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INSPECTION MANUAL FOR ENFORCEMENT OF NEW SOURCE PERFORMANCE STANDARDS

VOLATILE HYDROCARBON STORAGE TANKS

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Enforcement
Office of General Enforcement
Washington, D.C. 20460

INSPECTION MANUAL FOR THE ENFORCEMENT OF NEW SOURCE PERFORMANCE STANDARDS: VOLATILE HYDROCARBON STORAGE

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1.0 INTRODUCTION

Pursuant to Section 111 of the Clean Air Act (42 USC 1857 et. seq.), the Administrator of the Environmental Protection Agency (EPA) promulgated standards for performance of new and modified storage vessels for petroleum liquids. These proposed standards were issued in the Federal Register of June 11, 1973, and final standards (40 CFR 60.112) became effective on February 28, 1974. These standards were amended on December 16, 1975. The standards apply to all sources whose construction or modification commenced after June 11, 1973, subject to the exceptions outlined in Section 2.2 of this report. Appendix I summarizes the applicable regulations as of February 27, 1976.

Enforcement of these standards may be delegated by the EPA to individual state agencies for all sources except those owned by the U.S. Government. Each state must first, however, develop a program which includes inspection procedures for verifying compliance with the standards, and EPA must approve the program.

The purpose of this document is to provide guidelines for the appropriate enforcement agency in the development of inspection programs for petroleum liquid storage vessels which are covered by New Source Performance Standards (NSPS). Included are sections which explain the process, the regulations, control techniques and the responsibilities of the enforcement agency personnel.

2.0 STATE IMPLEMENTATION PLANS (SIP) AND NEW SOURCE PERFORMANCE STANDARDS (NSPS)

2.1 EXISTING SOURCES - SIP

SIP regulations applying to hydrocarbon storage are generally expressed in terms of required control devices and precautions rather than in terms of emission limitations. This same approach is utilized in the New Source Performance Standards for petroleum storage.

2.1.1 Summary of Typical SIP Regulations

A majority of the states have petroleum storage regulations in their final SIP's. Typically, a SIP regulation will be worded in the following manner: "No person shall place, store or hold in any stationary tank, of more than 40,000 gallons capacity, any volatile organic compounds unless such tank is a pressure tank capable of maintaining working pressures at all times to prevent vapor or gas loss to the atmosphere, or is designed and equipped with one of the following vapor loss control devices: floating roof, vapor recovery system, or other equipment or means of equal efficiency for purposes of air pollution control as approved by the Agency." The most common difference between regulations in various states is the specification of a different minimum tank capacity covered by the regulation.

The "cut-off" vapor pressure limits which provide the basis for selection of a particular system of storage (e.g., floating roof, vapor recovery system) in NSP standards (see Table 2.1, Section 2.3.1) are essentially the same values as for most SIP regulations.

2.2 SUMMARY OF NEW SOURCE PERFORMANCE STANDARDS

Performance standards for new storage vessels for petroleum liquids apply only to vessels of more than 151,412 liters (40,000 gallons) capacity with the following exceptions:

- Pressure vessels which are designed to operate in excess of 776 mm Hg (15 psig) without emissions to the atmosphere except under emergency conditions.
- Subsurface caverns or porous rock reservoirs.

- Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

- Tanks storing materials having a true vapor pressure, as stored, of less than or equal to 26 mm Hg (0.5 psia).

- Storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

- Tanks with a capacity of less than 246,000 liters (65,000 gallons) upon which construction or modification began between June 11, 1973 and February 27, 1974. The proposed NSP standards presented June 11, 1973 had a minimum regulated capacity of 246,000 liters. The adopted rules which appeared on February 27, 1974 had a minimum regulated capacity of 151,412 liters.

These standards are stated in terms of equipment specifications, in which the type of equipment specified is related to the true vapor pressure of the liquid to be stored. Compliance will be determined by inspection of equipment and records of material stored and of temperatures within the stored liquids.

2.2.1 Equipment Specifications

2.2.1.1 Equipment for Storage of Liquids of Intermediate Volatility

Liquids having a true vapor pressure equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia) must be stored in vessels equipped with a floating roof or a vapor recovery system or an equivalent control system. A floating roof may be a double-deck, or flexible single-deck, pontoon-type cover which rests upon and is supported by the stored liquid.

2.2.1.2 Equipment for Storage of Liquids of High Volatility

Liquids having true vapor pressure in excess of 570 mm Hg (11.1 psia) must be stored in vessels equipped with vapor recovery systems or equivalent vapor control systems. A vapor recovery system includes a system of collecting vapors and gases so as to prevent their emission to the atmosphere (see pp. 110-112 of Reference 8).

2.2.2 Record Keeping

The owner or operator of a new volatile hydrocarbon storage facility will be required to maintain daily records and monthly summaries, and to retain such records and summaries for two years.

2.2.2.1 Information to be Filed

Information required by these regulations for each storage vessel on a daily basis includes the type of petroleum liquid stored, the typical Reid vapor pressure of the petroleum liquid stored, the dates during which the tank is storing materials and the periods the tank is empty. Monthly summaries of average temperatures and true vapor pressures of the liquids must be maintained for any vessels which contain petroleum liquids in the following two categories.

- If the true vapor pressure, as stored, is greater than 26 mm Hg (0.5 psia) but less than 78 mm Hg (1.5 psia) and the storage vessel is not equipped with a floating roof, vapor recovery system or equivalent.

- If the true vapor pressure, as stored, is greater than 470 mm Hg (9.1 psia) and the storage vessel is not equipped with a vapor recovery system or equivalent.

The average monthly storage temperature is an arithmetic average calculated for each calendar month, from bulk liquid storage temperatures determined at least once every seven days. The true vapor pressure at each bulk liquid temperature is to be determined in accordance with American Petroleum Institute Bulletin 2517, "Evaporation Loss from Floating Roof Tanks."

2.2.2.2 Notifications Regarding Initial Start-Up

The owner or operator of any new facility for volatile hydrocarbon storage is required to furnish to the Administrator of the Environmental Protection Agency written notifications of anticipated initial start-up date and actual start-up date of the new facility. The notification of the anticipated start-up date must be postmarked no more than sixty (60) days nor less than thirty (30) days prior to that date; notification of actual start-up must be postmarked within fifteen (15) days after its occurrence.

2.2.2.3 Records Regarding Start-Up, Shutdown and Malfunction

Records regarding start-up, shutdown, or malfunction of the facility must be maintained for a period of two years following each occurrence. A similar period of maintenance is required for the records regarding operation of the facility, as described above (Section 2.2.2).

Records should include the nature and cause of any malfunction, together with a notation as to corrective action and any measures undertaken to prevent recurrence.

In this connection, "start-up" refers to a renewed operation of the facility at any time; "shutdown" means the cessation of operations of the facility; and "malfunction" is defined as any sudden, unavoidable failure of air pollution control equipment, or of the storage vessel itself, to operate in a normal manner. Preventable failures, such as may be caused by poor maintenance or careless operation or by equipment breakdown due to such causes, are not included in this definition.

2.2.2.4 Quarterly Reports

Quarterly reports are to be filed on the 15th day following the end of each calendar quarter. These reports should include the monthly summaries from the monitoring of operations, as well as the records of start-up, shutdown, and malfunction during the calendar quarter. Details should be furnished as to causes of malfunctions and corrective measures applied.

2.3 APPLICABILITY OF STANDARDS

2.3.1 Determination of Vapor Pressure

Both equipment specifications and monitoring requirements are keyed to the volatility of the petroleum liquids to be stored in the new volatile hydrocarbon storage facility. This, in effect, divides petroleum into five volatility classes, as shown in Table 2.1.

Because the vapor pressure of a volatile hydrocarbon depends upon its temperature, some petroleum liquids may belong to one volatility class in cool weather, and to another, higher volatility class in warm weather. In such cases, ambiguity arises regarding which set of regulations is appropriate, or whether different procedures should be followed with any given liquid when its volatility class changes due to a change in the temperature.

Table 2.1
VOLATILITY CLASSES OF PETROLEUM LIQUIDS
AS RELATED TO NEW SOURCE PERFROMANCE STANDARDS
FOR STORAGE FACILITIES

Volatility Class	True vapor pressure, range	Type of control required*	Maintain file for type of petroleum liquid stored, typical Reid vapor press. and dates of storage	Record keeping for average monthly storage temp. and true vapor pressure
I	0 to 26mm Hg (0 to 0.50 psia)	None	no	no
II	26 to 78mm Hg (0.50 to 1.50 psia)	None	yes	yes
III	78 to 470mm Hg (1.50 to 9.1 psia)	F.R. or V.R.	yes	no
IV	470 to 570mm Hg (9.1 to 11.1 psia)	F.R. or V.R.	yes	yes
V	Above 570mm Hg (above 11.1 psia)	V.R.	yes	no

* F.R. = Floating Roof
V.R. = Vapor Recovery System

In such cases, the proper course of action is to require the storage of any given liquid to be performed in a vessel of the type required for the highest volatility class expected of that liquid while it is in storage. Also, to avoid infractions of the record keeping requirements, records should be maintained at all times on any liquid which could at any time move into a volatility class for which reporting is required, as shown in Table 2.1.

For record keeping purposes, the true vapor pressure (the vapor pressure at storage temperature) of a stored liquid is used. This pressure can be determined by procedures specified in American Petroleum Institute Bulletin 2517, "Evaporation Loss from Floating Roof Tanks." For storage vessel planning purposes, if the Reid vapor pressure [the vapor pressure at 37.8°C (100°F)] is known, the true vapor pressure at any expected temperature (of the bulk liquid) can be estimated from the nomograph shown in Figure 2.1. Thus, if the maximum expected temperature can be estimated, the highest volatility class can be determined from the estimated true vapor pressure at that temperature.

2.3.2 Computational Estimates of Emissions

Although the Administrator has determined that equipment specification is the most acceptable approach to standards of performance for storage vessels, the regulations do allow for the use of equivalent technology, provided the same degree of emission control can be demonstrated.

One method of demonstrating emission control is a calculation procedure developed by the American Petroleum Institute for the estimation of product losses. Factors entering the computation include average wind velocity, average ambient diurnal temperature change, product physical characteristics, tank size and mechanical conditions, and volume throughput. Figures 2.2 and 2.3 show nomographs taken from API Publication 4080, for estimating losses of gasoline from fixed-roof tanks.

Emission losses from a fixed-roof tank consist of losses due to the movement of material into and out of a tank (working losses) and losses resulting from standing storage (breathing losses). Figure 2.2 provides a means to calculate working losses. In Step 1, draw a line through the number of tank turnovers per year and the true vapor pressure (calculated from Figure 2.1) through the pivot. In Step 2, connect the throughput in barrels with the pivot intersection and extend that line until it intersects the scale identifying gasoline working losses in barrels.

Figure 2.3 provides a means for calculating breathing losses. The method requires five steps.

1) After finding the average atmospheric temperature change in degrees Fahrenheit on the diagonal scale in the upper right, move vertically upward to the corresponding paint factor.

2) From the point on the paint factor scale move horizontally to the right to the corresponding tank outage (height) value.

