontinuities. The wet method is adaptable to irregular, relatively small surface areas such as valves.

Penetrating Dye. The penetrating dye method involves applying a liquid which will seep into any surface cracks or discontinuities through capillary action. After the surface is wiped dry, a developer is applied to the surface and becomes tainted by the original liquid as it seeps out of the cracks, delineating the cracks or discontinuities in the surface. The method is effective on non-porous metallic materials, both ferrous and nonferrous, and on non-porous, nonmetallic materials such as ceramics, plastics, and glass.

Radiographic. Radiographic testing uses X-rays, nuclear radiation, or both to detect subsurface discontinuities in solid materials, and presents their images on a recording medium (film), known as a radiograph. Any flaws detected by the test will appear as darkened areas in the shape of the flaw against the uniformly lighter background of the intact area. Radiography may also be used for determining wall thickness, product buildup, blockage, and the condition of internal equipment such as trays, and valve parts. Radiography can only be conducted by qualified radiographers. In addition, training and experience are required to interpret the images produced on the radiographic film correctly.

Spark Testing. High-voltage, low-current electrical spark tests are performed by passing an electrode over a non-conducting material, such as a tank lining or coating. The other end of the circuit is attached to the conductive wall. Any defects will cause an electrical arc to pass through at the point of the defect. Care must be taken not to exceed the dielectric constant, or damage to the lining may result.

Ultrasonic Testing. Ultrasonic testing detects subsurface discontinuities from the interruptions they cause in pulse or resonant vibrations transmitted through the metal until they reach a reflecting surface, which returns the waves. The time interval required for the waves to complete this "round trip" indicates the metal thickness from a fraction of an inch to several feet. Ultrasonic instruments can also be used to measure the tank's thickness and determine the location, size, and nature of defects. Most importantly, ultrasonic testing can be performed while the tank is in operation as only the outside of the tank needs to be contacted.

Vacuum Box. In this method, also called soaping, the lips of the open side of the vacuum box are covered with a sponge rubber gasket. The bottom of the box is made of glass. A vacuum gauge and air siphon connection are installed inside the box. The seam of the tank shell is first wetted with a soap solution, then the vacuum box is pressed tightly over the seam. The foam-rubber gasket forms a seal that allows a vacuum to build up inside the box by air siphon. If any leak exists, soap bubbles will form inside the box and can be seen through the glass.

### 4.2.10.2. Underground Tank Testing

#### Pressure Testing

Pressure testing methods are usually performed for underground systems because they do not require uncovering and exposing the tank. Uncovering and exposing a tank is costly, time-consuming, and can very easily cause a leak that did not previously exist. Pressure testing methods consist of filling a tank system with a fluid (usually water) or air, until a certain pressure is reached, and observing if a loss of the fluid or pressure occurs. Drawbacks with these methods include:

- Excessive pressures can rupture a tank or indicate leaks where none exist if non-representative liquids (i.e. different density than product stored) are used. Therefore, the method and liquid used should duplicate normal conditions as close as possible.
- Methods lose accuracy for tanks of 20,000 gal capacity or more, since undetectable product level changes (hundredths of an inch), represent large volume losses.
- Corrections for substance-specific volume and temperature variations are required. Some methods do not compensate for this variation. Also, correction factors are not available for many chemicals and usually they must be determined in the field.
- Methods require a relatively constant temperature over the test period. Even results from applications where small temperature changes occur over a 24-hour period are not reliable.

The tank tightness testing discussed in Section 4.2.12 is now commonly used in lieu of pressure testing for tanks, but not for piping. Although 40 CFR 112 stipulates pressure testing, most EPA Regions will accept the use of the generally more accurate tank tightness testing methods developed for use on USTs. Pressure testing is now usually done only prior to installation of a new tank and is not commonly used on existing in-service tanks.

Some of the most common underground tank testing methods are discussed below.

