TREATING OILFIELD EMULSIONS
FOURTH EDITION
# Treating Oilfield Emulsions

## Contents

<table>
<thead>
<tr>
<th>Illustrations</th>
<th>viii</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tables</td>
<td>vi</td>
</tr>
<tr>
<td>Foreword</td>
<td>ix</td>
</tr>
</tbody>
</table>

**Segment I**

<table>
<thead>
<tr>
<th>Objectives</th>
<th>ix</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chapter 1. The Treating Problem</td>
<td>1</td>
</tr>
<tr>
<td>Chapter 2. The Theory of Emulsions</td>
<td>3</td>
</tr>
<tr>
<td>Chapter 3. Emulsions and Production Practices</td>
<td>7</td>
</tr>
<tr>
<td>Chapter 4. The Basic Principles of Treating</td>
<td>11</td>
</tr>
<tr>
<td>Chapter 5. The Application of Heat in Treating</td>
<td>17</td>
</tr>
</tbody>
</table>

**Study Questions**

| Segment Questions | 27  |

**Segment II**

<table>
<thead>
<tr>
<th>Objectives</th>
<th>33</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chapter 6. The Principles of Chemical Treating</td>
<td>35</td>
</tr>
</tbody>
</table>

**Study Questions**

| Segment Questions | 49  |

**Segment III**

<table>
<thead>
<tr>
<th>Objectives</th>
<th>53</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chapter 7. Treating with Heater-Treaters</td>
<td>55</td>
</tr>
<tr>
<td>Chapter 8. Automatic Central Oil-Treating Systems</td>
<td>61</td>
</tr>
<tr>
<td>Chapter 9. Sampling Procedures</td>
<td>65</td>
</tr>
<tr>
<td>Chapter 10. Testing for Sediment and Water</td>
<td>71</td>
</tr>
<tr>
<td>Chapter 11. Treating Cost Records</td>
<td>79</td>
</tr>
</tbody>
</table>

**Study Questions**

| Segment Questions | 83  |

**Glossary**

| 89  |

**Index**

| 95  |

**Answer Key**

| 103 |
After completing Segment I, you should be able to —

1. Recognize the characteristics that make a well produce an emulsion.
2. Recall the conditions that may result in emulsion production.
3. State pipeline specifications for oil and identify the reasons for these specifications.
4. Recall refinery requirements for oil.
5. Identify the duties of the production foreman and the pumper (lease operator).
6. Recall the factors that should be considered in determining the type of treating.
7. Recall the consequences of using excessive heat in emulsion treating.
8. Identify emulsion components and types.
9. Identify the effect that chemicals, heat, and electricity have on an emulsion and recall when they are used in emulsion treating.
10. Recall the conditions that create a stable emulsion and recall how to prevent the formation of such an emulsion.
11. List the causes of agitation.
12. Recognize the flow line characteristics that may cause stable emulsions to form.
13. Recall ways of minimizing stable emulsions in pumping wells.
14. List the various treating methods and recall their effects on an emulsion.
15. Recall the factors that influence treating.
16. Recognize the equipment used in emulsion treating and recall how the various components operate.
17. List the main parts of an indirect heater.
18. Recall the proper procedure for firing up a heater.
19. Recall how an indirect heater operates.
At some time in the life of almost every oilwell, more water is produced with the crude oil than is acceptable to the pipeline company or other carriers. Some wells may produce water from the beginning, but, more often, water encroachment comes later in the life of the field. Figure 1 shows, in simplified form, one source of water produced with oil. Both oil and water are contained in the pores of the rock that makes up the reservoir. In figure 1, a large quantity of water lies under the oil. Early in the life of the field, some of the wells that are drilled near the point of oil-water contact (A) produce excessive amounts of water. Other wells, which are drilled higher on the reservoir (B, C), may produce clean oil at the beginning. Figure 2 shows the same reservoir later in the life of the field. Note the relationship at this later date between the position of each well and what each is producing.

Figure 3 illustrates another possible cause of water in oilwells. Casing failure coupled with a poor cementing job at a point above the producing zone allows water to enter the well and contaminate production. To correct the problem, the casing can be patched and a squeeze cementing job can be performed, or a packer can be placed in the tubing-casing annulus to form a temporary seal above the oil zone and exclude the water.

Figure 1. Sketch showing relative position of oil and water in early life of reservoir. Well A requires plugging back. Wells B and C produce clean oil.

Figure 2. Same reservoir as in figure 1, portraying later conditions in life of field. Well A is completely watered out. Well B produces water and cut oil. Well C continues to produce clean oil.
An emulsion is a combination of two liquids that do not mix under normal conditions. Such liquids are said to be immiscible, or incapable of mixing. In an emulsion, one of the liquids is spread out, or dispersed, throughout the other in the form of droplets. These droplets can be of all sizes, from fairly large to very small. Sometimes droplets are so small that more than fifty of them could be placed on the head of a pin. A stable emulsion is an emulsion that will not break down without some form of treating. Three conditions are necessary for the formation of a stable emulsion: (1) the liquids must be immiscible; (2) sufficient agitation must occur to disperse one liquid as droplets in the other; and (3) an emulsifying agent, or emulsifier, must be present.