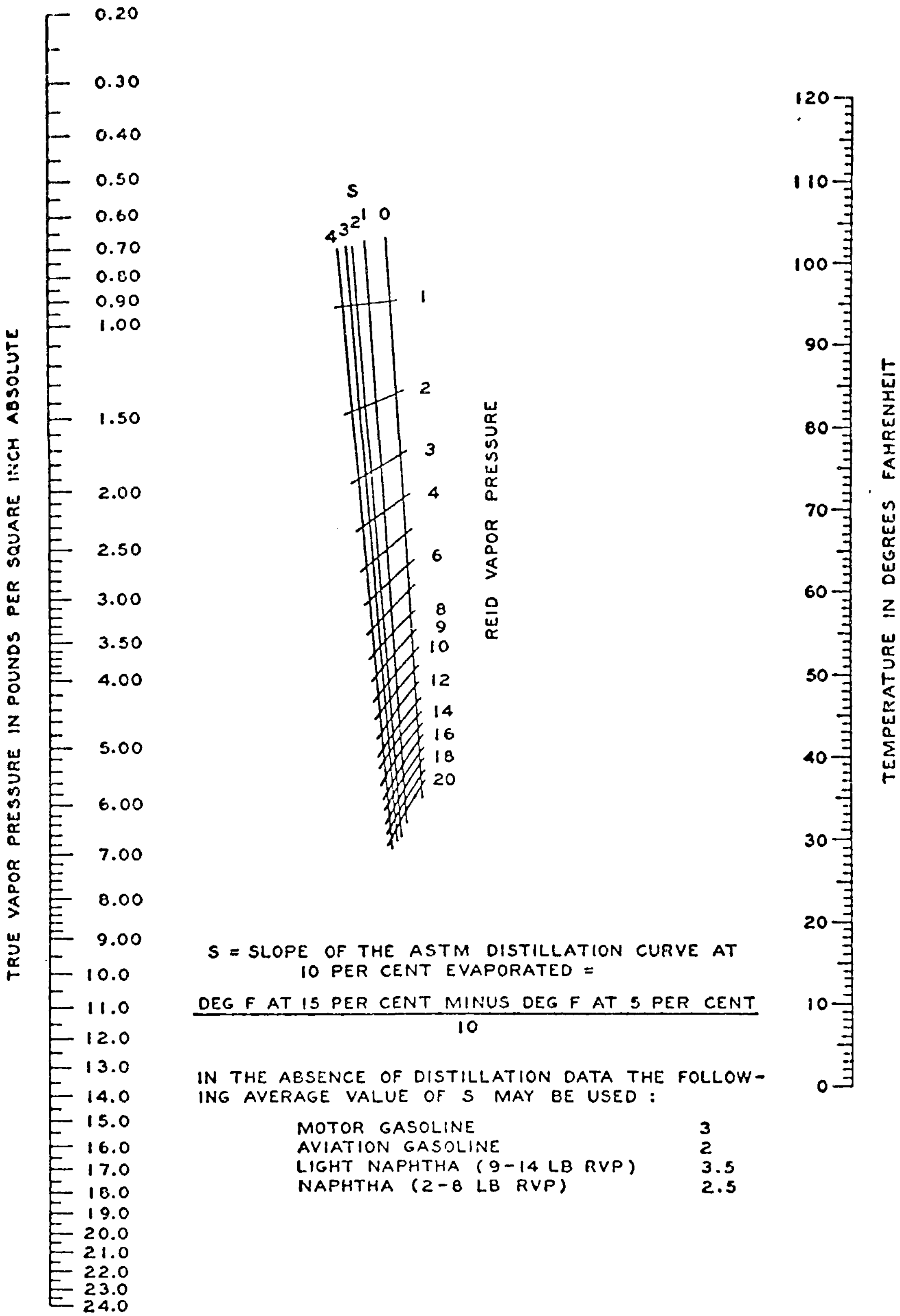
3) Move vertically downward to the corresponding true vapor pressure (calculable with knowledge of the Reid vapor pressure, the storage temperature and Figure 2.1).

4) From this point move horizontally to the left to the tank diameter.

5) From this point move vertically downward to the value for breathing losses in barrels per year.

It may also be necessary to calculate emissions from a floating roof tank for comparison. Emissions from a floating roof tank consist of losses due to standing storage and liquid withdrawal. The standing storage emission is a function of a series of factors which include (1) type of product stored, (2) Reid vapor pressure, (3) average storage temperature, (4) type of shell construction, (5) tank diameter, (6) color of tank paint, (7) type of floating roof, (8) type and condition of seal, and (9) average wind velocity in area.

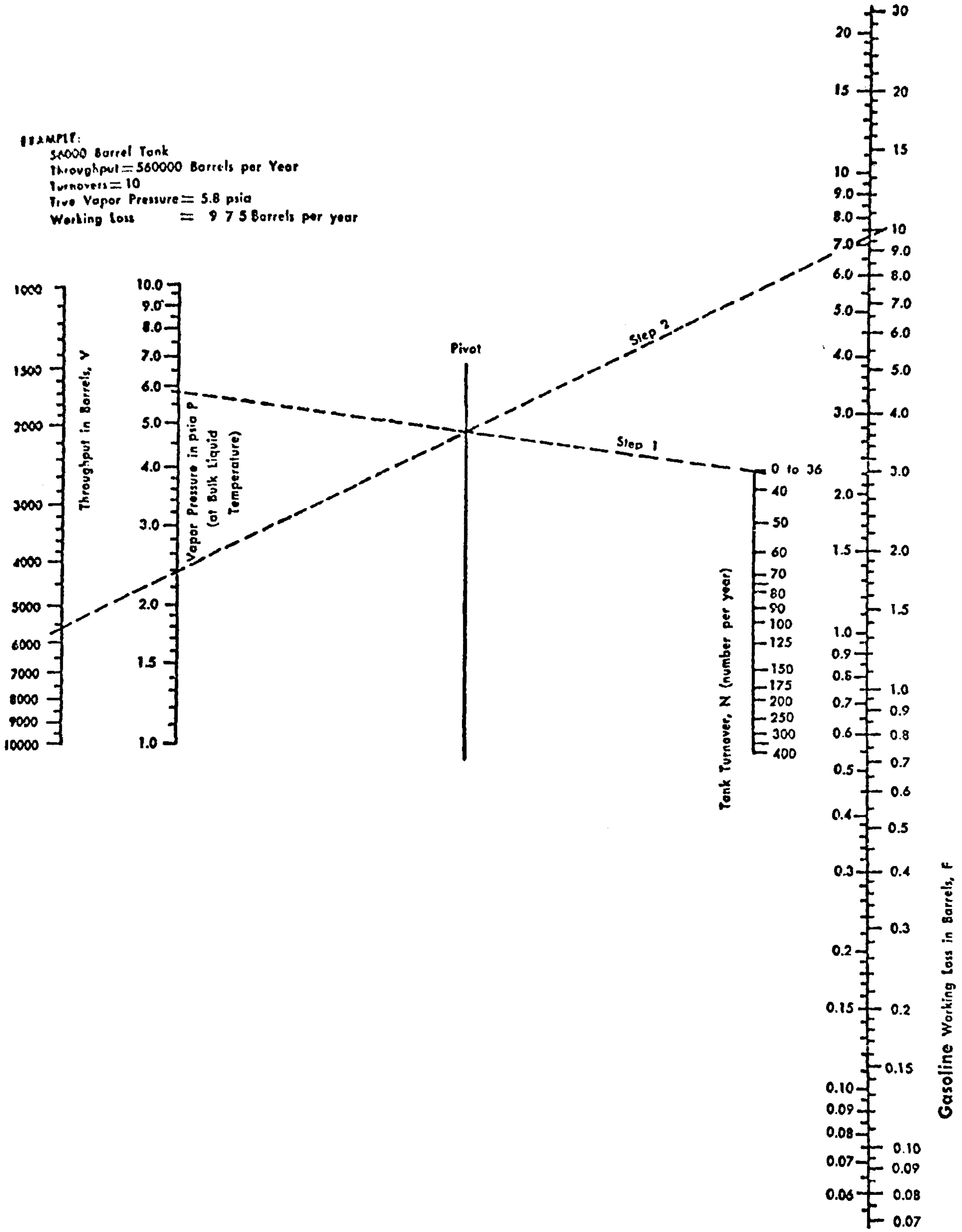
The equations used in this method were developed by API between 1952 and 1957 and were based on an intensive study of available data from the petroleum industry. Up until the last few years, these equations were used throughout the industry as the best method of calculating tank emissions. Recently, a great deal of testing has been performed to restudy the mechanisms which are responsible for the evaporative emissions. There is good reason to believe that the API equations will be revised to reflect the new testing. One important preliminary result of the new work has indicated that wind is the most important factor in determining the emission level. The amount of seal gap is also a significant factor, but stopping wind impacts with a good double seal may be more effective than totally eliminating the gap.



Source: Nomograph drawn from data of the National Bureau of Standards.

(API PUBL. NO. 4080)

Figure 2.1 VAPOR PRESSURES OF GASOLINES AND FINISHED PETROLEUM PRODUCTS



Note: The throughput is divided by a number (1, 10, 100, 1,000) to bring it into the range of the scale. The working loss, read from the scale, must then be multiplied by the same number.

(API PUBL. NO. 4080)

Figure 2.2 WORKING LOSS OF GASOLINE FROM FIXED-ROOF TANKS

(API PUBL. NO. 4080)

EXAMPLE:
T = 14°F
F_p = 1.33
H = 23 Feet
P = 5.8 psia
D = 100 Feet
L_y = 1350 barrels per year

Tank Color		Paint Factor, F_p	
Roof	Shell	Paint in Good Condition	Paint in Poor Condition
white	white	1.00	1.15
aluminum (specular)	white	1.04	1.18
white	aluminum (specular)	1.16	1.24
aluminum (specular)	aluminum(specular)	1.20	1.29
white	aluminum (diffuse)	1.30	1.38
aluminum (diffuse)	aluminum (diffuse)	1.39	1.46
white	gray	1.30	1.38
light gray	light gray	1.33	1.46
medium gray	medium gray	1.46	1.46

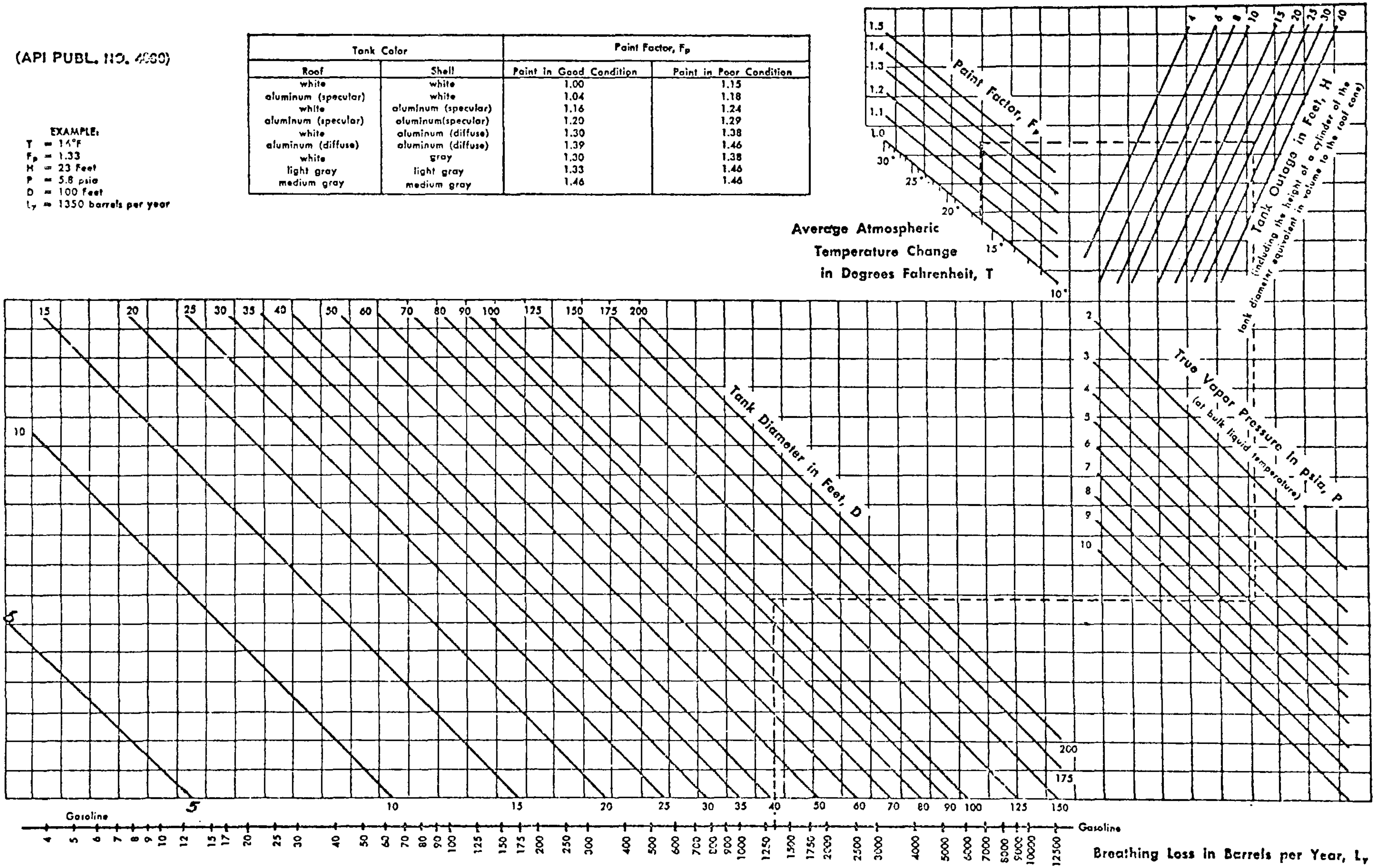


Figure 2.3 BREATHING LOSS OF GASOLINE FROM FIXED-ROOF TANKS

Table 2.2 STANDING STORAGE EVAPORATION EMISSIONS FROM FLOATING-ROOF TANKS: L_y (LOSS IN bbl/yr) = L_f (LOSS FACTOR FROM FIGURE 2.4) TIMES MULTIPLYING FACTOR (FROM THIS TABLE) (AP-40, Page 633.)