Hydrostatic (water or another liquid) Pressure Tests are relatively simple tests which can quickly indicate a leak. If the pressure drops, it indicates the possibility of a leak, and it is recommended that a volumetric tightness test be performed. A loss of liquid pressure can be attributed to the following: a leak, a decrease in liquid temperature, distortion due to the pressure, or trapped vapor.

The Pneumatic (air) Pressure Test is not recommended for tanks because of many drawbacks: it is not sensitive enough to detect small leaks; it is extremely hazardous to perform especially for tanks storing flammable or combustible liquids (explosions have resulted in death), large amount of product may be forced out of the system undetected; it may cause leaks due to over pressurization; and it will not compensate for thermal expansion or contraction. NFPA 329 states that pressure tests for tanks containing flammable or combustible liquids should be done with inert gases instead of air. Section 4-4.4.2 of NFPA 329 states that the pressure exerted by both the product and inert gas must not exceed the limits recommended by the tank manufacturer and the use of pressure-limiting devices is required in this application.

Air testing is acceptable for new tanks that have not yet been in use to store flammable or combustible liquids or vapors. New tanks and piping systems are routinely tested using air before being placed into service. Underground systems are generally tested before they are buried. When air testing is done, all joints and seams should be sprayed with a soap solution. Leaks can be detected by inspecting these joints and seams for soap bubbles during the test. This is one of the best ways to determine the location of a leak. The test can still be dangerous if done incorrectly and the accuracy of the test is limited because of thermal expansion and contraction.

<u>The J-tube Manometer Test</u> measures product level drops as small as 0.02 inches caused by tank leaks. Accuracy is proportional to the time span of the test. For instance, a 0.02 in. drop is equivalent to 2.12 gal/hr for a 1-hour test and 0.212 gal/hr for a 10-hour test. Test equipment is easy to transport, assemble, and operate, eliminates risk of tank or pipe damage due to over pressurization, and allows testing several tanks simultaneously. A drawback of this method is that it does not detect leaks above the product level. Also, temperature variations as small as 1°F during the test can void the results.

#### 4.2.10.3. Corrosion Protection Systems

All UST cathodic protection systems must be tested within 6 months of installation and at least every 3 years as required under 40 CFR 280.31. 40 CFR 112.7(e)(7) states that an area should prepare and maintain a written procedure for inspecting and testing pollution prevention equipment which includes the corrosion protection system required by the same regulation.

Corrosion field investigations fall into the following classifications:

- Visual, physical inspections of tank equipment
- Study of maintenance records
- Soil resistivity measurements
- Potential (voltage) of structure-to-soil measurements
- Cathodic protection current requirements

Additional information on corrosion protection can be found in DM-22 and MIL-HDBK-1004/10.

### 4.2.11.Tank Inspections

SPCC regulations (40 CFR 112.7(e)(8)) require that written inspection procedures be developed for the area, as well as maintenance or records of inspections. The written procedures and the record of inspections are made part of the SPCC plan and maintained for a period of three years.

Leaks through the bottom of aboveground tanks are difficult to detect. Visual inspection during routine tank cleanings and strict inventory control are the best methods for detecting a leak in the bottom of an aboveground tank.

#### 4.2.11.1. Oil Storage Tanks (40 CFR 112.7(e)(2)(vi))

A SPCC regulation, 40 CFR 112, requires visual inspections of aboveground storage tanks. This regulation does not specifically address internal tank inspections. However, tanks commonly corrode from the inside out, and signs of corrosion may not be visible until the tank fails. At a minimum, the inspection should include the following system components:

- Tanks - walls, supports, foundation, coatings, pipe connections
- Piping, pumps, valves, and fittings
- Level sensing devices
- Alarms and automatic shut-off or flow control devices
- Loading and unloading areas and operations
- Spill control structures

#### 4.2.11.2. HW Storage Tanks Inspection Procedures (40 CFR 264.195)

Tanks used to store or treat HW must develop and follow an inspection schedule to include the following:

