Specification for Vertical and Horizontal Emulsion Treaters

API SPECIFICATION 12L
FIFTH EDITION, OCTOBER 2008

EFFECTIVE DATE: APRIL 1, 2009

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Upstream Segment

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Specification for Vertical and Horizontal Emulsion Treaters

1 Scope

1.1 General

This specification covers minimum requirements for material, design, fabrication, and testing of vertical and horizontal emulsion treaters. The jurisdiction of this specification terminates with each pressure vessel as applicable: the emulsion treater with firetube(s) and, if used, the heat exchanger(s) and water siphon. Pressure vessels covered by this specification are classified as natural resource vessels by API 510, *Pressure Vessel Inspection Code*. An emulsion treater is a pressure vessel used in the oil producing industry for separating oil-water emulsions and gas, and for breaking or resolving emulsified well streams into water and saleable clean oil components. Emulsion treaters are usually equipped with one or more removable firetubes or heat exchange elements through which heat is applied to the water and/or emulsion to aid the emulsion breaking process.

1.2 Background

Emulsion treating is normally conducted on crude oil immediately after it is separated from its associated gas in a vessel referred to as a treater or sometimes as a heater treater. High gas-oil ratio wells or those produced by gas lift may require the installation of an oil and gas separator upstream of the treater to remove most of the associated gas before the emulsion enters the treater. Where the water to oil ratio is high, Freewater knockouts may be required upstream of the treater. The function of the treater is to dehydrate (or dewater) the produced crude oil to a specified level of basic sediment and water (BS&W). Oil-water separation may be enhanced by heating, emulsion breaking chemicals, coalescing media, and/or electrostatic fields in vessels sized for substantial liquid residence time. Process considerations are covered in Annex A. Refer to Figure 1, Figure 2 and Figure 3, which show general arrangements of components, piping and instrumentation. (Some of the illustrated features are considered optional.)

2 References

API Specification 5L, *Specification for Line Pipe*

API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

API Standard 2000, *Venting Atmospheric and Low-Pressure Storage Tanks: Nonrefrigerated and Refrigerated*

ASME B1.1 [1], *Unified Inch Screw Threads, (UN and UNR Thread Form)*

ASME B16.5, *Pipe Flanges and Flanged Fittings*

ASME B16.11, *Forged Steel Fittings, Socket-Welding and Threaded*

ASME B18.2.1, *Square and Hex Bolts and Screws, Inch Series*

ASME B18.2.2, *Square and Hex Nuts*

ASME B31.1, *Process Piping*

ASME *Boiler and Pressure Vessel Code, Section IX—Welding and Brazing Qualifications*

ASME *Boiler and Pressure Vessel Code, Section VIII, Division 1—Rules for Construction of Pressure Vessels*

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[1] ASME International, 3 Park Avenue, New York, New York 10016, www.asme.org.

ASTM A36 [2], *Standard Specification for Carbon Structural Steel*

ASTM A36P, *Standard Specification for Carbon Structural Steel: Plates*

ASTM A53, *Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless*

ASTM A105, *Standard Specification for Carbon Steel Forgings for Piping Applications*

ASTM A106, *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service*

ASTM A123, *Standard Specification for Zinc (Hot-Dip Galvanized) Coatings on Iron and Steel Products*

ASTM A153, *Standard Specification for Zinc Coating (Hot-Dip) on Iron and Steel Hardware*

ASTM A181, S*tandard Specification for Carbon Steel Forgings, for General-Purpose Piping*

ASTM A216, *Standard Specification for Steel Castings, Carbon, Suitable for Fusion Welding, for High-Temperature Service*

ASTM A283, *Low and Intermediate Tensile Strength Carbon Steel Plates of Structural Quality*

ASTM A285, *Standard Specification for Pressure Vessel Plates, Carbon Steel, Low- and Intermediate-Tensile Strength*

ASTM A307, *Standard Specification for Carbon Steel Bolts and Studs, 60,000 PSI Tensile Strength*

ASTM A1011, *Standard Specification for Steel, Sheet and Strip, Hot-Rolled, Carbon, Structural, High- Strength Low-Alloy, High-Strength Low-Alloy with Improved Formability, and Ultra-High Strength*

ASTM B454, *Specification for Mechanically Deposited Coatings/Cadmium/Zinc on Ferrous Metal*

AWS A 5.1 [3], *Specification for Carbon Steel Electrodes for Shielded Metal Arc Welding*

NACE RP 0372 [4], *Method for Lining Lease Production Tanks with Coal Tar Epoxy*

NFPA No. 30 [5], *Flammable and Combustible Liquids Code*

3 Definitions

3.1
basic sediment and water
BS&W
Commonly used as a measure of treating performance.

NOTE Treating performance is highly variable, but most crude oils are treated to a range of 0.2% to 3.0% BS&W. ASTM Standard Test No. D96-82 is an accepted standard for this test.

[2] ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.
[3] American Welding Society, 550 N.W. LeJeune Road, Miami, Florida 33126, www.aws.org.
[4] NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.
[5] National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.

3.2
burner system
A system of firing accessories, including treater firetubes designed for the specific fuel and may be either natural or forced draft design.

NOTE Intake flame arrestors and other optional burner accessories as listed in Annex G may also be included.

3.3
coalescing
Process of causing small dispersed water-in-oil or oil-in-water droplets to combine into larger droplets which are easier to separate by gravity.

NOTE Coalescing sections provide large surface areas per unit of volume and usually consist of fibrous beds such as excelsior (referred to as hay sections), or compartments of specially designed components. Electrostatic fields are another means of inducing, coalescence, commonly referred to as electrostatic treating.

3.4
collector pipe
Perforated or slotted pipe near the top of the coalescing section in a treater to remove the treated oil as uniformly as possible through this portion of the treater.

3.5
desalting
A form of emulsion treating which may be identical to conventional treaters with the addition of supplemental injection and mixing of low salinity water into the feed emulsion to dilute the brine phase and thereby lower the salt content of the treated crude.

NOTE Desalting is used both in oil producing areas and refineries. It may consist of one or more stages to achieve maximum desalting efficiency.

3.6
design pressure
Pressure used in the design of a vessel for the purpose of determining the minimum permissible thickness or physical characteristics of the different parts of the vessel.

NOTE When applicable, static head shall be added to the design pressure to determine the thickness of any specific part of the vessel.

3.7
electrostatic treater
Emulsion treating vessel that utilizes an electrical grid and usually a fire tube to coalesce the fluid. This type of treater usually operates at lower temperatures than ones without grids.

3.8
emulsion
Relatively stable dispersion of water and oil which normally exists in the production stream from flowing or pumped oil wells.

3.9
firebox
Complete assembly consisting of the firetube(s), mounting flange(s), intake(s) and stack adapters.

3.10
firetube
Portion of the firebox in contact with the liquids consisting of one or more U-tubes fired at one end and exhausting through a vertical stack for each U-tube.

NOTE Natural gas or hydrocarbon liquids are normally used to fire the treater through a submerged furnace chamber called the firetube. In larger treaters the firetube may consist of a large diameter first pass firetube and multiple return tubes manifolded into a common stack.

3.11
grid
Electric field in electrostatic treater that is distributed by a steel assembly of plates, rods, screens or combinations of these, which enhances coalescing of the water droplets.

NOTE The grid does not provide heat. The projected grid area is significant to the performance and capacity of the treater.

3.12
heat density
Term commonly applied to the heat release through the cross section of the firetube, expressed as BTU/hr/in.^{2} of cross sectional area.

3.13
heat duty
Heat absorbed by the process, expressed as BTU/hr.

3.14
heat exchanger
Shell-and-tube, plate type or other heat exchanger optionally employed to recover heat from the heated crude oil by preheating the incoming emulsion.

3.15
heat flux
Term commonly applied to the average heat transfer rate through the firetube, expressed as BTU/hr/ft^2 of exposed area.

