Specification for Vertical and Horizontal Emulsion Treaters

API SPECIFICATION 12L
FOURTH EDITION, NOVEMBER 1, 1994

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

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Exploration and Production Department

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FOREWORD

This specification is under the jurisdiction of the API Committee on Standardization of Production Equipment.

This standard shall become effective on the date printed on the cover but may be used voluntarily from the date of distribution.

Specification for Vertical and Horizontal Emulsion Treaters

1 Scope

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.

2 References

Industry Codes, Specifications and Recommended Practices are referenced in this specification and, as applicable and referenced, become requirements of API Spec 12L. Unless otherwise specified, the latest editions and revisions of this specification, and the referenced industry codes, specifications, recommended practices and other requirements current at the time of publication should be considered applicable at the time of manufacture of Emulsion Treaters conforming to this specification. Referenced documents may be obtained from the following sources.

ANSI	*American National Standards Institute, 1430 Broadway, New York, NY 10018*
API	*American Petroleum Institute, Production Department, 700 North Pearl, Suite 1840 (LB-382), Dallas, TX 75201-2845*
ASME	*American Society of Mechanical Engineers, 345 E. 47th St., New York, NY 10017*
ASTM	*American Society for Testing and Materials, 1916 Race St., Philadelphia, PA 19103*
AISC	*American Institute of Steel Construction, 400 N. Michigan Ave., Chicago, IL 60611*
NACE	*National Association of Corrosion Engineers, P.O. Box 218340, Houston, TX 77218*

3 Definitions

3.1 INTRODUCTION

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 & 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 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 Appendix A. Refer to Figures 1, 2 and 3 which show general arrangements of components, piping and instrumentation. (Some of the illustrated features are considered optional.)

3.2 bs&w: This term refers to basic sediment and water and is commonly used as a measure of treating performance. Treating performance is highly variable, but most crude oils are treated to a range of 0.2 to 3.0 percent BS&W. ASTM Standard Test No. D96-82 entitled *Water and Sediment in Crude Oils* is an accepted standard for this test.

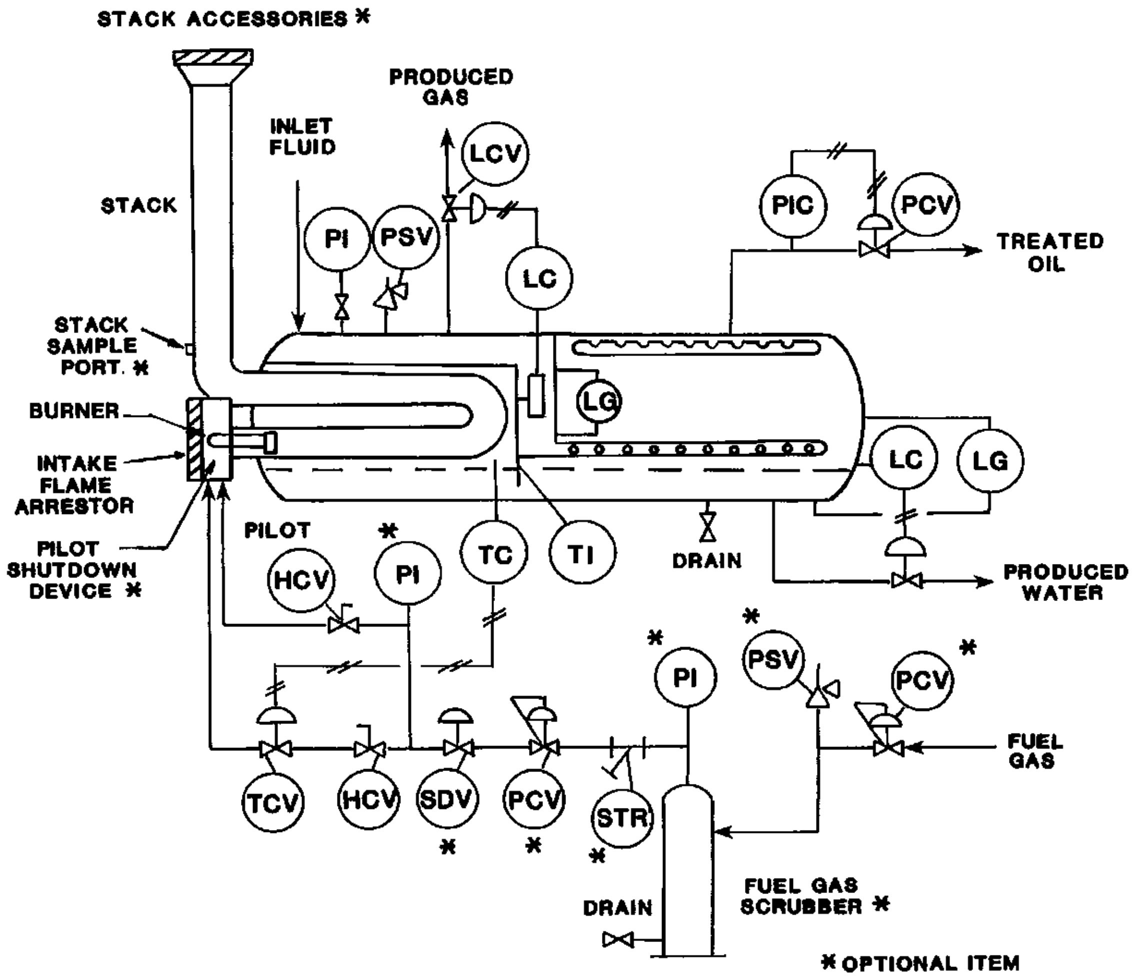
3.3 burner system: Treater firetubes require burner systems designed for the specific fuel and may be either natural or forced draft design. When multiple U-tubes are used, they should be designed to use separate burners, pilots and stacks. The burner system includes the firing accessories. Intake flame arrestors and other optional burner accessories as listed in Appendix G may also be included.