- At least once a day, inspect aboveground portions of the tank system for corrosion or releases of HW
- At least once a day, inspect data gathered from monitoring and leak detection equipment,
- At least once a day, inspect tank construction materials and surrounding secondary containment systems for signs of leaks (i.e., wet spots or dead vegetation)
- Regular inspections of overfill controls
- Impressed current cathodic systems must be inspected every 60 days to ensure that it is operational
- Cathodic protection system must be inspected within six months after initial installation and annually thereafter

#### 4.2.11.3. Underground Storage Tanks Inspection Procedures (40 CFR 280)

New UST and upgraded USTs require proper inspection to ensure tank integrity prior to its installation or operation. 40CFR 280.20, 280.21, 280.31, and 280.40 lists the following inspection requirements for tank systems and components:

- New UST installations need to be inspected and certified before use.

- Repaired tanks must be internally inspected or tightness tested.
- USTs which are upgraded with an interior liner must be internally inspected within 10 years after lining, and every 5 years thereafter.
- Before upgrading a UST with a cathodic protection system, the tank is to be internally inspected and assessed to ensure that the tank is structurally sound and free of corrosion holes. Tanks less than 10 years old have additional options available.
- All cathodic protection systems must be tested within 6 months of installation (and after repair) and at least every 3 years thereafter.
- USTs with impressed current cathodic systems must be inspected every 60 days to ensure that it is operational.
- Records of cathodic system operation must be maintained to include the results of the last three inspections and the results of testing from the last two testing/inspection events.
- Release detection systems must be checked for evidence of a release at least every 30 days.

### 4.2.12.Leak Detection and Monitoring (40 CFR 112.7(e)(2)(vi))

40 CFR 112 requires visual inspections of the exterior of ASTs for signs of leaks. Where applicable, the discharge from internal heating coils should also be monitored for signs of leaks (i.e., tank contents mixed with heating medium).

40 CFR 280.40 requires that new and existing UST systems provide a method, or combination of methods, of release detection that can detect a release from any portion of the tank and the connected underground piping that routinely contains product. UST release detection systems must be monitored for releases at least every 30 days. Underground piping that routinely contain oil and HS must also be monitored for releases. Methods of release detection for tanks include the following (40CFR 280.43):

- Inventory control,
- Manual tank gauging,
- Tank tightness testing,
- Automatic tank gauging
- Vapor monitoring,
- Groundwater monitoring,
- Interstitial monitoring, and
- Line monitoring

**Inventory Control**

For leak detection purposes, 40 CFR 280.43 requires that HS or oil inventory control be performed once a month to detect a monthly release rate of at least 1.0 percent of flow-through plus 130 gallons using the following methods:

- Inventory volume measurements for material inputs, withdrawals, and amount remaining in the tank are recorded each operating day;
- The equipment used can measure the product level over the full range of the tank's height to the nearest one-eighth of an inch;
- The material inputs are reconciled with the delivery receipts by measurement of the tank inventory volume before and after delivery;
- Deliveries are made through a drop tube that extends to within one foot of tank bottom (method to reduce splashing and entrainment of liquid droplets in the vapor);
- Material dispensing is metered and recorded within the local standards for meter calibration or an accuracy of 6 cubic inches for every 5 gallons of product withdrawn; and
- Measurement of any water level at the bottom of the tank is made to the nearest one-eight of an inch at least once a month.

### Manual Tank Gauging

Manual tank gauging can only be used for tanks of 2,000 gallons or less capacity. The equipment used is a gauge stick made of varnished hardwood or other non-sparking material. The stick should be long enough to reach the bottom of the tank. Level measurements must be taken at the start and end of a period of at least 36 hours during which no liquid is added to or removed from the tank. The average of two gauge readings is used for level measurement. A leak is suspected when the variations between period beginning and ending measurements exceed the weekly or month standards as presented in Table 4-7.

