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UNITED STATES
DEPARTMENT OF THE INTERIOR
J. A. KRUG, SECRETARY

BUREAU OF MINES
JAMES BOYD, DIRECTOR

REPORT OF INVESTIGATIONS

# PETROLEUM-ENGINEERING STUDY OF ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

This paper represents work done under a cooperative agreement between the Bureau of Mines, United States Department of the Interior, and the Arkansas Oil and Gas Commission

BY

C. H. RIGGS

1849 1949



A Century of Conservation

R. I. 4455,
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UNITED STATES DEPARTMENT OF THE INTERIOR - BUREAU OF MINES

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By C. H. Riggs[2]

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2/ Petroleum engineer, Petroleum and Natural Gas Branch, Bureau of Mines, Petroleum Experiment Station, Bartlesville, Okla.

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## INTRODUCTION

This petroleum-engineering report of the Atlanta oil field in southern Arkansas reviews reservoir conditions and pressure-production history of one of the important Smackover limestone fields in southern Arkansas. The study of the field was made and the report prepared to aid operators in this and similar fields to increase the efficiency of recovery through the application of better engineering practices. A similar study of the Magnolia field in Arkansas by Carpenter and Schroeder 3/ was the first of these reports prepared under a joint agreement between the Arkansas Oil and Gas Commission and the Bureau of Mines.

The increasing demands for petroleum and its products and the steadily increasing cost of discovering and developing oil fields emphasize the importance of conserving known reserves of oil and gas. In recent years vast improvements have been made in the technique of oil recovery, both by better utilization of the natural energy stored in the reservoir and by improved methods of applying external energy to the reservoir system. This report may aid in oil conservation by careful evaluation of the several factors that did or did not contribute to greater recovery in the Atlanta field and by suggesting improvements in production methods and applications.

Most of the data on which this study is based were obtained from records of the Arkansas Oil and Gas Commission at El Dorado, Ark. However, some special production tests were made by Commission and Bureau of Mines engineers. Samples of produced and injected fluids were collected and analyzed in the Bureau of Mines laboratories at Bartlesville, Okla. Although not as complete as might be desired, the data permit a fairly accurate analysis of reservoir conditions and production-energy relationships in this field.

## ACKNOWLEDGMENTS

The petroleum-engineering study of the Atlanta oil field, Columbia County, Ark., was conducted by the Bureau of Mines under a cooperative agreement with

3/ Carpenter, Charles B., and Schroeder, H. J., Petroleum-Engineering Study of the Magnolia Field, Columbia County, Ark., pt. I: Bureau of Mines Report of Investigations 3720, 1943, 74 pp.

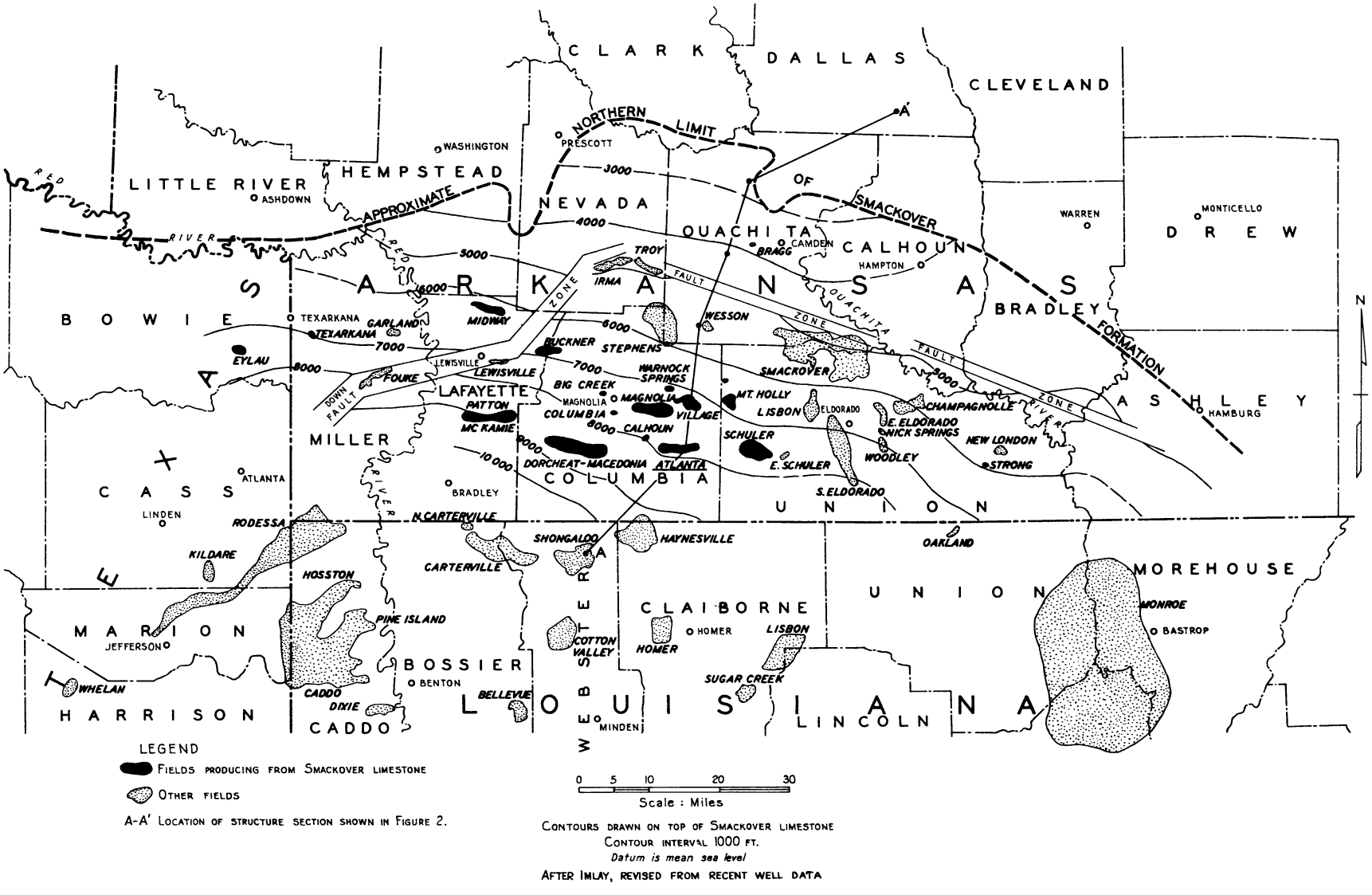


FIGURE 1. – REGIONAL MAP OF ARKANSAS, EASTERN TEXAS, AND NORTHERN LOUISIANA, SHOWING LOCATION OF SMACKOVER LIMESTONE AND OTHER OIL FIELDS.

the Arkansas Oil and Gas Commission. The work was done under the general supervision of R. A. Cattell, chief, Petroleum and Natural Gas Branch, Bureau of Mines, Washington, D. C., and H. C. Fowler, supervising engineer, Petroleum Experiment Station, Bureau of Mines, Bartlesville, Okla., and under the direct supervision of the late Ludwig Schmidt, principal petroleum engineer, Bureau of Mines, Bartlesville, Okla.

The writer gratefully acknowledges the cooperation and assistance of O. C. Bailey, chairman, and members of the Arkansas Oil and Gas Commission. Special acknowledgment is due to Lester Danforth, director, Loyd Jordan, senior engineer, Donald MacKay, senior geologist, and all of the other members of the staff of the Arkansas Oil and Gas Commission.

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## GENERAL GEOLOGY

### Location of Atlanta Field

The Atlanta oil field in Columbia County, Ark., is one of a group of oil fields in southern Arkansas that produce petroleum from the Smackover limestone and are similar in many reservoir characteristics. The oil fields that produce from the Smackover limestone are shown in solid black on a regional map (fig. 1) and other oil and gas fields in southern Arkansas, eastern Texas, and northern Louisiana are shown in lighter shade. The northern limit of the Smackover limestone and its approximate depth below sea level are shown.

The Atlanta field is between the Red and Ouachita Rivers near the inner margin of the Gulf Coastal Plain. A small creek, Cornie Bayou, runs through the eastern part of the field. Surface soil in the eastern part of the field is clay bottom land, but in the western part it is sandy upland. A comparatively small part of the area included within the limits of the field is now cultivated, as many of the farms were abandoned when oil development began.

Magnolia, 12 miles northwest, and El Dorado, 22 miles southeast, are principal cities in the vicinity of the Atlanta field. U. S. highway 60 runs between the two cities and is 6 miles north of the field. The nearest railroad is the Louisiana & Northwestern, 8 miles southwest at the town of Brister, Ark.

## Regional Stratigraphy and Structure

### Stratigraphy

The oil fields of southwestern Arkansas, northern Louisiana, and eastern Texas are in the coastal plain physiographic and stratigraphic province, where the Tertiary sediments that overlie the Cretaceous formations dip gently southward with progressively younger beds offlapping to the south. Regional stratigraphy and structure of the area are shown in figure 2. According to Weeks[4/]

> The most pronounced subsurface feature of this area, and probably the most important from a stratigraphic standpoint, is the extensive pre-Gulf truncation of the older sedimentary rocks. Thus 10,000 feet, plus or minus, of rocks in the southwest corner of the State is progressively truncated northeastward so that the entire section is missing within 100 miles, in the southern part of Dallas County.

A revised geologic column after Fancher and MacKay[5/] is shown in figure 2. In southern Arkansas and northern Louisiana few wells have penetrated below the Smackover limestone,[6/] and the character and stratigraphy of these older formations are not well-known. The smackover, principal producing formation in the Atlanta area, was first described by Bingham[7/] following its discovery in

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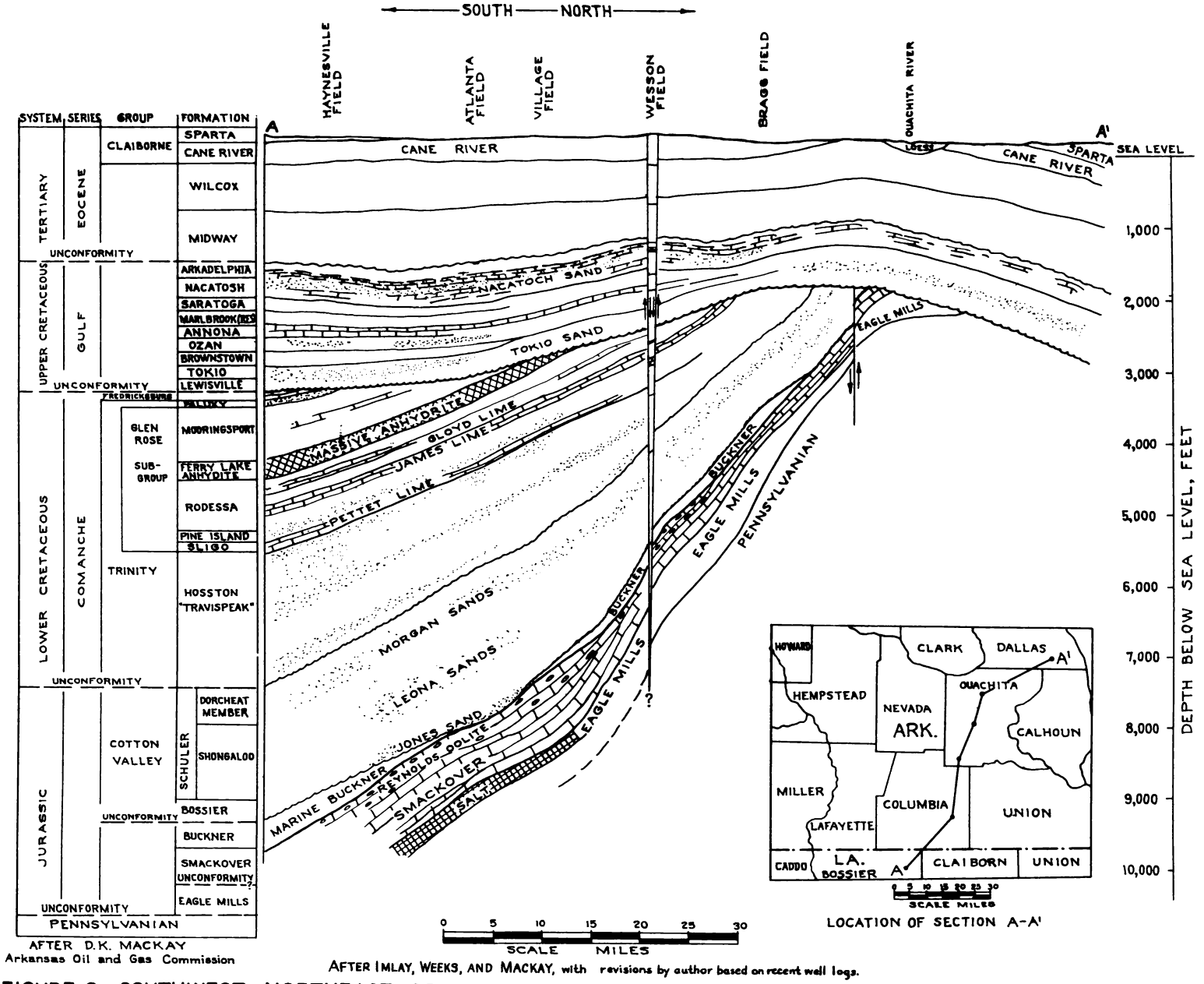
4/ Weeks, Warren B., South Arkansas Stratigraphy with Emphasis on the Older Coastal Plain Beds: Bull. Am. Assoc. Petrol. Geol. vol. 22, August 1938, pp. 953-83.

5/ Fancher, George H., and MacKay, Donalk K., Secondary Recovery of Petroleum in Arkansas--A Survey: Arkansas Oil and Gas Commission, Rept. to 56th Gen. Assembly, State of Arkansas, 1946, 249 pp.

6/ Hazzard, Roy T., Spooner, W. C., and Blanpied, B. W., Notes on the Stratigraphy of the formations which underly the Smackover Limestone in South Arkansas, Northeast Texas, and North Louisiana: 1945 Reference Rept. on Certain Oil and Gas Fields of North Louisiana, South Arkansas, Mississippi, and Alabama, vol. 2 Shreveport Geol. Soc.

7/ Bingham, D. H., Developments in Arkansas-Louisiana-Texas Area 1936-1937: Bull. Am. Assoc. Petrol. Geol., vol. 21, August 1937, pp. 1068-1073.




AFTER D.K. MACKAY
Arkansas Oil and Gas Commission

LOCATION OF SECTION A-A'

AFTER IMLAY, WEEKS, AND MACKAY, with revisions by author based on recent well logs.