Multiplying factors apply to L_f	Welded tanks				Riveted tanks															
	Pan or pontoon roof				Pan roof								Pontoon roof							
	Single or double seal				Single seal				Double seal				Single seal				Double seal			
	Modern		Old[a]		Modern		Old[a]		Modern		Old[a]		Modern		Old[a]		Modern		Old[a]	
	Tank paint[b]		Tank paint		Tank paint		Tank paint		Tank paint		Tank paint		Tank paint		Tank paint		Tank paint		Tank paint	
	Lt grey	White	Lt grey	White	Lt grey	White	Lt grey	White	Lt grey	White	Lt grey	White	Lt grey	White	Lt grey	White	Lt grey	White	Lt grey	White
Gasoline	1.0	0.90	1.33	1.20	3.2	2.9	4.2	3.8	2.8	2.5	3.8	3.4	2.8	2.5	3.8	3.4	2.5	2.2	3.3	3.0
Crude oil	0.75	0.68	1.0	0.90	2.4	2.2	3.1	2.8	2.1	1.9	2.8	2.5	2.1	1.9	2.8	2.5	1.9	1.7	2.5	2.2

[a]Seals installed before 1942 are classed as old seals.
[b]Aluminum paint is considered light grey in loss estimation.

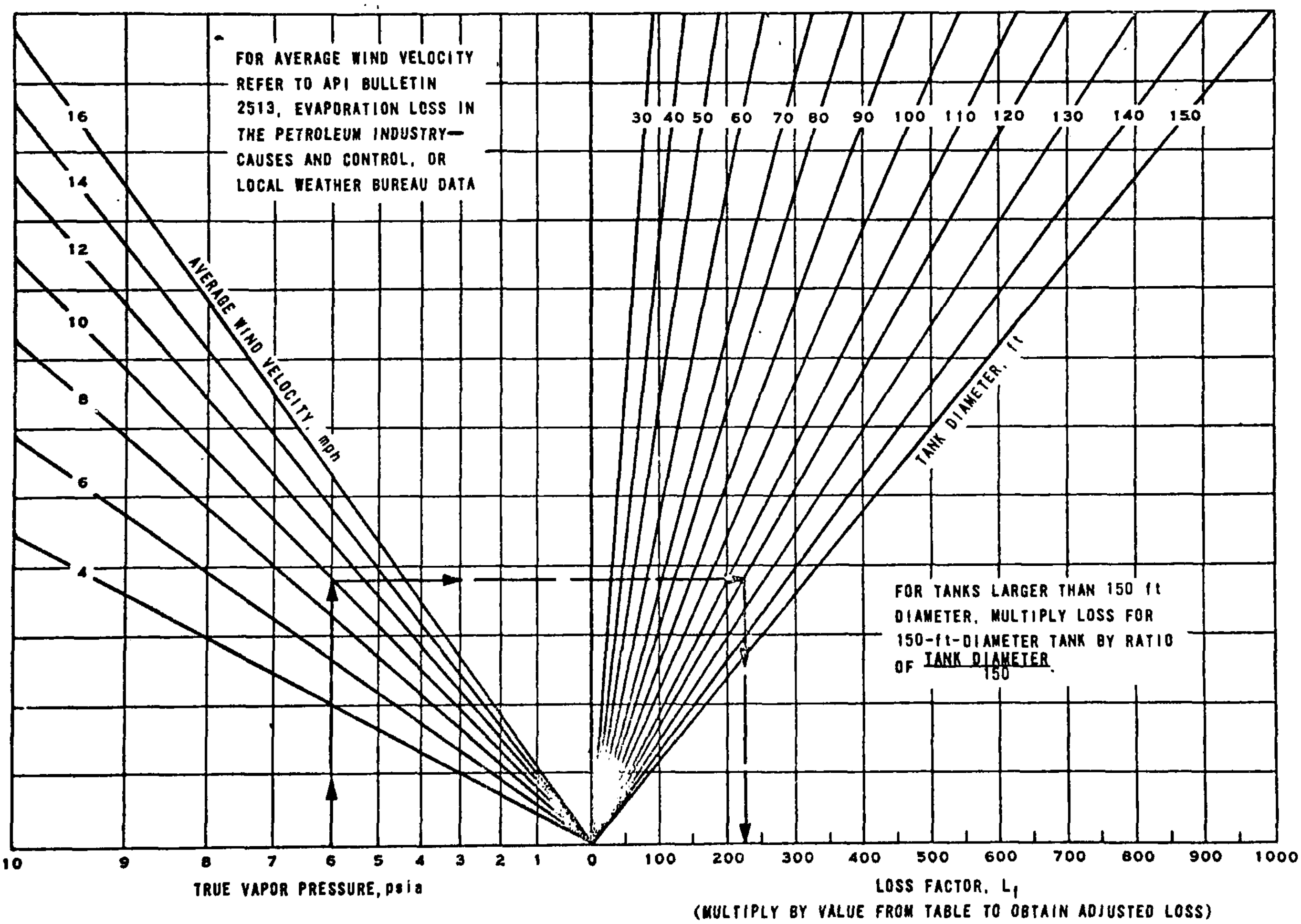


Figure 2.4 CALCULATION OF EMISSION FACTOR, L_f, FOR STANDING STORAGE EVAPORATION EMISSIONS FROM FLOATING-ROOF TANKS (AP-40, page 633.)

With values for these parameters and Table 2.1 and Figure 2.4, the standing losses from a floating roof tank can be estimated. The process involves five steps.

1) After establishing the true vapor pressure in psia for the liquid stored using the Reid vapor pressure, the storage temperature and Figure 2.1, find the corresponding value on the scale in the lower left hand corner of Figure 2.4.

2) From this point move vertically upward to the corresponding average wind velocity measured in miles per hour.

3) From this point move horizontally to the right, past the zero line, to the corresponding tank diameter.

4) Move vertically downward to the corresponding loss factor, L_f.

5) Once L_f has been determined, consult Table 2.2 to establish the adjusted loss value based upon type of tank, type of roof, type of seal and its condition, paint color, and product type.

Such computations could be useful in support of an argument that emissions of hydrocarbons from an installation under particular conditions were not excessive. However, compliance with NSP standards cannot be established through this approach, since the standards are not given in terms of actual emission rates.

REFERENCES FOR CHAPTER 2

1. Duncan, L. J., "Analysis of Final State Implementation Plans - Rules and Regulations," Environmental Protection Agency, Office of Air Programs, Research Triangle Park, N.C., Publication Number APTD - 1334, July 1972.

2. Federal Register, Vol. 36, December 23, 1971.

3. Federal Register, Vol. 38, No. 111, June 11, 1973.

4. Federal Register, Vol. 38, No. 198, page 28564, October 15, 1973.

5. Federal Register, Vol. 39, No. 47, page 9307, March 8, 1974.

6. Federal Register, Vol. 39, No. 75, page 13776, April 17, 1974.

7. Federal Register, Vol. 39, No. 116, page 20794, June 14, 1974.

8. "Field Surveillance and Enforcement Guide of Petroleum Refineries (Final Draft)," prepared by The Ben Holt Co., Pasadena, California , for Environmental Protective Agency, Research Triangle Park, N.C., July 1973.

9. Air Pollution Engineering Manual, Second Edition. Publication Number AP-40, May 1973.

3.0 PROCESS DESCRIPTION, ATMOSPHERIC EMISSIONS AND EMISSION CONTROL METHODS

3.1 PROCESS DESCRIPTION

Four types of tanks predominate in the storage of petroleum liquids: Cone (or fixed) roof, floating roof, pressure and variable vapor space tanks. Cone roof tanks are generally simple cylindrical steel vessels with conical steel roofs. They are normally designed to withstand only a few inches of water pressure or vacuum in the enclosed vapor space. From an air pollution standpoint, they are thus only suitable for storing low vapor pressure materials unless equipped with vapor recovery devices.

Floating roof tanks are similar to cone roof tanks except that they are fitted with a deck or roof that floats on the surface of the stored liquid. A sliding seal is provided at the tank wall, and the tank may have a cone roof in addition or may rely solely on the floating deck for a roof. Such tanks limit hydrocarbon losses because the roof floats upon the product and the air space in contact with the volatile stock is almost completely eliminated.

Pressure tanks are designed to contain substantial pressure and are frequently made in the form of spheresor cylindrical "bullets." They are normally designed to contain the stored material without venting except in emergencies. Since pressure tanks are much more expensive to construct than cone or floating roof tanks, their use is usually restricted to the storage of high vapor pressure materials such as butane. Nonventing pressure tanks are not subject to NSPS. Pressure tanks that vent can be considered as a special form of fixed roof tank and will not be treated separately.

Variable vapor space or conservation tanks are equipped with expandable vapor reservoirs to accommodate vapor volume fluctuations attributable to temperature and barometric pressure changes. Variable vapor space tanks are sometimes used independently, however, a variable vapor space tank is normally connected to the vapor spaces of one or more fixed roof tanks.

3.1.1 Cone Roof Tanks

Cone roof tanks are normally cylindrical, constructed of welded steel plate, with a welded steel floor. The tank walls are self-supporting and normally a ladder is provided for access to the roof. Near the base of the tank wall, flanged cleanout doors, entry manways, water drains, firewater connections and product lines are attached. The tanks are usually surrounded by firewalls which would contain any product spill. The construction of this firewall is subject to the provisions of the Spill Prevention Control and Countermeasure (SPCC) Plans. The tank has a welded steel plate roof which is attached to the upper rim of the tank walls. The roof is supported by a welded steel structure in larger tanks. There is generally a manway in the roof for access, a connection for the tank level indicator, a small hatch for sampling and hand gauging, and a conservation vent. The conservation vent is a relief type valve which allows a small pressure or vacuum to build in the tank before it opens to the atmosphere. It is usually set at 2 oz/sq. in. This helps minimize vapor losses due to breathing effects. Some fixed roof tanks have gas blanketing systems which are used to keep a positive pressure on the inside of the tank in order to prevent oxygen from entering. The gas can be natural gas, refinery gas, or an inert gas such as nitrogen. Fixed roof tanks are also associated with vapor recovery systems. These systems collect all excess vapors and dispose of them in an environmentally acceptable manner.

3.1.2 Floating Roof Tanks

The principle used in floating roof tanks is the elimination of vapor spaces. This is accomplished by floating a rigid deck or roof on the surface of the stored liquid. The roof then rises and falls according to the depth of stored liquid. The roof is equipped with a sliding seal at the tank wall so that the liquid is completely covered. No additional roof is required, however, many tanks are equipped with a standard fixed roof that covers the floating roof.

Sliding seals are an important feature of all floating roofs. The ideal seal would be vapor tight, long lasting and require little maintenance. However, some clearance between seal and tank wall is necessary for roof movement. Seals are situated at the rim of the roof, at support columns and at all points where tank appurtenances pass through the roof (see Figure 3-1). Two basic types of seals are commonly used today; the metallic and the nonmetallic seal. The conventional metallic seal generally consists of vertical metal plates or shoes connected by braces or pantograph (electrical) devices to the floating roof. The shoes are suspended in such a way that they are forced outward against the inner tank wall. An impervious fabric bridges the area between the tops of the shoes contacting the tank wall and the circumference of the floating roof. The fabric is often protected by a metal cover (see Figures 3-2 through 3-4). Riveted tanks, as opposed to welded structures,

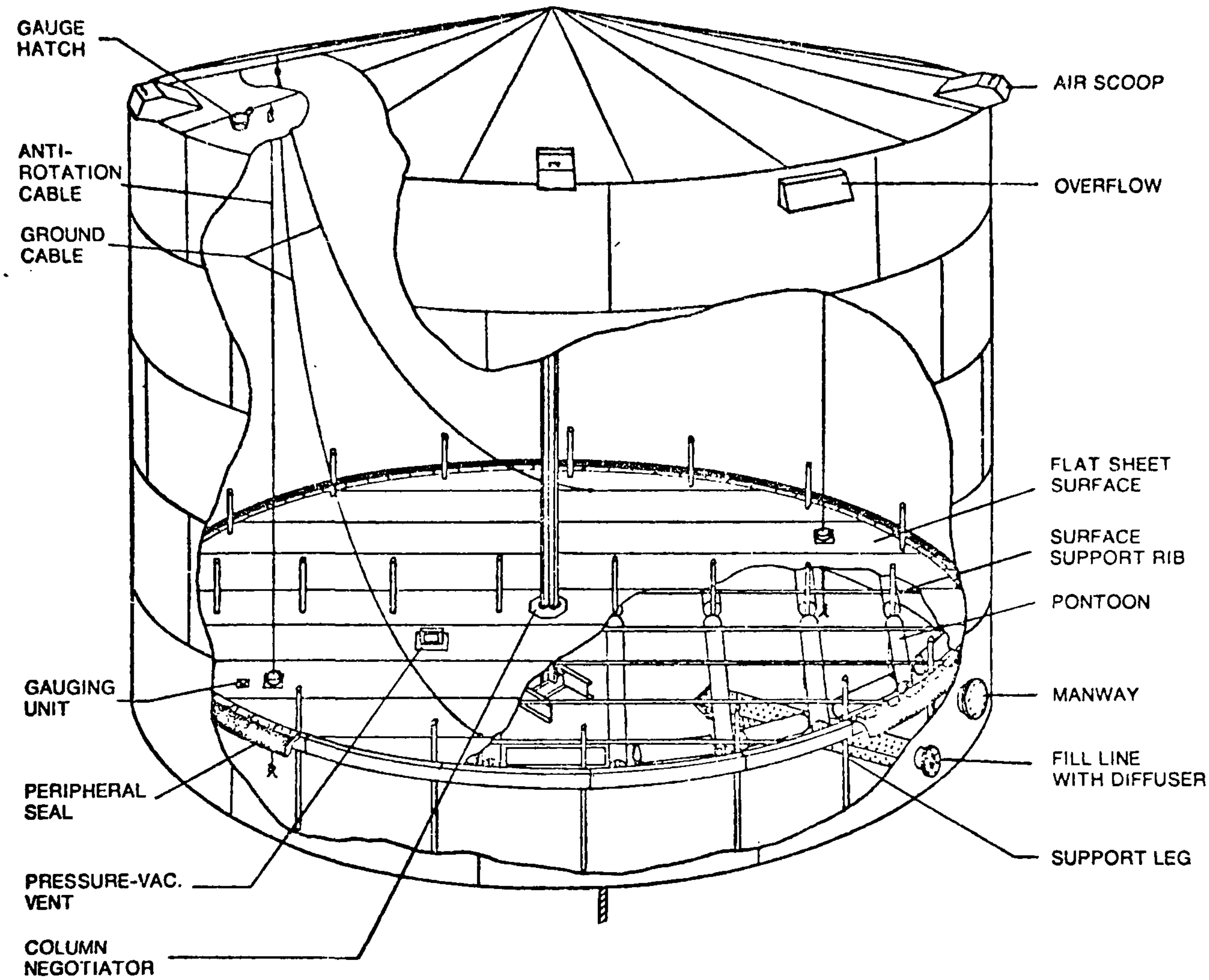
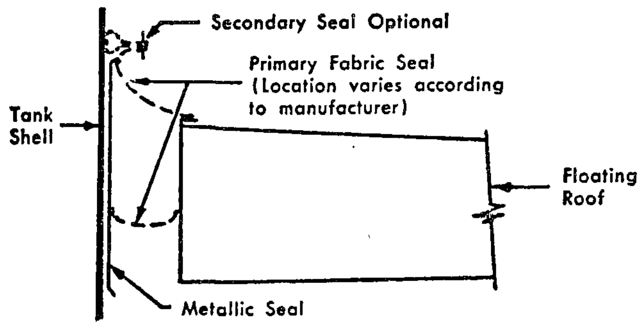