3.16
heating shroud or hood
Baffle surrounding firetubes in treaters designed to increase emulsion heating efficiency by minimizing the heating of free water which separates from the emulsion before heating.

3.17
intake flame arrestor
Device placed on the air intake of the firetube to prevent propagation of flame from inside the firetube to the outside atmosphere, normally consisting of a corrugated aluminum cell mounted in a metal housing which attaches to the firebox.

3.18
interface drain
Pipe connection extending to the normal interface level with a vortex breaker which is used periodically to drain off any accumulated sludge.

3.19
liquid (fluid) packed
Condition in horizontal treaters where the coalescing section or entire treater operates completely full of liquid.

3.20
maximum allowable working pressure
MAWP
Maximum gage pressure permissible at the top of a completed vessel in its operating position for a designated temperature, based on calculations for every element of the vessel using nominal thicknesses exclusive of allowances for corrosion and thickness required for loadings other than pressure.

NOTE This is the basis for the pressure setting of the pressure relieving devices protecting the vessel.

3.21
mid-baffle
Bulkhead in horizontal emulsion treaters, located between the heating section and the coalescing section.

3.22
operating pressure
Pressure at the top of a pressure vessel at which it normally operates, not exceeding the MAWP and usually kept at a suitable level below the setting of the pressure relieving devices to prevent their frequent opening.

3.23
pounds per thousand barrels
PTB
Pounds of salt per thousand barrels of crude oil, used in conjunction with BS&W to express the quality of untreated and treated crude oils in relation to desalting applications of emulsion treaters.

3.24
removable
Total component that is field replaceable without welder assistance.

3.25
sand jets
System of one or more perforated pipes, or nozzles, located near the bottom of emulsion treaters which is used periodically to clean out sediments by flushing with water.

3.26
sand pans
Inverted angle baffles or troughs located above the sand (sediment) outlet connections to facilitate uniform sand or sediment removal, with notches in the troughs or pans to increase the velocity of the water leaving the vessel to prevent bridging.

3.27
spark arrestor
Device placed on the exhaust of the stack to prevent sparks from being emitted to the outside atmosphere, normally consisting of a metallic wire screen attached across the top diameter of the stack.

3.28
spreader(s)
Device or system designed to distribute the incoming emulsion as uniformly as practical through the cross section of the vertical or horizontal shell.

3.29
stack downdraft diverter
Device attached to the top of the stack designed to reduce the effects of wind currents on the burner system.

3.30
stack flame arrestor
Device placed on the exhaust of the stack to prevent propagation of flame from inside the firetube to the outside atmosphere, normally consisting of a corrugated aluminum or stainless steel cell mounted in a metal housing which attaches to the top of the stack.

3.31
stack rain shield
Device attached to the top of the stack to prevent rain from falling directly into the stack. It may also serve as a stack downdraft diverter.

3.32
treating
Separation of gas, oil and water from emulsified well streams by gravity and enhanced means of breaking emulsions such as heating, chemical and/or coalescing sections.

3.33
turbolaters
Core of baffles designed to induce turbulence in the return leg of firetubes which enhances heat transfer efficiency.

3.34
vortex breaker
Device located on outlet nozzles to prevent vortex formation.

3.35
water siphon (water leg, grasshopper)
Piping system for the controlled flow of water from the treater which sets the water/oil interface level within the treater, where the water flows through a vertical loop of piping set at an adjustable level below the treater oil level with the top of the loop equalized in pressure with the gas zone of the treater.

4 Material

4.1 ASME Code

All material used in the fabrication of emulsion treaters, including firetubes, siphons and heat exchangers included in the scope of this specification shall comply with the material requirements of the latest edition of Section VIII, Division 1 of the ASME *Boiler and Pressure Vessel Code*, hereinafter referred to as the ASME Code.

4.2 Non-pressure Parts

Steel parts such as stacks, ladders and platforms not welded directly to the ASME Code vessel shall be weldable carbon steels, selected from ASTM, API or AISI specifications. Corrosion resistant materials such as reinforced plastic may be used inside the vessel or inside the water siphons for non-pressure service.

4.3 Material Selection

Materials for corrosive fluids should be selected based on a review of NACE publications for materials that conform to 4.1. Consideration should be given to material selection as it relates to weight loss corrosion, sulfide stress cracking (SSC), chloride stress cracking, or other forms of corrosion. It is the responsibility of the user to determine what consideration for corrosion should be made to the vessel during its intended life (reference ASME Code, Section VIII, as applicable to corrosion.) Corrosion control guidelines are given in Annex B.

4.4 Corrosion

Corrosion control consideration for treaters furnished to this specification shall be for the pressure containing parts and as can be identified as falling within the requirements of the applicable sections of the ASME Code. Corrosion control considerations for vessel internals (non-pressure parts and fire-tube) is by mutual agreement between the purchaser and the manufacturer and not a part of this specification.