FIGURE 2.- SOUTHWEST - NORTHEAST CROSS SECTION ACROSS NO. LOUISIANA AND SO. ARKANSAS

1936 at Snow Hill in the extension of the old Smackover field. According to Bruce,8/

> The Smackover extends from the unconformity, which is the limit on the north, indefinitely into Louisiana on the south. The Smackover lime covers most of the East Texas Basin, North Louisiana, South Arkansas, south of the line of truncation and extends across Mississippi into Alabama. It is not known whether this formation has porosity over all this area; however, porosity has been found in Limestone County, Tex., and several miles east of Schuler, Ark., and it is believed to lie in a band at least 30 miles wide between these points.
>
> There is no known outcrop nor is it likely that water entered or left this formation after Cretaceous time.

The Smackover limestone is thinnest, being about 450 feet at the line where truncation begins, and thickens southward. It is 941 feet thick on the axis of the Atlanta structure and 910 feet thick in the McKamie field, Lafayette County, Ark. According to Imlay,9/

> The Smackover limestone in Arkansas is comprised of two members which are transitional into each other and show marked lateral variation in lithology. Probably neither member represents exactly the same time interval throughout its extent, but each member probably represents a depositional facies which overlaps in time with the other.
>
> The upper member ranges from 280 to 500 feet in thickness and thickens towards the south. It consists mainly of white to brown "oolitic" to chalky, porous limestone in which the "oolites" are most common near the top. This is the zone of greatest porosity. The porosity of the "oolitic" limestones is probably due to lack of cementation. The porosity of the fossiliferous limestones is due mainly to solution of the organic remains. --- Fossils from the Smackover limestone show that its age is middle or upper Jurassic.

Economically the Smackover limestone is the most important oilbearing formation in Arkansas; 46 percent of the total oil produced in the State in 1946 and more than 70 percent of the flush production from the newer oil fields came from this formation. In recent years the search for oil in the Smackover limestone has led to stratigraphic studies of the older formations in the Arkansas,-Louisiana,-Texas area, but outside of Arkansas only one field - the Eylau field in Texas - produces oil from the Smackover limestone.

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8/ Bruce, W. A., A Study of the Smackover Limestone Formation and the Reservoir Behavior of its Oil and Condensate Pools: Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 155, 1944, pp. 88-120.

9/ Imlay, Ralph W., Jurassic Formations of the Gulf Region: Bull. Am. Assoc. Petrol. Geol. vol. 27, November 1943, pp. 1407-1530.

In most sections of Arkansas the Buckner formation overlies the Smackover limestone, the contact between them being a few feet of dolomitic limestones or shales that might logically belong to either formation. The Buckner formation is absent in the area of the Atlanta, Schuler, and Smackover fields, and the Cotton Valley formation rests directly on the eroded surface of the Smackover limestone. At the type locality, the Buckner formation is anhydrite and red shale, but southward it changes to a marine facies; it does not include equivalent dark shales in northern Louisiana.

The Cotton Valley group differs markedly from the Smackover and Buckner formations below. The Cotton Valley group includes several sands that are restricted in areal distribution but are oilbearing in several fields. The Jones sand, an important oil-producing sand in the Schuler field, directly overlies the Smackover limestone in several wells in the Atlanta field. The Morgan and Leona sands, named in the Schuler facies, have not been correlated definitely with Cotton Valley sands elsewhere.

The character and distribution of the lower Cretaceous rocks that overlie the Cotton Valley formation with only a slight unconformity have been described in the literature by Imlay,[9] Weeks,[4] and others. These rocks include important oil reservoirs in the Rodessa field in southwestern Arkansas, but as yet no oil has been produced from them in the Atlanta field.

The marked stratigraphic break and angular unconformity between the Upper and Lower Cretaceous rocks already has been mentioned. The Lower Cretaceous rocks were folded and eroded before deposition of the Upper Cretaceous, so that structures mapped at the surface or based upon information from shallow wells do not reflect in full degree the attitude of the underlying rocks. The Upper Cretaceous formations have been studied and mapped in detail by Spooner[10] and Weeks.[11] In general the Upper Cretaceous formations thin northward toward the pre-Gulf uplift (fig. 2).

## Structure

The petroliferous areas in Arkansas occupy an extension of the East Texas Basin. The Ouachita geosyncline in southeastern Oklahoma and southwestern Arkansas and the Sabine uplift in northern Louisiana are major structural features of the basin. A zone of faulting in southwestern Arkansas is alined more or less with extensions of the Mexia fault zone of Texas. The western end of the Arkansas fault zone is a graben about 3 miles wide in which the center block is displaced downward some 300 feet. (See fig. 1.) The east-west elongation of most of the Smackover limestone fields and the general distribution of these fields suggest folding of the older rocks in a belt roughly parallel to the outcrop of the Mesozoic sediments.

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10/ Spooner, W. C., Oil and Gas Geol. of the Gulf Coastal Plain in Arkansas: Ark. Geol. Survey, Bull. 2, Parke-Heeper Publishing Co., Little Rock, Ark., 1935 pp. 474.

11/ Work cited in footnote 4.

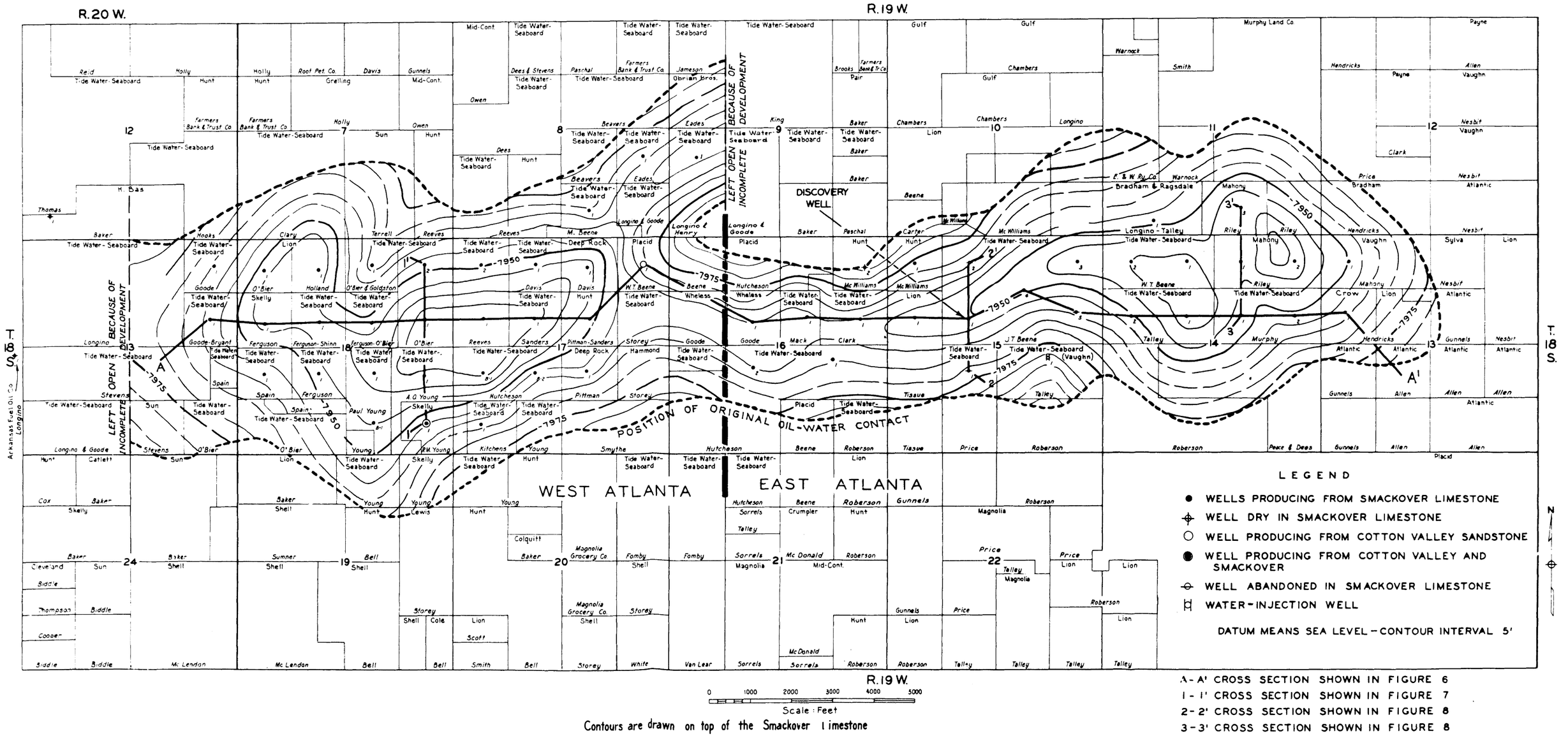



FIGURE 3.- STRUCTURE MAP OF ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

According to Spooner and others, the structural history of southern Arkansas began with folding of the north edge of the Ouachita geosyncline to form the Ouachita Mountains in Carboniferous and Permian time. By Mesozic time, the area had been reduced to a peneplain. Following deposition of the Eagle Mills, Smackover, and Buckner formations by northward-advancing Jurassic seas, the area was again uplifted and folded, and the Buckner and upper beds of the Smackover limestone were removed from some of their marginal areas and locally from some of the structural highs. During Upper Jurassic and Lower Cretaceous time, the south end of the Ouachita Basin continued to sink, as is indicated by the southward increase in number and thickness of the beds deposited. (See fig. 2.) The uplift, folding, and subsequent truncation of the pre-Gulf-Cretaceous rocks is the most important structural event in the history of this area. Considerable faulting accompanied this deformation and continued during Cretaceous and Tertiary time. Most of these faults are normal and result from the differential settling of the heavier sediments to the south. During historical times earthquakes, which are considered to be the result of settling of rocks several miles below the surface of the earth,12/ have been concentrated in a zone of weakness along the inner border of the Gulf coastal plain.

## DEVELOPMENT OF ATLANTA FIELD

### Discovery

The discovery of oil in the Smackover limestone in the Snow Hill field in 1936 led to a search over much of southern Arkansas for oil in that formation. Geophysical methods were employed to determine the attitude of the rocks below the mid-Cretaceous unconformity. The seismograph proved useful in locating structures, and during the next few years the Schuler, Buckner, Magnolia, and Atlanta fields were located and developed.

Drilling of the Tide-Water Associated Oil Co. and Seaboard Oil Co. of Delaware J. T. Beene well No. 1, SE-1/4NW-1/4 sec. 15, T. 18 S., R. 19 W., Columbia County, Ark., began September 12, 1938, on a structure located by seismograph surveys (see fig. 3). The well was completed on December 8, 1938, at a depth of 8,332 feet as the discovery well in the Atlanta field. Initially the well produced 202 barrels a day of 44° A.P.I. gravity oil a day through a 1/8-inch surface choke with casing perforations between 8,212 and 8,220 feet. Subsequent development of the field proved the discovery well to be close to the axis of the structure but west of the highest part of the dome. After preliminary testing the well was shut in until April 1939 awaiting a pipe-line outlet.

In accordance with Special Order 14-30 (see Appendix), the second well, Tide-Water Associated Oil Co. and Seaboard Oil Co. of Delaware Price well No. 1, was located in the center of the 40-acre tract immediately south of the discovery well. The well was drilled into bottom water between 8,235 and 8,237

12/ Sheets, Martin M., Diastrophism During Historic Time in Gulf Coastal Plain: Bull. Am. Assoc. Petrol. Geol. vol. 31, 1947, pp. 201-226.

feet and plugged back to 8,233 feet. Five-and-one-half-inch casing, set and cemented at a depth of 8,237 feet, was perforated with 67 shots between 8,227 and 8,233 feet. After fresh water was circulated, the well flowed 197 barrels of 45° A.P.I. gravity oil through a 1/8-inch choke with a back pressure on the tubing of 1,500 pounds per square inch. This well was 20 feet lower structurally than the discovery well and defined the southern limit of economic oil production. The next two wells were drilled west of the discovery well and indicated the east-west alinement of the structure. The sixth well to be drilled, J. K. Mahony, E. Riley well No. 1, NW-1/4NE-1/4 sec. 14, T. 18 S., R. 19 W., located the crest of the east dome and extended the field 1-1/4 miles eastward. During the next 2 years drilling proved the area between the discovery and Mahony wells and determined the north and east economic limits of oil production.

The existence of a structure in the West Atlanta area in secs. 17 and 18, T. 18 S., R. 19 W., was indicated by seismograph surveys. A map published in 1940 by Crowell[13] shows this undrilled structure. The discovery well in the West Atlanta field was Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware A. O. Young well No. 1, NE-1/4SE-1/4 sec. 18, T. 18 S., R. 19 W., completed June 1, 1943, in the Smackover limestone at a depth of 8,356 feet. Initial production was 347 barrels daily of 44° A.P.I. gravity oil produced through casing perforations between 8,294 and 8,300 feet, with a 1/4-inch surface choke and with a tubing pressure of 1,500 pounds per square inch. The 5-1/2-inch casing was perforated opposite the Cotton Valley sands between 7,222 and 7,224 feet and the oil flowed through the annular space between tubing and casing. The highest initial rate of production from the Cotton Valley sand was 356 barrels of 40.7° A.P.I. gravity oil daily through a 1/4-inch surface choke with 750 pounds per square inch back pressure. The next four wells completed only in the Smackover limestone were east, west, south, and north offsets to the discovery well in the west field and indicated an east-west structure of considerable size with a thick gas cap. Subsequent drilling proved that the Atlanta and West Atlanta fields were parts of the same field separated only by a narrow structural saddle. Development in the West Atlanta field progressed slowly because of shortages of casing and equipment during the war. Two wells were completed along the north edge of the field early in 1947. These wells indicated a considerable extension of the field in sec. 9, T. 18 S., R. 19 W. The status of wells in the Atlanta field as of July 1, 1947, is shown in table 1.

## Drilling and Completion Practices

The locations of all wells in the Atlanta field were in accordance with regulations of the Arkansas Oil and Gas Commission, Orders 14-39 and 15-45, which provide that no well should be drilled less than 1,320 feet from any well spudded or less than 660 feet from any property or division line. Wells should be spaced within 100 feet of the center of Government 40-acre drilling units, except as the commission may grant exceptions where a well regularly spaced would be outside the pool or topographical conditions would make drilling difficult. (See Appendix.)

13/ Crowell, Alex M., Latest Engineering Practices Embodied in Arkansas Conservation Act: Oil and Gas Jour. vol. 38, Feb. 15, 1940, p. 49.