Many emulsions, such as insecticides and medicines, are prepared for commercial use. They are made up of two or more liquids that do not normally mix, plus the emulsifying agent. A common household emulsion is mayonnaise. Basically, it is made of vegetable oil and vinegar with eggs used as the emulsifying agent. This combination would not remain mixed if the eggs, or some other emulsifying agent, were not present. The oil and vinegar could be mixed by violent agitation, but they would soon separate after agitation was stopped. Similarly, to form a stable emulsion of crude oil and water, an emulsifying agent must be present. Emulsifying agents commonly found in petroleum emulsions include asphaltenes, resinous substances, oil-soluble organic acids, and other finely divided materials that are more soluble, wettable, or dispersible in oil than in water, for example, iron, zinc and aluminum sulfates, calcium carbonate, silica, and iron sulfide. Each of these emulsifiers usually occurs as a film on the surface of the dispersed droplets.

In an emulsion, the liquid that is broken up into droplets is the discontinuous, dispersed, or internal phase. The liquid that surrounds the droplets is the continuous, or external, phase. An emulsion of oil and water may have either oil or water as the dispersed phase, depending on the characteristics of the emulsifying agent. In most cases, however, water is dispersed as droplets in oil (fig. 4). An oil-water emulsion may contain from a trace to 90 percent or more water. An emulsion may also be tight (difficult to break) or loose (easy to break). Whether an emulsion is tight or loose depends on a number of factors, four of which are (1) the properties of the oil and water; (2) the amount of agitation, or shear, it undergoes; (3) the percentage of oil and water found in the emulsion; and (4) the types and amount of emulsifiers present.

Occasionally, emulsions produced from some fields are reverse emulsions, in which oil is the internal phase and is dispersed as droplets in water. Very rarely, oil is produced in a dual emulsion, in which the dispersed phase is droplets of oil-in-water emulsion and the external phase is oil. As stated before, however, most oilfield emulsions are normal emulsions in which water is dispersed throughout the oil.

In a water-in-oil (normal) emulsion, two forces are in direct opposition. One force is the film of emulsifying agent that surrounds the water droplets. This force tends to prevent the droplets from merging to form larger drops, even when the droplets collide. The other force is the opposite tendency, that of water droplets to join to form larger drops. Larger drops tend to yield to the
As oil and water are produced from a well, if an emulsifying agent is present and if agitation of this combination of well fluids occurs, an emulsion will form. Once an emulsion forms, it may remain loose and be relatively easy to treat or it may, because of the way in which it is handled in the production system, turn into a stable and difficult-to-treat emulsion. Unfortunately, many other problems occur besides those involving emulsions, and sometimes the action required to solve those problems may not be ideal for preventing the formation of tight emulsions. Instituting new methods or installing new equipment just to minimize the formation of tight, stable emulsions is, however, frequently not economically justifiable. Operators must formulate production techniques by taking into account all factors, not merely those that pertain to emulsion problems.

Each oil well has its own characteristics and offers individual problems, but previous experience on similar wells often indicates a solution. Trial and error, however, is sometimes the only way to find the cause or to minimize the formation of a difficult emulsion. Some general practices are available, however, that, if followed, can reduce oil-and-water emulsification.

As mentioned before, certain conditions must exist before an emulsion can form: (1) the liquids must be immiscible; (2) sufficient agitation must occur to disperse one liquid as droplets in the other; and (3) an emulsifying agent must be present to stabilize this dispersion. In oil production, all of these conditions frequently occur. In some cases, however, it is possible to minimize, if not prevent, two of the three conditions. Since treating is done to disrupt or counteract the effect of the emulsifying agent, either (1) water and oil must not be produced simultaneously, or (2) any agitation great enough to form a more stable emulsion must be avoided. Water production can sometimes be reduced, if not eliminated, by remedial cementing procedures, such as plugging back the wellbore, so that the production is withdrawn from a point higher in the reservoir. Because it is usually very difficult to exclude water from the wellbore completely, however, the best method for avoiding a tight, difficult-to-treat emulsion is to minimize agitation.

The amount of water that disperses in oil with a given amount of agitation depends on the relative amounts of the two liquids. If there is not much water, not much agitation is needed to disperse it in the oil. Conversely, if there is a lot of water, a lot of agitation is needed to disperse it in the oil. If there is a lot of water in an emulsion being agitated, the emulsion tends to break down because the large number of water droplets in the emulsion strike each other frequently, coalesce, and fall out. Therefore, less water gets dispersed, and the stability of the emulsion is reduced. It is possible, in some instances, to reduce treating difficulties by adding water to the well fluid ahead of the point of agitation. This procedure is used in relatively few cases, however.

