Bulletin 232

DEPARTMENT OF THE INTERIOR
HUBERT WORK, SECRETARY.
BUREAU OF MINES
H. FOSTER BAIN, DIRECTOR

MANUAL FOR OIL AND GAS OPERATIONS

INCLUDING OPERATING REGULATIONS
TO GOVERN THE PRODUCTION OF OIL AND GAS UNDER THE
ACTS OF FEBRUARY 25, 1920, JUNE 4, 1920, and MARCH 4,
1923, AND UNDER SPECIAL AGREEMENT BY
THE UNITED STATES

By

T. E. SWIGART and C. E. BEECHER

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First edition, August, 1923.

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Form 6-330

LOCATE WELL CORRECTLY

U. S. Land office ....

Serial number ....

Lease or permit to prospect ....

DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

PETROLEUM DIVISION

LOG OF OIL OR GAS WELL

Company .... Address ....

Lessor or Tract .... Field.................. State..................

Well No.......... Sec. ...... T. ...... R. ...... Meridian .... County ....

Location ......ft. {N. / S.} of ...... Line and ......ft. {E. / W.} of ...... Line of .... Elevation .... (Derrick floor relative to sea level.)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed ....

Date.................. Title..................

The summary on this page is for the condition of the well at above date.

Commenced drilling.................., 19.... Finished drilling.................., 19....

OIL OR GAS SANDS OR ZONES

(*Denote gas by G*)

No. 1, from .... to .... No. 4, from .... to ....

No. 2, from .... to .... No. 5, from .... to ....

No. 3, from .... to .... No. 6, from .... to ....

IMPORTANT WATER SANDS

No. 1 from .... to .... No. 3, from .... to ....

No. 2, from .... to .... No. 4, from .... to ....

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated		Purpose
							From	To	

CASING OR TOOLS LOST OR SIDETRACKED

From .... to .... Description ....

From .... to .... Description ....

From .... to .... Description ....

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used

FOLD MARK.

PLUGS AND ADAPTERS

Heaving plug—Material .... Length .... Depth set ....

Adapters—Material .... Size ....

SHOOTING RECORD

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out

TOOLS USED

Rotary tools were used from ....feet to..................feet, and from..................feet to..................feet

Cable tools were used from..................feet to..................feet, and from..................feet to..................feet

DATES

.................., 19 Put to producing.................., 19

The production for the first 24 hours was..........barrels of fluid of which......% was oil; ....% emulsion; ....% water; and .... % sediment. Gravity, °Bé. ....

If gas well, cu. ft. per 24 hours .... Gallons gasoline per 1,000 cu. ft. of gas..................

Rock pressure, lbs. per sq. in. ....

EMPLOYEES

.................., Driller ...., Driller

.................., Driller ...., Driller

FORMATION RECORD

From	To	Total feet	Formation

FOREWORD.

To oil and gas lessees under the act of February 25, 1920, the act of June 4, 1920, the act of March 4, 1923, and under special agreement by the United States:

This manual has been prepared at the specific direction of the Secretary of the Interior for the purpose of calling to your attention the necessity and feasibility of practicing conservation in drilling for and in producing oil and gas, as well as for acquainting operators on Government land with the department's operating regulations.

The methods set forth in the descriptive section of this manual will serve in general as the department's policy where they are applicable, although exceptions occasioned by local conditions will be recognized and dealt with by the supervisory force of the Bureau of Mines in a practical manner.

The department is determined not to allow any preventable wastes of oil and gas, and it will support the supervisory force of the Bureau of Mines in enforcing the operating regulations to the end that all operations on public lands be carried on according to the most approved methods.

Respectfully,

E. B. FINNEY, *Acting Secretary.*

JULY 5, 1923.

MANUAL FOR OIL AND GAS OPERATIONS, INCLUDING OPERATING REGULATIONS TO GOVERN THE PRODUCTION OF OIL AND GAS UNDER THE ACTS OF FEBRUARY 25, 1920, JUNE 4, 1920, MARCH 4, 1923, AND UNDER SPECIAL AGREEMENT BY THE UNITED STATES.

By T. E. Swigart and C. E. Beecher.

INTRODUCTION.

PURPOSE AND SCOPE.

The Federal Government, as the largest lessor of oil and gas lands in the United States, is vitally interested in the conservation of those resources. This manual has been prepared at the direction of the Secretary of the Interior to call the attention of lessees of public oil and gas lands to the most common oil and gas field wastes and the best methods of preventing them; to outline the policies of the Interior Department on field operations; and to give information as to how the "Operating Regulations" of the department will be interpreted by the Bureau of Mines.

The oil industry has progressed steadily. Present operating methods are much more efficient—and less wasteful—than those of a few years ago; moreover, the art of producing oil and gas is continually advancing. Public interest requires that improved methods, which will result in obtaining the greatest possible amounts of oil and gas from the natural deposits, shall be developed and used. Part I of this manual points out types of oil and gas wastes and suggests, in detail or by reference, the most practical and effective methods in current practice for stopping these wastes. Throughout Part I the department's operating policy is given, with interpretations of the "Operating Regulations" for enforcing every practical measure of conservation. Part II comprises the revised "Operating Regulations" which supersede all previous regulations and will govern future operations on public lands; it will be found in the pocket in the back cover of this bulletin.

TRUE CONSERVATION.

"Conservation" has almost become a slogan of the American people. Conservation of natural wealth is unquestionably one of the most vital issues confronting the country, for the future growth, prosperity, and success of the Nation depend largely on natural resources.

The popular conception of conservation as applied to mineral wealth is the nonuse of minerals and their retention in the original state and place. Such an interpretation, if strictly applied, would be more harmful to the advancement of civilization than would be the use of those minerals required for public needs, even if the waste were considerable. Had early settlers not drawn upon the mineral supply, the America of to-day would be far different. Transportation, manufactures, power, communication, science, and invention would not have reached their present stage and many commodities no longer regarded as luxuries but as necessities would not be readily available.

In discussing the meaning of conservation, Franklin K. Lane said:[1]

> The word should mean helpfulness, not hindrance—helpfulness to all who wish to use a resource and think in larger terms than that of the greatest immediate profit; hindrance only to those who are spendthrift. A conservation which results in a stalemate as between the forces of progress and governmental inertia is criminal, while a conservation that is based on the fuller, the more essential, use of a resource is statesmanship.
>
> To know what we have and what we can do with it—and what we should not do with it, also is a policy of wisdom, a policy of lasting progress. And in furtherance of such a policy the first step is to know our resources—our national wealth in things and in their possibilities; the second step is to know their availability for immediate use; the third step is to guard them against waste, either through ignorance or wantonness; and the fourth step is to prolong their life by invention and discovery.

The conservation of natural resources, therefore, can not be interpreted as nonuse, but as use with minimum waste. A greater gift to posterity than undeveloped supplies of raw minerals is the advanced civilization made possible by the thoughtful use of a necessary portion of these minerals.

In the United States much of the mineral wealth is privately owned. Unfortunately all these owners have not learned the lesson of modern civilization—that private ownership is in reality public trust and that the owner's right to do as he pleases, even to squander natural resources, can not and will not be tolerated indefinitely by society.

No one will deny that the oil and gas industry has been wastefully operated. Much of the waste probably could have been avoided, although critics must concede that the hazardous nature of the industry and lack of operating experience that could be gained only by time are partly responsible. Little good will come of deploring past errors, but great good may result from studying the causes of these wastes and their future prevention.

The American petroleum industry is now in its sixty-fourth year. During this time recovery methods have been almost revolutionized.

[1] Lane, Franklin K., Conservation through engineering: U. S. Geol. Survey Bull. 705, 1920, 35 pp.

When conducted properly the best practice of to-day permits little waste of oil and gas. Realizing, however, that all operations are not so conducted the Secretary of the Interior has charged the Bureau of Mines with the supervision of drilling and production on public oil and gas lands. He has, moreover, instructed the Bureau of Mines to require of Government lessees the strictest compliance with the orders and regulations in Part II of this manual, which have been prepared with the sole intent of promoting conservation in its true sense.

ACKNOWLEDGMENTS.

The writers gratefully acknowledge the aid rendered by members of the Bureau of Mines in compiling this manual. A. W. Ambrose, assistant director, F. B. Tough, chief petroleum engineer, and H. H. Hill, supervisor of oil and gas operations, offered constructive criticisms and suggestions. E. P. Campbell and R. C. Patterson, deputy supervisors, M. J. Kirwan, petroleum engineer, and R. A. Cattell and John M. Alden, natural gas engineers, read the manuscript in detail and made many helpful suggestions. H. J. Lowe, petroleum engineer, and H. B. Hill, associate petroleum engineer, supplied valuable information. Gertrude E. Burt prepared most of the drawings. In addition, various oil companies in California and Wyoming furnished information on operating practice.

PART I.—PREVENTION OF LOSSES IN OIL AND GAS PRODUCTION.

WATER PROBLEMS IN OIL AND GAS FIELDS.

WASTES FROM INFILTRATION OF WATER.

The losses of oil and gas through the infiltration and encroachment of water in oil sands can not be determined; unquestionably they have been enormous, for entire oil and gas fields have been damaged irreparably by flooding.

Encroaching water traps underground oil that probably never will be recovered and causes losses of gas and natural-gas gasoline, and water in an oil well so increases lifting costs that many wells are abandoned before the normal recovery of oil and gas is obtained. Many underground waters are so corrosive that the useful life of casing, tubing, sucker rods, pumps, and other equipment is shortened, causing loss of material and perhaps a permanent loss of oil and gas to the operator. Moreover, water emulsifies with oil; treatment to separate the oil and the water is expensive and invariably results in a loss of some oil.

WAYS IN WHICH WATER MAY ENTER A WELL.

CLASSIFICATION OF OIL-FIELD WATERS.

Oil-field waters may be classed as top water, middle or intermediate water, edge water, and bottom water, according to position with respect to the oil sands. Top water is the term usually applied to any water in a stratum above the main oil-producing stratum. Intermediate waters are sometimes called top waters, but in the strict meaning of the term intermediate water is that in a stratum between two oil-bearing strata. Bottom water lies in a stratum below the oil-producing stratum and is separated from it by an impervious layer. In many fields, water in the base of the oil sand is termed bottom water. Strictly speaking, this is edge water, since it occurs in the down-slope parts of an oil or gas sand. As oil or gas is removed, the line of contact or the "edge-water line" moves up slope. Relations between the various water sands and the oil strata are illustrated in Figure 1.

INFILTRATION OF TOP WATER.

The infiltration of top water, or water above the productive measures, is one of the most common troubles in oil fields. Top water may gain access to a well by (1) the casing being set too high or too low, (2) the unsystematic casing of wells of a group with respect to one another, (3) leaks around the shoe of the water string, (4) improper coupling of the joints of casing by cross threading or insufficient screwing, (5) collapsed casing, (6) split casing, (7) line-worn casing, and (8) corroded casing.

As casing must be landed below the lowest top-water sand but above the productive sand to shut out upper waters effectively, the selection of the point for landing it is evidently quite as important as the mechanical features of the shut-off. The history of oil-field

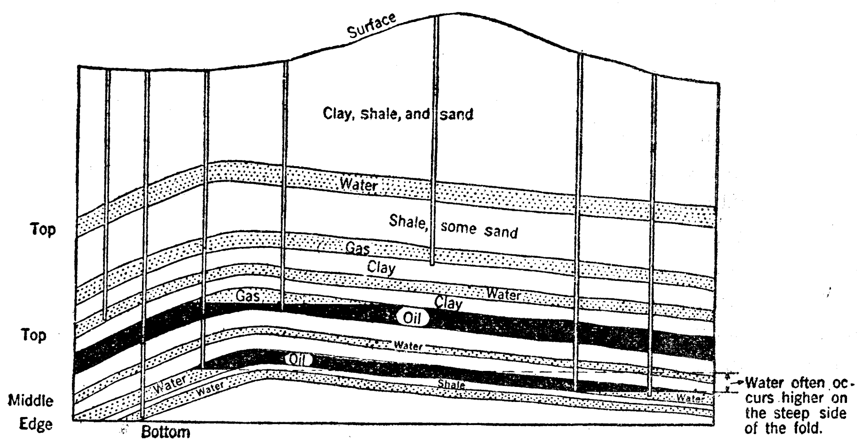


FIGURE 1.—Hypothetical sketch to show different water sands.

development has shown that defective shut-offs and improper casing points have caused the loss of immense quantities of oil and gas; for this reason the Department of the Interior will require lessees to consider carefully all phases of the upper water problem in the various localities.

ENCROACHMENT OF EDGE WATER.

Encroachment of edge water usually indicates the exhaustion of a part of an oil field. It can not be guarded against, although certain practices, such as swabbing or other methods of producing an edge well too fast that may cause edge water to encroach prematurely with a corresponding loss of oil and gas may be prohibited. "Base water," which occurs only in flat-dip fields, often does more damage to a well than true edge water. Base water may be encountered when a well is first drilled in and it may greatly increase production costs as well as decrease the ultimate production by cutting off portions of the productive measures. True edge water seldom appears in steep-dip fields until the well approaches exhaustion and therefore does not trouble the producer for the same period of time as does base water. Drilling in too deep, swabbing, flowing without back pressure, or pumping flowing oil wells with an air lift may result in the entrance of base water.

ENTRANCE OF BOTTOM WATER.

Bottom water usually gains access to a well which has been drilled too deep and has passed through the parting between the productive measures and the bottom-water sand. If a neighboring well has been drilled too deep, bottom water may find its way to the well in question through some sand below the water strings in the two wells.

ACTION OF CORROSIVE WATERS.

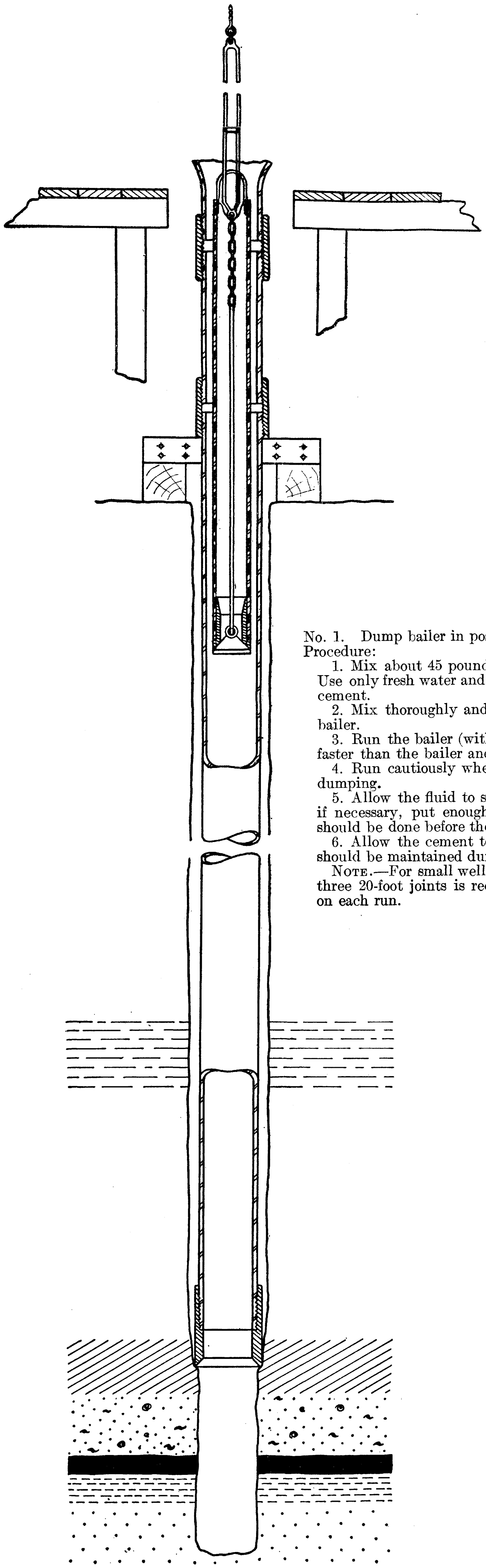
Corrosive waters [2] which attack casing and eventually eat holes in it are found in many oil fields. Such action results in water entering a well and causes loss of oil and rapid deterioration of tubing rods and other equipment. Unless the space between the casing and the wall of the hole is filled with mud fluid or cement to prevent the corrosive waters from touching the casing corrosive waters may be very destructive. In the Eldorado field, Kans., for example, it costs operators thousands of dollars each year to replace casing, tubing, sucker rods, and other equipment destroyed by corrosive water.

MIGRATION OF WATER.

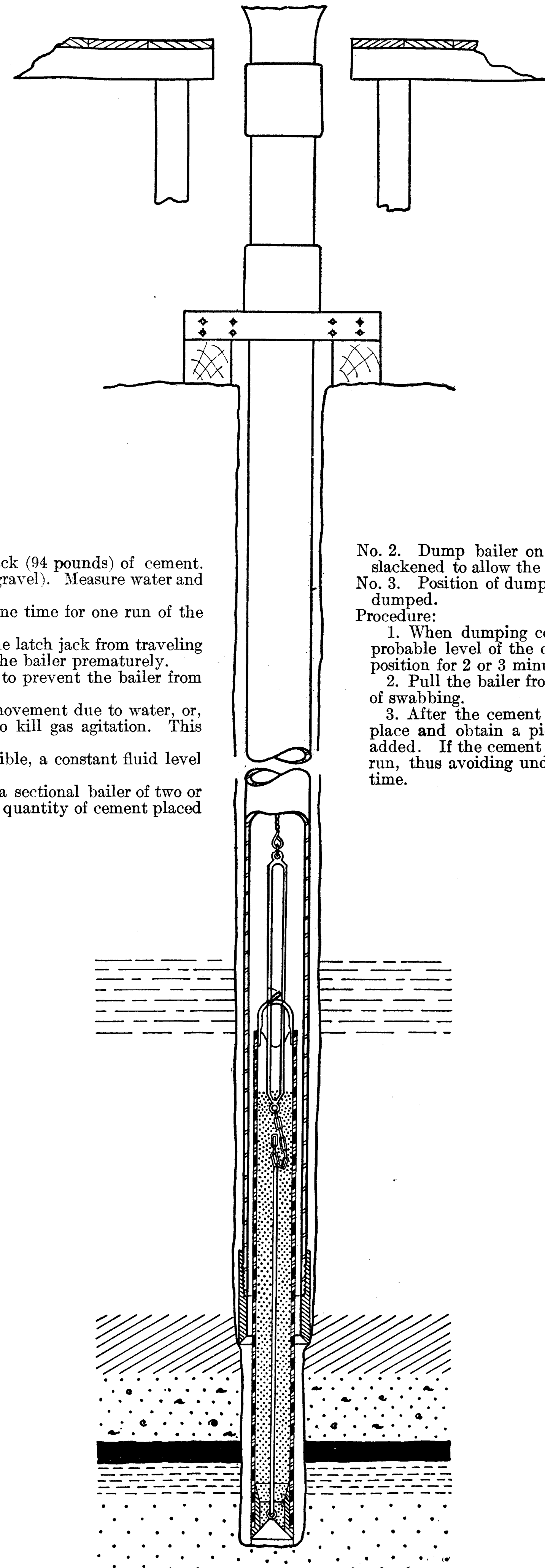
Waters that are not confined to the strata in which they occur but are allowed to migrate back of the casing into oil and gas formations are a source of serious yet preventable underground loss in oil fields. Top water, which may reach an oil sand in large volume, may prevent oil from entering a well and sometimes destroy other wells by migrating to them through oil or gas sands. Gas wells are easily flooded, possibly because the sands are dry and therefore offer less resistance to water than sands containing oil.

When a water sand is found between two productive strata, the water should be confined so that it can not migrate to these strata. If the water is under pressure, it may flood the top oil zone as readily as the bottom one. Often an upper oil stratum is productive in one well but is not in a neighboring well. Both strata should be protected from water, otherwise the upper oil sand in the producing

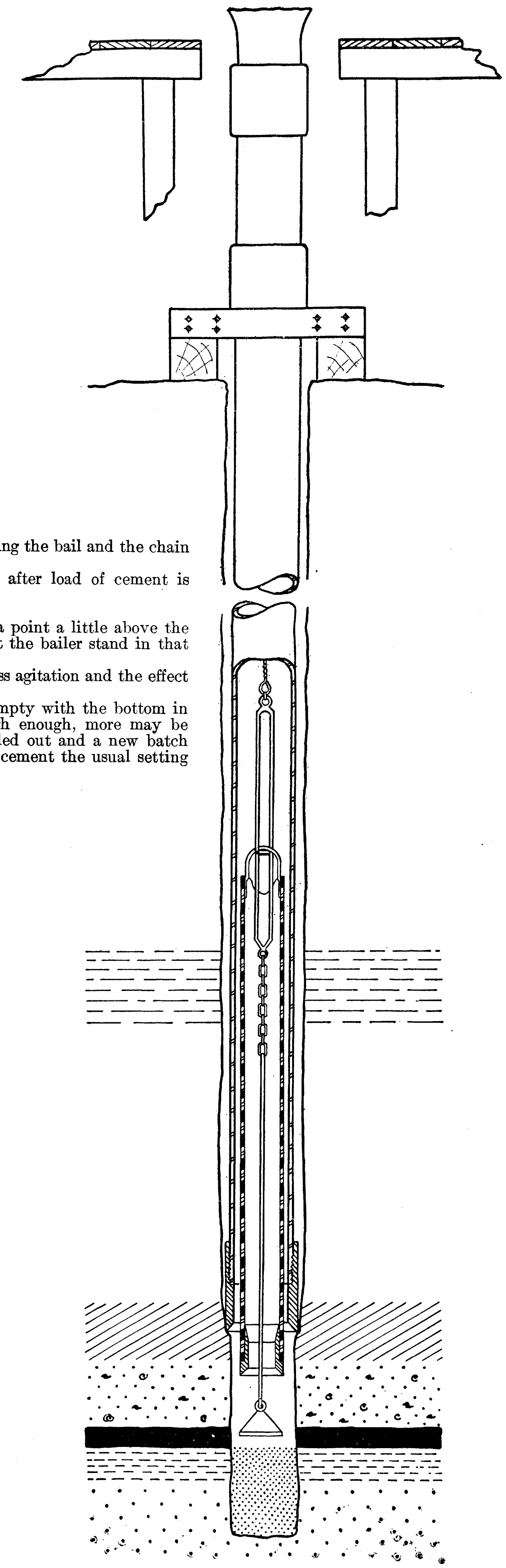
[2] Mills, R. Van A., Protection of oil and gas field equipment against corrosion: Bull. 233, Bureau of Mines. (In press.)



NO. 1.



NO. 2.



NO. 3.

No. 1. Dump bailer in position to be filled with cement.

Procedure:

1. Mix about 45 pounds ($5\frac{1}{2}$ gallons) of water to 1 sack (94 pounds) of cement. Use only fresh water and mix cement neat (no sand or gravel). Measure water and cement.
2. Mix thoroughly and rapidly and just enough at one time for one run of the bailer.
3. Run the bailer (with cement) slowly to prevent the latch jack from traveling faster than the bailer and tripping, thereby dumping the bailer prematurely.
4. Run cautiously when approaching the fluid level to prevent the bailer from dumping.
5. Allow the fluid to seek its own level to prevent movement due to water, or, if necessary, put enough water or mud in the hole to kill gas agitation. This should be done before the cement is placed.
6. Allow the cement to set at least 10 days. If possible, a constant fluid level should be maintained during this time.

NOTE.—For small wells (6-inch diameter or under) a sectional bailer of two or three 20-foot joints is recommended for increasing the quantity of cement placed on each run.

No. 2. Dump bailer on bottom with the latch jack catching the bail and the chain slackened to allow the bottom bailer valve to open.

No. 3. Position of dump bailer with bottom valve open after load of cement is dumped.

Procedure:

1. When dumping cement, raise the bailer slowly to a point a little above the probable level of the cement dumped on that run. Let the bailer stand in that position for 2 or 3 minutes before raising.
2. Pull the bailer from the well slowly to avoid needless agitation and the effect of swabbing.
3. After the cement has set 3 hours, run the bailer empty with the bottom in place and obtain a pick-up. If the cement is not high enough, more may be added. If the cement has failed to set, it may be bailed out and a new batch run, thus avoiding undue loss of time by allowing poor cement the usual setting time.

PLACING CEMENT WITH A LATCH-JACK DUMP BAILER.

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well may be flooded by water from the other well and thus cause premature abandonment of the producing well. Failure to shut off water properly often affects a distant well. This was clearly demonstrated by repairs on a well in the Cushing field, Okla., described by Ambrose.[3] The work resulted in shutting off water not only in the well repaired but in a well approximately 1,300 feet distant. Before the original well was repaired, the daily production of the distant well was only 20 barrels of oil and a large amount of water; after the repairs the daily production of the distant well increased to 600 barrels of oil per day.

Although water travels slowly through sands, it has been known to migrate several miles through sands in Pennsylvania. Water from one well may migrate to other wells and damage a large part of an oil field. In fact, whole fields have been damaged in this way.

DRILLING INTO WATER.

In an attempt to obtain greater production, operators have ruined many good wells by drilling through an oil sand and into water. When there is danger of drilling into water in the base of a sand or into a separate water sand below but near the oil sand, an operator can better afford to stop drilling before the water is reached and have a relatively small well than to continue drilling until the water sand is penetrated and then be confronted with the wastes that such a condition may entail. Deep water sands often carry water under high head. If an oil well is drilled into water in the base of a sand, the water may form a "cone" as the well is operated that eventually will shut out the oil. Plate XV, *A* (see p. 94), illustrates this coning effect of water. In the experiments that served as a basis for this photograph, oil, gas, and water were extracted rapidly and the water cone formed at the well. Water coning may occur when a well is drilled only a short distance into an oil sand, if bottom water is present and the well is produced too rapidly.

Perhaps one of the most familiar examples of the damage to oil fields from failure to protect oil sands properly is the Kern River field, Calif.[4] The yield of oil was so low and the production of water so high that operators were finding it unprofitable to operate their wells longer. An engineering investigation[5] was made which later served as a basis of repair work. Repairs at one well increased the production of several near-by wells from 25 barrels to 59 barrels per day and reduced the amount of water lifted from 15,927 barrels to

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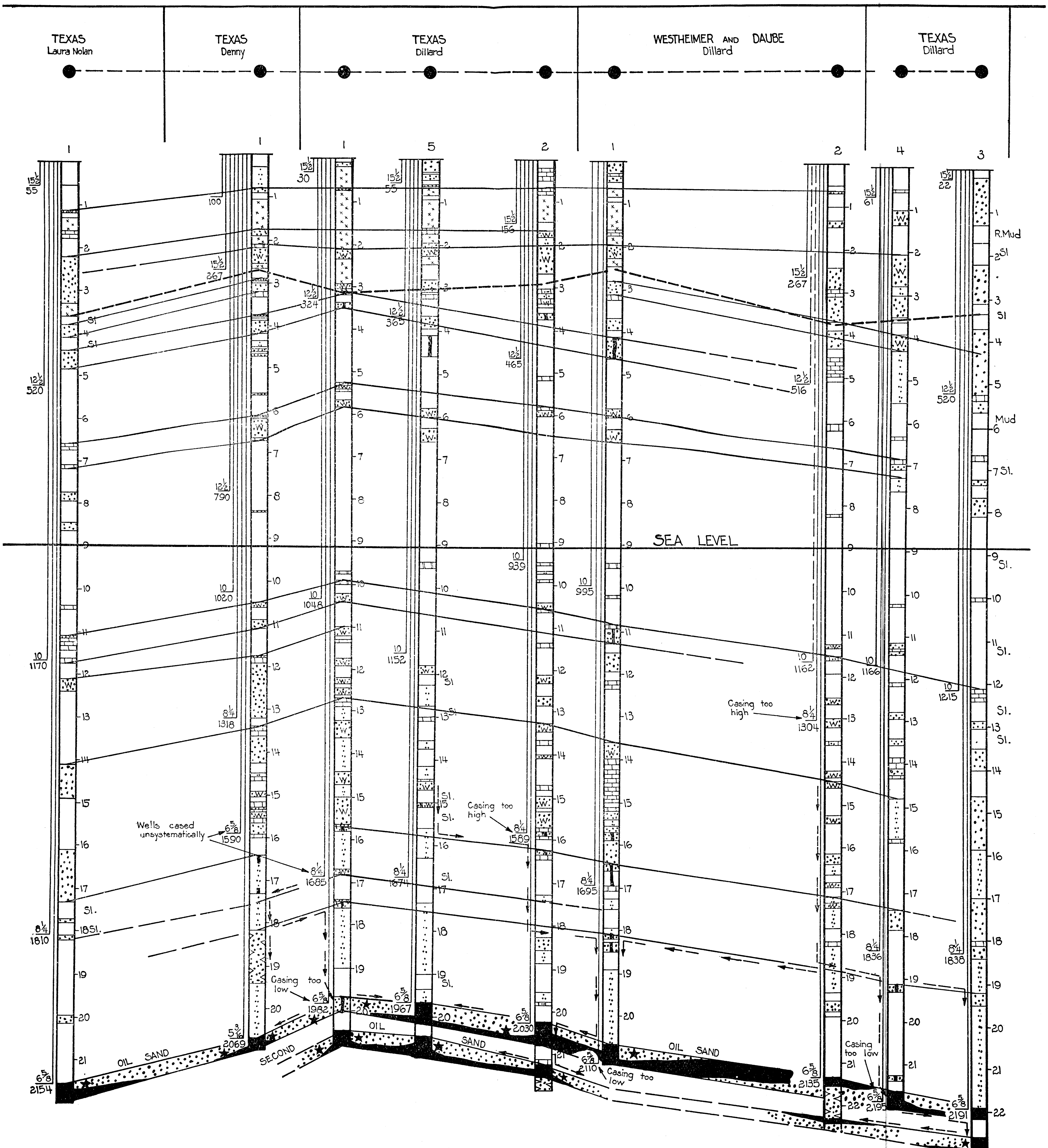
[3] Ambrose, A. W., Underground conditions in oil fields: Bull. 195, Bureau of Mines, 1921, p. 74.

[4] Second annual report of the State oil and gas supervisor for 1915-1916: California State Min. Bur. Bull. 82, 1918, pp. 225-260.

[5] Ferguson, R. N., Report on cause of damage by water in the southwestern portion of the Kern River oil field, Kern County, Calif.: California State Min. Bur., Summary of Operations, vol. 5, No. 3, Sept., 1919, p. 5.



CROSS SECTION OF A PORTION OF THE HEWITT FIELD, OKLA., SHOWING UNSYSTEMATIC CASING, AND ILLUSTRATING THE STUDY OF UNDERGROUND CONDITIONS IN OIL FIELDS. THE HEAVY BROKEN LINE NEAR THE TOP OF THE SECTION DENOTES THE BASE OF THE PERMIAN "RED BEDS."

46467—23. (Face p. 8.)

240 barrels per day. If work in shutting out water had not been done, parts of this field would have had to be abandoned before all the recoverable oil was obtained.

UNSYSTEMATIC CASING.

Failure to recognize the various oil, gas, and water strata often results in unsystematic casing. For example, one operator may protect certain oil or gas bearing formations and another near-by operator may ignore them entirely, offsetting the good work of the first operator by failing to protect them.

Plate I illustrates the possibility of water entering an oil well or group of wells if certain wells are unsystematically cased. It also shows the clearness with which details of underground conditions can be depicted by accurate well-log cross sections. Such engineering work, coupled with careful noting of formations encountered in drilling wells, may save an operator thousands of dollars by enabling him to understand better the underground conditions in his field.

Plate II shows an actual example of water migration into the gas sand of a well which was properly drilled and cased. The migration of water was made possible by the improper casing methods employed in an adjacent well. The adjacent well was drilled into a deep oil zone without protecting the upper gas sand from water encountered below it. This water gained entrance to the shallow well by migrating back of the casing from the sand in which the water occurred to the upper gas sand, which it entered and flooded. Plate II also illustrates the possibility of gas escaping from the upper gas sand because of a deep well not being mudded or cemented.

METHODS FOR DETERMINING SOURCES OF WATER.

VALUE OF WELL RECORDS.

To determine the source of water in a well often requires careful study of the records of the well producing water and of neighboring wells, in addition to the usual field tests. Well records, to be of greatest value, should be accurate and complete. Failure to recognize this fact has frequently been costly to oil operators; however many operators still fail to realize the necessity for accurate records, and consequently when extensive repairs must be made are handicapped by not having exact histories of their wells. Well records are of prime importance in studying water problems and constitute the basis on which a complete survey is made. When augmented by actual field tests and data on repairs, well records often simplify and hasten the solution of difficult water problems that might otherwise defy all efforts toward correction. Because of the vital importance of complete and dependable records, the Government requires all lessees to file with the Bureau of Mines essential data pertaining to the drilling and operation of all wells on Government land. (See Part II, sec. 5.)

USE OF WATER ANALYSES.

Investigations of a number of oil fields have shown that waters from different depths and strata often differ greatly in chemical properties, and therefore can be distinguished by their composition. Water analyses have been used in determining the source of water in a number of fields.[6] Water analyses are now used successfully in California and Kansas as a guide for routine operation, and have been used at various times in other fields. Some operators, realizing the importance of chemical analysis in determining the source of water, take samples of water when possible from all water-bearing sands as each well is drilled. If there is no immediate call for the data, the samples may be labeled and stored for later use if a water problem arises.

When water is being obtained for analysis, care is necessary to insure that a true sample of the water and not one mixed with drilling water or with water from other sands is collected. Sometimes it is impossible to get an unmixed sample of water from a certain sand because the driller may be carrying a "wet" hole, and shutting off the upper waters may not be practicable. If this is so, some mixed samples should be kept, because the water behind the pipe may be mixed eventually and an analysis of a mixed water might assist later in determining the source of the water. The samples should be large enough (1 or 2 gallons) to allow a complete analysis to be made.

Water analyses may be presented in a number of ways to assist identification. It frequently happens that water from a certain source has some distinctive chemical property that permits easy recognition. Possibly the "total solids" will enable the operator to identify the water. In the East Side Coalinga field, Calif., the complete analyses are studied carefully, because the upper waters in general have high sulphate salinity and high primary salinity, whereas bottom waters are low in sulphates and have high primary alkalinity. In the Eldorado, Kans., field the chloride content, which can be determined within a few minutes after the sample is taken to the laboratory, enables the operator to determine whether the water is top water or from below the oil-bearing strata. In fact, the distinction is so clear that one can often tell whether the water is a mixed sample, and if so, about what proportion is top water and what proportion is lower water.

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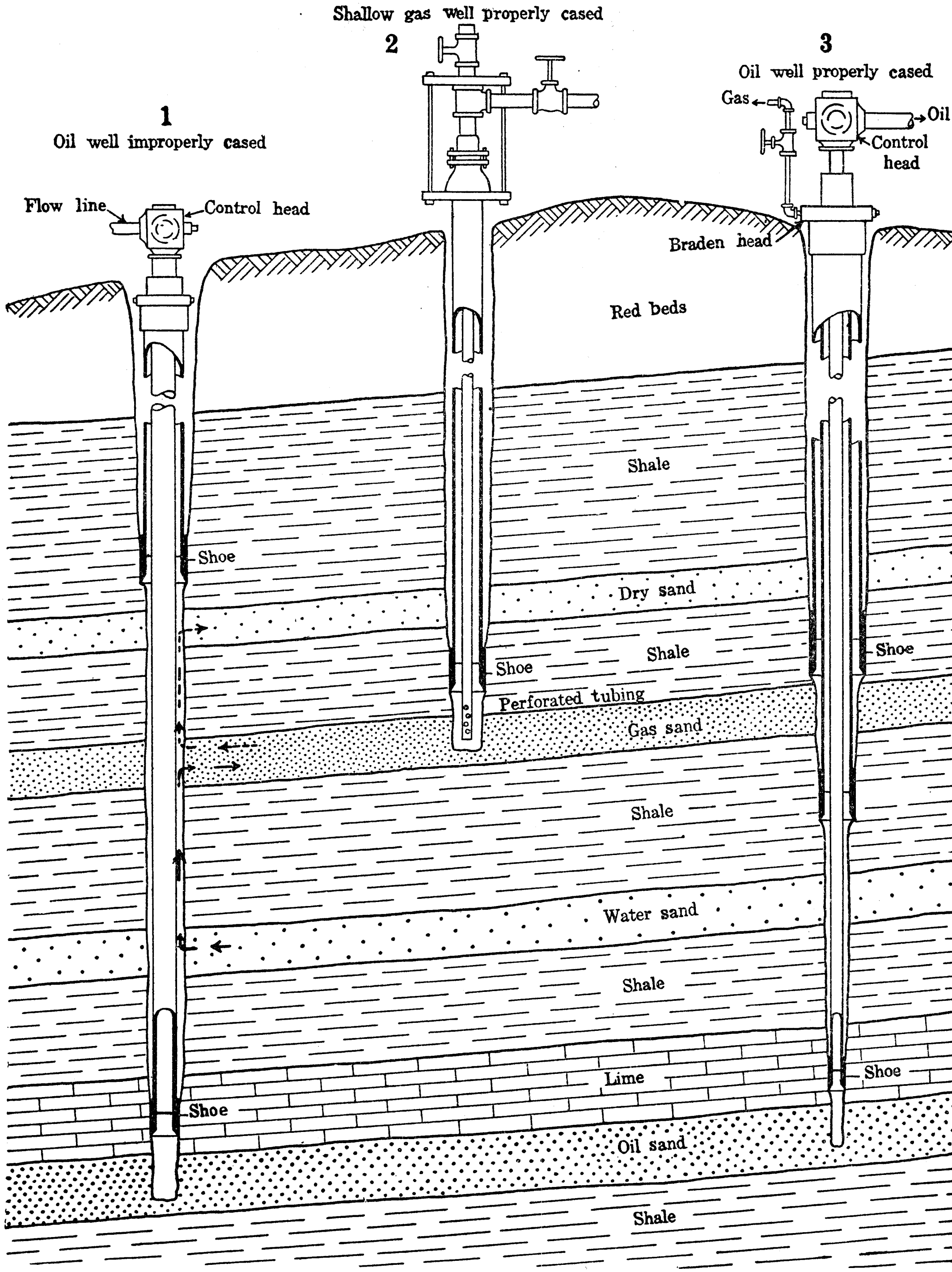
[6] Ambrose, A. W., Underground conditions in oil fields: Bull. 195, Bureau of Mines, 1921, 238 pp.; Rogers, G. S., The Sunset-Midway oil field, Calif., Part II, Geochemical relations of the oil, gas, and water: Prof. Paper 117, U. S. Geol. Survey, 1919, 103 pp.



EXAMPLE OF UNSYSTEMATIC CASING AND IMPROPER PROTECTION OF UPPER GAS SAND.

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DYES.

Dyes have been used to trace and locate underground waters, but their application is limited. Dyes such as fluorescein, eosine, methylene blue, Venetian red, and acid orange have been used in oil wells because small quantities of such dyes can be readily detected. Fluorescein and eosine dyes have an advantage over other dyes of being fluorescent and therefore more easily detected when diluted. Acid orange (red) is a relatively cheap dye and has been used by the Bureau of Mines in Oklahoma. Ambrose[7] has discussed dyes and their use in some detail; they will not be considered further in this manual.

FLUID LEVELS.

Fluid levels may assist the determination of the source of water in a well. Fluid levels of top water sands vary, but generally differ from the fluid levels of bottom or base waters. If fluid levels have been recorded, the height at which fluid stands in various wells may indicate the source of the water. The interpretation of fluid levels should be carefully made by an experienced engineer familiar with local conditions.

TESTING WITH MUD FLUID.

The source of water sometimes can be tested by filling the hole with heavy mud fluid, then bailing the well down from the top of the fluid until clear water appears. It may be assumed that the mud below the point at which the water is entering will remain almost undiluted while the fluid in the hole above the place where water enters will be thinned and eventually become almost clear. The bailer may then be run to certain depths to "feel" for the mud. The surface of the undiluted mud, when found, is usually near the point of entry of the water. This method may indicate whether water is coming through a casing leak, around the shoe, from the sand, or at the bottom of the hole.

MUDDY WATER FROM BEHIND CASING.

If the water string of a well has been landed with a column of mud behind it and water appears in a well later, the condition of the water, whether clear or muddy, may tell the operator whether the water in the well is upper water or water from some source below the shoe. This test is not positive, but if muddy water does appear indications are that the leak is around the shoe or through the casing, unless by chance the mud has migrated, through the oil or gas sand, from a near-by well which has mudded off that sand.

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[7] Ambrose, A. W., Underground conditions in oil fields: Bull. 195, Bureau of Mines, 1921, pp. 106–122.

IMPORTANCE OF DIRECT EVIDENCE.

The operator must study his individual water problems carefully and should weigh every bit of evidence before he starts repairs. If the source of the water can be determined with some certainty before repairs are started, time and money can be saved. Operators, however, are warned not to put too much reliance on any but direct and accurate evidence, else the cost of an attempt to shut off water at the wrong source may exceed that of plugging a well by stages to determine the source accurately.

FIELD TESTS FOR THE SOURCE OF WATER.

When the source of water can not be determined from a study of records and other available information, the only expedient is to test the well for water from various sources. If the condition of the well permits testing the casing with a casing tester, this can be done first. Should the casing be found tight, other sources of water must be investigated. Perhaps the most thorough and satisfactory way of testing to determine the source of water is to start at the bottom of the hole and plug by stages, eliminating the various sources in this way. First, bottom water would be shut off, if present; next, water in the bottom of the sand; third, water from a sand between the casing shoe and oil sand; and, finally, leaks around the casing shoe. In work of this sort a bailing or production test should be made after each new plug has been placed and the production of the well gaged in order to ascertain the exact result of the work. It is important to know whether any casing was left in the hole or sidetracked, for such casing might afford an open watercourse beside the plug.

In the following sections are some suggestions for conducting tests to determine the source of water in wells.

TESTS FOR TOP WATER.

Top water may gain access to the oil sand through a leak in the water string, around the shoe if the shut-off is defective, or by migration through a porous formation above an oil sand that has been unsystematically cased with respect to other wells.

CASING TESTER.

If the operator has reason to believe that the water is coming from upper sands, he should first test the casing for leaks.

If the fluid in the well can be bailed down, a casing tester or swab bailer may be run. A casing tester or swab bailer (see Fig. 2) is a tube closed at the bottom and having a flange with a gasket cut to fill the annular space at the top between the bailer and the casing.

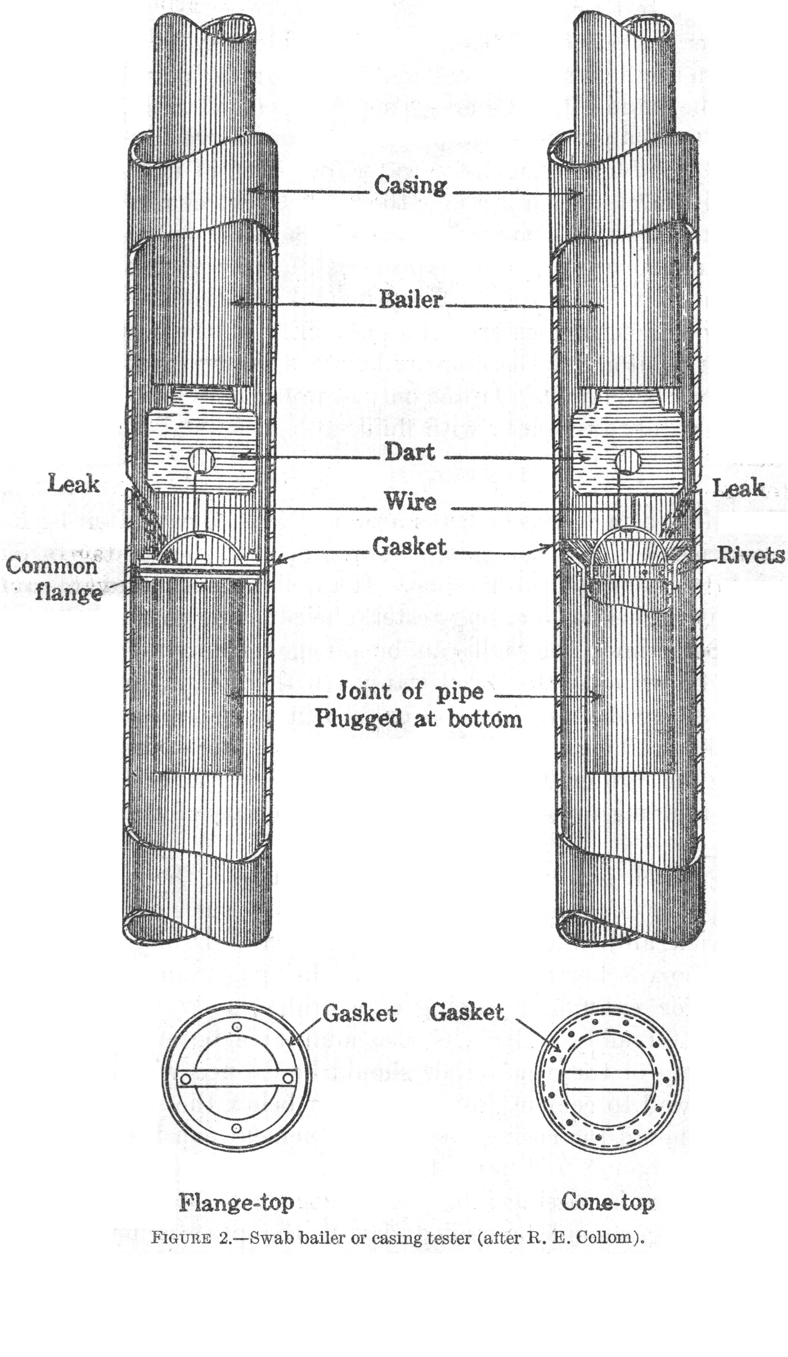

FIGURE 2.—Swab bailer or casing tester (after R. E. Collom).

Casing testers can be purchased from most oil-well supply stores. Collom[8] describes a swab bailer that can be assembled in the field and used to test casing.

In order that a casing tester or swab bailer may be used, the water or fluid in the hole must be bailed down below the point at which the test is to be made. The tester—generally attached to the bailer dart—is then run to a given depth, preferably just above the shoe, and allowed to stand long enough for water to collect in it if the casing is leaky. If the casing leaks above the point at which the tester is stopped, the tester will contain water when withdrawn. By repeating this operation at successive points up the casing, the position of the leak can eventually be located. The principal drawback to testing water strings with a casing tester is the possibility of the well filling with fluid to a point above the point of leak before the test can be made. The tester, therefore, is adapted only to wells that can be bailed down and do not fill too rapidly with fluid.

PLUGGING THE WELL AND BRIDGING THE HOLE.

Tests for casing leaks or leaks around the shoe can often be made more satisfactorily by plugging the well up into the shoe or bridging the hole below or up into the shoe. If a well fills with fluid too rapidly to permit the use of a casing tester, the plugging method should be used. Sometimes the well can be plugged from the bottom with cement, or with sand or brick capped with cement, but if the hole is to be plugged more than 30 or 40 feet it is usually desirable to bridge about 10 feet or so below the shoe and plug up into the casing, capping the bridge with cement. This procedure eliminates the work of building up a long plug and the trouble of drilling out the plug.

When a well is plugged or bridged for a test, the plug or bridge may be built of almost any material handy, such as sand, gravel, rocks, brick, and chunks of broken-up cement. Drillers usually have a satisfactory scheme for starting the bridge. Sand is a desirable material for extending a plug or a bridge, as it can be bailed or washed out readily. Brick is also adaptable because it drills out easily. Any of these materials should be capped with cement. In fact, it is well to cement from a few feet below the shoe up into the shoe, for should the casing be tight the cement can be drilled out of the pipe to about 1 foot below the shoe and a test made to determine whether water is passing around the shoe.

The casing should be bailed dry if the pipe is heavy enough to withstand the fluid pressure at that depth; otherwise, the fluid should be bailed to a certain level and the sand line marked care-

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[8] Collom, R. E., Casing leaks: Advance chapter, California State Min. Bur. 4th Ann. Rept., May, 1919, pp. 8–11.

fully so that on testing it can be determined whether or not any water has come in. After the casing is bailed dry or bailed down, the well should stand at least 12 hours (overnight) before the bailing test is made. If the casing proves to be leaking, the fluid can perhaps be bailed down long enough to permit running a casing tester and determining the exact depth of the leak. If the casing proves to be tight, the next step is to drill the cement out of the pipe and repeat the bailing test in order to ascertain the tightness of the shoe.

PLUG METHOD FOR LOCATING CASING LEAKS.