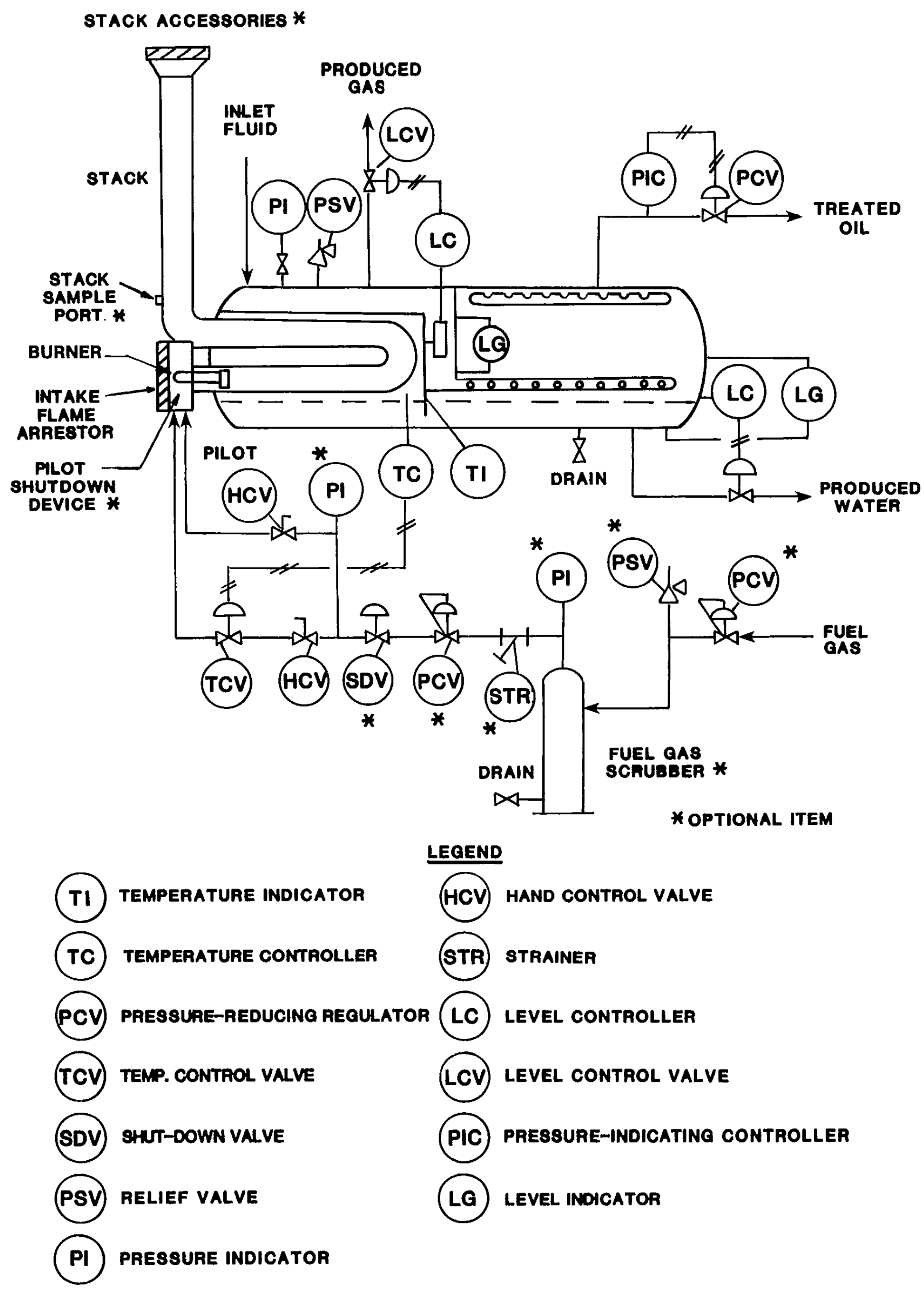
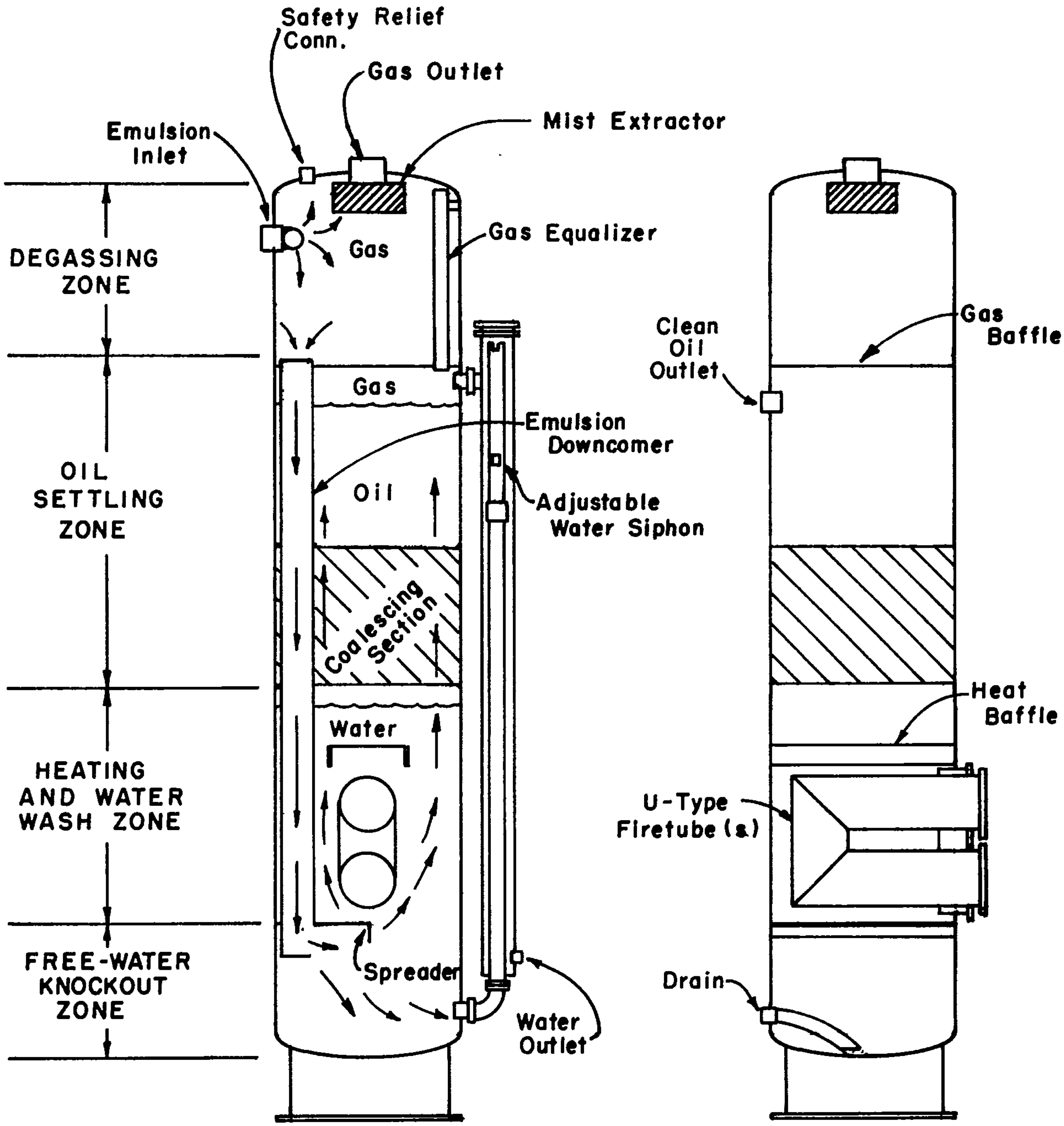
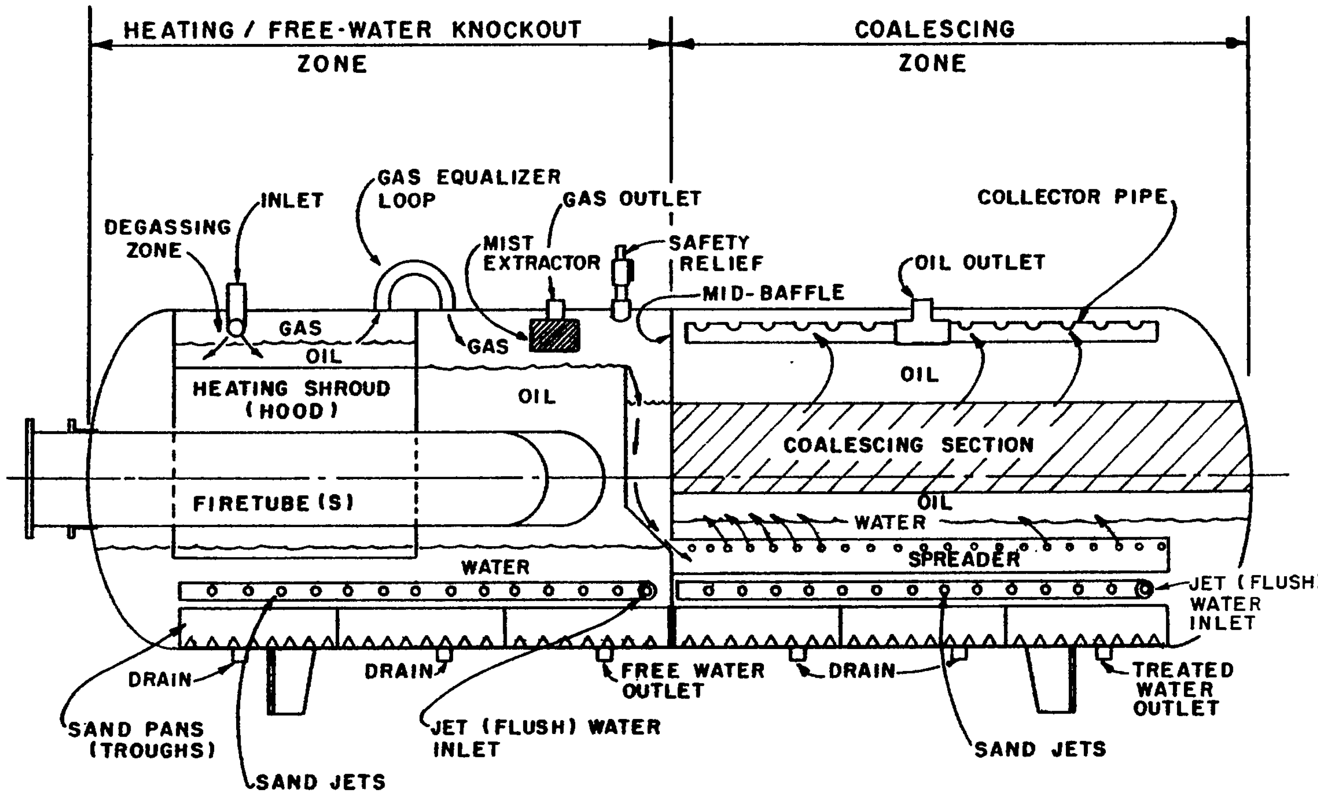


Figure 1—Typical Treater Assembly



NOTE Many variations of design are available from different manufacturers.