Figure 3.1 SCHEMATIC VIEW OF TYPICAL FLOATING DECK (FROM ALTECH INDUSTRIES, INC., ALLENTOWN, PENNSYLVANIA, TECHNICAL LITERATURE)



Note: Seal supports not shown.

Figure 3.2 SCHEMATIC OF A METALLIC SEAL
(A.P.I. PUBLICATION NO. 2517)

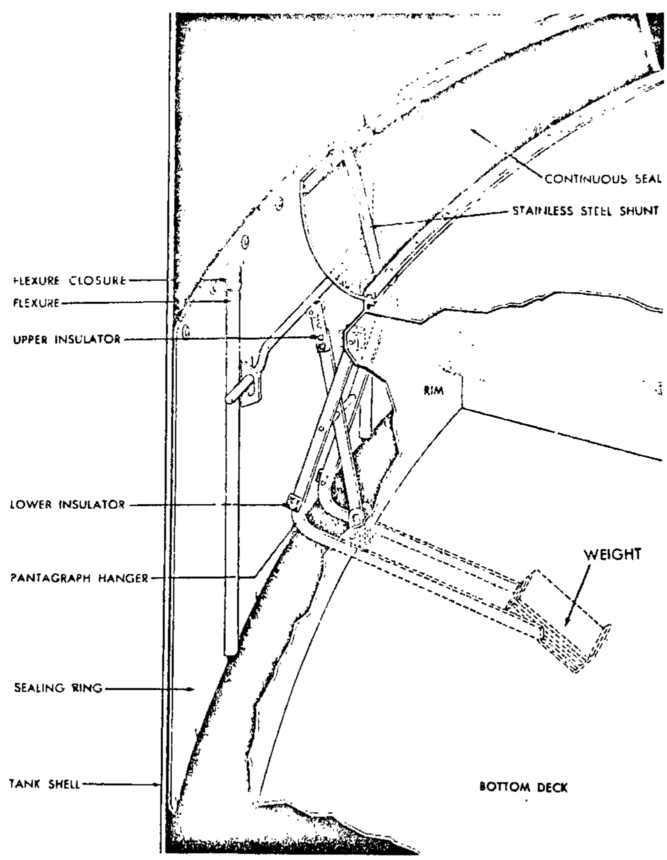


Figure 3.3 METALLIC SEAL SITUATED IN A DOUBLE-DECK FLOATING ROOF
(CHICAGO BRIDGE AND IRON CO., CHICAGO, ILL.)

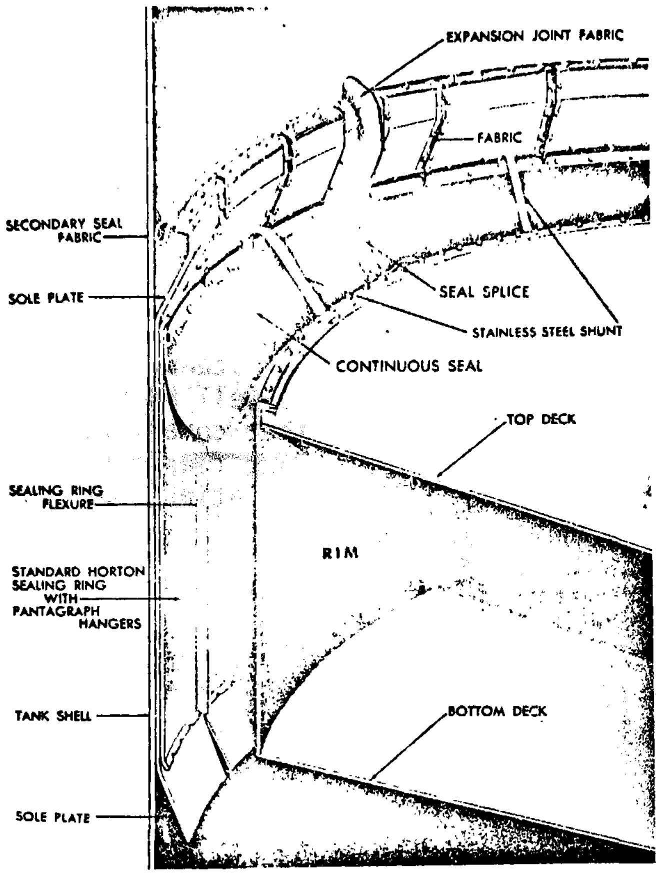


Figure 3.4 METALLIC SEAL EQUIPPED WITH SECONDARY SEALS TO STOP VAPOR LOSSES DUE TO HIGH WINDS ON RIVETED TANKS (CHICAGO BRIDGE AND IRON CO., CHICAGO, ILL.)

pose a special problem at the gap between seal and tank wall. Rivet heads may extend from the wall by as much as an inch at the bottom of the tank where the walls are thickest. Therefore, the spaces between the rivet heads create gaps. Also, the rivets can tear seal fabrics. To resist tearing, seal fabrics must be thick and tough, and hence may not be flexible enough to conform to the irregularities of the tank wall.

The nonmetallic seal is usually made of a hollow flexible plastic or fabric tube filled with plastic foam, liquid or compressed air (see Figures 3-5 through 3-8). The pneumatic, inflated seal is provided with uniform air pressure by means of a small expansion chamber and control valves. The sides of the tube remain in contact with the roof and inner shell. The liquid-filled tube holds a ribbed scuff band against the tank wall. The ribbed band acts as a series of wiper blades as well as a closure. All tubes are protected by some type of weather covering. Column and guide cable seals are usually close fitting flexible plastic sheets. The sheets cover holes cut in the floating roof and are sealed at the edges of the holes by resting on plastic or metal rims fitted around the holes. The sheet is sometimes allowed to slide horizontally on the rim to provide for vertical misalignment of the column.

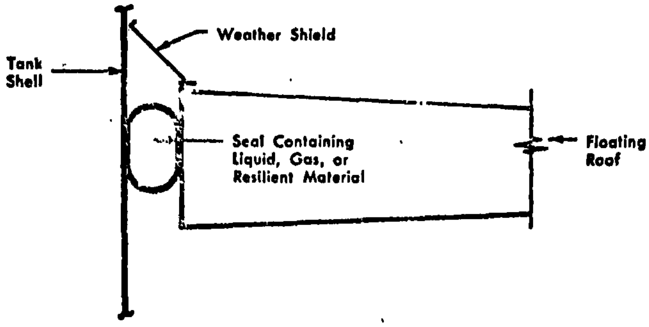
Floating roofs are taken as the standard of effective emission control for storage tanks. Their effectiveness depends on the material stored and the total throughput. Significant reductions over emissions generated using a fixed roof tank are achieved with floating roof tanks.

3.1.2.1 Single Floating Roof

Where single floating roofs are employed the roof is exposed to the weather. Provisions must be made for draining off rain water and for snow removal, and the sliding seal usually requires protection from dirt. Maintenance costs are normally higher than for covered floating roofs. In general, single floating roofs are not recommended for aviation fuels, particularly where rain or snowfall are heavy.

3.1.2.1.1 Pan-Type

The pan-type was the first floating roof developed. This consists of a flat metal plate with a vertical rim and sufficient stiffening braces to maintain rigidity. The plate is sloped downward toward the center where a drain is provided for rainwater. Since the roof floats up and down with the liquid level, a flexible drain connection must be removed manually as necessary to prevent sinking the roof. Metallic seals are commonly used with pan-type floaters. The roof is equipped with automatic vents for pressure and vacuum release, adjustable legs to limit low level travel, manways, gauge hatch, and a roller footed ladder that adjusts to the roof level.



Note: Seal supports not shown.

Figure 3.5 SCHEMATIC OF A NONMETALLIC SEAL
(A.P.I. PUBLICATION NO. 2517)

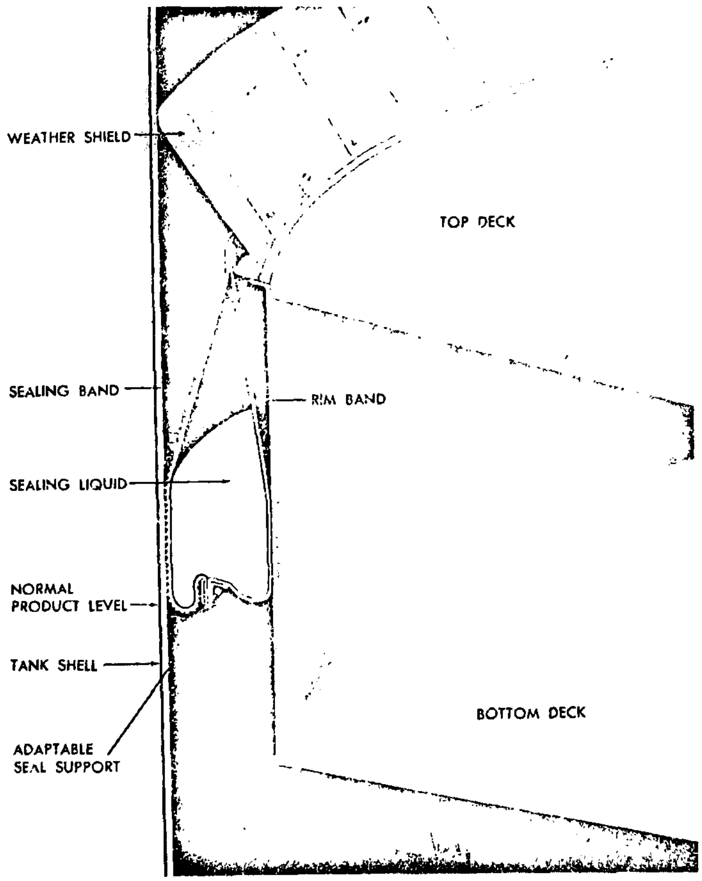


Figure 3.6 LIQUID-FILLED NONMETALLIC TUBE SEAL
(CHICAGO BRIDGE AND IRON CO., CHICAGO, ILL.)