A free water knockout—a vessel that removes free water from the well fluids—may be placed ahead of the point of agitation. This works very well if the well fluid is easily separated into free oil and water; however, this procedure could have a detrimental effect if the presence of excess water makes the emulsion looser.

**Minimizing Stable Emulsions in Flowing Wells**

Violent agitation of oil and water being produced in flowing wells causes water droplets to disperse in the oil and leads to the formation of very stable emulsions, which are often difficult to treat. Such agitation is caused primarily by gas coming out of solution as pressure is decreased and by turbulence that occurs when production flows through restrictions, fittings, and sharp bends in the tubing and lead lines.

**Surface Chokes**

When a surface choke or a back-pressure valve is used to control production, most of the emulsion is formed immediately downstream from it. Upstream from the choke or the valve, pressure is relatively high compared to that on the downstream side. (Higher upstream pressure can be confirmed by noting that tubing pressure at the
For purposes of this manual, *treating* refers to any procedure designed to separate foreign matter from crude petroleum. *Foreign matter* may include water, salt, sand, sediment, and other impurities in oil; paraffin wax and asphaltenes are not considered impurities here. Basically, treating involves allowing time for water to settle out of an emulsion and be drained off. Settling time and draining are accomplished in various mechanical devices such as gun barrels (wash tanks) and free-water knockouts. To speed up settling time, one or more of the following procedures may also be used:

1. applying heat;
2. applying chemicals;
3. applying electricity; and
4. adding diluents to reduce viscosity.

**Factors Influencing Treating**

The factors involved in treating water-in-oil emulsions include breaking the films surrounding the small water droplets, coalescing the droplets to produce larger drops, and allowing the water drops to settle during or after coalescence. In theory, all emulsions separate into oil and water if allowed to settle for an unlimited time. Indeed, a considerable amount of water produced with petroleum does separate without the assistance of heat, chemicals, or other devices. However, the small water particles in water-in-oil emulsions are usually surrounded by a tough film that gives the appearance of plastic wrap when viewed under a microscope (fig. 10). This film resists being broken, and, until it is broken, the water droplets cannot coalesce—at least, not in any reasonable length of time (fig. 11). Therefore, heat, chemicals, electricity, mechanical devices, and various combinations are normally required to cause the film around the water droplets to break and coalesce (fig. 12).

It should be emphasized that no two oilfield emulsions are alike. The procedures used to treat the emulsion produced from one field almost never work on an emulsion from a different field. In fact, the emulsion produced from individual wells within the same field sometimes varies.

![Figure 10](image10.png) A photomicrograph of a water droplet in a water-in-oil emulsion. Note that the rigid film surrounding the water droplet looks like plastic wrap.

![Figure 11](image11.png) A photomicrograph of a water-in-oil emulsion showing two water droplets touching but unable to merge because of film around the droplets.

![Figure 12](image12.png) A photomicrograph of a single water droplet in a treated emulsion. Note that the film is breaking.
Heat alone does not cause an emulsion to break down, except in rare instances. Usually, the application of heat is an auxiliary process to speed up separation. Indeed, if at all possible, heat is eliminated entirely from the treating process. Further, in those cases where heat is necessary, the heater is usually an integral part of a single treating vessel in which heating and treating are both accomplished. Because separate heaters are sometimes employed in treating systems on certain leases, and because the operation of separate heaters is applicable to the operation of heaters combined with treating vessels, it is worth studying them.

Indirect Heaters

While a few direct heaters are still in use where separate heaters are employed, far and away the most common type of heater is the indirect heater. Unlike direct heaters, in which emulsion is put into direct contact with fire tubes, indirect heaters are constructed so that a hot water bath transfers its heat to the emulsion.

An indirect heater consists of three main parts: (1) the shell; (2) the flow-tube bundle; and (3) the fire tube (fig. 20). In operation, the shell is filled with a bath of water, corrosion inhibitors, and, in cold climates, diethylene glycol, or antifreeze. The water bath transfers heat from the fire tube to the flow-tube bundle. As cold emulsion passes through the bundle, it is in turn heated to a selected outlet temperature. The heated water bath circulates in the shell by means of a thermosiphon effect, in which the warm water rises and the cool water falls to be reheated by the fire tube. The fire tube and flow-tube bundle are removable for easy cleaning, inspection, and replacement.

Since the flow tube is subject to corrosion both from the emulsion flowing inside it and from the water bath surrounding it, the return bends in the flow tube are safety drilled, that is, a small hole on the outside of each bend is drilled about halfway through the metal of the tube where corrosion forces are most concentrated (fig. 21). When corrosion erodes through a safety drilling—about half of the flow tube's thickness—emulsion will leak through the corroded safety drilling and into the water bath. An alert operator will be able to see the leaking emulsion in the water bath and know that repair is required before continuing to operate the heater.