**Table 4-7**
**Standards for Measurement Variations for Manual Tank Gauging**

| Tank Capacity | Weekly Standard (one test) | Monthly Standard (average of four tests) |
|---|---|---|
| 550 gallons or less | 10 gallons | 5 gallons |
| 551 - 1,000 gallons | 13 gallons | 7 gallons |
| 1,001 - 2,000 gallons | 26 gallons | 13 gallons |

### Tank Tightness Testing

Tank tightness testing must be able to detect a 0.1 gallon per hour leak rate from any portion of the tank, with at least 95% probability of detection and no more than 5% probability of false alarm, taking into account the effects of thermal expansion, vapor pockets, tank deformation, and water table. The two methods that can be used to perform tank tightness are volumetric and non-volumetric testing. Volumetric testing measures product level changes over time. Non-volumetric testing can include applying vacuum and measuring the loss of vacuum over a period of time, adding a tracer to the tank and measuring the tracer gas in the surrounding soil, mass technology, and acoustic technology.

### Automatic Tank Gauging

Inventory control and equipment that detects 0.2 gallon per hour leak rate from any portion of the tank are used to perform automatic tank gauging. Because of the variety and sophistication of modern electronic and mechanical tank gauging and monitoring systems, such systems should be installed and maintained in strict accordance with the instructions of the manufacturer. To ensure accuracy, the systems should be tested and calibrated at the time of installation.

### Vapor Monitoring

Vapor monitoring tests the vapors within the soil of the tank excavation area. This method is used only if the soils are sufficiently porous and the stored material is sufficiently volatile to allow for a vapor level detectable by monitoring devices. Vapor monitoring is not effective in areas where there is a high or fluctuating water level, or in areas where a previous release is present. Monitoring may employ continuous electronic systems or manual procedures done periodically.

### Groundwater Monitoring

Testing and monitoring groundwater can be used to determine if a UST is leaking. Groundwater monitoring wells are installed in the vicinity of the tank and are checked for the presence of product material. There are several considerations for the design of a groundwater monitoring system, including the type of material stored in the tank, groundwater level, hydraulic conductivity of the soil, and other well design requirements.

### Interstitial Monitoring

In double-walled tanks, the interstitial space between the outer wall and the inner tank can be monitored through the use of a variety of either manual or electric systems designed to detect the presence of vapor, stored liquid, water, or pressure change within the interstice. Vapor and liquid monitoring system probes are installed in the interstice. In some systems, a liquid is introduced into the interstice and the level of this liquid is monitored either visually or electronically. Any change in the liquid level in the interstice indicates a leak in either the inner or the outer wall. All interstice monitoring systems, whether mechanical or electrical, require precise installation, testing, and calibration.

### Line Monitoring

Monitoring can be performed with the use of automatic line detectors, line tightness testing, or any of the applicable tank release detection methods described above. Line leak detectors are available for underground pressurized lines. A leak is indicated by a restriction or shut off of flow through piping or when an alarm is triggered. Mechanical leak detectors normally utilize a pressure-sensing valve that severely reduces flow when tripped.

### 4.2.13.Certification

40 CFR 280.20 (e) requires that owners and operators certify that tanks have been properly installed in accordance with a code of practice developed by a nationally-recognized association or independent testing laboratory, and in accordance with the manufacture's instructions. This certification can be performed by an installer who has been certified by the tank manufacture; using an installer who is certified by the implementing agency, a professional engineer trained and experienced in tank system installation, or by the implementing agency.

RCRA HW regulations under 40 CFR 264.191 also requires installation, assessment and certification of HW tanks system and components design by an independent, qualified registered professional engineer.

## 4.3. CONTAINER STORAGE

Petroleum products such as lube oil are routinely stored in small containers, typically 55-gallon drums. Since 40 CFR 112 applies to oil areas with an aboveground storage capacity of over 1,320 gallons of oil (provided that no single container has a capacity of over 660 gallons), an area can require an SPCC Plan. However, a storage area with less than 1,320 gallons of oil may still want to observe SPCC practices; inclusion of such a site in the SPCC plan is at the discretion of the spill control coordinator.