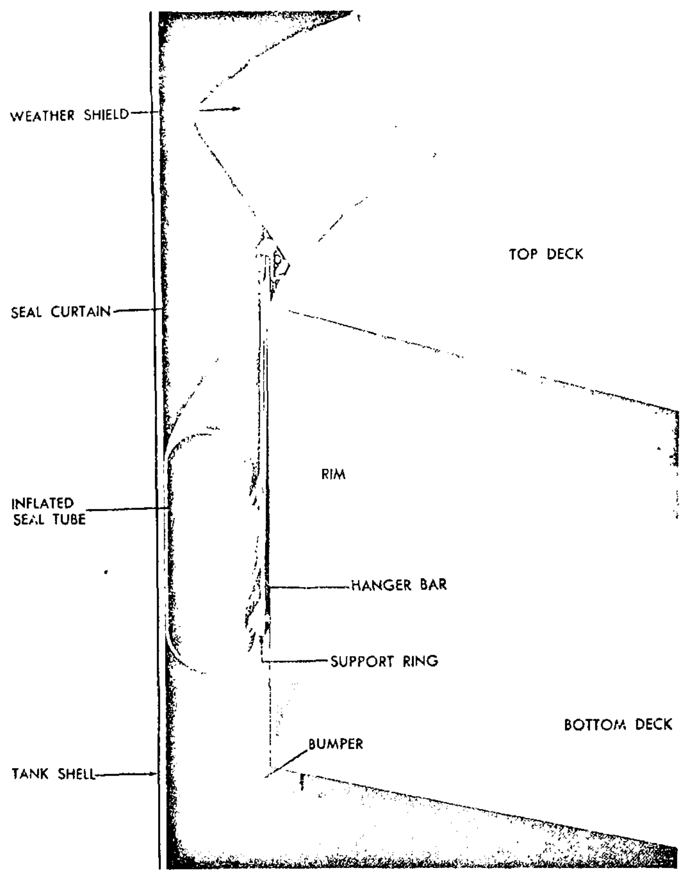


Figure 3.7 AIR INFLATED NONMETALLIC TUBE SEAL
(CHICAGO BRIDGE AND IRON CO., CHICAGO, ILL.)

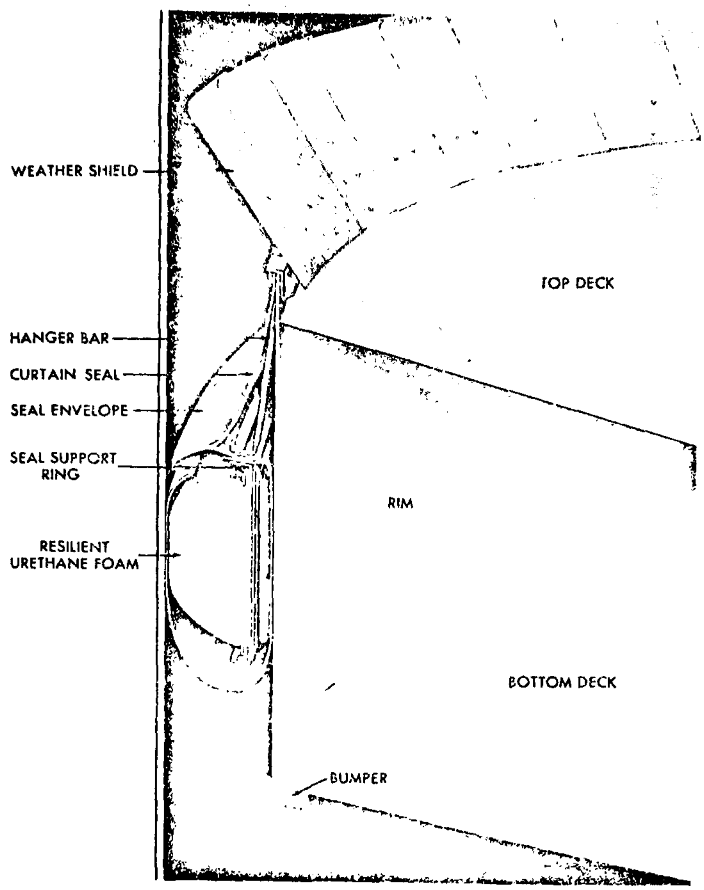


Figure 3.8 FOAM-FILLED NONMETALLIC TUBE SEAL (CHICAGO BRIDGE AND IRON CO., CHICAGO, ILL.)

Although simple and relatively inexpensive, the pan-type is now seldom used as a single roof. Tilting, holes, and heavy snow or rain loads have caused a significant number of these roofs to sink. Also, the single metal plate in contact with the liquid readily conducts solar heat with resulting high vaporization losses. Applications of pan-type floaters is limited today to internal floating roof tanks.

3.1.2.1.2 Pontoon

In order to overcome the problem of sinking and improve emission control efficiency, the pan-type roof was modified by the addition of pontoon sections to the top of the deck. The added expense of the pontoons is generally felt to be justified by the better stability achieved. The installation of a center drain with hinged or flexible connections can aid in roof draining and help reduce the sinking problem. Nonmetallic seals are generally used on pontoon roofs. All other accessories used with pontoon roofs are the same as those used with pan-type roofs.

Although the problem of roof stability is solved by the use of pontoons, the high vaporization losses resulting from solar heating are not noticeably reduced over those for the pan-type roof.

3.1.2.1.3 Double-Deck

Extending the pontoon sections to completely cover the roof results in a new design, the double-deck roof. The added expense of this design is generally considered to be justified by the added rigidity and by the insulation provided by the dead air space between the upper and lower deck plates. The compartmented dead air space is usually over one foot deep and provides enough insulation to significantly reduce vapor losses from solar boiling. The space may contain a mixture of air and organics, primarily methane. The upper deck is sloped to a centrally located drain, the rain water is removed through a flexible hose or drain pipe. The bottom deck is domed upwards to trap any vapor entrained with incoming liquid or formed in storage. Nonmetallic seals are commonly found on this type of roof. Accessories are similar to those used with pan-type or pontoon roofs.

3.1.2.2 Covered Floating Roof

The American Petroleum Institute has designated the term "covered floating roof" to describe a fixed roof tank with a steel pan-type floating roof inside. The term "internal floating cover" has been chosen by the API to describe covers constructed of materials other than steel, such as aluminum and urethane foam. Floating roofs and covers can be installed inside fixed roof tanks.

Since the fixed roof protects the floating roof from the weather, no provision is required for rainwater removal. Maintenance is reduced since the internals, particularly the seal, are protected and the product is less likely to be contaminated by dirt or water. The rolling stairway is eliminated, but antirotational guides are added to maintain alignment between fixed roof and floating roof openings. If the tank has support columns they must penetrate the float, and the opening must be sealed. Practical column seals have been devised, but they add to the installed and maintenance costs. Also, the space between the roofs must be vented to prevent the possible formation of a flammable and therefore explosive mixture. Hooded vents provide adequate ventilation for aboveground tanks, but underground tanks may present a special problem. A possible solution is the use of blowers. Underground steel tanks with horizontal stiffening rings at the wall cannot be sealed with the usual seal rings. A satisfactorily smooth vertical surface can probably be supplied by filling the space between stiffening rings with Gunite or steel plates, but no existing installations of this sort are known.

The conversion of existing fixed roof tanks to covered floaters is standard practice in the industry. In fact, the cost of conversion is usually less than the cost of converting the tank to a single roof floating roof tank.

3.1.2.2.1 Pan-Type

Although pan-type roofs are no longer considered suitable for single roof tanks, they are used as internal floating roofs. They are cost competitive with other types of internal floating covers when they are installed as part of a new tank. They can also be added to existing tanks, but at a cost that is somewhat higher than for some of the newer covers such as those made from rigid polyurethane.

3.1.2.2.2 Pontoon

Since covered floating roofs are protected from the elements, the added cost of pontoons does not appear to be justified.

3.1.2.2.3 Double-Deck

Double-deck floats are more expensive than pontoons, and the added cost does not appear to be justified.

3.1.2.2.4 Rigid Polyurethane

Rigid polyurethane foam floating covers are a recent innovation, and several different styles of covers are now being offered by various companies. The number of installations and their service record is sufficient reason to consider them to be an established system, but there has not been enough service time to establish the superiority of one style over another.

One of the first styles to appear on the market used a polyurethane core with a laminated aluminum sheet covering. Difficulty was experienced when the solvent being stored in the tank attacked the adhesive used and loosened the aluminum sheeting. A new method of bonding the sheet to the core has been developed that is said to overcome this problem.

Most of the polyurethane covers being offered are covered with fiberglass. The resin for bonding the glass must be chosen with regard to the material being stored; however, it is now possible to provide a resin that has shown to be satisfactory for use with gasoline and turbine fuels.

One type of cover is assembled from fiberglass covered polyurethane foam planks. The finished assembly weighs only about one pound per square foot, but has sufficient strength to permit maintenance and inspection personnel to walk on the cover while standing on its legs with the tank dry. Closed cell foam is used so that even if the cover is punctured it will not sink or become saturated by the stored liquid. Column seals, manways and other accessories are easily installed by cutting an opening in the deck and cementing an appropriate fitting in place. Column seals can be designed for abnormal vertical misalignment in excess of four to six inches by increasing the diameter of the deck opening. The wiper is attached to a section of board that is free to slide horizontally across the seal between the board and the opening. A temporary two foot by eight foot hole must be cut in existing tanks to permit installation of this type of roof, but the installation labor and time is about half that for a pan-type deck.

3.1.2.2.5 Floating Fabric Covers

Flexible coated fabric covers have been in use for a number of years, particularly in Europe. Urethane coated nylon with an inflatable tubular float of the same material around the circumference is one type. Other covers are only suitable for use in small diameter tanks, and, therefore, are not of use in the tanks under consideration.

3.1.3 Variable Vapor Space Tanks

Variable vapor space (also called conservation) tanks consist basically of two different types: lifter-roof tanks and tanks with internal flexible diaphragms or internal plastic floating blankets.

3.1.3.1 Lifter-Roof Tanks

The lifter-roof, commonly called a gas holder, is used for low-pressure gaseous products or for high-volatility liquids. This type of vessel can be employed as a vapor surge tank when manifolded to vapor spaces of fixed roof tanks. The lifter-roof tank has a telescoping roof that fits loosely around the outside of the main tank wall. The space between the roof and the wall is closed by either a dry seal consisting of a gastight flexible fabric, or a liquid seal. The sealing liquid can be fuel oil, kerosene, or water. Water should not be employed as a sealing liquid where there is danger of freezing.

The physical weight of the roof itself floating on vapor maintains a slight positive pressure in the lifter-roof tank. When the roof has reached its maximum height, the vapor is vented to prevent overpressure and damage to tank.

3.1.3.2 Internally-Modified Fixed-Roof Tanks

The second type of conservation tank consists of fixed-roof tanks equipped with internal flexible diaphragms or internal plastic floating blankets. The internal coated fabric diaphragm is flexible and rises and falls to balance changes in vapor volume. Normal operating pressure is 1/2 ounce per square inch, which is approximately one-eighth the operating pressure possible with most gas holders. Two basic types of diaphragm tanks are the integrated tank, which stores both liquid and vapor, and the separate tank which stores only vapor.

3.2 ATMOSPHERIC EMISSIONS

Hydrocarbon emissions from storage tanks arise from breathing loss, working loss, standing storage loss, end spills, and leaks. With proper operating and maintenance practices, spills and leaks should not be significant except for accidents or emergencies. Breathing losses occur when the vapors contained in a tank expand because of changes in temperature or atmospheric pressure. Diurnal temperature variations can lead to significant hydrocarbon emissions. The amount of loss is a function of the volume of vapor space in the tank, changes in liquid level and temperature, changes in atmospheric pressure, the venting pressure of the tank, and the vapor pressure of the stored material.

Working losses occur when tanks are filled; the incoming liquid displacing the vapor from the tank. The amount of loss is a function of the volume of liquid transferred, the temperature, and the vapor pressure of the stored material. Splash or above surface loading can result in significantly higher losses than subsurface or submerged loading. Floating roof tanks theroetically have no significant working losses.

Floating roof tanks are subject ot reduced breathing and working losses due to the nature of the tank operations. Different causes of emissions are associated with a floating-roof tank. These causes are known as standing (wicking) and withdrawal evaporation losses (wetting). Wicking emissions are caused by the capillary flow of the liquid between the outer side of the sealing ring and the inner side of the tank wall. The wetting emission results when the floating roof moves toward the bottom of the tank during emptying and leaves the inner tank shell covered with a film of liquid, which evaporates when exposed to the atmosphere. Procedures for estimating losses from hydrocarbon storage, with examples, are presented in the following publications, available from the American Petroleum Institute, Publications and Distribution Section, 1801 K Street, N.W., Washington, D.C. 20006. Use of these equations should be carefully considered. The equations are based upon measurements performed on older tanks storing gasoline and crude oil. Estimating emissions from modern tanks storing other petroleum liquids based upon these equations does not have a measured statistical basis and may provide misleading values. (See Section 2.3.2)

BULLETIN	TITLE
2512	Tentative Methods of Measuring Evaporation Loss from Petroleum Tanks and Transportation Equipment (1957)
2513	Evaporation Loss in Petroleum Industry - Causes and Control (1959)
2514	Evaporation Loss from Tank Cars, Tank Trucks and Marine Vessels (1959)
2515	Use of Plastic Foam to Reduce Evaporation Loss (1961)
2516	Evaporation Loss from Low Pressure Tanks (1962)

BULLETIN	TITLE
2517	Evaporation Loss from Floating Roof Tanks (1962)
2518	Evaporation Loss from Fixed Roof Tanks (1962)
2519	Use of Internal Floating Covers for Fixed Roof Tanks to Reduce Evaporation Loss (1962)
2520	Use of Variable Vapor Space to Reduce Evaporation Loss (1964)
4062	Investigation of Passenger Refueling Losses APRAC Project CAPE-9-68 Coordinating Research Council
4080	Recommended Procedures for Estimating Evaporation and Handling Losses

3.3 EMISSION CONTROL METHODS

3.3.1 Conservation Vents

Adequate emission control for the storage of low vapor pressure hydrocarbons(<1.5 psia TVP) can be obtained by equipping cone roof tanks with conservation vents. A conservation vent is a form of pressure and vacuum relief valve that provides a large gas flow area with a differential pressure setting of a few inches of water. The seal is provided by gasketed metal plates held in place over an opening by a system of levers and adjustable weights. The use of a conservation vent reduces the amount of breathing losses by venting only when the set pressure differential is exceeded.