Figure 20. An indirect heater
After completing Segment II, you should be able to —

1. Identify the conditions that determine when chemicals should be added in the treating process.
2. Identify the various points at which chemicals can be added in the treating process and recall the advantages and disadvantages of each.
3. Recall the ways in which chemicals may be added in the treating process.
4. Recall the types of chemical feed pump, how they operate, and how they are maintained.
5. Identify the effects of temperature and settling time on chemicals used in treating.
6. Identify the reasons for the appearance of free water in an oil stock tank and list possible remedies.
7. Recall the reason for performing a bottle test on a normal and a reverse emulsion and how this test is performed.
8. Identify solvents that may be used to dilute a chemical demulsifier.
9. List the steps in a centrifuge test using slugging compound.
10. Recall the purpose of a ratio test and how one is performed.
11. Explain why reverse emulsion tests are becoming more common and how they differ from bottle tests used for normal emulsions.
12. List the steps for selecting the preferred chemical compound for treating an emulsion.
13. Explain what to do with the results of a bottle test.
14. Determine the best point at which to add chemical to the production system.
In the early days of the oil industry, treating was a makeshift proposition, with each lease handled differently. Many operators depended on the people in the field to treat the oil and made no organized effort to determine which chemicals were most efficient at breaking emulsions. During this period, however, many chemicals were found, through trial and error, to be beneficial, including lye, hydrochloric acid, and soap powders. The chemical companies now familiar to the petroleum industry got their start experimenting with these chemicals. Today the principal business of a number of companies is the manufacture and sale of modern emulsion-breaking compounds and other oilfield chemicals. Several companies have research laboratories and a force of field engineers to assist the producer in selecting the proper chemicals and in other matters pertaining to treating done in the field.

For a chemical to work as an emulsion breaker in a water-in-oil emulsion, it must be able to deactivate the emulsifying agent that surrounds the dispersed water droplets. Chemicals that are soluble or dispersible in oil and surface-active (i.e., they dissolve in the oil and work on the surfaces of the water droplets to cause them to break) are added in small amounts at some point in the treating system. Emulsion-breaking chemicals must also be polar materials; that is, they must be attracted to the emulsifying agents, which are also polar materials. This attraction is much like the action of two bar magnets being drawn to each other. The chemical contacts the emulsifying agent and, in effect, weakens it. When the freely moving water droplets in the oil collide, the droplets easily merge to form larger drops that will settle out. Figure 23 shows two samples of the same emulsion, one with and one without the addition of an emulsion-breaking chemical.

Chemicals used to treat reverse, or oil-in-water, emulsions differ from those used to treat water-in-oil emulsions in that they are water soluble; that is, they dissolve in water so that the chemical can contact the surface of the oil droplets suspended

![Figure 23. Two samples of the same water-in-oil emulsion maintained at the same temperature over a number of days. Demulsifier has been added to the lower sample. No chemical has been added to the top sample.](image-url)
After completing Segment III, you should be able to—

1. Recall the differences between the types of heater-treaters and how they operate.
2. Explain how a central oil-treating system works.
3. List the basic principles of tank sampling and tell when a sample is acceptable.
4. List the types of sample and explain the differences between them.
5. Describe the API-recommended method of determining S&W in a sample.
6. List the API-recommended steps in saturating a solvent with water.
7. List the types and uses of treating cost records.
A heater-treater (also called a flow treater or emulsion treater) is a device that combines all the various pieces of equipment used to treat an emulsion in one vessel. Thus, a heater-treater is the vessel in which the effects of chemicals, heat, settling, and, often, electricity are applied to an emulsion.

**The Construction of Heater-Treaters**

A heater-treater (fig. 32) is designed to include in one unit any or all of the following elements: oil and gas separator, free-water knockout, heater, water wash, filter section, stabilizing section, heat exchanger, and electrostatic field. A large number of modifications in the basic pattern of heater-treaters are available. Any of its functions may be emphasized, depending on the service for which it is designed. For example, a heater-treater may have greater free-water capacity or less heating capacity, and it may or may not have a hay section—a section packed with excelsior, which acts as a filter. In addition, each model may be available in a number of sizes to handle different volumes of well fluids and may be available in a vertical or a horizontal configuration. Some treaters are designed for use in extremely cold climates; others are designed especially to treat foaming oil. Selecting the right treater for any given set of conditions is a complex engineering decision that can be made only after a large number of factors are known.

**Types of Heater-Treaters**

Treaters can be operated at atmospheric pressure, but they often operate under low working pressure—from 5 to 50 psi—depending on the construction of the vessel and the type of controls needed. It is often advantageous to use the treater as a low-pressure, second-stage separator as well as a treating unit. Where flow-line pressures are low, it can be used as a primary separator, thus eliminating the need for a regular separator. Use of the treater as a second-stage separator may increase the API gravity of the oil over that which was obtained with other types of treating equipment and thus increase the selling price of the oil.