A third method of testing for casing leaks and simultaneously locating them in wells in which "circulation" can be obtained consists of forcing a wood plug, such as a plug used in cementing, down the casing by pumping in water or mud fluid. One cementing contractor in Oklahoma uses a bob and a measuring line which plies through a special stuffing box at the well head for locating the position of the plug at any time. To quote Swigart and Schwarzenbek: [9]

> If circulation is established the job may proceed in the usual manner of a two-plug cementing job except that first the bottom plug with the heavy flexible belting washers, larger than the casing, is inserted and mud fluid pumped in behind. The plug, in traveling down the casing, forces the fluid ahead of it out through the channel through which the water is entering the well. The progress of the plug is closely checked by the use of the measuring-line device. If at some point part way down the casing the measuring line shows the plug to have stopped but the pump still continues to supply fluid without hesitation, the proof of the casing leak just above the plug is almost conclusive. As the plug passes the point of release in pressure it is supported by an incompressible column of fluid below it while the fluid above the plug seeks the point of diminished pressure, which is through the casing leak into the water sands. If the plug does not stop in the casing but continues to a point just below the shoe as determined by the measuring line and then stops, it is certain that the point of release in pressure is past the shoe, thus indicating that water is coming around the shoe. It is seen that in both cases the success of the method depends upon the characteristics of water sands in taking fluid and oil sands in resisting the entrance of fluid as the plug would not stop below a leak in the casing or just below the shoe if there was no point of diminished pressure or supporting column of fluid below.

STUDY OF UNSYSTEMATIC CASING.

No specified rules can be given for determining the source of water when the water is entering a well which is unsystematically cased. If good logs are available, a study of well-log cross sections often reveals the possibility of water entering because of unsystematic casing (see Pl. I). The operator should study his records carefully to learn whether one string of casing has been landed stratigraphically higher or lower than other strings which are shutting out

[9] Swigart, T. E., and Schwarzenbek, F. X., Petroleum engineering in the Hewitt oil field, Oklahoma: Coop. rept., Bureau of Mines and Ardmore, Okla., Chamber of Commerce, pp. 59-67. (Description of the Halliburton process.)

water in neighboring wells. Analyses of the water may help to determine if it is from above the oil sand, although waters may change in composition if they migrate to a neighboring well through some formation other than their native sand. Such analyses, provided the top water had distinctive chemical properties, combined with stage plugging up through the oil sand, should eventually reveal the source of this water.

TESTS FOR INTERMEDIATE WATER.

If an intermediate sand carries water when a well is drilled, the operator may recognize the source. In any event, if water is encountered during the "drilling in" of a well, the well should not be drilled further until the source of the water is determined and the water confined to its own sand. Sometimes the upper oil sands are cased off because they are not as productive as lower sands. Under such circumstances, an intermediate water, if present, becomes top water to the main oil sand and bottom water to upper oil sands that have been cased off. A test for the intermediate water in this particular event becomes a test for top water. Unfortunately, there is seldom an opportunity to learn later if such an intermediate water is flooding an upper sand, because of imperfect protection to that sand, although the circumstantial evidence of such a condition may be strong.

If water suddenly enters the hole during drilling below an oil sand, usually the operator's first thought is that the water shut-off has failed. However, if the water comes into the well when the drill penetrates a new sand, the evidence is equally strong that the new sand carries water. No effort should be spared to determine accurately the source of water before the hole is drilled further. The operator should plug the bottom of the hole immediately and thus learn whether or not the water is coming from the bottom. Plugging may be done with a minimum of effort and loss of time at that stage of the work, but if drilling is continued and oil or gas is found at a greater depth, the problem becomes greatly complicated.

PLUGGING.

Although intermediate water struck during drilling may be identified by simple tests, the identification of water that later appears in a well because of the encroachment of edge water in some intermediate oil sand is not so simple. Such water troubles have baffled producers and engineers for months or even years. It is believed that the most satisfactory method to be followed when the source of water is unknown is to plug the hole by stages from the bottom. If the plugs hold, eventually the source of the water will be determined, for some stage of the plugging will cut off the flow. Cement, if it can be made to set, is the best material for stage plugging. Mechanical plugs can not always be trusted to fill the hole although a mechanical plug will often cut down the movement of water or gas in a well long enough to permit a cement cap to set.

TESTS FOR BOTTOM WATER.

Bottom water in an oil or gas well generally results from drilling the hole too deep, although a strong flowing well that is permitted to flow unrestricted may "drill itself into" bottom water, if a bottom-water sand is separated from the oil or gas sand by a relatively thin "break." Such an occurrence is not common, however, if a distinct break of limestone or shale of appreciable thickness actually exists.

Bottom water usually enters a well while drilling is in progress. If the bottom-water sand is some distance below the oil sand which has been passed through and is separated from it by an impervious formation, the driller may be able to decide, without any testing, that water which suddenly rises in the well during drilling is coming from the deeper sand into which he drilled. However, the problem often is not so simple. Perhaps the casing has been set in the formation without careful testing. The well may be flowing hard during the drilling in. If water suddenly appears the driller may be at a loss to know whether he has drilled through a shell and into a water sand, whether there is water in the base of the oil sand, or whether the casing or water shut-off is leaking. "Water in the sand" is generally the verdict, as this source relieves the owner of the responsibility for a poor shut-off and perhaps failure to test the shut-off or of poor judgment in drilling a good or fairly good well deeper in the hope of increasing its production.

If a bottom water has been identified in other parts of the field, a stratigraphic study of well logs usually will help the operator to determine whether or not the water in a certain well is coming from the bottom. A field test for true bottom water is not nearly as difficult as a test for water from other sources, because of the impervious layer between a bottom-water sand and the oil sand. The bottom of the hole can usually be plugged to the base of the oil sand with cement and the water shut off. As many as five or six trials are often made when an operator has reason to believe that water is coming from the bottom, before a successful shut-off can be effected.

TESTS FOR EDGE WATER.

ENGINEERING STUDY OF THE FIELD.

Edge water and water in the base of the sand are much alike, although the character of the geologic structure emphasizes a distinction between the terms. In fields with steeply dipping formations, the edge-water limits of a certain oil sand are usually clearly defined. This is generally true in the California and Rocky Mountain fields, and holds in the Hewitt field, Okla., one of the few Mid-Continent fields with steep dips. In such fields, edge water can usually be detected without elaborate testing. For example, if a well in an outlying part of a field is drilled into the main productive horizon, as determined by subsurface study of the local underground formations after the water string has been set and tested dry, and the hole fills with water as soon as the sand is penetrated, there is little doubt that the well has found edge water.

If producing wells in fields with steep dips begin to show water, an operator can usually determine the source by an engineering study of the field. For example, if such a well is near the productive limits of the field and is stratigraphically deeper than other wells near by that still produce clean oil but is about the same stratigraphic depth as other wells that have been flooded by edge water, the source of water is probably the down-slope part of the sand. If the operator is in doubt he should plug the hole up to the shoe and test the shut-off and the casing for tightness before he abandons the well.

Water analyses also may assist in determining whether or not the water is edge water. For example, the Shell Co. of California is so well acquainted with the properties of waters from the various horizons in the Coalinga field that when the sample tests edge water the company does not waste time making expensive field tests for top and bottom water.[10]

In so-called "flat-dip" fields, the water level and the limits of water in the base of an oil or gas sand are not so clearly defined as in steep-dip fields. The water may be, and usually is, an edge water; that is, the water in the base of the sand is supplied by the body of water in the down-slope parts of the productive sands. Since a number of variable factors tend to overcome the action of gravity, water in the base of the sand (or edge water) may exist in a sand in high parts of the geologic structure. It is not uncommon to find water in the sand in practically every part of a field, regardless of whether the water in the sand "up dip" is of higher elevation than oil in part of the same sand "down dip."

An operator, therefore, may face a perplexing problem if water suddenly appears during the drilling in of a well that is not near the edge of the field. Water analyses should be of value in determining the source of the water in such cases, but few operators in the Mid-Continent and Eastern fields, where flat dips occur, have ever used them. When drilling in, most operators depend upon observations of the sand and the action of the well to warn them when drilling should be stopped.

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[10] Ambrose, A. W., Underground conditions in oil fields: Bull. 195, Bureau of Mines, 1921, p. 103.

PLUGGING BY STAGES.

If the casing has been properly set and tested dry prior to the drilling in of a well and water appears while the well is being drilled in it may be advisable to plug the well by stages, unless indications are that the water shut-off has failed. Cement, if it can be made to set, is by far the most satisfactory material for plugging. If the well has not been shot and the hole is fairly smooth, a limit plug, mandrel plug, spiral plug, or other type of bottom-hole plug can possibly be used with success. Lathe cuttings and lead plugs are giving good results in some fields. Of course, a positive test for edge water involves shutting off the water or reducing the quantity; hence the test and the repair job are identical.

No mention has been made of older producing wells that begin to show water without any apparent cause. Such an occurrence is more perplexing than drilling a well into water, because in a producing well the casing may have corroded or the casing seat given way and therefore the source may be top, intermediate, or edge water.

METHODS FOR EXCLUDING WATER FROM OIL AND GAS SANDS.

FORMATION SHUT-OFF.

A formation shut-off is made by landing casing on a shoulder or seat in an impervious formation. The effectiveness of this type of shut-off depends on the close bond between the casing shoe and the walls of the hole and, to some degree, on the effectiveness with which the sharp edge of the shoe cuts into the formation and makes a tight seat. Cavings back of the pipe which pack above the shoe sometimes assist in effecting a shut-off. If the bond between the casing shoe and the wall of the hole is poor, water, especially if under pressure, readily finds its way to the bottom of the shoe. The shut-off then depends entirely on the thin contact between the cutting edge of the shoe and the formation, and any irregularities of this contact will allow water to enter the well. When casing is landed in a hard formation, the size of the hole is usually reduced to the exact diameter of the casing shoe for a short distance—possibly twice the length of the shoe—above the casing seat. If the casing must be landed in a shale, clay, or gumbo, the hole may be reduced to a size somewhat smaller than the outside diameter of the casing shoe, so that the shoe will cut its own hole and thus effect a tight fit. Driving casing to a seat or raising it two or three joints and allowing it to fall in attempts to force the shoe onto its seat is dangerous practice, which may result in pinching the shoe or in damaging the casing higher up.

A casing shoe is essential when a formation shut-off is being made. Shoes of various types—plain casing shoes, tapered shoes, or extra long shoes—may be used, but those with notched edges are not recommended for water strings, particularly with a formation shut-off.

Formation shut-offs are usually more effective if there is a caving formation above the casing seat, as the cavings will fall in and pack around the bottom of the casing and help to insure a tight job. The effectiveness of many formation shut-offs can be greatly increased by placing heavy mud-fluid between the casing and the wall of the hole.

If casing is set in the formation, the hole should be bailed dry and allowed to stand for several hours to test the shut-off. If water enters the hole during this period, the casing should be raised and a new seat made, onto which the casing may be lowered. Another test for water shut-off should then be made. Drilling should not proceed until a tight shut-off has been obtained. After two or three feet of hole has been drilled beyond the shoe, another test should be made before the well is drilled into the producing sand, for the jarring action of the tools against the casing may cause water to break in around the shoe.

ADAPTABILITY OF THE FORMATION SHUT-OFF.

Formation shut-offs should not be relied on when a top-water sand lies close above the oil sand, for the thinness of the impervious formation between the water sand and the shoe may not permit a permanent job. Formation shut-offs are not recommended when the formation between the upper water and the oil sand is too soft to bear the weight of the casing. "Rotten" and sandy shales are poor materials for a casing seat and should not be trusted to shut off water without the use of cement.

If wells are to be shot, the formation shut-off is convenient, because the casing can be raised during the shooting and reseated afterwards. However, if the casing seat is too near the oil sand that is being shot, there is danger of the shot destroying the seat.

Formation shut-offs are successfully made in some fields where limestones or hard shells lie a short distance above the productive formation, although good shut-offs are often made in shales and gumbos. In many Oklahoma fields where the formations are hard and stand up well, formation shut-offs are used to advantage; they are not adaptable to the fields (Rocky Mountain and California) where the principal operations on Government lands are now being undertaken. The formations encountered in the Rocky Mountain and California fields are in general not well adapted to the formation shut-off, which is therefore not to be regarded with favor. Operators in the Salt Creek field, Wyo., realizing the hazards of the formation shut-off, recommended the use of cement in all wells drilled through the First Wall Creek sand prior to the Bureau of Mines order to that effect.

USE OF PACKERS.

CASING PACKERS.

Wall packers for excluding top water from the oil sands are not recommended for permanent water shut-offs. Although wall packers are frequently used with apparent success, the effective life of the shut-off may be limited because of the deterioration of the expanding material, usually rubber. Wall packers are handy, however, for making temporary shut-offs in some fields to test shows of oil and gas found unexpectedly during drilling. If the oil or gas sand is penetrated by the bit, there may be no opportunity to make a casing seat for a temporary formation shut-off. In order to make a satisfactory test, the upper waters must be shut off. This may be done by setting a hook-wall or disc-wall packer, or in some cases even an anchor packer, above the sand on a string of pipe.

When a packer is set for a temporary shut-off it should be set in a fairly hard and compact formation because the effectiveness of a packer depends on the bond the expanding material makes with the wall of the hole. A soft formation, such as shale or clay, may "give" under the pressure of a packer and also make a shut-off practically impossible. Packers can seldom be set effectively in holes that have been shot, because of their uneven surface.

TUBING PACKERS.

A casing leak may be temporarily overcome by running a tubing packer on tubing and expanding it in the casing below the leak. This prevents water from gaining access to the oil sand. Although tubing packers are inexpensive, their use is not recommended as a permanent repair measure. Every time the tubing and packer are pulled the rubber must be renewed; and every time the packer is pulled the sand is flooded with water that has collected in the space between the tubing and the casing.

USE OF CEMENT IN OIL AND GAS WELLS.[11]

Cement is used in oil wells for a number of purposes. It is placed behind casing to shut off top water and to prevent the migration of oil and gas around the shoe. It also reinforces the casing and the casing seat, thus insuring a permanent shut-off in soft formations. Sometimes cement is forced back of the casing to seal oil, gas, and water in their respective strata. Occasionally it has been desirable to use enough cement to reach from the shoe to the surface. Cement is also used for shutting off bottom water, to plug abandoned wells, and for many special oil-well jobs to which it is adapted.

[11] Tough, F. B., Method of shutting off water in oil and gas wells: Bull. 163, Bureau of Mines, 1918, 122 pp.; Collom, R. E., Third annual report of the State oil and gas supervisor for 1917–1918: California State Min. Bur. Bull. 84, pp. 110–197.

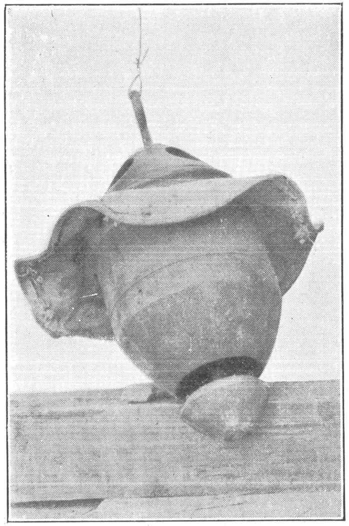
Two general classes of cements are used in the oil fields—the standard quality of Portland cement and special brands of so-called "oil-well cement." Some grades of oil-well cement are specially ground and proportioned; others are of the best quality of standard Portland cement, as determined from tests made by the manufacturers. Many standard brands of Portland cement can be used for cementing oil wells, if the job is carried out properly and without undue delay. Cements begin to set after mixing as soon as movement or agitation stops. When mixed with water to the consistence commonly used in the oil fields, oil-well cements become too thick or viscous to handle with pumps if allowed to stand undisturbed for more than about one hour. The general tendency is to mix the cement too thin. Thick mixtures set more quickly and acquire a much greater initial strength. Oil-well cement can be obtained from oil-well supply houses and its use is recommended. Ten days or two weeks are required for ordinary Portland or "oil-well" cements to set hard enough to insure safety.

Cement should be mixed neat (without sand) with clear water to a consistence as thick as can be handled by pumps or a dump bailer and should be free from all lumps. From 40 to 45 pounds of water (5 to 5½ gallons) per sack of cement (about 94 pounds) will give a relatively thick mixture and is recommended. The use of higher proportions of water unduly weakens the cement and is discouraged. Mixing should be as rapid as possible, whether done mechanically or by hand. The cement should be placed immediately after it is mixed.

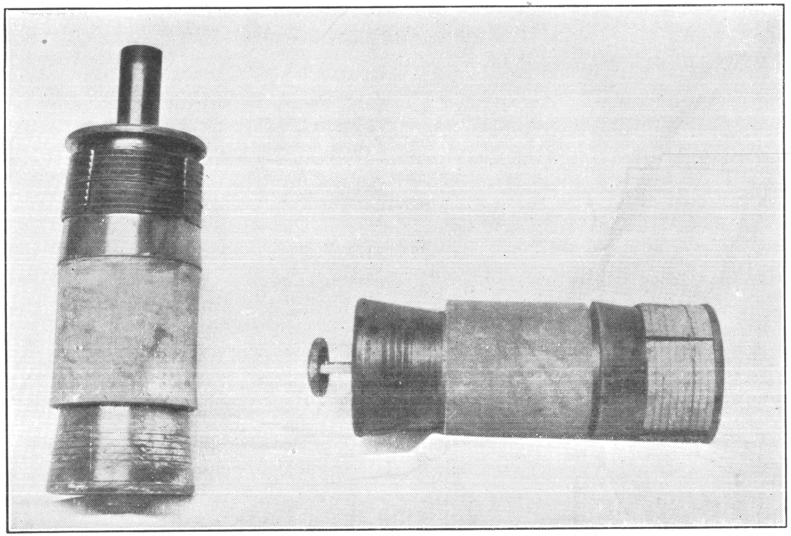
Cement should not be placed until the hole is in proper condition and the casing has been tested for leaks, otherwise the cement may fail to exclude upper waters. The usual method of testing casing for leaks prior to cementing a string of casing is to set the casing on bottom and apply pump pressure. If fluid can be pumped in, it is generally assumed that the casing leaks. In such event it is desirable to pull and examine the casing before placing the cement. When pumps are not required for a cementing job, the casing can usually be tested with a casing tester or swab bailer, as described on page 12.

The diameter of a cable-tool hole is usually only slightly larger than that of the casing collar. For this reason, it is good practice to underream 10 to 20 feet or more of the hole above the casing seat in order to provide a larger annular space for the cement between the casing and the wall of the hole. In a rotary-drilled hole the diameter of the hole is considerably larger than that of the casing and it is not necessary to underream the hole near the casing seat.

Past experience has demonstrated that water can be most effectively shut off by using mud fluid and cement behind casing. When gas or water pressure is high and the formations are not



A. BAKER SURE-SHOT CEMENT PLUG, FOR USE WITH DUMP-BAILER METHOD OF CEMENTING.



B. BAKER CEMENT RETAINER FOR USE WITH TUBING METHOD OF CEMENTING.

adapted to formation shut-offs, use of mud fluid and cement is often the only method that will insure against loss of oil and gas. The subject has been discussed in detail by other writers.[12]

Because of its migratory character, gas tends to dissipate around the shoe of a string of casing unless the shut-off is exceedingly tight. The bureau recommends that casing in a gas well should always be cemented, especially if the gas is under high pressure; otherwise, considerable loss is almost bound to occur.

METHODS OF PLACING CEMENT IN OIL AND GAS WELLS.

DUMP-BAILER METHOD OF PLACING CEMENT.

A dump bailer is a special type of bailer which deposits its load and can be withdrawn empty when run to the bottom of a hole. When casing is cemented by means of a dump bailer, the casing should be run into the well, then lifted some 20 or 40 feet off of bottom or to some point that will be above the level of the cement when placed in the well. After the cement has been dumped, there are two general methods of completing the job: First, to lower the casing without a plug or tight head and allow as much cement to stand inside the pipe as outside; and second, to force the cement back of the pipe as the pipe is lowered, either by filling the casing with water and putting on a tight head before lowering or by using a special plug in the shoe to force the cement back of the pipe as the casing is lowered. The first method is a satisfactory way of cementing a conductor string in a dry hole or when the casing will not stand full of fluid. Twenty to forty sacks of cement may be placed in this manner with good chances of success.

The usual method of cementing casing with a dump bailer is to place the cement in the bottom of the hole, fill the casing and the hole with water, then put a tight head on the casing which has been lifted up into the derrick the distance lifted off bottom (necessarily not more than 40 or 50 feet), and lower the casing. The casing, being filled with water, displaces the cement in the bottom of the hole and forces it upward around the outside of the pipe. Time can be saved by raising the casing off bottom and completely filling the hole with water before the cement is placed. The placing of cement may require a number of runs and considerable time, but the cement must be in position back of the pipe before it sets appreciably. The greatest difficulty in cementing by this method is to keep the casing, which is standing in the derrick, full of water long enough to get the

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[12] Tough, F. B., Method of shutting off water in oil and gas wells: Bull. 163, Bureau of Mines, 1918, 122 pp.; Lewis, J. O., and McMurray, W. F., The use of mud fluid in oil and gas wells: Bull. 134, Bureau of Mines, 1916, 86 pp.; Heggem, A. G., and Pollard, J. A., Drilling wells in Oklahoma by the mud-laden fluid method: Tech. Paper 68, Bureau of Mines, 1914, 27 pp.; Third annual report of the State oil and gas supervisor, California State Min. Bur. Bull. 84, 1917–18, 617 pp.

tight head on. If circulation is free the water may run out at the surface back of the casing as fast as it is pumped into the casing. Rather poor circulation, due perhaps to cavings, may allow the pipe to be filled and the tight head placed before the water column inside the pipe recedes. The pipe should be lowered to bottom immediately after the tight head is put on to prevent circulation of water past the shoe before the shoe joint is lowered into the cement.

Patented cementing plugs which can be placed in the casing shoe after the cement has been dumped and before the casing is lowered on bottom are sometimes used. These plugs answer the same purpose as the column of water and tight head; that is, they force the cement back of the casing and prevent it from rising inside of the casing as it is lowered to bottom. Plate III, *A*, shows a plug of cast iron that can be easily drilled up without damage to the casing or shoe. A valve permits the free passage of air, gas, or fluid as the plug is forced down the casing. A large canvas gasket and a thick band of rubber, similar to a packer rubber, produce a tight seal as the plug is pulled or forced into the casing shoe from below. Many operators prefer to use such plugs when cementing with the dump bailer.

Plate IV illustrates the placing of cement in a hole with a latch-jack dump bailer; in this drawing the cement is being placed to exclude bottom water. For any job the method of dumping the cement is the same. Dumping devices that fit any standard size of pipe enable operators to assemble large-capacity dump bailers by screwing together several joints of ordinary casing or tubing. The Baker dump bailer and the glass-bottom bailer are of this type.

The dump-bailer method is simple and handy when small quantities of cement are placed in a hole. It may be used to cement a string of casing, plug off bottom or edge water, place cement caps on temporary bridges or plugs, plug the hole with cement, or do other jobs that require fairly small amounts of cement and are not subject to the disturbing effects of high-pressure flows of gas, oil, or water. This method is not adapted to cementing casing when large quantities of cement are used or for cementing under more or less treacherous conditions, such as are often encountered in the California and Rocky Mountain fields.

TUBING METHOD OF PLACING CEMENT.

By the tubing method, neat cement is pumped back of the casing through tubing which extends to within a few feet of the bottom of the casing that is being cemented. The tubing is packed off to prevent the cement from rising between the casing and the tubing. A packer or patented cement retainer (see Pl. III, *B*) may be placed between the tubing and the casing near the bottom, or the casing may be filled with water and the tubing packed off at the surface by a stuffing-box casing head. Water in the space between the tubing and casing prevents the cement from rising into that space and thereby forces it around the shoe. Circulation with water or mud fluid around the shoe and back of the casing should be obtained before the cement is placed. Circulation either may be complete to the surface or into some porous formation above the shoe.

Plate V shows the various stages of cementing an oil or gas well by the tubing method with a tight casing head. Sketch A shows the casing raised off bottom and being filled with water with the casing head open; in sketch B, the casing head is closed and water is being circulated back of the casing; sketch C shows the cement being forced down the tubing and around the shoe into the space between the casing and the wall of the hole; and sketch D shows the cement in place, the casing set on bottom, the tubing head open, and water being circulated down the casing and up through the tubing to wash the cement out of the tubing. By this method of flushing out the tubing, less water is required and cement does not come in contact with the inside of the casing except near the bottom; therefore washing out can be done more quickly. After the tubing is flushed, it is pulled and the casing is filled with water, closed, and allowed to stand until the cement sets.

The amount of water pumped into the tubing on top of the cement must be carefully gaged before the casing is lowered to bottom. Too much water will force the cement out of place and leave water opposite the shoe. Too little water will fail to force all of the cement back of the casing, leaving some in the casing and tubing. However, before all of the cement has been forced out of the tubing the pump should be shut down to eliminate any possibility of water displacing cement at the shoe. It is well to mix a little more cement than is actually needed around the shoe and to pump in about three-fourths of the theoretical amount of water to displace the cement in the tubing instead of the full theoretical amount. This precaution obviates the danger of pumping in too much water. The cement in the tubing may be flushed out immediately, or as soon as the casing is lowered, if the casing is free, by pumping water into the casing and back up through the tubing in the usual manner. One advantage in the tubing method is that good cement is left around the shoe and so-called "washed cement" (see p. 28) is flushed out of the well.

Plate III, *B* (see p. 22), shows a Baker cement retainer which can be lowered on tubing and set near the bottom of the casing to be cemented. It acts as a packer between the tubing and casing. An automatic valve in the bottom of the plug prevents the cement from coming back into the hole when the tubing is unscrewed. The plug is made of cast iron and can be drilled out easily after the cement has set. Such a device can be used in cementing a frozen string of casing, which can not be lowered to bottom, as it holds the cement back of the string.

A small plug, somewhat similar to the top plug used in the two-plug method of cementing casing, is sometimes used in checking the proper amount of water to pump in after the cement. When a plug is used, the tubing has a swaged nipple at the bottom through which the plug can not pass. When the plug strikes the swaged nipple, the pump will stall. All other work is done in the usual manner.

The tubing method of placing cement is employed by many operators for recementing when circulation is uncertain. Circulation, either back of the casing to the surface or into the formations, should always be obtained before the cement is pumped into the tubing. If circulation is lost before all or part of the cement is placed, the method enables the operator immediately to flush out the excess cement without damaging his well in any way.

The tubing method can also be used to place cement for bottom-hole jobs when large quantities of cement are required, that is, larger quantities than could be placed quickly by a dump bailer.

ADVANTAGES OF TUBING METHOD.

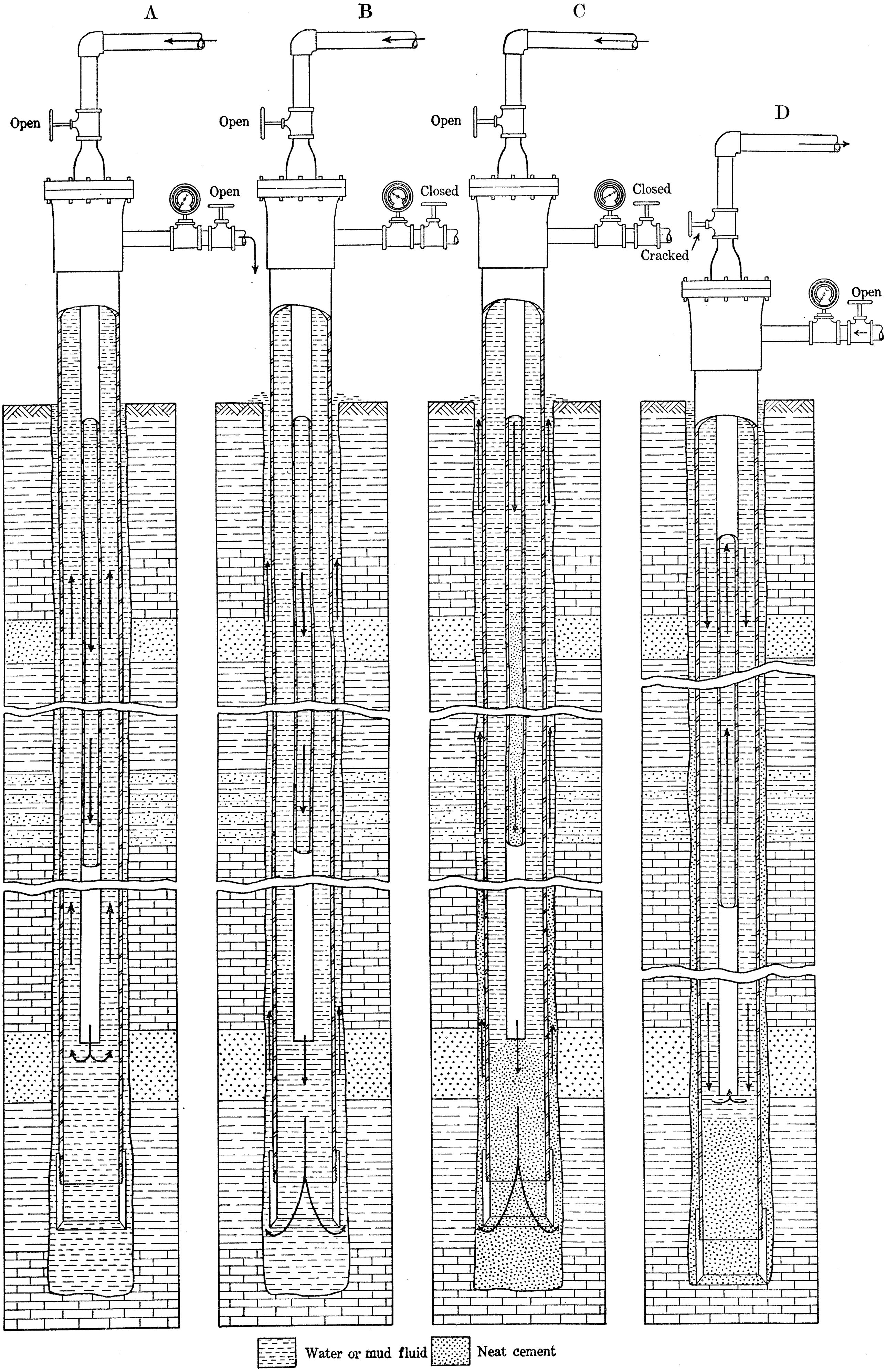
Advantages claimed for the tubing method are these: (1) The time required between the initial wetting of the cement and the completion of the job is less than by other methods; (2) any amount of cement desired may be left inside the casing; (3) a smaller amount of wash water is needed than for the casing methods; (4) in a cable-tool hole there is less danger of caving behind the water string than with casing methods because a much smaller volume of water is circulated; (5) the method is adapted to placing cement under conditions requiring high pressure.

DISADVANTAGES OF TUBING METHOD.

The chief disadvantage of the tubing method is the time needed for running the tubing, which makes the overall time greater than that for a two-plug casing job. The method also necessitates having the string of tubing at the well, which may entail additional expense and trouble.

CASING METHOD OF CEMENTING.

The casing method of cementing involves the pumping of cement into the well through the casing with or without barriers between the "slug" of cement and the fluid below and above. When barriers are used, the method is variously known as the Perkins process, the one-plug method, or the two-plug method. Circulation around the shoe, whether into the upper formations or behind the casing to the surface, must be obtained before the cement is mixed



STAGES OF CEMENTING OIL AND GAS WELLS BY THE TUBING METHOD. (SEE TEXT.)

46467—23. (Face p. 26.)

and started into the casing. If the job is being done in a rotary hole, circulation generally can be obtained, for circulation is usually kept up from the time drilling stops until the cement is placed, except while the casing is run. In fact, during the running of a string of casing it is often necessary to put a head on the casing and resume circulation for a few minutes to keep the pipe free or to knock out any small bridges that may have formed. As cable-tool work now is largely confined to districts in which the formations stand up fairly well in open hole, there is seldom much difficulty in "getting circulation" in those holes.

Some operators cement without barriers. This is satisfactory if the water that is pumped on top of the cement is carefully gaged and precaution is taken to leave several feet of cement in the casing. However the method has certain disadvantages. The exact position of the cement can only be learned by measurement of the water pumped in behind it. If the casing leaks, the cement may pass out through the leak and not reach the shoe. The operator receives no warning of this condition as he does when barriers are used. The method requires, moreover, that clear water and necessary gaging facilities be available, because of the impracticability of gaging mud fluid. When small batches are to be placed, additional cement is required to allow for what will be lost by mixing with the mud fluid or water in passing down the casing.

TWO-PLUG METHOD.

In the two-plug method of cementing, two wooden plugs—which may be of various designs—fitted with leather or rubber gaskets to fill the annular space between the plugs and the casing are used. One plug is placed below the column of cement and the other above it. Plate VII, *C* (p. 30), shows the type of plugs used in the Perkins process. The lower plug (No. 2 in the picture) is necked upward and provided with necessary holes through which the cement can pass out of the casing and around the shoe into the space between the hole and the casing when that plug reaches bottom. The plug must be long enough to extend from the bottom of the hole up into the shoe, in order that it may stop the upper plug, or else a shoe guide must be used in the shoe to stop the first plug when it reaches the bottom of the casing. The gasket or gaskets on the upper plug are stronger and are placed near the top of the plug. Usually an additional gasket is placed near the bottom. The upper gasket prevents fluid from passing by the plug, and as the top plug comes into contact with the lower plug the pump stalls, because the top plug fills the casing and the fluid can not escape by it readily. The plugs are made of some soft wood that can be drilled up easily without injuring the cement or the casing.

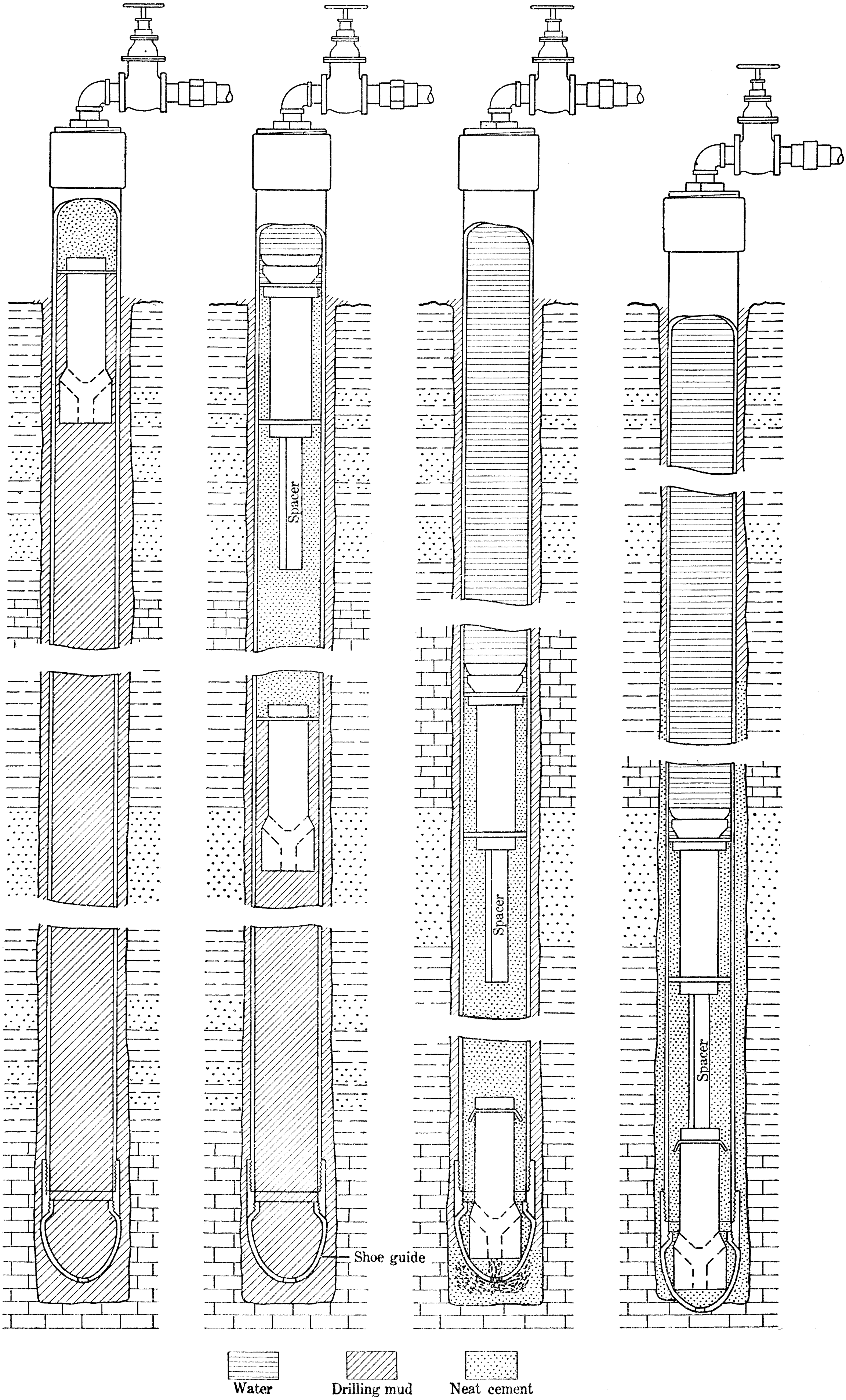
Plate VI illustrates the stages of cementing a well by the two-plug method. After circulation has been obtained, the circulating head is removed and the bottom or dead-end plug is inserted in the top of the casing. The head is then replaced and the cement is pumped on top of the bottom plug. When all the cement is in, the tight head is removed long enough to insert the spacer (if used) and the top plug. After the tight head is replaced, water or mud fluid is pumped in to force the cement down the casing. If water is used, the volume of water pumped in after the second plug should be carefully metered or gaged, in order to check the position of the top plug. When the lower plug reaches bottom, the pump generally warns the workmen by slowing down and "laboring" that the cement is passing outside the casing. When the top plug reaches the bottom plug, it seats on the bottom plug and stalls the pump. Finally, the casing, which has been held off bottom about 1 or 2 feet, is lowered to bottom, the casing head closed in tightly for at least a day or so, and the cement allowed to harden for 10 days or 2 weeks.

The top part of a column of cement is usually termed "washed cement"; it seldom develops much strength and often does not even set; therefore the top plug should be stopped at such a point that some cement is left in the casing to insure cement of maximum strength remaining around the shoe. Wood spacers of suitable lengths (from about 5 to 25 feet) are often used between the plugs in order to stop the top plug and leave the washed cement inside the pipe. They are put in just ahead of the top plug, and are not difficult to drill out.

Shoe guides are used in many rotary holes because the casing is not run until drilling to the casing point has been completed. Plate VII, *A* and *B*, shows two types of shoe guides. Shoe guides are rarely used in cementing cable-tool holes. If the water string is being "carried," the casing would have to be withdrawn in order to put on the guide. As a shoe guide holds the plug within the casing, the bottom plug must have holes (see Pl. VII, *C*, 2) through which the cement can pass.

Before the plugs and cement that may be left in the casing are drilled up the holes should be bailed to test for casing leaks. Likewise, after a foot or so is drilled below the shoe another bailing test should be made to determine whether or not the shut-off at the shoe is effective. The general procedure should be followed regardless of the means used to effect a water shut-off.

The two-plug method is used most commonly for cementing casing in well drilling. In general both the two-plug process and the tubing method are approved by the Bureau of Mines. The advantages of the two-plug method are: (1) A large quantity of cement can be placed quickly and satisfactorily by this method if an ade-



STAGES OF CEMENTING OIL AND GAS WELLS BY THE PERKINS PROCESS. (NOTE.—A SPACER IS NOT ORDINARILY USED WITH A SHOE GUIDE.)

quate cementing outfit is available; (2) the method is simple and requires little extra equipment; (3) it is adapted both to cable-tool and rotary drilled wells; (4) it is the method most commonly used and hence best handled by oil-field workmen.

In the one-plug method of cementing a bottom plug is not used. The intermingling of the cement and mud is believed to be slight. Use of a shoe guide to stop the one (top) plug when it reaches bottom is desirable, although the plug may be stopped by making it long enough to reach the bottom of the hole and still stand up inside the pipe. It may also be stopped by the use of a spacer.

The most common mistake in cementing oil wells is the use of too much water and the waste of too much time in placing cement. It is recommended that cementing outfits of all kinds be designed to meet the two following requirements:

1. Maximum amount of water to each sack of cement, 45 pounds, or about 5½ gallons.

2. Maximum period from time water is first added to cement until cement is in place, one and one-half hours.

CEMENTING CASING OFF BOTTOM BY CONSTRUCTION OF A BRIDGE.

High-pressure oil and gas sands may be penetrated unexpectedly, in which event top water must be shut off before the well can be completed as a producer. Since there is no casing seat, the pipe can not be landed in the formation to shut off the water, and cementing it off bottom is desirable. Cementing casing off bottom is commonly done by constructing a bridge, capped with a cement plug, a short distance below the point where the casing is to be set and cementing the casing by one of the various methods.

CEMENTING CASING OFF BOTTOM WITHOUT BRIDGING.

Experience has shown that a virgin oil sand, if saturated with oil, will usually take a little water and practically no mud fluid under pressure. A partly drained oil sand will often take some fluid under pressure, but sands that have been drained until they are small producers or not commercially productive will take considerable clear water and almost as much thin mud fluid under pressure. On the other hand, as a rule water sands readily take clear water under pressure, and unconsolidated sands take large amounts of mud fluid when enough pressure is applied to overcome the hydrostatic head of their water. In Oklahoma, Texas, and California, operators have found that the oil sands in old wells often take great quantities of water; whereas the oil sands of new wells will take little water, if any, and practically no mud.

Although no conclusive evidence is at hand, observations have indicated that virgin oil sands will probably take some oil under pressure, if the pressure is held on the sands for a number of days, but in all likelihood will refuse to take more than small amounts of water under the same conditions. That partly drained sands will readily take quantities of oil is well known, and has been demonstrated in Oklahoma and California fields, where hot oil has been pumped into a well in an attempt to revive production.

Field observations that are the basis for the generalities in the paragraphs above have been substantiated to some extent by laboratory experiments of the Bureau of Mines. For example, Mills [13] points out that the reluctance of oil sands to take water under pressure may be due to a number of factors, such as texture, porosity, bedding, proportion of gas to oil (in the reservoir rocks), selective permeability, and other less important causes. The differences in the action of water and mud fluid are also of prime importance.

The cementing of casing off bottom without the use of a bridge depends upon the action of the fluid below the shoe in resisting the downward flow of the cement, thus causing the cement to pass up behind the pipe. Either the casing or tubing method can be used for cementing casing off bottom without the use of a bridge. The tubing method is carried on as usual. The one or two plug method may also be used, preferably with a shoe guide to stop the plugs. Although some of the cement and the fluid below the shoe may mix, the amount of cement lost by mixing will be slight if reasonably large quantities of cement are to be placed, and the chances for obtaining a successful shut-off will be good. For example, when the cement plug in one well of a southern California field that had been cemented in this manner was drilled out, cement was found for only 5 feet below the shoe. However, had the cement penetrated the fluid below the shoe for even 25 feet or so the success of a cementing job that involved the use of 250 or 300 sacks of cement would not have been jeopardized.

HALLIBURTON METHOD.

The Halliburton method of cementing, which is essentially a modified two-plug method, is adapted to cementing casing off bottom and has been described in a former report.[14] Its distinctive feature is a special casing-head connection with a stuffing box through which an ordinary steel tape may pass. With a steel tape and a 13-pound bob, the position of the top plug may be determined at any time while the plug is being forced down; thus the need for metering the

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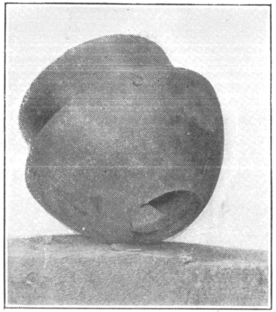
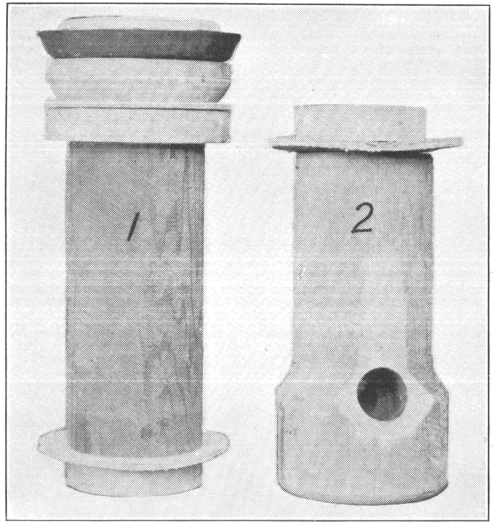
[13] Mills, R. Van A., Experimental studies of subsurface relationships in oil and gas fields: Econ. Geol., vol. 15, 1920, pp. 398-421. Relations of texture and bedding to the movements of oil and water through sands: Econ. Geol., vol. 16, 1921, pp. 124-141.

[14] Swigart, T. E., and Schwarzenbek, F. X., Petroleum engineering in the Hewitt oil field, Okla.: Coop. rept., Bureau of Mines, State of Oklahoma, and Ardmore Chamber of Commerce, p. 60. Obtainable from Ardmore (Okla.) Chamber of Commerce.

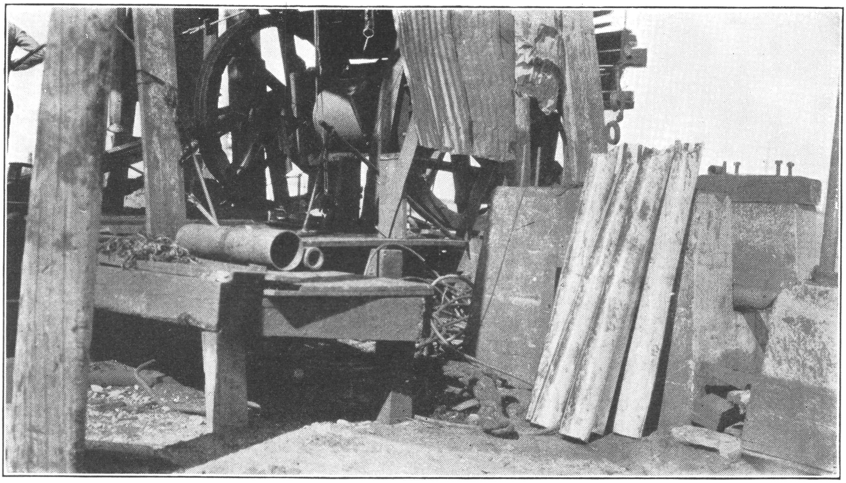
A. CAST-IRON SHOE GUIDE AND BARREL.



B. CAST-IRON SHOE GUIDE OR FLOATING PLUG.



C. PLUGS USED IN THE PERKINS PROCESS OF CEMENTING: *1*, TOP PLUG; *2*, BOTTOM PLUG.



A. SHEET-IRON CANISTERS FILLED WITH LATHE CUTTINGS FOR PLUGGING OFF BOTTOM WATER.

B. LEAD PLUG FOR CAPPING A PLUG OF LATHE CUTTINGS, READY FOR RUNNING INTO THE WELL.

water or depending on the stalling of the pumps to determine when the plug has reached bottom is avoided. Should the plug hang in the casing before it reaches bottom, and stall the pump, this will be recognized and the exact position of the plug determined at once. Moreover, the bob and measuring line permit the plug being stopped at any desired point.

In common with certain other methods previously described, the Halliburton method depends upon the characteristic refusal of virgin oil sands to take water or mud fluid. It is also applicable to sands that do take fluid slowly, for the job may be rushed through so quickly that the cement is placed and takes its initial set before the fluid below the bottom plug recedes and permits the temporary bridge (formed by the bottom plug) to give way. When casing is cemented off bottom by this method, the dead-end plug, which is provided with large, strong gaskets, passes out of the casing, and the gaskets expand to the walls of the hole and thus make a temporary bridge supported by the column of fluid in the hole below. By aid of the measuring line, the top plug can be stopped at any point above the shoe, leaving a given amount of "washed cement" inside the casing.

PRACTICABILITY OF METHODS.

Cementing off bottom without bridging can not be relied on in older fields, where the oil sands have become partly exhausted and possibly will take large quantities of fluid under pressure, but casing has been cemented off bottom with success in so many wells that the practicability of the work has been clearly shown. Cementing off bottom may best be done in new fields where the sands are undrained; in fact, the greatest call for such work naturally comes during the drilling of new fields where the gas pressures are high.

REPAIRING CASING LEAKS.