3.3.2 Floating Roofs

Floating roofs may be used for the storage of hydrocarbons with true vapor pressures (TVP) at storage conditions of 11.1 psia or less. The use of a floating roof eliminates any vapor space in storage vessel and this significantly reduces breathing and working losses. To be successful, the floating roof must be equipped with an adequate and well maintained roof-to-wall sliding seal. Gauge hatches and other openings must also be provided with seals. Deterioration of the condition of these seals can significantly affect the degree of control achievable from a floating roof. Therefore, the type of seal being installed should be carefully reviewed for its maintenance and reliability history.

The floating roof tank is generally accepted as the standard for adequate control for storing hydrocarbons such as gasoline, when the TVP at storage conditions is 11.1 psia or less. In some cases, cooling systems, such as circulation through water-cooled heat exchangers, are used to lower the hydrocarbon TVP so as to permit storage in floating roof tanks.

3.3.3 Flares

Flares may sometimes be used for the control of hydrocarbon emissions from storage tanks. Since the hydrocarbon is burned, the practice is wasteful and the installation must be carefully designed to avoid the hazards of fire and explosion. For these reasons the use of flares is generally limited to small, remotely located installations.

3.3.4 Recovery to Fuel Gas

Petroleum refineries utilize fuel gas systems to collect overhead gasses generated from various processing units and distribute it to heaters and other users. Cone roof storage tanks can be connected to the fuel gas system in such a way that fuel gas is used to blanket the tanks and any vented vapor is put back into the fuel gas system. Figure 3.9 is a sketch of such a system. Fuel gas is admitted to the storage system through a pressure regulating valve as required. Excess pressure is relieved through a second pressure regulating valve and the vented vapor is compressed and sent to the fuel gas system.

Such a system is reliant on a functioning compressor at all times. The compressor forces the blanketing fuel gas into the tanks and draws off the vented vapors. A malfunction of the compressor could result in the venting of gases generated during this period to the atmosphere. Serious consideration should be given to the type of compressor used, the reliability history of this unit, and what provisions for standby capabilities are being made.

3.3.5 Vapor Recovery Systems

There are a number of different recovery system designs now in use. Those that are commonly used which can meet the NSPS employ compression, absorption, refrigeration, or a combination of these steps to recover the hydrocarbon. One such system, shown in Figure 3.10, uses gasoline as an absorbent to recover the hydrocarbon. The vapor vented from gasoline storage tanks is largely a mixture of air and butane. The vapor is saturated with gasoline to ensure that the vapor composition is above the flammable limit. The saturated vapor is accumulated in a variable vapor space gas holder and

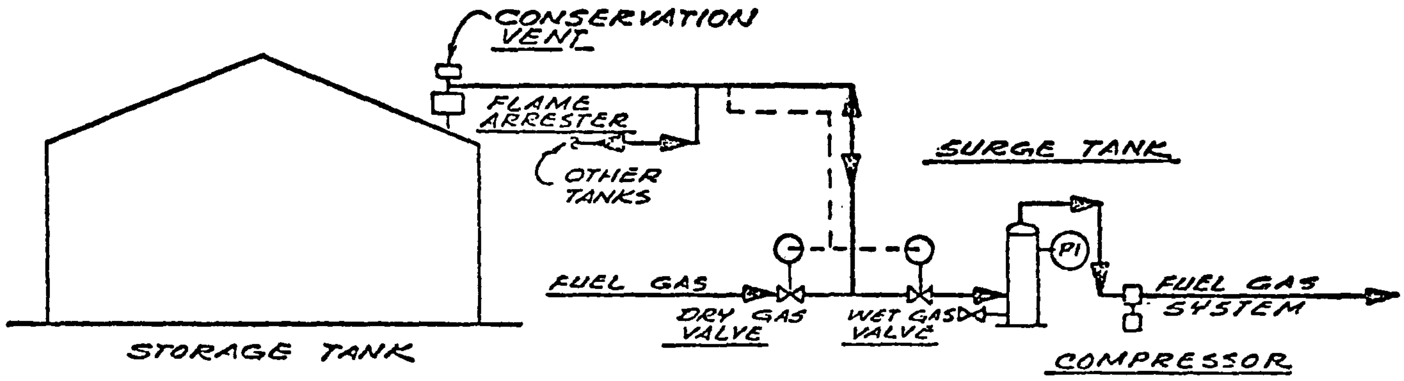


Figure 3.9 VAPOR RECOVERY SYSTEM FOR STORAGE TANKS

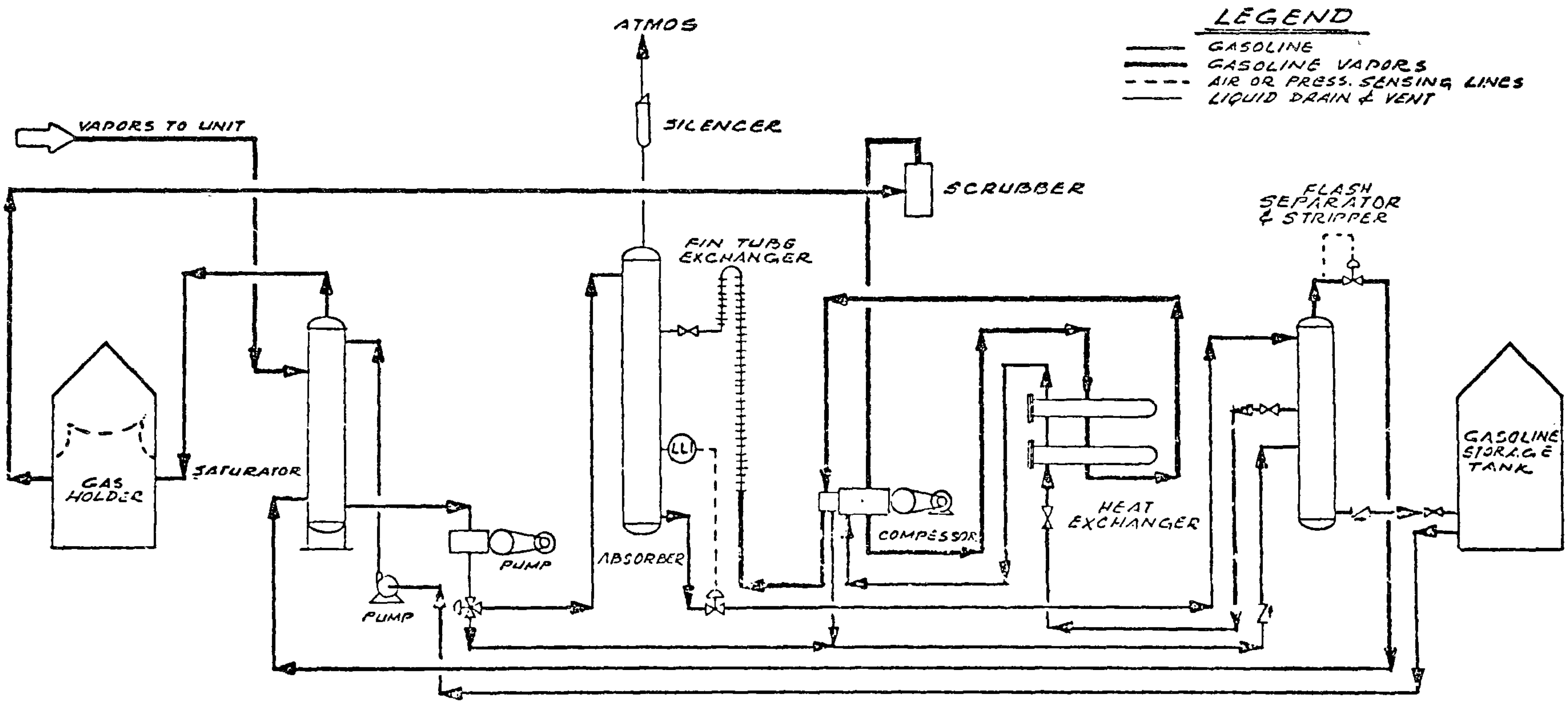


Figure 3.10 HIGH PRESSURE ABSORBER UNIT

is compressed and fed to the absorber where it is brought into contact with gasoline pumped from storage. The gasoline absorbs the hydrocarbon from the mixed vapor and the air is vented. The gasoline from the absorber is reduced in pressure in the flash separator and stripper, and, still containing most of the absorbed butane, is returned to storage. Vapor balance lines between tanks are frequently used to reduce the load handled by the recovery system.

For more detail on the design of emission control equipment, refer to "Air Pollution Engineering Manual (Second Edition)," John A. Danielson, available from the Government Printing Office as EP 4.9:40-2 and "A Study of Vapor Control Methods for Gasoline Marketing Operations," 2 Volumes, prepared by Radian Corporation, available from the Government Printing Office as EPA-450/3-75-046-a.

4.0 PROCESS AND CONTROL DEVICE INSTRUMENTATION

4.1 PROCESS INSTRUMENTATION

Storage tanks are frequently equipped with level gauges and temperature indicators. Sometimes provision is made for remote reading at a control house. Vapor pressure of the stored material is usually determined by manual sampling and testing in the control laboratory.

4.2 CONTROL DEVICE INSTRUMENTATION

Recovery to fuel gas systems normally have pressure gauges indicating fuel gas supply pressure, tank header pressure, compressor inlet vacuum, and compressor discharge pressure. The tank header pressure should be less than the set pressure of the conservation vent, since otherwise the tanks will vent to the atmosphere. If the compressor cannot maintain a vacuum at the inlet, the compressor is probably undersized or malfunctioning.

Vapor recovery system instrumentation should include devices for reading absorber pressure, the temperature of the gasoline to the absorber, the flow rate of the gasoline to the absorber, and the flow rate of the vapor through the compressor. These values should be checked against design values.

5.0 START-UP/MALFUNCTIONS/SHUTDOWN

Tanks require periodic cleaning and occasional repair, but will probably only be taken out of service for such purposes once every few years. When a tank is taken out of service, the petroleum liquid is first completely drained out. The empty tank is then injected with low pressure steam for approximately 24 hours to eliminate hydrocarbons still present. The steam is vented to the atmosphere causing emission of hydrocarbons. Once the hydrocarbon level of the tank atmosphere has been reduced to below the low explosibility limit, air eductors are attached, usually to the bottom manhole. Plant air is circulated through the tank and exits through the open upper manhole. The air cools the tank and ventilates the internal atmosphere to a level which is tolerable for the workers. Any hydrocarbons remaining after the steaming cycle would escape during this airing out process.

Normal care to avoid spills and following good maintenance procedures should be sufficient to avoid significant emissions. The seals on conservation vents, gauge hatches, and floating roof wall seals should be inspected regularly to avoid malfunction.

Recovery to fuel gas and vapor recovery systems do not present any particular problems from the point of view of pollutant emissions. The most common malfunctions are failure of pressure control valves and compressor and pump breakdowns, and the affected tanks will vent to the atmosphere if the control system is not operating. A good inspection and maintenance program will prevent most such malfunctions.

6.0 INSPECTION PROCEDURES

An air pollution inspection consists of entering a facility to determine if the equipment or processes meet the standard and comply with the rules and regulations of the air pollution control agency. The inspection process also includes a spot-check of selected records maintained by the operator. The Inspecting Officer (IO) must observe, in a qualitative manner, the items associated with atmospheric emissions - volatile hydrocarbon storage tanks in the present case. Condition and type of equipment, procedure for filling and emptying the tanks, and general housekeeping all influence the emission rate. Tank design is a major factor that must be reviewed at the time the construction permit or operating permit applications are evaluated.

The importance of plant inspection as a field operations activity that provides for the systematic detection and observation of emission sources cannot be overemphasized. The whole process of inspection follows certain rules and guidelines which are discussed briefly in the following sections.

6.1 CONDUCT OF INSPECTION

There are four important components in the conduct of inspection of volatile hydrocarbon storage tanks:

- Formal procedure (e.g., use of credentials, ask to see appropriate official).
- Overall inspection process (e.g., review of process and records).
- Safety precautions and procedures.
- Frequency of inspection.

Description of the above four components follows.

6.1.1 Formal Procedure

Prior to the actual on-site inspection, the IO should investigate and familiarize himself with any available data on plant operations. In preparation for the inspection, the official should obtain the following data:

- Information for each major storage tank (capacity greater than 40,000 gallons), including material stored, operating conditions and normal filling and emptying schedules. Much of this information may be entered in forms such as those shown in Figure 6.1 for easier reference.