Figure 2—Typical Vertical Treater



NOTE Many variations of design are available from different manufacturers.

Figure 3—Typical Fluid Packed Horizontal Treater

5 Design

5.1 Type, Size, Pressure and Temperature Ratings

Treaters furnished to this specification are vertical or horizontal and are available in sizes and pressure ratings shown in Table 1 and Table 2 as nominal industry standards. Other sizes and pressure ratings may be furnished by agreement between purchaser and manufacturer. Maximum design temperature may be limited by flange ratings or the gasket material. Refer to the applicable sections of the ASME Code for design temperatures below –20°F.

Table 1—Typical Vertical Treater Dimensions and Pressures

Outside Diameter ft	**Shell Length Head Seam to Head Seam** ft, ± 6 in.	**Minimum Design Pressure** psig
3	10, 12 or 15	50
4	10, 12, 20 or 27 1/2	50
6	12, 20 or 27 1/2	50
8	20 or 27 1/2	40
10	20 or 27 1/2	40

Table 2—Typical Horizontal Treater Dimensions and Pressures

Outside Diameter ft	Shell Length Head Seam to Head Seam ft, ± 6 in.	Minimum Design Pressure psig
3	10, 12 or 15	50
4	10, 12 or 15	50
6	10, 15 or 20	50
8	15, 20, 25 or 30	50
10	20, 30, 40, 50 or 60	50
12	30, 40, 50 or 60	50

5.2 Firebox Rating

Some recommended firebox ratings for vertical and horizontal emulsion treaters furnished to this specification are listed in Table 3.

Table 3—Typical Firebox Ratings

Outside Diameter ft	Vertical		Horizontal	
	Minimum Area ft^2	Heat Duty BTU/hr	Minimum Area ft^2	Heat Duty BTU/hr
3	10	100,000	15	150,000
4	25	250,000	25	250,000
6	50	500,000	50	500,000
8	100	1,000,000	75	750,000
10	125	1,250,000	200	2,000,000
12	—	—	320	3,200,000

5.3 Firetube Heat Flux

The average heat flux shall be no higher than 10,000 BTU hr/ft^2 of exposed area.

EXAMPLE

8 5/8-in. OD, Sch. 20, 0.25-in. wall firetube having 25.0 ft^2 of firetube surface, 51.85 in.^{2} cross sectional area and rated @ 250,000 BTU/hr.

$$\text{Average Heat Flux} = \frac{\text{Firetube Ratings (BTU/hr)}}{\text{ft}^2 \text{ of Firetube Surface}} = \frac{250{,}000}{25.0} = 10{,}000 \text{ BTU/hr/ft}^2$$

5.4 Firetube Heat Density

Heat released through the cross-sectional area of the firetube is regulated by the burner mixer and burner nozzle. Treaters conforming to this specification will have a maximum heat density of 15,000 BTU/hr/in.^{2} for natural draft burners.

EXAMPLE from 5.3

$$\text{Heat Density} = \frac{\text{Firetube Rating (BTU/hr)}}{(\text{Cross Sectional Area, in.}^2)(\text{Efficiency})} = \frac{250{,}000}{51.85 \times 0.70} = 6{,}888 \text{ BTU/hr/in.}^2$$

5.5 Firetube

The wall thickness of the firetube shall be established as required by the ASME Code rules, including but not limited to design rules for vessels subject to external pressure and vessels subject to direct firing and shall be not less than $^{3}/_{16}$ in. for vertical treaters and $^{1}/_{4}$ in. for horizontal treaters. Corrosion allowance is not normally added to the firetube wall thickness.

5.6 Stack Height

The height of the stack shall be no less than required to provide draft sufficient to overcome the pressure drop in firetube, stack, returns, turbolaters and any stack or flame arrestors. The operating site elevation shall be considered in the draft calculations. The purchaser shall advise the manufacturer of the site elevation.

5.7 Additional Information

A suggested checklist of information for treater design is included in Annex C.

Typical design and sizing calculations are given in Annex D.

Annex E gives an example calculation for treater sizing.

6 Fabrication, Testing and Painting

6.1 Fabrication

Emulsion treaters, including firetube(s), heat exchangers and water siphons (6 in. nominal and larger if used), shall be shop constructed, tested, and stamped in accordance with the latest edition of ASME Code, Section VIII, Division 1. Water siphons smaller than 6 in. shall be designed and constructed in accordance with ASME B31.3. Additional testing for internal leaks, seal welding, etc., may be required by agreement between the purchaser and manufacturer.

6.2 Painting

Before shipment, equipment covered by this specification shall be cleaned of rust, grease, scale, and weld spatter, and externally coated with one application of a good grade of commercial metal primer. Internal coating and finish coating shall be applied if so agreed upon between the purchaser and manufacturer.

6.3 Internal Coating

Where internal coating is specified by the purchaser, all non-removable internal attachments shall be seal welded and prepared for coating in accordance with the purchaser's specifications. In the absence of purchaser's specifications, some acceptable practices are listed in Annex B. After coating, the vessel shall be stenciled in a conspicuous location "Internal Coating—Do Not Weld."

6.4 Preparation for Shipment

Prior to shipment all foreign matter (including hydro-test water) shall be removed from the vessel, both internally and externally. All openings shall be protected with shipping covers or plugs.

7 Marking

7.1 API Nameplate

Emulsion treaters furnished to this specification shall be identified by a nameplate of corrosion resistant material securely attached to the shell or to a suitable bracket seal welded to the shell. The nameplate shall bear the information in items 1 through 11 below, as shown in Figure 4:

1) Specification 12L;
2) manufacturer's name;
3) manufacturer's serial number;
4) year built;
5) weight empty, in pounds;
6) shell size, outside diameter, length seam-to-seam, in feet;
7) design pressure, in pounds per square inch at temperature degrees Fahrenheit;
8) firebox rating, in British thermal units per hour;
9) firebox surface area, in square feet;
10) additional information required by State or other political subdivision regulations;
11) additional markings desired by the manufacturer or requested by the purchaser are not prohibited.

Manufactured in Accordance with API Specification 12L

Manufacturer ________________________________

Serial Number ________________________________

Year Built ________________________________

Vessel Weight Empty ________________________________ lb

Shell Size ________________________________ OD (in ft) x length (in ft)

Design Pressure ________________________________ oz

Firebox Rating ________________________________ BTU/hr

Firebox Surface Area ________________________________ ft^2

____

____

Figure 4—Emulsion Treater Nameplate

7.2 ASME Code Nameplate

Emulsion treaters furnished to this specification shall have a nameplate affixed to the vessel as required by the latest edition of the ASME Code. If allowed by the ASME Code, the information required by 7.1 may be included on the ASME nameplate, otherwise two nameplates are required.

Stamping directly on the treater shell may be injurious to the treater and is not permitted under this specification.

8 Inspection and Rejection

8.1 ASME Code Inspection

The authorized inspector required by the ASME Code shall make all inspections specifically required of him/her by the Code plus such other inspection as they believe necessary to enable them to certify that all vessels which they authorize to be stamped with the Code symbol meet all of the applicable requirements of the Code. The authorized inspector shall sign the Certificate of Inspection on the manufacturers data report when the vessel, to the best of their knowledge and belief, is complete and is in compliance with all of the provisions of the Code.

8.2 Inspection Notice

Where additional inspection is required by the purchaser, the extent of such inspection should be stated on the purchase order. Where the inspector representing the purchaser desires to inspect vertical and horizontal emulsion treaters purchased or witness any specification tests or evaluate the results of any nondestructive examinations, the manufacturer shall give reasonable notice of the time at which such inspections should be made.