In a preceding section (pp. 12 to 15) methods for detecting a casing leak were described. The usual way of repairing a casing leak, if the casing can not be pulled or if a packer is not run on tubing as a temporary measure, is to bridge the hole to a foot or so below the leak, then to attempt to gain circulation by pumping in water under pressure at the top of the casing and cement the leak. If circulation can be obtained or if the hole will take an appreciable amount of water, tubing should be run and packed off at the surface with a stuffing-box casing head. Cement is next mixed and pumped in under pressure. The tight head and casing full of water, with the bridge, divert the flow of cement outward through the break in the pipe. When the hole will take no more fluid or enough has been pumped in to insure a good job, a valve on one outlet of the stuffing-box head is "cracked" and water is pumped in, or better, the direction of flow is reversed and the excess cement flushed back through the tubing as described on page 25. The pressure must be kept up by cracking the outlet valve but slightly, otherwise some of the cement behind the casing will run back in. The tubing must be flushed thoroughly, however, because it can not be withdrawn after flushing but must be left in the hole with the valves closed to hold pressure on the well for 10 or 15 days while the cement is setting.

At the end of 10 days it is usually safe to bail the well down to the bridge. After the well has stood untouched 8 to 12 hours the bailer should be run again to see if any water has entered. If the water is shut out, any cement capping the bridge may be knocked out with the tools and the bridge removed.

Halliburton's cementing method, which uses the steel tape and bob to check the position of the top plug, permits a determination of the depth of a casing leak and its repair. If a plug is run as in the plug process of cementing, and the plug stops at some point off bottom but the casing continues to take water, indications are that the casing leaks. The procedure that follows is determined largely by the size of the leak. If the pump builds up pressure and can only force fluid out slowly, showing that the leak is small, it is often desirable to perforate the leaky joint to permit enough cement to be placed behind the casing to shut off the water. In some fields, such as those of California or the Gulf Coast, however, to perforate the casing may be dangerous because the water sands are so loose that they may run into the hole. If the sands "stand up" fairly well, then the rapidity with which the formation makes water or takes fluid before and after the perforating, the nature of the formation behind the pipe, and whether the hole is cable-tool or rotary, are bases for determining the details of the method of repair.

If, on testing, the hole takes fluid rapidly and circulation outside the casing is obtained, the decision may be made to introduce, for example, 100 or 200 sacks of cement by the two-plug method, and to rely on the fluid in the well to support the lower plug just below the leak.

Although the Halliburton method with two plugs is often used for repairing casing leaks, it is believed that on the whole the tubing method is more readily adaptable; in fact, it may be used in conjunction with the first plug, which is run to determine the location of the leak. If, after the casing is perforated, the formations take fluid slowly and uncertainly, tubing with a tight casing head is believed to be the safest method of introducing the cement, because it provides for stopping the introduction of cement as soon as the formation refuses to take more and for flushing out all the cement inside the tubing. It also allows for a continued supply of cement if a large amount is needed, but has to be pumped in slowly.

USE OF MUD-LADEN FLUID IN SHUTTING OFF WATER.

The term "mud-laden fluid," as used in this discussion, applies to any mixture of water and shale or clay-like materials that remain in suspension for a long period of time and is practically free from sand, grit, limestone, or other coarser materials that settle out.

The essential qualities desired in mud fluid are weight and fluidity; that is, the mud fluid should be as heavy as possible and still be fluid enough to be pumped readily. The effectiveness of mud fluid in holding up the walls of a hole or overcoming gas pressure depends largely upon its specific gravity. The specific gravity of the average oil-field mud fluid will probably range from 1.05 to 1.30, approximately 8.75 to 11.0 pounds per gallon or 66 to 82 pounds per cubic foot. (Pure water weighs 8.33 pounds per U. S. gallon or 62.5 pounds per cubic foot.) A mud fluid so thick that it can just be handled by the pumps may not be as heavy as a thinner mud fluid made from a different material. Experiments have shown that the same volume of two different shales mixed with equal quantities of water may give mud fluids of different specific gravities and viscosities. For example, in California, shale known to be adaptable to mud making is often hauled for miles, although there are large amounts of shale of one kind or another near all the wells. If an especially heavy mud fluid is needed for holding down high-pressure gas, the thickness of the mud fluid should not be relied on as an indication of weight. Actual tests by weighing or by a special hydrometer should be made. It has been suggested that when an extra heavy mud fluid is required, some substance, such as iron oxide,[15] may be added to increase the specific gravity of the mud fluid without decreasing its fluidity.

The circulation of thick mud fluid in high-pressure gas fields often has resulted in the mud fluid becoming impregnated ("aerated") with gas and thus lightened. Thick, viscous mud fluid is more likely to become lightened by gas bubbles than is thinner, less viscous mud fluid. The mud fluid may become so lightened that the gas pressure is greater than the static pressure of the column of mud fluid, and a blow-out results. In actual practice, when the returned mud fluid shows signs of becoming aerated ("cut" or "feathered"), the mud fluid from the well either is thinned with water before it is returned or is run into a storage sump and new mud fluid from the mixing pit pumped into the well. Thin mud fluid is not as heavy as thick mud fluid, and not as good for holding back strong gas pressures. Thin mud fluid, however, because it is not so readily "feathered" by gas as heavy mud fluid, often has a higher specific gravity at the

[15] Stroud, B. K., Mud Fluids and tables on specific gravities and collapsing pressures: Louisiana Department of Conservation, Tech. Paper 1, March, 1922, 9 pp. Obtainable from Department of Conservation, New Orleans and Shreveport, La.

time of use than thick mud fluid that has been circulated a short while, and for that reason may be of more practical value in overcoming strong gas pressures.

METHODS OF PLACING MUD FLUID.

There are several methods of placing mud fluid back of casing. The condition of the hole and of the casing as well as other factors enter into the problem. Whenever possible, mud pumps should be used and mud fluid circulated down through and up around the casing. If the casing is free and circulation can be obtained, this method is by far the most satisfactory for practically all mudding jobs, for it insures a column of mud of fairly uniform consistence throughout the length of the hole and for the most part is adaptable for use under the conditions prevailing in wells on Government lands in California and the Rocky Mountains.

In some fields, such as those of northeast Oklahoma or the Appalachian district, mudding is not a common practice. The formations are relatively hard and do not cave in open hole. Operators in those fields often wish to place mud fluid behind casing to assist in effecting a water shut-off, to protect pipe from corrosive waters, or to seal off upper productive sands. Inexperienced men may attempt to pour mud fluid behind the casing after it has been set. This method is unsatisfactory because there is no assurance that the mud fluid will settle to the shoe, and the pouring in of the mud fluid induces caving. Moreover, the column of mud fluid will not be of uniform consistence; the chances are that in the lower part of the hole, where it is most needed, the mud fluid will be diluted; in fact, none of it may get that far.

Mud fluid, properly used, will often protect upper oil and gas formations, eliminate the bad effects of unsystematic casing, protect the casing from corrosive waters, and tend to keep it free. High-pressure gas wells can be controlled with mud fluid, and it is one of the most effective means of plugging abandoned wells.

In many wells one or more oil, gas, or water bearing formations must be cased off to obtain production from a lower and more productive sand. These upper sands may not contain enough oil or gas to warrant producing from them when the well is drilled, but they may be of commercial value later. Moreover, these sands may be producing oil or gas in neighboring wells. In either event, it is the operator's duty to take adequate measures to prevent the sands being flooded by water or losing oil or gas through its migration back of the pipe.

In the dry-hole method of drilling extra casing is needed to protect upper productive sands. Its use causes delays and so increases the cost of drilling that the casing necessary for proper protection is not placed in many wells. Mud fluid, properly used, is the cheapest way of protecting upper oil and gas formations.

A definite casing program should be followed in each field in order that the casing will be landed systematically with respect to all oil, gas, and water sands. Unsystematic casing is common in spite of all efforts. If, as pointed out in the preceding section, heavy mud fluid is circulated in a well before casing is landed and allowed to stand back of the casing most of the loss and damage from this source can probably be eliminated.

USE OF MUD FLUID IN PREVENTING CORROSION.

In some fields corrosive waters cause much trouble and expense. They destroy casing, tubing, pumps, and other underground equipment, thereby increasing the operating costs and even injuring productive oil and gas zones. A column of mud fluid back of the casing is one of the most effective means of reducing trouble from corrosive waters in strata which may be cased off. Ordinarily a column of mud fluid will exert enough pressure to hold ground waters in their native sands, and if the well has been thoroughly mudded behind the casing any damage from corrosive waters reaching the casing should not be large. Mills [16] has pointed out that certain alkaline reagents, if added to the mud fluid, will neutralize the corrosive effects of the water and tend to hold the finely divided particles of the mud in suspension. It seems probable that further advances in the preparation and use of mud fluid will largely prevent casing being corroded by waters that stand behind it.

SHUTTING OFF BOTTOM WATER AND WATER IN OIL SAND.

The need for plugging off bottom water or water in an oil sand frequently confronts producers. Water from either source may cause loss of oil and gas. As the practicability of shutting off such water is often worth determining, a brief description of some of the methods commonly used is included.

USE OF CEMENT FOR PLUGGING OFF WATER.

Bottom water can be plugged off more easily than water in the sand, because the break that separates true bottom water from the productive sand furnishes a means of completely excluding the water. When water is coming through the oil sand, it can seldom be plugged off permanently, because there is no break or impervious formation to aid the plug in holding the water back. Moreover, water coning probably starts as soon as an oil well drilled into the water-bearing

[16] Mills, R. Van A., Protection of oil-field equipment against corrosion: Bull. 233, Bureau of Mines. (In press.)

part of the sand begins to produce. To shut out the water after coning has started requires a plug reaching higher into the sand than the normal water level; such a plug in turn may reduce the production of oil.

Under most conditions cement is the best material for plugging off both bottom water and water in the sand, although other methods are sometimes more satisfactory for shutting off water.

Cement has the advantage of flowing readily, thus filling all irregularities in the wall of the hole. Under favorable conditions it makes an excellent bond with the walls of the hole. A cement plug is usually adapted for plugging holes that have been shot because it fills the irregular shot hole more satisfactorily than any other plug. Moreover, a cement plug of any desired length can be placed quickly and cheaply. The only delay occurs while the cement is setting, and that is only about 10 days.

Cement may be placed in a well by a dump bailer or by the tubing method. The dump-bailer method, which is the simpler (see p. 23) and generally used, is illustrated in Plate IV (p. 24) and has been described by Tough.[17] Gas, moving waters, or waters under high pressure may cause trouble by preventing cement from setting or by channeling through a cement plug before it takes initial set. There are several ways of reducing these movements of gas or liquid, or "killing the flow"; they include mudding prior to cementing, placing cement in the well in canisters or sacks and breaking the containers by running tools on them, permitting the water to reach its natural level before a job is started, and plugging part way with other materials to cut down the flow of the water long enough to permit the cement which caps the plug to set.

The tubing method of cementing off bottom water [18] has been used with fair success at various times. It has been successful in wells where gas keeps the fluids agitated and is also suited to jobs that take large amounts of cement.

PLUGGING WITH LATHE CUTTINGS.

Lathe cuttings lowered into the well in 4-foot canisters of thin sheet iron, just small enough to pass freely through the casing (see Pl. VIII, *A*, p. 31) have been successful in some Kansas fields for plugging off water occurring in the same formation as the oil. A canister is lowered on a string of tools and then "run on" until it is tamped down. A 4-foot canister may tamp down to a plug 6 inches or 1 foot in height, depending on the size of the cavity in the well and the character of the formation, and under extreme conditions it may not fill up the hole at

[17] Tough, F. B., Methods of shutting off water in oil and gas wells: Bull. 163, Bureau of Mines, 1918, pp. 63–64.

[18] Thoms, C. C., Recementing wells through tubing: Oil and Gas Jour., Nov. 19, 1920, pp. 86–87.

all. After a few canisters have been run, the number depending on local conditions, a bailing test may be made to determine if the rate at which fluid comes into the hole has decreased. When, in the judgment of the operator, the greatest amount of water has been shut off with the least amount of oil, a solid lead plug (see Pl. VIII, *B*) is usually lowered and driven with the tools to cap the plug of lathe cuttings. The advantages of this method are that it can be used in wells where cement will not set. Moreover, the plug can be driven to the exact level that will give the best results. Experience has shown that sometimes this level is a matter of inches, too much plug cutting off the oil and too little not decreasing the water enough.

LEAD WOOL.

Lead wool is sometimes used to plug off bottom water. A few hundred pounds of the wool is placed in the bottom of the hole and tamped into a solid mass with a flat-bottomed bit. The loose spongy wool as it consolidates is forced into the irregularities of the wall of the hole. If the first plug does not shut off the water, more wool can be added and tamped. After water is shut off with lead wool, it is good practice to cap the lead with cement, if there is room, and thus insure a more durable plug. By the use of lead wool, a flow of water in excess of 5,000 barrels per day, with a gage pressure of over 150 pounds per square inch at the casing head, was recently shut off in a well in Cat Creek, Mont.

MECHANICAL PLUGS.

A number of mechanical plugs are made for plugging off bottom water. They are variously known as bottom-hole plugs, rubber plugs with wood mandrel, solid lead plugs, lead plugs with mandrels, lead and rubber plugs with mandrels, limit plugs, and spiral plugs. When circumstances favor their use, these plugs are often effective. It is almost essential that they be set in hard formations and in holes that have not been shot, otherwise tight bonds between the plugs and the walls of the hole can not be effected. In general, mechanical plugs are not adapted to the conditions on Government lands in the Rocky Mountain district and California. The department will discourage their use except in emergencies or for reducing the underground movements of fluids so that cementing can be done.

ASSISTANCE BY SUPERVISORS.

The deputy supervisors will advise and assist operators in handling jobs that involve shutting off water. As in a majority of other matters that pertain to well operation, the methods to be employed have not been specified by regulation because it is believed that best

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results can be obtained by cooperation between the operators and the Bureau of Mines representatives.

TESTING WATER SHUT-OFFS.

In the prevention of underground loss of oil or gas probably no measure is more important or is more frequently neglected than the testing of water shut-offs. Experienced operators realize the need for shutting off water before drilling into the oil sands and often spend considerable time and money to accomplish it, yet fail to test the effectiveness of the shut-off. Unless a careful test is made, a leak around the shoe or in the casing may not be detected. Such a leak can often be repaired easily before the well is drilled in, but if not repaired at that time may become a serious problem and cause much damage later.

The ordinary test for water shut-off consists of two tests, one for casing leaks and one for leaks around the shoe.

TESTING CASING FOR LEAKS.

When a cement shut-off is made, it is common practice to leave a few feet of cement in the casing. This cement plug ordinarily shuts off any water from below.

For the first part of the test, the hole should be bailed dry or bailed down to a certain level (see p. 12), and the well allowed to stand 12 hours or more. Then if bailing shows that water has entered the hole since the previous bailing, the casing probably leaks. The difference in fluid levels will indicate the amount and rate at which it is leaking. A casing leak should be repaired before the well is drilled deeper. If there is a large leak that can not be repaired, it may be necessary to drill out the plug, set a smaller string of casing below the shoe of the original string, and make a second shut-off.

If a formation shut-off has been made, the hole should always be bailed dry. If water rises in the casing after 12 hours or more, it may enter either through a casing leak or around the shoe. The casing can be tested and the depth to the leak determined by the use of a casing tester as described on pages 12 to 14. If the leak is not in the casing it is around the shoe, and a new seat must be provided or the pipe cemented.

TESTING FOR LEAKS AROUND THE SHOE.

In the second part of the test for water shut-off, the effectiveness of the shut-off at the shoe is determined. If the well is cemented, the cement should be drilled out of the casing and drilling continued until the formation is touched. If the pressure of fluid outside the pipe is heavy, an operator, before drilling out a cement plug, should run enough fluid into the hole almost to equalize the pressure from outside and thus provide against the pipe collapsing near the shoe, where the tools work. After the cement plug is drilled through, the hole should again be bailed dry or bailed down to a certain level, allowed to stand 12 hours, and bailed again to determine whether or not water has entered. If the shut-off at the shoe is not tight, the well should be repaired before it is drilled deeper. A similar test should always be made of a formation shut-off after the hole is drilled a few feet below the shoe. This test is especially important because small leaks may develop while hole is being made near the casing and these small leaks may rapidly become large ones.

The second part of the water shut-off test may develop into a production test if the well was drilled into the oil or gas sand before the casing was landed. In some fields where rotary tools are used, many wells are drilled into the oil sand before they are cased in order to determine the casing point with certainty. As soon as the cement plug is drilled through in such holes, the well either starts to flow or partly fills with oil. Obviously a well in this condition can not be bailed down for a water shut-off test. Instead of the usual bailing test, a temporary production test should be made to determine whether or not the water has been shut off. If such a well will not flow, it should not be drilled in with the hope of making it flow but should be tubed and pumped for the production test.

A water sand of low head may not "break in" around a defective water shut-off for months if the fluid level is not lowered appreciably during that time. For this reason, a production test for water shut-off in a well that has penetrated the oil or gas sand is not always conclusive.

COLLAPSING PRESSURES OF CASING.

Whether to bail the well dry or to a certain level when the casing or shut-off is being tested depends on local conditions. If the operator prefers to bail the fluid in a deep well down to a certain level when he tests for water shut-off, he should bail the fluid down until the differential head on the outside of the casing is at least 1,000 feet. This method of testing is adapted to wells in which the external pressure on the casing, when the well is bailed down, would exceed the allowable collapsing pressure with a safety factor of two, and is advisable as a protection against the overloading of "green" cement. Casing heavy enough to withstand the collapsing pressure during a bailing test should be used, otherwise it would not be safe to lower the fluid level to a point near the top of the oil sand or lower after the well is put to producing. In fact, all operators know that eventually the fluid level must be lowered to a point below the shoe, although the hazard of collapsing from external fluid pressure still exists. Table 1 (see p. 43) gives the collapsing pressures and capacities of standard brands of casing and should guide operators in choosing casing for oil and gas wells on public lands.

IMPORTANCE OF TESTING WATER SHUT-OFFS.

The careful testing of water shut-offs is a matter of insurance, to operators and to the Government, against losses from faulty work. Even though the water shut-off has been made in the most approved manner and with the greatest care, an operator is not relieved of his obligation to test it. The Bureau of Mines will insist on suitable tests for determining the effectiveness of water shut-offs in all wells drilled on Government lands. In each locality and in special cases the local deputy supervisor will designate suitable methods for testing shut-offs and whenever possible will be present or designate a representative to witness the test. Government lessees should not drill in wells before the shut-off is tested. (See sec. 2, par. j, and sec. 5, par. c, of the "Operating Regulations," Part II of this manual.)

CHOICE OF CASING FOR OIL AND GAS WELLS.

Poor or secondhand casing has caused loss of oil and gas in many wells. In many deep wells, the water pressure behind the casing amounts to hundreds of pounds per square inch and the casing may collapse unless it is strong. If casing collapses oil and gas usually are lost in the manner described in previous sections. Water entraps oil and gas and unless shut off will ruin a well.

CARE IN HANDLING CASING.

Running or pulling casing, and setting up or breaking joints subject pipe to stresses which cause wear and possible injury. Cross threading may also occur unless workmen are extremely careful. Used casing is often weakened by corrosion. The points of weakness thus created may not be detected at the surface, but may cause failure when the casing is subjected to high fluid pressure. Old casing should be carefully inspected for splits, corroded areas, dents, and poor threads before being run. Defects scarcely discernible on the surface may prove serious when the casing is subjected to high fluid pressure and the stresses incident to its handling in the well.

An example of the trouble caused by running poor casing in a well was observed in the Burbank pool, Osage County, Okla. A new string of $8\frac{1}{4}$-inch casing had been landed in a well at approximately 2,350 feet but failed to shut off the water. The string was pulled, carefully examined, and rerun several times after new casing seats were prepared, but each time failed to shut off the water. A split was found in the bottom joint the first time the casing was pulled, but even after the defective joint was replaced the shut-off could not be effected. Eventually the casing was condemned and a complete new string was purchased and run, shutting off the upper waters without more trouble.

Water often enters a well through leaky casing joints. It is not uncommon for operators to screw up a water string as it stands in the hole and thus stop a casing leak. In the Hewitt field, Okla., a well that had been cemented showed a casing leak when tested. The string was screwed up a total of 18 inches, then a test showed no leak. At another well, a water string was screwed up some 30 inches. These are extreme examples of careless work. Casing is not commonly taken up more than 5 or 6 inches, particularly when it is cemented. The operator should use judgment in attempting to screw up a cemented water string, and if the "back lash" amounts to half of a reasonably short stroke of the tongs, continued screwing may cause collapse of the pipe. Rush work, such as is carried on in so-called "boom fields," often results in casing being set up carelessly. Operators must require their own crews to set up casing properly when running it. In contract work, the well owner should exercise even greater vigilance and have a competent company representative present while the casing is being run.

SIZE AND WEIGHT OF CASING.

Too often operators overlook the advantages of using the heavier weights of casing to insure against collapsing from fluid pressure and from possible shifting formations. When casing is being chosen for a hole of a certain depth, the usual oil-field practice is to employ casing of such size and weight that its collapsing strength is twice the pressure exerted by a column of fluid of the same length as the casing. This is considered good practice and is recommended by the Bureau of Mines. The length of casing, of given weight and size, that will withstand the pressure of a column of water of equal length with a safety factor of 2 is given in Table 1, column 10. For example, if a 3,300-foot hole is to have $8\frac{1}{4}$-inch casing, the operator should consult Table 1, columns 1, 2, and 10. He will find that $8\frac{1}{4}$-inch, 32-pound casing can only be used safely to depths of 2,478 feet or less; that $8\frac{1}{4}$-inch, 36-pound casing can be used up to 3,033 feet; and that $8\frac{1}{4}$-inch, 38-pound casing is safe for a 3,323-foot hole. Likewise, if a 4,400-foot well is to be cased, the operator either must use $6\frac{5}{8}$-inch, 30-pound casing or one of smaller size. In the new Santa Fe Springs field, Calif., operators are setting $8\frac{1}{4}$-inch, 43-pound water strings at depths of from 3,600 to 3,900 feet.

An operator can not be too particular in using sufficiently heavy pipe, especially in fields where the formations are soft and somewhat unconsolidated and where mud fluid or water stands behind the pipe level with the surface. When mud fluid stands back of the casing, account should be taken of the difference in the specific gravity of mud fluid and water. For example, if an operator desired to case a hole to a depth of 2,250 feet with 6⅝-inch casing, he will find by consulting Table 1, column 10, that 6⅝-inch, 20-pound casing is safe to use if water stands behind the pipe. However, if the operator is using mud fluid of, say, 1.2 specific gravity, the pressure exerted by the 2,250-foot column of mud fluid would equal 1,169 pounds per square inch, which is equivalent to a water column of 2,700 feet when a safety factor of 2 is used. Table 1, column 10, shows that 6⅝-inch, 24-pound casing should be used when mud fluid is back of 6⅝-inch casing in a well of this depth.

Casing should be strong enough to allow the hole to be bailed dry with safety. In exceptionally deep wells, the allowable depths for various larger sizes of casing can be increased by the use of large amounts of cement which extend up into the hole back of the casing far enough to bring the effective depths within the safe limits for the particular casings being used.

TABLE 1.—*Collapsing pressures and capacities of casing.*

Nominal size, inches.	Weight per foot with collars, pounds.	Actual outside diameter, inches.	Actual inside diameter, inches.	Thickness, inch.	Couplings, outside diameter, inches.	Thread, per inch.	Collapsing pressure, per square inch, pounds.	Collapsing depth, feet.	Collapsing depth with safety factor of 2, feet.[1]	Capacity per linear foot in— U. S. gallons.[2]	Capacity per linear foot in— Cubic feet.	Capacity per 100 linear feet, barrels.	Brand.
4¼	6.75	4.500	4.216	0.142	5.021	14	1,348	3,106	1,553	0.725	0.097	1.73	Standard casing.
4¼	9.50	4.500	4.090	.205	5.021	14	2,562	5,903	2,951	.683	.091	1.62	Do.
4½	7.25	4.750	4.460	.145	5.271	14	1,259	2,900	1,450	.812	.109	1.94	Do.
4½	9.50	4.750	4.364	.193	5.271	14	2,135	4,920	2,460	.780	.104	1.85	Do.
4½	16.00	4.750	4.082	.334	5.364	10	4,708	10,850	5,425	.680	.091	1.62	Diamond B X casing.
4½	12.85	5.000	4.506	.247	5.686	10	2,895	6,670	3,335	.828	.111	1.98	Diamond B X drive pipe.
4½	15.00	5.000	4.424	.288	5.923	10	3,606	8,310	4,155	.798	.107	1.90	Do.
4¾	8.00	5.000	4.696	.152	5.521	14	1,248	2,876	1,438	.900	.120	2.14	Standard casing.
4¾	12.85	5.000	4.500	.250	5.491	10	2,948	6,793	3,396	.826	.110	1.96	Diamond B X casing.
4¾	15.00	5.000	4.408	.296	5.491	10	3,744	8,627	4,313	.793	.106	1.89	Do.
5	16.00	5.250	4.648	.301	5.800	11½	3,583	8,256	4,128	.881	.118	2.10	Standard casing.
5 3/16	9.00	5.500	5.192	.154	6.078	14	1,040	2,397	1,198	1.100	.147	2.62	Standard.
5 3/16	13.00	5.500	5.044	.228	6.050	11½	2,206	5,083	2,541	1.040	.139	2.48	South Penn.
5 3/16	17.00	5.500	4.892	.304	6.155	11½	3,404	7,844	3,922	.976	.130	2.32	Do.
5⅝	10.50	6.000	5.672	.164	6.664	14	983	2,265	1,132	1.313	.176	3.13	Standard casing.
5⅝	12.00	6.000	5.620	.190	6.636	11½	1,359	3,132	1,566	1.289	.172	3.06	Do.
5⅝	14.00	6.000	5.552	.224	6.636	11½	1,855	4,275	2,137	1.258	.168	2.99	Do.
5⅝	17.00	6.000	5.450	.275	6.636	11½	2,586	5,960	2,980	1.212	.162	2.88	Do.
5⅝	20.00	6.000	5.352	.324	6.765	10	3,294	7,590	3,795	1.169	.156	2.78	Diamond B X casing.
6	19.408	6.625	6.065	.280	7.473	8	2,277	5,247	2,623	1.501	.201	3.58	Drive pipe.
6¼	12.00	6.625	6.287	.169	7.308	14	824	1,900	950	1.613	.216	3.85	Standard casing.
6¼	13.00	6.625	6.257	.184	7.280	11½	1,021	2,353	1,176	1.597	.214	3.81	South Penn.
6¼	17.00	6.625	6.135	.245	7.280	14	1,819	4,192	2,096	1.536	.205	3.65	Do.
6¼	20.00	6.625	6.049	.288	7.390	10	2,381	5,487	2,743	1.493	.200	3.56	Diamond B X casing.
6¼	24.00	6.625	5.921	.352	7.390	10	3,222	7,424	3,712	1.430	.191	3.40	Do.
6¼	26.00	6.625	5.855	.385	7.390	10	3,650	8,410	4,205	1.399	.187	3.33	Do.
6¼	28.00	6.625	5.791	.417	7.390	10	4,069	9,376	4,688	1.368	.183	3.26	Do.
6⅝	13.00	7.000	6.652	.174	7.692	14	768	1,770	885	1.791	.239	4.26	Standard casing.
6⅝	17.00	7.000	6.538	.231	7.664	10	1,474	3,397	1,698	1.744	.233	4.15	Do.
6⅝	20.00	7.000	6.456	.272	7.698	10	1,981	4,565	2,282	1.701	.227	4.04	Diamond B X casing.
6⅝	20.00	7.000	6.450	.275	7.699	10	2,018	4,650	2,325	1.697	.227	4.04	South Penn.
6⅝	24.00	7.000	6.334	.333	7.699	10	2,737	6,307	3,153	1.637	.219	3.90	Do.
6⅝	26.00	7.000	6.276	.362	7.698	10	3,095	7,131	3,565	1.607	.215	3.83	Diamond B X casing.
6⅝	28.00	7.000	6.214	.393	7.698	10	3,480	8,020	4,010	1.575	.211	3.76	Do.
6⅝	30.00	7.000	6.154	.423	7.698	10	3,851	8,874	4,437	1.545	.207	3.69	Do.

[1] Water specific gravity=2.

[2] 1 U. S. gallon=231 cubic inches; 42 U. S. gallons=1 barrel.

TABLE 1.—*Collapsing pressures and capacities of casing*—Continued.

Nominal size, inches.	Weight per foot with collars, pounds.	Actual outside diameter, inches.	Actual inside diameter, inches.	Thickness, inch.	Couplings, outside diameter, inches.	Thread, per inch.	Collapsing pressure per square inch, pounds.	Collapsing depth, feet.	Collapsing depth with safety factor of 2, feet.[1]	Capacity per linear foot in— U. S. gallons.[2]	Capacity per linear foot in— Cubic feet.	Capacity per 100 linear feet, barrels.	Brand.
7⅝	16.00	8.000	7.628	0.186	8.788	11½	632	1,457	728	2.374	0.317	5.64	Standard casing.
7⅝	20.00	8.000	7.528	.236	8.788	11½	1,175	2,708	1,354	2.312	.309	5.50	Do.
7⅝	26.00	8.000	7.386	.307	8.888	10	1,939	4,470	2,235	2.226	.298	5.31	Diamond B X casing.
8	32.334	8.625	7.917	.354	9.882	8	2,171	5,003	2,501	2.557	.342	6.09	Drive pipe.
8¼	17.50	8.625	8.249	.188	9.413	11½	510	1,176	588	2.776	.371	6.61	Standard casing.
8¼	20.00	8.625	8.191	.217	9.413	11½	794	1,830	915	2.737	.366	6.52	Do.
8¼	24.00	8.625	8.097	.264	9.358	11½	1,267	2,920	1,460	2.675	.358	6.38	South Penn.
8¼	28.00	8.625	8.003	.311	9.358	8	1,740	4,010	2,005	2.613	.349	6.22	Do.
8¼	28.00	8.625	8.017	.304	9.627	10	1,669	3,846	1,923	2.622	.351	6.25	Diamond BX casing.
8¼	32.00	8.625	7.921	.352	9.627	10	2,151	4,957	2,478	2.560	.342	6.09	Do.
8¼	36.00	8.625	7.825	.400	9.627	10	2,633	6,067	3,033	2.498	.334	5.95	Do.
8¼	38.00	8.625	7.775	.425	9.627	10	2,884	6,646	3,323	2.466	.330	5.88	Do.
8¼	43.00	8.625	7.651	.487	9.627	10	3,507	8,081	4,040	2.388	.319	5.68	Do.
8⅝	19.00	9.000	8.608	.196	9.788	11½	519	1,196	598	3.023	.404	7.19	Standard casing.
9⅝	22.75	10.000	9.582	.209	10.911	11½	458	1,056	528	3.746	.501	8.92	Do.
9⅝	30.25	10.000	9.434	.283	10.911	11½	1,066	2,457	1,228	3.631	.485	8.64	Do.
9⅝	33.00	10.000	9.384	.308	11.002	10	1,283	2,956	1,478	3.593	.480	8.55	Diamond BX casing.
10	32.515	10.750	10.192	.279	11.958	8	863	1,989	994	4.238	.567	10.10	South Penn.
10	35.00	10.750	10.146	.302	11.958	8	1,049	2,418	1,209	4.200	.562	10.01	Do.
10	40.00	10.750	10.054	.348	11.866	10	1,419	3,270	1,635	4.124	.551	9.81	Diamond BX casing.
10	45.00	10.750	9.960	.395	11.866	10	1,798	4,143	2,071	4.047	.541	9.63	Do.
10	48.00	10.750	9.902	.424	11.866	10	2,032	4,683	2,341	4.000	.535	9.53	Do.
10	54.00	10.750	9.784	.483	11.866	10	2,508	5,780	2,890	3.906	.522	9.30	Do.
10⅝	26.75	11.000	10.552	.224	11.911	11½	424	977	488	4.542	.607	10.81	Standard casing.
11	46.953	11.750	11.000	.375	12.950	8	1,380	3,180	1,590	4.937	.660	11.75	Drive pipe.
11	47.00	11.750	11.000	.375	12.866	10	1,380	3,180	1,590	4.937	.660	11.75	Cal. spl. casing.
11	60.00	11.750	10.772	.489	12.866	10	2,221	5,118	2,559	4.734	.633	11.27	Do.
11⅝	31.50	12.000	11.514	.243	12.911	11½	417	961	480	5.409	.723	12.88	Standard casing.
11⅝	40.00	12.000	11.384	.308	13.116	10	838	1,931	965	5.287	.707	12.59	Diamond BX casing.
12	45.358	12.750	12.090	.330	13.950	8	857	1,975	987	5.964	.797	14.19	Drive pipe.
12	51.067	12.750	12.000	.375	13.950	8	1,153	2,657	1,328	5.875	.785	13.98	Do.
12½	36.50	13.000	12.482	.259	14.025	11½	396	913	456	6.357	.850	15.14	Standard casing.
12½	40.00	13.000	12.438	.281	14.116	10	500	1,153	576	6.312	.844	15.03	Diamond BX casing.
12½	45.00	13.000	12.360	.320	14.116	10	747	1,722	861	6.233	.833	14.83	Do.

12½	45.00	13.000	12.356	.322	14.085	8	760	1,752	876	6.229	.833	14.83	South Penn.
12½	50.00	13.000	12.278	.361	14.085	8	1,020	2,351	1,175	6.151	.822	14.64	Do.
12½	50.00	13.000	12.282	.359	14.116	10	1,020	2,351	1,175	6.155	.823	14.66	Diamond BX casing.
12½	54.00	13.000	12.220	.390	14.116	10	1,214	2,798	1,399	6.092	.815	14.51	Do.
13	56.849	14.000	13.250	.375	15.438	8	935	2,154	1,077	7.163	.958	17.06	Drive pipe.
13½	42.00	14.000	13.448	.276	15.139	11½	385	887	443	7.379	.987	17.58	Standard casing.
13½	50.00	14.000	13.344	.328	15.151	10	644	1,484	742	7.265	.971	17.29	Diamond BX casing.
14	61.005	15.000	14.250	.375	16.438	8	780	1,798	899	8.285	1.108	19.73	Drive pipe.
14½	47.50	15.000	14.418	.291	16.263	11½	370	852	426	8.481	1.134	20.19	Standard casing.
15	65.161	16.000	15.250	.375	17.438	8	645	1,486	743	9.489	1.269	22.60	Drive pipe.
15½	52.50	16.000	15.396	.302	17.263	11½	345	795	397	9.671	1.293	23.03	Standard casing.
15½	70.00	16.000	15.198	.401	17.477	10	786	1,812	906	9.424	1.260	22.44	Diamond BX casing.
17 O. D.	73.00	17.000	16.214	.393	18.675	8	617	1,422	711	10.676	1.427	25.41	Drive pipe.
18 O. D.	81.00	18.000	17.182	.409	19.913	8	506	1,166	583	12.045	1.610	28.67	Do.
20 O. D.	90.00	20.000	19.182	.409	21.913	8	386	890	445	15.012	2.007	35.74	Do.

[1] Water specific gravity=2.

[2] 1 U. S. gallon=231 cubic inches; 42 U. S. gallons=1 barrel.

At many wells in the Monroe gas field, La., the collapsing strength of casing is tested with a special machine before the casing is run into the well.[19] In a test of one string of casing, 20 out of 60 joints leaked at the "factory collar" end and 1 joint split. There can be no doubt of the advantage of that test, for if the string had failed in the well a hole costing from $20,000 to $30,000 might have been lost, in addition to untold quantities of natural gas. The testing machine used is simple, and pipe can be tested rapidly at small expense.

The department desires to prevent the losses of oil and gas that usually result from junked holes or the flooding of oil and gas sands by water and wishes to assist its lessees in handling their wells at a minimum expense. Poor material and poor workmanship are costly in oil-field operations.

Lessees on Government lands will be required to use casing strong enough to insure against probable failure. Lessees must also exercise extreme care in running casing to prevent cross threading and to prevent leakage through failure to screw up the joints tightly. When submitting Form 6–331a (Notice of intention to drill) the lessee, in addition to giving the estimated depths at which he proposes to set the various strings of casing, should also indicate the weights of the various sizes he proposes to set at these depths. (See Part II, "Operating Regulations," sec. 5, par. c, note 1.)

TESTING FORMATIONS.

During the drilling of a test well, all formations that give evidence of carrying gas or oil should be tested to determine their productivity. In cable-tool work this can usually be done satisfactorily unless the driller is "carrying" a wet hole and drills into a sand without leaving a casing seat above. To test a sand properly the water must be shut off; in a hole in which no shoulder is left for the casing this may prove troublesome. Sometimes a packer can be set that will hold back the water long enough for a test, but often the packer method is not practicable. To cement the casing may not be desirable, because, if the sand is not commercially productive, the operator may wish to deepen the well to a lower sand. Also, should the drill strike another water sand before finding an oil sand, an extra string of casing must be run if the previous string has been cemented. The extra string is costly and the disadvantages of drilling a well "down to a point" are well recognized.

In rotary wells the same need arises for testing formations by setting casing and shutting out upper water. If the territory has soft, cavey formations, such as occur in the Gulf Coast district and some California fields, which will freeze the pipe shortly after it is set, the operator may

[19] Bell, H. W., and Cattell, R. A., The Monroe gas field, Louisiana: Louisiana Department of Conservation Bull. 9, July, 1921, pp. 55–56.

as well cement his pipe properly once and for all. However, if the chances are that the casing can be moved and lowered later if the test is unsuccessful, the problem of temporarily shutting off the water becomes of most importance. The diameter of a rotary hole is considerably larger than the diameter of the casing which is run in that hole and a temporary shut-off may be difficult to make. It is usually necessary to cement casing in a rotary hole if test is to be made, although under some circumstances packers are used successfully on temporary jobs.

CORE BARRELS AND FORMATION SAMPLERS.

In recent years the use of core barrels or formation samplers has been generally adopted in most fields drilled by the rotary method. In the California fields, at least one core barrel has been developed for use with rotary tools. This barrel has taken continuous cores up to 8 or 10 feet in length. Core barrels are a necessity when prospecting is being done with rotary tools, because many formations capable of producing fairly large quantities of oil and gas may be passed without being recognized. To pass productive formations results in losses of oil and gas which might be recovered without the expense of additional drilling if the operator knew the value of the formations. Productive sands are often passed and logged as "shows." Moreover, if an operator is not aware of the presence of productive upper oil or gas sands he may fail to mud the hole properly or to protect upper formations behind the casing, thus allowing the waste of oil or gas by migration or by flooding with water.

In modern rotary practice, all formations that give evidence of carrying oil and gas are cored. Moreover, careful operators often "rat tail" ahead or core for distances of one or two hundred feet when approaching the prospective producing zone if the approximate depth of the zone is not known with greater accuracy. Perhaps the greatest value of the rotary core-barrel at present is to assist in determining the point for water shut-off.

Core drilling has been discussed by Collom [20] and Elliott.[20a] Other articles on core drilling may be found in text books and oil-trade journals.[21]

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20 Collom, R. E., Notes on core-drilling methods in oil fields: California State Min. Bur. Summary of Operations, vol. 6, No. 12, June, 1921, pp. 3–15.

20a Elliott, J. E., Core drilling with rotary tools in California: Bull. Am. Assoc. Petrol. Geol., vol. 7, No. 3, May–June, 1923, pp. 250 to 262. Elliott, J. E., and Merritt, F. C., Core drilling in the oil fields of southern California: California State Min. Bur. 7th Ann. Rept., vol. 8, No. 1, July, 1922, pp. 5–12.

21 Suman, John R., Petroleum production methods, 1921, pp. 31–40. See also Oil Age, vol. 18, No. 3, March, 1922, p. 10, for a discussion of the Elliott core-drilling method now being successfully used in the southern California oil fields.

IMPORTANCE OF TESTS.

The difficulties and hazards of making tests often result in producing formations of commercial importance being passed and not tested. Many upper sands have been found productive after a number of wells have been drilled through them and have not recorded the presence of oil and gas. Experienced operators know many ways of making tests and the method used must be adapted to the particular conditions existing in the well to be tested. The department will expect its lessees to employ suitable measures in order that recoverable oil and gas in upper formations will not be overlooked.

EXPLORATION WITH THE DIAMOND DRILL.

Diamond drilling is believed to have a field of use as a method of prospecting for oil. For prospect drilling the diamond drill has the advantage over cable or rotary tools that it takes a continuous core of the formations penetrated and under some conditions makes hole at lower cost, if the hole is not of too large diameter.

Perhaps the most important advantage of diamond drilling is the excellence of the geological evidence supplied by the core. If a producing oil sand is found, its exact physical character at that point can be determined. Water sands, gas sands, and other formations can be located and examined and plans made for dealing with them properly when wells are drilled later by standard or rotary methods.

DISADVANTAGES.

The principal disadvantage of drilling test wells with the diamond drill is the difficulty of making a production test if a sand gives evidence of carrying oil in commercial quantities. The diameter of the diamond-drill hole which is ordinarily drilled for recovering cores is rather small for satisfactory production tests. Diamond drills have not been developed for drilling large holes and handling heavy strings of casing. For example, assume that a $2\frac{13}{16}$-inch diamond-drill hole penetrates an oil sand that shows a little gas and the hole fills up with oil about 25 feet in 12 hours. As a rule, an oil man would expect a small well. However, if the hole was 6 inches or more in diameter so as to allow a good-sized shot, a large well might be developed. In the central Texas oil fields it was not uncommon for wells which scarcely showed oil when first drilled in to produce as much as 1,000 barrels a day or more after the producing formation (limestone) was shot.

ATTITUDE OF INTERIOR DEPARTMENT.

Prospecting permits granted by the Secretary of the Interior under the act of February 25, 1922, state:[22]

2. Within six months (two years in Alaska) from date hereof to install upon some portion of the lands a substantial and adequate drilling outfit and to commence actual drilling operations.
3. Within one year (three years in Alaska) from date hereof to drill one or more wells, not less than 6 inches in diameter to a depth of at least 500 feet each, unless valuable deposits of oil or gas shall be sooner discovered.
4. Within two years (four years in Alaska) from date hereof to drill one or more wells to a depth of at least 2,000 feet, unless valuable deposits of oil or gas shall be sooner discovered.

The department recognizes the value of the diamond drill for exploration. In the following letter from Acting Secretary Finney, the department's policy is clearly stated:

DEPARTMENT OF THE INTERIOR

WASHINGTON.

February 11, 1922.

Mr. DAN SUTHERLAND,
Alaskan Delegate, House of Representatives, Washington, D. C.

MY DEAR MR. SUTHERLAND: Referring to the letter from * * * dated January 9, 1922, regarding the use of diamond-core drilling in Alaska on Government lands:

The regulations governing prospect work upon Government lands provide that within one year (three years in Alaska) from a certain date the permittee must drill one or more wells not less than 6 inches in diameter to a depth of at least 500 feet each, unless valuable deposits of oil and gas are encountered sooner.

It does not seem advisable to change the regulations reducing the diameter of the hole in prospect wells, but I appreciate that there are many cases when diamond-drill work would be perfectly satisfactory in order to test out land. It is my belief that in certain cases the Secretary of the Interior will be willing to waive the requirement as to the diameter of the hole, provided, of course, that he is satisfied the work will be carried on in a workmanlike manner and for the purposes of actually testing out the area. Obviously, each case must be handled separately, and it would be my suggestion for anyone wishing to sink diamond core-drill holes to meet the requirements of the permit, that they petition the Secretary of the Interior to be granted permission to do so.

Very truly yours,

E. C. FINNEY,
Acting Secretary.

In general, a hole large enough for a production test will be required of permittees who are allowed to fulfill the provisions of their permits by putting down their first test well with a diamond drill. This diameter will not be made subject to regulation, however, as it is conceivable that sometimes it may be desirable to allow a permittee to prospect with a drill of smaller size.

When operators are authorized to use the diamond drill in prospecting, they will be subject to the same supervision and rigid requirements by the department as are other prospectors in regard to shutting off water, wasting oil and gas by allowing wells to blow open, or to damaging possibly productive strata through failure to protect them during drilling and in abandonment. Deputy supervisors will cooper-

[22] Regulations concerning oil and gas permits and leases, etc., authorized by the act of Feb. 25, 1920 (Public No. 146), General Land Office Circular 672, 1920.

ate with lessees using diamond drills to insure that these regulations are followed and that the most thorough tests are made of formations that may be productive.

Some recent articles on the use of the diamond drill in oil fields are listed below:

RECENT ARTICLES ON DIAMOND DRILLING.

DANFORD, M. O., The diamond drill as a wildcat aid. Petrol. Age, vol. 7, October, 1920, pp. 73–74.

EDSON, FRANK A., Diamond drilling for production. Bull. Am. Assoc. Petrol. Geol., vol. 6, March, 1922, pp. 91–97.

——, Drilling oil wells with the diamond drill. Bull. Am. Assoc. Petrol. Geol., vol. 5, May–June, 1921, pp. 386–393.

ELLEDGE, G. A., The diamond drill in oil-field practice. Oil and Gas Jour., vol. 20, December 23, 1921, p. 82.

FAY, ALBERT H., The diamond drill as an aid to oil prospecting. Eng. and Min. Jour., vol. 110, December 11, 1920, pp. 1133–1134; Oil and Gas Jour., vol. 19, January 7, 1921, p. 88.

GILL, FREDERIC C., Adapting the diamond drill to the oil field. Oil Weekly, vol. 26, No. 9, August 26, 1922, p. 16.

LONGYEAR, ROBERT DAVIS, The diamond drill in oil exploration. Bull. Am. Assoc. Petrol. Geol., vol. 6, No. 2, March–April, 1922, p. 98.

MITCHELL, J. S., Prospecting for oil with the diamond drill. Eng. and Min. Jour., vol. 113, January 7, 1922, pp. 18–19.

NATIONAL PETROLEUM NEWS, Diamond-core drills; inexpensive tests for structure. Vol. 14, October 11, 1922, p. 43.

SUMAN, JOHN R., Taking cores in rotary drilling operations. Min. and Met., October, 1922, pp. 21–24.

LOSS BY FAILURE TO CONFINE UPPER PRODUCTIVE SANDS.

Migration of oil or gas from its original strata results in great underground loss, the extent of which, as from flooding with water, can not be determined. Numerous examples, however, can be cited which indicate that these losses often are considerable.

Many wells are drilled through several gas and oil bearing formations before they reach the sand from which it is desired to produce. Often these upper sands carry gas under high pressure and, less frequently, oil under fairly high pressure. Although productive oil sands are not passed up as frequently as are gas sands, when a well is drilled with the rotary tools or with cable tools and a "hole full of fluid" such a sand may be overlooked. Losses occur if such sands are cased off without their fluids being confined. Gas, for example, moving toward the point of least pressure will migrate readily up or down between the casing and the wall of the hole and will eventually find its way to the surface or into some porous formation. Enormous volumes of gas have been wasted in this way. Gas has been known to migrate through the formations and appear at the surface several hundred feet from the well. Gas that has been allowed to escape into a barren sand has been known to create a stray gas sand with enough volume and pressure to cause trouble in other wells. Sometimes these sands blow out after a well has been completed, the flow of gas resulting in a fire hazard in addition to the waste.

To a somewhat lesser extent oil under pressure can migrate if not properly confined. For example, one experienced operator has found that sands in the Old Spindletop field, Tex., which were known as barren sands to operators when drilling wells in 1902 to 1904, now carry considerable oil. During its early days this field was operated without due regard to shutting out water by systematically casing the wells and plugging abandoned wells.

Migration of oil and gas past the shoe of a water string where water shut-offs are imperfect has caused great waste. In one field where a well was producing against back pressure, and the casing was poorly seated and not cemented, oil and gas escaped around the shoe. The oil not only escaped at the surface near the well but worked its way through the porous formations and thence to the surface, some 300 feet from the well. As previously stated, unsystematic casing may cause much loss of oil or gas. Plate II (see p. 10) is an example of unsystematic casing in an Oklahoma field, by which water gained access to a gas sand and gas migrated to a dry sand. Had well 1 been properly cased, as was well 3, this underground waste of gas could not have taken place.

PROTECTING UPPER OIL AND GAS FORMATIONS.

Two methods for protecting upper sands are in common use. The first is to seal off upper formations with mud fluid or cement; the second is to land casing above and below the producing strata. By the first method several formations may often be confined and protected back of one string of casing, not only decreasing the cost of the well by reducing the amount of casing required but allowing a larger hole to be carried for a greater depth.

PROTECTING FORMATIONS WITH MUD FLUID.

High-pressure gas sands may be encountered above the main producing oil sand; the flow of gas from such sands may have to be "killed" before a well is drilled deeper. In rotary-drilled wells these sands are usually mudded off with little difficulty by the circulating mud. If this method fails, the formation may possibly be sealed by forcing mud fluid into it under pressure, the necessary pressure being obtained by using a tight head or blow out preventer between the casing and the drill pipe. In a cable-tool well a gas sand can sometimes be killed by placing mud fluid in the hole and continuing drilling until the sand is passed, and then landing casing, with mud fluid behind it, below the sand. If the gas is not "killed," mud fluid should be circulated or, if necessary, the gas sand mudded under pressure.