3.4 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. 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.

3.5 collector pipe: A 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.

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

3.7 design pressure: The pressure used in the design of a vessel for the purpose of determining the minimum permissible thickness or physical characteristics of the



LEGEND

TI	TEMPERATURE INDICATOR
TC	TEMPERATURE CONTROLLER
PCV	PRESSURE-REDUCING REGULATOR
TCV	TEMP. CONTROL VALVE
SDV	SHUT-DOWN VALVE
PSV	RELIEF VALVE
PI	PRESSURE INDICATOR
HCV	HAND CONTROL VALVE
STR	STRAINER
LC	LEVEL CONTROLLER
LCV	LEVEL CONTROL VALVE
PIC	PRESSURE-INDICATING CONTROLLER
LG	LEVEL INDICATOR

Figure 1—Typical Treater Assembly

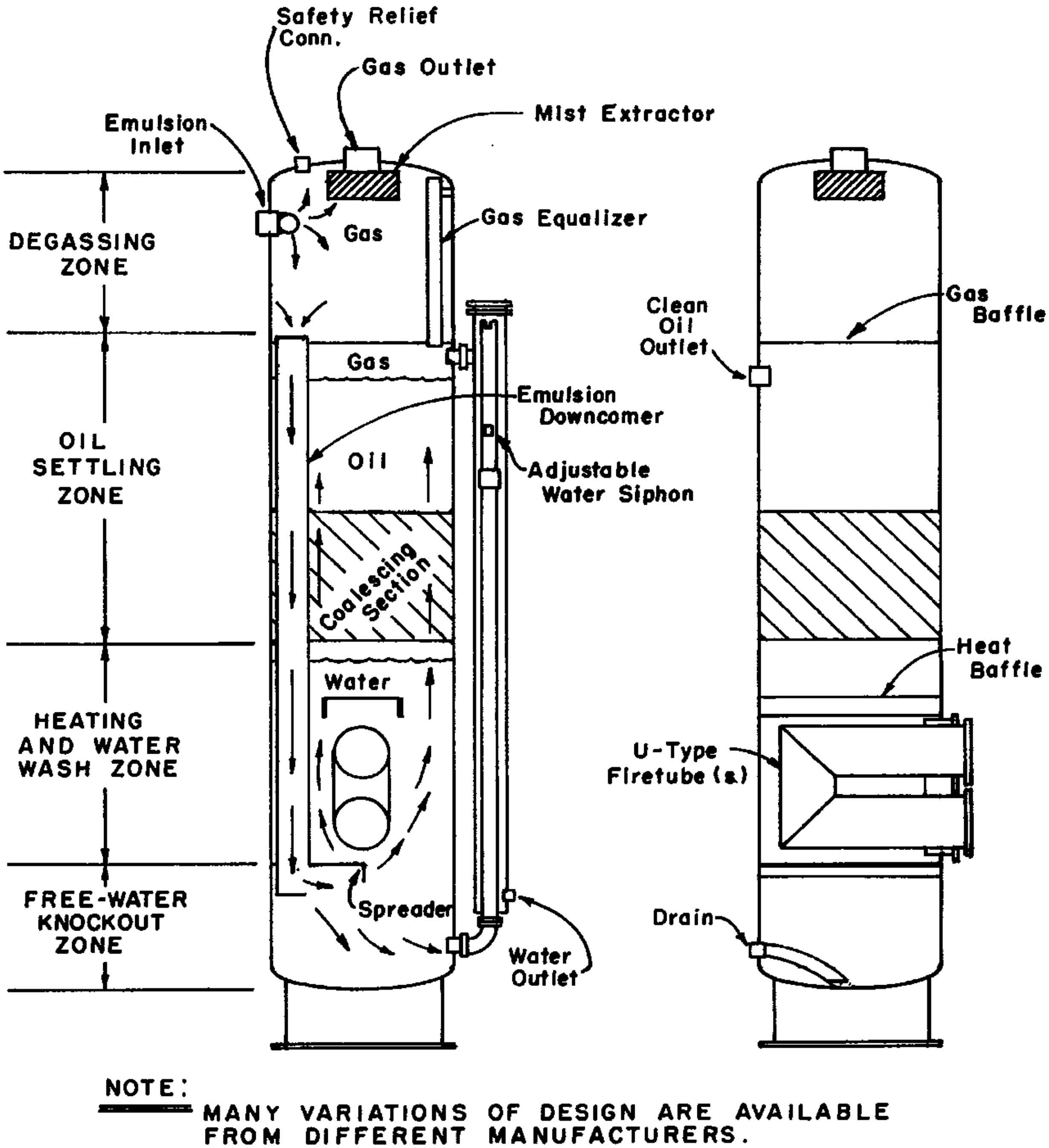


Figure 2—Typical Vertical Treater

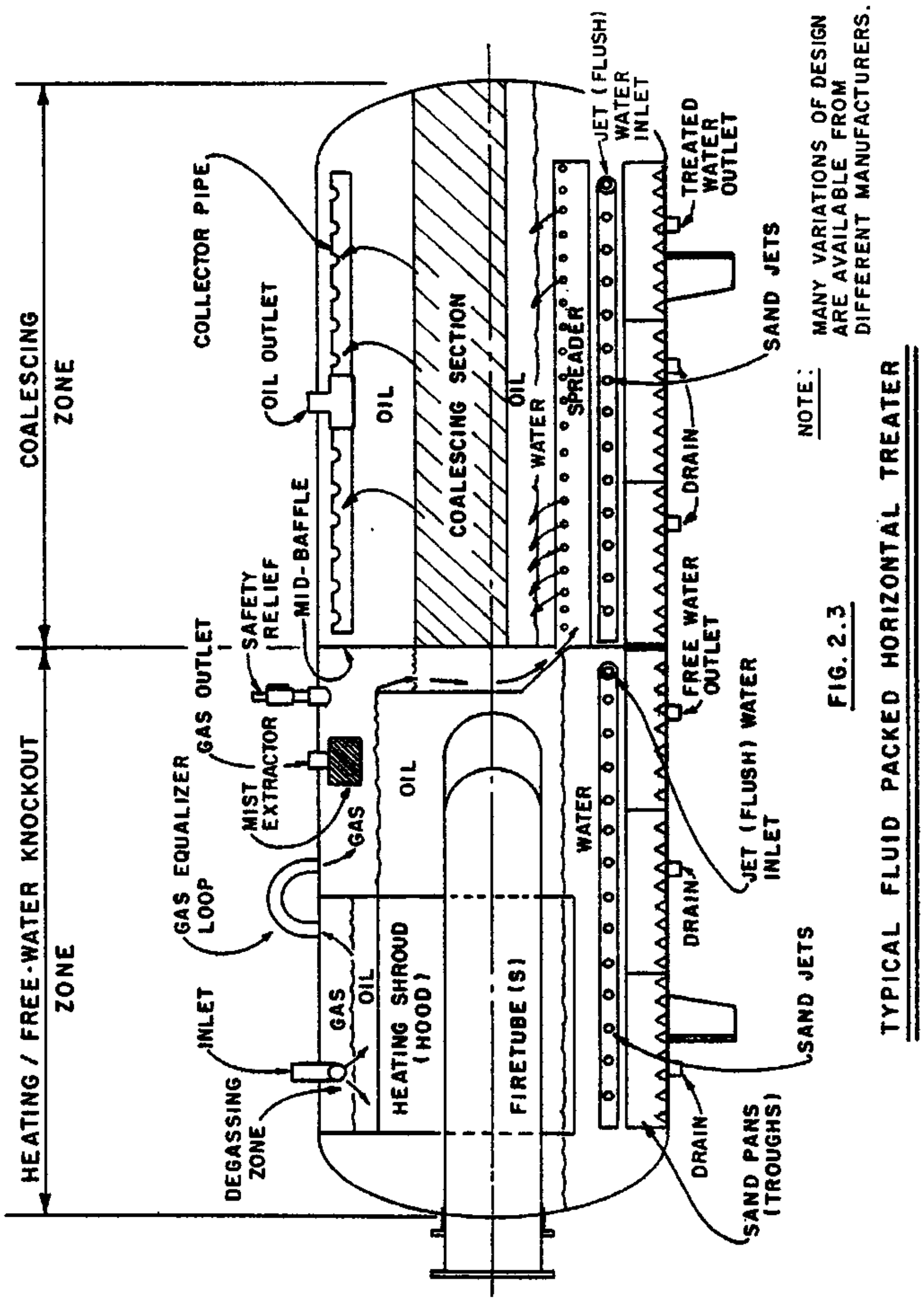


Figure 3—Typical Fluid Packed Horizontal Treater

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

3.8 electrostatic treater: An 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.

3.9 emulsion: A relatively stable dispersion of water and oil which normally exists in the production stream from flowing or pumped oil wells.