- Plot plans showing disposition of all major units of the facility including the locations of all petroleum liquid storage tanks.

- Business and ownership data including names of responsible management personnel.

At the time of inspection, the IO must have with him the credentials showing his identity as an official of an air pollution control agency. He should arrange an interview with the management of the facility. The interview with plant managers and equipment operators can verify data gathered and clarify and any misunderstanding with regard to the information reviewed prior to the inspection.

6.1.2 Overall Inspection Process

Some inspections, especially initial ones, are comprehensive, designed to gather information on all the equipment and processes of the facility. Others are conducted for specific purposes such as:

- Obtaining information relating to violations.

- Gathering evidence relating to violations.

- Checking permit or compliance plan status of equipment.

- Investigating complaints.

- Following up on previous inspection.

- Obtaining emissions information by source testing.

- Evaluating compliance with SPCC spill regulations and other regulations.

An initial inspection lays the groundwork for evaluating potential emissions of hydrocarbons from tanks and for assessing the relative magnitude of pollution control problems requiring correction, reinspection, or further attention.

The initial inspection has two phases: a plant survey and a physical inspection of the equipment and processes. After this inspection is complete, routine surveillance continues.

Periodic reinspections are scheduled and occasional special purpose inspections (unscheduled) may be required. During the initial survey, the inspector examines the possible effects of emissions on property, persons and vegetation adjacent to the source; he may also collect samples or specimens that exhibit possible pollution-related damage. Sensory observations (odor detection) in case of excess hydrocarbon vapor discharge from vapor controlled tankage are also made.

Sources like storage tanks are so similar that standard inventory forms are used to report them (see Figure 6.1). These inventory forms record the type of tank, vapor control, function, dimensions, product stored, Reid vapor pressure, storage temperature, etc., of each tank to determine compliance with rules. The NSP Standards for storage tanks are stated in terms of equipment specifications (e.g., type of tank and vapor recovery system). The details have already been given in Section 2.2, where the records related to tanks which must be maintained were also discussed (Section 2.2.3.2). The inspector must also review these records kept by the operator.

An aid to the IO is the information incorporated in applications to operate the equipment. The permit status of the equipment should be routinely checked to detect any changes in equipment or process that might invalidate an existing permit or conflict with the variance conditions.

Similarly, alteration of equipment is frequently detected by discrepancies in the equipment description (size of the tank for example) or by changes noted on engineering applications in the permit file.

6.1.3 Safety Equipment and Procedures

All facilities have standard safety procedures for employees and visitors. These procedures also concern the IO. The IO is accompanied to the unit or units to be inspected by the air pollution representative within the plant or by such other informed plant personnel as he might indicate.

Personal protection is necessary in many of the industrial locations (including storage tanks for hydrocarbons) that an Inspection Officer may be required to visit.

The IO should wear a head covering while in a plant, preferably a hard safety hat. He should wear rubber gloves and goggles when necessary. In the event of fire in the area of inspection, the IO

AREA GRID NO. ____________ M.R.NO. ____________

FIRM NAME ____________ TEL. ____________ ZONE ____________

ADDRESS OF PREMISES ____________ CITY ____________ POSTAL ZONE ____________

NATURE OF BUSINESS ____________

RESPONSIBLE PERSON TO CONTACT ____________ TITLE ____________

INSPECTION REPORT

TANK GROUP NO. ____________ INSPECTOR'S NAME ____________ DATE ____________ 19____

Reinspection Record on Back of Sheet

Tank No.	Height	Diam.	Type	Gen. Cond.	Product Stored	RVP (lb.)	Product Storage Temp.	Service	Vapor Control	Permit Status	Rules Affected	Remarks

Codes and Standard Terminology

Type: C-Fixed Roof; F-Floating Roof; P-Pressure; O-Open Top; S-Spheroid; H-Horizontal; U-Underground.

Condition: G-Good; P-Poor; B-Bad

Service: Rundown; Storage; Blending or Mixing

Control: N-None; PVV-Conservation Vents; F-Floating Roof (SS-Single Seal; DS-Double Seal); V.R.-Vapor Recovery; V.D.-Vapor Disposal; V.B.-Vapor Balance.

Figure 6.1 TANK INSPECTION CHECKLIST

must leave immediately, and remain outside the area until the "All Out" signal is sounded. He should use the buddy system when taking a sample or gauging a tank of volatile or gaseous hydrocarbons. The IO should be accompanied by another person and two persons should remain together until the job is completed. Before sampling a tank, he must make certain that all equipment is in workable order. He must not smoke or carry cigarette lighters which may ignite when dropped within a dangerous area such as an oil refinery. He should use only approved flashlights in oil refineries.

6.1.4 Frequency of Inspections

Because of the complexity of many of the industries under consideration, unit processes must be inspected systematically and regularly. The frequency of reinspection of storage tanks is based upon the findings during the initial inspection and the recommendations of the IO and his supervisor. These recommendations obviously depend on whether or not the "good" maintenance practices from the pollution standpoint are being followed by the operator. Further, the frequency would depend on the overall inspection load of the control agency for the whole district. The reinspections are scheduled so that they can be completed within a month. The number of reinspections assigned per district is based on the estimate that all required inspections can be completed within one year.

The Inspection Officer may have occasion to inspect the tanks out-of-schedule because of complaints or violations. In these cases, he does not make a formal inventory reinspection, but uses the copy of the previous inventory record (equipment list) from his files as a check on status of the permit, compliance, or other situation.

6.2 INSPECTION CHECKLIST

Data obtained during an inspection can be summarized on forms similar to the one shown in Figure 6.1. These forms also serve as a record of inspection. During the inspection, data on these forms will be completed and verified. In addition to the parameters specifically mentioned in Figure 6.1, there are other factors which should be considered for incorporation into a complete checklist.

1) In the event that the inspected facility has underground tanks, what is the material throughput of each tank?

2) As a check to determine the applicability of NSPS, the IO should obtain the dates of construction start, completion, and initial service for each tank which has a questionable status.

3) For vapor control systems:
   a) Manufacturer
   b) Description of the type of system
   c) Capacity
   d) Estimation of efficiency. The IO should ask if any source tests have been conducted to determine a measured effeciency.

4) The IO may also want to climb the floating roof tanks to determine the liquid level with relation to the tank height. From this vantage point, the officer will also be in position to examine seal gaps and seal conditions. Materials used to measure seal gaps can vary in sophistication from the use of sized aluminum dowels and a ruler to a single calibrated adjustable expansion device. Careful note of the liquid level will aid the inspector in evaluating how much of a variance in seal gaps can be attributed to a tank being out-of-round. As the liquid level in the tank increases, distortions in the tank diameter also increase. While on the tank roof, the inspector may wish to use an explosimeter (JW meter) to check for leaky seals. These devices can also be used to document visual observations of large seal gaps.

5) Compliance schedule data if necessary.

6) Individuals contacted

7) Tank capacity

8) Shell construction (riveted or welded)

9) Submerged fill (yes or no)

10) Roof Color

11) Shell Color

12) Paint condition:
    a) Amount of chipping and flaking visible
    b) The date of the last painting of the tank

13) Molecular weight and liquid density of material stored.

14) Average vapor space volume

15) Storage temperature (average and maximum)

16) Average ambient temperature

17) Average wind velocity

18) Hydrocarbon emission rate

6.3 INSPECTION FOLLOW-UP PROCEDURES

Upon completion of the on-site inspection, an inspection report should be written. This report should include data obtained for each tank such as liquid level, temperature, and apparent odors. Other equipment attached to the tank such as mixers or heaters should also be noted. Finally, a statement should be made which indicates approval of the tank's control system or notes any conditions which may necessitate further action such as reinspection or denial of permit to operate.

If an inspection indicates that a source is not operating in compliance with applicable regulations, the IO should follow established Agency procedures regarding notice of violation, request for source test, and related matters.

He checks to ensure that permits have been granted for all applicable processes and equipment and their modifications. For any later public complaints, he determines cause of complaint, records pertinent data, issuing violation notices if appropriate, and ascertaining adequacy of plans for prevention of future incidents. He periodically reviews emergency procedure plans. He makes sure that all shutdown procedures are being implemented during periods of process curtailment. He coordinates with other agencies participating in pollution reduction effort. As a part of inspection follow-up procedures, he also checks to see that engineering, procurement, installation, and testing of equipment is proceeding according to the approved plan.

In the case of incident and complaint investigations, court actions, and variance board activity, the IO will require the data collected during his previous inspection visits to the facility. For example, the point of emission of excessive odors may be traced from an incident described in an operator's log or from an odor survey record.

REFERENCES FOR CHAPTER 6

1. Weisburd, M. I., "Air Pollution Control Field Operations Manual, a Guide for Inspecting and Enforcement," Department of Health, Education and Welfare, Public Health Service, Division of Air Pollution, Washington, D.C., Publication No. 937, 1962.

2. Brandt, C. S., and W. W. Heck, "Effects of Air Pollutants on Vegetation," in "Air Pollution," Vol. 1, Stern, A. C. (Ed.), Academic Press, New York, 1968.

3. "Guide for Compiling a Comprehensive Emission Control Inventory (Revised)," Environmental Protection Agency, Research Triangle Park, N. C., Publication No. APTD - 1135, March 1973.

4. "Field Surveillance and Enforcement Guide for Petroleum Refineries (Final Draft)," prepared by The Ben Holt Co., Pasadena, California for Environmental Protection Agency, Research Triangle Park, N. C., July 1973.

7.0 PERFORMANCE TEST

7.1 PROCESS OPERATING CONDITIONS

To comply with NSPS, it is not necessary for source testing to be conducted on petroleum liquid vessels, however, certain design features must be inspected to determine that adequate provision has been made for minimization of hydrocarbon emissions to the atmosphere.

Petroleum liquids are classified for storage purposes according to their vapor pressures. Inspectors must determine that the following conditions are met:

- Vessels used to store petroleum liquids having true vapor pressures between 78 mm Hg (1.5 psia) and 570 mm Hg (11.1 psia) must be of the "floating roof" design or be equipped with a vapor recovery system or equivalent.

- Vessels used to store petroleum liquids having a true vapor pressure in excess of 570 mm Hg (11.1 psia) must be equipped with a vapor recovery system or equivalent vapor reclaiming system.

7.2 PROCESS OBSERVATIONS

Processes related to petroleum liquid vessels are basically two: storage and working (filling and draining). Emissions from storage of such liquids result from "breathing" losses caused by thermal expansion and contraction of the liquid and its container, while the working losses result from the transfer of bulk liquid to and from the vessel. Process observations of these operations during an inspection are very limited. During loading and unloading operations, however, the inspector should attempt to uncover any leakage problems.

There are several means easily available to the IO which will aid him in determining whether or not a leak exists. The presence of an odor may indicate escaping gas, as well as hissing sounds and heat plumes. Stains on paint surfaces could indicate a leak in the tank wall. The IO can be prepared to verify any suspicions by having access to gas testing equipment such as explosimeters and by carrying soap or other bubbling solutions which could be applied to a suspected leak.

During the course of the process observation, actual sampling and analysis of the tank contents should be made to verify that the material being handled is being stored in an acceptable manner. If at all possible, the seal gaps at various liquid heights should be measured to determine how much of the gapping, if any, can be attributed to tank out-of-round conditions.

7.3 EQUIPMENT OBSERVATIONS

While no defined provisions exist for emission testing of storage vessels for petroleum liquids, inspectors should check the existing storage facilities to make sure they are being properly used and in good repair.

If the true vapor pressure of the liquid being stored or worked is between 78 mm Hg and 570 mm Hg (1.5 psia and 11.1 psia), the storage vessel must be of the "floating roof" design or be equipped with a vapor recovery system or an equivalent. In cases where the liquid being stored or worked has a true vapor pressure in excess of 570 mm Hg (11.1 psia), the vessel must be equipped with a vapor recovery system or equivalent vapor reclaiming system.

Tanks and vessels used to store petroleum liquids with true vapor pressure 78 mm Hg (1.5 psia) and greater should be painted and maintained such that excessive temperature and vapor pressure increases are prevented. Paint should be continuous and of a heat-reflective nature. Check all seals on the floating roof (usually these are of a rubberized fabric type) for continuity and to make sure no deterioration or wear has caused seals to develop holes or gaps. Many times these seals will have a metal shield to protect seal from sharp objects; these shields should be checked for completeness and to make sure that they are not deformed so as to interfere with the function of the seal. All gauging and sampling devices should be checked to make certain that seals are effective at all times except when sampling and gauging is taking place.

The anti-rotational stabilizers should be inspected to ensure proper operation. Water drainage ducts should be examined for the presence of oil.

7.3.1 Emission Monitoring

No provisions for instrumental monitoring of hydrocarbon vapors are established. Certain records must be maintained, however, which can be used to determine emissions for a particular period of time, should the need arise. Such records must be kept on file at least two (2) full calendar years.