Frequently small amounts of oil and gas are seen escaping from a well at the surface, either outside of or between two strings of casing. In the Hewitt field, Okla., many wells produced gas from an upper sand behind the water string a short time after the casing had been set, despite the fact that wells were drilled with rotary tools and had columns of mud fluid standing back of the pipe. In the Salt Creek field, Wyo., Government lessees are shutting off flows of oil, gas, and water that are coming from behind the casing in some of the older wells by mudding.

Oil, gas, and water can usually be confined to the formations in which they occur if the operator is willing to take the proper precautions. A column of mud fluid may overcome the pressure of gas, oil, or water and prevent them from migrating. Ordinary mudding is done by circulating mud down through tubing or casing and back to the surface past the exposed formations that are to be mudded. The pressure exerted on the formations by a column of mud fluid is due to the weight of the column of mud fluid plus any frictional resistance offered by the outer surface of the casing and the walls of the hole.

Under some conditions a greater pressure than that exerted by a column of mud fluid is required to seal formations effectively; this additional pressure must be obtained by the use of high-pressure pumps. In the usual method of mudding under pressure the mud fluid is pumped down through the tubing or water string and back to the surface outside of the tubing or casing and past the formations that are to be mudded. By means of a packing head placed between the strings of pipe and suitable control valves, a high pump pressure can be put on the well. Two pumps should be provided, one for handling mud fluid up to pressures of approximately 250 pounds and one capable of developing a pressure of 1,000 pounds.

Some specific examples of conditions under which it has been found desirable to mud under pressure are cited in a recent report by a committee representing California oil operators and the department of petroleum and gas of the California State Mining Bureau.[22a]

THICKENING MUD FLUID.

Occasionally an extremely porous sand will continue to take large amounts of mud fluid even though the mud is mixed as thick as the

[22a] Gaylord, E. G., Burrell, Logan, Wagy, E. W., Case, J. B., and Barns, R. M., The use of mud fluid for the protection of oil and gas sands: California State Min. Bur., Feb., 1923, 85 pp. Available from California State Mining Bureau, San Francisco, Calif. See also Collom, R. E., Mud fluid for rotary drilling and the use of mud fluid to prevent water infiltration in oil and gas wells: California Min. Bur. Summary of Operations, vol. 8, No. 7, Jan., 1923, 84 pp.

pumps can handle it. If this happens, sawdust, chopped straw, chopped rope, manure, hydraulic lime, or other materials should be added to thicken the mud fluid and to clog the pores of the sand. Mud fluid that is being pumped into one well may appear in adjoining wells.[23] To prevent near-by wells being damaged the mud fluid should be thickened or other ingredients added, as noted above, when the formations take unusually large quantities of mud fluid.

LUBRICATOR FOR INTRODUCING MUD FLUID.

In some wells the gas pressure is so great that pumping mud fluid in may be difficult with ordinary methods. At these wells a lubricator [24] may be used for introducing the mud fluid until the gas pressure has been sufficiently overcome to permit mud fluid being pumped in directly.

Figure 3 is a sketch showing the essential details of a lubricator for introducing mud fluid into a well under high gas pressure. It operated as follows:

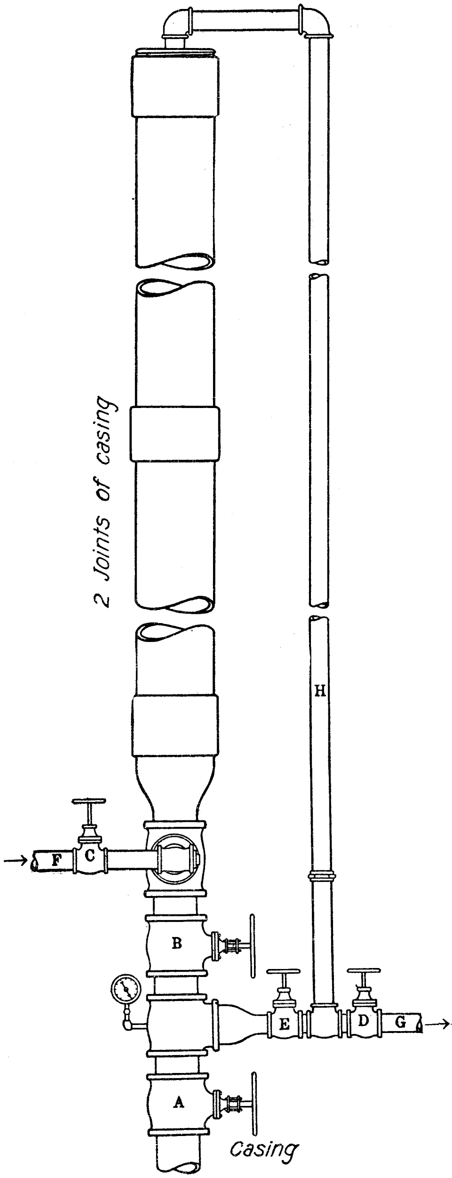


FIGURE 3.—Lubricator for introducing mud fluid into high-pressure gas wells.

The lubricator is hoisted into the derrick and screwed on the casing above the master valve A. The lubricator control valve B is closed. The valve C on the pump discharge line and the relief valve D are opened, valve E on the by-pass line being closed. Mud fluid is pumped into the

[23] Third annual report of the State oil and gas supervisor: California State Min. Bur. Bull. 84, 1917–1918, pp. 77–106.

[24] Lewis, J. O., and McMurray, W. F., The use of mud-laden fluid in oil and gas wells: Bull 134, Bureau of Mines, 1916, 86 pp. Thomson, H. B., Monthly report of State oil and gas supervisor: California State Min. Bur., September, 1921, pp. 5–6. Tough, F. B., Report of operations: Rocky Mountain Petroleum Association in cooperation with the U. S. Bureau of Mines, 1919–1921, pp. 78–79.

lubricator through the pump discharge line F until the lubricator is full, as indicated by excess mud flowing off through the overflow line G. Valves C and D are then closed and valve E on the by-pass line and master valve A are opened. Gas under high pressure is thus admitted to the top of the lubricator through the by-pass line H. Control valve B is opened and the mud fluid flows into the well. The operation may be repeated until enough mud has been run into the hole to control the gas and permit the necessary work to continue. To drain the lubricator the master valve A should be closed and valves B, E, and D opened.

Since mud fluid may be employed in numerous ways as circumstances direct, the Bureau of Mines will not prescribe specific rules for its use, but will expect to consider each case with regard to local conditions. In general, the bureau favors the use of mud fluid to protect oil and gas formations against damage and waste. To encourage the use of mud fluid as a conservation measure, the deputy supervisors will advise with, and whenever possible assist, Government lessees or other operators in conducting their mudding jobs.

PROTECTING FORMATIONS WITH CASING.

In some wells a productive gas sand, which is needed for fuel, is encountered above the oil sand. By landing two strings of casing, one above and the other below the gas sand, and installing a braden head, the gas may be utilized while drilling proceeds. A well cased in this way is seldom free from gas leaks and is therefore somewhat dangerous because of the fire and explosion hazard, particularly if the gas pressure is high. This practice has caused the loss of several lives and many thousands of dollars in recent years.

Braden heading gas sands is not entirely satisfactory from a practical standpoint. Usually the distance between the bottom of the two strings of casing greatly exceeds the thickness of the gas sand; therefore gas may have access to other formations, some of which may be dry and somewhat porous and gas will be lost by migration into these formations. Moreover, the gas sand may be flooded by water, which in one way or another may gain access to a gas sand or cavings from exposed formations above the gas sand may gradually shut off the flow of gas.

When gas sands are cased off, the two strings of pipes should be landed as near, above and below, the gas sand as is feasible. Unless the larger sized casing is cemented above the gas sand, much high-pressure gas may migrate past the shoe and eventually escape, allowing upper waters to flood the gas sand as well. If the pipe below the gas sand is neither cemented nor landed with a tight shut-off, gas will continually waste by escaping around the shoe and up inside the well. If water from any source collects in the gas sand, large wastes of gas will take place as it is blown off, and, as the gas pressure declines, the water eventually will drown out the gas entirely.

The production of gas between casings is a practice not generally approved and should be done only in emergencies, when the gas is needed for carrying on operations or the volume of gas is too small to warrant separate gas wells.

Oil from an upper sand usually is not under enough pressure to flow and therefore can be protected by landing strings of casings above and below the sand. The flooding of an upper oil or gas sand by water from a water sand below may be prevented by landing a string of casing and making an effective shut-off just above the water sand. The protection of lower producing sands by landing a second string of casing below the water sand will also be necessary. In general, the method of protecting upper productive formations by the use of casing alone is expensive and often unsatisfactory because not enough care is taken in choosing the proper casing point and in mudding, cementing, and testing the various strings of casing. The Bureau of Mines will encourage the proper use of mud fluid and cement in place of extra casing when in the judgment of the deputy supervisor this method will sufficiently protect the upper productive formations.

SPACING OIL AND GAS WELLS.

The spacing of wells is an economic problem which is governed by many factors. These include the profits that may be derived, the recoverable amount of oil or gas, the porosity, saturation, and thickness of the producing sands, the extent and structure of the productive area, the gravity of the oil, gas pressure, and depth. Theoretically, the closer the spacing the greater the ultimate recovery of oil from an oil sand; consequently it would seem the Government's best course to encourage close spacing so that the maximum amount of royalty oil would be recovered. However, as will be pointed out, the many factors opposed to close spacing far outweigh the possible benefits of greater recovery.

TOWN-LOT DRILLING.

The term "town-lot drilling" has been applied to unusually close spacing of oil wells and implies the influence of promotion schemes. Town-lot drilling usually is not practiced by bona fide operators except when necessary for the protection of their property. Unscrupulous promoters often sell parcels of land far too small to warrant the drilling of a well from an economic standpoint, causing adjacent operators to drill an unnecessarily large number of wells to protect their holdings against drainage. Speed in getting a well into the pay sand is a prime requisite because the first well in any locality benefits by obtaining the flush production. It often happens that a well will produce more oil during the first 10 days or 2 weeks than can afterwards be pumped in a year or more. Extreme speed in drilling is largely responsible for the waste that always accompanies town-lot drilling. In order to be the first to drill into the pay sand careless and inexperienced operators often neglect to shut off water properly and to protect sands; hence wastes from infiltration of water, dissipation of gas, and the migration of oil and gas are often tremendous. Another waste occurs because of the unprofitable yield of many wells and the carelessness with which they are abandoned.

Although oil can be recovered more rapidly and in larger amounts with a greater number of wells if they are drilled before the gas pressure is reduced, too rapid exhaustion of oil and gas may cause the rapid approach of edge water. During its encroachment, the edge water may "pocket" large quantities of oil. When wells are spaced too closely, the gas pressure, which causes oil to flow to a well, declines rapidly and the wells soon cease to flow.

The Burkburnett town-site pool in Texas furnishes a typical example of losses and wastes from close drilling.[25] Within six months after the first well was drilled, the average initial daily production per well had dropped from 2,000 barrels to 300 barrels; within a year the average initial production was only 38 barrels a day per well. In the town site proper, the average spacing was less than 1 acre per well.

Town-lot drilling has recently become a factor in the development of the new fields of southern California. Wells are being drilled in the Santa Fe Springs field on adjacent town lots, some of which are not more than 120 feet square. Because of the great depth and the high cost of these wells the cost of developing this field will be excessive, and many wells doubtless will not pay for themselves.

REGULATIONS FOR GOVERNMENT LANDS.

Spacing varies in different fields and no set rule can be laid down that will necessarily apply to more than one field. On Government lands, the regulations provide that no well shall be drilled closer than 200 feet to the outer boundary line of the lease or permit except along a boundary line common to non-Government land. If this spacing is carried out on the rectangular system it will provide an area of 3.67 acres per well. Operators in the Cat Creek field, Mont., agreed on a spacing of 440 feet, or 4.44 acres per well, as most economical. In the Slick field, Okla., one well to 10 acres has been the rule,[26] but

[25] Collom, R. E., Spacing of oil wells and town-lot development: California State Min. Bur. Monthly Rept., January, 1921, pp. 7-11. Bell, H. W., and Kerr, J. B., Petroleum engineering in the Burkburnett field: Oil and Gas Jour., vol. 20, March 24, 1922, pp. 78-81 (continued in subsequent issues).

[26] Schwarzenbek, F. X , and Ross, J. S., Petroleum engineering in the Slick oil field, Okla.: Coop. rept., Bureau of Mines and Bartlesville, Okla., Chamber of Commerce, 1922, 39 pp.

as the wells are spaced only 220 feet from the line a large area is left in the center of each 40 acres, and there a fifth well could be profitably drilled on many 40's, which would reduce the drainage area to 8 acres per well. Bell [27] has said that 7 acres per well is too close for the Eldorado field, Ark. Statistics [28] for proved and completely drilled areas in California show the following acreage per well: Kern River, 3.4 acres; McKittrick, 5 acres; Ventura-Newhall, 4.8 acres; and Salt Lake-Los Angeles, 3.8 acres.

Cutler [29] has shown that delay in drilling results in loss of recoverable oil because of reduced gas pressure. He also points out that widely spaced wells have a larger ultimate production, but the production per acre for the tract as a whole is much smaller than when wells are closely spaced. It is, therefore, just as important not to overspace wells as it is not to space them too closely. Overspacing decreases the amount of recoverable oil; underspacing usually causes financial loss.

The Government prefers that its lessees adopt a normal and reasonable drilling campaign by which the greatest amount of oil can be recovered with the least waste. Although the Government is anxious to have the maximum amount of oil recovered, it realizes that an economic balance must be struck whereby the cost of recovery is not excessive with respect to the value of the oil recovered.

LOSSES FROM FLOWING WELLS.

Aside from the large losses of oil and gas occasioned by "wild wells" which, from one cause or another, get beyond control (see pp. 59 to 61), considerable oil and gas are often lost while a well is being completed after it has tapped the productive formations. The flows of such wells may be controllable and thus may be diverted to tanks, as when wells are being drilled in or cleaned out. However, when tubing is being run the casing head must be left open and a well may flow considerable oil and gas.

As efficient devices for controlling wells are available, there is little excuse for wasting oil and gas during drilling in, bailing, or cleaning out. Only a few years ago, however, it was common practice to let wells flow open while they were being drilled in. During the boom days of Spindletop, Tex. (1901–1902), a half dozen or more of the enormous gushers then flowing in that field at times were turned into the air for the amusement of sightseers. To-day such waste would be considered criminal. Indeed, the present view exemplifies the

[27] Bell, H. W., and Kerr, J. B., The Eldorado, Ark., oil and gas field: Coop. rept., Bureau of Mines and State of Arkansas, 1922, pp. 44–48. Obtainable from J. G. Ferguson, Commissioner, Bureau of Mines, Manufactures, and Agriculture, Little Rock, Ark.

[28] McLaughlin, R. P., Control of California oil lands: 6th annual report, State oil and gas supervisor, California State Min. Bur., vol. 6, No. 4, Oct., 1920, p. 6.

[29] Cutler, W. W., and Clute, W. S., Relation of drilling campaign to income from oil properties: Reports of Investigations, Bureau of Mines, Serial No. 2270, Aug., 1921.

changed attitude of the industry and the public as well toward the Nation's oil and gas resources.

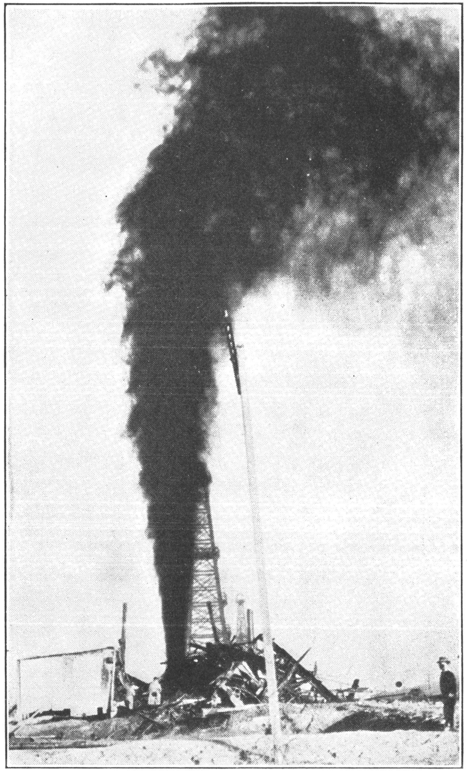
Plate IX, *A*, gives some idea of the magnitude of the losses that may occur if large flowing wells are allowed to flow open. Nowadays, wells of this size are generally brought in without being allowed to flow into the air. Plates IX, *B*, X, XI, and XII, *C*, illustrate up-to-date methods for controlling flowing wells. While the well shown in Plate IX, *B*, was being drilled in, it was flowing at the rate of 250 barrels of oil a day, but scarcely any oil leaked by the oil saver as drilling in continued. The use of "Christmas tree" fittings at the casing head (see Pl. X) for controlling wells drilled in with rotary tools is described in detail in a later section of this manual (pp. 66 and 67).

There are many reasons why operators have wilfully allowed oil wells that could be put under control to flow open. At times the flow occurs while the operator is still drilling in or attempting to run casing. At other times, because of the high rock pressure, operators are afraid to close in a well lest it blow off the fittings. However, many wells are permitted to flow open when no tankage is available, even though they could be shut in, because some operators believe that to close in a flowing well will ruin it.

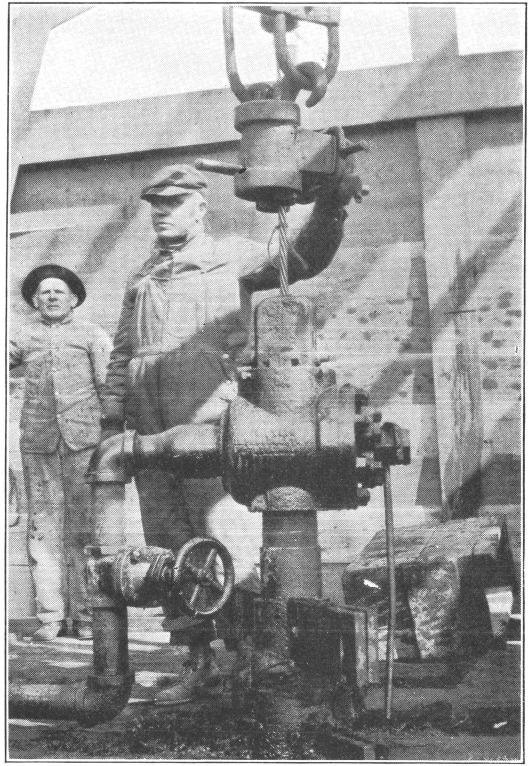
CLOSING IN FLOWING WELLS.

In general, the department does not agree that closing in a flowing well will injure it. Before a well is drilled into an oil or gas bearing stratum, oil, gas, and water that may be present are confined and probably are in approximate equilibrium in that stratum. After a well has been drilled into the stratum, there is little reason why that well must be left open, if the mechanical conditions of the well and the characteristics of the formations are such that it will not be injured through infiltration of water, caving, or packing of sand against the oil string. That a well may be injured if it is closed in when the casing has failed to shut out upper water is recognized. Such a well should be repaired immediately and then closed in until tankage is erected or pipe-line connections are made. Moreover, the danger of closing in a well in fields such as those in the Texas Gulf Coast is recognized because of the extreme danger of sanding up and consequent injury to production. On the other hand, wells in "hard-sand" fields, as in Wyoming and northern Oklahoma, are sometimes closed in for weeks or months without injury. If an operator wishes to flow a well, the Government expects him to provide adequate tankage and pipe-line facilities in advance. Failing in this, he will be expected to shut the well in until such facilities are provided.

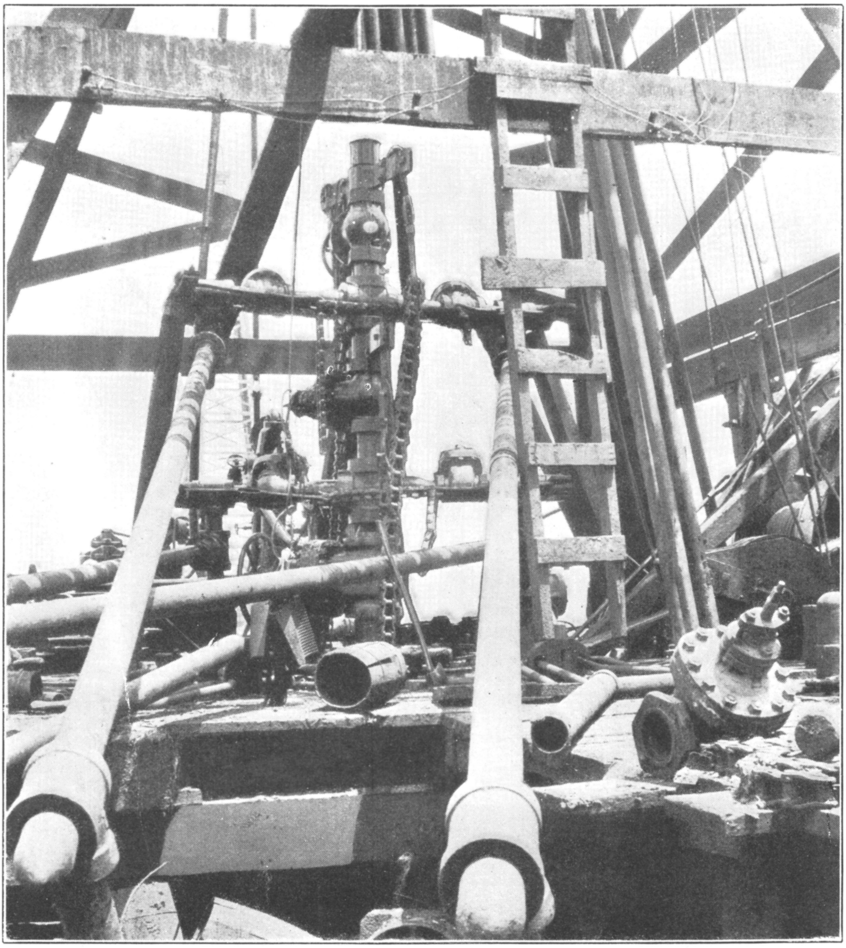
A large loss of the oil and gas that are produced while wells are being allowed to blow open occurs even though a catchment basin is



A. GENERAL PETROLEUM CO.'S BLACK AND DRAKE WELL NO. 1, SIGNAL HILL FIELD, CALIF., SHORTLY AFTER "GOING WILD."



B. METHOD FOR DRILLING IN FLOWING OIL WELL WITH CABLE TOOLS WITHOUT WASTE.



DOUBLE "CHRISTMAS TREE" FOR CONTROLLING FLOW OF LARGE WELL.

provided, and many times no effort is made even to catch the oil from a flowing well. Seepage and the carrying and evaporation of oil spray by the wind may account for the loss of considerable quantities of crude oil and natural gas.

Another loss that is difficult to overcome may occur while tubing is being run or pulled. In new fields wells flowing into the derrick while the tubing gang is at work are a common sight.

ATTITUDE OF BUREAU OF MINES.

The Bureau of Mines will not permit operators to waste oil while drilling in when reasonable methods can be used to prevent such waste. In a following section methods for preventing wastes while wells are being drilled in are discussed, and operators on public lands will be expected to use such of these or other approved methods as may be adaptable to their particular conditions. Willful blowing of oil wells when tankage is not available will not be permitted. The bureau feels that if wells have been properly drilled and cased no damage to the oil deposits can result from closing in flowing wells, although due allowance will be made for extreme conditions. The belief of some operators that, it is better policy to lose a number of days' oil production by blowing a well open until tankage is erected or pipe-line connections are made than to close in a flowing well, will not be approved by the department, and such practice can not be sanctioned on Government lands. Operators on public lands must expect to curtail wastes that can be prevented with reasonable precaution and expense.

WASTES FROM "WILD" OIL OR GAS WELLS.

Drilling into gas or oil deposits of high rock pressure often results in a "blow-out" or a "wild" well. The usual causes of wild wells are failure to provide suitable control equipment and mistakes by inexperienced workmen, although unforeseen occurrences may also result in a well getting out of control. In the early days of the oil industry most large wells flowed oil and gas into the air until the flow subsided naturally or was cut off by the well caving or sanding up. The gradual development of suitable control heads and fittings, the use of rotary drilling, and the introduction of mud fluid have cut down the number of wells that go wild. In fact, equipment and methods are so well developed at this time that there is little excuse for wells getting out of control, and repetition of such occurrences in the same field must be attributed to negligence.

Wild wells waste oil and gas both above and below ground. The losses from evaporation and seepage when oil is sprayed in the air and on the ground are enormous. Such surface wastes are self-evident, but the underground waste caused by wild wells is often even more serious. In

Louisiana and Arkansas strong flows of gas have unseated well casing, and in consequence large volumes of gas have been dissipated into upper formations. Occasionally the drill pipe is blown from one of these wells during drilling and before casing has been run, and a crater is formed 500 feet or more in diameter. Gas has appeared on the surface as far as 2,000 feet from a well, proving that there has been extensive migration through various sands. Around a recent wild gas well north of Eldorado, Ark., gas came up through the ground as far as 3,000 feet from the well. Unquestionably much gas was also lost by being trapped underground.

Additional sources of loss from wild wells are the premature encroachment of water, the breaking in of bottom water, or the breaking in of top water. Strong flows of water may ruin an oil or gas deposit by drowning out the gas and trapping the oil in the sand.

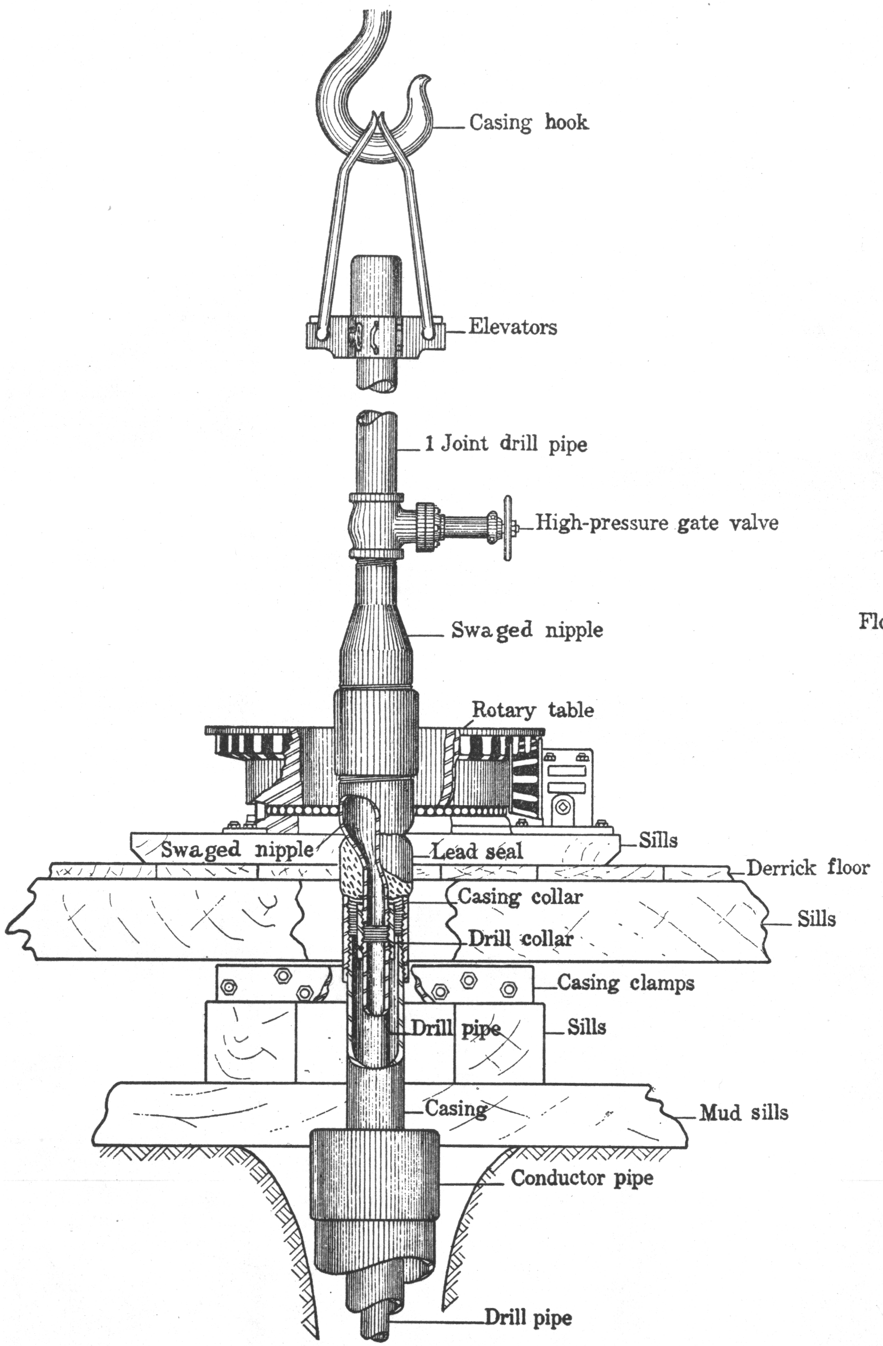
Precautions for controlling wells, in keeping with possible high pressure in territory being explored, should be taken before a well is started. In some proved fields, operators may be reasonably certain before drilling is started that high-pressure deposits of gas and oil will not be found. No such certainty can be assumed for wildcat wells, or even for wells that test out deeper formations in known fields.

EXAMPLES OF WILD WELLS.

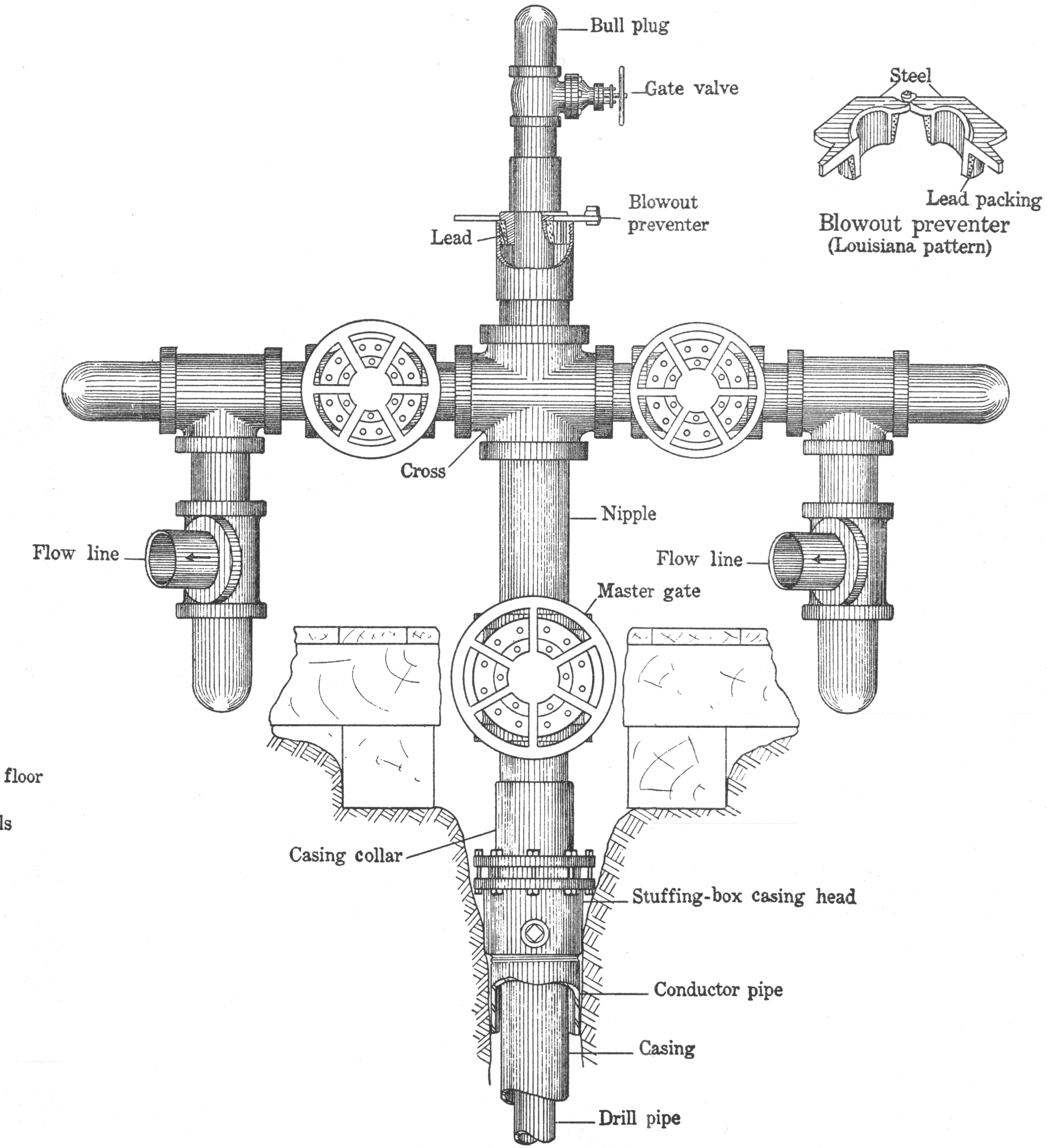
The wild wells that have attracted most attention recently are those in the gas fields of northern Louisiana and the new oil fields of southern California. A number of such wells in the Monroe, La., gas field are described by Bell and Cattell.[30–31] At Signal Hill, Long Beach, Calif., the well shown in Plate IX, *A* (see p. 58), exemplifies the loss from wild oil wells. While the plug was being drilled out preparatory to drilling the well in, the well began to flow. Although it was said that heavy control fittings had been provided in anticipation of a strong well, the pressure was so great and the flow so sudden that the gate valves were torn from the casing head and all means of checking the flow were eliminated. A tremendous flow of gas wrecked the derrick and a flow of oil approximating 6,000 barrels per day wasted into the air. Fortunately the well did not catch fire and sanded up after 25 hours, although the oil damaged near-by residences, lawns, orchards, and shrubbery.

At Santa Fe Springs, Los Angeles County, Calif., three large gas wells blew out and caught fire within about one month. One well blew 500 feet of rotary drill pipe from the hole, wrecked the derrick, and made a crater of such dimensions that it completely engulfed the

[30–31] Bell, H. W., and Cattell, R. A., The Monroe gas field: Coop. rept., Bureau of Mines and Louisiana Dept. of Conservation, 1921, 100 pp. Obtainable from M. L. Alexander, Commission of Conservation, New Orleans, La.



A. BLOWOUT PREVENTER, GULF COAST TYPE (FOR ROTARY).



B. TYPICAL CONNECTIONS FOR LOUISIANA BLOWOUT PREVENTER (FOR ROTARY).

wrecked rig, the engine, draw works, rotary drill, mud pumps, and other equipment.

In the southern California fields, there have been numerous blow-out and wild wells, despite the fact that rotary tools with heavy mud-laden fluid have been used in drilling and unusual precautions have been taken to control the extraordinarily strong flows. The numerous wild wells drilled in southern Arkansas and the Gulf Coast and southwest regions of Texas magnify the need for taking utmost precautions when prospecting in unknown territories.

LOSS OF LIFE FROM WILD WELLS.

Plate XII, *A* (see p. 68), pictures a burning oil and gas well on Government land in the Salt Creek field, Wyo. The well caught fire while being drilled in. There was large waste of oil and gas, and three workmen were burned to death. In May, 1923, a large flowing well in Navarro County, Tex., caught fire during drilling in and 16 lives were lost. The well defied all efforts at extinguishing it for 11 days, during which time it flowed several thousand barrels of oil daily.

NATURE OF LOSSES FROM WILD WELLS.

The value of the gas wasted by wild wells far exceeds the value of oil similarly wasted. When a gas well goes wild, all the gas is lost, whereas much oil from a wild oil well can often be saved by erecting dikes. The principal loss of oil results from evaporation, seepage into the ground, and spray. Even an approximate estimate of the quantity of oil and gas wasted by wild wells can not be made, but certainly it would amount to millions of barrels of oil and billions of cubic feet of gas.

Application of modern oil and gas well-drilling methods should materially reduce future losses by wild wells. The engineers of the Bureau of Mines will exercise every precaution to insure that operators on public lands provide suitable equipment and experienced men, and conduct their operations in such manner as to prevent blow-outs and wild wells. In addition, the bureau will require that special precautions be taken to safeguard the lives of workmen.

PREVENTION OF WASTE DURING DRILLING IN AND WASTE FROM WILD WELLS.

In most proved fields operators can foretell with some accuracy whether or not a large flowing well will be found. If the field has been tested and the well is an inside location, the operator would not be expected to provide extra heavy control fittings when there was every reason to believe the well would not flow. Numbers of such wells are drilled in each year, and control fittings are unnecessary.

However, a great many wells to be drilled on public lands will not be of this nature. Many will be wildcat wells, wells to extend a field, or wells to test new sands. Under such conditions the department will expect operators on public land to take every reasonable precaution against blowouts and wild wells.

COMPLETION OF WELLS WITH CABLE TOOLS.

CONTROL OF WELLS DURING DRILLING.

When drilling is done with cable tools in areas where high-pressure oil and gas sands are likely to be penetrated, it is good practice to place a master gate on the last string of casing that is landed. This gate should be a high-pressure valve packed with fire-resisting packing. The master gate should be screwed to a nipple, which in turn is screwed into the casing collar just above the casing clamps. The gate, with an extra set of clamps to hold it, should be placed below the derrick floor in the cellar so that it will not hinder the workmen. An extension arm should also be provided so that the well may be shut in quickly in case of fire. The master-gate connection is a relatively inexpensive addition to well equipment and may save an operator from heavy loss and claims for damage by controlling a wild well that might otherwise wreck the rig, ruin crops or dwellings, pollute streams, catch fire, or result in loss of life. Moreover, such a connection insures against loss of oil or gas, the possible junking of the hole by caving, the cutting out of casing by sand with the oil, and the drawing in of water.

After the water string has been set, the method of completing a cable-tool hole to insure against a blow-out depends on the kind of formations being penetrated. In eastern fields, in most fields of the Mid-Continent region, and in the Rocky Mountain district the oil sands are consolidated and "stand up" in open hole. In these fields a control casing head should be placed on the water string in oil territory or a master gate on the water string in any locality where gas is likely to be found before drilling in is attempted. An operator will generally be able to choose the fitting appropriate for the locality; in a wildcat well a master gate below the floor is always a desirable precaution. If a flowing oil well is brought in, a control casing head may be attached above the master gate. The Bureau of Mines favors the use of a master gate below the control head on all flowing wells except those of relatively low pressure. The master gate usually should be put below the derrick floor, while the control head, which is essentially a fitting for a producing well, and which is constructed so that ordinary work can be done through it, should be placed above the level of the derrick floor.

DRILLING IN WITH CABLE TOOLS.

If the well being drilled in with cable tools is in a field where the sands are soft, as in California, the well must be controlled differently. In such wells an oil string with screen or perforated pipe is set opposite the oil sand to prevent the hole from caving before the well is put to producing. In California practically all wells are now drilled to the water shut-off point and the water string of 8, 10, or 12 inch casing landed and cemented with rotary tools. After the well has stood cemented for the prescribed length of time, a bailing test for water shut-off is made. Many big wells blow in during the drilling out of the cement plug for part of this test, although if the water string is landed high enough the well will not blow in until more hole is made below the shoe and the sand penetrated. If a well should blow in while being drilled in with cable tools and before the oil string is run, the master gate on the water string is closed to hold the well in check. When drilling is being done with cable tools through the oil sands in California it is customary to maintain a column of water or mud fluid in the hole. This holds up the walls of the hole and controls the flow during the completion of the drilling-in process.

There are two general methods of drilling in these soft-sand wells with cable tools. The well may be drilled in with a column of water or mud in the hole, and the oil string, with necessary perforation, run after the oil sand has been penetrated to the desired depth; or, if the hole tends to cave, the oil string, with all blank pipe, may be carried during the drilling in, also with a column of water in the hole. If the latter method is used, a sufficient column of water or, if the pressure is high, a column of mud fluid is run into the well to prevent a blow-out or caving after the hole is drilled to the desired depth. The oil string is either withdrawn to substitute the necessary perforated joints, after which it is again run and landed or the blank oil string perforated in the hole.

In the Rocky Mountain, Mid-Continent, or Eastern fields, where the oil sands usually are consolidated and do not cave, drilling in wells with cable tools is simpler than in California. As there is little danger of the hole caving badly, casing is not carried during drilling in, and therefore a master gate in gas territory or a control casing head in oil fields may be placed directly on the water string and drilling in done through an oil saver. The well may and often does flow hard while drilling in is being done. (See Pl. IX, *B*, p. 58.) The use of mud fluid to control wells that "go wild" during drilling in with cable tools is described in a bulletin by Lewis and McMurray.[32]

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[32] Lewis, J. O., and McMurray, W. F., The use of mud-laden fluid in oil and gas wells: Bull. 134, Bureau of Mines, 1916, 86 pp.

On pages 53 to 66 of that bulletin examples of controlling high-pressure wells are cited.

CONTROL OF WELLS DURING DRILLING WITH ROTARY TOOLS.

The control of a well during drilling or drilling in is less difficult with rotary tools than with cable tools. In fields having soft and cavey formations the rotary method is now widely used. Many of these fields, notably those of Louisiana, Arkansas, part of southern Oklahoma, the Gulf Coast, and California, are the very ones in which high-pressure gas and oil sands are being encountered, and the rotary method, therefore, is well adapted both to drilling the wells and to holding them under control. Even with the precautions possible and the general advantages of the rotary method for holding high-pressure oil and gas sands in check, blowouts do occur.

CAUSES OF BLOWOUTS WHEN MUD FLUID IS CIRCULATED.

Usually when drilling is done with rotary tools the circulating column of mud fluid tends to "hold down" high-pressure gas or oil. In most gas or oil fields, the initial closed-in pressure is slightly less than the hydrostatic pressure of a column of water of the depth of the sand penetrated, although in certain fields the gas pressure is far greater than the weight of such a column of water. Since mud fluid weighs more than water, the control of most wells by a column of rotary mud seems possible. There is one factor, however, that tends to cause blowouts even when mud fluid is circulated and the gas pressure is considerably less than the hydrostatic pressure of the column of mud. Some gas may escape from the sand, mix with the mud, and "aerate" it. Drillers refer to this action of the gas as "feathering" or "cutting" the mud. Continued mixing with gas eventually will lighten the mud column until the gas pressure can overcome the fluid pressure, and a blowout occurs. Drillers should be cautioned to watch their mud closely. If the mud fluid begins to "cut" with gas, it should either be run out of the circulating pit and fresh mud used in its place or water should be substituted. Although considerably lighter than mud fluid, water will not cut like mud fluid and therefore it is the best temporary circulating fluid under such circumstances. In general, the heavier the mud fluid the greater the tendency to cutting by gas.

If a well is being drilled in a field where there are high gas pressures, and is not quickly controlled, the well may "clean" itself. Wells in such areas should be provided with an extra or "stand-by" pit of mud mixed especially for high-pressure work. Mud should be chosen by its specific gravity and not by its "thickness" or consistence, as is generally done.

In a few fields the closed-in pressures have equalled, and even exceeded, the pressure of a column of rotary mud of the depth of the sand, and for that reason have caused wells to blow out. Blowouts also happen when rotary drill pipe is pulled from a well after it has penetrated a high-pressure sand. The level of the mud fluid is lowered by the removal of the drill pipe, and should the pressure in the sand be almost equal to the column of mud when the hole was full, the lowering of the fluid may be just enough to allow the well to blow in.

USE OF CONDUCTOR CASING.

In rotary drilling, operators must be prepared to control wells at any time before drilling is completed and even before any casing other than the conductor pipe is set. Modern practice in rotary drilling includes the landing and cementing of conductor casing. This practice is recommended for any field where high-pressure gas may be found, although the exact length of the conductor is determined by local conditions. Sometimes conductor strings consist of 1,000 to 1,500 feet of large-sized pipe well cemented. Less than 100 feet (5 joints) of heavyweight pipe is seldom recommended for a conductor and with such short strings no less than 25 to 50 sacks of cement should be used, unless that amount more than filled the hole behind the pipe. If a conductor of this kind is cemented in the well, the operator by having a blowout preventer handy can protect against a high-pressure gas sand "cleaning the hole" of mud fluid and possibly blowing out the rotary drill-pipe or even junking the well.

Operators using rotary rigs in high-pressure territory keep an extra mud-pit handy for use if the driller "loses his returns" or if a pocket of gas should clean the hole of drilling mud. Frequently it is necessary to hold back pressure on the return column of mud at the well head to prevent gas from blowing the mud out as fast as it is put in. Because of the need for applying certain well-anchored fittings to hold back pressure in emergencies and the danger of "wild" wells forming craters and wasting untold quantities of gas or oil, it is highly important to land and cement a conductor string when drilling with rotary tools.

In a part of Naval Reserves 1 and 2 in California, a string of casing over 1,000 feet long is landed and cemented above the big gas zone that closely overlies the oil sands. This casing not only protects the gas zone from upper waters but provides an excellent means for anchoring and packing off additional strings of casing if high pressures are encountered below. In other fields, the depth for setting the next string of casing after the conductor or surface string will depend largely on where a test is to be made. In high-pressure territory, it is well to cement this string also, but in ordinary wildcat drilling, where the possibilities of finding a productive sand and the location of possible deeper water sands are unknown, it is not always good practice to cement a string for a test.

When drilling is done with rotary tools, the control of high-pressure wells can be effected more readily if the water string has been set. However, unless the water string is landed in a hard formation and is well cemented, the closing in of a well may prove disastrous. Many of the wild wells in northern Louisiana were caused by high-pressure gas working out behind the water string, unseating it and eventually causing a crater.

USE OF BLOWOUT PREVENTERS.

When drilling is done with rotary tools, it is desirable to have some type of blowout preventer handy. In California, one of the valve-type preventers, such as the Union blowout preventer, is used. With this type of preventer back pressure can be built up on the circulating mud by closing the jaws of the preventer against the drill pipe and continuing to pump mud. Other types of blowout preventers for rotary tools may be assembled and stood in the derrick for immediate use if there is a suitable conductor string or a full string of casing in the well on which to seat the preventer.

A common type of preventer is a swaged nipple, around the necked portion of which is cast a lead seal (see Pl. XI, *A*). On the bottom of the swaged nipple is the male end of a tool joint. Above the swaged nipple are a collar, another swaged nipple, a high-pressure valve, and one joint of drill pipe with a collar at the upper end. The drill pipe is handy for picking up and "stabbing" the preventer. If the mud fluid begins to flow out of the well while the drill pipe is being pulled, the workmen quickly set aside the "grief joint" or stand of drill pipe being pulled and hook into a pair of elevators, which are thrown on the preventer. The preventer is then swung over the hole and screwed into the tool collar just above the rotary table. The slips then are removed and the drill pipe lowered until the lead seal seats on the top collar of the smallest casing in the well. This prevents the flow between the drill pipe and the casing and by applying heavy mud from the reserve pit any high gas pressures that may develop can usually be kept down.

Once a rotary well is drilled into the sand as far as desired, the drill pipe is pulled to permit running the screen or perforated pipe. In California, a full oil string is run with the screen or perforated pipe on the bottom. In the Gulf Coast and Louisiana fields, a liner is run on the bottom of the drill pipe with blank, screen, or perforated pipe at the desired intervals. To provide against blowouts during the setting of screen and the washing of a well, another type of blowout preventer is often used. In Texas and Louisiana, the rotary table is removed before the screen is run and the casing-head fittings, called a "Christmas tree," are screwed on the water string (see Pl. X, XI, *B*, and XII, *B*). The rest of the work is done through the Christmas tree. The control of the well from this point on may be assured by lowering the drill pipe, or the oil string, upon a Louisiana pattern blowout preventer (Pl. XI, *B*), which in turn is seated on the nipple in the top of the four-way T in the Christmas tree. Plate XI, *B*, shows a master gate and a Christmas tree on the water string, and a string of drill pipe hung in the hole on a blowout preventer. This installation is typical for fields in which liners are set, and represents the ordinary method of controlling a well that starts to blow in during "washing" and before the drill pipe can be pulled. By using a preventer and anchoring the drill pipe, all waste from oil flowing into the derrick may be avoided and the danger of a wild well averted.

CONTROL OF WELL DURING PROSPECTING AHEAD.