3.10 firebox: A complete assembly consisting of the firetube(s), mounting flange(s), intake(s) and stack adapters.

3.11 firetube: The firetube is that portion of the firebox in contact with the liquids. Natural gas or hydrocarbon liquids are normally used to fire the treater through a submerged furnace chamber called the firetube. The firetube normally consists of one or more U-tubes fired at one end and exhausting through a vertical stack for each U-tube. In larger treaters the firetube may consist of a large diameter first pass firetube and multiple return tubes manifolded into a common stack.

3.12 grid: In electrostatic treaters the electric field is distributed by a steel assembly of plates, rods, screens or combinations of these, commonly referred to as the grid. The grid establishes the electric field which enhances coalescing of the water droplets. The grid does not provide heat. The projected grid area is significant to the performance and capacity of the treater.

3.13 heat density: This term is commonly applied to the heat release through the cross section of the firetube, expressed as btu/hr/square inch of cross sectional area.

3.14 heat duty: Heat absorbed by the process, expressed as btu/hr.

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

3.16 heat flux: This term is commonly applied to the average heat transfer rate through the firetube, expressed as btu/hr/square foot of exposed area.

3.17 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.

3.18 intake flame arrestor: A device placed on the air intake of the firetube to prevent propagation of flame from inside the firetube to the outside atmosphere. It normally consists of a corrugated aluminum cell mounted in a metal housing which attaches to the firebox.

3.19 interface drain: A pipe connection extending to the normal interface level with a vortex breaker which is used periodically to drain off any accumulated sludge.

3.20 liquid (fluid) packed: In horizontal treaters the coalescing section or entire treater may operate completely full of liquid. This condition is referred to as liquid (fluid) packed.

3.21 maximum allowable working pressure: The maximum gage pressure permissible at the top of a completed vessel in its operating position for a designated temperature. This pressure is 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. It is the basis for the pressure setting of the pressure relieving devices protecting the vessel.

3.22 mid-baffle: In horizontal emulsion treaters a baffle or bulkhead may be located between the heating section and the coalescing section. This member is commonly referred to as a mid-baffle or bulkhead which can be identified in Figure 3.

3.23 operating pressure: The pressure at the top of a pressure vessel at which it normally operates. It shall not exceed the maximum allowable working pressure and it is usually kept at a suitable level below the setting of the pressure relieving devices to prevent their frequent opening.

3.24 ptb: This term refers to pounds of salt per thousand barrels of crude oil. It is used in conjunction with BS&W to express the quality of untreated and treated crude oils in relation to desalting applications of emulsion treaters.

3.25 removable: Total component is field replaceable without welder assistance.

3.26 sand jets: A 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.

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

3.28 spreader(s): A 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 spark arrestor: A device placed on the exhaust of the stack to prevent sparks from being emitted to the outside atmosphere. It normally consists of a metallic wire screen attached across the top diameter of the stack.

3.30 stack downdraft diverter: A device attached to the top of the stack designed to reduce the effects of wind currents on the burner system.

3.31 stack flame arrestor: A device placed on the exhaust of the stack to prevent propagation of flame from inside the firetube to the outside atmosphere. It normally consists of a corrugated aluminum or stainless steel cell mounted in a metal housing which attaches to the top of the stack.

3.32 stack rain shield: A 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.

3.33 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.

3.34 turbolators: A core of baffles designed to induce turbulence in the return leg of firetubes which enhances heat transfer efficiency.

3.35 vortex breaker: A device located on outlet nozzles to prevent vortex formation.

3.36 water siphon (water leg, grasshopper): A piping system for the controlled flow of water from the treater which sets the water/oil interface level within the treater. To accomplish this control 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, 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 Appendix 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.

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 Tables 1 and 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 27½	50
6	12, 20 or 27½	50
8	20 or 27½	40
10	20 or 27½	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

	Vertical		Horizontal	
Outside Diameter ft.	Minimum Area sq. ft.	Heat Duty BTU/hr.	Minimum Area sq. ft.	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

*These are suggested minimum requirements. Heat requirements of the process and fluid characteristics should be considered in sizing the firebox.

5.3 FIRETUBE HEAT FLUX

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

Example: $8^5/_8$" OD, Sch. 20, 0.25" wall firetube having 25.0 square feet of firetube surface, 51.85 sq. in. cross sectional area and rated @ 250,000 BTU/hr.

$$\text{Average Heat Flux} = \frac{\text{Firetube Ratings (BTU/hr)}}{\text{Sq. Ft. of Firetube Surface}}$$

$$= \frac{250{,}000}{25.0} = 10{,}000 \text{ BTU/hr/sq. ft.}$$

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/sq. in. for natural draft burners.

Example from 5.3.

$$\text{Heat Density} = \frac{\text{Firetube Rating (BTU/hr)}}{\text{(Cross Sectional Area, in}^2\text{) (Efficiency)}}$$

$$\frac{250{,}000}{51.85 \times 0.70} = 6{,}888 \text{ BTU/hr/sq. in.}$$

5.5 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, turbolators 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.