TABLE 1. - Number and status of wells in the Atlanta oil field, Columbia County, Ark., July 1, 1947

| | Number of wells | |
|---|---|---|
| | At completion | Active as of July 1, 1947 |
| Smackover limestone oil wells drilled | 54 | 50 |
| Cotton Valley sand oil wells drilled | 1 | 1 |
| Dry holes drilled | 2 | 1 1/ |
| Total wells drilled | 57 | 57 |
| Dual completions | 2 | 0 |
| Abandoned Smackover wells | - | 4 |
| Water-injection wells | 0 | 1 |
| Total flowing oil wells | 53 | 36 |
| Total pumping wells | 0 | 14 |
| Smackover limestone oil wells producing more than 2 percent water | 4 | 34 |
| Wells producing free or liberated gas with oil | 8 | 28 |
| Wells incapable of producing prorated oil allowable | 1 | 5 |
| Smackover wells with oil allowable restricted because of high gas production | 5 | 9 |

1/ One converted to water injection well.

The wells in the Atlanta field were drilled with medium-heavy rotary equipment using steel derricks 124 and 136 feet high. The discovery well and a few others were drilled with Diesel engines, but most wells were drilled with steam rigs fired with natural gas. After the first few wells were completed, a loop gas line from high-pressure oil-gas separator vents supplied gas for drilling purposes. About 40,000,000 cubic feet of gas was required to drill each Smackover limestone well. Ample surface water for drilling usually was available.

From 30 to 60 days were required to drill the wells in the Atlanta field to the Smackover limestone and 5 to 10 days to complete wells after setting casing. Tests to determine the deviation of the drill hole from the vertical were made at frequent intervals, and inclinations of the bore hole were held to 1° or less. With the exception of the limestone and anhydrite strata of the Glen Rose group, the formations above the Smackover are soft sands and shales that drill easily. These shales provided ample mud-fluid for drilling, but before casing was set or drilling into oil- or gas-bearing formations was done, the drilling fluids were conditioned with mixtures of bentonite and barite to weigh 11 pounds per gallon. The weight of the conditioned mud column provided pressures at the face of the penetrated formations that were 1-1/3 the original reservoir pressure, and all wells were completed without blow-outs. Average costs of a completed well are shown in table 2.

The Arkansas Oil and Gas Commission specifies the minimum lengths of casings and the minimum quantity and the method of placing the cement behind the casing. (See rules, regulations, and orders of the Arkansas Oil and Gas Commission pertaining to the Atlanta field in the Appendix to this report.)

The general procedure was to set 150 to 300 feet of 13-5/8-in. conductor pipe and to cement this casing from the bottom to the surface. To protect the oil-bearing sands of the Gulf series, an intermediate string of 9-5/8-inch O.D. casing was set at approximately 3,500 feet and cemented with enough cement to fill the annular space into the surface casing.

TABLE 2. - Estimated cost of completing a well in 1945 in the Smackover limestone, Atlanta field, Ark.

| | | |
|---|---|---|
| Drilling | | |
| 8,300 feet of hole at $5.00 per foot (includes cost of derrick, digging cellar and pits, fuel, water, and mud fluid not to exceed $1,500.00) | | $41,500.00 |
| Casing and tubing | | |
| 200 feet of 13-5/8-in. 36 lb. O.D. Armoa casing | 458.00 | |
| 3,500 feet of 9-5/8-in. 36 lb. O.D. H-40 ss casing | 6,650.00 | |
| 6,300 feet of 5-1/2-in. O.D. 17 lb. J-55 ss casing | 5,859.00 | |
| 2,000 feet of 5-1/2-in. O.D. N 80 ss casing | 2,100.00 | |
| 8,300 feet of 2-3/8-in. O.D. J-55 ss tubing | 2,573.00 | |
| Total cost of casing and tubing | | 17,640.00 |
| Equipment | | |
| Bradenhead | 265.00 | |
| Gate valves | 200.00 | |
| Christmas-tree assembly | 1,200.00 | |
| Miscellaneous | 300.00 | |
| Total cost of equipment | | 1,965.00 |
| Materials | | |
| Cement | 3,000.00 | |
| Mud | 2,000.00 | |
| Water | 2,000.00 | |
| Miscellaneous | 1,000.00 | |
| Total cost of material | | 8,000.00 |
| Services of Rig for completion (10 days at $500.00) | 5,000.00 | |
| Trucking | 1,750.00 | |
| Labor | 2,000.00 | |
| Cementing | 905.00 | |
| Well logging | 520.00 | |
| Coring and analyses | 500.00 | |
| Gun perforating | 200.00 | |
| Drill stem testing | 700.00 | |
| Total cost of service | | 11,575.00 |
| Total cost of well | | $80,680.00 |

Coring and Logging

Five wells were cored through the Cotton Valley sands and one through the Jones sand, and the Smackover limestone was cored in 51 of the 57 wells drilled

in the Atlanta field. About 8 or 10 feet of formations were cored during each run of the core barrel, and the recovery ranged from 50 to 100 percent, depending on the friability of the rock. During coring operations, the weight on the bit, the speed of the rotary table, and the viscosity and pressure of the drilling fluid were maintained as nearly uniform as possible, so that the rate of penetration of the rock would reflect, to some extent, differences in texture of the strata. Coring time was recorded in minutes required to drill each foot of formation.

All wells were electrically logged from the base of the intermediate casing string to the bottom of the hole. A few wells also were logged through the Gulf series before the intermediate string of casing was set. The electric logs recorded a standard self-potential curve and three resistivity curves with different electrode spacings. In logging the Smackover limestone an amplified self-potential curve was added to show more distinctly the differences in character of the strata. In several wells, where electric logs had indicated possible oil-productive sands, side-wall cores were taken for additional information. Several edge wells were drill-stem-tested in the Cotton Valley or Smackover formation for information on the productivity of the zones before the casing was set.

Casing and Gun Perforating

Field rules of the Arkansas Oil and Gas Commission (see Appendix) require that the producing string of casing be set and cemented below the gas-oil contact. In several early wells the casing was set at the top of the oil-producing zone, but in later wells the 5-1/2-inch casing set on bottom with a guide shoe and float collar was cemented with 600 to 1,000 sacks of Portland cement and then gun-perforated with 11 to 72 shots. As gas:oil ratio tests proved that the producing string was set too high in one well, a 4-1/2-inch liner was set on bottom, cemented into the 5-1/2-inch casing, and then perforated opposite the oil-bearing zone. To insure an adequate seal around the casing seat, cement left in the perforated casing usually is not drilled out to the bottom of the hole. As the allowable oil production of wells that produce more than 3,000 cubic feet of gas per barrel of oil is restricted by the Arkansas Oil and Gas Commission to an extent depending upon the voidage of the reservoir by the excess produced gas (see Appendix), it is to the advantage of oil producers to be assured that the casing is gun-perforated only opposite the oil-saturated sand. Several wells were drill-stem-tested before completion to determine the relative volumes of oil and gas produced through the perforations. If gas:oil ratio tests indicated that the perforations were too high, the holes were squeeze-cemented, and the casing was reperforated below. In later wells, and following trouble with corroded casing in the Magnolia field,[14] the 2-3/8-inch O.D. tubing was set with a tubing packer above the oil producing section of the Smackover limestone and the conditioned mud was left in the annulus between the tubing and casing as a protective measure.

14/ Work cited in footnote 3.

Two wells were dually completed to produce from both the Cotton Valley and Smackover formations. In these wells the casing opposite the Cotton Valley sand was gun-perforated, and a drill-stem test was made before the casing was opened to the Smackover limestone. A tubing packer was set below the Cotton Valley perforations, and the annulus above the packer was left open to flow the Cotton Valley production through the casinghead. A schematic drawing of a dually completed well is shown in figure 4. Although this type of completion saved material, it was not entirely satisfactory because the flowing life of Cotton Valley sand wells in the Atlanta field is comparatively short and artificial-lift methods in the annulus of a dually completed well have not been perfected.

Initial Production

The surface equipment of all flowing wells in the Atlanta field was pretested to withstand 10,000 pounds per square inch pressure. Bolted connections were used from the casinghead to the choke. After surface connections were made, the wells were "brought in" by circulating fresh water to lighten the column of drilling fluid until oil began to flow. One or more trips with tubing swab were sometimes required to start the upward flow of oil and gas. After the well cleaned itself of water and drilling fluid, the production was turned into the gas:oil separator, and a test was made of the daily production of oil, gas, and water. Initial producing rates through chokes 1/8 to 1/4 inch in diameter ranged from 27 to 519 barrels of oil daily. A productivity index test made on the discovery well in the West Atlanta field in July 1943 indicated a bottom-hole pressure drop of 11 pounds per square inch when the production rate was 252 barrels of oil daily for an index of 22.9.

Initial gas:oil ratios of wells in the East Atlanta field approximately equaled the solution gas:oil ratio of 1,100 cubic feet per barrel, but a few structurally high wells in the western part of the field produced more than 20,000 cubic feet of gas per barrel of oil. The gravity of the produced oil ranged from 42° A.P.I. when the gas:oil ratio was near the solution gas:oil ratio, to 59.2° A.P.I. for a well producing 21,000 cubic feet of gas per barrel of oil. The higher-gravity oil probably was caused by dilution of the oil with gasoline vapors that condensed from gas produced with the oil.

Because initial oil-producing rates were high as compared to daily allowables, no wells were treated with acid initially. Four wells have been acidized since completion with treatments ranging from 250 to 1,500 gallons of acid.

## RESERVOIR CONDITIONS - SMACKOVER LIMESTONE

### Sources of Information

Knowledge of the subsurface conditions in the Atlanta field is based on measurements made in the wells and on examination and measurements of samples of rocks and fluids brought to the surface. Drillers' logs, coring-time records, core analyses, core descriptions, and electric logs of nearly all wells were available to aid in interpreting reservoir conditions. Depths to

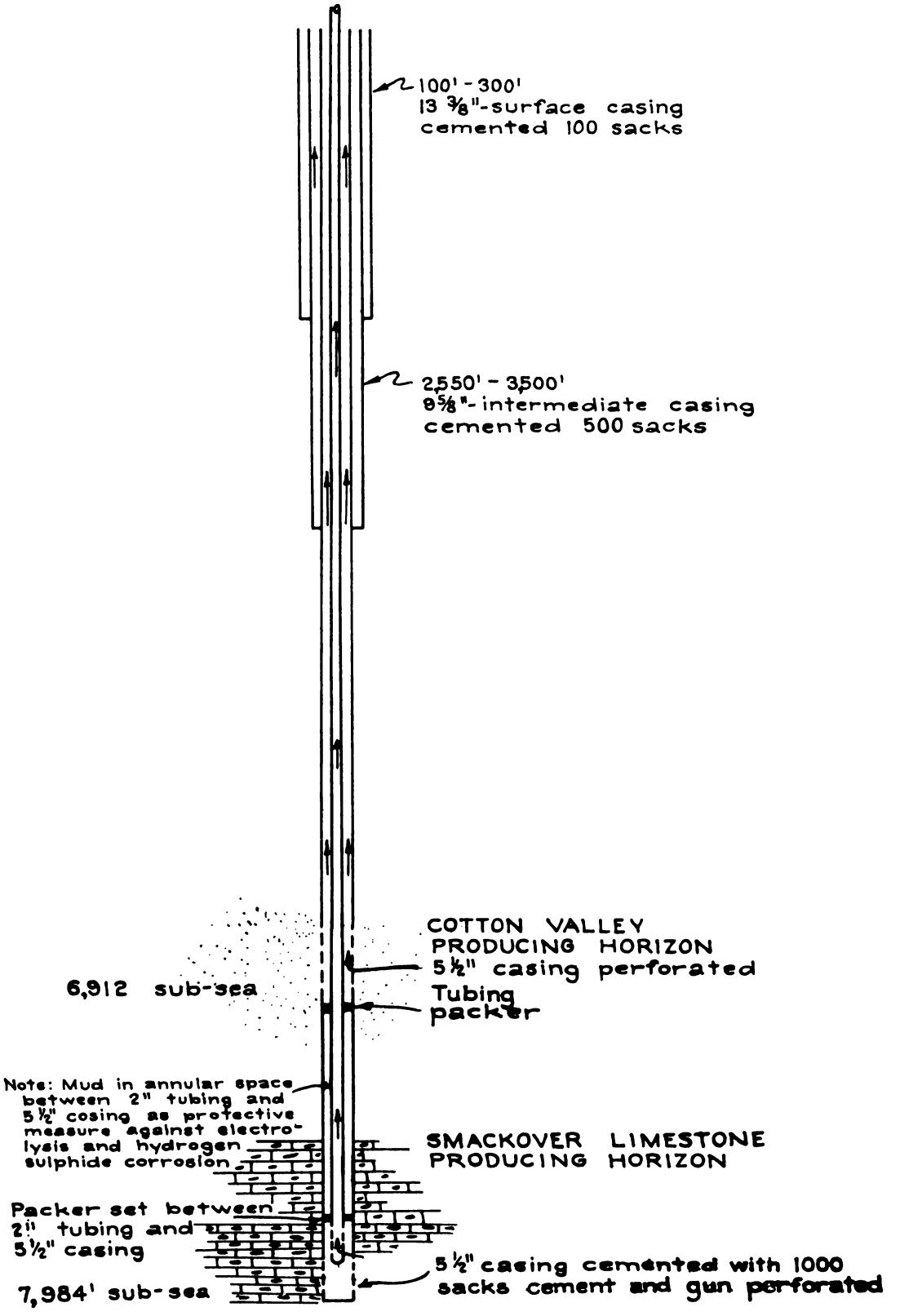



FIGURE 4. -SCHEMATIC DIAGRAM OF A DUALLY COMPLETED WELL IN THE ATLANTA FIELD, COLUMBIA COUNTY, ARK.

formations and zones as recorded on drillers' logs agreed with those shown on the coring-time records, core analyses and descriptions, and with measurements made of casing and drill pipe. If depth measurements made by electric-logging instruments did not agree with these depths, the electric logs were adjusted to conform to the other measurements. Wherever coring operations commenced above and continued through the upper beds of the Smackover limestone, the tops of the limestone and of the underlying porous zone were determined by cores and coring time. If core recovery was incomplete (sometimes as low as 30 percent), coring-time records were used to fix the position of each portion of the core within the cored section, instead of assuming that the recovered portion was the uppermost part cored and that the lower portion of the core was lost. In general, it was assumed that soft rock with short coring time probably was lost and that the harder portions of the rock were more likely to be recovered in the core barrel. Usually visual examination and descriptions of the cores were made on the derrick floor by geologists and engineers, and these descriptions were useful in correlations. Cores from the last three wells drilled in 1946 and 1947 were examined and analyzed at the Petroleum Experiment Station of the Bureau of Mines at Bartlesville, Okla.

All of the cores were cut with a rotary core barrel while regular aqueous drilling fluid was being circulated in the wells. Several cores were analyzed on location; others were canned and analyzed later. All cores were so badly flushed by the drilling fluid that no appreciable differences in oil or water saturation could be attributed to time elapsed after coring. Porosity and permeability measurements were more useful than saturation data in the study.