8.3 Inspection by Purchaser

While work on the contract of the purchaser is being performed, the inspector representing the purchaser shall have free entry at all times to all parts of the manufacturer's works which concern the manufacture of the material ordered. The manufacturer shall afford, without charge, all reasonable facilities to satisfy the inspector that the material is being manufactured in accordance with this specification. All inspections shall be made at the place of manufacture prior to shipment, unless otherwise specified on the purchase order; and shall be so conducted as not to interfere unnecessarily with the manufacturer's operations.

8.4 Compliance

The manufacturer shall be responsible for complying with all of the provisions of this specification. The purchaser may make any investigation necessary to satisfy themselves of compliance by the manufacturer and may reject any material that does not comply with this specification.

Annex A
(informative)

Process Considerations

A.1 Gas Separation

For either vertical or horizontal treaters the gas separation portion must be adequate for the design flow conditions. Mist extractors may be used on the outlet gas connection when the gas separation zone is operated at high loading or surging conditions. Gas separation sizing assistance may be found in API 12J.

A.2 Heating

For efficient emulsion breaking it is generally recommended that the oil viscosity within the coalescing section of the treater not exceed 150 Saybolt universal seconds (SSU). Emulsion heating with one or more firetubes may be required to maintain this viscosity limit. Emulsion heating may also be required to eliminate wax or bitumen as particulate matter that would tend to accumulate at the interface. The required treating temperatures are typically in the range of 100°F to 250°F depending on the above described factors. The heat load is normally calculated on the assumption that the water content of the emulsion being heated will not exceed 20% of the treated oil rate. A heating shroud around the firetube is useful to minimize the heat load to free water that can settle without heating. A maximum firetube heat flux of 10,000 BTU/hr/ft^2 is allowed for design. If a heat exchanger is employed and maintained to recover heat from the treated crude for the feed emulsion, an appropriate reduction in fuel consumption may be realized.

A.3 Coalescing

The heated emulsion is conveyed to the coalescing zone for the final stage of water separation. A wide range of proprietary baffle and plate configurations is employed in both vertical and horizontal treater designs to enhance the separation performance. Residence time in the oil settling zone is typically in the range of 30 to 100 minutes. The corresponding residence time in the water settling zone is typically in the range of 15 to 30 minutes.

Where excelsior (or hay) beds are used for coalescing, maximum design oil emulsion velocities are generally in the range of 7 BPD/ft^2 to 40 BPD/ft^2 for vertical treaters and 17 BPD/ft^2 to 120 BPD/ft^2 for horizontal treaters.

When electrostatic coalescing is used this area of design is considered proprietary.

A.4 Chemical Injection

Chemical injection into the feed emulsion may be required to further enhance coalescing performance to meet specified BS&W limits. The selection of demulsifying chemicals and injection rates is generally based on field experience or with the assistance of chemical specialists.

Annex B
(informative)

Corrosion Control Guidelines

B.1 Considerations

The following guidelines are recommended for determining corrosion considerations for a treater and accessories.

Well streams that contain water as a liquid and any or all of the following gases may be corrosive and should be considered under these specifications (see API 14E, NACE MR 0175):

a) oxygen—O_2;

b) carbon dioxide—CO_2;

c) hydrogen sulfide—H_2S.

The following guidelines are not mandatory but may be used to judge the extent of the corrosive environment, with respect to carbon steels.

a) Oxygen:

1) less than 0.005 ppm in natural brine—non-corrosive;

2) from 0.005 ppm to 0.025 ppm requires consideration;

3) greater than 0.025 ppm in natural brine—corrosive.

b) Carbon dioxide:

1) less than 600 ppm in natural brine—non-corrosive;

2) from 600 ppm to 1200 ppm requires consideration;

3) greater than 1200 ppm in natural brine—corrosive.

c) Hydrogen sulfide.

1) No lower limit of hydrogen sulfide has been identified as being non-corrosive. With hydrogen sulfide present, the environment should be considered corrosive.

2) NACE MR 0175 (latest edition) should be used for all cases of hydrogen sulfide content for selection of materials resistant to sulfide stress cracking (SSC).

Some of the other factors that influence corrosion include: temperature, pressure, fluid velocities, metal stress and heat treatment, surface condition, solids and time.

B.2 Corrosive Environment Practices

If the environment is justified as being subject to SSC from the criteria of NACE MR 0175 as stated in B.1.2 above, then all provisions of this NACE standard as apply to the heads, shell and accessories should be followed. It is the responsibility of the purchaser to advise the manufacturer when the requirements of NACE MR 0175 apply.

If the environment is judged as corrosive from any of the other criteria stated in B.1.2 above, the intent of this specification will be met provided any one or combination of the following practices are used.

a) An allowance for corrosion to the parts may be made according to ASME Section VIII, Division 1.

b) Corrosion effects may be disregarded provided they can be shown to be negligible or entirely absent on a historical basis. However, the system should be monitored periodically for possible new corrosion.

c) Corrosion effects may be reasonably controlled with holiday-free internal coatings on all exposed metal surfaces. NACE RP 0181 and NACE RP 0178 present guidelines and procedures for coating vessels such as emulsion treaters.

d) Some materials, such as copper bearing alloys, should be avoided where hydrogen sulfide is present in the process streams.

Cathodic protection should be considered in the water area of the treating vessels. This protection may be in the form of sacrificial anodes placed in the vessel or through the vessel wall, and may be either of the galvanic or impressed current type. NACE RP 0575 (latest edition) presents guidelines and information on this subject.

Annex C
(informative)

Treater Design Information

Field Name and Location ____________________

Design Conditions

Oil Rate ____________ bbl/hr Oil Gravity ____________ °API

Oil Viscosity SSU ______ @ ______ °F ______ @ ______ °F ______ @ ______ °F

Pour Point ______ °F

Water Rate ____________ bbl/hr, Water Specific Gravity ____________

Gas Rate ____________ SCF/hr, Gas Specific Gravity ____________

Sand, Salt or Solids Present: Describe ____________________

____

Gas/Oil Ratio (GOR) Average ____________________ SCF/bbl

Percent H_2S ____________ % Percent CO_2 ____________ %

Surging or Instantaneous Flow: Describe ____________________

____

Foaming or Paraffin (if Present, Describe) ____________________

____

Recirculating Rate (if Any) ____________________

Production Temperature to Treater ____________ °F

Estimated Treating Temperature (if Known) ____________ °F

Operating Pressure Required ____________ psig

Design Pressure ____________ psig. (Normal is 50 psig)

Design Temperature °F ______ Max ______ Min

Required BS&W of Outlet Oil ______%

Fuel Source ____________ High Heating Value (HHV) ____________ BTU/SCF, BTU/lb

Fuel Supply Pressure ____________ psig

Disposition of Effluent Water: (Describe) ____________________

____

Firetube Minimum Thickness: ____________ if Greater Than Standard

Optional Requirements

Vertical or Horizontal (Preference) ____________________

Type Coalescing: Hay Section, Electric, Plates ____________________

Skid Mounted (Horizontal) __________ Yes ________ No ________

Lifting Lugs ____________________ Stack Flame Arrestor ____________________

Stack Down-draft Diverter ____________________

Corrosion Allowance: Pressure Parts ____________________, Non-pressure Parts ____________________,

Firetube ____________________

Seal Welding: Internal ____________________, External ____________________

Flame Arrestor ____________________

Stack Gas/Temperature Connection ____________________

Sample Cocks in Lieu or Gage Glass ____________________

Special Paint of Coating: Internal: ____________________

External: ____________________

Firetube: ____________________

Stack: ____________________

Fuel Gas Scrubber: __________ Yes/No. Internal Float Shutoff: Yes/No __________

Valves & Controls: Mfg. Standard ____________________ Others ____________________

Pilot Igniter __________ Yes/No __________ Flame Detector/Shutdown __________ Yes/No

Anode Connections: __________ Yes/No __________ Qty __________ Size __________Type

Interface Drains: __________ Sand Jets (Manual/Auto) __________ Sand Pan __________

Space/Height Limitations or Size Preference ____________________

Heat Efficiency Options:

a. Burner Stack Draft Controller ____________________
b. Flue Gas Economizer ____________________
c. Heat Exchanger ____________________ Type ____________________
d. Insulation: Specify ____________________
e. Turbolater: ____________________
f. Others ____________________

Comments: ____________________

____

Annex D
(informative)

Design and Sizing Calculation

D.1 Sizing of Treaters

The following calculations should be used with caution since they do not consider several important variables in the sizing of treaters such as:

1) proprietary internals;
2) physical properties of emulsion;
3) method of the oil production;
4) chemical treatment;
5) treating temperature;
6) contaminants;
7) interface area requirements.