Spills from 55-gallon drums are largely due to negligent handling practices such as dropping, tipping, or otherwise rupturing drums during transfer and handling. A common cause of a drum rupture is puncture during forklift operations. Another major cause of leaking drums is improper storage conditions - drums being stored outdoors where they are susceptible to weathering, corrosion, or vandalism.

Drums are routinely handled by equipment such as forklifts, warehouse tractors, cranes, and hand trucks. Within shops, drums are often stored on pallets constructed of wood or metal. Pallets generally store four drums, and pallets of drums are often stacked on top of each other. As a rule of thumb, pallets of drums should never be stacked more than three levels high. Pallets not only allow for easier handling of the drums, but also facilitate visual inspection of the drums for leaks or spills, as well as keeping drums off the ground where they could contact standing water or other liquids that could cause the drums to corrode.

Ideally, drums should be stored where they will be protected from the elements, either indoors or in a covered outdoor storage area. If drums must be stored outdoors, the storage area should be away from traffic, and the drums should be on pallets or racks to protect the drums from standing water. Additionally, drums should be stored on their sides so that water will not accumulate on top of the drum and encourage corrosion of the drum. All outdoor drum storage areas vulnerable to traffic collision damage should be moved to traffic-safe areas or should be protected with properly marked, visible crash posts, or similar barriers.

Secondary containment for container storage areas is often curbing (see Chapter 7). For uncovered outdoor drum storage areas that are curbed, drainage control becomes a significant issue; if no means of drainage control is provided, drums may end up rusting in accumulated precipitation. To correct such a case, a roof could be built over the storage area, accumulated precipitation could be pumped out as necessary using a vacuum or defueling truck, or a drain pipe could be installed that will lead to a treatment unit such as an oil/water separator. Figure 4-19 shows a typical drum storage area.

With container storage areas, a major SPCC concern is good housekeeping practices. The storage area should be clean and orderly to reduce safety hazards and accidental releases. Good housekeeping practices also allow the detection of leaks and spills from drums. The container storage area should have adequate aisle space to permit unobstructed movement of personnel and material handling equipment such as fork-lifts. These aisles should be kept clear, and drums and other containers should be kept from protruding into the aisle space. As a rule of thumb, main aisles that are used for entry and exit should be at least 8-feet wide, while all other aisles should be at least 4 feet wide.

NFPA 30 apply to storage of flammable and combustible liquids in containers and portable tanks with capacities of less than 60 gallons. The code applies to the design, construction, and operation of storage cabinets, inside liquid storage areas, hazardous material storage lockers, and other areas used for incidental flammable and combustible liquid storage. NFPA 30 should be referred to for general storage requirements. Leakage control and spill containment systems are required to prevent flow into adjoining areas, property, or critical natural resources. For lockers, the containment system should have the capacity to contain 10% of the total volume of liquid stored or the volume of the largest container, whichever is greater.

Polychlorinated Biphenyls (PCBs) stored for disposal must have secondary containment (40 CFR 761.42). Containment structures must comply with standards for capacity, structural strength, material compatibility, impermeability, and integrity to prevent contained HS from escaping confinement. Small sumps (3 to 4 gallons) or drip pans, can also be placed around a fill port to collect spills from disconnected transfer lines. Adequate drainage systems must also be provided in these areas to prevent contaminated run-off from discharging into navigable waters.