Electric logs of all wells were available and were used extensively, with and without other data, to fix the top of the Smackover limestone and to establish the position of the more porous and permeable zones of that formation. In general, the top of the Smackover limestone was determined at a point of low self-potential which corresponded in depth with a marked increase in resistivity as indicated by the normal and third curves of the electric logs. The top of the first productive zone (frequently called "porosity") is indicated by a marked increase in the self-potential, usually shown on the amplified curve, and by a decrease in resistivity at the same depth as indicated by the third or lateral curve.

## Structure

The structure of the Atlanta field as shown by contours drawn on top of the Smackover limestone (fig. 3) is an east-west anticline divided by a saddle into East and West fields. The structure of the West field is modified by parallel northeast-southwest cross folds. As the structure at the west and north edges of the field was not definitely determined when this study was made, the contours were left open. Also development operations in section 9, T. 18 S., R. 19 W., are still in progress and probably will extend the field in that area.

The West field is structurally higher than the East field, the highest well in the former being about 34 feet above the saddle between the two areas as compared with 28 feet above for the highest well in the East field. Structure in the West field is accentuated by the northeast-southwest cross folding.

The structure of the upper surface of the first "porosity" of the Smackover limestone is shown in figure 5. As is explained later, the top of this zone does not correspond with any definite stratigraphic horizon, and consequently the structure of this "pseudo-surface" differs from that shown in figure 4. The main axis and general configuration of the contours shown on the maps of both figures are similar.

The absence of the Buckner formation and of upper beds of the Smackover limestone in some structurally high wells and the distribution of the porous zones indicate the possibility that some form of the Atlanta structure existed as a topographic feature during the post-Buckner emergence. The tectonic history of the area, however, is too long and complex for the early form to have resembled closely the present structure.

The structural position of "zones of porosity" and of the reservoir fluids in the Smackover limestone is shown by west-east and south-north cross sections in figures 6, 7, and 8. Figures 6 and 7 show four electric logs through the Cotton Valley formation. Figures 7 and 8 show the position of gas-, oil-, and water-saturated zones as interpreted from core data and electric logs.

## Lithology of Reservoir Rock

In some areas of the Atlanta field the Smackover limestone is overlain directly by the Jones sand, which is a hard, greenish-gray, fine-grained sandstone, but more often a dark gray dolomitic shale 3 to 8 feet in thickness separates the Jones sand from the Smackover limestone. The top beds of the Smackover limestone are reported to be hard, greenish-gray dolomitic limestones, or hard and tight oolitic or granular limestone. Cores recovered from the Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware, T. W. Murphy well No. 1, sec. 14, T 18 S., R. 19 W., are described in table 3.

Photomicrographs of representative cores, "A", "B", "C", and "D" (fig. 9) illustrate the different character of the porous zones of the Smackover limestone in the Atlanta field. Core "A" is a fine-grained rock with oolites 0.4 mm. in diameter; the small amount of cementing material between the oolite grains results in a rock of comparatively high porosity and low permeability. Core "B" has larger oolites with more cementing material, resulting in greater permeability but less porosity than core "A". Core "C" is a limestone conglomerate composed of pisolites 3.0 mm. in diameter, small oolites, and fossil shell fragments lined with calcite crystals. The reworked character of some of the upper beds of Smackover limestone is shown by photomicrograph "D". A large subangular pebble surrounded by a matrix of small oolites is evident in the upper central part of this picture. The large pebble is itself composed of oolites and subangular fragments cemented together in an earlier rock and later incorporated in the rock of the cored stratum.

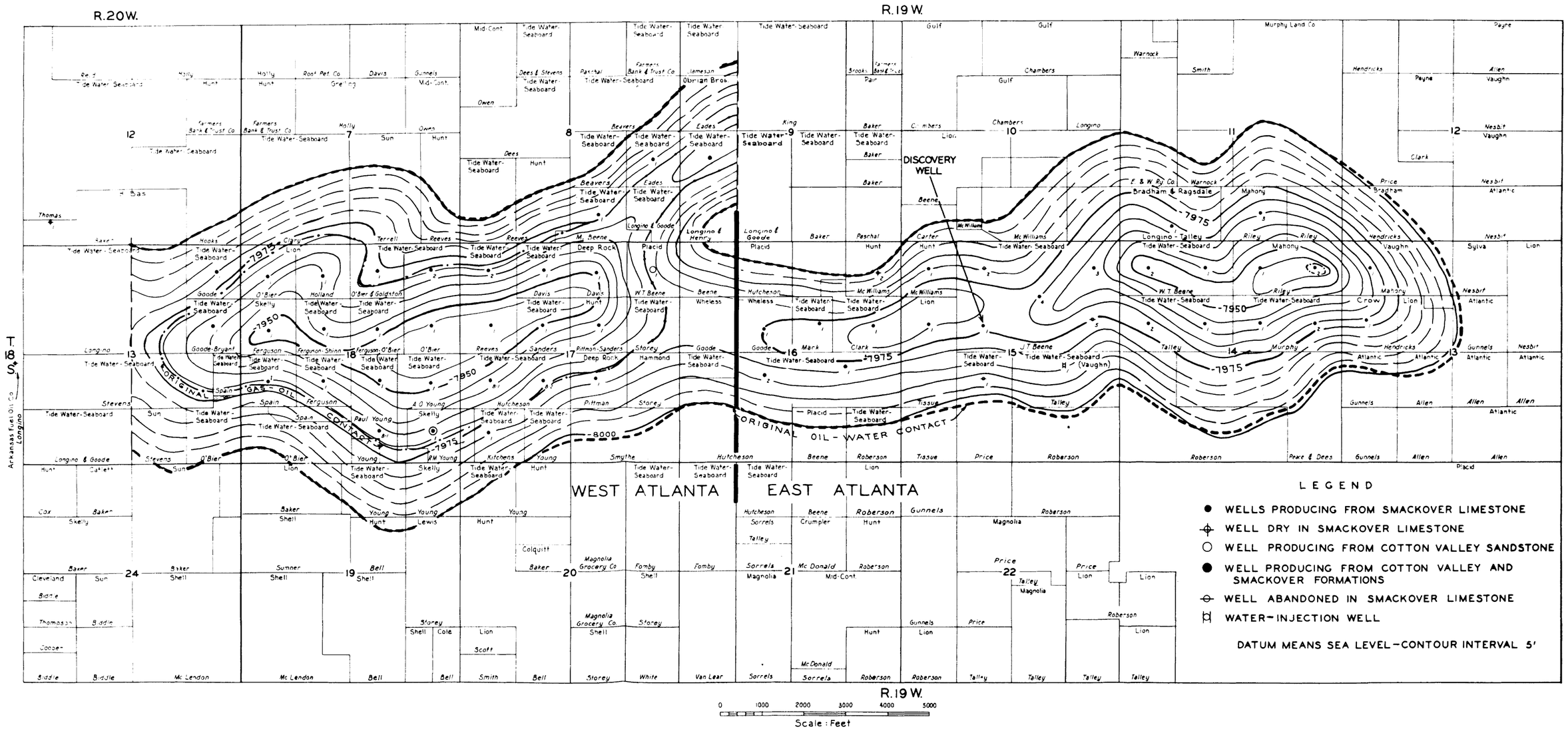



FIGURE 5.- STRUCTURE MAP OF ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