**Vertical Heater-Treaters**

In vertical heater-treaters, the emulsion usually passes through a heat exchanger, where it is preheated by the warmer outgoing clean oil. Then the emulsion enters the vessel, splashes over a pan, and falls downward through a downcomer tube. At the bottom, any free water in the emulsion falls out, and the emulsion flows upward through the water, which serves as a washing medium. The water is heated by a fire tube projecting into this compartment. After leaving the heated water wash, the emulsion rises into a settling space where water broken out of the emulsion settles out and falls back into the water.
In areas where one company operates a number of leases, all of which are established in a particular field, it is possible to employ an automatic central treating facility to handle the emulsion from most or all the leases. Figure 39 shows such a facility. Where applicable, a central treating plant can effect great savings. Traditionally, a treating plant was set up on each lease, but with the advent of automation and computerized production control, production from all leases can now be commingled, or mixed together, and then piped to a large central plant, where all the production is treated. Because no actual treating vessels are installed at the individual lease sites, one large facility replaces a number of plants.

In a typical central treating facility, the well or wells on each lease are produced into a header. The well fluids are normally diverted into production separators by use of automatically actuated valves (fig. 40). If a well is to be tested, the valve on the header can be directed automatically to divert the well fluids to a test separator. The automatic valves are usually equipped with diaphragm or motor actuators, which are, in turn, electrically operated by a solenoid that is controlled by an electronic computer. The separators are generally located at some convenient point on each lease; they may be either two- or three-phase (fig. 41), depending on the characteristics of the fluids being produced. Treating chemical is usu-

Figure 39. A central treating station with free-water knockout, electrostatic treaters, and stock tanks. A vapor recovery system, not visible, is also in use.
All oil delivered to pipeline companies is subject to their testing. Therefore, to assure that the oil will be accepted, the producer should sample and test the oil in the same manner as prescribed by the pipeline company that purchases it. The procedures for taking samples and making water and sediment tests vary from field to field and company to company and must be agreed on by both the buyer and the seller. Any agreement found to be mutually acceptable serves the purpose.

The Measurement Coordination Department of the American Petroleum Institute has published standards for measuring, sampling, and testing petroleum and petroleum products. These standards reflect procedures that are considered acceptable in the absence of any specific agreement between the buyer and the seller of crude oil; they are not intended to conflict with or supersede any contractual agreement entered into between the buyer and the seller. The material for this chapter is drawn from API, Manual of Petroleum Measurement Standards (MPMS), chapter 8, section 1, Manual Sampling of Petroleum and Petroleum Products, and chapter 8, section 2, Automatic Sampling of Petroleum and Petroleum Products.

The basic principle of any sampling procedure is to obtain a sample or a composite of several samples that is truly representative of the oil in a tank or other container. The sample can then be tested to determine properties that have a bearing on the measurement of the oil sampled. Two basic sampling methods are available: tank, or manual, sampling; and automatic sampling. If, however, a tank's contents are not homogeneous from the top to the bottom, or if certain other conditions are not met, automatic sampling is recommended. For tank sampling to be acceptable, the contents of the tank must be homogeneous and (1) the tank must contain a heavy component (such as water), which clearly separates from the main component, (2) the tank must be equipped with either a swing suction or a weir on the outlet that prevents shipment of the heavy component, and (3) the tank samples must be taken so that none of the heavy component is included. In addition to automatic sampling, API recommends three manual procedures suitable for sampling tanks that contain crude oil: thief sampling, bottle sampling, and tap sampling.

Thief Sampling

Probably the most common method of obtaining samples of crude oil in lease tanks is by means of a thief. A thief is a round tube with a uniform cross section, that has a capacity dependent on the size of the sample required (fig. 46). It is suspended by a chain or rope at its upper end; a
After a representative sample has been obtained, the next operation is to determine the percentage of S&W present in the sample, thus ensuring that the oil meets pipeline specifications. Or, as stated in API, MPMS, chapter 10, section 4, Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure), second edition, May, 1988, "A determination of sediment and water content is required to determine accurately the net volumes of crude oil involved in sales, taxation, exchanges, inventories, and custody transfers. An excessive amount of sediment and water in crude oil is significant because it can cause corrosion of equipment and problems in processing and transporting and may violate federal, state, or municipal regulations." The testing method presented in this chapter is paraphrased or quoted from MPMS, chapter 10, section 4.

The most common method of determining the percentage of S&W in treated oil on a lease employs a centrifuge. In brief, the procedure is to place known volumes of crude oil and solvent (water-saturated, if required) in a centrifuge tube and to heat them to 60°C ± 3°C (140°F ± 5°F). For some waxy crude oils, temperatures of 71°C (160°F) or higher may be required to melt the wax crystals completely so that they are not measured as sediment. If temperatures higher than 60°C (140°F) are necessary to eliminate this problem, they may be used with the consent of the parties involved.