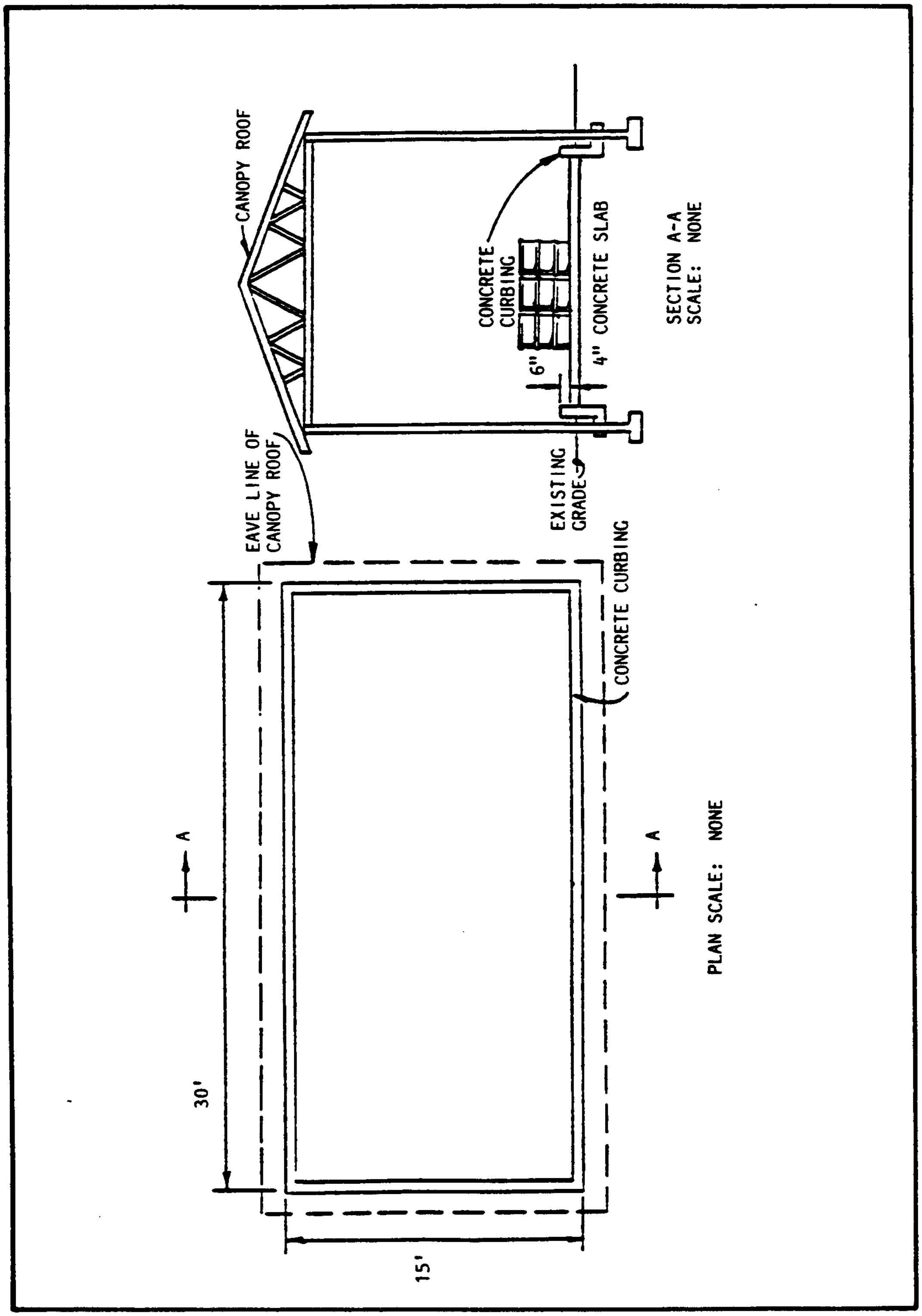



**Figure 4-19**
**Typical Drum Storage Area**

## 4.4. IDENTIFICATION AND LABELING.

Tanks and other types of containers should be properly marked and labeled to identify their content. Operator errors such as opening the wrong valve or loading the wrong tank or container can be prevented if equipment is properly identified. DOT and NFPA labels, color-coding and MIL specs labels are methods widely used in the Navy. Hatching couplings and color-coding of transfer lines are very effective means to prevent incompatible mixing and product contamination.

Tanks are commonly placarded and labeled using the DOT and NFPA systems. These systems are described in detail in Section 5. DM-5.13 requires aboveground pipes 3/4" outside diameter (0.D.) or larger to bear legends identifying their contents and arrows showing direction of flow. Labels must have color-coded backgrounds signifying the level of hazard they present. For legends, the type and size of characters must comply with MIL-STD-161E.