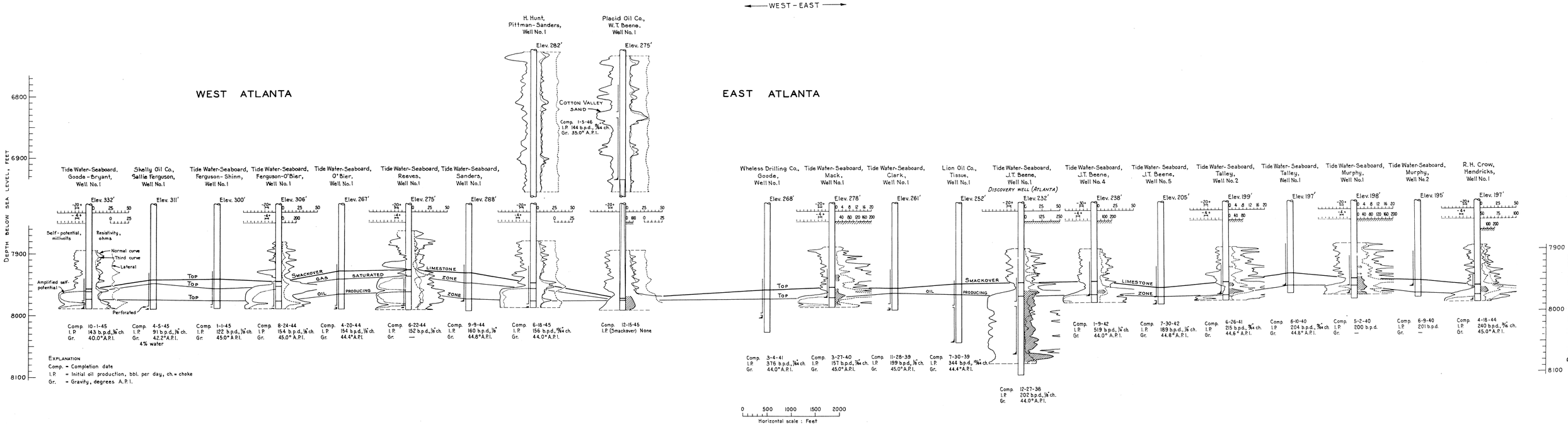



FIGURE 6. - WEST - EAST STRUCTURE SECTION A-A THROUGH ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

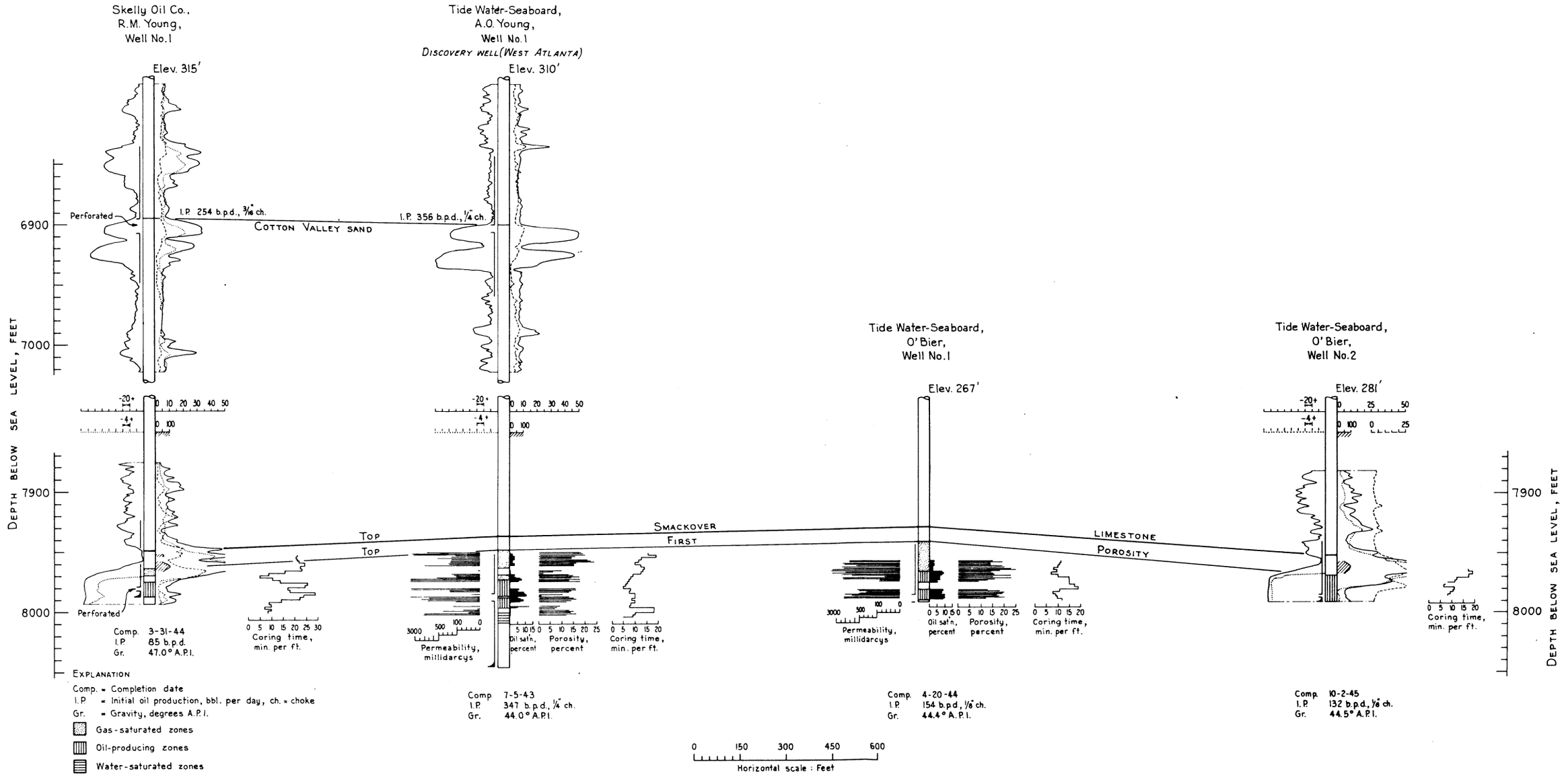



FIGURE 7. – SOUTH – NORTH STRUCTURE SECTION I–I′ THROUGH ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

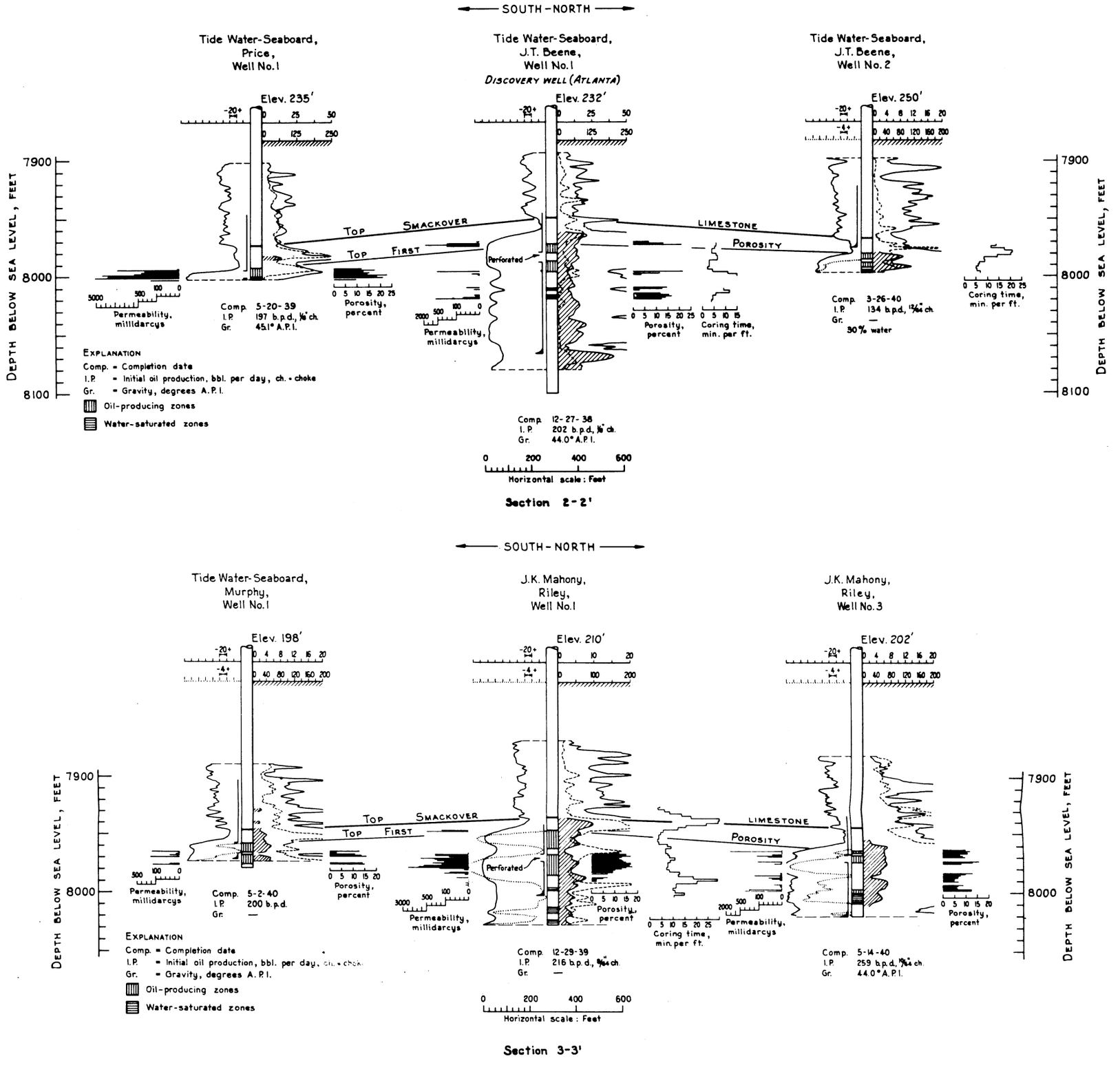
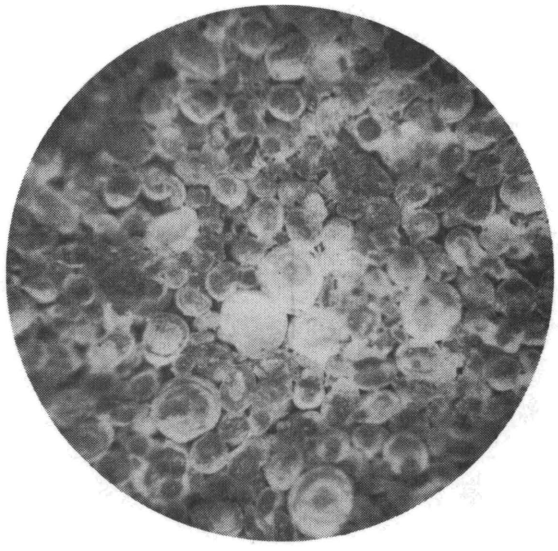
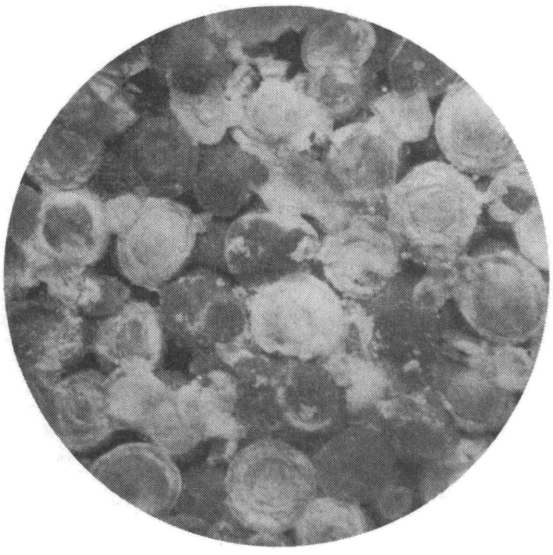



**FIGURE 8.– SOUTH–NORTH STRUCTURE SECTIONS 2–2' AND 3–3' THROUGH ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.**

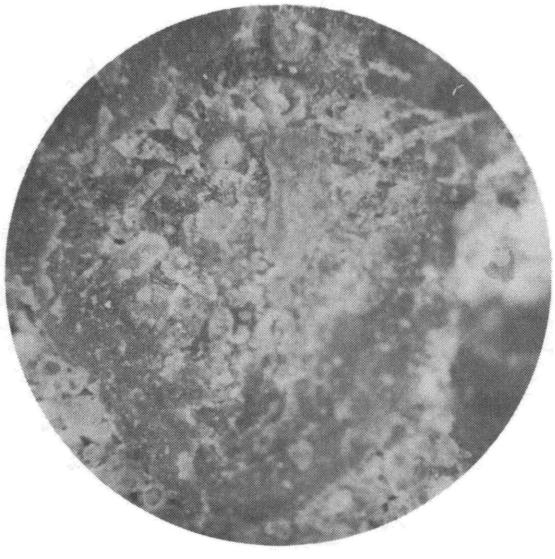


A. Oolitic; porosity 18.0 percent, permeability 86 md.



B. Pisolitic; porosity 14.9 percent, permeability 550 md.

C. Fossiliferous; porosity 17.6 percent, permeability 290 md.



D. Conglomerate; porosity 14.9 percent, permeability 86 md.

Figure 9. - Photomicrographs of Smackover limestone reservoir rock x 14 d.

TABLE 3.-Description and anaylses of cores from Tide Water Associated Oil Co. and Seaboard Oil Co. of Del., T. W. Murphy well No. 1, sec. 14, T. 18 S., R. 19 W.

| Description | Depth, feet | Thickness, feet |
|---|---|---|
| Bossier Formation | | |
| Gray calcerous sand, slightly porous | 8,237-8,237 | 3 |
| Dark gray shale | 8,237-8,239 | 2 |
| Gray calcerous sand, tight to slightly porous | 8,239-8,241 | 2 |
| Grayish green dolomitic shale | 8,241-8,243 | 2 |
| Smackover Formation | | |
| Gray, dense oolitic limestone with streaks of dense limestone | 8,243-8,245 | 2 |
| Dense gray limestone with streaks of oolitic limestone | 8,245-8,250 | 5 |
| Not cored, (limestone) | | 12 |

| | Porosity, percent | Permeability, millidarcys | | |
|---|---|---|---|---|
| Oolitic limestone, slightly porous | 12.7 | 125 | 8,262-8,264 | 2 |
| Dense, oolitic limestone | 12.0 | 25 | 8,264-8,266 | 2 |
| Oolitic limestone, slightly porous | 15.9 | 224 | 8,266-8,268 | 2 |
| Oolitic limestone, dense with streaks of porous lime | 13.6 | 44 | 8,268-8,272 | 4 |
| Oolitic limestone, finely porous | 14.6 | 195 | 8,272-8,274 | 2 |
| Dense oolitic limestone, no porosity | | | 8,274-8,277 | 3 |

## Porosity and Permeability of Reservoir Rock

With the exception of a bed of anhydrite 25 to 35 feet below the top of the Smackover limestone recorded in logs of wells in the eastern part of the field, no definite stratigraphic horizons in the Smackover limestone have been identified from cores or logs. Apparently porous zones do not conform to stratigraphic horizons but grade laterally and vertically into tighter limestones, depending on the amount of cementing material between the grains. Although a few cores show solution channels in the limestone, most of the porosity is of the interstitial type between the round oolites. An isogram map based on average porosity of cores from each well shows higher porosity in the West than the East field and highest porosity along the north and south flanks of the structure. In the western part of the field the upper beds are more porous than lower beds, but no such relation is apparent elsewhere in the field.

The permeability of the Smackover limestone varies widely both horizontally and vertically. The average horizontal permeability of cores from two wells on the same lease were 20 and 688 millidarcys, respectively. A work map, not included in this report, contoured on average permeability of cores from each well, shows no definite pattern of high and low permeabilities but indicates higher average permeabilities in the saddle between the two parts of the fields and more uniform permeability between wells in the eastern than in the western parts of the field. Cores from individual wells indicated considerable vertical variation in permeability, with a few thin streaks of low permeability within the porous zones. Measurements on the same core sample disclosed that vertical permeability usually was only slightly less than the horizontal permeability. Average permeability of a zone above the oil-water contact, 15 feet thick, was 560 millidarcys as compared to 1,090 millidarcys for the main body of the oil reservoir and 1,150 millidarcys for the gas reservoir in the western part of the field.

## Original Gas-Oil and Oil-Water Contacts

Interconnected pore spaces in the Smackover limestone are assumed to have been filled originally with gas, oil, and water in varying proportions, depending upon their structural position. Data from which relative initial gas, oil and water saturations of the reservoir rock can be calculated, however, are inconclusive because all cores were flushed badly by the drilling fluid. Samples from one representative well showed total water saturations of from 38 to 63 percent, of which only 0.7 to 25 percent was calculated to have contained chlorides equivalent in amount to that present in the interstitial water. Some relationship between permeability and flushing of the cores is indicated by data on 237 core samples; water saturations of cores of very low air permeability averaged 35 percent, whereas, the water saturations of cores having air permeabilities of 4 or 5 darcys averaged 45 percent.

Original reservoir liquids that were not flushed from the cores during drilling expanded and were lost partly when the cores were brought to the surface; in fact, total liquid saturation of all cores averaged less than 50 percent. The average residual oil content of 31 cores from the gas-saturated sand at the top of the structure was 2.35 percent, and the average residual oil saturation of 307 cores from the oil-productive section was 7.7 percent. In terms of reservoir oil these saturations would represent 4.0 and 13.1 percent, respectively.

Core analyses and other data indicate a gas cap of several hundred acres in the West Atlanta field. The exact position of the original gas-oil contact is uncertain, because wells in the West field were drilled after oil and gas withdrawals from the East field had reduced the reservoir pressure and after some solution gas had been liberated. The analyses of cores from several wells showed a marked increase in oil saturation at about 7,970 feet below sea level as an indication of the gas-oil contact. (See Tide Water-Seaboard, O'Bier 1 and A. O. Young 1, section 1-1', fig. 7). Electric logs could be interpreted in only a few wells to fix the gas-oil contacts. Based upon all available data, the original gas-oil contact was fixed at between 7,970 and 7,976 feet below

sea level in the area of each well in the West field. The edge position of the gas-oil contact is shown by the dot-dash line in figure 5.

The gas-oil contact in the J. K. Mahony E. Riley well No. 2, in the East field was at 7,956 feet below sea level. Other wells in this area were lower structurally, and the top of the First Porosity was saturated with oil.

Thirteen wells in the Atlanta field were drilled through the oil-saturated portion of the Smackover limestone and into underlying water-saturated limestone below. Electric logs and core-analysis data from these wells indicate that the oil-water contact was at a depth of approximately 8,000 feet below sea level. The water level was higher in structurally high wells than in wells along the flanks; at a subsea depth of 7,995 feet in stratigraphically lower beds on top of the structure and at about 8,002 feet below sea level in the off-structure wells. Based on water-level data, a contour map (not included in this report) was prepared to show the estimated position of the original oil-water contact throughout the field, and this map was used to estimate the base of the oil-productive portion of the reservoir rock in the area about each well.

## Reservoir Volume

Cores from individual wells showed that some zones are of low permeability, through which fluids would move only under relatively high pressure differentials. In the production process, the more permeable zones are first oil-depleted and become avenues for advancing edge or bottom-hole water. In the Atlanta field, wells were abandoned when advancing water comprised more than 95 percent of the total liquid production. At this stage and pressure-differential the tightest zones may have yielded comparatively little oil to the well. For practical purposes zones having air permeabilities of less than 10 millidarcys were considered nonproductive. Zones of low permeability, as indicated by core analyses, were correlated with zones of comparatively lower self-potential and higher resistivity, as shown by electric logs (see Mahony Riley well No. 1, section 3-3', fig. 8) and with zones of longer coring time (see Tide Water-Seaboard, A. O. Young 1 and O'Bier 1, fig. 7). These correlations gave qualitative data that were applied to other well records to identify tight zones on which porosity and permeability measurements were not available. Based upon core analyses, core descriptions, coring time, and electric logs, the gas- and oil-producing zones for each well were determined and plotted on east-west and north-south cross sections (see figs. 6, 7, and 8).

Although the porous zones do not follow stratigraphic horizons, they can be correlated from well to well over short distances and by interpolation and extrapolation the probable position and thickness of unpenetrated producing zones in each well was estimated. A study of these cross sections indicated that 8 wells in the East field and 12 structurally high wells in the West field penetrated a top porous zone 3 to 10 feet thick above the main porosity. The main porosity zone 10 to 20 feet below the top of the Smackover limestone is divided by 1 to 10 feet of dense limestone into upper and lower zones. Dense limestone streaks several feet thick sometimes occur in both upper and lower members. (See figs. 8 and 9.) Most wells in the East field were completed in the upper part of the main porosity; only 6 were drilled through the lower member. In most areas of the West field the upper member is gas-saturated, and wells were completed in the lower zone.

The total net thickness of gas sands above the gas-oil contact and the total net thickness of oil sands above the oil-water contact (both penetrated and unpenetrated) as calculated from logs and cross sections, by isopachous maps are shown in figures 10 and 11.

Available porosity measurements of cores from 34 wells in the Atlanta field were plotted on cross sections as the first step in estimating the average porosity of unmeasured producing zones in the area of other wells. By comparing core descriptions, coring-time records, and formation resistivity as indicated by the third and lateral curves of electric logs, an average porosity was assigned to all penetrated but unmeasured oil- and gas-producing zones in each well. An estimated porosity was assigned to each of the probable producing zones in the unpenetrated section above the water-oil contact about each well by interpolation and extrapolation. Unquestionably, many sources of error enter into this method of estimating reservoir voids, but correlations between wells are considered more accurate than correlations between upper and lower beds in the same well. An estimated porosity of each zone, based on all known factors, is considered more accurate than to assign the arithmetical average of all measured porosities to the unmeasured zones. The void space of each productive zone is the product of the thickness of that zone and its porosity expressed as a decimal. The sums of the voids in all zones give the total reservoir void space at each well. These sums were plotted as isograms on a work map. When the isogram work map was laid over the effective-thickness map (fig. 11), many of the lines crossed. The intersection of these lines provided additional points for estimating the effective thickness and porosity. The indicated pore volumes at these points between wells were plotted and used with the individual well data to construct an isovol work map showing the volume of the oil-saturated reservoir. Based on this map the oil reservoir was calculated to include 8,042 acre feet of void space. In like manner the void spaces in the West Atlanta gas-cap area were calculated to be above 1,630 acre-feet.