Table 3 shows rotation speeds necessary to produce the required relative centrifugal force for centrifuges of various sizes. An equation may also be used. If the diameter of the swing is in mm (swing diameter is the distance between the tips of opposite tubes when the tubes are in their rotating position), the equation is

\[ \text{rpm} = 1,135 + \text{rcf} + d. \]

If the diameter of the swing is in inches, the equation is

\[ \text{rpm} = 265 + \text{rcf} + d. \]

5. Use the top 50 ml (100 parts) of the mixture from each tube for test purposes. Take particular care not to pour any of the free water in the tip of each tube into the sample.
Treating Oilfield Emulsions

age, effect of
on emulsions 9, 36, 37
on solvent solutions 38
agitation 7, 8, 10–15, 42–43
causes of 11
in pumps 13
effect of
on amount of water dispersed in oil 11, 42–43
on emulsion formation 10–15
on emulsion stability 7, 8, 11
on reverse emulsions 40
role of
in emulsion formation 13–14
in stable emulsion formation 7
air-gas adjustment 24
alcohols 38, 42
methanol 38
Stoddard solvent 38, 71
toluene 38, 71
aluminum sulfates 7
API gravity 6, 9, 25, 55
apron, 19, 20, 67
asphaltene 7, 9, 17
atmospheric pressure 20, 37, 44, 55
automatic central treating facility 61–64
basic sediment and water (BS&W) 37. See also sediment and water.
batch treating 37, 43, 46–47, 80
blizzard box 59
bottle test. See tests: bottle
bottomhole choke 12
Brownian movement, 8
BS&W 37. See also sediment and water.
calcium carbonate 7
capacitance probe 62, 63
capital outlay 5. See also costs.
carbon 9
cement 3, 4, 11
central treating plant 61–64
centrifuges 37–38, 39, 71–78
API requirements for 72–73
centrifuge tubes 73
chemical 4, 11, 17, 35–47
added by means of flow-line lubricator 44, 47
application, types of 43
compared 43–47
combined with solvent 38
early use of 35
effect of
on emulsions 8
on settling time 17
on water droplet size 18
temperature on 36
emulsion-breaking, characteristics of 35
injection 46, 60
point of 36, 44
point of application of 42–47
related to settling time 36
speed of 36
surface-active 8, 9, 35
tank 46
to combine with solvent 38
classes
clearance volume 13
coaclusation 36
corrosion 4, 6, 23, 25, 57, 60, 79
cost records 5, 6, 79–81
costs
batch treating 80
chemical 5, 80
equipment 79
fuel 5
initial treating 79
installation 79
investment 79, 80
labor 79, 80
maintenance 79, 80, 81
material 79, 81
of gas losses 12
operating 80
other expenses 80, 81
production 5
transportation 79, 81
treating 5, 79–81
CPC 62
demulsifier 8, 35, 38, 74. See also chemical; emulsifying agent
desalting plant 58–59
diluents, effect of 
on settling time 17
on viscosity 18
on water separation 18
discharging phase 4, 7
dispersed phase 4, 7
dispersion 11, 43–44
medium 4
distributing rack 18
downcomer tube 55
downhole treating 43–44
electricity 8
  effect of, on settling time 17
  use of, in treating 8
electrostatic fields 18, 55
  effect of, on water droplet size 17
treater 56, 63
emulsification 13–14
  effect of pump efficiency on 13–14
emulsifying agent 7–9, 11, 35–36, 42–43
emulsion 4, 5, 8, 13–14, 20
  age of, 8–9
  behavior of 36
  changes in, over time 17–18
  conditions for formation of 11
  differences between 18
  dual 7
  effects of
    age on 36
    heat on 25, 36
  formation of 11, 12
  how to determine treatment of 11
  loose 7, 11
  normal 7, 8, 9, 17, 18, 70
  oil-water 7, 8, 18
  reverse 7, 8, 35, 40
  effect of agitation on 42–43
  stability of 8–10, 11–14
  sight 7, 11
  factors determining 7
  water-in-oil 7, 8, 9, 17, 18, 70
emulsion-breaking compounds 8, 35, 38, 74. See also chemical; emulsifying agent.
equipment wear, factors in 6
erosion 4
excelsior 19, 21, 55, 59, 60
expenses. See costs.
external phase 7
fail-safe devices 25, 63
field foreman 5
field testing 40
filter section 55
firebox 24
fire tube 23, 24, 25, 55
flame, color of 24–25
flow-line lubricator 44, 47
flow lines, laying of, and emulsion formation 14
flow-tube
  bundle 23, 24
  failure 24
foreign material 4, 17, 58
  allowable percentage of 4
free oil 11
free water. See water: free.
free-water knockout (FWKO) 11, 17, 55, 60, 63
  definition of 21
  three-phase 21, 63
  two-phase 21
FWKO. See free-water knockout.
gas
equalizers 20
gathering system for 14, 20
in pumping wells 17
leaving solution 11, 12, 59
lift wells 12–13
lines 20
removal of, from well fluid 20
separation of 20
gathering system 14, 20
gauge glasses 20
glassware, cleaning of 42
glycol 24
grasshopper 20
gravity 8, 9, 18, 19, 25, 60
differential 18, 40
  definition of 18
  effect of
    on treating 18
    on treating procedures 18
    on water separation 18
effect of
  on emulsion formation 14
  on reverse emulsions 40
flow 14
  gathering system, compared to pumping system 14
losses 25
  compared to volume losses 25
  used to move well fluids 14
gun barrel 17, 19–20, 21, 61
  functioning of 20
  parts of 19