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

5.7 Typical Design and Sizing Calculations are given in Appendix D.

5.8 Appendix E gives an example calculation for treater sizing.

5.9 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 $^3/_{16}$ inch for vertical treaters and $^1/_4$ inch for horizontal treaters. Corrosion allowance is not normally added to the firetube wall thickness.

6 Fabrication, Testing and Painting

6.1 FABRICATION

Emulsion treaters, including firetube(s), heat exchangers and water siphons (6" 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" shall be designed and constructed in accordance with ANSI 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 Appendix B. After coating, the vessel shall be stenciled in a conspicuous location "INTERNAL COATING—DO NO 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*

*Users of this specification should note that there is no longer a requirement for marking a product with the API monogram. The American Petroleum Institute continues to license use of the monogram on products covered by this specification but it is administered by the staff of the Institute separately from the specification. The policy describing licensing and use of the monogram is contained in Appendix I, herein. No other use of the monogram is permitted.

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 Fig. 4.

1. Spec 12L.
2. Manufacturer's name.
3. Manufacturer's serial number.
4. Year built.
5. Weight empty, pounds (lbs.).
6. Shell size, outside diameter (OD), length seam to seam, feet (ft.).
7. Design pressure, pounds per square inch (psi) at temperature degrees Fahrenheit (°F).
8. Firebox rating, British Thermal Units per hour (BTU/Hr.).
9. Firebox surface area, square feet (Sq. Ft.).
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.

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 Par. 7.1 may be included on the ASME nameplate, otherwise two nameplates are required.

7.3 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 by the Code plus such other inspection as he believes necessary to enable him to certify that all vessels which he authorizes 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 his knowledge and belief, is complete and is in compliance with all of the provisions of the Code.

8.2 INSPECTION BY THE PURCHASER

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

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

SPEC 12L

MANUFACTURER ____________________
SERIAL NUMBER ____________________
YEAR BUILT ____________________
VESSEL WEIGHT EMPTY ____________________ LBS
SHELL SIZE, OD x LENGTH __________ FT. x __________ FT.
DESIGN PRESSURE __________ PSI @ __________ °F
FIREBOX RATING ____________________ BTU/HR
FIREBOX SURFACE AREA ____________________ SQ. FT.
____
____

Figure 4—Suggested Emulsion Treater Nameplate

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

APPENDIX A—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 Spec 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 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°-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 to 40 BPD/Ft.^{2} for vertical treaters and 17 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.

APPENDIX B—CORROSION CONTROL GUIDELINES

B.1 Considerations

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

B.1.1 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 (Reference API Recommended Practice 14E, NACE MR-01-75):

a. Oxygen—O_2
b. Carbon Dioxide—CO_2
c. Hydrogen Sulfide—H_2S

B.1.2 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 Standard MR-01-75 (latest edition) 'Materials Requirement—Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment,' should be used for all cases of hydrogen sulfide content for selection of materials resistant to sulfide stress cracking (SSC).

B.1.3 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

B.2.1 If the environment is justified as being subject to sulfide stress cracking (SSC) from the criteria of NACE MR-01-75 as stated in Par. 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-01-75 apply.

B.2.2 If the environment is judged as corrosive from any of the other criteria stated in Par. 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 Standards RP-01-81 (*Recommended Practice: Liquid Applied Internal Protective Linings and Coatings for Oil Field Production Equipment*) and RP-01-78 (*Design, Fabrication, and Surface Finish of Metal Tanks and Vessels to be lined for Chemical Immersion Service*) 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.

B.2.3 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 Standard RP-05-75 (latest edition)—*Recommended Practice—Design, Installation, Operation, and Maintenance of Internal Cathodic Protection Systems in Oil Treating Vessels,* presents guidelines and information on this subject.

APPENDIX C—TREATER DESIGN INFORMATION

FIELD NAME AND LOCATION ______________________________

DESIGN CONDITIONS

OIL RATE ______________ BBLS/Hr. OIL GRAVITY ______________ °API

OIL VISCOSITY SSU ________ @ ________ °F ________ @ ________ °F ________ @ ________ °F

POUR POINT ________ °F

WATER RATE ______________ BBLS/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 OF GAGE GLASS ____________________

SPECIAL PAINT OR 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. TURBOLATOR: ____________________

f. OTHERS ____________________

COMMENTS: ____________________

____

APPENDIX D—DESIGN AND SIZING CALCULATION

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 the 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.

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 formula:

$$R = \frac{1440(V)}{W} \qquad V = \frac{(W)(R)}{1440}$$

Where:

T = retention time, minutes
W = emulsion flowrate, Bbl/day
V = 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 settling 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.