## Interstitial Water

No samples of water taken from the bottoms of wells were available for analysis. Because of concentration by evaporation or dilution by condensed water vapor, samples of water produced with oil vary somewhat in composition, depending on the production mechanism or the point in the process at which the sample was obtained, and are not necessarily representative of the interstitial water in the reservoir. Analyses of several produced water samples are shown in table 4. These nine samples were obtained at comparable stages in the production process and are presented in order of decreasing mineral content. The higher mineral content of water samples from wells with high water:oil and low gas:oil ratios is apparent. Water from highest gas:oil ratio well No. 9 was lowest in total solids. These data suggest that free gas moving through the reservoir evaporated some of the interstitial water which later condensed in the flow string and diluted the water samples. Such a process has been observed by the writer in gas wells or oil wells with high gas:oil ratios in other fields, and may account for salt crystals deposited in and around the well bore.

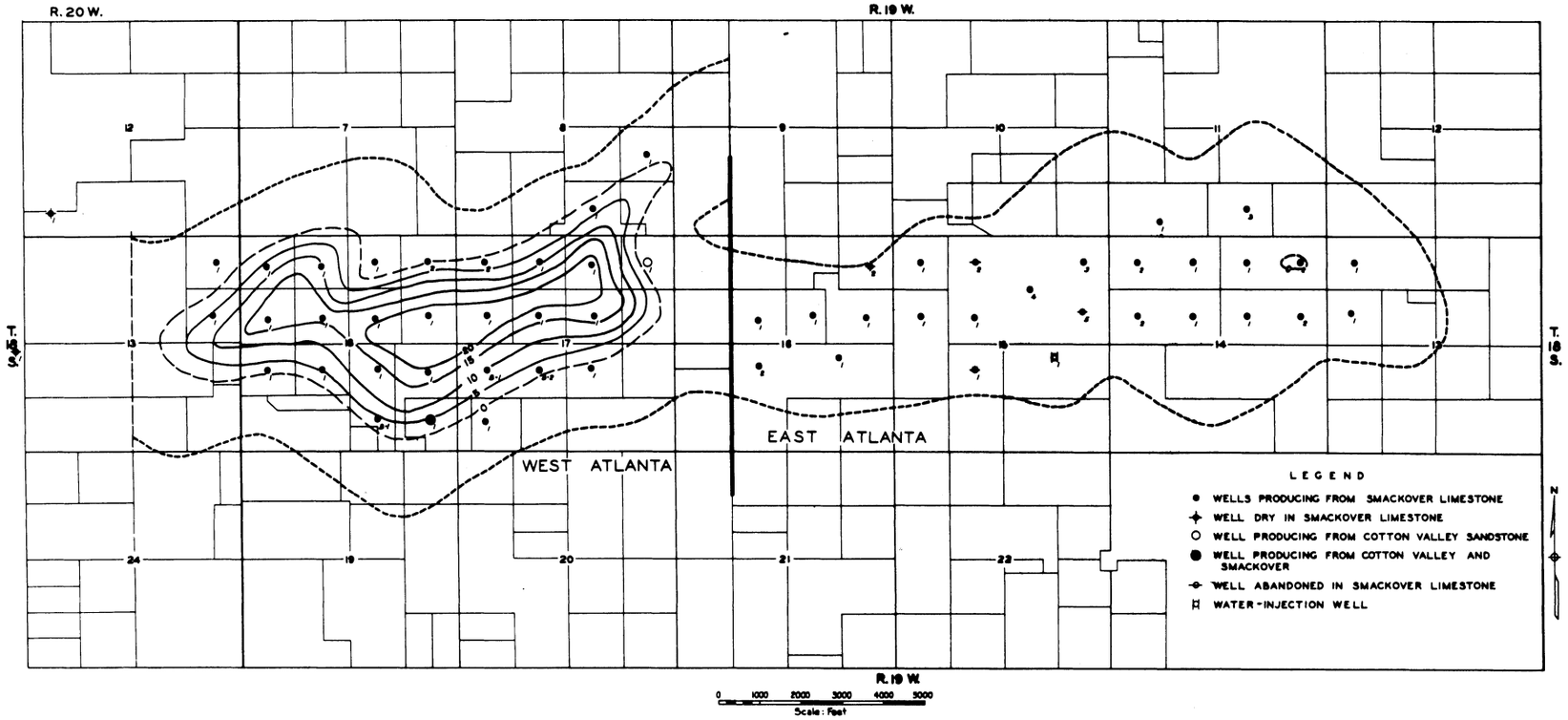



FIGURE 10.- ISOPACHOUS MAP SHOWING NET THICKNESS OF GAS-SATURATED ROCK, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

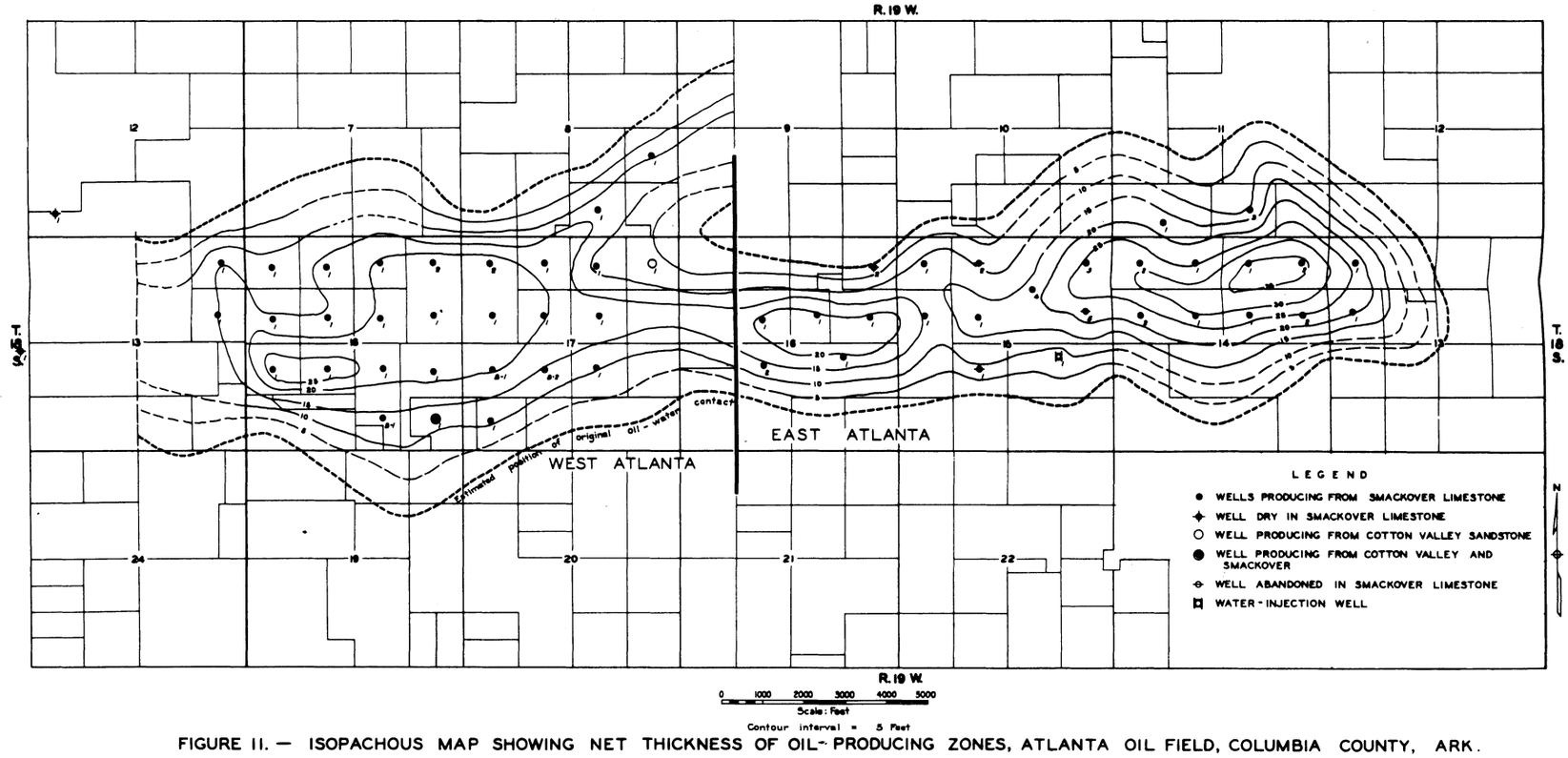



FIGURE 11. — ISOPACHOUS MAP SHOWING NET THICKNESS OF OIL-PRODUCING ZONES, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

TABLE 4. - Analyses of samples of water produced with oil, Atlanta field, Columbia County, Ark.

| Well | Sp. gr. | Parts per million, milligrams per liter | | | | | | | Water, percentage of produced liquid | Free gas:oil ratio 1/ |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Cl. | Na. | Ca. | Mg. | $SO_4$ | $HCO_3$ | Total solids | | |
| 1 | 1.228 | 202,800 | 79,300 | 40,000 | 3,090 | 115 | 179 | 326,000 | 37 | 0 |
| 2 | 1.226 | 202,100 | 78,900 | 40,000 | 3,370 | 113 | 186 | 325,000 | 30 | 0 |
| 3 | 1.226 | 202,100 | 78,600 | 40,300 | 3,310 | 103 | 179 | 325,000 | 22 | 0.41 |
| 4 | 1.228 | 200,700 | 78,200 | 39,800 | 3,360 | 119 | 182 | 322,000 | 80 | .16 |
| 5 | 1.224 | 200,000 | 76,700 | 40,600 | 3,450 | 85 | 153 | 321,000 | 39 | .27 |
| 6 | 1.224 | 199,300 | 76,900 | 39,900 | 3,420 | 120 | 81 | 320,000 | 55 | .14 |
| 7 | 1.224 | 197,800 | 76,400 | 39,800 | 3,340 | 113 | 81 | 318,000 | 39 | .50 |
| 8 | 1.220 | 196,400 | 76,600 | 39,100 | 3,240 | 105 | 183 | 316,000 | 1 | .22 |
| 9 | 1.166 | 146,800 | 56,500 | 29,800 | 2,430 | 132 | 129 | 236,000 | .2 | 2.16 |

1/ In order to show the ratio of gas to oil in the fluid entering the well bore, gas and oil volumes were converted to the same units at reservoir pressure and temperature.

Difficulty with the deposition of salt has been experienced in other fields producing from the Smackover limestone, and tubing was plugged twice with salt crystals in one high-gas:oil ratio well in the Atlanta field.

In the Atlanta field all cores were cut while aqueous drilling fluid was being circulated, and consequently measured water saturations have little, if any, relationship to the original interstitial water content. Recently the restored state method[15] for determining original water saturation of the reservoir rocks by brine displacement from cores, has been accepted by petroleum engineers as providing information usable in estimating the connate water content of oil-bearing rocks. Twenty-six cores from four wells along the north edge of the Atlanta field were tested by this method, and results of displacement of brine by air are shown in table 5.

Leverett[16] has shown that the reservoir fluids coexist in porous mediums in volumes proportional to their capillarity. In a static reservoir, the forces of capillarity are balanced exactly by the difference in gravitational forces acting on the fluid phases. It is assumed generally that, during accumulation, oil migrated into and displaced water from the pore spaces of the reservoir rock under a pressure resulting from the differences in the density of the oil and water. In the Atlanta oil field this force is calculated to have been equivalent to 0.247 pound per square inch per foot of height above the water level.

15/ Bruce, W. A., and Welge, H. J., The Restored State Method for Determination of Oil in Place and Connate Water: Oil and Gas Jour., vol. 46, July 26 1947, p. 223.

16/ Leverett, M. C., Capillary Behavior in Porous Solids: Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 142, 1941, pp. 152-168.

TABLE 5. - Water saturation of cores from walls in Atlanta oil field, Columbia County, Ark. (restored-state method), using air

| Core No. | Porosity, percent | Perm., Md. | Minimum displacing pressure, lb. per sq. in. | Minimum water content percent |
|---|---|---|---|---|
| 2258 | 9.4 | 18 | 23 | 36.0 |
| 2268-1 | 19.3 | 64 | 22 | 31.4 |
| 2348-1 | 14.0 | 76 | 22 | 41.0 |
| 2272 | 11.9 | 110 | 20 | 27.0 |
| 2343-1 | 14.6 | 160 | | 32.8 |
| 2248 | 15.3 | 175 | | 44.5 |
| 2351 | 15.5 | 180 | | 38.1 |
| 2173-5-4 | 16.7 | 190 | | 40.2 |
| 2173-5-5 | 15.1 | 190 | | 39.6 |
| 2347 | 17.3 | 200 | | 50.2 |
| 2285 | 8.9 | 240 | | 26.7 |
| 2262 | 12.9 | 310 | | 26.0 |
| 2263-1 | 13.7 | 370 | 20 | 28.3 |
| 2352 | 13.7 | 390 | | 37.9 |
| 2238 | 9.7 | 450 | 20 | 37.6 |
| 2269 | 17.3 | 640 | | 33.6 |
| 2264 | 11.0 | 670 | 16 | 36.9 |
| 2265-1 | 17.3 | 720 | 15 | 36.3 |
| 2267 | 20.1 | 1,200 | | 32.9 |
| 2280 | 14.7 | 1,400 | | 25.5 |
| 2275 | 12.8 | 1,500 | | 24.1 |
| 2284 | 14.2 | 1,500 | | 18.6 |
| 2283 | 15.3 | 1,600 | | 21.7 |
| 2261 | 17.3 | 1,800 | | 28.2 |
| 2260-1 | 19.4 | 1,900 | 12 | 24.0 |
| 2259 | 17.6 | 2,900 | | 18.6 |

In attempts to simulate reservoir conditions by displacing brine from cores with oil, Bruce and Welge[17/] found that:

> As the pressure difference between the phases is increased, a pressure difference is finally reached after which there is no appreciable reduction in water saturation with increase in pressure on the oil phase.

The pressure above which the water saturation is not appreciably reduced by pressure increases comparable to gravitational forces in oil reservoirs is defined as the "minimum displacing pressure," and the water saturation at and above this pressure is defined as the "minimum water content." In the upper portion of the reservoir where the pressure resulting from gravitational forces exceeds the minimum displacing pressure, the water saturation of the rock is assumed to be equivalent to the minimum water content: and in the lower portion, where the displacing pressure is less, the water saturation increases downward to a theoretical 100 percent.