When wells are drilled with rotary tools, it has also become the custom to core or "rat-tail" ahead when the drill approaches the depth at which productive sands may be expected. The findings during this work enable the driller to decide where to set the water string. If a good show of oil or gas is found, the water string is run and set above. In "rotary-tool" country, the water string when set can seldom be moved, hence it is desirable to set the water string low enough to shut off the last water. While "prospecting ahead" is being done there is constant danger of blowouts. Moreover, while a well is being drilled in with a full-sized bit after the water string is set there is risk of a well blowing out. The blowout preventer in Plate XI, *A*, is adapted to guarding against blowouts during this work, because it can be set through the rotary table and pump pressure applied to "kill" the gas during the drilling of a well.

NEED FOR KEEPING THE HOLE FULL OF FLUID.

Operators using rotary outfits are extremely careful, when drilling in high-pressure territory, to keep the hole full of fluid at all times. During the pulling of rotary drill-pipe, it is common practice to run mud into the well to keep the fluid level near the surface. Plate XII, *B* (p. 68), illustrates the unusual care taken by some rotary crews. The drill pipe had been pulled a number of hours before and the hole filled with mud at that time. As an added precaution, however, the driller required that the hole be filled again before he attempted to set the screen pipe, as a blowout during that work might have proved disastrous.

COMPLETING ROTARY-DRILLED WELLS.

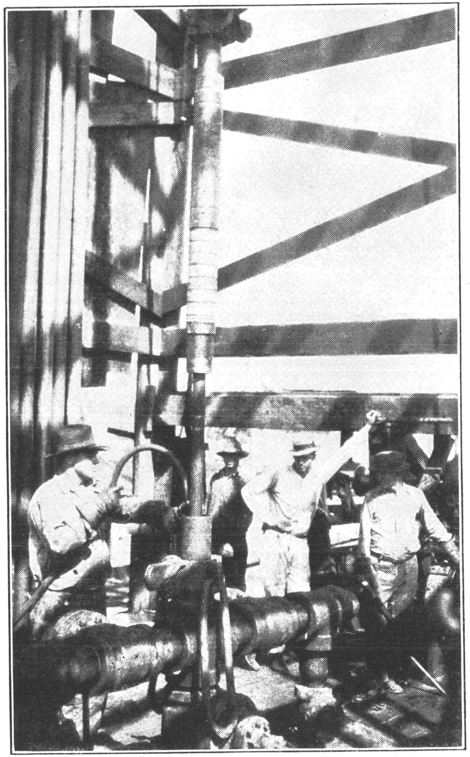
The methods of completing rotary-drilled wells in California differ from those used in the Gulf Coast and north Louisiana fields primarily because a full oil string is used instead of an oil liner. The oil string is run with the necessary screen or perforated pipe and is set on a stuffing-box casing-head or other tight head, such as the Trout and Butler pattern. If the well has to be washed, it is washed with drill pipe or tubing run inside the oil string. A possible blowout during washing could be prevented by setting the wash string down on the oil string with one of the blowout preventers described. This is seldom, if ever, needed, however, because the larger wells are usually not washed and the small wells that are washed are not likely to blowout.

When completing a well that is not washed, some California operators have recently adopted the practice of tubing the well with 2, 2½, or 3 inch tubing, setting this on a tight head, then bailing or swabbing the well through the tubing. Tubing-head fittings, commonly known as "deer horns" (see Pl. XII, *C*) are placed on the tubing before bailing is started, and when the well starts to flow it is brought under control at once. Plate XII, *C*, shows typical fittings on a flowing well that has been completed by the methods now in use in California. The master gate is placed on the tubing just above the Trout and Butler pattern head, seen just above the floor. The by-pass flow lines each contain one of the new type replaceable-core flow nipples.

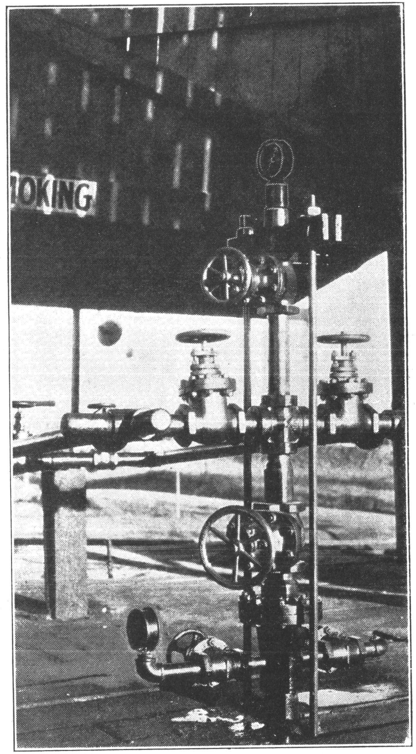
ASSEMBLY OF CASING-HEAD FITTINGS.

At large flowing wells, especially those in California fields and certain wells in the Texas coastal fields which produce considerable sand with the oil, the fittings have to be assembled so that sand will not cut them out at bends. Usually a solid plug or a "cushion" of fluid at the bends is provided. This cushion may be produced by using T's with either solid or regular bull plugs in the direction of flow in place of the usual L. At a few wells the casing heads and fittings have been set in concrete to prevent the wells from going wild if the casing should be cut through. For example, at West Columbia, Tex., the Texas Co. set the casing head of its Abrams No. 1 in a mound of concrete. This practice has been duplicated in California and Mexico at a few wells and has some advantages. The concrete prevents vibration and possible blowing off of the fittings and also gives additional weight to the casing. Should a fitting be cut through unexpectedly, the well would not go wild. Disadvantages of this practice, however, offset the advantages. As fittings are cut out, they can not be replaced. If the well sands

A. BURNING OIL AND GAS WELL IN THE SALT CREEK FIELD, WYO.

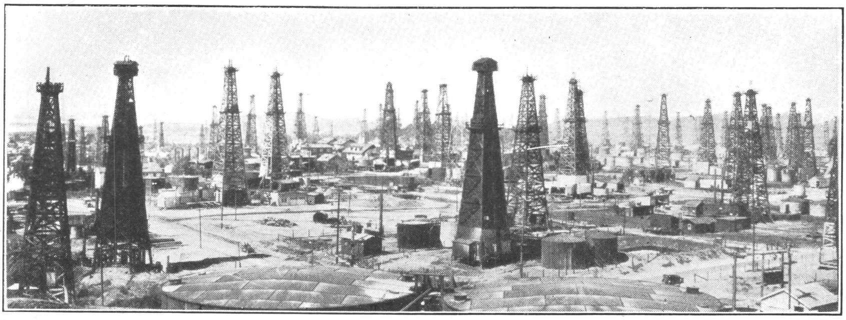


B. FILLING HOLE WITH MUD FLUID PRIOR TO RUNNING SCREEN LINER ON DRILL PIPE (WITH SETTING TOOL AND SEAL) IN A ROTARY HOLE.

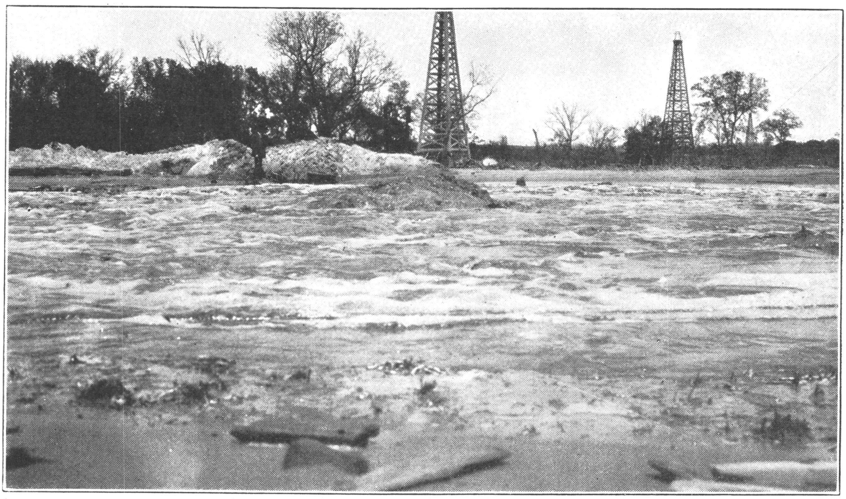


C. TYPICAL FITTINGS FOR WELLS FLOWING THROUGH TUBING, IN SOUTHERN CALIFORNIA FIELDS.

68—1



A. DERRICKS COVERED TO PREVENT WASTE AND DAMAGE FROM FLOWING WELLS, SIGNAL HILL FIELD, CALIF.



B. CRATER OF MAGNOLIA CO.'S MAYS-NEWBERRY WELL NO. 1, AFTER BLOWING WILD FOR ABOUT THREE MONTHS, AND A RELIEF WELL, ROBBERSON FIELD, OKLA. (Courtesy of M. J. Kirwan.)

IMPROPERLY ABANDONED WELL FLOWING SOME OIL, GAS, AND WATER SOON AFTER BEING "PLUGGED."

68—3

up, caves in, or stops flowing for any reason the concrete must be removed before tools can be run and repair work done.

When sand cuts out control fittings rapidly, operators usually install two flow lines, as shown in Plates XI, *B*, and XII, *C*, so that the well may flow through one line while the fittings in the other are being replaced. Plate X (see p. 59) shows two Christmas trees on a large flowing well. The lower Christmas tree was used while the fittings in the upper were being replaced. The large flow of oil caused the owner to install duplicate sets of flow lines so that the well would not have to be partly closed in while fittings were being renewed.

The installation of chokers or flow-nipples is discussed on page 112.

METHODS OF CONTROLLING WILD WELLS.

Oil operators should be familiar with methods of controlling wild wells. Lewis and McMurray [33] have already described methods of mudding under pressure and of lubricating large flowing wells out of control. The following account of the work in controlling a wild well, in which the Bureau of Mines cooperated, may be of interest.

On February 16, 1922, while mud fluid was being circulated before cementing was started, the Magnolia Petroleum Co.'s Mays-Newberry No. 1, in the Robberson field, Okla., started to blow out gas behind the 8¼-inch pipe that was to be cemented, and inside the 12-inch pipe. The blowout probably was due to the weight of the column of mud fluid being lessened by gas mixing with the mud. The gas soon became so strong that the boiler was shut down because of the danger of igniting the gas. Before the boiler could be moved back and set up again the hole had caved behind the 12-inch casing and had formed a crater into which the rig machinery and tools fell. The well formed a crater 100 feet or more in diameter (see Pl. XIII, *B*), which completely submerged the wreckage caused by the rig and equipment. This crater made the handling of the well difficult, so it was decided to drill another well 75 feet south of the original one. (See the derrick in the center of Pl. XIII, *B*.) A string of casing was cemented in the second or relief well at 1,050 feet. After the shut-off was tested the well was drilled into the gas sand, which was found at 1,290 feet. The relief well was then allowed to blow wide open and in 16 hours the gas in the crater well ceased to flow. The crater well had been blowing from the open hole for about three months. Mud was pumped in the relief well to protect the gas sand in the crater well. Drilling a near-by or offset well and mudding through the formation is also a method that has been employed with some success to overcome the flow from crater wells.

The boarding up of derricks as shown in Plate XIII, *A*, is a conservation measure employed in many localities. In addition to

[33] Lewis, J. O., and McMurray, William F., The use of mud-laden fluid in oil and gas wells: Bull. 134, Bureau of Mines, 1916, 86 pp.

facilitating the recovery of oil which flows from a wild well it prevents the pollution of streams and damage to dwellings, orchards, and crops.

INTERIOR DEPARTMENT REGULATIONS.

Additional information on the control of wild wells may be found in several publications,[34] some of which have been cited already. The department will expect operators on public lands to adopt all reasonable measures in preparation for the control and handling of large gas or oil wells. Because of the variable conditions under which operations will be conducted no set rules have been formulated, but deputy oil and gas supervisors and their representatives will confer with operators on preparations for large oil or gas wells and methods of handling wild wells. In cases of doubt or necessity, operators should confer with the bureau's field force at the nearest local office. (See list of field offices, p. 138.)

SHOOTING OIL WELLS.

Wells that produce from hard, tight sands are often shot when they are "brought in" to make them produce at the maximum rate. The size of the shot depends on the thickness, hardness, and porosity of the oil sand and on various other factors. Although shooting is necessary in many fields, to obtain the maximum production it also may cause the loss of much oil. Perhaps one of the most common injuries to wells from shooting is "shooting into water." If there is water either in the base of the oil sand or in a lower sand that is separated from the oil sand by a thin break, shooting is likely to fracture the formations and open channels through which this water may enter the well.

When shooting is done to increase production from an oil sand, it is advisable, when possible, to bail down the fluid in the hole below the bottom of the casing and thus reduce the danger of damaging the pipe.

Shooting may damage casing and ruin casing seats if shots are placed too near the casing seat or if casing is not lifted far enough. When the casing is reseated it may be impossible to effect a water

[34] Lewis, J. O., and McMurray, W. F., The use of mud-laden fluid in oil and gas wells: Bull. 134, Bureau of Mines, 1916, 86 pp.

Tough, F. B., Method of shutting off water in oil and gas wells: Bull. 163, Bureau of Mines, 1918, 122 pp.

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Heggem, A. G., and Pollard, J. A., Drilling wells in Oklahoma by the mud-laden fluid method: Tech. Paper 68, Bureau of Mines, 1914, 27 pp.

Bell, H. W., and Cattell, R. A., Monroe gas field: Coop. rept. Bureau of Mines and Louisiana Department of Conservation, 1921, 99 pp. (Obtainable from M. L. Alexander, Commissioner, Department of Conservation, New Orleans, La.)

shut-off. Sometimes when the water string is seated at some distance above the oil sand and the operator believes it unnecessary to lift the pipe before shooting, the force of the shot may unseat the casing and destroy the shut-off, thus allowing water to enter the hole. Premature explosions injure and may junk a well. In shooting oil wells every precaution should be taken to insure against injury to the casing or shooting into water, for repair work on wells that have been shot is especially difficult and the eventual loss may be considerable.

Not only are oil sands shot to increase production, but wells often are shot to overcome some trouble in drilling. For example, shooting may be done to assist in sidetracking lost tools or casing, to straighten a hole, to part the casing, or to open the casing opposite an oil sand. Shooting for these purposes requires skill and experience, as a hole may be easily ruined by a misplaced or too heavy shot.

NOTICE OF INTENTION TO SHOOT.

Because shooting may either make a well more productive or may damage or ruin it, the department feels justified in requiring a notice of intention to shoot (see Part II, "Operating Regulations," sec. 5, par. c). That this regulation may not become burdensome by delaying operations more or less routine in character, the deputy supervisor may, in specified instances, waive the requirement of filing a notice of intention to shoot. In certain proved fields, shooting wells to increase production may be a routine procedure and part of the usual drilling practice. If, in the judgment of the deputy, shooting as ordinarily practiced in those fields does not subject a well to possible injury, he may waive the notice of intention to shoot. When the operator feels that the shooting which he may wish to do will be of this nature, he should request authority to shoot to increase production during the completion of his well and should make this request on the "Notice of intention to drill" at the time he files the notice (Form 6–331a). The deputy supervisor will be justified in granting prior authority only when the lessee plans to shoot to increase production during the completion of wells within the limits of proved fields, and when the sand conditions, location of water sands, and the general character of the well may be appraised with some accuracy before drilling is started. The deputy may also grant prior authority to shoot during the drilling of a well should it become necessary, if there is no danger of damaging possible oil or gas bearing formations by shooting in the upper part of the hole. When other shooting is contemplated, such as shooting to break up pipe or sidetrack pipe or tools in the well, during drilling, repair, or abandonment, the department wishes to be advised of the proposed work by the usual notice of intention.

SWABBING OIL WELLS.

Swabbing a well during its completion as a producer may be desirable, as this assists in opening up channels and stimulating the flow of oil and gas toward a well. Swabbing is particularly adapted to cleaning out and completing rotary-drilled wells that do not have gas pressures strong enough to clean themselves of drilling mud: As soon as there is evidence that the maximum production has been obtained, swabbing should be discontinued. Vigorous and continued swabbing of any oil well should not be practiced, for it endangers the water shut-off or may pull in edge or bottom water or collapse the casing.

LOSSES FROM SWABBING.

Swabbing may and frequently does cause considerable underground loss of oil and gas, although little oil or gas may be lost at the surface. If the casing is collapsed or water pulled in, the life of the well will probably be shortened. The main loss therefore results from failure to recover oil that normally would be recoverable. If water troubles develop, some oil is almost sure to be trapped underground. The loss of casing-head gas during swabbing is worthy of mention because a well is seldom swabbed into a trap.

OBJECTIONS TO SWABBING AS A PRODUCTION PRACTICE.

Swabbing is not recommended by the department as a production practice. Operators frequently run a swab on a string of tools, then "take a hitch" and swab on the beam, using the swab as a large pump. Such practice pulls in water and wears out casing. Swabbing in the water string is uniformly dangerous and should not be practiced. The department expects operators who desire to swab in order to clean their wells to use judgment in running the swab, lest the wells be injured.

ABANDONMENT OF OIL AND GAS WELLS.

DAMAGE FROM IMPROPER ABANDONMENT.

Oil and gas wells are usually abandoned because they cease to produce oil or gas in paying quantities. Drilling wells are abandoned when they fail to find an oil or gas sand or find a sand that does not yield enough oil or gas to make the well pay. Drilling wells also are abandoned at times because of bad mechanical conditions, such as collapsed casing or difficulty in excluding water. Although a sand may not produce in one well it may be commercially productive in an adjoining or nearby well. Such a sand in a well that is to be abandoned must be protected from flooding by water and from a possible loss of gas pressure, or from migration of oil and gas. Failure to abandon wells properly has caused great waste in oil fields by permitting the flooding of oil and gas sands with water and the migration of oil and gas. In some fields, until recent years, abandonment usually involved only the pulling of the casing.

Water, if not plugged off when a well is abandoned, may migrate through the oil sand to adjacent producing wells and eventually ruin them. Gas sands may also be flooded and gas wasted if gas is allowed to escape through the well into the air. Plate XIV pictures an abandoned oil well soon after the well was supposed to have been plugged and exemplifies inefficient abandonment. If gas and oil escape at the surface, even greater damage is probably being done to underground deposits by infiltering water. The numerous State laws and regulations on the plugging of abandoned wells prove that the damage resulting from failure to plug wells properly has been generally recognized. Every operator should consider the proper abandonment of a well a moral and economic obligation.

METHODS OF PLUGGING WELLS.

Mud-laden fluid and cement are the most effective materials for plugging a well and under some conditions are the only practical means for protecting oil and gas bearing formations. In oil fields with strong water pressures, unconsolidated formations, and other treacherous conditions, the abandonment of a well must be done with great care and may entail considerable expense. Procedure varies from well to well, and, as previously stated, methods employed in one well will not be suited to another.

EXAMPLE OF ABANDONMENT OPERATIONS.

The following record of abandonment operations is given as an illustration of a thorough and costly plugging job. An old well in the Coalinga field, Calif., was producing about 5 barrels of oil and 100 barrels of water daily. The owner therefore decided to abandon the well because of possible injury to near-by wells.

Important features of the log of this well are shown at the left of Figure 4. The well had been redrilled a number of times and consequently its exact condition was not known. A water analysis showed a mixture of top and bottom water. The details of the work during abandonment were as follows:

1. Well was cleaned to bottom (1,845 feet), 6 5/8-inch casing being carried during the cleaning.
2. Cement, 10 sacks, dumped in, filling the hole to 1,820 feet (cement stood 25 feet in hole). About 37 per cent of the cement entered the formation; cement allowed to set seven days.
3. Shot from 1,753 to 1,810 feet with 100 pounds gelatin.

4. Red mud circulated for three days. Amount unknown. Maximum pump pressure, about 250 pounds per square inch. Mud did not appear in any adjoining well, as sands in this neighborhood are compact.
5. Cement, 138 sacks, put in through tubing. Hole filled to 1,575 feet (cement stood 245 feet). About 57 per cent of cement entered formation. Cement allowed to set seven days.
6. Shot from 1,500 to 1,575 feet with 240 pounds gelatin; red mud circulated for three days under pressure. About 15 cubic yards used.
7. Filled to 1,360 feet with 55 sacks cement. Should have taken 70 sacks cement to fill the 8 inch casing to this point. Hole either filled upon being shot or mud settled in it, causing it to take less cement than calculated.
8. Filled to 1,280 feet with 25 sacks cement inside 8 inch casing.
9. After cutting 8-inch casing and pulling, hole filled to 1,100 feet with 31 sacks cement. Should have taken 86 sacks.
10. Pulled casing, 1,198 feet of 8-inch, 1,043 feet of 10-inch, 400 feet of 12-inch.

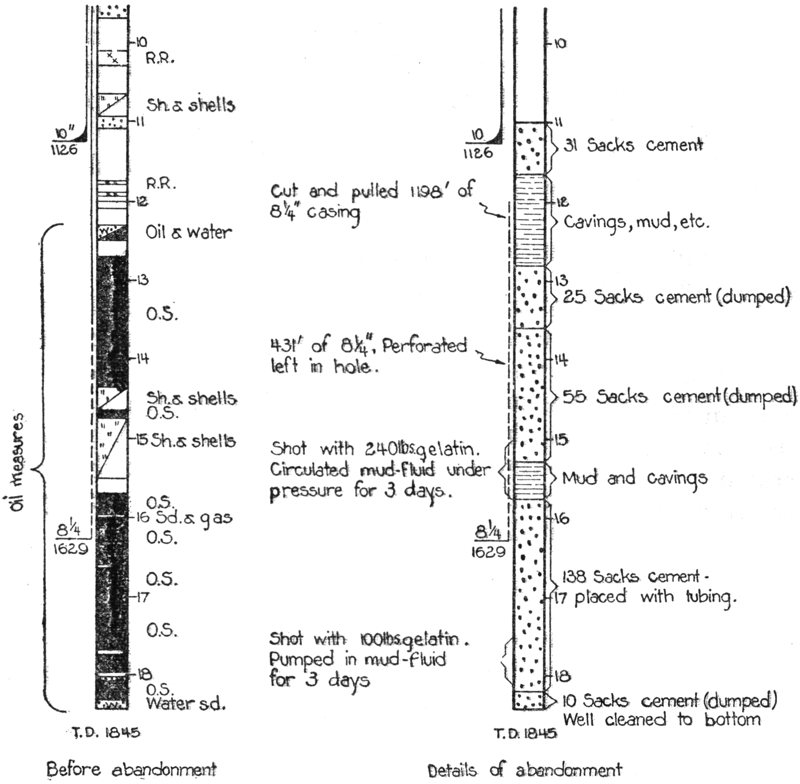

FIGURE 4.—Log of abandoned well, before and after plugging, Coalinga field, Calif.

DEPARTMENTAL POLICY.

In fields where conditions do not require such care in abandonment the Bureau of Mines will permit operators to use simpler methods when abandoning wells. For example, if a drilling well is to be abandoned after a dry or water sand is struck, instead of an oil or gas bearing formation, the hole should be filled to a point near the top of the sand with rock, drill cuttings, or similar material, and a cement cap extending several feet into the impervious formation above the sand, placed on the plug. It is essential that dry sands, as well as any oil and gas sands, be plugged off so that upper waters will not enter them and do damage by migrating to other wells.

In general, the department's policy on the abandonment of wells is to consider each well individually in the light of local conditions. The department has purposely avoided the adoption of set regulations prescribing methods to be used when wells are abandoned. A lessee, however, is required to submit to the deputy supervisor a proposal for abandonment (see Part II, "Operating Regulations," sec. 5, par. c) which gives a detailed description of the proposed work. The deputy supervisor, after consideration of the proposal, will either approve the plan of abandonment or recommend modifications which he may consider necessary under the circumstances.

The basic principle of the department's requirements is so to abandon a well that oil, gas, and water are confined to the strata in which they occur. The actual work of abandoning may vary from the introduction of mud fluid and cement under pressure—which possibly would require several weeks or months of careful work—to the simple process of filling the hole with mud fluid, or placing wooden plugs above and below each oil or gas sand and filling the hole with mud fluid.

The abandonment of a well within the limits of or near a producing field will ordinarily require more elaborate procedure than will the abandonment of a dry or unproductive "wildcat" well. The policy of the department is to leave wells which can not be profitably operated or which must be abandoned for mechanical reasons in or near proved territories, in such a condition that they can be reentered and repaired at any future date, if subsequent developments show this to be desirable. As the effectiveness of abandonment operations in a proved field can not be determined when the work is done and may not be evident for months or even years, the planning of the abandonment to permit reentry to the well for repair is most important; otherwise, an abandoned well may constitute a permanent menace.

When any well is abandoned in or near a proved field, the department requires that at least a few joints of conductor pipe be left in the well. In more extreme cases, the department may require a full string of casing or a conductor consisting of telescoped strings of casing, produced by cutting off each string in the shoe joint of the next larger, to be left in the well to permit reentry.

As a rule, the abandonment of a dry or nonproductive wildcat well which is not adjacent to a known productive area will not be subject to the same rigid requirements as a well in a proved field. However, the abandonment of such a well may embody the protection of usable waters from pollution, and possibly of oil or gas bearing strata or coal beds from injury. The abandonment of a wildcat well may thus involve the same careful preparations for abandonment as a well within a proved field.

In an endeavor to prevent injury to adjoining properties from improperly abandoned wells, the Bureau of Mines will insist that all wells on Government land be plugged in an approved manner before they are abandoned. The deputy supervisors will advise and assist operators in properly abandoning wells, as the matter of careful abandonment and proper protection is of vital interest to both the Government and the lessee. When deemed necessary by the Bureau of Mines its representative will be present during the work.

INTENTIONAL BLOWING OF GAS WELLS.

BLOWING INTO OIL.

In keeping with the anticlinal theory of accumulation, natural gas often occupies the uppermost portion of a sand or even an entire sand on higher portions of an anticline structure and is flanked by oil down the slopes of the structure. When wells are drilled into the top layers of an oil and gas sand in a locality where gas exists to the exclusion of oil, a well may "come in" as a gas well but later, when some of the gas is removed, blow into an oil well.

Unless a ready market is available, an operator may regard gas in excess of that needed to satisfy his fuel requirements as a nuisance. Being familiar with the history of many wells in which oil has followed gas into the well if enough gas was removed, oil men frequently open gas wells with the hope of "blowing them into oil."

In the Osage Indian Reservation, Okla., for example, gas wells which later blow into oil are often found. In this district, the gas leases and oil leases are awarded separately, therefore two lessees may be operating on the same property. The regulations state that if an oil lessee drills a gas well, he shall communicate with the superintendent of the Osage Nation, who will turn over the well to the gas lessee; the gas lessee is then required to reimburse the oil lessee for drilling the well. Conversely, should a gas lessee drill in an oil well, arrangements are made for the oil lessee to take over the well and reimburse the gas lessee for drilling. The result of these regulations has been that an oil lessee who happens to drill in a gas well which may give some indication of blowing into oil tends to let the well blow, hoping that the oil will come in so that he can keep the well. A gas lessee who drills in a small gas well, which is some distance from his gathering line, is often glad to blow the well into oil, if possible, so that he can be reimbursed for the cost of the well and saved the expense of connecting up with and operating it. The Government, through its inspectors on the Osage Reservation, is very strict in prohibiting such willful wastes, and neither gas nor oil lessees are allowed to shirk their responsibility at the expense of a waste of natural gas.

CHANCES OF BLOWING WELLS INTO OIL.

The actual chances of blowing a gas well into oil are slight. By far the greater portion of commercial gas wells in the United States produce from gas sands in which little or no oil is known to exist. Generally the field is exclusively a gas field, or the sand from which the gas is obtained in that field is exclusively a gas sand. The Elk Hills field of California may be cited; there the formations which carry gas are distinctly higher than the oil zone which is encountered below.[35] The Monroe, La., gas field is also exclusively a gas field, for little or no oil has been found. The Nichlos gas sand in the Chickasha field, Okla.,[35a] produces relatively dry gas and carries only small amounts of oil down dip. In Oklahoma, Kentucky, West Virginia, and Pennsylvania most gas wells produce from gas sands that carry no oil in that particular pool or locality.

Large volumes of gas are often wasted before it becomes evident to the operator that oil will not come in. The blowing open of large gas wells in areas where the presence of oil has not been proved is an even worse violation of the principles of conservation than would be the same practice in Osage County, Okla., where there is a possibility of blowing wells into oil.

CONDITIONS IN WILDCAT TERRITORY.

In extreme southwest Texas, for example, a number of large gas wells have been found within the past few years by independent operators seeking oil. When such wells are struck, the operators usually want to blow off the gas with the hope of bringing in an oil well. The region is thinly populated and sale of the gas is almost impossible. The extent and longevity of life of the fields can seldom be estimated, therefore industries in need of cheap fuel can not safely chance the building of a plant near these gas wells. High-pressure gas is generally a nuisance in drilling. The operator usually feels that blowing off the gas under such circumstances is his right, because he can not afford to shut in his one well and seek elsewhere for oil, nor is it always practical to seal in the gas and continue the search for oil in the same well.

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[35] McLaughlin, R. P., Natural-gas development in the Elk Hills, Kern County, Calif.: California State Min. Bur. Summary of Operations, May, 1919, p. 4. Thoms, C. C., and Smith, F. M., Notes on Elk Hills oil field: California State Min. Bur. Summary of Operations, July, 1921, p. 7.

[35a] Kirwan, M. J., and Swigart, T. E., Engineering report on the Chickasha gas field, Grady County, Okla.: Coop. rept., Bureau of Mines and Bartlesville, Okla., Chamber of Commerce, May, 1923. Obtainable from Bartlesville Chamber of Commerce.

The shutting in of a gas well in an isolated territory, when the bringing in of an oil well may be essential for the continued existence of a prospecting company, is somewhat of a hardship for the operator. The Federal Government, however, can not sanction willful waste of a resource so valuable as natural gas, even though individual operators lose money.

REGULATIONS FOR GOVERNMENT LESSEES.

Should gas be found by a lessee drilling for oil on Government land, the Bureau of Mines will require him to close in the well or properly protect the gas sand, should he desire to drill deeper. The Government will not sanction the willful waste of gas, even from isolated wells. Natural gas is an important national resource, and if there is no use for it at the time of discovery, it is far better for it to remain untouched in the natural reservoir than to be wasted to save one individual from failure. If a wildcat well should produce a large volume of gas and the operator wishes to continue drilling in search of oil, he should apply to the deputy oil and gas supervisor or his representatives at the nearest field office of the Bureau of Mines if he is uncertain of the proper procedure.

SEALING OFF A GAS SAND.

Should a well blow in as a gas well when oil is being sought, the operator may seal off the gas and continue the hole in search of deeper oil sands. The most approved method of shutting in a gas sand to prevent waste is to mud the sand and land a string of casing below it, cementing the casing to a point a number of feet above the gas sand if necessary. If the gas sand contains high-pressure gas, it is particularly desirable to cement only after the sand is mudded thoroughly. Should an operator desire to braden head the gas for fuel purposes, one string of casing must be landed above and one below the gas sand, with as little open hole as possible above and below this sand. As stated on page 54, this is not always practical although gas sands found in drilling for oil can often be braden headed and the fuel bill eliminated from that time on. Even such use of braden head is dangerous with high-pressure gas, and is not recommended.

OPEN-FLOW TESTS.

DEFINITION OF OPEN-FLOW VOLUME.

The term "open flow" is generally interpreted to mean the volume of gas, usually measured in cubic feet at standard conditions, which a gas well will yield against atmospheric pressure. The standard cubic foot for gas measurement on public lands has been specified by the Secretary of the Interior to be a cubic foot of gas at a pressure 10 ounces above an assumed atmospheric pressure of 14.4 pounds per square inch at a temperature of 60° F.

Open-flow readings, at the best, are estimates read at atmospheric temperature and pressure. Although the standard of gas measurement on public lands is as specified above, the ordinary open-flow tables which are based on a pressure 4 ounces above an assumed atmospheric pressure of 14.4 pounds per square inch and 60° F. temperature will be considered accurate enough for reducing open-flow tests.

STATE REGULATIONS.

Some States specify that open-flow tests of gas wells shall be taken at regular intervals in order that the actual production into the line shall not exceed a stated percentage, usually 20 or 25 per cent, of the wells' open-flow capacity. For example, rules 31 and 32 of the "Rules, Regulations, and Requirements" promulgated by the corporation commission of Oklahoma state:

Rule 31.—Gage to be taken; reports to commission. All oil and gas operators shall between the first and tenth of each calendar month take a gage of the volume and rock pressure of all wells producing natural gas, and shall forthwith report to the corporation commission on gage blanks furnished by the commission. (Rule 26, Order 937.)

Rule 32.—Production to be restrained to 25 per cent of potential capacity. When the gas from any well is being used, the flow or production thereof shall be restrained to 25 per cent of the potential capacity of the same, that is to say, in any day (24 hours) the well shall not be permitted to flow or produce more than one-fourth of the potential capacity thereof, as shown by the last monthly gage. (Rule 29, Order 937.)

The regulations governing operations on Osage Indian lands provide:

36. The inspector may limit the percentage of the open-flow capacity of any well which may be utilized when, in his opinion, such action is necessary to properly protect the gas-producing formation.

WASTE FROM OPEN-FLOW TESTS.

Although open-flow tests are prescribed by various States and commissions, the waste that occurs when such tests are made can not be overlooked. Open-flow tests may result in a well blowing at full capacity for intervals ranging from a few minutes to one hour.

In 1920, Oklahoma produced, exclusive of waste, 166,265,000,000 cubic feet of natural gas from approximately 1,600 wells. The average production per well per day, therefore, was about 284,000 cubic feet. If operators complied with the law, the average open-flow capacity of these wells would have been at least four times 284,000 cubic feet, or 1,136,000 cubic feet per day. The average open flow should be considerably more than four times the average production, because the 25 per cent rule limits the maximum rate at which gas may be taken from the wells and the wells will produce at the maximum rate for only a small part of the year, owing to variations in the demand for gas. Furthermore, the amount of gas lost in blowing wells for open-flow tests is more than the amount indicated by the open-flow measurements, because a well is allowed to blow off until the flow of gas becomes uniform before the open-flow test is made. This entails the loss of a large volume of gas, as wells produce at much greater rates when first opened than after the "head" has partly blown off. On the basis of the potential open-flow capacity, estimated by multiplying the average production per well by four, the following tabulation has been compiled to show the possible losses resulting from open-flow tests in Oklahoma during 1920.

Interval of test, minutes.[1]	Estimated total loss in Oklahoma in 1920, cu. ft.	Per cent of entire state production in 1920.
5	76,000,000	0.46
10	152,000,000	.92
15	227,000,000	1.37
30	455,000,000	2.74
45	682,000,000	4.10
60 (1 hour)	909,000,000	5.47

[1] Test made once each month, in compliance with State ruling.

While 1 or 2 per cent is seemingly a small waste, the Bureau of Mines does not wish to permit even this waste of gas from public lands if it can be prevented by the substitution of other methods.

DAMAGE TO WELLS.

Aside from the actual waste of gas into the air, open-flow tests are undesirable because of the possible damage to a well. The sudden release in pressure at the casing head causes a rush of gas toward the hole. A "suction" is set up in the well which tends to draw both formations and fluids into the hole. Allowing wells to blow open has frequently resulted in water breaking into the well either from the bottom or around the shoe of the casing. If water has encroached in the base of the gas sand to a point near the well, blowing open is almost certain to bring it in. The well may be drowned out and a large volume of gas may be cut off in the sand and isolated so that it never will be recovered. Heavy flows of gas may cut away the casing seat and endanger the water shut-off, or may cause the hole to cave and otherwise damage the well. The losses which result from premature flooding because of water breaking into a well can not be estimated accurately, and indeed the operator is seldom aware of them. They are important enough to warrant every attention on the part of a gas-well operator.

SUBSTITUTE METHODS.

Enough experimental data are not available to permit the establishment of a strict rule or a substitute method for the blowing of gas wells in determining open-flow capacities. Information at hand has indicated that an approximate relation between the decline of rock pressure and of open-flow volume often holds, although this relation can not always be relied on. The following table on open-flow decline and rock-pressure decline for an Oklahoma gas well illustrates the general relation:

Months.	Per cent of first month's open-flow capacity.	Per cent of first month's rock pressure.
1	100	100
2	50	48. 3
3	46	47. 2
4	42. 5	45. 3
5	41. 5	43. 8
6	40. 5	41. 8

It is believed that by taking open-flow readings about once every six months and rock-pressure readings once each month an operator under ordinary circumstances would be able to estimate within fairly reasonable limits the open-flow capacity of his wells on the basis of the closed-in pressure at intermediate dates.

The disadvantages of this method are (1) the well would have to be off the line for a number of hours that the rock pressure might be obtained, and (2) the ratio of decline of open flow might not be sufficiently near the ratio of decline in rock pressure to permit reasonably accurate estimates. Cutting a well off the line to let it "rock up" often may work a serious hardship. However, an open-flow test may not be practical, either, if certain operations are mainly dependent upon that well for their supply of gas, as that test also necessitates taking the well off the line.

Eventually the Bureau of Mines hopes to collect data which will permit the establishment of a reliable substitute method for open-flow readings. It has been suggested that a definite relationship between line or working pressure and rock pressure and delivery capacity may exist. The two curves shown in Figure 5 have been compiled by John M. Alden, natural-gas engineer of the Bureau of Mines, from data from two different sources to illustrate this suggested relation. The ordinates represent line or working pressures divided by rock pressures and the abscissas represent the per cent of the open flow that the well is delivering into the line. For example, if the line pressure is 200 pounds and the rock pressure is measured and found to be 300 pounds, the operator should trace along the abscissa on Figure 5 that represents $\left(\frac{200 \text{ pounds}}{300 \text{ pounds}}=\right)0.67$ to an average curve (not shown) which would fall between the two curves shown on this graph and read 20 per cent on the horizontal scale. This would mean that, if the well was delivering 500,000 cubic feet of gas daily into the

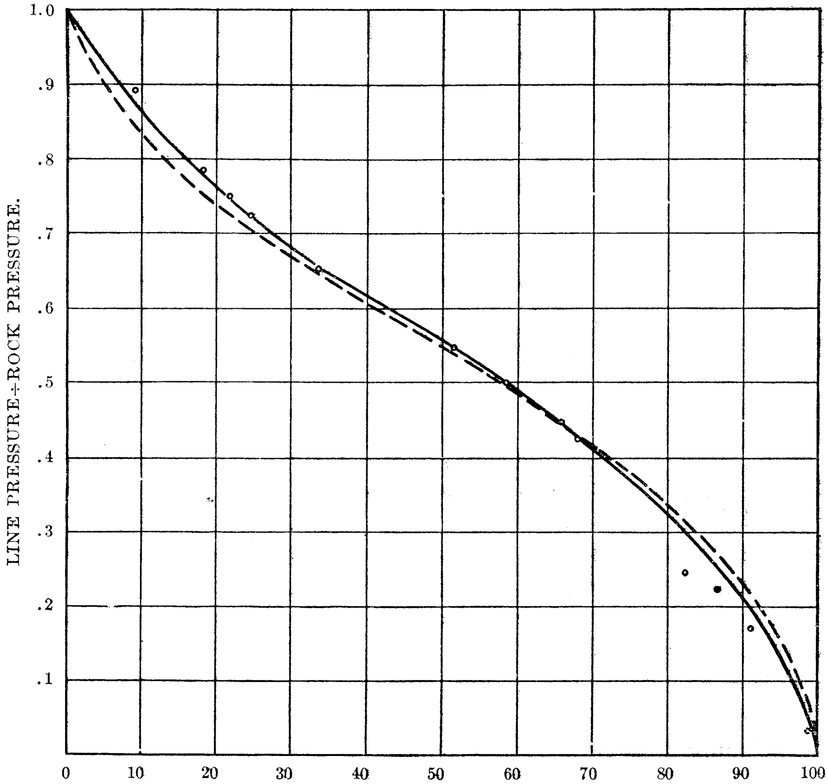

FIGURE 5.—Curves illustrating the relationship of open-flow capacities and line and rock pressures of a gas well: — — —, curve plotted from Westcott's "Handbook of Natural Gas," p. 265; ▬▬, curve plotted from figures on Petrolia, Tex.

line under these conditions, the open-flow volume of that well would be about $\left(\frac{500,000}{0.20}=\right)$ 2,500,000 cubic feet per day.

DEPARTMENTAL REGULATIONS.

In view of the losses of gas and danger of injury to gas wells incident to taking open-flow tests, the department is anxious to obtain the cooperation of its lessees in perfecting some other method of determining the capacity of wells. It is believed that rock pressures give a more reliable indication of the depletion of a gas reservoir than do open-flow tests,[36] but until better methods can be devised,

[36] Bureau of Internal Revenue, Treasury Department, Manual for the oil and gas industry under the revenue act of 1918, revised August, 1921, p. 33.

the department will approve an open-flow reading when a well is first drilled in.

The department does not require open-flow tests at stated intervals at all wells. To the contrary, the department recommends that, unless necessary for some particular purpose, wells on Government lands be not blown open for testing oftener than once every six months, unless repairs to the well require its being blown between times. In this event, an open-flow test should be made at the time of blowing. However, the deputy supervisor or his representative may require an open-flow test of any well to be made, when in his opinion, such a test is necessary.

CLEANING GAS WELLS BY BLOWING.

In most gas fields, some of the wells produce water daily. This water must be removed regularly, or the wells will be drowned out. As long as the rock pressure in the field is high enough, many operators blow these wells open as often as may be necessary to rid them of water. Blowing open also cleans out, to some extent, sand and other cavings which collect in the bottom of a well and eventually clog the well so that the flow is reduced. One operator was known to blow a number of his wells open daily for from 1 to 15 minutes to rid them of water that had collected overnight.

The loss of gas from a 1,000,000-foot gas well in 1 minute of open flow is 690 cubic feet. If the well is blown open for 1 minute daily, the monthly loss of gas is 21,000 cubic feet. Here again, these losses seem comparatively small, but the aggregate losses from many wells amount to millions of cubic feet of natural gas per year. In addition, as pointed out in another section (p. 80), the dangers to wells and resultant losses of natural gas from underground migration and isolation are so great that blowing open wells for removing water can not be recommended as a regular practice.

WATER-SIPHON LINES.

If possible, gas wells which produce water should be so repaired as to shut out the water. This is not always possible, and the operator, therefore, may be called upon to remove the water at frequent intervals, so that it will not drown out the gas. The water-siphon line which has been used successfully in many of the eastern fields and in Oklahoma is recommended for this purpose.

Figure 6 is a sketch of a siphon line as commonly installed. This usually consists of standard black pipe with extra-heavy collars, ranging in size from three-fourths to $2\frac{1}{2}$ inches. At the bottom of the siphon are two T's or a perforated pipe to admit water and gas. The siphon is held by a special bushing at the surface or by a stuffing-box casing head.

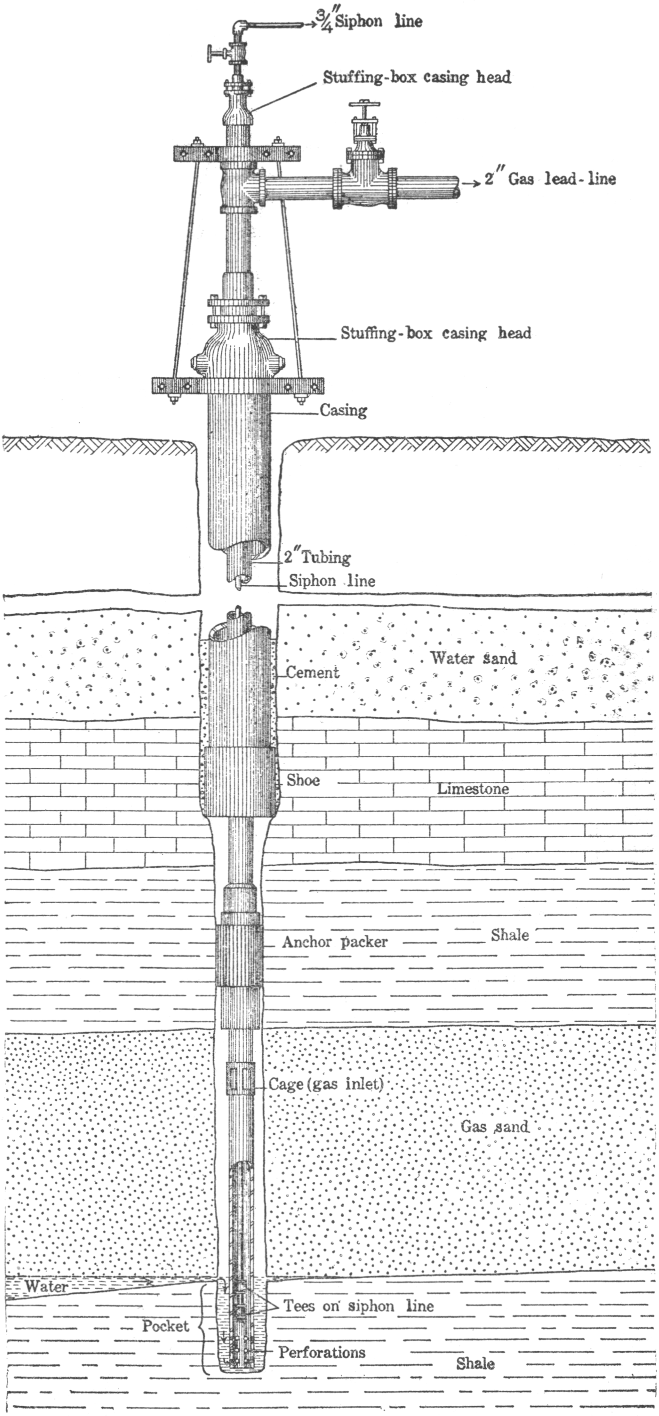

FIGURE 6.—Details of siphon for removing water from gas wells.

INSTALLATION AND OPERATION.

The siphon line will not operate successfully under all conditions. For example it can not be expected to clear a well of water when the water has risen so high that the gas pressure has been overcome. Such a well must be bailed or pumped down and revived before the line is installed. The siphon line operates on the air-lift principle; therefore the submergence must not be too great or it will not start to flow the water. If a siphon line will not operate because of too much water in the well, it must be lifted until it will operate and the water blown down as the siphon is lowered by stages. If the well is completely drowned out, it may be necessary to pull the siphon line and bail the well down until it is at least partly revived. The siphon must be blown often enough to keep the water down, else the "lift" will not start when the siphon is opened.

Siphons are adapted both to high and fairly low pressure gas wells if properly installed and operated. Sometimes it is impractical to attempt to install a siphon line in a large gas well because of the mechanical difficulties occasioned by a strong flow of gas. Moreover, when wells reach a low gas pressure, trouble may be encountered because the gas pressure is not sufficient to operate the siphon (gas lift). This factor, of course, depends on the depth of the well and the actual gas pressure. Siphons may operate continuously if the well produces large quantities of water, but ordinarily they are opened up and the well blown dry once or twice each day. If a well is blown open continuously, considerable gas may be wasted, even through small tubing. If blown open once or twice each day for short intervals a well only loses small amounts of gas. Should a use for low-pressure gas exist, the siphon may be connected to a drip on the lead line from the well, thus eliminating any waste of gas caused by blowing the siphon line into the air.

EXAMPLE OF USE.

Siphon lines have given excellent service in gas wells in Eastern fields of the United States and the Osage Indian Reservation, Okla. One group of wells had an average rock pressure of 240 pounds when siphon lines were put on, and three months later their rock pressure had not been reduced. The wells were drawn on at about 25 per cent of their open-flow capacity during this time. Other wells in the vicinity which were not equipped with siphon lines showed a marked decrease in rock pressure during this same interval, due principally to injury by water and blowing open. Some gas wells on Government land are now equipped with water-siphon lines.

UNIT PUMPING OUTFITS.

Unit pumping outfits for removing water from gas wells are manufactured by many concerns. As gas wells often have 2, 2½, or 3 inch tubing, the unit outfits are made for use inside tubing. One type consists of an inserted plunger liner with a perforated anchor attached.[37] The sucker rods consist of three-fourths-inch pipe. The top cage is a closed cage so that the water from the gas well is pumped inside the hollow rods. The polished rod is a hollow tube also. The gas is taken off from the ordinary size tubing, inside which the pumping string works. The plunger liner is provided with a plunger bottom valve which is advantageous in pumping fluid from a gas well. High-pressure gas tends to collect and cushion between the valves of an ordinary cup plunger pump and prevent the pump from functioning. The plunger bottom valve works so close to the standing valve that the chances for gas cushioning are cut to a minimum.

The tubing in a gas well that produces water should be perforated near the bottom as well as toward the top of the sand, so that the water level can be lowered. The perforated anchor of the unit pumping outfit should be set low in the sand. If conditions will permit, a pocket should be drilled below the gas sand for the collection of water, but when there is any danger of drilling into a water sand, the operator should not chance the drilling of a pocket.