The records required to be maintained are the bulk petroleum liquid temperature and true vapor pressure of petroleum liquid at bulk liquid temperature. Monthly summaries should be kept of the following information: type of petroleum liquid being handled, true vapor pressure and bulk liquid temperature. If Reid vapor pressures are maintained, they should have been determined according to ASTM method D-323-58. True vapor pressure may be obtained from the Reid vapor pressure if the storage temperature of the material is known (see Figure 2.1 of this manual).

REFERENCES FOR CHAPTER 7

1. Federal Register, Vol. 36, December 23, 1971.

2. Federal Register, Vol. 38, No. 111, June 11, 1973.

3. "Field Surveillance and Enforcement Guide for Petroleum Refineries (Final Draft)," prepared by the Ben Holt Co., Pasadena, California for Environmental Protection Agency, Research Triangle Park, N. C., July, 1973.

APPENDIX

Subpart J—Standards of Performance for Petroleum Refineries 5

§ 60.100 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: Fluid catalytic cracking unit catalyst regenerators, fluid catalytic cracking unit incinerator-waste heat boilers, and fuel gas combustion devices.

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) "Process gas" means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) "Fuel gas" means any gas which is generated by a petroleum refinery process unit and which is combusted, including any gaseous mixture of natural gas and fuel gas which is combusted.

(e) "Process upset gas" means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) "Refinery process unit" means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) "Fuel gas combustion device" means any equipment, such as process heaters, boilers and flares used to combust fuel gas, but does not include fluid coking unit and fluid catalytic cracking unit incinerator-waste heat boilers or facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) "Coke burn-off" means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

§ 60.102 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator or from any fluid catalytic cracking unit incinerator-waste heat boiler:

(1) Particulate matter in excess of 1.0 kg/1000 kg (1.0 lb/1000 lb) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting 30 percent opacity or greater, except for 3 minutes in any 1 hour. 18

(b) In those instances in which auxiliary liquid or solid fossil fuels are burned in the fluid catalytic cracking unit incinerator-waste heat boiler, particular matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate emissions shall not exceed 0.18 g/million cal (0.10 lb/million Btu) of heat input attributable to such liquid or solid fuel.

§ 60.103 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from the fluid catalytic cracking unit catalyst regenerator any gases which contain carbon monoxide in excess of 0.050 percent by volume.

§ 60.104 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall burn in any fuel gas combustion device any fuel gas which contains H_2S in excess of 230 mg/dscm (0.10 gr/dscf), except as provided in paragraph (b) of this section. The combustion of process upset gas in a flare, or the combustion in a flare of process gas or fuel gas which is released to the flare as a result of relief valve leakage, is exempt from this paragraph.

(b) The owner or operator may elect to treat the gases resulting from the combustion of fuel gas in a manner which limits the release of SO_2 to the atmosphere if it is shown to the satisfaction of the Administrator that this prevents SO_2 emissions as effectively as compliance with the requirements of paragraph (a) of this section.

§ 60.105 Emission monitoring.[18]

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator as follows:

(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator. The continuous monitoring system shall be spanned at 60, 70, or 80 percent opacity.

(2) [Reserved]

(3) A continuous monitoring system for the measurement of sulfur dioxide in the gases discharged into the atmosphere from the combustion of fuel gases (except where a continuous monitoring system for the measurement of hydrogen sulfide is installed under paragraph (a)(4) of this section). The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be sulfur dioxide (SO_2). The span shall be set at 100 ppm. For conducting monitoring system performance evaluations under § 60.13(c), Reference Method 6 shall be used.

(4) [Reserved]

(b) [Reserved]

(c) The average coke burn-off rate (thousands of kilogram/hr) and hours of operation for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102 or 60.103 shall be recorded daily.

(d) For any fluid catalytic cracking unit catalyst regenerator which is subject to § 60.102 and which utilizes an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil fuels (liters/hr or kilograms/hr) and the hours of operation during which liquid or solid fossil fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) [Reserved]

(2) [Reserved]

(3) [Reserved]

(4) Any six-hour period during which the average emissions (arithmetic average of six contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the standard under § 60.104.

§ 60.106 Test methods and procedures.

(a) For the purpose of determining compliance with § 60.102(a)(1), the following reference methods and calculation procedures shall be used:

(1) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 5 for the concentration of particulate matter and moisture content,

(ii) Method 1 for sample and velocity traverses, and

(iii) Method 2 for velocity and volumetric flow rate.

(2) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) For exhaust gases from the fluid catalytic cracking unit catalyst regenerator prior to the emission control system: the integrated sample techniques of Method 3 and Method 4 for gas analysis and moisture content, respectively; Method 1 for velocity traverses; and Method 2 for velocity and volumetric flow rate.

(4) Coke burn-off rate shall be determined by the following formula:

$$R_c = 0.2982\,Q_{RE}\,(\%CO_2+\%CO) + 2.088\,Q_{RA} - 0.0994\,Q_{RE}\left(\frac{\%CO}{2}+\%CO_2+\%O_2\right) \text{ (Metric Units)}$$

or

$$R_c = 0.0186\,Q_{RE}\,(\%CO_2+\%CO) + 0.1303\,Q_{RA} - 0.0062\,Q_{RE}\left(\frac{\%CO}{2}+\%CO_2+\%O_2\right) \text{ (English Units)}$$

where:

R_c = coke burn-off rate, kg/hr (English units: lb/hr).
0.2982 = metric units material balance factor divided by 100, kg-min/hr-m^3.
0.0186 = English units material balance factor divided by 100, lb-min/hr-ft^3.
Q_{RE} = fluid catalytic cracking unit catalyst regenerator exhaust gas flow rate before entering the emission control system, as determined by method 2, dscm/min (English units: dscf/min).
$\%CO_2$ = percent carbon dioxide by volume, dry basis, as determined by Method 3.
$\%CO$ = percent carbon monoxide by volume, dry basis, as determined by Method 3.
$\%O_2$ = percent oxygen by volume, dry basis, as determined by Method 3.
2.088 = metric units material balance factor divided by 100, kg-min/hr-m^3.
0.1303 = English units material balance factor divided by 100, lb-min/hr-ft^3.
Q_{RA} = air rate to fluid catalytic cracking unit catalyst regenerator, as determined from fluid catalytic cracking unit control room instrumentation, dscm/min (English units: dscf/min).
0.0994 = metric units material balance factor divided by 100, kg-min/hr-m^3.
0.0062 = English units material balance factor divided by 100, lb-min/hr-ft^3.

(5) Particulate emissions shall be determined by the following equation:

$$R_E = (60\times10^{-6})\,Q_{RV}\,C_s \text{ (Metric Units)}$$

or

$$R_E = (8.57\times10^{-3})\,Q_{RV}\,C_s \text{ (English Units)}$$

where:

R_E = particulate emission rate, kg/hr (English units: lb/hr).
60×10^{-6} = metric units conversion factor, min-kg/hr-mg.
8.57×10^{-3} = English units conversion factor, min-lb/hr-gr.
Q_{RV} = volumetric flow rate of gases discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator following the emission control system, as determined by Method 2, dscm/min (English units: dscf/min).
C_s = particulate emission concentration discharged into the atmosphere, as determined by Method 5, mg/dscm (English units: gr/dscf).

(6) For each run, emissions expressed in kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the catalyst regenerator shall be determined by the following equation:

$$R_s = 1000\frac{R_E}{R_c} \text{ (Metric or English Units)}$$

where:

R_s = particulate emission rate, kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1000 = conversion factor, kg to 1000 kg (English units: lb to 1000 lb).
R_E = particulate emission rate, kg/hr (English units: lb/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(7) In those instances in which auxiliary liquid or solid fossil fuels are burned in an incinerator-waste heat boiler, the rate of particulate matter emissions permitted under § 60.102(b) must be determined. Auxiliary fuel heat input, expressed in millions of cal/hr (English units: Millions of Btu/hr) shall be calculated for each run by fuel flow rate measurement and analysis of the liquid or solid auxiliary fossil fuels. For each run, the rate of particulate emissions permitted under § 60.102(b) shall be calculated from the following equation:

$$R_s = 1.0 + \frac{0.18\,H}{R_c} \text{ (Metric Units)}$$

or

$$R_s = 1.0 + \frac{0.10\,H}{R_c} \text{ (English Units)}$$

where:

R_s = allowable particulate emission rate, kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1.0 = emission standard, 1.0 kg/1000 kg (English units: 1.0 lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
0.18 = metric units maximum allowable incremental rate of particulate emissions, g/million cal.
0.10 = English units maximum allowable incremental rate of particulate emissions, lb/million Btu.
H = heat input from solid or liquid fossil fuel, million cal/hr (English units: million Btu/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(b) For the purpose of determining compliance with § 60.103, the integrated sample technique of Method 10 shall be used. The sample shall be extracted at a rate proportional to the gas velocity at a sampling point near the centroid of the duct. The sampling time shall not be less than 60 minutes.

(c) For the purpose of determining compliance with § 60.104(a), Method 11 shall be used. When refinery fuel gas lines are operating at pressures substantially above atmospheric, the gases sampled must be introduced into the sampling train at approximately atmospheric pressure. This may be accomplished with a flow control valve. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For most fuel gases, sample times exceeding 20 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.

(d) Method 6 shall be used for determining concentration of SO_2 in determining compliance with § 60.104(b), except that H_2S concentration of the fuel gas may be determined instead. Method 1 shall be used for velocity traverses and Method 2 for determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 6 shall be the same as for determining volumetric flow rate by Method 2. The sampling point in the duct for determining SO_2 concentration by Method 6 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals.

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids[5]

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for ~~the crude~~ petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.[8]

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Storage vessel" means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Number 2 through Number 6 fuel oils as specified in A.S.T.M. D396–69, gas turbine fuel oils Numbers 2–GT through 4–GT as specified in A.S.T.M. D2880–71, or diesel fuel oils Numbers 2–D and 4–D as specified in A.S.T.M. D975–68.[8]

(c) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.[8]

(e) "Hydrocarbon" means any organic compound consisting predominantly of carbon and hydrogen[6]

(f) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.[8]

(h) "Drilling and production facility" means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of petroleum but does not include natural gasoline plants.[8]

(i) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(j) "Floating roof" means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) "Vapor recovery system" means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM–D–323–58 (reapproved 1968).

§ 60.112 Standard for hydrocarbons.

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

§ 60.113 Monitoring of operations.

(a) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel maintain a file of each type of petroleum liquid stored, of the typical Reid vapor pressure of each type of petroleum liquid stored, and of the dates of storage. Dates on which the storage vessel is empty shall be shown.

(b) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel determine and record the average monthly storage temperature and true vapor pressure of the petroleum liquid stored at such temperature if:

(1) The petroleum liquid has a true vapor pressure, as stored, greater than 26 mm Hg (0.5 psia) but less than 78 mm Hg (1.5 psia) and is stored in a storage vessel other than one equipped with a floating roof, a vapor recovery system or their equivalents; or

(2) The petroleum liquid has a tru[e] vapor pressure, as stored, greater tha[n] 470 mm Hg (9.1 psia) and is stored i[n] a storage vessel other than one equippe[d] with a vapor recovery system or it[s] equivalent.

(c) The average monthly storage tem[-]perature is an arithmetic average cal[-]culated for each calendar month, or por[-]tion thereof if storage is for less than [a] month, from bulk liquid storage tem[-]peratures determined at least onc[e] every 7 days.

(d) The true vapor pressure shall b[e] determined by the procedures in AP[I] Bulletin 2517. This procedure is de[-]pendent upon determination of th[e] storage temperature and the Reid vapo[r] pressure, which requires sampling of th[e] petroleum liquids in the storage vessel[s]. Unless the Administrator requires i[n] specific cases that the stored petroleu[m] liquid be sampled, the true vapor pres[-]sure may be determined by using th[e] average monthly storage temperatur[e] and the typical Reid vapor pressure. Fo[r] those liquids for which certified specifi[-]cations limiting the Reid vapor pressur[e] exist, that Reid vapor pressure may b[e] used. For other liquids, supporting ana[-]lytical data must be made available o[n] request to the Administrator when typi[-]cal Reid vapor pressure is used.

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16. ABSTRACT

The purpose of this document is to assist air pollution agencies in the enforcement of Federal new source performance standards (NSPS) for volatile organic storage tanks. The manual actually serves a twofold purpose in that it outlines the requirements of the regulations and also describes methods for conducting inspections of tanks to verify their compliance with these requirements.

The NSPS regulations are applicable to storage tanks of 40,000 gals capacity or greater storing organic material of greater than 0.5 psia true vapor pressure. The standards are written in terms of the type of roof required and the type of records to be kept on file based upon the volatility of the material stored. The various types of tanks are described in the manual so that the inspection officer can recognize which tanks are affected by the standards during an on-site inspection. A checklist is included to be used to gather tank data, and procedures are outlined which allow the inspector to monitor and verify proper performance test conditions.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
POL Storage Vapor Pressure Standards	New Source Performance Standards Inspection Procedures Volatile Organic Storage Performance Testing	1308/0703 0704 1407

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