17/ Work cited in footnote 15.

In the tests on samples of reservoir rock from the Atlanta field, cores were saturated under vacuum with artificial brines having a surface tension of 59.2 dynes per centimeter, equivalent to that of the natural brine. Brine was then displaced from the cores with air. Because the interfacial relationships between the displacing air and the saturating brine in the laboratory differ from those of the reservoir oil and brine underground, the minimum displacing pressures shown in table 5 are not directly applicable to the Atlanta reservoir. Based upon laboratory measurements of interfacial tensions between brine and stock-tank oil and upon changes with pressure, temperature, and gas in solution as indicated in experiments by Hocott[18], the interfacial tension between oil and brine in the natural reservoir was calculated to have been about 16.4 dynes per centimeter. The ratio of these tensions (59.2 to 16.4) gives a factor (3.6) to divide into the minimum displacing pressures of the air-brine system shown in table 5 to calculate the probable minimum displacing pressures in the natural reservoir system. The minimum displacing pressures thus calculated, ranged from 3.3 to 6.3 pounds per square inch varying indirectly with the permeability of the reservoir rock. The average permeability of the upper portion of the oil reservoir was calculated to be 1,090 millidarcys and the indicated minimum displacing pressure for cores of this permeability was about 4 pounds per square inch.

The density of reservoir oil from the Atlanta Smackover limestone at original reservoir pressure and temperature is calculated to have been about 0.60 gram per milliliter and of the natural brine 1.17 grams per milliliter. The difference in density of these two fluids is equivalent to a hydrostatic pressure of 0.247 pound per square inch per foot of height above the level of 100 percent water saturation. The nominal oil-water contact, at a subsea depth of 8,000 feet in the Atlanta field, is not the level of 100 percent saturation, since this contact represents a level at which oil saturation is so low, and water saturation so high, that no oil moves from the porous rock into the bore hole. Water saturation at this level depends upon the effective permeability of the rock to water and oil. From residual-oil saturation tests on Smackover limestone cores of comparable permeability[19], water saturation at the contact in the Atlanta field was estimated to have been about 81 percent. The differential hydrostatic pressure at the oil-water contact was calculated from displacement pressure vs. brine saturation curves to have been about 0.8 pound per square inch.

The difference between the minimum displacing pressure and the pressure at the oil-water contact, (4.0 - 0.8 lb. per sq. in.) divided by the differential hydrostatic pressure per foot (0.247 lb. per sq. in.), gives the height (13 feet) above the oil-water contact where the differential hydrostatic pressure equals the minimum displacing pressure and above which the water saturation should be equivalent to the minimum water content. These data indicate that, in the gas

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18/ Hocott, C. R., Interfacial Tension between Water and Oil under Reservoir Conditions: Trans. Am. Inst. Min. and Met. Eng., vol. 132, 1939, pp. 184-190.

19/ Welge, Henry J., Displacement of Oil from Porous Media by Water or Gas: Presented before Am. Inst. Min. and Met. Eng. meeting, Oct. 8,-10, 1947, Tulsa, Okla.

zone and in that portion of the oil zone above 7,987 feet subsea, the water saturation in the Atlanta field was equivalent to the minimum water content.

The core samples are arranged in table 5 in order of increasing permeability, and the approximate inverse relationship between permeability and minimum water content is apparent. Other variables, particularly the surface area and geometry of the pore spaces,[20] also control the minimum water content. Microscopic examination of the core samples indicated that the surfaces of some oolites were much rougher that others. The roughness and shape of the individual oolites affects the surface area of the pore spaces and indirectly the amount of interstitial water retained in the pore. The total surface area of the pore spaces is not directly reflected by either porosity or permeability measurements; and in the present study, it was not practical to evaluate this area or its effect on the minimum water content. Instead, average interstitial water content of the oil and gas reservoirs was determined directly from curves of minimum water content plotted against permeability. Core analyses indicate that the average permeability of the gas reservoir was 1,150 millidarcys and the average permeability of the upper portion of the oil reservoir was 1,090 millidarcys. Minimum water contents corresponding to these permeabilities were 25 percent for the gas zone and 25.9 percent for the oil reservoir.

It is assumed that the lower portion of the Atlanta reservoir included a transition zone in which the original water saturation increased downward from the minimum water content at 7,987 to about 81 percent at 8,000 feet below sea level. The average permeability of the reservoir rock in this transition zone was 760 millidarcys. From permeability-saturation data the volumetrically weighted average water saturation of the transition zone was calculated to have been about 41.8 percent.

## Estimates of Volume of Reservoir Occupied by Oil and Gas

The gas cap in the West Atlanta field included 1,630 acre-feet of pore spaces, with an average interstitial water content of 25 percent, equivalent to the minimum water saturation of cores of comparable permeability. Based on average residual oil saturation of 31 core samples from the gas cap, about 4 percent of the voids was assumed to have been filled originally with reservoir oil. Although the increase in the percentage of one fluid replacing another probably is transitional, the gas-oil contact may be assumed to be at a definite horizon around each well. Seventy-one percent (100-(25+4)) of the pore spaces between the gas-oil contact and the top of the productive zone was assumed to have been filled with gas; and on that basis the original volume of reservoir gas in the West Atlanta field was calculated to have been about 9,000,000 barrels, equivalent to 14.9 billion cubic feet of gas at atmospheric pressure and 60° F.

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20/ Popovich, Michael J., A Study of the Relationship between Grain Size and Capillary Pressure Curves: Producers Monthly, vol. 40, No. 12. October 1947, pp. 27-32.

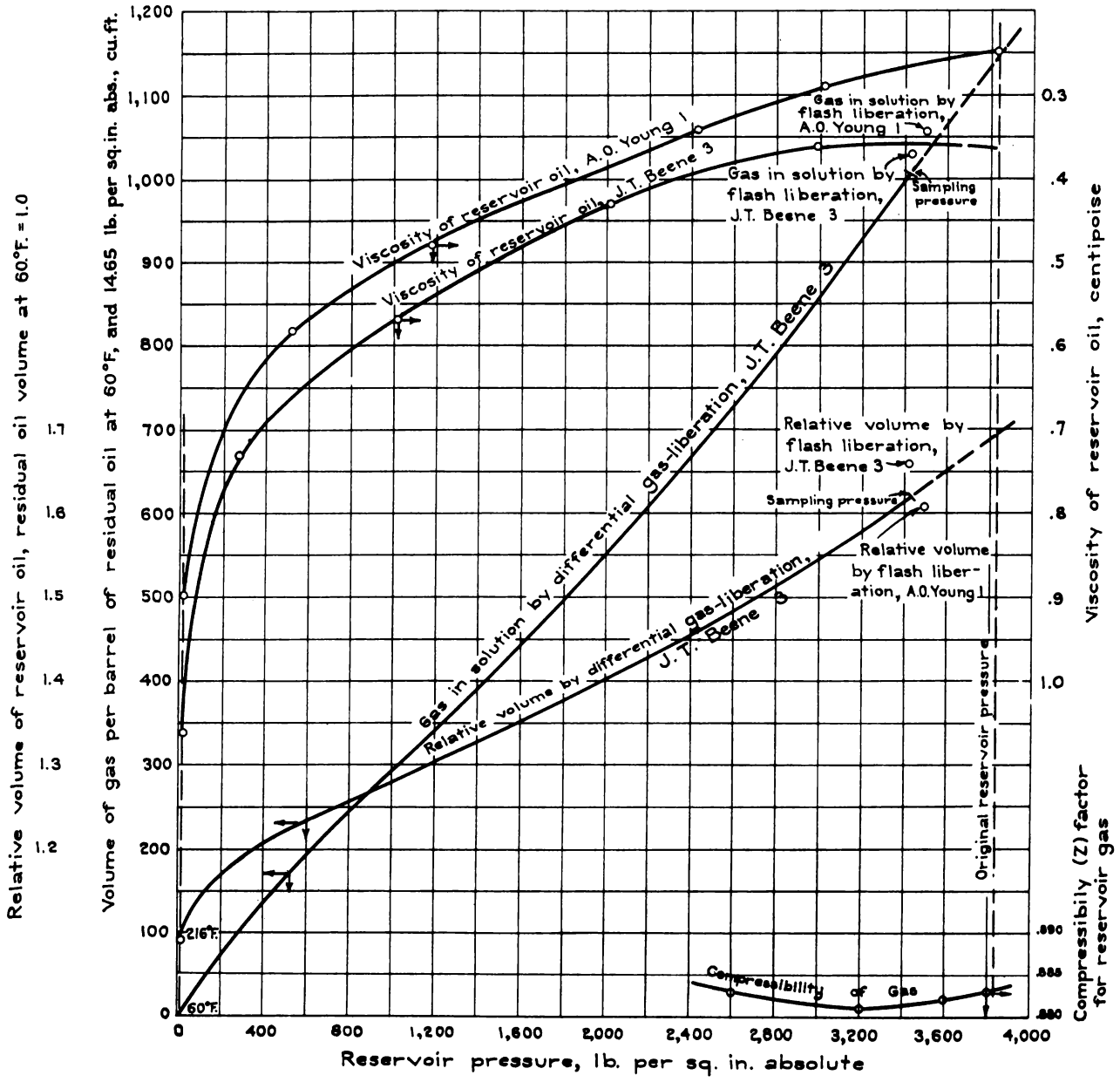


FIGURE 12.—CURVES SHOWING CHARACTERISTICS OF SUBSURFACE SAMPLES OF RESERVOIR OIL FROM TWO WELLS, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK. (CORE LABORATORIES, INC.).

The upper portion of the oil reservoir (above 7,987 feet subsea) included 3,890 acre-feet of pore spaces. Average interstitial water saturation in this zone was calculated to have been 25.9 percent, allowing 74.1 percent of the pore space to have been filled originally with 22,362,000 barrels of reservoir oil. The transition zone between 7,987 and 8,000 feet below sea level included 4,152 acre-feet of reservoir voids with an average water saturation of 41.8 percent. It is calculated that this zone originally contained 18,733,000 barrels of reservoir oil. The original reservoir oil of both zones was 41,095,000 barrels.

## Physical Properties of Reservoir Fluids

### Reservoir Oil

The character of the oil in the Atlanta reservoir is known from two subsurface samples taken by Core Laboratories, Inc., in 1943, after reservoir pressure had declined from 3,821 to 3,480 pounds per square inch in West Atlanta and to 3,410 pounds per square inch in the East Atlanta field. The sample from the East field had a viscosity of 0.35 centipoise at reservoir pressure and temperature. By flash gas-liberation to atmospheric pressure and temperature it yielded 1,031 cubic feet of gas with a decrease in volume of 39.8 percent. The viscosity of the sample from the West field was 0.25 centipoise at reservoir pressure and temperature; by flash liberation the oil yielded 1,058 cubic feet of gas and decreased 38 percent in volume. Shrinkage and solution gas data from differential gas liberation of the subsurface sample from Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware, J. T. Beene well No. 3 in the East field, are shown as curves in figure 12. Based on extrapolation of the curves, it is estimated that the original reservoir oil contained 1,146 cubic feet of solution gas per barrel of residual oil and that liberation of this gas to atmospheric pressure and 60° F. resulted in shrinkage of specific volume from 1,695 to 1.0. Assuming that the average specific gravity of the solution gas was 0.8 (air = 1.0) the specific gravity of reservoir oil was calculated to have been about 0.60 (water = 1.0). The 41,095,000 barrels of oil originally in the reservoir of the Atlanta field was calculated to represent 24,245,000 barrels of stock-tank oil.

Although the two subsurface samples were taken from widely separated areas of the field, both areas were structurally high and therefore the oil samples may not be representative of all the reservoir oil. Carefully measured, low gas:oil ratios at the J. T. Eades well No. 1, and Longino-Henry well No. 1, completed in 1947, suggested to some engineers that the oil in the Atlanta reservoir is not uniform in composition and that the oil in structurally lower areas contains less solution gas than is shown by the analyses of the two subsurface samples. Unfortunately, essential data to support this theory are lacking, and calculations shown herein are based on the assumption that the two samples are representative of all the reservoir oil.

### Reservoir Gas

Little definite information is available regarding the composition of Atlanta reservoir gases at different pressures. With decrease in pressure,

certain hydrocarbons were liberated from the oil phase, and others may have condensed from the gas phase. Analyses of two samples of gas taken at atmospheric temperature from tubing and casing heads of shut-in wells are shown in table 6.

TABLE 6. - Analyses of gas samples from Atlanta field, Columbia County, Ark.

| Component | Sampling pressure lb. per sq. in. gage: 1,006 Tubinghead, Mole percent | 2,425 Casinghead, Mole percent |
|---|---|---|
| Methane | 94.81 | 98.16 |
| Ethane | 2.70 | .92 |
| Propane | 1.35 | .28 |
| Isobutane | .31 | .05 |
| Normal butane | .46 | .25 |
| Isopentane | .17 | .11 |
| Normal pentane | | .20 |
| Heptanes and heavier | .07 | .04 |
| Hydrogen sulfide | .13 | |
| Total | 100.00 | 100.00 |
| Specific gravity (air = 1.) | .624 | .584 |

Because these samples were obtained at atmospheric temperature from shut-in wells, the analyses could not be used to calculate the composition and compressibility ratios of the original reservoir gas.[21] Instead, five representative gas samples from three similar fields in Arkansas that produce from the Smackover limestone were used to calculate pseudo-critical data to construct the Z curve of compressibility ratios of the reservoir gas as shown in figure 12.

The composition of produced gases varies widely depending upon the temperature and pressure at which the gas separated from the oil. The percentage of hydrogen sulfide in the gas from the Atlanta field increases from a trace at 2,400 psi. to about 2 percent in the gas liberated from oil at atmospheric pressure.

## Summary of Reservoir Data

Pertinent data for both oil and gas reservoirs are summarized in table 7.

21/ Correspondence with C. K. Eilerts, Bureau of Mines, Bartlesville, Okla.