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:

$$Q = (W_O)(C_O)(T2 - T1) + (W_W)(C_W)(T2 - T1)$$

Where:

Q = heat required, BTU/hr
W_O = flow rate of the oil, lbs/hr
W_W = flow rate of the water, lbs/hr
C_O = specific heat of the oil, btu/(lb-F)
C_W = specific heat of the water, btu/(lb-F)
$T1$ = initial temperature, F
$T2$ = final temperature, F

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

$$W_O = 14.58\,(W)\,(1\text{-}X)\,(s_O)$$
$$W_W = 14.58\,(W)\,(X)\,(s_W)$$

Where:

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

Where:

W = emulsion flow rate, bbl/day
X = volume fraction of water, fraction
s_O = specific gravity of oil, water = 1.0
s_W = 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.

$$Q = W\,(6.44 + 8.14\,(X))\,(T2 - T1)$$

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.

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 formula:

$$Q_l = K\,(D)\,(L)\,(T2 - Ta)$$

Where:

Q_l = heat loss, btu/hr.
K = Constant
= 15.7 for 20 mph wind
= 13.2 for 10 mph wind
= 9.8 for 5 mph wind
= 9.3 for still air
D = Diameter of treater, ft
L = Height or length of shell, ft
$T2$ = Treating temperature, F
Ta = Design minimum outside ambient temperature, F

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

APPENDIX E—EXAMPLE CALCULATION

DESIGN DATE

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	$T1$	= 70F	
Emulsion Treating Temperature	$T2$	= 120F	
Assumed Retention Times, Oil	R_O	= 60	minutes
Water	R_W	= 30	minutes

RETENTION VOLUMES

Oil

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

Water

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

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.

HEAT DUTY

Emulsion Heating

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

Heat Loss

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

Vertical Treater

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

Horizontal Treater

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

Total Heat Required

$$Qt = 240{,}120 \text{ btu/hr}$$
$$Qt = 216{,}360 \text{ btu/hr}$$

Table 3 indicates that both the vertical and horizontal 4' 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 (Table E-1).

SUMMARY

The horizontal 4' x 15' treater and the vertical 4' x 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 Appendix D, the above design procedure is limited and should be used with caution.

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 the manufacturer.

Table E-1

	Vertical Treaters		Horizontal Treaters	
Treater Size	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

APPENDIX F—STRUCTURAL DESIGN GUIDELINES

F.1

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 Boiler and Pressure Vessel 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.

F.2

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 ⅔ 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 may not be suitable for lifting the total assembly.

F.3

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

F.4

No more than two saddles should be used on a cylindrical shell.

F.5

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

APPENDIX G—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

APPENDIX H—COMBUSTION EFFICIENCY

H.1

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

Treater performance can be easily determined by an analysis and temperature of the flue gas taken from the base of the stack. Fig. 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 is used 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 to 400°F for sulfur contents ranging from approximately 0.05 to 1.0 percent by volume in the fuel gas. This 300-400°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 heating valve (HHV), operating with flue gas of 4 vol % residual oxygen and 900°F stack gas temperature.