hay 19, 21, 55, 59, 60
header 63
heat 5–6, 17, 41
  and chemicals, when to add 18
  application of, in treating 23–25
  effect of
    in testing 41
    in treating 5–6
    on chemicals 36
    on conservation of resources 25
    on emulsions 8, 18, 25, 36
    on API gravity 25
    on oil 25
    on settling time 17
    on viscosity 9, 18
    on volume 25
    on water separation 18
exchanger 55–56, 63
heater 55, 60
  burner safety-shutdown control 25
  direct 23
  fail-safe devices 25
  fire tube 23, 24, 25, 55
  indirect 23–24
    compared to direct 23–24
    firing up of 24–25
    functioning of 23–24
    inlet gas regulator 25
    maintenance of 24
    parts of 23, 24, 25
heater-treater 55–61
  Chemelectric® 57, 58
    advantages of 57
    when to use 57–58
  electrochemical. See Chemelectric®.
  electrostatic See Chemelectric®.
    functioning of, in cold climate, 59
  horizontal 56–57
    compared to vertical 56
    disadvantage of 56–57
improper functioning of, 60
  modification of, for cold climate 59
    modification of, for tight emulsion 59
operation of 60
  parts of 55
  types of 55
  vertical 55–56
heating
  section 59
  system 36
hydrochloric acid 35
immiscibility 7, 11
improved recovery methods 4
initial treating installation 5
inlet line 19
intermitters 12
  compared to bottomhole chokes 12
  compared to surface chokes 12
  effect of, on agitation 12
  role of, in emulsion formation 12
internal phase 7
investment, initial 5
iron
  sulfates 7
  sulfide 7
kerosene 38, 42, 71
knockout drops 37, 40
LACT unit. See lease: automatic custody transfer (LACT) unit.
lease
  automatic custody transfer (LACT) unit 14
  operator 5, 36, 41
  superintendent 5
light ends 5, 6, 19
liquids
  density of 9
  immiscible 7
  weight of 9
losses
  gravity 36, 56
  heat 60
  volume 25, 36
lye 35
maintenance costs 5, 80, 81
measurement, API standard for 65
meniscus 74
methanol 38
naphtha 42
net-oil
  computer 62
  volume 62