The purchaser should consult the manufacturer for a more detailed design and sizing. Sizing should be based on the maximum expected instantaneous rate.

In the separation of an oil and water mixture, the heavier water droplets settle out of the oil phase and the oil particles rise out of the water phase due to the difference in densities of the two fluids. However, the droplets of water in crude oil emulsions frequently can not coalesce, but proper chemical treatment, heat, or an electrical current will usually improve this condition. Assuming proper application of one or more of these methods of treatment, the separation of an oil and water emulsion becomes essentially a mechanical problem.

D.2 Liquid Capacity

The liquid capacity of a treater is primarily dependent upon the retention time of the liquid in the vessel. Good separation requires sufficient time to break the emulsion.

The retention time (settling time) or the retention volume may be determined using the following equation:

$$R = \frac{1440(V)}{W} \qquad V = \frac{(W)(R)}{1440} \tag{D.1}$$

where

T is the retention time, minutes;

W is the emulsion flowrate, bbl/day;

V is the retention volume, bbl.

The oil and water retention times should be determined separately using the retention volume of each as related to its portion of the total flow.

The retention time in the setline zone is typically in the range of 30 to 100 minutes. The corresponding residence time in water settling zone is typically in the range of 15 to 30 minutes.

D.3 Heat Duty

To determine the required capacity of a treater, it is first necessary to assume a treating temperature considering the gravity, viscosity and emulsion characteristics. The maximum viscosity of the oil at the treating temperature should be approximately 150 SSU (25 to 30 centipoise).

The heat duty is determined by the sum of the heat requirements for the oil and water as given by the following equation:

$$Q = (W_O)\,(C_O)\,(T_2 - T_1) + (W_W)\,(C_W)\,(T_2 - T_1) \tag{D.2}$$

where

Q is the heat required, BTU/hr;

W_O is the flow rate of the oil, lb/hr;

W_W is the flow rate of the water, lb/hr;

C_O is the specific heat of the oil, BTU/(lb-F);

C_W is the specific heat of the water, BTU/(lb-F);

T_1 is the initial temperature, °F;

T_2 is the final temperature, °F.

The emulsion rate may be broken into the oil and water flow rates by using:

$$W_O = 14.58\,(W)\,(1 - X)\,(s_o) \tag{D.3}$$

$$W_W = 14.58\,(W)\,(X)\,(s_w) \tag{D.4}$$

where

$$14.58 = \frac{42\text{ gal/bbl }(8.33\text{ lb/gal})}{24\text{ hr/day}}$$

where

W is the emulsion flow rate, bbl/day;

X is the volume fraction of water, fraction;

s_o is the specific gravity of oil, water = 1.0;

s_w is the specific gravity of water, water = 1.0.

Combining the above equations and then substituting values for a 35 API oil with a specific gravity of 0.8498 and a specific heat of 0.52 BTU/lb-F along with values for water of a specific gravity of 1.0 and a specific heat of 1.0 BTU/lb-F gives the following simplified equation.

$$Q = W\,[6.44 = 8.14\,(X)]\,(T_2 - T_1) \tag{D.5}$$

It must be remembered that the heat required is the heat delivered to the fluid and does not include any heat loss or the additional heat required for combustion efficiency.

D.4 Heat Loss

In determining the total heat input required for treating systems, the maximum amount of heat loss from the shell of the treating vessels or heat generating equipment should be taken into account. The heat loss for uninsulated vessels may be approximated from the following equation:

$$Q_1 = K\,(D)\,(L)\,(T_2 - T_\alpha) \tag{D.6}$$

where

Q_1 is the heat loss, BTU/hr;

K is constant;

is 15.7 for 20 mph wind;

is 13.2 for 10 mph wind;

is 9.8 for 5 mph wind;

is 9.3 for still air;

D is the diameter of treater, ft;

L is the height or length of shell, ft;

T_2 is the treating temperature, °F;

T_α is the design minimum outside ambient temperature,°F.

For insulated vessels, the heat loss may be estimated in the range of 5% to 10% of what the bare vessel heat loss would be.

Annex E
(informative)

Treater Sizing Example Calculation

E.1 Design Data

Total Emulsion Flow Rate	W	=	400	bbl/day
Water Fraction	X	=	0.1	
Oil Flow Rate	W_O	=	360	bbl/day
Water Flow Rate	W_W	=	40	bbl/day
Emulsion Inlet Temperature	T_1	=	70°F	
Emulsion Treating Temperature	T_2	=	120°F	
Assumed Retention Times, Oil	R_O	=	60	minutes
Water	R_W	=	30	minutes

E.2 Retention Volumes

Oil

$$V_O = [(360)(60)]/(1440) = 15.0 \text{ bbl}$$

Water

$$V_W = [(40)(30)]/(1440) = 0.83 \text{ bbl}$$

E.3 Vessel Selection

Selection from Table E.1:

Vertical 4' × 20'
Horizontal 4' × 15'

These vessels will satisfy the retention volume requirements based on the design flow rate and assumed retention times.

E.4 Heat Duty

Emulsion Heating

$$Q = (400)[6.44 + (8.14)(0.1)](120 - 70) = 145{,}080 \text{ BTU/hr}$$

The examples on this page are for illustration purposes only (each company should develop its own approach). They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information or equations contained in this document.

Heat Loss

Assume a 30°F ambient air temperature and a 10 mph wind.

Vertical Treater

$$Q_1 = (13.2)\ (4)\ (20)\ (120 - 30) = 95{,}040 \text{ BTU/hr}$$

Horizontal Treater

$$Q_1 = (13.2)\ (4)\ (15)\ (120 - 30) = 71{,}280 \text{ BTU/hr}$$

Total Heat Required

$$Q_t = 240{,}120 \text{ BTU/hr}$$

$$Q_t = 216{,}360 \text{ BTU/hr}$$

Table 3 indicates that both the vertical and horizontal 4-ft diameter treaters are rated at 250,000 BTU/hr which exceeds the heat duty requirements of the treater and confirms the treater selection based on the retention volume requirements (see Table E.1).

E.5 Summary

The horizontal 4' × 15' treater and the vertical 4' × 20' treater will satisfy the requirements of the design. Selection should be made based on cost, installation, and other factors governing the purchase. As stated in Annex D, the above design procedure is limited and should be used with caution.

E.6 Treater Retention Volumes

Table E.1 gives the retention volumes of oil and water for conventional treaters. These volumes are illustrative only and actual volumes for specific equipment should be confirmed by manufacturer.