From Fig. 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

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

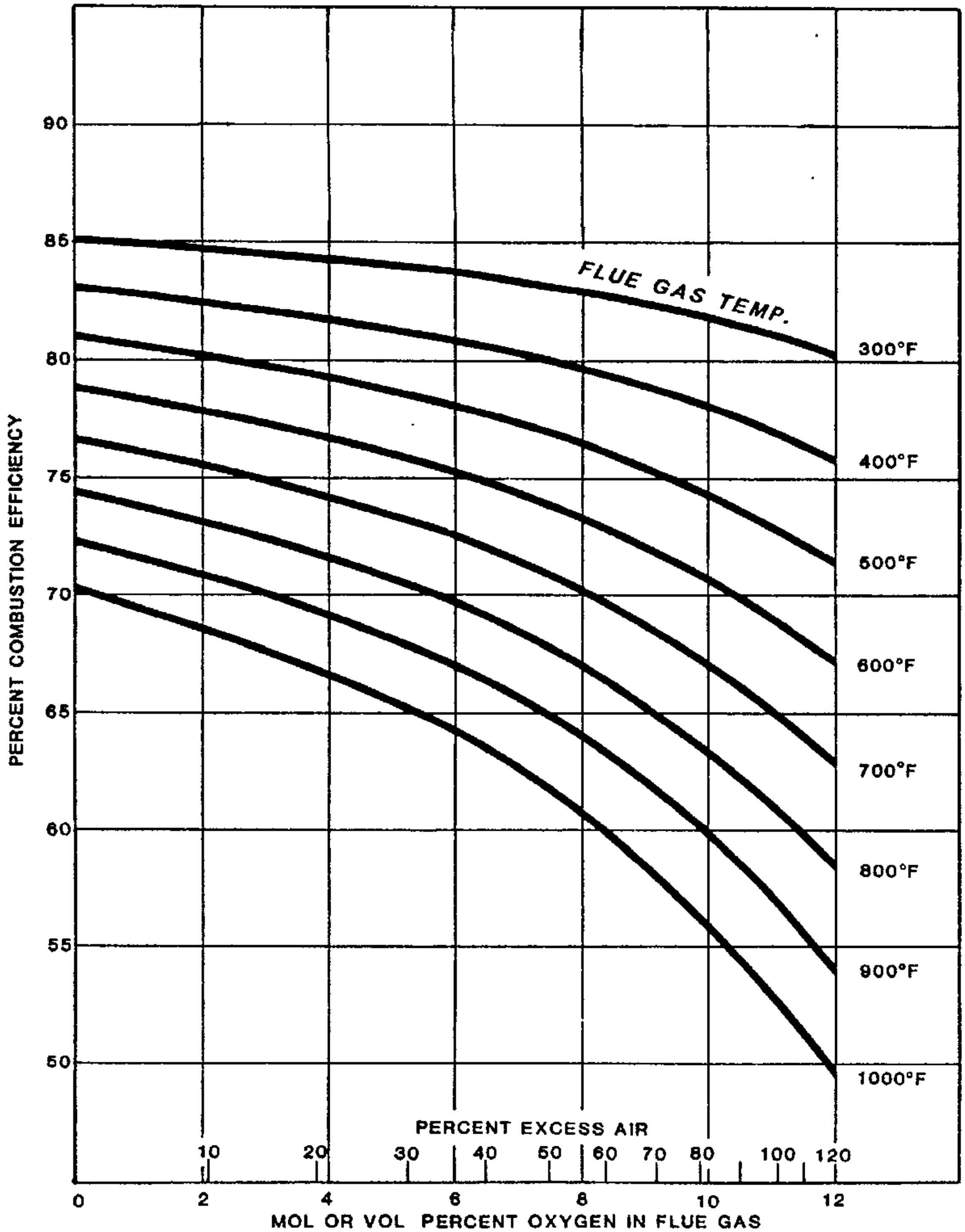


Figure H-1—Approximate Combustion Efficiency of Natural Gas (1050 BTU/SCF, HHV) in Emulsion Treaters

APPENDIX I—USE OF API MONOGRAM

The API monogram is a registered trademark of the American Petroleum Institute.

Manufacturers desiring to warrant that articles manufactured or sold by them conform with this specification shall obtain the license to use the Official API Monogram .

The original resolutions adopted by the Board of Directors of the American Petroleum Institute on Oct. 20, 1924, embodied the purpose and conditions under which such official monogram may be used.

The following restatement of the resolution was adopted by the Board of Directors on November 14, 1977.

WHEREAS, The Board of Directors of the American Petroleum Institute has caused a review of the Institute's program for licensing the use of the API monogram and

WHEREAS, It now appears desirable to restate and clarify such licensing policy and to confirm and make explicitly clear that it is the licensees, not API, who make the representation and warranty that the equipment or material on which they have affixed the API monogram meets the applicable standards and specifications prescribed by the Institute;

NOW, THEREFORE, BE IT RESOLVED, That the purpose of the voluntary Standardization Program and the Monogram Program of the American Petroleum Institute is to establish a procedure by which purchasers of petroleum equipment and material may identify such equipment and materials as are represented and warranted by the manufacturers thereof to conform to applicable standards and specifications of the American Petroleum Institute; and be it further

RESOLVED, That the previous action under which the following monogram was adopted as the official monogram of the American Petroleum Institute is reaffirmed;

BE IT FURTHER RESOLVED, That the American Petroleum Institute's monogram and standardization programs have been beneficial to the general public as well as the petroleum industry and should be continued and the Secretary is hereby authorized to license the use of the monogram to anyone desiring to do so under such terms and conditions as may be authorized by the Board of Directors of the American Petroleum Institute, provided that the licensee shall agree that the use of the monogram by such licensee shall constitute the licensee's representation and warranty that equipment and materials bearing such monogram comply with the applicable standards and specifications of the American Petroleum Institute; and that licensee shall affix the monogram in the following manner;

BE IT FURTHER RESOLVED, That the words "Official Publication" shall be incorporated with said monogram on all such standards and specifications that may hereafter be adopted and published by the American Petroleum Institute. as follows:

OFFICIAL PUBLICATION

REG. U.S. PATENT OFFICE

I.1 API Monogram

The API monogram— —is a registered trademark/servicemark of the American Petroleum Institute. Authorization to use the monogram is granted by the Institute to qualified licensees for use as a warranty that they have obtained a valid license to use the monogram and that each individual item which bears the monogram conformed, in every detail, with the API Specification applicable at the time of manufacture. However, the American Petroleum Institute does not represent, warrant or guarantee that products bearing the API monogram do in fact conform to the applicable API standard or specification. Such authorization does not include use of the monogram on letterheads or in advertising without the express statement of fact describing the scope of licensee's authorization and further does not include use of the monogram, the name AMERICAN PETROLEUM INSTITUTE or the description "API" in any advertising or otherwise to indicate API approval or endorsement of products.

The formulation and publication of API Specifications and the API monogram program is not intended in any way to inhibit the purchase of products from companies not licensed to use the API monogram.