oil
  and gas separator 19
  -emulsion interface 20
  free 11
  outlet line 20
  produced 24
  -soluble organic acids 7
  viscosity of 8, 9, 18, 36, 40, 43, 71
  water-cut 14, 18
  -water contact 3
  -water interface 8, 20, 56, 67, 77
  wet 14
  zone 3
operating conditions 79
operating costs 79, 80
organic acids 9
outside siphon 20
paraffin wax 17
perforating 4, 12
phase inversion 8
pilot light 24
pipeline specifications 4, 37, 71
plant efficiency 80
plug-back procedures 4, 11
polar
  materials 35
  molecules 8
preheaters, API requirements for 73
preheater section 60
pressure
  across choke 11-12
  atmospheric 20, 37, 44, 55
  differential 12
  drop 12, 37
  flow-line 55
  high 11, 12
  inlet gas 25
  separator 12
  tubing 11
  upstream 11
price of crude oil, determinants of 5-6
producing zone 3
production
  balancing 12
contaminated 3
control of 12
expense 5
foreman 5
  duties of, in treating 5
practices
  effect of, on treating of emulsions 11
regulation of 11-12
system 40, 42
pump
  chemical feed 44-46
  types of 44-45
efficiency
  achieving of 13-14
  effect of, on agitation 13-14
  effect of, on emulsification 13-14
plunger clearances
  effect of, on emulsification 13
positive-displacement 14
pounding, effect of, on emulsification 13
pumping
  effect of, on emulsion formation 14
  effect of, on fluid agitation 14
wells, emulsification in 13
pumps
  centrifugal, effect of, on emulsification 14
  chemical injection 41, 44-46
  positive-displacement, effect of, on emulsification 14
ratio of treating compound to emulsion 36
records, treating cost 79-81
recovery methods
  cyclic steam injection 40
  enhanced 4
  huff 'n' puff 40
  improved 4
  primary 4
  secondary 40
  tertiary 40
reports, plant performance 80, 81
resinous substances 7
restrictions
  effect of, on emulsion formation 11
  type of 11-12
rust 25
safety drilling 23
salt 9, 17, 24, 57
  content 5, 58
saltwater and sediment content 5
sample
agitated 37
all-level 66, 67
bomb 37
bottle, methods of obtaining 66-67
clearance 67
cock 36, 67
composite 37, 65
emulsion 37, 38
freshness of 36
order of obtaining 66, 68
receivers, API-recommended designs for
representative 36, 37, 71
running 67
size of 37
tank 67
treated 37
untreated 37
sampler, automatic 68-69
sampling
API standard for 65
automatic 68-70
basic principles of 65
bottle 66-67
deVICES 74
beaker 74
bottle 74
LACT sample container 74
manual 65
methods of 65
tank 65
tap 67-68
thief 37, 59, 65-66
use of solution in 38
sand 17
S&W. See sediment and water.
scale 6, 25, 58, 69
sediment 17
primary 37
secondary 37, 40
sediment and water (S&W) 37, 38, 39, 41, 58, 71,
76, 77
determining percentage of 71
in a sample, API-recommended procedure for determining 74-77
separation 15, 23, 39, 40, 62
of gas from oil 12
of oil and water 17
separator 15, 45, 55, 64
horizontal 15
oil and gas 55
primary 55
production 61
second-stage 55
test 61
three-phase 61
two-phase 61
settling 18, 20
rate 18
section 60
space 55
tank 18-19
time 17, 36, 58
ways to speed up 17
shear 7, 10, 37
silica 7
siphon box 56
skim pit 19
slugging compound 37, 40
soap powder 35
solution 38
1-percent 38, 40, 42, 43
10-percent 38, 39-40, 41, 42
2-percent 38
use in sampling 38
solvents 37, 38, 39, 71-72, 74
alcohols 38, 42
API-recommended 71-72
health risks associated with 38, 72
avoiding 72
kerosene 38, 42, 71
Stoddard 38, 71
to combine with chemicals 38
toluene 38, 71
water saturation of, API-recommended
procedure for 71-72
water 38
xylene 38, 42, 71
specific gravity 8, 9, 18, 20
specifications, pipeline 4, 37, 71
spreader 19, 20
stabilizing section 55
steam, injection of, into reservoir 3, 40
stock tank 14, 36, 60
Stoddard solvent 38, 71
surface-active agent 8, 9, 35
surface choke 11-12
surfactant 8, 9, 35
surge tank 19
swing diameter 71
tank battery 5
temperature 18
   bottomhole 12
   effect of
      on chemicals 36
      on treating 18
      on viscosity 18
   of emulsion 36
   surface 12
testing
   API standard for 65
   by pipeline companies 65
   by producers 65
tests
   bottle 36–42, 60
   centrifuge 37
   field 40
   for S&W 37
   on reverse emulsions 40, 42
   ratio 39, 40–41
   to compare treating compounds 40–41
   with concentrated compounds 40
thermometers, API requirements for 73
thermosiphon effect 23
thief 37, 59, 65–66
toluene 38, 71
treating 3–6, 17–22, passim
   batch 37, 43, 46–47, 80
   when to use 47
   compounds 39–40, 43
   cost records 5, 79–81
   costs
      determining 79
      outlined 80–81
      types of 79–80
   definition of 4, 17
downhole 43–44
   advantages of 44
   effect of
      age of field on 18
      amount of water on 11
      emulsion differences on 18
equipment 5, 6, 55
   facility 5
   set up 5
   factors involved in 17–18
flow-line 44
installation 5
plant 5, 80
   size of, related to
      chemicals used 36
      settling time 36
      temperature 36
   purpose of 4, 18
   program, establishing 18
   reasons for 4
   role of
      production foreman in 5
      pumper in 5
system 35–36
   total costs involved in 5–6
   types of, compared 40–41
   vessel 23, 55–61
valves
   back-pressure 12
   dump 14
   standing 13
   traveling 13
   vacuum relief 59
 viscosity 8, 9, 18, 36, 40, 43, 71
   effect of, on treating 18
   volume losses 25, 36
washing 18
wash tank 17, 19–20
water 3, 9, 11, 17, 38
   contamination 4
droplets
   coalescing of 11, 17, 18
   film around 17
   methods for breaking 18
      size of 18
   encroachment 4, 5
   causes of 3, 4
   prevention of 4
free 4, 9, 11, 14, 18, 20, 21, 35, 36, 37, 55, 54,
   60, 61, 63, 67
   removal of 21
fresh 9, 40, 58
injection of, into reservoir 4
in oilwells 3
layer 18, 19, 20, 55, 59
leg 19
-oil interface 8, 20, 56, 67, 77
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