Table E.1—Retention Volumes of Oil and Water for Conventional Treaters

Treater Size	Vertical Treaters		Horizontal Treaters	
	Oil bbl	**Water** bbl	**Oil** bbl	**Water** bbl
3' × 10'-0"	5.9	4.0	6.6	4.4
12'-0"	7.0	4.7	7.8	5.2
15'-0"	8.6	5.8	9.6	6.4
4' × 10'-0"	10.7	7.2	11.9	7.9
12'-0"	12.6	8.6	14.1	9.5
15'-0"			17.3	11.5
20'-0"	19.4	10.4		
2'-6"	30.3	17.1		
6' ×12'-0"	30.4	20.5	33.2	22.6
15'-0"			39.3	26.4
20'-0"	44.2	27.5	51.0	34.8
27'-6"	68.6	42.6		
8' × 15'-0"			69.4	46.5
20'-0"	78.3	48.0	88.4	59.2
25'-0"			108.7	73.0
27'-0"	121.4	74.9		
30'-0"			128.9	85.9
10' × 20'-0"	122.4	82.5	144.7	96.9
27'-6"	189.6	124.5		
30'-0"			217.8	142.6
40'-0"			284.7	183.9
50'-0"			351.8	227.2
60'-0"			419.0	270.6
12' × 30'-0"			324.7	217.6
40'-0"			422.6	284.6
50'-0"			521.3	351.1
60'-0"			619.9	417.5

Annex F
(informative)

Structural Design Guidelines

F.1 Saddles

Saddles for horizontal shells, and skirt/base ring supports for vertical shells should be designed so that excessive stresses are not induced in the shell or bottom head. Some useful guidelines and references may be found in Section VIII, Division 1, of the ASME Code. Caution is advised when angle legs are used to support the shell, because they may overstress the shell. The saddles or legs shall be adequate to support the treater assembly under normal operating conditions. No more than two saddles should be used on a cylindrical shell.

F.2 Lugs

Treaters that are furnished with insulation shall also be furnished with two lift lugs unless lifting lugs are furnished on the supporting skid. Each lift lug shall be designed using a design stress equal to $^2/_3$ of the specified minimum yield stress with a 2:1 safety factor based on the empty weight of what is to be lifted by each lug. A maximum lift angle of 30° with the vertical shall be assumed. The effect of the lugs on the shell should be investigated and reinforcement should be provided if required. The lugs should be designed for double shear tear-out and tension on the net section at the pin hole. Many manufacturers attach lift lugs to various components on the treater assembly that are intended for lifting that component only; however, they many not be suitable for lifting the total assembly.

F.3 Wind Force

Wind forces on the stack can cause a moment on the firetube cover plate which should be investigated.

F.4 Buoyancy

The firetube becomes buoyant when immersed in the treater bath and may need to be restrained from floating.

Annex G
(informative)

Typical List of Available Controls and Accessories

Drain valves

Emulsion temperature controller

External water siphon

Flame arrestor

Fuel gas control valve

Fuel gas manual valve

Fuel gas pressure regulator

Fuel gas scrubber

Fuel gas shutdown valve

Fuel gas strainer

Gage glasses with isolating valves

Gas back pressure valve

Heat exchanger

High emulsion temperature shutdown of fuel valve

Ladder and platform for horizontal treaters

Liquid dump valves

Low level shutdown of burner

Oil level controller with internal float

Pilot gas manual valve

Pilot gas pressure regulator

Pressure gauge with isolating valve

Pressure relief valve

Sample connections with sample cocks

Thermometer and thermowell for heated emulsion zone

Water interface controller with internal float

Annex H
(informative)

Combustion Efficiency

H.1 Operation

Proper operation of any treater depends on efficient burner performance and adequate firetube design and is commonly expressed as combustion efficiency. Good burner performance depends on proper adjustment of fuel gas pressure, primary and secondary air and the gas orifice size. Good firetube design depends on heat flux, heat density, temperature and firing.

H.2 Performance

Treater performance can be easily determined by an analysis and temperature of the flue gas taken from the base of the stack. Figure H.1 is a convenient chart for estimating combustion efficiency in a treater, based on residual oxygen (O_2) content and exit temperature of the stack gas, employing a methane-rich fuel gas with a high (or gross) heating valve (HHV) of approximately 1050 BTU/SCF. This chart assumes the residual level of combustibles in the flue gas is below 0.1% which is the maximum level for safe and efficient operation. While this chart is limited to natural gas, there is no intent to preclude other fuels.

H.3 Minimum Stack-gas Temperature

If a sulfur-free gas issued with uninsulated stacks, a minimum exit flue gas temperature of 250°F should be maintained to avoid internal stack corrosion. If sulfur is present in the fuel gas, the minimum exit flue gas temperature should be maintained in the range of 300°F to 400°F for sulfur contents ranging from approximately 0.05% to 1.0% by volume in the fuel gas. This 300°F to 400°F temperature range can be reduced by roughly 50°F for insulated stacks.

H.4 Example Calculation

Determine estimated fuel consumption for a treater with a firetube rating of 250,000 BTU/hr, fueled with natural gas of 1050 BTU/SCF HHV, operating with flue gas of 4 vol% residual oxygen and 900°F stack gas temperature.

From Figure H.1, read the following:

a) 4 vol% oxygen in flue gas corresponds to approximately 22.5% excess air for combustion;

b) combustion efficiency = 69% for 1050 BTU/SCF fuel gas.

$$\text{Estimated fuel gas consumption} = \frac{250{,}000 \text{ btu/hr}}{0.69 \times 950 \text{ eff.btu/SCF}} = 345 \text{ SCFH}$$