Unit pumping outfits are used in a number of gas fields of the United States. Pumping requires either a unit pumping-power of some kind at the well or a jack operated by a central power. If gas wells are scattered among oil wells, as may be the case if one sand happens to be a gas sand and others higher or lower oil sands, it is often possible to pump the water out of gas wells by the installation of an ordinary pumping jack and rod line to the gas well.

Pumping water from gas wells is less wasteful than blowing out water and is particularly adapted to wells in which the rock pressure is so low that a siphon will not operate satisfactorily. However, unless a power and jack system for pumping oil wells is handy, it is unlikely that pumping water from greatly depleted gas wells will be commercially feasible, as wells which are of such low pressure and production that the siphon line will not work are not likely to produce enough gas to pay for water pumping, particularly by a unit power outfit.

CLEANING A WELL OF CAVINGS.

In some gas fields, the producing formation is somewhat soft and friable and eventually caves until the hole is filled to near the top of the gas sand. Such wells should be cleaned by running tools and by

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[37] For the construction of plunger liners for gas wells, see Oil Well Supply Co. Catalogue 043, p. 368.

bailing. Many gas wells, however, will produce for years without filling with cavings.

Knowledge of local conditions must govern operators in handling such matters. Under some conditions, it is necessary to blow a gas well, but in general the less a well is blown the greater will be its ultimate useful production. The department is anxious that all blowing be eliminated when not absolutely necessary. Representatives of the Bureau of Mines will assist lessees in solving individual problems in connection with the loss of gas or possible injury to wells.

ALLOWABLE RATE FOR DRAWING ON GAS WELLS.

The injuries possible to gas wells and natural-gas deposits as a result of drawing on high-pressure gas wells too hard or blowing them open have been discussed. To guard against damage to wells and the resultant losses of natural gas some of the gas-producing States have specified, by law or regulation, a certain percentage of the open-flow capacity which shall be the maximum amount of gas taken from the well under usual working conditions.

The percentage of a well's open-flow capacity that should be taken depends upon a number of factors, including: (1) Possible mechanical damage to a well by drawing on it too hard; (2) water encroachment; (3) rock pressure and differential pressure between the well and the line; (4) nature of deposit, that is, whether large enough to warrant investment of capital for a gas-producing enterprise; (5) nature of the control of the source of supply of gas as well as the market, that is, whether highly competitive or monopolistic; (6) time necessary to return invested capital with fair earning.

During the period of a well's life when the rock pressure is relatively high, it is usually desirable to restrict its daily production of gas to about 25 per cent of its open flow. This not only protects the well from such mechanical injury as might be caused by caving of the formations around the shoe but protects the gas sand against the premature encroachment of edge water or water in the base of the sand or the breaking in of top or bottom water.

Under certain circumstances it may be desirable to take considerably more than 25 per cent of the open-flow capacity of the well. The differential pressure between the gas reservoir and the back pressure maintained at the casing head is really the controlling factor in so far as damage to the well is concerned. Although a well whose rock pressure is 500 pounds per square inch might be injured if it produced into the atmosphere, or even against a 50-pound pressure, a well whose rock pressure has declined to 25 or 50 pounds usually will have to be produced at almost atmospheric pressure or less in order to get an appreciable volume of gas. Thus a time arrives in the life of all gas fields when it becomes necessary to take the full production of the wells, first, to supply the demand, and, second, to make the ultimate recovery as complete as possible.

POLICY OF INTERIOR DEPARTMENT.

The Interior Department recognizes the soundness of rules regulating the rate for drawing on gas wells and usually will recommend that its lessees restrict the deliveries from gas wells of relatively high rock pressure to about 25 per cent of the open-flow capacity. However, the department also recognizes the impracticability of applying fixed rules to all conditions and for that reason has not issued specific rules restricting the amount of gas which can be taken from any well.

Factors such as are enumerated above must be given due weight in determining the amount of gas which may be taken from gas wells, but the department, within practicable limits, will consider cases on public lands first with regard to conservation and efficiency of production and second with regard to local business conditions.

The department reserves the right to recommend to its lessees in the various fields the percentage of the open-flow capacity that will be taken from any well or wells. When an operator disregards the department's recommendations and the deputy supervisor considers that such disregard subjects natural-gas deposits to unnecessary waste or loss, the deputy, after investigation, will specify a fixed percentage that the operator may take from his wells. It is believed that this practice will not only amply protect the natural-gas deposits but, because of its greater elasticity, will prove fairer than a fixed rule in adjusting the varied conditions with which the department has to deal.

LOSSES OF OIL FROM INEFFICIENT PRODUCTION OF GAS WITH OIL.

The importance of natural gas in the recovery of oil is becoming more fully understood. The following discussion refers only to wells that produce principally by gas pressure and does not apply to those in which water pressure is the chief factor in producing oil. A number of reports [38] by investigators of the Bureau of Mines have attempted to point out some of the relations between oil and gas during production.

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[38] Ambrose, A. W., Engineering applied to oil-field production problems (speech at Denver meeting): Indep. Oil Man's Assoc., Handbook of petroleum, 1921, p. 314; Reports of Investigations, Bureau of Mines, Serial No. 2165, September, 1920. Research in petroleum (paper before technical sessions of American Petroleum Institute, Chicago, Ill.): Proc. Am. Petrol. Inst., Dec., 1921, p. 32. Beal, C. H., and Lewis, J. O., Some principles governing the production of oil wells: Bull. 194, Bureau of Mines, 1921, 58 pp. Swigart, T. E., Experiments on back pressures on oil wells, extract from Tech. Paper 322, Bureau of Mines, read before the Denver meeting of the American Association of Petroleum Geologists, Oct. 28, 1922. Swigart, T. E., and Bopp, C. R., Experiments on back pressure on oil wells: Tech. Paper 322, Bureau of Mines, 1923. (In press.)

In general, the expansive force of natural gas absorbed in and associated with petroleum underground is thought to be the medium which causes oil to flow from more remote areas of the producing sand to a well. Natural gas in an oil sand is under pressure varying from approximately atmospheric to hundreds of pounds per square inch, and since an oil well is a point of diminished pressure, the gas flows toward it. Because of their intimate association, the flow of gas causes a simultaneous flow of oil. All oil producers know that when the gas pressure and therefore the quantity of gas in an oil field has diminished to a low point, the production of a well by natural drainage is almost negligible. At such times operators [39] resort to artificial stimulation of production, such as by vacuum pumping.

CONTROL OF GAS.

If more gas than is needed is used for producing oil, a direct waste of gas and an indirect waste of oil result, as so-called "dead oil" that can never be recovered by ordinary producing methods is left underground in the oil sand. To recover this oil would necessitate costly artificial methods which some day may include mining of the sands. Lewis [40] has estimated that ordinarily from 80 to 90 per cent of the original oil in an oil sand is left underground when a well is abandoned. If, by new methods of controlling the flow of gas, this percentage could be reduced by 10 or 20 per cent (and it seems reasonable to believe that even greater reductions may be possible), the benefits from increased oil recovery can not be overlooked. For this reason, if an operator permits more gas to flow into the well than is needed to bring the oil into the hole, he is wasting a commodity that the Government is anxious to conserve.

Swigart and Bopp [41] found that when handled in different ways, the pumping wells upon which they experimented would produce varying amounts of gas with the oil. A computed factor, termed the "gas factor of oil production," which in reality was the number of cubic feet of gas produced with a barrel of oil, was used as the measure of efficiency in producing oil in those experiments. Thus, the smaller the gas factor of oil production, the smaller would be the quantity of gas used in producing each barrel of oil, the slower the decline in rock pressure and depletion of the gas, and, consequently, the greater the ultimate quantity of oil that each well will produce.

[39] Lewis, J. O., Methods of increasing the recovery of oil from wells: Bull. 148, Bureau of Mines, 1917, 128 pp.; Comparative values of flooding and air pressure methods: Nat. Petrol. News, vol. 14, Apr. 5, 1922, pp. 83–84, 87–88. Smith, L. E., Opinions on the flooding method: Nat. Petrol. News, vol. 14, Feb. 15, 1922, pp. 67–68.

[40] Lewis, J. O., Methods of increasing the recovery of oil from wells: Bull. 148, Bureau of Mines, 1917, pp. 25–28.

[41] Swigart, T. E., and Bopp, C. R., Experiments on back pressure on oil wells: Tech. Paper 322, Bureau of Mines. (In press.)

Investigation has shown [42] that, in general, the number of cubic feet of gas per barrel of oil will vary between wide limits. With present methods of handling producing wells, under which no special efforts have been made actually to cut down the gas production, the gas factors of oil production are somewhat as follows:

Type of well.	Cubic feet of gas per barrel of oil.	Remarks.
Flowing wells	300 to 4,000 or more.	Gas wells that only spray oil are not considered. Wells that flow through tubing in general are most efficient. From 1,000 to 3,000 cubic feet per barrel are the common gas factors of flowing wells.
Pumping wells, natural	200 to 2,000 [1]	700 to 1,200 cubic feet per barrel.
Pumping wells on vacuum	1,000 to 4,000	Estimated from meager data.

[1] These factors are for more or less average wells. Many unusual wells will fall above the upper limits, but few fall below the lower limits.

METHODS OF REDUCING THE AMOUNT OF GAS PRODUCED WITH OIL.

HOLDING BACK PRESSURES.

Experiments by the Bureau of Mines on two wells in Osage County, Okla., and by operators in various fields warrant the conclusions that fairly high back pressures can be held on many pumping wells without cutting down their oil productions and that back pressures approaching closely the potential rock pressure of the reservoir can be held on some wells at a sacrifice of only small percentages of their present daily oil productions. These experiments have indicated that holding some back pressure on pumping wells cuts down the amount of gas produced per barrel of oil.

PROCEDURE.

Back pressures may be held either by closing in the casing head and producing casing-head gas through pressure-regulating valves or by maintaining certain fluid levels in a well. Tests by the Bedrock Petroleum Co. on a well in Magoffin County, Ky., reported to the Bureau of Mines by the president, Mr. G. S. Davison, showed that when the fluid was pumped down and the sand exposed the well produced about 18,000 cubic feet of gas daily, whereas with 338 feet of fluid in the hole it only gassed at the rate of 3,000 feet per day, thus indicating the effectiveness of a high fluid column in curtailing gas production.

In the light of results obtained so far, it appears that increasing the efficiency of recovery, that is, decreasing the number of cubic feet

[42] Swigart, T. E., and Bopp, C. R., work cited.

of gas produced with each barrel of oil, will involve slowing down the rate of oil and gas production of a well. Back pressure, whether caused by gas pressure in the casing or the fluid pressure of a high oil column, is certain to retard the rate at which oil enters the hole and thus cut daily production. However, it would seem that without some back pressure, gas in seeking the point of diminished pressure (the well) rushes through the sand and pushes some oil before it, but also it soon opens up channels of relatively low resistance through which excessive amounts of gas can escape without moving oil. Thus observations in the field, supplemented by laboratory work by Mills,[43] indicate that to prevent gas from by-passing oil in certain parts of the oil sand the rate of extraction must not be too high.

APPLICATION OF BACK-PRESSURE METHOD.

Certain practical considerations regarding holding back pressures on wells can not be overlooked. Swigart and Bopp say:[44]

> The practical application of the back-pressure method is limited, however. The amount of back pressure that can be held also depends on a number of variable factors difficult to weigh until actual experiments are made. The operator who wishes to hold some back pressure on his oil wells and thus delay the exhaustion of natural gas from his property must consider the possible effect if his neighbor continues producing at lower pressures or at atmospheric pressure. It is believed that, under ordinary circumstances, an operator who held back pressures of more than 5 or 10 pounds on his line wells which were offset at the usual distances would subject himself to a possible loss of oil by migration to a neighbor who was producing at atmospheric pressure. The operator's property would be an area of high pressure as compared to the offsetting properties if they were producing at atmospheric pressure and gas and oil would tend to flow away from the operator's line wells toward his neighbors rather than from the area between the line wells toward his own.
>
> An agreement between all operators in a field whereby everybody held some pressure would be most desirable. This would result in sustaining the rock pressure at comparatively high levels for many years in fields that now practically exhaust their gas within a very few years. It must be conceded that such agreements are not without the realm of possibility, for there have been numerous types and instances of cooperative agreements among oil operators whereby certain policies and cooperative operating methods have been adopted for the common benefit of all concerned. For instance, offsetting agreements, both as regards distance and time of drilling, the proration of oil production, the holding of vacuum or delaying the time of putting the vacuum, the swabbing of wells in certain localities, are all practices that are commonly made the subject of operating agreement. One of the most noteworthy examples of a production agreement was understood to have been made by the Mexican Petroleum, Mexican Seaboard, and Mexican Gulf Cos., operating in the Toteco-Cerro Azul pool, Mexico. On a number of successive occasions each of these concerns agreed to limit its daily production to a stipulated amount, in order to lengthen the productive life of the properties. Surely, if operators could be assured that concerted action in the matter of holding back pressures, properly regulated, would result in adding materially to the ultimate recovery of oil from their properties with only small decrease in present daily production they would give serious consideration to such a practice.
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> In general, back pressures of considerable magnitude can be held on isolated wells, on the "inside" wells of large tracts, or on all wells of isolated tracts without seriously cutting down the present daily production and without danger of loss of oils by migra-

[43] Mills, R. Van A., Experimental studies of subsurface relationships in oil and gas fields: Econ. Geol., vol. 15, No. 5, July–August, 1920, pp. 398–421: Movements of oil through sands: Econ. Geol., vol. 16, No. 2, March, 1921, pp. 124–141. See also Lewis, J. O., Methods of increasing the recovery from oil sands: Bull. 148, Bureau of Mines, 1917, pp. 8–31.

[44] Swigart, T. E., and Bopp, C. R., work cited.

tion. Perhaps the most difficult case to handle is that of the operator who has a relatively small tract on which every well is a line well. Back pressures higher than enough to collect the casing-head gas can not be recommended to such an operator unless his neighbors will put on pressure also. If an operator owns a lease of 80 acres or more on which he has inside locations he could probably afford to hold his inside wells under pressure and his line wells at the same, or a little above, the pressure of his neighbor's wells if they were producing at low pressure. Experiments will determine the advisability of this. The advantages gained in "keeping up" the rock pressure on his own property are such that he could afford to chance any small loss of oil and gas by migration past the barrier of line wells.

As long as wells are not closely offset by other wells producing at atmospheric pressure or a low back pressure, high back pressures are unlikely so to decrease the present daily oil production that the operator can not afford to sacrifice that decrease if it will greatly increase his ultimate production.

REDUCING PRODUCTION OF GAS WITH OIL.

The possibility of reducing the amount of gas produced with each barrel of oil by a flowing well is one now engaging the attention of the bureau's engineers. Most operators realize the need for holding some back pressure on large flowing wells. If the strong wells are allowed to flow without restraint they often cause untold damage by drawing in water, sanding up, cutting out casing with sand, cutting away the casing seat, and forming emulsions. Reducing the flow of strong flowing wells that tend to make water or sand, or, if very strong wells, reducing the flow on general principles as a safeguard against possible damage to the hole, is good practice. In most fields back pressure on flowing wells is held by flowing them through chokers (flow nipples or "beans") which are inserted in the flow line. Choking down a well tends to cause it to flow more steadily and protects it against the violent flowing action caused by high-pressure gas pockets reaching the hole. The exact effect on the efficiency of production of holding back pressure on flowing wells at the casing head has not been clearly established, although data at hand indicate that choking down a flowing well may decrease its efficiency unless additional measures are taken to control the flow, perhaps at some point in the well.

The number of cubic feet of gas produced with each barrel of oil is the true measure of efficiency of production of a well, because this factor takes into account both oil and gas productions. The most efficient well is the one operated so as to produce the minimum amount of gas per barrel of oil.

FLOWING WELLS THROUGH TUBING.

Flowing wells through tubing is recommended. Operators in the new southern California fields have found it advantageous to produce large flowing wells through tubing, even from the time they are first drilled in. Wells flowing up to 4,000 barrels per day are being produced through 3-inch tubing in these fields, while 1,000 to 2,000 barrel wells are flowed through 2-inch tubing. The gas factors of oil production of some of these wells of 2,500-barrel daily production or even more are as low as 640 cubic feet per barrel, which is lower than the gas factors of some other wells flowing through casing, on which records are available.

It is believed that a great deal of effective work in increasing the recovery of oil may be done by skillful manipulation, so that each cubic foot of gas may be utilized to lift the maximum amount of oil to the surface. Flowing wells through tubing with the tubing packed off at some certain level in the well, not necessarily at the top of the sand or at the casing head, and regulation of the flow, controlled by experiments involving the measurements of oil and gas, should result in increased production efficiency. Devices to flow wells on their own gas pressure, even after they have declined in rock pressure to relatively low levels, will doubtless be developed. Such devices combine efficiency of operation with low lifting costs.

ASSISTANCE BY BUREAU OF MINES.

The bureau's engineers feel that increasing the efficiency of oil production by controlling the natural gas produced with it is one of the most important problems in the producing industry. Therefore the bureau is anxious to assist operators in making tests which will develop more efficient production methods. In conducting such tests, the proper interpretation of experimental data, the necessity for full and accurate readings, and the control of tests with regard to results being obtained are of utmost importance. The bureau's engineers in the field will be ready to discuss with operators the possible solution of their problems and the results of tests being carried on. When possible, they will assist in planning and performing experiments.

The importance of increasing the recovery of oil from public lands, which can only be brought about by the application of the most efficient production methods known, leads the department to offer every encouragement to its lessees to use such methods. Whenever possible, the supervisory force will assist operators in negotiating suitable operating agreements with neighbors, should such agreements be essential to the successful conduct of the work.

LOSSES OF OIL FROM TOO RAPID EXTRACTION.

The losses of oil covered in this section are underground losses that result from too rapid extraction of oil and gas, principally from flowing wells. Observation of drill cuttings, combined with drillers' reports of the hardness and productivity of oil sands as they are penetrated, has proved that oil sands are seldom, if ever, of uniform porosity and texture. Lewis[45] has pointed out that "the more irregular the texture and the character and proportion of contents of a sand, the greater will be the waste of energy," due to the "by-passing" of gas and the leaving of oil behind in the sand.

Plate XV, *A* and *B*, has been prepared by Mills[46] to illustrate the conditions set up in an oil and gas sand in the base of which water exists. As explained on page 91, when a well is produced too rapidly gas tends to travel to the well faster than oil, which is left behind in the sand. As a rule, the tighter portions of the sand tend to retain the oil, while the porous streaks serve as channels through which some oil and an excessive quantity of gas travel.

An equally serious loss of oil may be occasioned by the too rapid extraction of oil and gas from an oil sand which carries water in its lower portions. Plate XV, *A*, shows what is known as "water coning" in an oil well. Allowing flowing wells to flow without restriction, swabbing, or fast pumping such as may be done with air-lift or large pumping outfits often results in water coning. When fluids are withdrawn rapidly, the water surface may gradually rise to form a cone with the well as the apex, and thus cut off the oil. Eventually the cone assumes such proportions that little or no surface of oil sand is exposed at the well.

Plate XV, *B*, shows still another effect of too rapid extraction of oil when water is associated with it in the sand. In this experiment, oil formerly was retained in the upper portion of the sand, but as fluid was extracted at the right, water advanced through the coarse portions of the oil sand ahead of oil in the lenses of finer sand. If such conditions occurred underground, oil so held could seldom be recovered. These experiments[47] and field observations have led to the belief that large amounts of oil that can never be recovered by wells are trapped in oil sands. Detailed laboratory studies of the movements of fluids through sands have been made by Mills, and his findings should interest oil producers, as many of his conclusions have practical application.

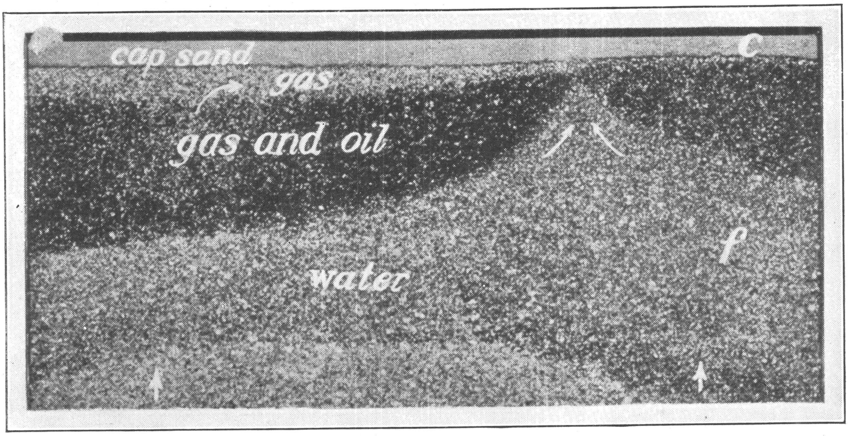
SELF DEEPENING OF OIL WELLS.

A strong flowing well that is drilled into the oil sand only a few feet will often deepen itself or "drill itself in" if it is allowed to flow unrestricted. The self-deepening of oil wells is especially dangerous because water may be drawn in from the lower portions of the oil

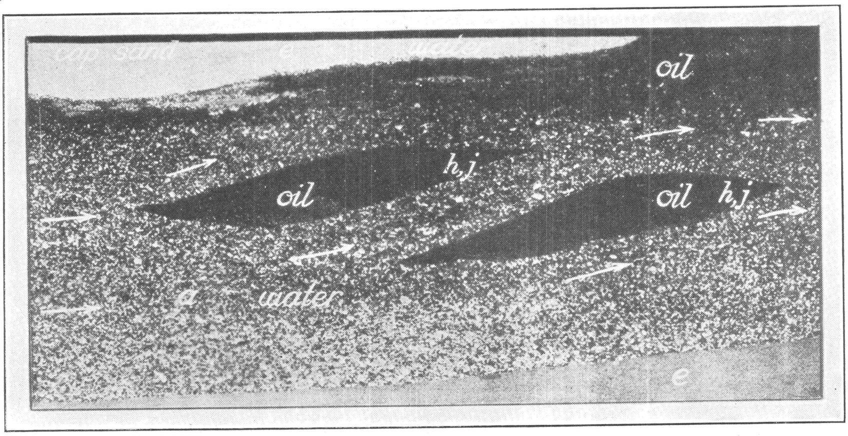
[45] Lewis, J. O., Methods of increasing the recovery of oil from wells: Bull. 148, Bureau of Mines, 1917, pp. 16–25.

[46] Mills, R. Van A., Experimental studies of subsurface relationships in oil and gas fields: Econ. Geol., vol. 15, No. 5, July–August, 1920, p. 398; Relations of texture and bedding to the movements of oil and water through sands: Econ. Geol., vol. 16, No. 2, March, 1921, p. 124.

[47] Mills, R. Van A., Relations of texture and bedding to the movements of oil and water through sands: Econ. Geol., vol. 16, No. 2, March, 1921, pp. 124–141.



A. ILLUSTRATION OF "CONING" OF WATER IN BASE OF SAND, CAUSED BY RAPID EXTRACTION OF THE OIL (AFTER R. VAN A. MILLS): *c*, CAP SAND; *f*, PAY SAND.



B. ILLUSTRATION OF ADVANCEMENT OF WATER AHEAD OF OIL THROUGH COARSE PORTIONS OF OIL SAND (AFTER R. VAN A. MILLS): *a*, SAND OF COARSE TEXTURE; *e*, SAND OF EXTREMELY FINE TEXTURE; *h*, *j*, SAND OF FINE TEXTURE.

sand or from a bottom-water sand, should the bottom water be separated from the oil sand by only a thin impervious layer. A strong flow of oil and gas may act on the principle of the injector and thus pull water into the well from some distance. Scott [48] found that several wells in the Haynesville oil field, La., deepened themselves into water and therefore warned operators against drilling too far into the sand on the lower parts of the structure and flowing wells "wide open." The injuries possible to a well from self-deepening are numerous and of such character that the full production may never be regained, while the ultimate recovery of oil and gas is reduced.

In fields where danger exists of drawing in water by allowing a well to flow too rapidly, wells should be choked and only a portion of their potential production taken. Likewise, fast pumping of wells which produce water may not always be advisable, for the extra cost of operation and upkeep may more than offset the additional oil recovered. The tendency is usually to increase the proportion of water (as compared to oil) by rapid extraction; therefore operators should investigate carefully the condition of their properties before deciding to flow wells open or pump them hard.

PRODUCTION FROM TWO OR MORE OIL HORIZONS.

In many fields of the United States several horizons produce oil in varying quantities. It may be possible to drain more than one sand into the same hole, but if this is not practical, separate wells may with profit be drilled to the less productive sands.

To penetrate the lower sands naturally requires drilling through the upper ones. These sands should be carefully logged and a test made to determine their probable value as producers. At the time of drilling, it may not be profitable to produce from certain upper sands, but at some later date it might be highly desirable to obtain the oil from these sands without the expense of an additional well. Blank pipe, which can later be perforated to obtain the production, may be set opposite the upper productive sands. Such procedure should not be followed, however, if it is possible for oil from these upper strata to migrate into other porous formations or if water exists between the upper and lower sands. The oil sands and porous formations should then be mudded off or additional casing used to protect them.

If draining two or more oil sands into the same well is practical, that method is desirable for the operator because of the saving in the cost of extra wells. The department, in general, will approve draining more than one sand into the same well if local conditions

[48] Scott, W. W., and Stroud, B. K., The Haynesville oil field: Louisiana Dept. of Conservation Bull. 11, 1922, 26 pp.

are such that this practice will exploit the two or more sands satisfactorily, and the quality of oil is such that the royalty will not be lowered by mixing the two grades of oil. This matter, however, interests the Government vitally and deputy supervisors will study conditions in each field before a definite local policy is adopted.

SIMULTANEOUS PRODUCTION OF OILS OF DIFFERENT GRAVITIES.

The gravity of oil produced from different sands often varies. By producing a high and a low gravity oil together the operator may lose the advantage of any premium paid on high-gravity oil. However, this frequently works to the operator's advantage, as the purchaser may take the combined oils, whereas he would not run the heavy oil. Since the Government's royalty scale is based on gravity, operators will not be allowed to mix light and heavy oils deliberately in a well in order to take advantage of the lower royalty scale on the heavier crude. The oils must be produced separately, if mixing them adversely affects the royalty scale or the price received by the Government for its royalty.

PARAFFIN DEPOSITS.

In many fields the collection of residues of paraffin, heavy ends of the oil, and mineral matter on the exposed surfaces of oil sands constitutes a serious operating objection to draining more than one sand into the same hole. To delay the deposition of such residues, it is desirable so to tube the well that the producing sands are always covered with oil. So-called paraffin deposits may very seriously affect the oil production of a well, and often result in large quantities of otherwise recoverable oil being left in the sand. After wells decline in production, the pump usually must be placed at such a point that the fluid level is lowered below the top sand. By thus exposing the sand to encrusting by residues, the ultimate recovery of oil may be greatly reduced.

In some Pennsylvania fields where wells are producing from two sands, the surface of the upper sand is kept covered with fluid by the use of a special packer and a short liner set opposite the top sand. This liner either extends from the bottom sand to some point above the top sand, or a short liner of two or three joints is supported by a packer which expands just below the top sand. The liner is perforated at some point above the oil sand so that the oil can not escape until it fills the space between the wall of the hole and the liner. By this method, the pump can be placed low enough in the hole to keep a low head of fluid on the bottom sand and yet keep the top sand continually covered with fluid. To a limited extent, this practice permits the draining of two sands into the same well, especially when one sand is such a small producer that separate wells to drain it are not profitable. In general, if conditions are such that paraffin or similar residues collect on the oil sands, the draining of two sands into the same hole will not be entirely practicable and separate wells will prove more satisfactory.

COMPUTATION OF GOVERNMENT ROYALTIES.

Shallow oil sands of relatively small production are found in many oil fields overlying deeper and more productive horizons from which the major portion of the production is obtained. These shallow sand wells often produce very small quantities of oil, but because the cost of drilling and operating is small it may be profitable to drill and operate them. Consider, for example, that a certain operator had five deep wells whose average daily production was 200 barrels. If this operator should drill five additional shallow wells which averaged 5 barrels per day each, his average daily production per well, including the five small wells, would be 102.5 barrels. The five deep wells alone would bring the Government a royalty of 5,268 barrels per month on the basis of a 30-day month and oil over 30° B. gravity, but the ten wells, five deep and five shallow, would bring the Government only 4,686 barrels of royalty oil per month.

The Government, realizing the possible hardship to its lessees of operating small wells at the regulation royalties, has in a spirit of fairness provided for their relief by incorporating in most leases a clause which stipulates that:

> Such royalties shall be subject to reduction whenever the average daily production of any oil well shall not exceed ten (10) barrels per day, if in the judgment of the lessor the wells can not be successfully operated upon the royalties fixed herein.

In view of the Government's recognition of this principle, the department does not wish lessees deliberately to drill wells of small production to reduce the average production per well of much larger wells and gain a corresponding reduction in royalties. When two or more producing horizons exist in one field, and the production from wells draining one or more of them is relatively insignificant as compared to the production from the main producing sands or horizons, the lessees will be required either to drain the sands of small production into the same wells that drain the main producing sands, if this is feasible, and compute the royalties in the usual manner, or to drill separate wells to the sands of small production and compute the royalties of the two groups of wells separately. Thus, under the circumstances cited above, if five wells produced 200 barrels per day each and five additional shallow wells were drilled that averaged 5 barrels per day each, the royalty would not be computed on the basis of 10 wells of average daily production of 102.5 barrels, which would net the Government a monthly royalty of 4,686 barrels. On the contrary, the operator would be compelled to pay 5,268 barrels of royalty per month on the five large wells (assuming a 30-day month and oil of over 30° B. gravity), and, in addition, he would pay a monthly royalty of probably 12½ per cent on the five small wells, or 93.75 barrels of royalty per month.

This should not be interpreted to mean that operators who happen to drill both large and small wells into the same sand will not be accorded the privilege of averaging their production per well for computing royalties. It is meant to apply where the average production from one sand or horizon is so much smaller than that from the main horizon that to drill wells to the shallow sand obviously would be for the purpose of reducing royalties.

WASTES IN THE PRODUCTION OF NATURAL GAS.

Natural gas is a valuable commodity in most localities. However, in some oil and gas fields so much gas has been produced, particularly with oil, that it has been regarded as a nuisance.

Gas is an ideal fuel and is desired as such by every operator. Moreover, it is extremely valuable as a producer of gasoline and much is now being saved. Unfortunately, in the early days more gas was produced than was needed and much was wasted.[49] As early as 1910 oil producers were accused of gross waste of gas when producing oil. In the proceedings of the fifth annual meeting of the Natural Gas Association of America the following statement appears:

> Many gas sands are entirely free from oil, while gas in varying quantities is almost always found in oil-bearing sands. All flowing wells are also gas wells of more or less volume. It is not uncommon to find an oil well producing 50 to 100 barrels of oil also producing from five to ten million feet of gas per day, the gas at a low rate being four or five times the value of the oil.
>
> The oil producer in his insane greed for riches, fortified by the long-established custom, is the principal transgressor. Having no immediate market for the gas of the upper sands, he allows it to exhaust itself in the air until the pressure is reduced to a point where he can resume drilling; then he penetrates the oil sand where he may and frequently does develop a well producing from 5 to 10 barrels of oil and from five to ten million feet of gas, the latter having a fuel value at a very low figure per thousand feet of many times the value of the oil. In nearly every new oil development the oil wells produce gas from the oil sand in considerable quantities. The oil producer, if in need of power, uses what gas he requires for power purposes and turns the balance loose, looking on any surplus gas as a nuisance, to be gotten rid of, claiming the right to do as he pleases with his own product, and in the absence of legislation on the subject he seems to be acting within his rights.

EXAMPLES OF WASTE.

Perhaps one of the most spectacular wastes of natural gas occurred in the Cushing field, Okla., in 1912 and 1913. Conservative estimates place the waste of gas in this field at 100,000,000 cubic feet or more

[49] Arnold, Ralph, and Clapp, F. G., Wastes in the production and utilization of natural gas and methods for their prevention: Tech. Paper 38, Bureau of Mines, 1913, 29 pp. Blatchley, R. S., Waste of oil and gas in the Mid-Continent fields: Tech. Paper 45, Bureau of Mines, 1914, 54 pp.

per day for a time. Large flowing wells which produced from 1,000,000 to 10,000,000 cubic feet of gas daily were allowed to flow unchecked; the oil alone was collected and the gas escaped into the atmosphere. Large amounts of gas are being wasted in practically every oil field. In the Salt Creek field, Wyo., and the Signal Hill, Huntington Beach, and Santa Fe Springs fields of southern California millions of feet of gas and quantities of natural-gas gasoline are being blown into the air daily.

Operators and the public have been educated to consider the willful waste of natural gas little short of criminal. However, there are still operators who do not recover their casing-head gas. For example, one oil man believed that the small amount of back pressure which would be caused by installing a gas separator on the flow lines would kill his flowing wells. Rather than chance the use of a gas trap, this operator permitted some four or five million cubic feet of gas to waste into the air each day. This operator had to buy 250 barrels or more of fuel oil each day at $2 per barrel to supply the fuel requirements of his drilling and pumping wells. Properly used, the natural gas which this operator allowed to escape, would have saved from three-fourths to four-fifths of his fuel bill. Later, gas traps were placed on some of these wells after they had settled to pumping wells, and the casing-head gas trapped from six pumping wells supplied sufficient fuel for 30 oil wells pumping on the beam, and for lighting and heating the field offices, warehouses, shop, and dwellings. Casing-head gas from many other wells was still being wasted, but the fuel saving, even at this stage of development, was estimated at more than $25,000 per annum.

F. B. Tough[50] states:

> During the fall of 1919, an investigation was made to determine * * * the amount of gas wasted in the Lance Creek field, Wyo. The total gas wasted up to the time of the investigation was estimated at 7,452,000,000 cubic feet. This gas was not a by-product of oil production but was the result of gas wells "going wild." By way of comparison, the thermal equivalent of the gas would be represented by about 250,000 tons of coal or 1,000,000 barrels of fuel oil.

In the Salt Creek field, Wyo., large amounts of natural gas are produced with the oil. In fact, a majority of the wells in this field flow by gas pressure. Bureau of Mines engineers believed the gas production to be about 58,000,000 cubic feet a day in November, 1922. The estimated amount of residue gas used as fuel in this field is about 14,000,000 cubic feet, and in addition, about 1,500,000 cubic feet of raw gas from oil wells is used in field operations. Until recently, no use was made of the rest of the gas produced, and the daily loss of gas in the Salt Creek field was probably about 42,500,000 cubic feet. If all the wells in the Salt Creek field had been opened to

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[50] Tough, F. B., Report of operations: Rocky Mountain Petroleum Association in cooperation with the Bureau of Mines. Obtainable from F. B. Tough, 206 Customhouse, Denver, Colo.

their normal production the gas yield probably would have been trebled and the waste of gas would have increased nearly four times.

ESTIMATED WASTES OF NATURAL GAS.

In 1921 the total amount of natural gas consumed in the United States amounted to 662,052,000,000 cubic feet.[51] This gas came both from gas wells and the casing heads of oil wells. No records are available of the percentage of this production furnished by either class of wells. The total oil production for 1921 [51a] was 472,183,000 barrels. Assume that an average of 1,000 cubic feet of gas was produced per barrel of oil. The estimated production of casing-head gas alone reaches the astounding figure of 472,183,000,000 cubic feet. Some of this gas was used locally for fuel on the leases and was not reported. However, this is no doubt more than offset by the large amount of gas from gas wells, probably half or more, which is included in the Geological Survey report. If half of the gas reported was produced by gas wells, the difference between 472,000,000,000 and 331,000,000,000, or 141,000,000,000 cubic feet, represents the estimated quantity of casing-head gas lost in 1921. The yearly loss of dry gas from gas wells is also large. These figures give an idea of the magnitude of the natural-gas waste in the United States. It seems probable that from about one-third to one-half of all the gas produced is wasted.

CONSERVATION MEASURES OF BUREAU OF MINES.

The Bureau of Mines is concerned over the waste of dry (residue) gas from public lands and is making arrangements to divert the present waste gas to a useful purpose. Unfortunately, the isolation of some of the Wyoming fields in which the Government owns land complicates the problem of marketing the gas. In fields where a market for the gas exists, all operators on public lands will be expected to lay gathering lines to their oil wells, in order to recover casing-head gas if it can be used and to dispose of the dry residual gas if a market is available.

LOSSES OF NATURAL GAS ON THE LEASE.

Losses during the transportation and use of natural gas under high pressure on leases often constitute a considerable waste which could be eliminated at little expense. In this discussion "high pressures" may be interpreted to mean pressures of 20 pounds per square inch or over.

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[51] U. S. Geological Survey, Natural gas in 1919–1921: Mineral Resources, 1921, part II, pp. 335–369.
[51a] U. S. Geological Survey, Petroleum in 1919–1921: Mineral Resources, 1921, part II, pp. 262–265.

GAS TRANSMISSION-LINES.

Gas is a valuable fuel in the field and is frequently piped to rigs, boiler houses, forges, dwellings, and other places for the generation of power and for heating and lighting. To pipe gas about a lease under a pressure of 100 pounds or over is not at all unusual. Gas transmission lines often consist of 2-inch "secondhand" pipe, carelessly put together and laid on the surface. These lines may vary in length from a few hundred feet to several miles. Temperature changes produce contraction and expansion stresses which cause the pipe to "creep," thus weakening the joints and resulting in leaks. Teams and motor trucks loaded with heavy equipment are often driven over the gas lines. In consequence, pipes may break at the joints or split along seams. Moreover, lease gas-lines are seldom coated with asphalt paint or similar protective material and the corrosive effect of water and some soils may bring about leaks.

Small openings allow great losses of gas when the gas in the line is under high pressure. Table 2 has been compiled to show the approximate losses that result from the escape of gas under various pressures through small openings of given diameter. From this table, it is evident that a few very small leaks in high-pressure gas lines will result in the loss of almost unbelievably large amounts of gas. Obviously, lessees should take every precaution to keep gas lines in good condition and prevent leaks, as small losses of such character may aggregate many thousands of feet of gas on a single lease in a year.

Good lead lines, tight fittings, and sufficient drips and other similar appurtenances of a well-handled lease save gas and lower the operating costs.

TABLE 2.—*Approximate volume in cubic feet of gas lost in 24 hours through small openings.*

Specific gravity of gas.	Line pressure, pounds per square inch.					
	10	20	50	80	100	125
Diameter of opening, one sixty-fourth inch; section area, 0.000192 square inch.						
0.6	156	221	418	613	743	903
0.8	135	191	362	531	644	783
1.0	121	171	324	475	576	700
Diameter of opening, one thirty-second inch; section area, 0.00077 square inch.						
0.6	636	902	1,700	2,480	2,990	3,660
0.8	551	782	1,470	2,140	2,600	3,180
1.0	493	699	1,320	1,920	2,320	2,840
Diameter of opening, one-sixteenth inch; section area, 0.00307 square inch.						
0.6	2,530	3,590	6,750	9,900	12,000	14,590
0.8	2,190	3,110	5,850	8,590	10,400	12,630
1.0	1,960	2,780	5,240	7,670	9,300	11,300

LOSSES FROM THE USE OF HIGH-PRESSURE GAS.

High-pressure gas is used for firing oil-field boilers and forges to the exclusion of low-pressure gas for the same purpose in most oil fields. Many operators object to the use of low-pressure gas for field operations, claiming that it delays operations because of slower steam generation. In general, this has been true because attempts have been made to use low-pressure gas with the same equipment and under the same conditions as high-pressure gas. For example, the fact that a larger pipe is required to deliver a given amount of gas at a low pressure than would be required to deliver the same volume of gas at a high pressure is often overlooked. The initial pressure required to deliver 6,000 cubic feet of gas per

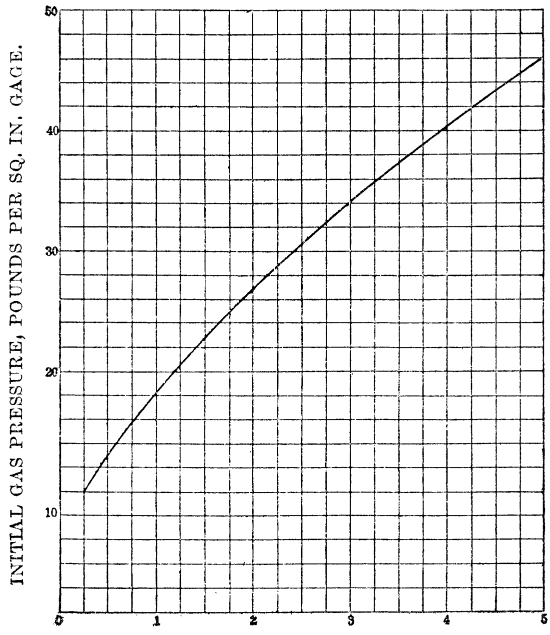

FIGURE 7.—Curve showing initial pressure necessary to deliver 6,000 cubic feet of gas per hour at 6-pound terminal pressure through various lengths of 2-inch pipe. (From Bureau of Mines report on low-pressure gas burners in Mid-Continent Year Book, 1921.)

hour through a 2-inch pipe varying in length from one-fourth to 5 miles is given by the curve in Figure 7. This volume of gas is ample to supply the average drilling well. By using slightly larger gas lines it is possible to obtain enough low-pressure gas to carry on the operations performed by high-pressure gas.

SUBSTITUTION OF LOW-PRESSURE GAS.

High-pressure gas is often purchased for lease-operation purposes at considerable expense when lease is actually producing sufficient low-pressure gas to supply all the demands if properly used. On one lease in Osage County, Okla., enough low-pressure gas to operate 20 drilling wells was being allowed to escape into the air from the casing heads of pumping wells that were only a few hundred yards distant from drilling wells for which high-pressure gas was being purchased.

The bureau [52] found after tests that low-pressure gas could be used as satisfactorily as high-pressure gas under oil-field boilers by using equipment adapted to low-pressure gas burning. As a result of these tests many operators, particularly those in Osage County, Okla., now use low-pressure gas for all lease operation, including drilling.

Losses from the use of gas under high pressure are, of course, correspondingly greater than those that would result under the same conditions at low pressures. Leaks that are insignificant at low pressures become important at high pressures. Moreover, with the methods commonly used in the field in burning high-pressure gas under boilers combustion is incomplete and frequently more gas is forced into the fire box than can possibly be burned.

SUBSTITUTION OF HIGH-PRESSURE GAS FOR STEAM OR COMPRESSED AIR.

Additional waste of high-pressure gas occurs when operators use gas directly in cylinders instead of steam or compressed air to drive engines, pumps, and similar equipment. The gas is not used as fuel under these circumstances, but the pressure of the gas is utilized for the direct operation of prime movers.

In one Wyoming field high-pressure gas was recently being used to operate machinery in this manner, the exhaust gas being dissipated into the air. High-pressure gas has also been used in drilling engines. The department will not permit gas to be used for carrying on drilling operations or, as a regular practice, for pumping. In extreme cases a well may constitute a fire hazard and this use of gas may be necessary in carrying on operations such as the completion of a well. It should be emphasized that such use is of extreme and temporary nature, for if wells are properly handled it is usually possible to generate steam in the near vicinity without great danger of igniting them.

NATURAL GAS FOR LIGHTING.

Flambeau lights, which are prohibited by regulation in most States, are a source of waste that should be eliminated, except in emergencies. The department encourages the use of turbo-generator

[52] Brewer, G. S., Youker, M. P., and Beecher, C. E., The use of low-pressure gas burners in oil-field boilers: 4th ann. rept., Mid-Continent Oil & Gas Asso., Tulsa, Okla., 1921, pp. 76–121. Youker, M. P., Use of low-pressure gas burners in field boilers: Reports of Investigations, Serial 2,329, Bureau of Mines, Feb., 1922.

sets and electric lights at rigs and at other necessary points in the field. Although the first cost of these sets is more than that of piping for gas lighting, their efficiency and safety are far greater. On one Oklahoma lease, a drilling well used an average of 8,400 cubic feet of gas per day for operating the forge and a generator for electric lights for the rig, while another well, lighted by flambeau lights, used a daily average of 24,477 cubic feet of gas for forge and lighting, or three times as much. The daily amount of gas required to operate the flambeau lights and forge on the second well was almost equal to half the amount of gas required to operate the boiler for drilling the well.

Since sparks from a turbo-generator will ignite explosive mixtures of gas and air, keeping such an outfit at a safe distance from a flowing well is as important as "moving the boiler back" before drilling in.

The bureau is encouraging the careful use of gas on the lease, and in particular the use of low-pressure gas, not only because less waste occurs in the transportation and utilization of low-pressure gas but also because large volumes of low-pressure gas are now wasted from the casing heads of oil wells.

LOSSES OF NATURAL-GAS GASOLINE.

The evaporation of natural-gas gasoline into the air has been one of the greatest preventable losses in oil-field history. As is the case with most oil-field losses, the waste can hardly be estimated, either by barrels or by money value. However, some examples may emphasize the magnitude of these losses.

STATISTICS ON THE PRODUCTION OF NATURAL-GAS GASOLINE.

The first natural-gas gasoline was produced in the United States at Titusville, Pa., in 1904, when 4,000 gallons were made in one small plant.[53] Natural-gas gasoline from all other gas produced in the United States was being wasted. By 1911, 7,426,000 gallons of gasoline were obtained from 2,476,000,000 cubic feet of natural gas; in 1921, 449,934,400 gallons of natural-gas gasoline were obtained from approximately 479,618,194,000 cubic feet.

Figure 8 shows that during 1911 to 1921, inclusive, although the production of oil and of natural gas was increasing 2.13 and 1.67 times, respectively (curves 3 and 4), the amount of natural-gas gasoline produced and the amount of natural gas treated for gasoline increased 63.7 and 189 times, respectively (curves 2 and 1). Thus, while no accurate figures on the losses of gasoline through failure to treat natural gas are available, it is estimated that since the first natural-gas gasoline was manufactured in 1904 at

[53] Burrell, G. A., Seibert, F. M., and Oberfell, G. G., The condensation of gasoline from natural gas: Bull. 88, Bureau of Mines, 1915, p. 9.

least 2,500,000,000 gallons of gasoline, or twice the amount actually recovered since that time, have been wasted. Moreover, it should be added that this estimate is based on the amount of natural-gas gasoline recovered in 1921, which is but a part of the total amount of natural-gas gasoline actually produced by wells during that year. In fact, it seems probable that from 25 to 50 per cent of the total amount of natural-gas gasoline produced by wells is lost at present.

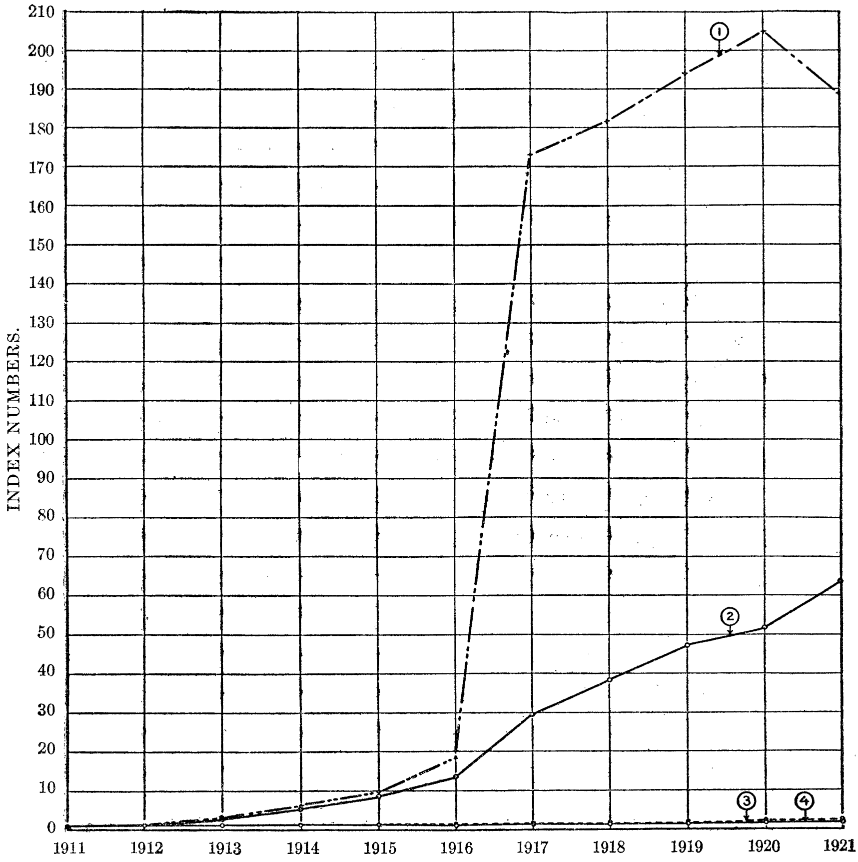

FIGURE 8.—Curves showing relation between (1) natural gas treated, (2) gasoline recovered, (3) crude oil produced, and (4) natural gas produced.