I.2 Application for Authority to Use Monogram

Manufacturers desiring to warrant that products manufactured by them comply with the requirements of a given API specification may apply for a license to use the monogram with forms provided in an appendix to each specification.

The "Agreement" form must be submitted in duplicate for each specification under which monogram rights are desired. One "Statement of Manufacturer's Qualifications" is required for each facility.

A manufacturer desiring to apply the monogram at more than one facility (a facility is any manufacturing location) must submit a separate application for each facility.

Applicants shall have an approved functioning quality program in conformance with API Specification Q1 prior to being issued a license to use the API monogram.

I.3 Authorization to Use the Monogram

A decision to award or withhold monogram rights will be made by the staff of the Institute. A survey of the applicant's facilities will be made by an approved Institute surveyor prior to a decision to approve or withhold the license. The basis of the survey shall be the appropriate product Specification and all applicable portions of API Specification Q1.

For a manufacturer having more than one facility (plant), each facility will be judged separately and if determined to be eligible for authorization to use the monogram will be granted a separate license for each Specification, or part thereof, under which authorization is granted. The application of the monogram may not be subcontracted.

I.4 Fee for Use of Monogram

INITIAL AUTHORIZATION FEE

The applicant will be invoiced an initial authorization fee for the first Specification included in the application, and a separate fee for each additional Specification included in the application. The applicant will also be invoiced for the surveyor's fee.

ANNUAL RENEWAL FEE

In addition to the initial authorization fee, licensees will be assessed an annual renewal fee for each specification under which he is authorized to use the monogram. Applicants issued monogram certificates dated November 1 through December 31 shall not be required to pay a renewal fee for the following year.

The fees assessed are to defray the cost of the Monogram Program.

I.5 Periodic Surveys

Existing licensees must be periodically surveyed by an approved Institute surveyor to determine whether or not they continue to qualify for authorization to use the monogram. The frequency of the periodic surveys will be at the discretion of the staff of the Institute. The surveyor's fee and expenses for making a periodic survey will be paid by the Institute.

I.6 Cancellation of Monogram Rights

The right to use the monogram is subject to cancellation for the following causes.

a. Applying the monogram on any product that does not meet the Specification.
b. Failure to maintain reference master gages in accordance with the Specifications.
c. Failure to meet the requirements of any resurvey.
d. Failure to pay the annual renewal fee for use of the monogram.
e. For any other reason satisfactory to the Executive Committee on Standardization of Oilfield Equipment and Materials.

I.7 Reinstatement of Monogram Rights

Manufacturers whose authorization to use the monogram has been cancelled may request reinstatement at any time. If a request for reinstatement is made within sixty (60) days after cancellation, and if the reason for cancellation has been corrected, no new application is necessary. A resurvey of the manufacturer's facilities will be made by an approved Institute surveyor prior to a decision to reinstate monogram rights. The manufacturer will be invoiced for this resurvey regardless of the Institute's decision on reinstatement. If the resurvey indicates that the manufacturer is qualified, the license will be reissued.

Request for reinstatement made more than sixty (60) days after cancellation shall be treated as a new application unless circumstances dictate an extension of this time period as agreed upon by the API staff.

I.8 Appeals

An interested party may appeal any API standards action. Appeals shall be directed to the Director, API Production Department, and handled by the General Committee of the Production Department with a further right of appeal to the API Management Committee. Competing suppliers or manufacturers of the product or service to which the standard applies or might apply may not be involved in appeals. The General Committee and the Management Committee may convene appeals boards to hear and act on appeals.

I.9 Marking

The following marking requirements apply to licensed manufacturers using the API monogram on products covered by this specification.

I.10 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 12 below, as shown in Fig. I-1.

1. API monogram.
2. Spec 12L.
3. Manufacturer's name.
4. Manufacturer's serial number.
5. Year built.
6. Weight, empty pounds (lbs).
7. Shell size, outside diameter (OD), length seam to seam, feet, (ft).
8. Design pressure, pounds per square inch (psi) at temperature degrees Fahrenheit (°F).
9. Firebox rating, British Thermal Units per hour (BTU/Hr).
10. Firebox surface area, square feet (Sq. Ft.).
11. Additional information required by State or other political subdivision regulations.
12. Additional markings desired by the manufacturer or requested by the purchaser are not prohibited.

I.11 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 I.10 may be included on the ASME nameplate, otherwise two nameplates are required.

I.12

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

SPEC 12L

MANUFACTURER ____________________

SERIAL NUMBER ____________________

YEAR BUILT ____________________

VESSEL WEIGHT EMPTY ____________________

SHELL SIZE, OD x LENGTH __________ FT. x __________ FT.

DESIGN PRESSURE __________ PSI @ __________ °F

FIREBOX RATING ____________________ BTU/HR

Figure I-1—Suggested Vertical and Horizontal Emulsion Treater Nameplate

10/94—2M (Johnston)

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