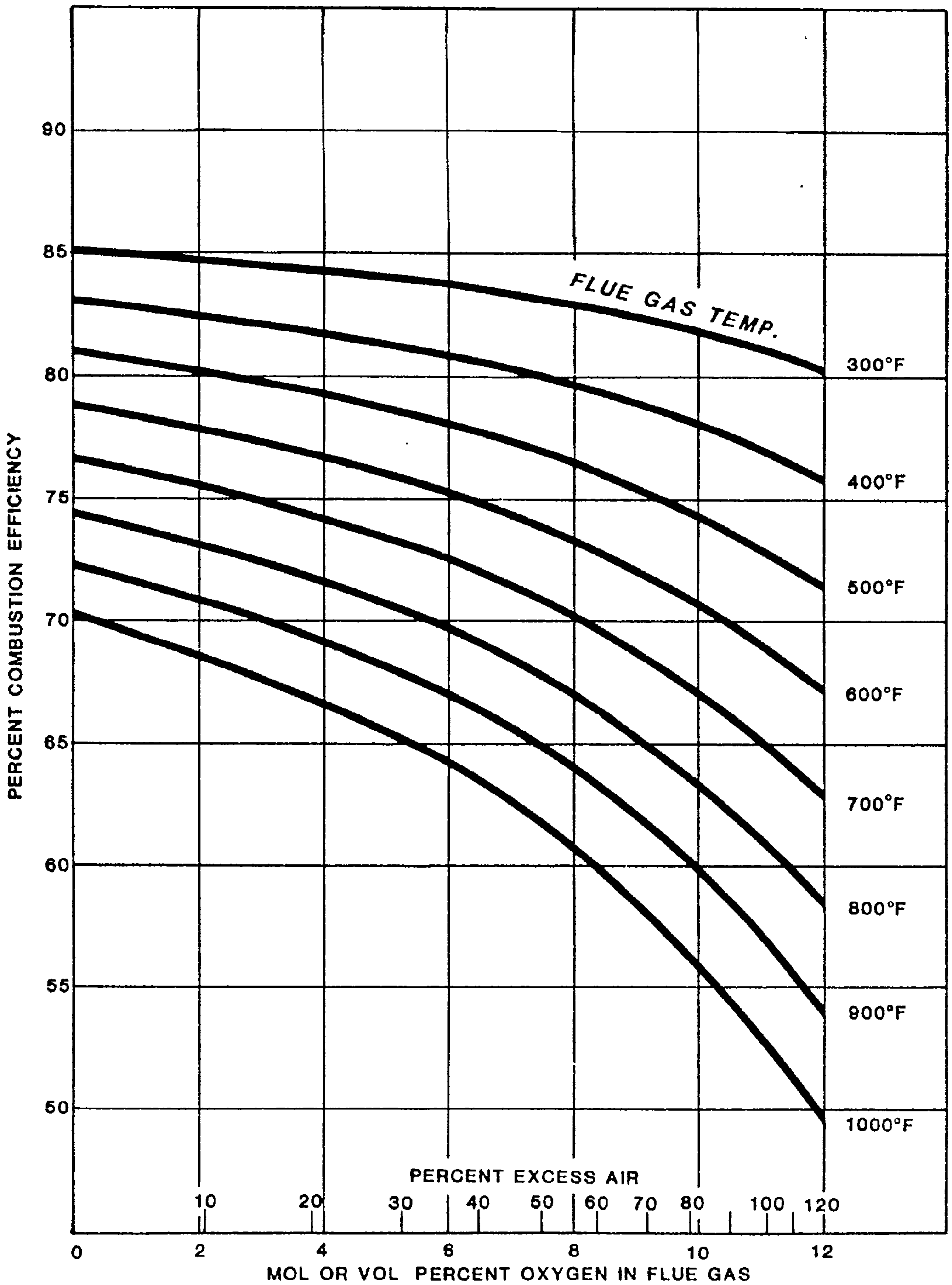


Figure H.1—Approximate Combustion Efficiency of Natural Gas (1050 BTU/SCF, HHV) in Emulsion Treaters

Annex I
(informative)

Use of the API Monogram by Licensees

I.1 Scope

The API Monogram Program allows an API Licensee to apply the API Monogram to products. The API Monogram Program delivers significant value to the international oil and gas industry by linking the verification of an organization's quality management system with the demonstrated ability to meet specific product specification requirements. The use of the Monogram on products constitutes a representation and warranty by the Licensee to purchasers of the products that, on the date indicated, the products were produced in accordance with a verified quality management system and in accordance with an API product specification.

When used in conjunction with the requirements of the API License Agreement, API Q1, in its entirety, defines the requirements for those organizations who wish to voluntarily obtain an API License to provide API monogrammed products in accordance with an API product specification.

API Monogram Program Licenses are issued only after an on-site audit has verified that the Licensee conforms to the requirements described in API Q1 in total, and the requirements of an API product specification. Customers/users are requested to report to API all problems with API monogrammed products. The effectiveness of the API Monogram Program can be strengthened by customers/users reporting problems encountered with API monogrammed products. A nonconformance may be reported using the API Nonconformance Reporting System available at https://ncr.api.org. API solicits information on new product that is found to be nonconforming with API specified requirements, as well as field failures (or malfunctions), which are judged to be caused by either specification deficiencies or nonconformities with API specified requirements.

This annex sets forth the API Monogram Program requirements necessary for a supplier to consistently produce products in accordance with API specified requirements. For information on becoming an API Monogram Licensee, please contact API, Certification Programs, 1220 L Street, N. W., Washington, D.C. 20005 or call 202-962-4791 or by email at certification@api.org.

I.2 References

In addition to the referenced standards listed in Section 2 of this document, this annex references the following standard:

API Specification Q1

For Licensees under the Monogram Program, the latest version of this document shall be used. The requirements identified therein are mandatory.

I.3 API Monogram Program: Licensee Responsibilities

I.3.1 For all organizations desiring to acquire and maintain a license to use the API Monogram, conformance with the following shall be required at all times:

a) the quality management system requirements of API Q1;

b) the API Monogram Program requirements of API Q1, Annex A;

c) the requirements contained in the API product specification(s) for which the organization desires to be licensed; and

d) the requirements contained in the API Monogram Program License Agreement.

I.3.2 When an API-Licensed organization is providing an API monogrammed product, conformance with API specified requirements, described in API Q1, including Annex A, is required.

I.3.3 Each Licensee shall control the application of the API Monogram in accordance with the following.

a) Each Licensee shall develop and maintain an API Monogram Marking Procedure that documents the marking/ monogramming requirements specified by the API product specification to be used for application of the API Monogram by the Licensee. The marking procedure shall define the location(s) where the Licensee shall apply the API Monogram and require that the Licensee's License number and date of manufacture be marked on monogrammed products in conjunction with the API Monogram. At a minimum, the date of manufacture shall be two digits representing the month and two digits representing the year (e.g. 05-07 for May 2007) unless otherwise stipulated in the applicable API product specification. Where there are no API product specification marking requirements, the Licensee shall define the location(s) where this information is applied.

b) The API Monogram may be applied at any time appropriate during the production process but shall be removed in accordance with the Licensee's API Monogram Marking Procedure if the product is subsequently found to be nonconforming with API specified requirements. Products that do not conform to API specified requirements shall not bear the API Monogram.

c) Only an API Licensee may apply the API Monogram and its License to API monogrammable products. For certain manufacturing processes or types of products, alternative Monogram marking procedures may be acceptable. The current API requirements for Monogram marking are detailed in the API Policy Document, *Monogram Marking Requirements*, available on the API Monogram Program website at http://www.api.org/certifications/monogram/.

d) The API Monogram shall be applied at the licensed facility.

e) The authority responsible for applying and removing the API Monogram shall be defined in the Licensee's API *Monogram Marking Procedure*.

I.3.4 Records required by API product specifications shall be retained for a minimum of five years or for the period of time specified within the product specification if greater than five years. Records specified to demonstrate achievement of the effective operation of the quality system shall be maintained for a minimum of five years.

I.3.5 Any proposed change to the Licensee's quality program to a degree requiring changes to the quality manual shall be submitted to API for acceptance prior to incorporation into the Licensee's quality program.

I.3.6 Licensee shall not use the API Monogram on letterheads or in any advertising (including company-sponsored web sites) without an express statement of fact describing the scope of Licensee's authorization (License number). The Licensee should contact API for guidance on the use of the API Monogram other than on products.

I.4 Marking Requirements for Products

These marking requirements apply only to those API Licensees wishing to mark their products with the API Monogram.

I.4.1 Manufacturers shall mark equipment on the nameplate with the information identified in Section 7 of this specification, as a minimum, including "API Spec 12L."

I.4.2 As a minimum, equipment should be marked with English (Imperial) units.

I.4.3 Nameplates shall be made of a corrosion-resistant material and shall be located as indication in the marking section of this specification. If the location is not identified, then I.3.3 a) of this annex shall apply.

I.4.4 Nameplates may be attached at the point of manufacture or, at the option of the manufacturer, at the time of field erection.

I.4.5 The API Monogram shall be marked on the nameplate, in addition to the marking requirements of this specification. The API Monogram License number shall not be used unless it is marked in conjunction with the API Monogram.

I.5 API Monogram Program: API Responsibilities

I.5.1 The API shall maintain records of reported problems encountered with API monogrammed products. documented cases of nonconformity with API specified requirements may be reason for an audit of the Licensee involved, (also known as audit for “cause”).

I.5.2 Documented cases of specification deficiencies shall be reported, without reference to Licensees, customers or users, to API Subcommittee 18 (Quality) and to the applicable API Standards Subcommittee for corrective actions.

Bibliography

[1] API Specification 12J, *Specification for Oil and Gas Separators*

[1] API Recommended Practice 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*

[2] ASTM Standard Test No. D96-82 [6], *Water and Sediment in Crude Oils*

[3] NACE MR 0175 [7], *Sulfide Stress Corrosion Cracking Resistant Metallic Materials for Oil Field Equipment*

[4] NACE RP 0178, *Design, Fabrication, and Surface Finish of Metal Tanks and Vessels to be Lined for Chemical Immersion Service*

[5] NACE RP 0181, *Liquid Applied Internal Protective Linings and Coatings for Oilfield Production Equipment*

[6] NACE RP 0575, *Design, Installation, Operation, and Maintenance of Internal Cathodic Protection Systems in Oil Treating Vessels*

[6] ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

[7] NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.

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