If true, this, in turn, would increase the estimated loss of 2,500,000,000 gallons since 1904 to 3,000,000,000 or 4,000,000,000 gallons, or enough to supply the United States for a year.

LOSS FROM FAILURE TO TREAT CASING-HEAD GAS.

In 1921, about 724,052,000,000 cubic feet of the natural gas produced was reported to the U. S. Geological Survey. In the same year, about 469,000,000,000 cubic feet of natural gas was treated for gasoline. The average yield was about 1 gallon per 1,000 cubic feet. Assuming that the other 389,000,000,000 cubic feet of gas reported would yield only one-eighth gallon of gasoline per 1,000 cubic feet, the loss of gasoline in 1921 would have been 48,600,000 gallons or 10 per cent of the amount recovered.

Some may argue that the 389,000,000,000 cubic feet of gas reported as produced was very lean gas. To some extent this is true. However, the great loss in natural-gas gasoline does not occur from failure to treat the gas from dry gas wells whose production may be reported but not treated, or whose production may not even be reported to the Geological Survey. The principal loss occurs from failure to recover and treat the rich casing-head gas from the thousands of small oil wells which produce from 700 to 2,500 cubic feet of gas with each barrel of oil. Unless this gas is recovered and used, it will not be included in the statistics of gas production. Likewise, the gas which accompanies the oil from the many large flowing or pumping oil wells in flush fields where no gasoline plants have been installed is a source of natural-gas gasoline loss.

LOSSES IN OKLAHOMA AND ARKANSAS.

Casing-head gas from oil wells will produce 0.5 to 8 gallons or more of gasoline for each 1,000 cubic feet of gas. In the Burbank field, Okla., the many large flowing wells produced during their first year enormous quantities of casing-head gas which were not measured and reported, as no gasoline plant was installed for a number of months. Hewitt field, Okla., produced over 9,000,000 barrels of oil in the one and one-half years before the first casing-head gasoline plant was installed. Investigation of the amount of gas produced with each barrel of oil, with tests of the richness of this gas (from 0.6 to 2.15 gallons per 1,000 cubic feet) indicate that more than 25,000,000 gallons of gasoline were probably lost during this time from this one field alone.

Eldorado field, Ark., produced about 12,000,000 barrels of oil during the first year, with at least 40,000,000,000 cubic feet of casing-head gas. No doubt the gasoline content of this gas was at least one-half gallon per 1,000 cubic feet, and probably 1 gallon per 1,000 was more nearly correct, resulting in a loss of from 20,000,000 to 40,000,000 gallons of natural-gas gasoline.

Kirwan and Schwarzenbek's report [54] indicates that from 15,000 to 20,000 gallons of gasoline daily were being wasted through failure to treat gas in the Deaner oil field, Okla., in February, 1921.

[54] Kirwan, M. J., and Schwarzenbek, F. X., Petroleum engineering in the Deaner oil field, Okla.: Mimeographed report, prepared by the Bureau of Mines in cooperation with the Bartlesville Chamber of Commerce. Obtainable from Chamber of Commerce, Bartlesville, Okla.

LOSSES IN TAIL GAS.

Experiments [55] have proved that the residual gas from compression plants often contains amounts of gasoline ranging from 0.1 to 0.8 gallon per 1,000 cubic feet. Tests at 30 plants in the Mid-Continent field showed an average of 0.337 gallon of gasoline per 1,000 cubic feet of gas. Contrary to the former belief, some gasoline is present in tail gas. Fairly large quantities of good gasoline can sometimes be recovered and retained by treating residual gas from gasoline plants. The cost of recovering this gasoline is comparatively low, as the apparatus is inexpensive to install and the process cheap to operate.

RECOVERY BY "TAIL ABSORBERS."

Six plants in Oklahoma installed "tail absorbers" for saving the gasoline that was being lost in residual gas. In 1920, these plants recovered 600,000 gallons of gasoline. Although it can not be said with certainty that all residual gas would yield 0.3 gallon per 1,000 cubic feet of gas treated, an estimate of the total amount of gasoline that might be recovered from tail gas is interesting. In 1921, 355,347,000,000 cubic feet of gas was treated for gasoline by the compression method. If 0.3 gallon per 1,000 cubic feet could have been obtained with tail absorbers, an additional production of 106,000,000 gallons of gasoline would have been produced. If the tail-absorber process had yielded only 0.15 gallon per 1,000 cubic feet, the additional production would still have amounted to 53,000,000 gallons; thus it seems certain that failure to treat tail gas from compression plants is the cause of a considerable waste of gasoline. The department expects operators to consider this matter and, where circumstances warrant, to make the installations necessary to cut down this waste.

CONSERVATION OF CASING-HEAD GAS.

The methods of separating and collecting casing-head gas are well known to oil men and will not be repeated at length in this report. The problem of saving casing-head gas from oil wells is largely economic; in fact, this has been one of the underlying causes of waste in the past few years.

The gas that accompanies oil from flowing wells should be separated by gas traps. Gas traps, their operation and adaptability, have been fully discussed by Hamilton.[56] These separators are adaptable to the separation of lead-line gas from pumping wells if the wells are large enough, or if enough wells can be turned into one trap to

[55] Dykema, W. P., and Neal, R. O., Absorption as applied to recovery of gasoline left in residual gas from compression plants: Tech. Paper 232, Bureau of Mines, 1920, 43 pp.

[56] Hamilton, W. R., Traps for saving gas at oil wells: Tech. Paper 209, Bureau of Mines, 1919, 34 pp.

warrant the cost of installation. Gas traps are now in use by operators on public lands. Plate XVI, *A* (p. 118), shows a battery of lease storage tanks and gas traps now in use in the Salt Creek field.

The principal complaint of some oil producers against gas traps has been that back pressure set up by the trap reduces oil production. Gas traps are constructed with relief valves which prevent pressures exceeding the maximum for which they are set. From 5 to 10 pounds of gas pressure is sufficient to make gas available for fuel on any good-sized lease. A 26-foot column of 35° B. gravity oil in a well exerts a pressure of approximately 10 pounds. In flowing wells, this much and more fluid often stands on the sand between flows and the pressure against the sand during a flow is much greater than 10 pounds; therefore it seems questionable if 5 or 10 pounds pressure would actually reduce the oil production in a flowing well, other conditions remaining the same. However, if holding 5 or 10 pounds back pressure on a flowing well should reduce the oil production, the operator must balance the saving in fuel costs against this loss in production, although it is not believed that an appreciable loss in oil production would be caused by holding small back pressures.

REGULATIONS FOR OPERATORS ON PUBLIC LANDS.

The department can not sanction the flowing of wells into open tanks and the failure to collect the gas accompanying the oil whenever there are possible uses for the gas. If the gas can be used in any way, the operator on public lands will be expected to install the necessary traps to recover this gas. Any controversies in this regard must be settled in consultation with a deputy oil and gas supervisor or his representatives.

If casing-head gasoline plants take the gas from oil wells, the objection to traps because of back pressure on the wells will seldom apply, as gasoline plants usually take gas under a low pressure or a small vacuum and consequently relieve any extra pressure on the casing head.

The casing heads of pumping wells may be closed and gas lead lines laid at small expense; or, if more adaptable to the particular property, a continuous or "belt" gas line may be laid from well to well and a number of wells may produce into it through relief valves. As previously mentioned, it seems probable that an operator can afford to hold enough pressure on his pumping wells to make his gas available for fuel without suffering an appreciable loss in present daily production.

Government lessees will be expected to experiment with their wells to learn the effect of holding back pressure before the department will sanction the waste of casing-head gas that could be used.

If possible, the department would prefer to have all casing-head gas from wells, provided this gas carried a reasonably large natural-gas gasoline content, treated before the gas is used as fuel; if there is no plant near by and the amount of casing-head gas available is insufficient to warrant the erection of one, the department is willing that the gas should be used directly for legitimate fuel purposes.

WASTES FROM THE FORMATION OF EMULSIONS.

DESCRIPTION OF EMULSIONS.

Oil-field emulsions are generally understood to be intimate physical mixtures of oil, water, gas, or air, and possibly foreign material, such as colloidal matter.[57] In a true emulsion, the water globules are so small that they do not settle out under ordinary conditions. As technical men do not agree on terms and definitions of oil-field emulsions, the terms "emulsion" and "cut oil" will be used interchangeably in this paper. These terms will cover what many operators call "B. S." when referring to the emulsion content of the oil from a producing well.

Emulsions vary from intimate mixtures of oil, water, gas, or air, and possibly some solid matter, which can be broken down into clean oil, free water, and impurities only with greatest difficulty, to mixtures of oil, water, and foreign matter, that break down in the flow tank without special treatment. The latter are not classed as true emulsions. Between these extremes are various types of emulsions, some which break down in a tank during warm weather, others which require heating to various temperatures, and still others which approach the extreme class and require electrical heating, chemical, or centrifugal treatment, high temperature and pressure, or other costly processes to break them down.

Emulsions may "settle out" or "break down," depending on their character. If emulsions settle out of oil so that the oil is acceptable to the pipe line, the oil can be run but the emulsion becomes part of the residue on the tank bottoms and the oil in that emulsion is lost when the tank is cleaned unless the "bottoms" are treated. If an emulsion breaks down, however, the oil is recovered as pipe-line oil and the water is drawn off as free water, no loss in oil taking place. Oil-water emulsions result in large wastes of oil. D. B. Dow estimates that in 1920 and 1921 more than 100,000,000 barrels of cut oil was produced in the Mid-Continent and Gulf Coast fields. Approximately one-half of this oil was treated, but the other half, worth about $100,000,000, was lost.

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[57] McCoy, Alex, Shidel, H. R., and Trager, E. A., Investigations concerning oil-water emulsions. Trans. Am. Inst. Min. Eng., vol. 65, 1920-1921, pp. 430-458.

FORMATION OF EMULSIONS.

In many oil fields the formation of oil-water emulsions causes the loss of large quantities of oil. Emulsions do not form unless water is present; however, the majority of oil wells produce some water. The water can not always be shut off, and many times the expense of shutting out relatively small amounts of water is too great to warrant the effort. Small amounts of water produced with oil will emulsify if operating methods happen to be conducive to the formation of emulsions.

Emulsions form both in flowing and pumping wells. There are innumerable cases on record of flowing wells which, because the water is not shut out, produce thousands of barrels of emulsified oil daily. A number of such wells were drilled in California in the early days of the oil industry in that State. One of the most noteworthy flowed emulsion at the rate of from 30,000 to 50,000 barrels daily. Soon after the well was completed it got beyond control, and the large amount of sand which accompanied the oil cut out the casing, letting in upper water. As much fluid as could be caught was stored in hastily constructed earthen sumps. The leakage from these sumps must have been enormous, as oil appeared some 4 or 5 miles distant. Later shafts, sunk into some of these showings 3 or 4 miles from the well, found oil at depths of 20 or 30 feet. The total amount of emulsion produced was estimated at 5,000,000 or 6,000,000 barrels. Unfortunately there is no record of the amount of emulsion actually saved and treated or the amount of oil finally marketed.

The history of most large flowing wells that have gotten beyond control has been that from one cause or another water has broken in and formed emulsions with the oil. In practically all fields except those of the East, many small flowing wells also produce varying amounts of emulsion. These emulsions vary in character and amount but always are an important problem to the oil producer.

When water appears in flowing wells, emulsions in varying quantities usually form. The violent agitation of fluids by gas in such wells is conducive to the formation of emulsions. Some may form as oil and water are propelled through the sand by gas, but by far the greater proportion of cut oil is formed in the well or in the surface connections. The violent flowing action of wells that produce water with the oil is almost certain to cut the oil because of the thorough mixing of the fluids. Moreover, sharp bends and fittings, such as plugged T's, gate valves, and chokers, cause emulsions to form when wells flow oil, gas, and water through the surface connections.

PREVENTION OF EMULSIONS IN FLOWING WELLS.

SHUTTING OFF WATER.

The most effective way to prevent the formation of emulsions by a flowing well is to repair the well and shut off the water if this can be done. Usually, if a well is strong enough to flow it is large enough to warrant the expenditure of a considerable sum to repair it. In some districts, however, there are many obstacles to repairing a flowing well. For instance, the Eldorado, Ark., field was noteworthy because of its high gas pressures and large flowing wells, but salt water apparently was present in the lower portions of the sand that carried the oil. The flowing wells soon made large quantities of water, even though they were drilled only a few feet into the sand. While some of these wells might have been repaired, in general successful repair work probably would have been impossible. Moreover, the flowing life of the wells would not be long enough to warrant the expenditure of large sums in attempting to repair them. Mechanical problems involved in repairing large flowing wells are many and difficult; and may render impractical the recommendation that water be shut out to prevent the formation of emulsions.

PROPER HANDLING OF WELLS.

When there is no recourse but to produce the water that may be entering flowing wells, the well should be handled to keep the emulsion content as low as possible. "Choking down" a well with a "bean" (choker or flow nipple) is a common way of handling such wells. In south Texas, Arkansas, north Louisiana, Wyoming, and California restriction of the flow of large flowing wells is common practice. Usually a pressure gage is put on the casing head and two chokers installed, one in the main flow line and one in a by-pass line so that the well need not be closed in while a choker is being replaced. The chokers are usually inserted in the flow lines between two gates and with a flange (or Chicago union) connection so that they can be removed and replaced when cut out by sand. If "Christmas tree" or "deer horn" casing-head connections (see Pl. X and XII, *C*, pp. 59 and 68) are being used, the two sides of the Christmas tree serve as by-pass lines and the chokers are placed in these lines.

BACK PRESSURE ON FLOWING WELLS.

Back pressure on a flowing well often reduces the volume of water or excludes it. Back pressure on flowing wells also prevents frequent violent heads of oil and gas and reduces the ebullition of gas through the column of fluid in the well. Instead of flowing violently by heads, a well, when choked down, tends to flow more quietly and steadily. Usual practice is to choke down a flowing well so that the greatest amount of oil could be produced with the least amount of emulsion and sand.

CHOKERS OR FLOW NIPPLES.

Chokers or flow nipples, also known as "beans," with removable cores are being used extensively in the southern California fields (see Fig. 9). If the sand cuts out the hole through the flow nipple, the flow of the well is turned through the by-pass line, the bull plug is removed from the cross through which the cores are changed, and a new bushing is inserted. Chokers of this type have two important advantages over the usual solid-type chokers. First, the bushing can be replaced in half the time it takes to replace the usual type of choker and with much less work; and second, the cost of the small replaceable flow bushing is considerably less than that of the larger flow nipple of solid steel. The details of operation will be self-evident upon examination of Figure 9.

FLOWING WATER THROUGH TUBING.

In extreme cases, the installation of tubing and a pump to lift water from the bottom of the well while the well flows oil and gas through the casing has been feasible. Such a scheme should be fairly successful in reducing the emulsion content of the oil if the pumping rate can be adjusted to keep the water down. As flowing wells decline in production, it may be found advisable to start pumping them before they stop flowing to prevent cut oil. For example, if a well would flow 250 barrels per day, but cut the oil badly, and the operator could obtain from 200 to 250 barrels per day of clean oil by pumping, it is believed that pumping might prove to be more profitable, especially if the cut oil required extensive treatment and was subject to heavy losses.

ELIMINATION OF BENDS IN FLOW LINES.

To cut down the percentage of emulsion formed in flow lines and fittings on the surface, all unnecessary bends should be eliminated. Chokers often cause emulsions to form. The proper size of choker must be determined by trial. To overcome this trouble, a special oil-water separator was used in the Eldorado, Ark., field.[58] The separator was placed between the well and the choker. Gas was taken off through one line and water was drawn off at the bottom. The clean oil passed through the choker alone. This arrangement was effective in preventing emulsions as long as the well pressure was sufficient to permit the use of a choker, but when the time arrived

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[58] Bell, H. W., and Kerr, J. B. (of the U. S. Bureau of Mines), The Eldorado (Ark.) oil and gas field; Geological outline, operation methods, conservation: Cooperative publication by the Bureau of Mines, the U. S. Geological Survey, the University of Arkansas, and the State Bureau of Mines, Manufactures, and Agriculture, 1922, 90 pp. Obtainable from Jim G. Ferguson, Bureau of Mines, Manufactures, and Agriculture, Little Rock, Ark.

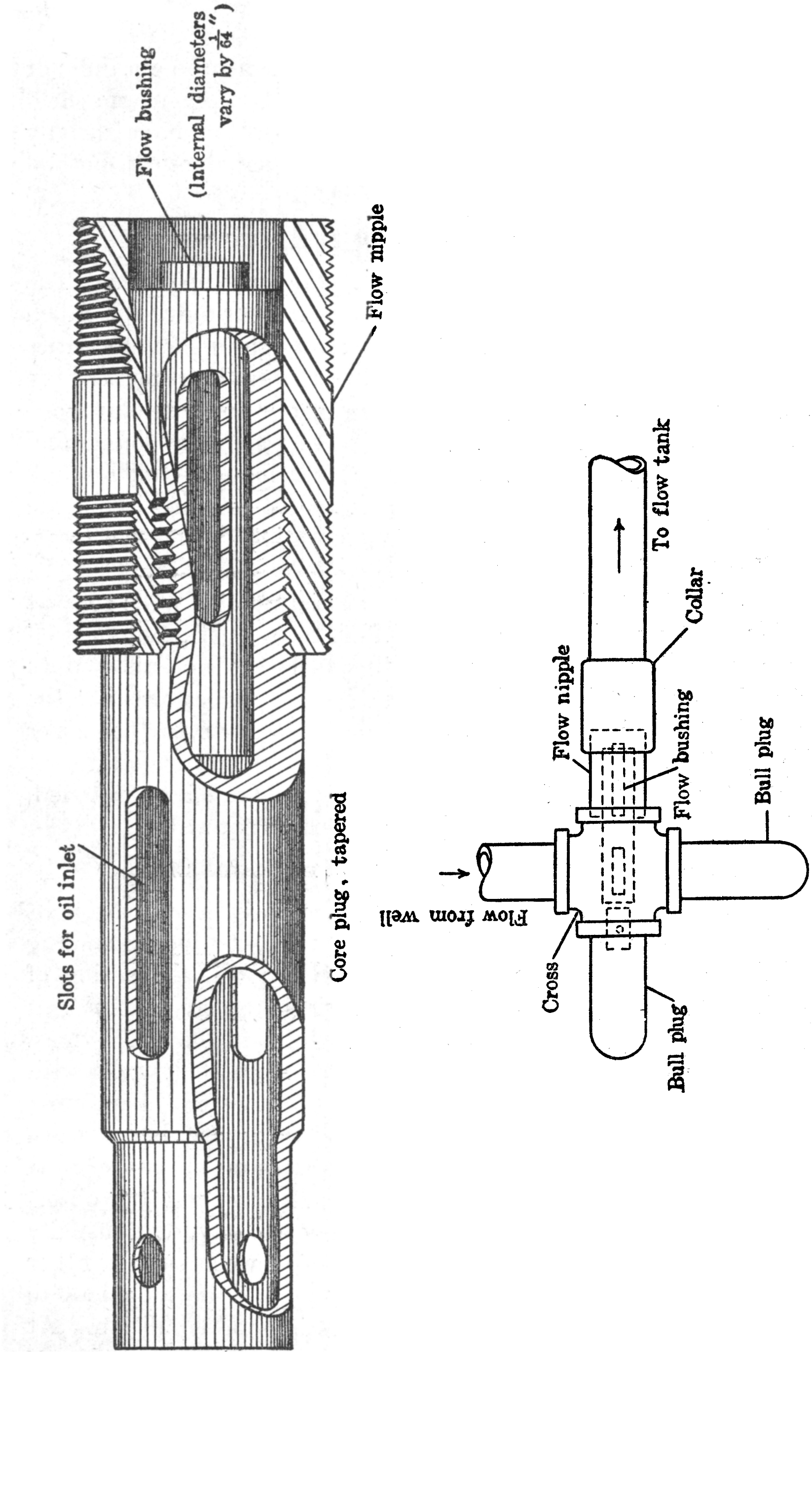


FIGURE 9.—Allen-type replaceable flow nipple and bushing used in the California fields.

for removing the back pressure and flowing the well through an open flow line, the separator could not be used, and there was no means of separating the water before the flow into the tank took place.

The prevention of emulsions in flowing wells is a problem difficult to solve. Remedies for this trouble that would apply in one field probably would not apply in another, hence operators have usually resorted to experiments to determine the most satisfactory method of handling their wells.

PREVENTION OF EMULSIONS IN PUMPING WELLS.

Pumping wells also "cut" their oil if not properly operated. The percentage of emulsified oil that pumping wells produce is much lower as a rule than that of flowing wells, although in some localities the quantity of emulsions is large enough to require treatment of the entire oil production. The loss of oil is largely due to those emulsions that can not be broken down with the equipment at hand and therefore are run into sumps and burned, the losses of oil in tank bottoms or B. S. which settles from the oil and is lost when tanks are cleaned, and the losses principally by evaporation during the treatment of the emulsions.

One of the chief duties of a pumper is to handle his wells so that they will produce a minimum amount of emulsion. If pumping-well equipment is in good condition and the wells are not allowed to pound and are otherwise handled properly, the chances are that the emulsion content of most of the oil can be kept down to 1 or 2 per cent or even less. It is impossible to maintain pumping equipment in perfect repair, however, as cups wear, balls and seats are scratched, dented, or flattened, and working barrels become scarred.

CAUSES OF THE FORMATION OF EMULSIONS.

The formation of emulsions in pumping wells is usually brought about by worn and leaky cups, leaky balls and seats, loose standing valves, leaky tubing, fast pumping, pounding down, the action of gas in the pump, the presence of finely divided foreign matter, gas action in the lead lines, and the churning of fluids in the well by gas. Experienced pumpers watch the oil produced from their wells with the greatest care. As soon as cut oil is detected, a pumper should remedy the trouble, if possible. If cups are badly worn or leaky, they are likely to cause the formation of cut oil. A pumper, from his knowledge of local conditions and his observation of the action of the well from day to day, can usually decide whether a well is cutting its oil because of worn cups or other causes. Sometimes, however, production men will be at a loss to account for cut oil when valves and cups are in good condition. At such times a leaky standing valve seat, a leak in the tubing, or possibly gas in the pump may be responsible for the emulsion.

Pumping wells too long—that is, pumping after they start to pump off—is a common cause of cut oil. In some fields holding back pressure on the sand by restricting the flow of gas at the casing head also causes emulsion to form. If it is desired to hold back pressures on pumping wells in a field where back pressure causes cut oil, the trouble can usually be overcome, either by installing long gas anchors (a full joint or more) or by holding back pressure by a high fluid level.

Finely divided foreign matter may cause emulsions to form when all other conditions are apparently conducive to the production of clean oil. Cleaning out the well may stop the emulsion. Fast pumping may also cause cut oil, particularly if the barrel does not fill on each stroke and the pump pounds. In Eldorado, Kans., it was found that oversized standing valves helped to reduce the amount of cut oil produced, no doubt because the barrel filled completely on the upstroke.

PREVENTIVE MEASURES.

Two leather and two composition cups on the same plunger have been used to good advantage in some fields. The composition cups, which are stiff, take the main burden of weight and the leather cups, which are more pliable, expand to fill the barrel and prevent slippage. Alone, leather cups may fail in a short time, while composition cups may cause emulsion to form because of their failure to fit a worn barrel tightly; together a maximum service is rendered with a minimum amount of emulsified oil.

The use of cup attachments on steel-plunger pumps may also prove satisfactory for temporarily reducing the amount of cut oil caused by worn plunger pumps. The attachment will cut down slippage past the plunger as long as the cups are good.

Pumping equipment can not be kept in perfect condition; consequently the operator may be bothered continuously with cut oil. In certain fields, cause of the trouble may be detected before any work on a well is undertaken, and the most effective solution of the problem may become routine practice. Care on the part of operators should enable them to keep the emulsion content of oil from their pumping wells within the limits allowed by pipe-line companies; operators on public lands are therefore urged to give this problem all attention necessary for keeping the emulsion content within these limits.

LOSSES DURING PULLING AND CLEANING OUT.

The oil producer usually does not depend on gusher wells or even large pumping wells for his daily production. Stability in the oil-producing industry generally is obtained by settled daily production from small but steady pumping wells. To operate such wells at a profit, a producer must cut down every possible item of cost and recover and save every barrel of oil possible. In other words, the producer must strive for efficiency in operation, with minimum waste. Therefore, while he must operate carefully any large wells that he may own, he must give his greatest attention to the efficient operation of small pumping wells. No loss is too small to warrant the attention of an operator of small pumping wells.

PULLING A "WET" STRING OF TUBING.

One of the most common small losses of oil occurs when a "wet" string of tubing is pulled. From Table 3, which shows the capacities of the sizes and weights of tubing in general use, it may be seen that the loss of oil when a string of tubing from 1,000 to 3,000 feet long is pulled may be considerable. The total amount of fluid indicated by the table is not actually lost in pulling, because the rods occupy some volume and the fluid may be "lightened" with gas. However, as an illustration, pulling a 2,000-foot string of 2-inch tubing probably means a loss of 4 or 5 barrels, while pulling a 3,000-foot string of 3-inch tubing results in a loss of from 12 to 20 barrels. These losses are therefore important when it is considered that oil companies operate hundreds of wells whose average production is less than 1 barrel per day each. In fact, in fields of eastern United States many wells produce only 3 or 4 barrels of oil per month.

TABLE 3.—*Capacities of oil-well tubing.*

Size of tubing.	Diameters.		Weight per foot.	Capacities, per 100 feet.	
	External.	Internal.		Cubic feet.	Barrels.
Inches.	*Inches.*	*Inches.*	*Pounds.*		
2	2.375	2.041	4.000	2.270	0.405
2	2.375	1.995	4.500	2.169	.387
2½	2.875	2.469	5.897	3.322	.592
2½	2.875	2.441	6.250	3.246	.578
3	3.500	3.068	7.694	5.130	.914
3	3.500	3.018	8.500	4.965	.885
3	3.500	2.922	10.000	4.652	.829
4	4.500	4.026	10.980	8.833	1.574
4	4.500	3.990	11.760	8.674	1.546
4	4.500	3.958	....	8.537	1.521

BAILING A WELL.

Another source of minor loss is the bailing of a well. While drilling in, cleaning out, or other work that involves bailing is being done, some oil is removed from the hole with the débris which must be bailed out. Moreover, bailing is necessary when water is being plugged off and the fluid levels and the quantity of oil and water in the hole are determined. If the well makes any oil, the bailer brings out some oil on almost every run. Bailings are often dumped into a sump, although this is not always done.

Considerable oil may be bailed during the routine of a cleaning out or repair job. For example, a $4\frac{1}{4}$-inch-diameter bailer 25 feet long for use in $5\frac{3}{16}$-inch casing holds 0.4 barrel, while a $5\frac{1}{2}$-inch, 30-foot bailer for use in $6\frac{5}{8}$-inch casing holds about 0.7 barrel. If these bailers come up only half full of oil on each run, a barrel of oil would be removed in every five runs of the former and every three runs of the latter.

Some wells in Pennsylvania and West Virginia which were being cleaned out and repaired were recently visited. In view of the extreme measures of economy practiced in other ways and the very small production of wells which are still being pumped, it was surprising to find that the bailings from a number of these wells were being dumped into a ditch which did not terminate in a sump from which the oil could be recovered. A barrel or so of oil would be bailed each day from some of these wells and these quantities approximated their full production.

A number of barrels of oil is often bailed each day from large wells during cleaning out or repairs. In view of the value of oil and the low cost of preventing such wastes, the bureau will expect Government lessees to eliminate small losses of this character. Other minor losses, such as may occur when the tubing head of a well is disconnected for pulling and the lead-line oil drains back upon the ground, should be avoided. Many small losses of this nature occur from time to time, more because operators fail to realize their importance than because they can not be prevented. Although individual losses may be small, the total loss to American producers is doubtless many thousands of barrels of oil each year. Unfortunately, no estimate of the amount can be made.

REDUCTION OF LOSSES DURING PULLING AND CLEANING OUT.

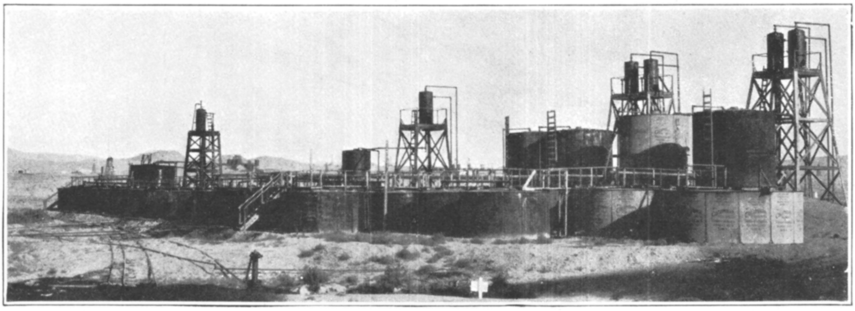
As pulling tubing is a daily occurrence on large oil properties and as the string is likely to be "wet," the saving of the oil that is brought up in the tubing is important to every producer. If the standing valve is pulled before the tubing is withdrawn, oil is drained into the well and saved and the tubing can be withdrawn more rapidly. However, in all fields it is not practical to pull the standing valve; in fact, more damage from caving will be done to some wells by pulling the standing valve and flushing the fluid back into the hole against the sand than can be overcome by weeks of cleaning out and pumping. Oil that sprays from each stand of tubing while a wet string is being withdrawn should be saved both as a conservation measure and as efficient operating practice. When a derrick floor—or if a well is on a pumping jack, the ground or platform adjacent to the well—becomes covered with oil or oil and water, working conditions are both unpleasant and unsafe.

Usual practice is to put a sack around the tubing collar just after the joint has been unscrewed but before it is lifted from the collar, then to raise the tubing a short distance and depend on the sack to confine the spray of fluid to an area near the casing. Sometimes the sack is effective and the oil runs down into the collar or the space between casings or between the casing and the hole, but more often one end of the sack is lifted by the oil and fluid is sprayed over the floor or ground. Even though the sack is effective, the oil is generally lost.

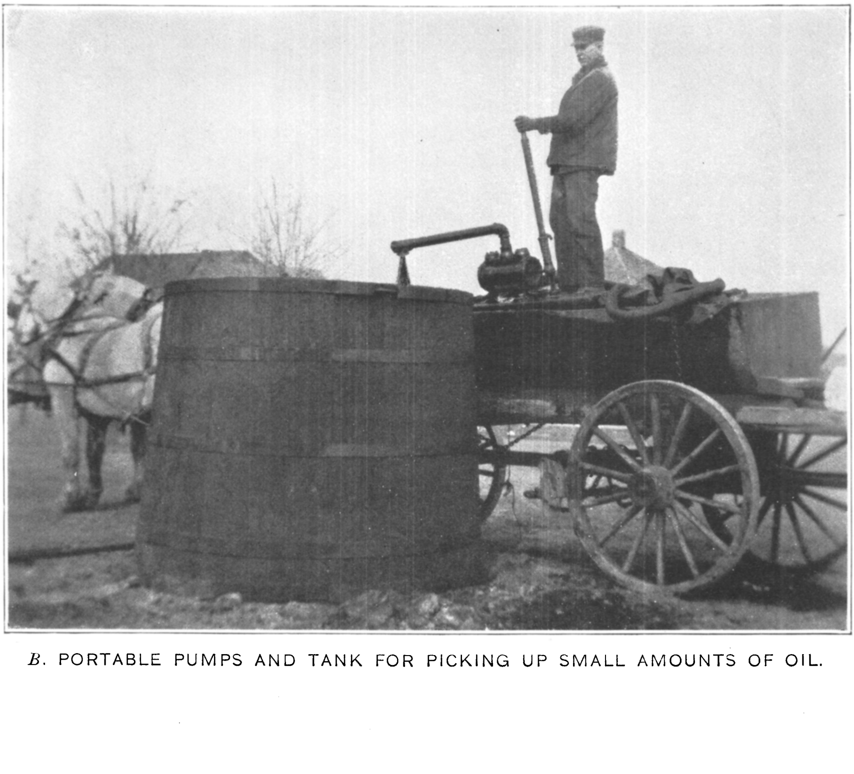
If the flow of oil is controlled by home-made devices or patented oil savers, the oil from tubing can be diverted into a sump or specially prepared pit and recovered by a hand pump. A box or other catch basin should be built around the casing to catch the oil which flows from the tubing and divert the flow back into the pit. If a heavy sack is carefully wrapped around the tubing and tightly fastened above and below so that the ends will not separate under the heavy flow, thus allowing the oil to spray, the oil can be recovered with a minimum of expense and trouble.

OIL SAVERS.

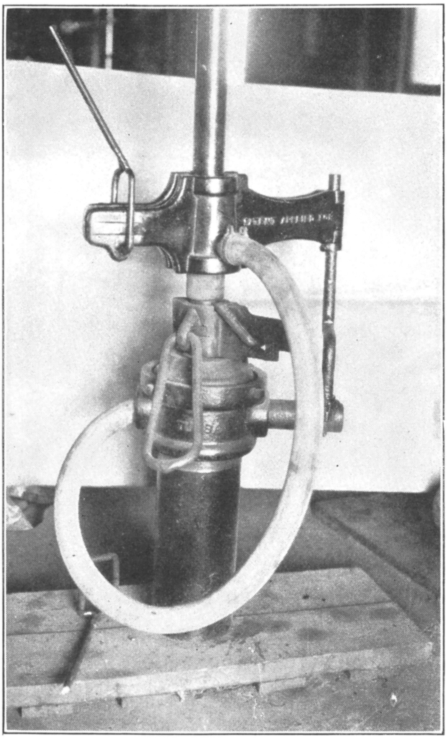
Plate XVII, *A*, shows one form of patented oil saver which recently has been placed on the market for use while tubing is being pulled. The photograph shows the tubing held by a pair of elevators resting on the casing-head top. The oil-saver arm is clamped to a 2-inch nipple, which is screwed into one hole in the casing head. The oil saver is opened and thrown back (see Pl. XVII, *B*), except when the stand is lifted from the collar. The saver is rubber packed to prevent leakage, and the hose connection leads off the fluid, which flushes out of the tubing above the collar on the elevators. The manufacturers suggest that the fluid can be run back into the casing, but this has the disadvantages of wetting the tubing which is being pulled, making the pulling job dirty and more or less dangerous, and causing the hole to cave if there is an open hole. It is better practice to run the oil into a basin from which it can be pumped and recovered. The principal objection to the saver is that it is somewhat in the way of the pulling crew and makes unscrewing a little slower and more troublesome. This is of minor importance compared to the saving that can be effected, for the oil saved from a few pullings pays for the appliance.



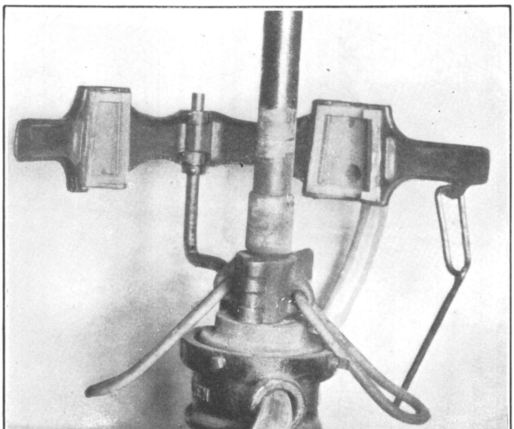
A. BATTERY OF TANKS AND GAS TRAPS ON GOVERNMENT LAND IN THE SALT CREEK FIELD, WYO.



B. PORTABLE PUMPS AND TANK FOR PICKING UP SMALL AMOUNTS OF OIL.



A. OIL SAVER FOR USE WHEN PULLING TUBING FILLED WITH OIL (CLOSED).



B. OIL SAVER FOR USE WHEN PULLING TUBING FILLED WITH OIL (OPEN).

PITS AND SUMPS.

As pointed out in former paragraphs, when an oil well is being cleaned out, deepened, or redrilled, tubing is being pulled, or other work is being done, considerable oil may be lost. The deliberate waste of oil by failing to run it into a pit or sump, so that the oil can be picked up and added to storage or, if badly weathered, used as fuel or road material in most instances is inexcusable.

Oil can be collected from sumps or pits in a number of ways. Light oil in sumps which are not too far removed or too low in the elevation below the ground adjacent to the beam end can be picked up with a tail pump on the beam and boosted into the receiving tank through the lead line. The tail pump need be "hooked on" only long enough to lift the oil from the sump. Heavy oil or medium oils in cold weather might not pump readily if a tail pump has to lift the fluid a few feet by suction. Likewise, if the sump is considerably lower than the ground surface in the vicinity of the beam, the tail pump could not be counted on to work satisfactorily.

Either rod-line pumps operated by shackle lines from a power or pumps operated from a crank on the band-wheel shaft are suitable for lifting oil if a number of wells can be drained into one sump. The disadvantage of installing tail pumps or rod-line pumps at individual wells is their cost and maintenance. The need for these pumps ordinarily is so infrequent that a company would not be justified in tying up capital in them.

USE OF PORTABLE HAND PUMPS.

A portable pump is more satisfactory for work of this sort. An ordinary hand double-action force pump can be carried to the well on the wagon or truck that accompanies the pulling crew. Even though only 1 barrel of oil is saved by skimming, the operator would be justified in assigning a man to pump it. If 4 or 5 barrels can be picked up, it would be profitable to have one man spend an hour or so in lifting it from the sump. Because of the difficulty in forcing the oil into the receiving tank unless this happened to be down hill, it would not be desirable to connect the hose discharge from the hand pump to the lead line. Better methods would be to load as many barrels or drums as would be needed on the wagon and pump the oil into them or to mount a small tank and hand pump on the wagon, using the pump both to load and unload the oil. Plate XVI, *B*, shows such an outfit delivering oil from a tank on the wagon to a lease tank. The oil had been recovered from a sump.

Although the saving of small amounts of oil here and there may not seem worth the effort, the equipment for picking them up is inexpensive. If a four-man tubing gang is at work, one man can always be spared long enough to pump a few barrels of oil with a hand pump. When a well is being cleaned out or deepened, the tool dresser can find time to pump the oil. The value of a few barrels of oil saved soon amounts to a number of dollars.

DEPARTMENT'S ATTITUDE.

Although it is recognized that careful operators will avoid minor losses of oil, the department will expect all Government lessees to employ reasonable measures to reduce such losses. Deputy supervisors are instructed to confer with careless operators to assist in preventing wastes.

SURFACE LOSSES OF OIL.

LEAKS AND OTHER MINOR LOSSES.

Numerous minor losses occur on a lease after oil reaches the surface. Most of these losses can be almost entirely eliminated and they seldom occur on properties that are efficiently operated.

LEAKS PAST THE STUFFING BOX.

Small losses of oil frequently occur from leaks past the stuffing box at the tubing head. Failure to keep good rings in the box or to keep the gland tight will eventually result in the loss of considerable oil. A badly worn and scarred polished rod injures stuffing-box rings and may make impossible the prevention of leaks past the stuffing box. Other factors which encourage leaks at the stuffing box are pumping up hill to a receiving tank, pumping oil through long lead lines, particularly in cold weather, clogging of lead lines with paraffin or foreign matter, sticking of check valve, and poor alignment of beam with respect to tubing. Stuffing-box losses may occur as constant small leaks, or, if a stuffing box is blown out, a barrel or more of oil may be lost at one time, depending upon conditions at the well.

LEAKS AROUND FITTINGS.

Leaks around the threads of loose fittings, past the plugs of stop cocks, and from flanges, valves, and corroded or split pipe are bound to occur from time to time, but failure to repair such leaks evidences careless operation. In the aggregate, much oil may be lost if a pumper neglects to stop these minor leaks about the lease.

BURST LINES AND VALVES.

Freezing weather often causes lines or valves to burst where water is not drained off. Leaks from such sources are only occasional and generally are found and repaired immediately. Since such a leak usually occurs in a low place, much oil may be lost in a tank drain or a long lead line before it is discovered. Low places in lines or at valves should be drained, if possible, to prevent the collection of water, or otherwise protected against freezing.

BLOWING OF DRIPS ON GAS LINES.

Gas lines on leases are almost always equipped with drips for drawing off water and any oil that may accompany the gas. These drips may be blown as seldom as once a week or as often as four or five times daily. Two losses may result from the blowing of drips, a loss of gas which escapes with the fluid, and a loss of natural-gas gasoline. Although these losses appear insignificant, in reality they may be appreciable if drips are blown often and for a considerable time. On one property in Wyoming the gasoline which collected from drips in the gas lines from one large well amounted to as much as 100 barrels per day.

NEEDLESS USE OF CRUDE OIL.

The use of fuel oil for necessary operations on the lease is permissible, but each operator should exercise every effort in the interest of himself and the Government to curtail its use. The department will not permit the use for roads of crude oil that could be refined. If road-surfacing material is needed, the operator should use fuel oil or skimmings from sumps.

STORAGE OR PIPE-LINE REQUIREMENTS AT DRILLING WELLS.

In the past many wells have been drilled in and allowed to flow, in spite of the fact that no facilities for storing or marketing the oil were available. Rather than chance the temporary closing in of a flowing well, some operators have been willing to make earthen reservoirs to catch the oil or even to waste the oil by permitting it to flow down streams or ravines.

DEPARTMENT POLICY ON STORAGE AT WELLS DISTANT FROM PIPE LINES AND RAILROADS.

Wildcat wells are more often allowed to flow wild than are wells in proved fields, because pipe-line connections are not always available. The department's policy will be that if a test well is drilled some distance away from pipe lines or railroads the operator must either erect steel or wooden storage to accommodate the oil or close in the well until a pipe-line connection to storage can be made. The need of letting a well flow or, if it will not flow, of pumping a well long enough to gain an idea of its capacity is recognized. Storage ample to accommodate the oil during such a test may be erected. Operators who believe that conditions on their leases merit special consideration should communicate with the deputy supervisor or his representatives at the nearest field office.

DEPARTMENT POLICY ON STORAGE IN PROVED FIELDS.

In proved oil fields lessees will not be allowed to produce wells into earthen sumps or to store oil in earthen reservoirs because of the losses that result from seepage and evaporation. Certain heavy-oil fields may be excepted from this ruling, and emergencies may, of course, necessitate such action. The department will, however, expect its lessees to take every precaution to prevent all possible waste of oil from wells that may get beyond control, by building dikes to catch the flows.

EARTHEN STORAGE.

Should it become necessary to provide temporary earthen storage, the seepage loss can be reduced by first thoroughly soaking the bottom and sides of the reservoir with water and then maintaining a layer of water on the bottom while oil is being stored. As soon as the well is under control storage must be made available at the well or by pipe-line connections; otherwise the well must be closed in.

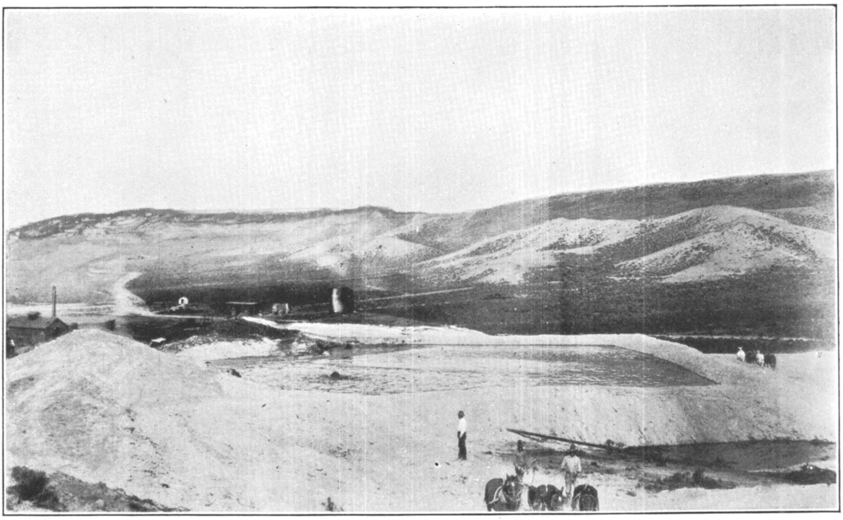
Plate XVIII, *A*, pictures an earthen storage reservoir built to receive the flow of a 2,000-barrel well brought in recently in a Wyoming field. Because of faulty casing and fittings the operator was afraid to close in the well lest it blow out and go wild. Since pipe-line connections and other storage facilities could not accommodate the flow, the oil was run into earthen sumps. The losses from evaporation and seepage were doubtless considerable, as the gravity of the oil was about 31° B. At the base of the embankment on the down-hill side (the right side in the photograph) oil seeped through the earthen wall in at least two places that could be observed at the surface. Plate XVIII, *B*, shows one of these seepages.

EVAPORATION LOSSES AND THEIR PREVENTION.[59]

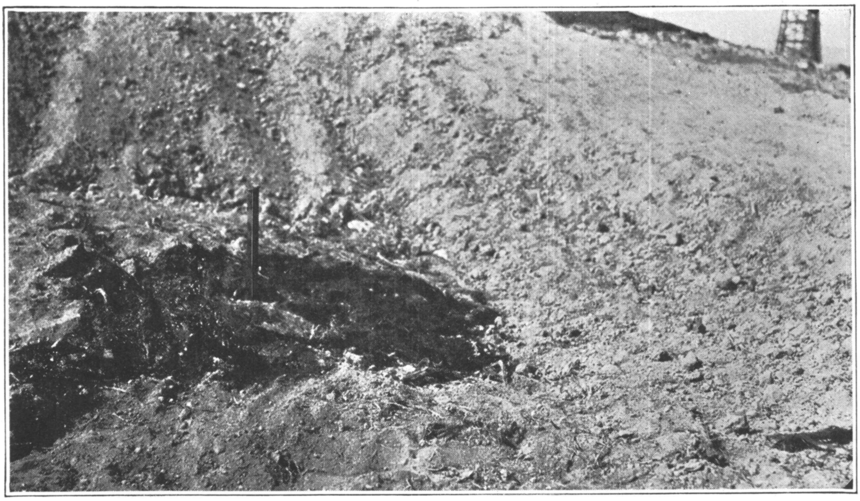
Readers are referred to two reports by J. H. Wiggins,[59] formerly of the Bureau of Mines, for detailed information on evaporation losses and their prevention.

Evaporation loss is a loss of oil that escapes into the air by changing from a liquid to a vapor state. This vapor comprises the lightest fractions of the oil and represents an equal volume of high-grade gasoline rather than so much crude oil. Evaporation will take place from a still oil surface, but agitation of the oil from wind, ebullition, the splashing of incoming oil, and convection currents

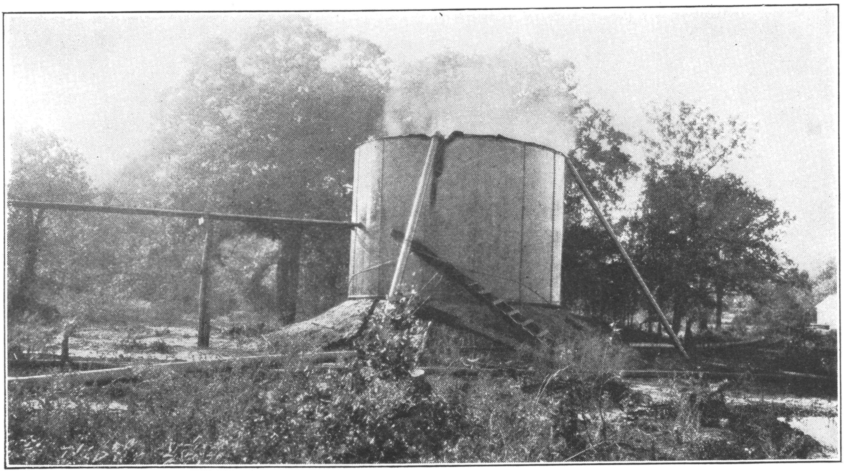
[59] Wiggins, J. H., Evaporation loss of petroleum in the Mid-Continent field: Bull. 200, Bureau of Mines, 1922, 110 pp.; Prevention of evaporation losses: Tech. Paper 319, Bureau of Mines, 1923, 56 pp.



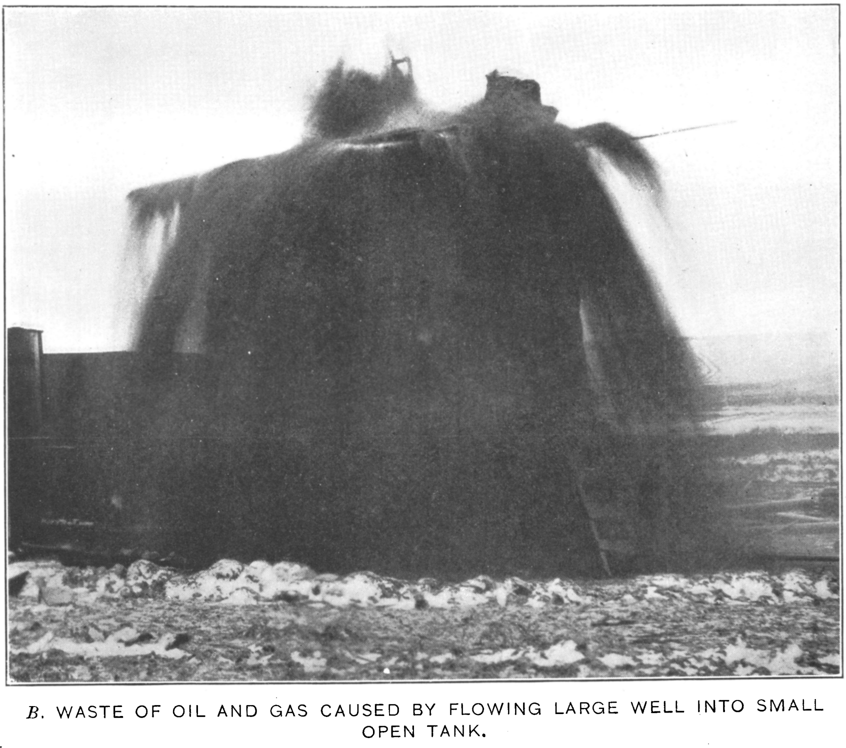
A. EARTHEN RESERVOIR FOR RECEIVING OIL PRODUCED FROM UNCONTROLLED WELL, LOST SOLDIER FIELD, WYO.



B. SEEPAGE FROM EARTHEN RESERVOIR SHOWN ABOVE.



A. VAPORS ESCAPING FROM OPEN FLOW-TANK.



B. WASTE OF OIL AND GAS CAUSED BY FLOWING LARGE WELL INTO SMALL OPEN TANK.

increases the volume of vapor formed and the evaporation loss if the vapor is allowed to escape.

FLOWING OIL INTO TANKS.

The losses that result when spray is blown into the air by wind as oil flows into a tank are really mechanical and are not grouped with losses from evaporation. The loss resulting from spray created within the tank, however, is considered evaporation. Such losses may be considerable. Plate XIX, *B*, illustrating the losses possible from spray, shows a tank too small to accommodate the flow of a well, every strong flow of the well making the oil splash out of the tank. The gas which accompanied the flow caused heavy spray to form, which was carried off by the wind. Plate XIX, *A*, illustrates an evaporation loss that resulted from the spray and vapor formed within the tank by agitation from overshot flow lines. Such a loss could be greatly reduced if vapor-tight tanks were used. If oil is flowed into open tanks through overshot connections the greatest possible loss results, but if oil is introduced at the bottom and the tanks are vapor tight the loss is reduced to a minimum.

GAS TRAPS.

When a field is new the gas pressure is high and much dissolved gas is produced with the oil. This volatilizes upon coming in contact with the air, carrying with it some of the lighter fractions of the oil. This loss can be largely eliminated by the use of gas traps [60] that separate oil and gas and save a valuable portion of crude oil which might otherwise be lost by evaporation. Plate XVI, *A* (p. 118), showed a battery of gas traps and lease storage-tanks on a lease in the Salt Creek field, Wyo. The gas from such traps or separators usually has high gasoline content and should be treated before being used. If the gas pressure is low oil can be run into a gas trap upon which a vacuum is maintained. In addition to removing the gas the vacuum decreases the pressure on the oil, thus causing some of the lighter and more volatile fractions, which would otherwise be lost by evaporation in the flow tank, to be given off.

VAPOR-TIGHT TANKS.

Oil fresh from the well has been found to be subject to the greatest evaporation loss. Experiments were made by the Bureau of Mines to determine the relative evaporation losses from three lease tanks of the same shape and size and filled with the same fresh oil, but with roofs that provide different degrees of tightness. These tests

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[60] Hamilton, W. R., Traps for saving gas at oil wells: Tech. Paper 209, Bureau of Mines, 1919, 34 pp.

demonstrated the value of vapor-proof tanks as compared with ordinary open tanks. Figure 10 gives curves illustrating the relative evaporation losses from the three tanks with different roofs. The loss from the open tank was a number of times that from the vapor-proof tank.

Ebullition is the bubbling produced by forcing oil containing gas or air into the bottom of a tank. The gas bubbles rise through the fluid rapidly and burst at the surface, disturbing the surface of the oil and forcing small particles of oil into the air. If the tank is not closed at the top, wind will not only carry off the vaporized oil but

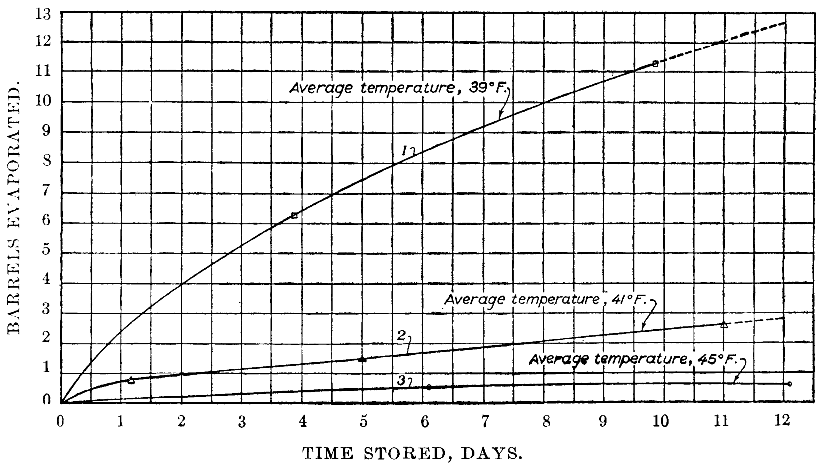

FIGURE 10.—Curves showing evaporation losses from three tanks with different kinds of roof: 1, Open tank; 2, 4-inch-vent tank; 3, pinhole-vent tank. (After J. H. Wiggins.)

will mechanically bear away some of the fine particles of liquid oil as they are forced into the air.

As evaporation increases, the gravity of the oil decreases. This is important to producers, particularly when the price of the oil varies with the gravity. In the tests cited above, the gravity of the oil in the open tank dropped 3.63° B. during 12 days.

The greatest evaporation losses occur on the lease between the time the oil leaves the well and when it is removed from the lease by the pipe-line company. These losses occur while receiving or flow tanks and lease storage tanks are being filled, while oil is being dehydrated and while it is standing in storage tanks on the lease.

Oil from a well is pumped or flowed into what is commonly known as the "flow tank" in many fields. In this tank, free water separates from the oil and settles to the bottom, while the oil floats on top and is drawn off into other tanks where it is stored until run to the pipe-line company. Gas separates from the oil in the flow tank and is usually wasted into the air. A flow tank should have a vapor-tight roof and the oil should be introduced with as little disturbance of the surface as possible; that is, by running the inlet pipe to a point near the bottom of the tank. A tight roof also prevents air currents from disturbing the surface. Any gas from this tank should be led off to a gasoline plant if available, although it is assumed that the operator already has recovered the bulk of the gas with a gas trap. Open tanks which permit the free circulation of air currents and overshot flow lines which allow the oil to splash into the tank are two of the greatest sources of evaporation in the field. Both of these can be eliminated with little expense and trouble, and the saving in oil will usually pay for the expense.

HOUSING FOR TANKS.

In a region of high temperatures and wind, many operators have provided shelters and even complete houses around their lease tanks. Tests by the Bureau of Mines [61] show evaporation loss from protected tanks to be considerably less than that for similar tanks not protected. Temperature changes also influence the volume of evaporation. During the summer months, for example, the evaporation rate is much higher than during the winter. Vapor-tight tanks and housed tanks are most effective for cutting down losses caused by heat.

CONTROL OF TEMPERATURE IN DEHYDRATION.

When an emulsion of oil and water is formed, water must be separated from the emulsion before the oil can be marketed. A method frequently employed in the field consists of heating the emulsion with steam or passing it through hot water. This treatment sets up conditions ideal for evaporation and, in fact, distillation does occur on a small scale. The distilled oil becomes the evaporation loss.

Temperature is one of the controlling factors in some dehydration processes. The fluid should not be heated above a temperature necessary to separate the oil and water or excessive and unnecessary loss will result. Table 4 shows the evaporation losses from a dehydration test. The loss that occurs when dehydration takes place at a temperature of 150° F. is approximately twice that for a temperature of 105° F. Similar results doubtless occur in most field heating systems. These data illustrate the need for limiting the temperature to that necessary for breaking down the emulsion.

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[61] Wiggins, J. H., Evaporation losses of petroleum in the Mid-Continent field; Bull. 200, Bureau of Mines 1922, pp. 42–70.

TABLE 4.—*Dehydration losses during test at Eldorado pool, Kans.*

Average temperature of dehydrations.	Amount of oil treated daily.	Volume lost.	
		Per cent.	Barrels.
°F.	*Barrels.*		
84	300	1.76	5.3
105	300	3.30	9.9
125	300	5.45	16.4
150	300	6.70	20.1
200	300	8.50	25.5

Evaporation generally results from the average process of dehydration, which requires heating the oil to from 100° to 200° F. Chemicals may cause oil and water to separate more readily, thus shortening the heating period and reducing the amount of evaporation. It is common practice to heat emulsified oil in the fields in open tanks by using steam coils or by introducing live steam directly into the oil. Both methods are conducive to high evaporation losses. Better practice is to heat the oil in a closed interchanger, from which it passes directly into a vapor-proof settling tank. When an emulsified oil is treated with heat, care should be exercised to apply only the heat necessary to break down the emulsion and to heat only that portion of the total production that contains cut oil.

RECOVERY OF VAPORS IN DEHYDRATING OIL.

Dehydration by the electrical method takes place in a practically vapor-tight container in which little or no evaporation results. One progressive oil company applied vacuum to its electrical dehydrator and passed the gas thus obtained through the gasoline compressor plant. Gasoline is conserved thereby and the fire hazard in the dehydrator is greatly reduced. This procedure could also be followed to advantage when emulsions are heated by steam in coils.

Another preventable dehydration loss occurs when an operator allows oil containing emulsion from one well to mix with clean oil from other wells and thereby necessitates dehydration of all the oil. By separating the production from a well that yields emulsion, it is often necessary to steam only a small proportion of the total production and save both the evaporation loss and the treating cost. An investigation of one such case by the bureau showed that a simple change in the piping plan and the method of handling the oil, whereby only that portion of the oil containing emulsions was heated, avoided shrinkage due to evaporation of some 350 barrels per month.

ADEQUATE LEASE STORAGE TANKS.

Lease storage tanks, as a rule, are not built as sturdily as the large storage tanks used by pipe-line companies. Moreover, a higher percentage of oil is evaporated from a small tank than a large one, because it is filled more frequently and a correspondingly larger volume of vapor is formed. Also, temperature changes cause greater evaporation in a small tank than in a large one. Therefore, oil should not be held in ordinary lease storage tanks any longer than necessary. Table 5, compiled by J. H. Wiggins, illustrates the volume of the evaporation loss which takes place in lease tanks of various sizes at different seasons of the year in the Mid-Continent district.

TABLE 5.—*Average evaporation losses from different size tanks during various seasons, Mid-Continent crude.*

Tank.		Volume lost, per cent.							
		Summer.		Autumn and spring.		Winter.		Yearly average.	
Kind.	Size.	1st day.	40th day.	1st day.	40th day.	1st day.	40th day.	1st day.	40th day.
	Barrels.								
Steel	250	0.80	10.90	0.58	8.06	0.42	6.1	0.61	8.52
Do	500	.52	7.74	.41	6.20	.30	5.22	.42	6.46
Wood	1,600	.20	3.67	.16	3.21	.12	2.93	.16	3.28

A test was conducted on thirty 55,000-barrel tanks storing 1,440,-235 barrels of crude oil. During one year, the evaporation loss was 32,100 barrels, whose value as gasoline at 22 cents per gallon (the average price that year) would be $297,000, or as crude oil at $2 per barrel, $64,200. This represents a yearly loss from each 55,000-barrel tank of $9,900 as gasoline, or $2,140 as crude oil.

Many oil companies and refineries are reducing the evaporation loss as well as the fire hazard by making the tanks vapor-tight[61a] and maintaining a slight vacuum on all tanks to remove any vapor which may be formed. The vapor thus obtained is treated to extract the gasoline which otherwise would have been lost. Devices, such as a permanent foamy mixture to cover the oil surface and floating roofs, are being used with success to prevent evaporation and reduce the fire hazards.

INSTRUCTIONS TO GOVERNMENT LESSEES.

Evaporation losses of crude oil on the lease can be greatly reduced by the installation of proper equipment, and all operators on Government land will be required to take reasonable precautions to prevent these losses. The portion evaporated consists of the lightest, most volatile, and most valuable fractions of the oil. Light oils are subject to greater evaporation losses than heavy oils, therefore greater care must be exercised in handling them.

[61a] Schmidt, Ludwig, The use of vapor-tight tankage in the oil fields: Mid-Continent Yearbook for 1922, Mid-Continent Oil and Gas Association; Reports of Investigations, Serial 2,442, Bureau of Mines. 1923, 11 pp.

The following tabulation gives some of the more important suggestions for reducing evaporation losses:

1. Use vapor-proof tanks and necessary vapor valves and thief-hole covers.
2. Eliminate all overshot connections.
3. Introduce oil from the bottom of tanks.
4. Provide gas traps to separate the oil and gas.
5. Maintain a slight vacuum on tanks to remove all vapors, and extract the gasoline from these vapors.
6. Use floating roof or foam to cut down breathing loss.
7. House tanks, use sprays, or water seal roofs to reduce temperature changes.
8. When dehydrating, use the minimum amount of heat required and do not heat longer than necessary. Chemicals may be used to speed up the process of dehydration.
9. Remove and treat the vapors from tanks in which oil is being heated.

MISCELLANEOUS LOSSES OF OIL.

LEAKAGE FROM TANKS.

In addition to the evaporation losses discussed in the previous section, other losses of oil occur during storage. In the oil fields, leakage around the seams of steel tanks is common and sometimes considerable. Government lessees will be expected to keep their tanks tight, so that persistent losses of this nature will not occur. Wooden tanks allow evaporation losses if they are not properly handled. Unless they are filled with water before they are used, wooden tanks that have stood empty are apt to leak. It is good practice to fill wooden tanks partly with water when idle. If leaks develop when the tanks are in use, the hoops should be driven. There is little need for warning against oil being allowed to run over tanks, owing to the carelessness of pumpers and gagers, as the running over of a tank is, by tradition, considered almost unpardonable negligence in the oil fields. All tanks should be set on a specially prepared grade and be surrounded with a suitable basin, so that oil leaks may be collected.

LOSSES OF OIL THROWN AWAY IN TANK BOTTOMS.

Almost every producer suffers material loss of oil from the collection of bottom sediment in the various tanks used upon the lease. The mixture on tank bottoms usually consists of oil, water, oil-water emulsion, and sometimes paraffin with sand, shale, or other foreign matter. The rate of collection of B. S. in tanks varies greatly. In Pennsylvania, for example, only an inch or so of B. S. may collect in two or three years, whereas in many Mid-Continent and California fields a foot or so of B. S. may collect in a month. Oil is lost in two ways when the tank is cleaned: First, as clean oil held in suspension with the foreign matter and carried out with the B. S.; and second, as emulsified oil which must be cleaned out. Producers' flow tanks may have to be cleaned quite often; then the loss is considerable. Even the large storage tanks of pipe-line companies collect large volumes of bottom sediment which must be cleaned out from time to time and oil is invariably lost.

TREATMENT OF TANK BOTTOMS.

When tanks are cleaned, bottom sediment should be run into a sump and allowed to settle. At times, considerable free oil may be recovered. The practice of burning sumps should be discouraged. The department is anxious for Government lessees to provide pick-up pumps, either portable or permanent, and to recover every barrel of oil possible by skimming sumps. It may even be desirable to install heating coils in some sumps to assist in breaking down B. S. into clean oil, water, and foreign matter. Should the oil which is finally recovered be too heavy (because of the loss of light hydrocarbons) for running to the pipe line, it should be utilized as fuel or as road material. Careless disposal of B. S. or other "waste" oil by running it down ravines and creeks will not be permitted on Government lands.

LOSSES FROM SUMPS AND FLOW PITS.

EVAPORATION AND SEEPAGE.

In some fields oil is flowed or pumped from the wells into earthen sumps or "flow pits." Plate XX, *B*, shows a flow pit into which a number of wells are pumping and flowing by air lift. This photograph also depicts careless lease conditions which may result in costly fires and in other wastes of oil and gas. Crude oil also is stored in large earthen sumps for months or years in some localities. Evaporation, fire, losses from cleaning out sumps, and losses from overflowing or leakage past broken dikes and seepage may result from these practices.

Next to evaporation seepage is probably the most important of these losses. The extent to which seepage through the earthen walls of a reservoir may take place varies. If light oils are stored and walls are carelessly made or are made of shales and clays that carry some sand, the seepage may be considerable. Even with heavy grades of oil formations 100 feet distant from large reservoirs are often saturated with oil to depths of 20 or 30 feet.[62]

BURNING SUMPS.

Oil is lost when a sump is cleaned out, just as when a tank is cleaned. The clean oil held by the B. S. is run off or burned with emulsified oil (see Pl. XX, *C*). Sump fires intentionally set to burn

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[62] Bowie, C. P., Oil-storage tanks and reservoirs, with a brief discussion of losses of oil in storage and methods of prevention: Bull. 155, Bureau of Mines, 1917, p. 37.

"dead" oil and emulsion are common in many fields. It is not uncommon for 50 or 100 barrels of dead or emulsified oil to be burned in a sump.

LOSSES IN LARGE EARTHEN RESERVOIRS.

The loss from seepage and evaporation in large well-constructed earthen reservoirs, holding as much as 500,000 barrels and covered with good roofs which prevent air currents from sweeping over the surface of the oil, varies from 1,500 to 4,000 barrels per month for California crudes of fairly light grade (about 26° gravity). A loss of several thousand barrels per month has been known to occur. Losses of this magnitude are usually due to some defect in the reservoir and can be greatly reduced.

Earthen reservoirs are often built in emergencies and the oil run into them is not gaged, hence the losses can not be ascertained. One company found that the combined losses of 14° to 16° B. gravity oil by seepage and evaporation from a 1,000,000-barrel reservoir amounted to 6.96 per cent per year. Bowie states that by lining such reservoirs with concrete the loss was reduced to 2.11 per cent per year, indicating that the seepage loss had been about 4.8 per cent per year.

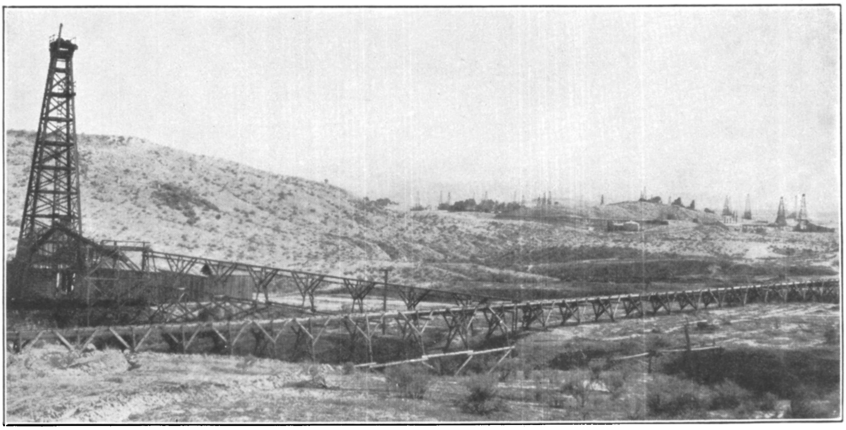
LOSS OF OIL IN SAND PUMPED FROM WELLS.

Open sumps for receiving the oil produced by flowing or pumping wells are used principally in California and the Gulf Coast of Texas. Some wells in both these States make considerable quantities of sand with the oil. In many parts of California much loose sand is produced with the oil and deposited in large mounds from which the oil is drained. This practice, though difficult to avoid, occasions considerable loss both because oil evaporates near the surface of these sands and because the sands are never treated for their oil content. Elliott [63] found that the oil sands produced by some wells in the San Joaquin Valley fields carried from 16 to 28 gallons of oil per ton as they lay on the surface. By computation it was found that oil sands of 25 per cent porosity could contain only about 26 gallons of oil of that gravity per ton; hence the indications are that the sands are almost completely saturated and that little oil drains from them into the pit. An economical method for extracting the oil from the sand has not been devised, but many California operators make good use of this oil-soaked sand by using it for road surfacing.

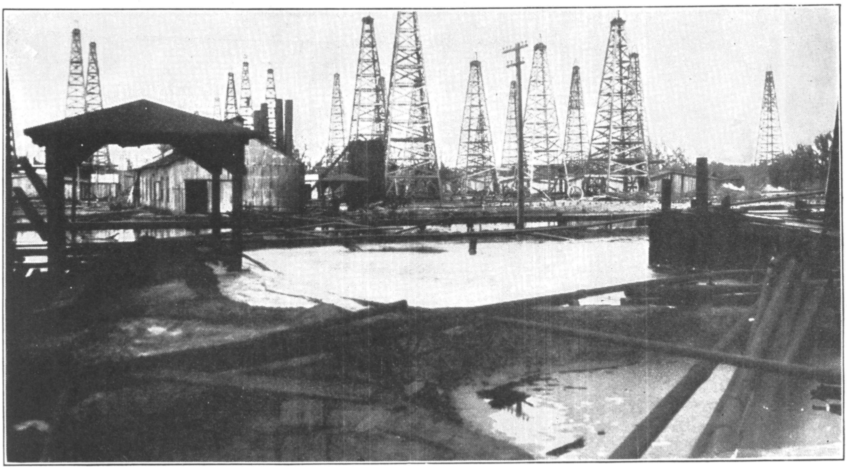
LOSSES FROM USE OF OPEN FLUMES.

In some California fields operators have constructed open flumes and ditches for conducting oil from one part of a lease to another. Plate XX, *A*, shows such a flume. This practice is confined to leases

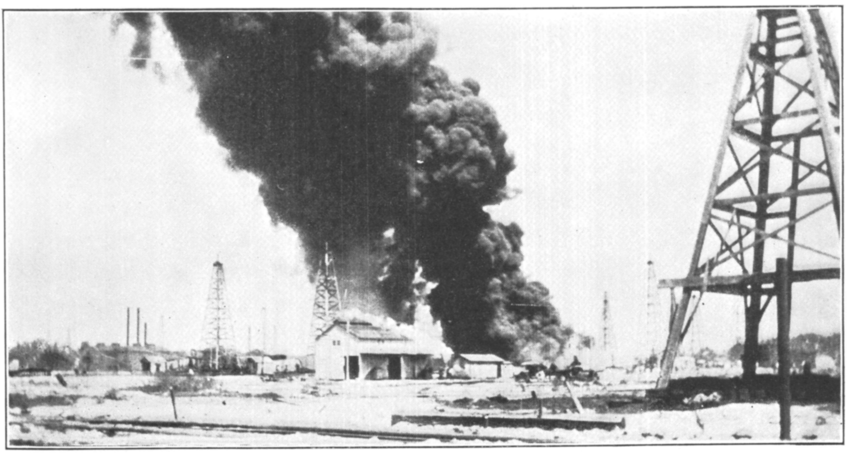
[63] Elliott, A. R., Recoverable oil in by-product sands and outcrops: Bureau of Mines, Repts. of Investigations, Serial 2,182, November, 1920.



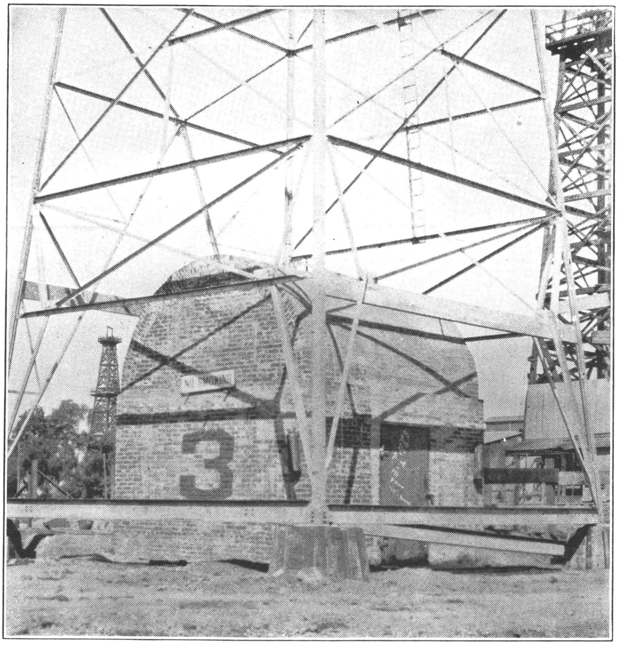
A. OIL FLOWING IN OPEN FLUME USED IN PLACE OF LEAD LINES IN A CALIFORNIA FIELD.



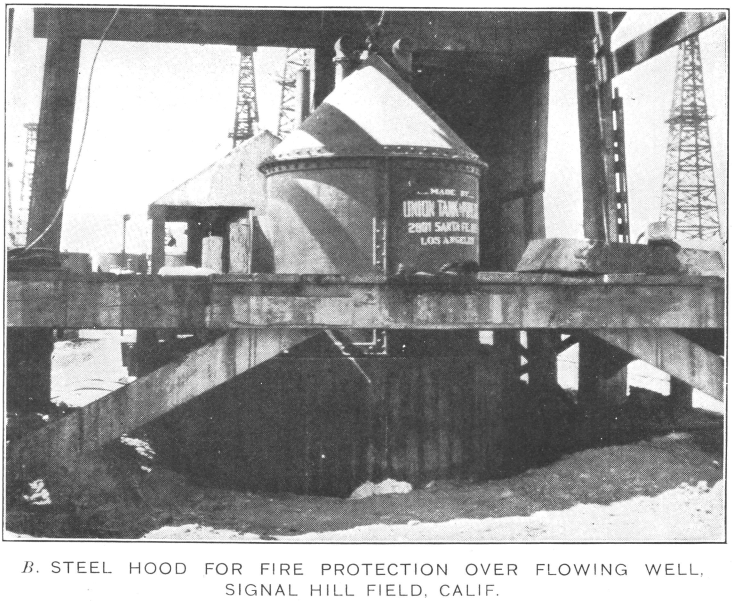
B. FLOW PIT, WEST COLUMBIA FIELD, TEX.



C. BURNING WASTE OIL IN A SUMP.



A. BRICK VAULT OVER FLOWING WELL, SANTA FE SPRINGS FIELD, CALIF.



B. STEEL HOOD FOR FIRE PROTECTION OVER FLOWING WELL, SIGNAL HILL FIELD, CALIF.

which produce very heavy oils and for that reason the evaporation loss is not heavy. Flumes also act as settling basins in which the sand separates from the oil. The seepage loss from the sand is appreciable, however, even with these heavy oils, and such practices will only be allowed on public lands by special permission.

DEPARTMENT'S ATTITUDE.

It is not possible even to estimate the losses which occur from these miscellaneous sources, but certainly they total thousands of barrels yearly. The department will not approve flowing oil into open pits, running it in open ditches, or storing it in earthen reservoirs, and only in emergencies will such practices be allowed. Suitable collection and skimming pits must be installed and waste oil recovered whenever possible. Sumps must not be burned out until as much oil as possible has been recovered.

PREVENTING AND EXTINGUISHING OIL FIRES.

If a fire loss is covered by insurance, the popular conception is that there is no loss. Unfortunately, this has been the attitude not only of the oil industry, but of all other industries. Most certainly such an opinion is perverted, for aside from the drain on insurance companies, which automatically operates to increase premium rates and thus causes those carrying insurance to pay the toll after all, the losses of natural wealth are irreplaceable. F. H. Wentworth, secretary of the National Fire Prevention Association, has said:

> The phrase, "The loss was fully covered by insurance," is the worst misleading combination of seven words in the language of modern business. Every bit of destroyed material is so much gone forever, and being destroyed before it has done useful work designed for it, it has suffered death as absolutely as a man suffers death. The fire waste is the great American pickpocket, but it operates more through the careless than through the cunning.

Although the interest of a company or individual may be protected by insurance, this in no way relieves them from their duty to take every reasonable precaution to protect the natural resources which they are exploiting.

STATISTICS ON OIL AND GAS FIRE LOSSES.

Recent statistics that give the total yearly oil-fire losses are not available. However, Bowie collected data on noteworthy oil and gas fires between 1908 and 1917, inclusive, by months, which demonstrate the importance of oil-fire losses. These statistics, although neither up to date nor inclusive of all the fire losses, are interesting in that they show the fluctuation in the occurrence of oil fires during the different seasons of the year.

TABLE 6.—*Noteworthy oil and gas fires in the United States during 1908–1917, inclusive.*

Month.	Number of fires reported.	Location.		Causes.		Estimated loss.	
		Mid-Continent and Gulf fields.	Other districts.	Lightning.	Other causes.	Oil.	Gas.
						Barrels.	*Cubic feet.*
January	8	3	5	....	8	62,000	950,000,000
February	23	15	8	10	13	233,000	390,500,000
March	33	26	7	14	19	357,200	....
April	32	25	7	22	10	610,350	....
May	46	39	7	31	15	1,614,000	1,041,000,000
June	92	75	17	73	19	2,334,500	800,500,000
July	72	49	23	45	27	2,580,600	147,006,000
August	80	71	9	69	11	3,262,400	550,000,000
September	44	35	9	32	12	693,250	....
October	31	17	14	12	19	535,400	....
November	20	13	7	2	18	510,600	1,125,500,000
December	22	6	16	....	22	56,200	20,000,000
Total	503	374	129	310	193	12,849,500	5,024,506,000

The yearly fire bill of oil producers runs into hundreds of thousands of dollars. According to the New York Journal of Commerce (August 8, 1922), the oil fires in July, 1922, which caused a loss of $10,000 or more each, totaled $3,140,000, and were as shown in Table 7.

TABLE 7.—*Oil fires in the United States in July, 1922.*

Location.	Plant or equipment destroyed.	Damages and loss.
Philadelphia, Pa	Oil refinery	$500,000
Bristow, Okla	Tanks	75,000
Burton, Kans	Oil cars	10,000
Orange, Tex	Tanks and derricks	50,000
Beaumont, Tex	Tanks	2,000,000
Laredo, Tex	Tanks	200,000
Jenks, Okla	Tanks	100,000
Sibley, La	Tanks	30,000
Sabine, Tex	Tanks	175,000
		3,140,000

The fire loss from oil fires for the first half of 1922 are given by the same journal as follows:

January	$165,000
February	100,000
March	640,000
April	1,205,000
May	1,305,000
June	220,000
Total for the 6 months	3,635,000

Data of the National Board of Fire Underwriters for the three-year period 1918–1920 show an aggregate loss from fires in storage farms, pipe-line systems, and refineries of $13,951,121. Of this amount, 52 per cent, or $7,264,933, of the fire loss resulted from lightning.

The subject of fire protection and fire prevention is so important and so complex that this manual can include only a few major features of work that has been done. However, the Bureau of Mines hopes to inaugurate some detailed investigative work on oil-fire prevention and protection in the near future and will work in cooperation with the oil industry and with fire-protection associations. The bureau will strive to increase the efficiency of known methods and devise new means of protection against fire losses.

CAUSES OF OIL-FIELD FIRES.

Many of the fires reported in Tables 6 and 7 are pipe-line, tank-farm, and refinery fires, and therefore are not indicative of the extent or number of oil-lease fires. Perhaps the fires least often reported are those on producing leases, but oil men familiar with field conditions are well aware of the danger of fires and the damage done by fires in oil fields. The majority of field fires probably are caused by lightning, although many oil-field fires result from carelessness or lack of suitable preventive measures. Lightning can not be avoided; consequently fires from this source are to be expected.

Gas or oil heated forges for heating bits and the fires under boilers are a source of numerous oil and gas well fires. Faulty electric connections and the breaking of electric bulbs at wells may cause fires. Sparks set off by stones or sand blown from gas wells, smoking, careless lighting of fires in the neighborhood of gas vapors, and brush and gas fires also cause oil-field fires.

The following account from the Daily Oklahoman of November 26, 1922, describes a disastrous oil-well fire in Arkansas from an unsuspected cause:

> The latest and worst blaze is at Jackson, Workman, and Thompson's No. 1 McDonald, in 1–16–16 of the Smackover field. The well was completed about November 1, and while cleaning itself it was ignited by a burning log, relic of a waste oil fire of a day or two previous. Spray from the well fell on this log and a favorable wind blew the flames through the oily mist to the well itself.
>
> Preparations for extinguishing the blaze have taken two weeks and $50,000 has been spent.
>
> Meanwhile Smackover's burning well is an economic loss of $5,000 daily.

FIRE HAZARDS ON THE LEASE.

The oil producer's fire hazards are of a different nature from those of the pipe-line or refining company. The oil producer is not likely to have large stocks of oil on hand stored in large steel tanks, but more often will have a number of tanks of about 250-barrel size that contain crude oil. These tanks may be either of steel or wood, and because they receive oil directly from the well often give off gaseous vapors that are highly inflammable. Fire hazards whose existence the operator must acknowledge include the crude oil itself, sumps or open pits, oil-soaked derricks, gaseous wells, and often dry grass or brush on the lease.

Lease-tank fires are particularly dangerous, because most lease tanks contain some water. When an oil tank burns, two factors which may operate to spread the fire are: First, the tank may boil over if water is present; and, second, the tank may become so hot that it fails. Burning oil, unless caught by a fire wall, often spreads to other tanks, to derricks, and to lease houses, resulting in serious property damage in addition to the loss of oil and, at times, in loss of life.

FIGHTING WELL FIRES.

GAS WELLS.

The protection against fire of wells which flow hard and possibly get beyond control is most important to the producer. Large gas wells which blow wild are likely to catch fire, either from some artificial source or from sparks caused by their throwing rocks and sand out of the hole through steel casing. Plate XII, *A* (p. 68), is a photograph of an oil and gas well fire at night and illustrates the fury of such fires.

Gas-well fires have been fought in various ways. One of the most successful methods of combating gas-well fires is to explode a charge of dynamite in the flame near the well. The discharge parts the flame and often creates a space between the unignited gas at the well mouth and the flame in the air that permits the flame in the air to be snuffed out before additional gas reaches it. An account of this method of gas-well fire fighting is given in the California World of September 8, 1921. A number of large gas-well fires in California have been extinguished by this method. Steam, mud fluid, and hoods have been used to extinguish gas-well fires; these have been described by Bowie.[64]

OIL WELLS.

Wild oil wells also constitute a fire hazard almost as great as wild gas wells and if they catch fire are much more troublesome to control. The flames from burning oil wells are not confined to the air. Burning oil falls to the ground and may ignite near-by structures, tanks, and sumps. Moreover, burning oil heats well fittings in addition to the ground and any near-by objects so that, although the flame may be smothered for a moment (as in a gas-well fire), the oil is reignited immediately by the hot objects or burning oil on the ground. The methods of fighting oil-well fires are many and varied, and local conditions will necessitate special arrangements for each fire. Steam and mud fluid are often employed. If burning oil or gas wells are flowing through casing on

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[64] Bowie, C. P., Extinguishing and preventing oil and gas fires: Bull. 170, Bureau of Mines, 1918, pp. 22–25

which are control fittings, it is sometimes possible to shut them in even after they catch fire. Men wearing asbestos suits often close in burning gas wells while workmen play streams of water from fire hoses on them.

FIGHTING TANK AND RESERVOIR FIRES.

Methods of fighting tank and reservoir fires vary, but in general this problem has been pretty well solved. Water, which is perhaps the most common agent for fighting ordinary fires, is usually the least satisfactory in fighting oil fires. Oil floats on water and does not mix with it, therefore water spreads oil fires. Likewise, water in a tank which catches fire may cause that fire to be more severe than if a clean tank of oil were burning. The water, upon becoming heated, boils and causes the tank to "boil over" spreading burning oil over near-by objects. The need for fire walls and suitable catch basins around tanks is well recognized.

Tank fires are usually fought with steam and foam-forming chemical solutions. Steam is effective with steel roofs, but can not be relied on at tanks with wooden roofs. A wooden roof soon burns and falls in and the effectiveness of steam as a smothering agent is lost. On the whole, the frothy mixture system is considered to be one of the most satisfactory and efficient ways of fighting tank fires. Frothy mixtures must be handled properly to be effective. Recently an oil-tank fire occurred in a Mid-Continent refinery. To combat this fire two tank cars of the chemicals which when mixed produce a foaming solution were hauled to the refinery. The solution was unsuccessful in putting out the fire, and investigation showed that either one chemical did not reach the tank at all or the two chemicals did not reach the mixing chamber together, and the foam therefore did not form. This illustrates neglect in the proper application of an effective fire-fighting method rather than a fault in the method itself.

PROTECTION AGAINST WELL FIRES.

STEEL DERRICKS, EARTH MOUNDS, AND MASONRY VAULTS.

Some operators in congested fields where fire hazards are naturally greatest use steel derricks for drilling and pumping to protect against the burning of rigs. Another protective measure employed at times in south Texas, California, and old Mexico is a mound of earth or a masonry vault over the casing head of a large flowing well. Plate XXI, *A*, shows a brick vault in the Santa Fe Springs field, Calif. Although such vaults are a good protection against fire, they are limited in their practicability to large flowing wells that are likely to continue flowing without interruption for a long time and are not likely to need working on. (See page 130 for Plate XXI.)

STEEL HOODS.

Plate XXI, *B*, shows a fire-protection device being used in the Signal Hill field, Calif. The steel hood completely houses the well connections and is bolted to a concrete foundation. The gas vents at the top are equipped with fine wire screen to prevent the travel of fire into the hood. Water connections are made which allow the inside to be flooded if necessary. This type of hood has an advantage over brick or concrete vaults which are sometimes built over wells in that it can easily be removed to allow work on a well to proceed. The steel hood can be used on other wells. The only permanent feature is the concrete foundation. The initial cost of this type of protection may be higher than some others, but its life and usefulness are greater.

CLEARING AWAY UNDERGROWTH.

Oil leases should be cleared of thick undergrowth and a space around derricks, tanks, and other structures cleared of grass and weeds. When setting grass fires to eliminate fire hazards, operators should use the utmost caution in keeping such fires always under control. The walls of sumps should be cleared of grass and, if possible, the sumps should be some distance from wells and tanks.

GAS TRAPS.

Ordinary open flow-tanks are fire hazards of the first order. The gas which rises from these tanks mixes with air and forms an extremely inflammable mixture. Gas is heavier than air and tends to collect in the low places. Where gas is escaping, great care should be exercised to keep fires away from the low points where gas is likely to collect. The most desirable method of eliminating this hazard is to flow or pump wells into a gas trap from which the gas is taken off for fuel or treatment in a gasoline plant. Similarly, by holding a vacuum of less than 1 ounce on a gas-tight tank, excess vapors can be removed and treated and the fire hazard reduced. Such practice also reduces evaporation losses.

TIGHT-TOPPED STORAGE TANKS.

Wiggins [65] has pointed out that tight-topped lease storage tanks reduce evaporation losses. Such tanks also reduce fire hazards. It is likely that tight-topped lease storage tanks from which the vapors are collected under a very slight negative pressure (vacuum) and are carried to a gasoline plant for treatment will come into general use in the future. Such installations have already been made in a number of fields.

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[65] Wiggins, J. H., Evaporation losses of petroleum in the Mid-Continent fields: Bull. 200, Bureau of Mines, 1922, pp. 44–70; Prevention of evaporation losses in lease tanks: Rept. of Investigations, Serial 2,236, Bureau of Mines, April, 1921.

PROTECTION AGAINST LIGHTNING.

Lightning is the greatest hazard to lease tanks and few measures have been known to prevent ignition by lightning. A steel tank in itself is fair protection against discharges within the tank, but discharges and sparks do occur outside the tank and near the vent pipe if the tank is so equipped. According to Sir Oliver Lodge,[66] a major discharge caused by lightning itself may not be the cause of igniting vapors, but an "insignificant subsidiary spark, such as is liable to occur in the neighborhood of a lightning flash in quite unsuspected * * * places," may ignite any gas in the vicinity. The installation of tight-topped tanks to prevent gas leakage would therefore seem to be most important. Leading off vapors through a vent pipe, either to a gasoline plant or to some spot away from the tanks, likewise would be a measure of protection. If vertical vents are used, the "oil sealed" or other effective vent and suitable wire gauze to prevent the flame from entering the tank should be used. The concensus of opinion seems to be not to erect lightning rods on or around tanks because sparks are not wanted even in the vicinity of tanks. The best practice is to prevent the escape of inflammable vapors and their accumulation over or near oil tanks.

In the Gulf Coast fields of Texas and in some California fields large storage reservoirs, either earthen or earthen with concrete linings, are covered with wood roofs and tar paper. Such roofs can not be gas-tight in all places and are provided with hatches or vents to permit the escape of gas. Sometimes the hatches are covered with wire mesh and sometimes simply left wide open. The oils stored in these reservoirs are not usually of high gravities, yet they give off enough gas to make their storage dangerous. Nevertheless oil fires in these reservoirs are unusual, although the Gulf Coast district is subject to frequent and violent electrical storms. A noteworthy exception is the recent fire at Humble, Tex., that destroyed two large earthen storage tanks containing approximately 800,000 barrels of Gulf Coast crude oil.

CONCLUSION.

In carrying out the "Operating Regulations" that comprise Part II of this manual, the oil and gas supervisor and his deputies will adopt, in so far as possible, the policies that have been outlined in Part I. The Secretary of the Interior is determined that wasteful production methods which can be eliminated shall not be used on Government lands. Of course, many methods suggested in this report are inapplicable to every well or every lease. In general, however, the department will insist that these or similar methods be followed to insure the maximum conservation of oil and gas.

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[66] Lodge, Oliver: Protecting oil-storage tanks against lightning: Quar. Nat. Fire Protec. Assoc., Jan., 1920, pp. 241–244.

In recognition of the differences in the applicability of certain methods in various fields, the strict interpretation of the suggestions in this descriptive section and of the "Operating Regulations" will be left to the judgment of the supervisory force of the Bureau of Mines. These men will act as consultants and advisors in the application of improved methods or experiments for testing new methods. However, the supervisor and his representatives are empowered to require all work to be done in such manner as will insure the least possible waste commensurate with good operating practice, and when negligence is willful they will be expected to require operators on public lands to cease wasteful practices.

Fixed rules often work hardships on operators; hence the operating regulations, as a whole, have been made general in character. The department and the supervisory force expect to make detailed application of the regulations in the light of practical operation in various localities, and in a spirit of fairness and justice to the lessee. Obviously, such regulations can be applied with success only by trained men of experience and judgment; but if they are so applied, the maximum conservation and efficiency with the least hardship should result. If question or controversy arises, the deputies will thoroughly investigate alleged wasteful methods before rendering final decision as to the application of conservation measures in the particular locality. Although the bureau will firmly oppose inefficiency and waste, it believes that the spirit of cooperation that has characterized the relations between operators on public lands and the department's supervisors will continue and that with this cooperation losses may be reduced to the mutual benefit of lessees and the public.

BUREAU OF MINES FIELD OFFICES.

The field offices through which the Bureau of Mines supervises oi and gas production on Government lands are as follows:

Denver, Colo., 206 Customhouse.
Bakersfield, Calif., 304 Hopkins Building.
Taft, Calif., Bureau of Mines field office.
Casper, Wyo., 508 Consolidated Royalty Building.
Salt Creek, Wyo., Bureau of Mines field office.
Winnett, Mont., care of United States Bureau of Mines.
Shreveport, La., 614–616 Merchants Building.

Field offices of the Bureau of Mines which are devoted to petroleum and natural gas investigations are:

Bartlesville, Okla., Petroleum Experiment Station.
San Francisco, Calif., 502 Customhouse.
Boulder, Colo. (Shale oil investigations).

PUBLICATIONS ON OIL FIELD TECHNOLOGY.

A limited supply of the following publications of the Bureau of Mines has been printed and is available for free distribution until the edition is exhausted. Requests for all publications can not be granted, and to insure equitable distribution applicants are requested to limit their selection to publications that may be of especial interest to them. Requests for publications should be addressed to the Director, Bureau of Mines.

The Bureau of Mines issues a list showing all its publications available for free distribution, as well as those obtainable only from the Superintendent of Documents, Government Printing Office, on payment of the price of printing. Interested persons should apply to the Director, Bureau of Mines, for a copy of the latest list.

PUBLICATIONS AVAILABLE FOR FREE DISTRIBUTION.

BULLETIN 134. The use of mud-laden fluid in oil and gas wells, by J. O. Lewis and W. F. McMurray. 1916. 86 pp., 3 pls., 18 figs.

BULLETIN 148. Methods of increasing the recovery of oil from wells, by J. O. Lewis. 1917. 128 pp., 4 pls., 32 figs.

BULLETIN 163. Methods of shutting off water in oil and gas wells, by F. B. Tough. 1918. 122 pp., 20 pls., 7 figs.

BULLETIN 170. Extinguishing and preventing oil and gas fires, by C. P. Bowie. 1918. 44 pp., 19 pls., 4 figs.

TECHNICAL PAPER 42. The prevention of waste of oil and gas from flowing wells in California, with a discussion of special methods used, by J. A. Pollard, by Ralph Arnold and V. R. Garfias. 1913. 15 pp., 2 pls., 4 figs.

TECHNICAL PAPER 45. Waste of oil and gas in the Mid-Continent fields, by R. S. Blatchley. 1914. 54 pp., 2 pls., 15 figs.

TECHNICAL PAPER 66. Mud-laden fluid applied to well drilling, by J. A. Pollard and A. G. Heggem. 1914. 21 pp., 12 figs.

TECHNICAL PAPER 68. Drilling wells in Oklahoma by the mud-laden fluid method, by A. G. Heggem and J. A. Pollard. 1914. 27 pp., 5 figs.

TECHNICAL PAPER 209. Traps for saving gas at oil wells, by W. R. Hamilton. 1919. 34 pp., 3 pls., 15 figs.

TECHNICAL PAPER 232. Application of the absorption process to recover gasoline from residual gases of compression plants, by W. P. Dykema and Roy O. Neal. 1920. 43 pp., 6 pls., 10 figs.

TECHNICAL PAPER 247. Perforated casing and screen pipe in oil wells, by E. W. Wagy. 1920. 48 pp., 6 pls., 12 figs.

PUBLICATIONS THAT MAY BE OBTAINED ONLY THROUGH THE SUPERINTENDENT OF DOCUMENTS.

BULLETIN 155. Oil-storage tanks and reservoirs, with a brief discussion of losses of oil in storage and methods of prevention, by C. P. Bowie. 1917. 73 pp., 21 pls.

BULLETIN 158. Cost accounting for oil producers, by Clarence G. Smith. 1917. 123 pp., 15 cents.

BULLETIN 177. The decline and ultimate production of oil wells, with notes on the valuation of oil properties, by C. H. Beal. 1919. 215 pp., 4 pls., 80 figs. 30 cents.

BULLETIN 182. Casing troubles and fishing methods in oil wells, by Thomas Curtin. 1920. 48 pp., 3 pls., 15 figs.

BULLETIN 194. Some principles governing the production of oil wells, by C. H. Beal and J. O. Lewis. 1921. 58 pp., 2 pls., 8 figs. 10 cents.

BULLETIN 195. Underground conditions in oil fields, by A. W. Ambrose. 1921. 154 pp., 23 pls., 43 figs. 65 cents.

BULLETIN 201. Prospecting and testing oil, gas, and water-bearing strata, by R. E. Collom. 1922. 170 pp., 6 pls., 12 figs. 25 cents.

TECHNICAL PAPER 38. Wastes in the production and utilization of natural gas, and methods for their prevention, by Ralph Arnold and F. G. Clapp. 1913. 29 pp. 5 cents.

TECHNICAL PAPER 70. Methods of oil recovery in California by Ralph Arnold and V. R. Garfias. 1914. 57 pp., 7 figs. 5 cents.

TECHNICAL PAPER 130. Underground wastes in oil and gas fields and methods of prevention, by W. F. McMurray and J. O. Lewis. 1916. 28 pp., 1 pl., 8 figs. 5 cents.

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