TABLE 7. - Reservoir data, Smackover limestone, Atlanta oil field

OIL RESERVOIR

| | |
|---|---|
| Total productive area, acres | 4,172 |
| Total volume of effective oil reservoir rock, acre-feet | 53,170.7 |
| Average effective thickness, feet | 12.7 |
| Weighted average porosity of reservoir rock, percent | 15.1 |
| Volume of reservoir voids between 7,987 and 8,000 feet below sea level (transition zone), acre-feet | 4,152 |
| Weighted average permeability of transition zone, millidarcys | 760 |
| Volumetrically weighted average interstitial water content of reservoir rock in transition zone, percent | 41.84 |
| Calculated volume of reservoir oil originally in transition zone, barrels | 18,733,000 |
| Volume of reservoir voids in oil reservoir above 7,987 feet subsea, acre-feet | 3,890 |
| Weighted average permeability of upper oil reservoir rock, millidarcys | 1,090 |
| Average interstitial water content of upper zone, percent | 25.9 |
| Calculated volume of reservoir oil originally in upper zone, barrels | 22,362,000 |
| Volume of reservoir oil originally in both zones, bbl. | 41,095,000 |
| Original reservoir pressure at 7,900 feet below sea level, lb. per sq. in. abs. | 3,835.65 |
| Formation volume factor (by differential data) | 1.695 |
| Volume of original reservoir oil at standard pressure and temperature, barrels | 24,245,000 |
| Volumetrically weighted average stock-tank oil per acre-foot, barrels | 455.98 |
| Average temperature of oil reservoir, degrees F. | 218 |
| Gas in solution in reservoir oil per barrel of stock-tank oil (differential liberation), cu. ft. | 1,146 |
| Average viscosity of reservoir oil, centipoise | 0.35 |
| Specific gravity of reservoir oil, calculated | 0.60 |
| Calculated interfacial tension between oil and brine, dynes/cm. | 16.4 |

GAS RESERVOIR (West Atlanta)

| | |
|---|---|
| Total productive area, acres | 930 |
| Total volume of effective gas-saturated reservoir rock, acre-feet | 18,637.6 |
| Average effective thickness, feet | 11.08 |
| Volume of void spaces in gas reservoir rock, acre-feet | 1,629.7 |
| Average permeability of gas reservoir rock, millidarcys | 1,147 |
| Interstitial water saturation of gas reservoir rock, percent | 25 |
| Average residual oil saturation of gas reservoir cores, percent | 2.35 |
| Calculated average saturation of gas reservoir with reservoir oil, percent | 4 |

TABLE 7. - Reservoir data, Smackover limestone, Atlanta oil field (Cont'd)

| | |
|---|---|
| GAS RESERVOIR (West Atlanta) (Cont'd) | |
| Calculated original volume of reservoir gas, barrels | 8,976,796 |
| Average temperature of gas reservoir, degrees F. | 216 |
| Compressibility factor of free gas at original pressure | 0.886 |
| Volume of 1 M cu. ft. gas at reservoir pressure and temperature, bbl | 0.60142 |
| Volume of free reservoir gas at standard pressure and ", M cu. ft | 14,926,000 |

## PRODUCTION

The oil, gas, and water production histories of the Atlanta field are shown graphically in figure 13. The area under curve A represents monthly production of stock-tank oil and the volume which this oil occupied in the reservoir immediately before production is shown as the area under curve B. The volume of free (or liberated gas) produced with the oil is shown as the area between curves B and C. Monthly water production is shown as the area between curves C and D, and the net volume of water returned to the reservoir during 1946 and 1947 is shown as the area between curves D and E. The total monthly fluid withdrawals from the reservoir (gross) is the area under curve D; net withdrawals, the area under curve E.

To compute the volume of reservoir oil and free gas produced each month, a bottom-hole pressure, calculated from tests or isobaric maps, was assigned to each well. A produced gas:oil ratio, based on periodic tests and corrected to include gas in solution at test-separator pressure, was assigned to each well. The formation factor of the oil and the volume of gas in solution at the assigned reservoir pressure were taken from curves shown in figure 12. The difference between the corrected produced gas:oil ratio and the solution gas:oil ratio was assumed to be the produced free-gas:oil ratio, and the volume of the free gas produced at the then prevailing reservoir pressure and temperatures was calculated with the aid of the Z curve shown in figure 12. Monthly water production calculated from water:oil ratio or water-production tests was corrected to formation temperature.

Since March 1, 1939, the allowable oil production per well has been regulated by the Arkansas Oil and Gas Commission. As shown by curve F in figure 13, the maximum allowable ranged between 100 and 200 barrels daily. Oil production from wells with high water:oil and high gas:oil ratios is further restricted in proportion to the reservoir voidage by the water and excess gas produced. (See Appendix for method of calculating oil allowables.)

### Material-Balance Equations

Equations to calculate current volumes of oil, gas, and water in the reservoir have been derived by Cook.[22/] One of these equations states that the

22/ Cook, Alton B., Derivation and Application of Material-Balance Equations: Bureau of Mines Rept. of Investigations 3720, part II, 1943, pp. 79-81.

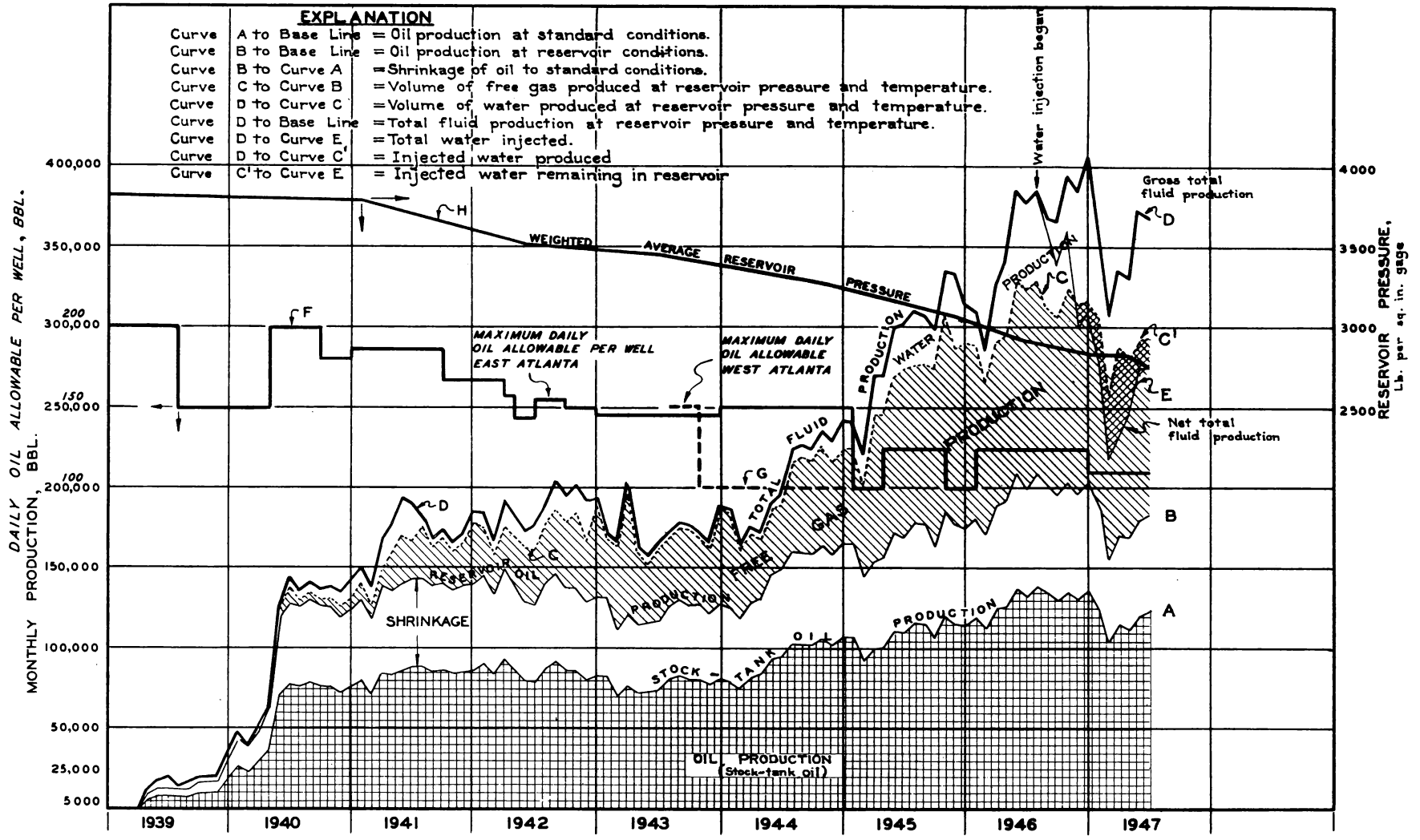


FIGURE 13. — FLUID PRODUCTION HISTORY, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

increase in volume of the original gas and oil to a subsequent pressure and date, plus the volume of water entering the reservoir to that date, is equivalent to the total fluid production as measured at the subsequent pressure.

$$(G_1 \frac{f_1}{f_2} - G) + (\frac{N_2 F_2}{F_1} + \frac{N_1}{F_1} \times \frac{S_1 - S_2}{f_2} - N_1) + We = (g_2 - \frac{S_2 - S_s}{f_2} n) + nF_2$$

Where

N total volume of gas-saturated oil in reservoir at indicated temperature and pressure, bbl.

G total volume of gas phase in reservoir (measured at specified reservoir pressure and temperature), bbl.

g cumulative volume of gas produced (at 14.65 lb. per sq. in. and 60° F.), bbl.

S volume of gas in solution, cubic feet of gas (at 14.65 lb. per sq. in. and 60° F.) per bbl. of "stock-tank" oil

P absolute pressure, pounds per square inch

T reservoir temperature, degrees F absolute

n cumulative volume of stock-tank oil produced at atmospheric pressure and 60° F.

We net volume of encroached water in the reservoir by a date under consideration, bbl.

w cumulative volume of water produced

I cumulative volume of water injected

Z compressibility factor of reservoir gas (dimensionless)

F relative volume of reservoir oil to stock-tank oil (dimensionless)

f factor for correcting volume of gas in reservoir from a given pressure and temperature to a pressure of 14.65 lb. per sq. in. absolute and 60° F. (dimensionless)

$$f_1 = \frac{P\ T}{14.65\ 520\ Z}$$

C rate of water encroachment, bbl. per lb. per sq. in. of pressure/decline per month

Subscript 1, 2, and s, Different time during the exploitation of the reservoir are designated by numerical subscripts. For example $n_s$ represents the volume of produced oil measured at gas-oil separator pressure and temperature.

The relationship of remaining and produced fluids can be restated in simpler form, that the volume of water entering the reservoir is equivalent to the difference between the original and subsequent volumes of oil and gas in the reservoir:

$$We = N_1 + G_1 - N_2 - G_2.$$ [23]

The original volumes of oil and gas in the reservoir have been calculated from porosity and saturation data discussed earlier. Subsequent volumes have been calculated from production data and from changes, with pressure reduction, in the volume and the phase of the reservoir fluids, as indicated by curves shown in figure 12. Table 8 shows the steps involved and equations used in these calculations. The calculations are based upon the assumptions that curves shown in figure 12 are representative of the behavior of reservoir fluids and that water alone entered the reservoir from outside the measured limits shown in figure 11. The volumes of oil and gas remaining in the reservoir and the volume of water which entered to replace the produced fluids is shown graphically in figure 14. Curve A represents the estimated volume of oil which remained in the reservoir at each period as measured at stock-tank conditions. Line B represents the estimated original quantity of this oil, (about 24 million barrels) and the difference between curve A and line B represents the cumulative production of stock-tank oil, about 8-1/2 million barrels to July 1, 1947. Curve C represents the estimated volume of the remaining reservoir oil at the subsequent pressures. The total volume of oil and gas in the reservoir at the indicated pressure is shown by curve G. The difference between this volume and the original volume as indicated by line H represents the estimated volume of water which has entered the reservoir to replace the produced hydrocarbons.

In discussing water entry into reservoirs, Schilthuis[24] stated:

> In many cases, it may be assumed that the rate at which water enters a field is proportional to the pressure gradient that exists between the water-bearing strata and the oil- and gas-reservoir. For practical purposes, the value of this gradient would be the difference between the value of the original reservoir pressure and any subsequent value, or $(P_1 - P_2)$.

The rate of water entry into the Smackover limestone reservoir of the Atlanta field, in barrels per month, and barrels per month per pound per square inch of difference between the original and the subsequent reservoir pressure are shown in lines 17 and 18 of table 8. In general these data show a decline in the rate of water entry per unit of pressure differential. This indicated decline in the rate of entry may be the result of pressure drop in the aquafer surrounding the field, as shown by Bruce,[25] or it may be the result of expanding oil or gas which entered, instead of water, from outside the measured limits of the field.

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23/ A transposition of the equation $G_2 = N_1 + G_1 - (We + N_2)$ shown by Cook[22]

24/ Schilthuis, Ralph J., Active Oil and Reservoir Energy: Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., 1936, p. 39.

25/ Work cited in footnote 8.

TABLE 8. - MATERIAL BALANCE DATA, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

| ITEM | Date and reservoir pressure, pounds per square inch gage: Original 3821 | 9-1-41 3680 | 7-1-43 3450 | 5-1-44 3340 | 11-1-44 3250 | 7-1-45 3147 | 12-1-45 3065 | 7-1-45 2920 | 1-1-47 2850 | 7-1-47 2800 |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. Cumulative "stock-tank" oil produced, bbl. $N_p$ | 0 | 1,479,287 | 3,311,237 | 4,118,433 | 4,722,863 | 5,624,815 | 6,134,204 | 7,005,825 | 7,814,224 | 8,508,809 |
| 2. Cumulative production of reservoir oil, bbl. $N F_1$ | 0 | 2,507,000 | 5,613,000 | 6,981,000 | 8,005,000 | 9,534,000 | 10,397,000 | 11,875,000 | 13,245,000 | 14,422,000 |
| 3. Volume of oil remaining in reservoir at $P_1$, bbl. $N - NF_1$ | 41,095,000 | 38,588,000 | 35,482,000 | 34,114,000 | 33,090,000 | 31,561,000 | 30,698,000 | 29,220,000 | 27,850,000 | 26,623,000 |
| 4. Weighted average reservoir pressure, lb. per sq. in. abs. $P$ | 3,835.65 | 3,694.65 | 3,464.65 | 3,354.65 | 3,264.65 | 3,161.65 | 3,079.65 | 2,934.65 | 2,864.65 | 2,814.65 |
| 5. Shrinkage factor of oil to indicated pressure $\frac{F_2}{F_1}$ | 1.0000 | .9819 | .9573 | .9453 | .9375 | .9272 | .9200 | .9062 | .8991 | .8961 |
| 6. Remaining reservoir oil, bbl. 1/ $\frac{N_1 F_2}{F_1} = N_2$ | 41,095,000 | 37,889,000 | 33,967,000 | 32,248,000 | 30,691,000 | 29,263,000 | 28,242,000 | 26,479,000 | 25,037,000 | 23,898,000 |
| 7. Volume factor of free or liberated gas $\frac{P.\ T.}{14.65\ T_b Z} = f$ | 227.08 | 219.11 | 205.65 | 199.12 | 193.95 | 187.82 | 182.79 | 174.19 | 169.89 | 166.91 |
| 8. Original free gas, bbl. 1/ $G_1 \frac{f_1}{f_2}$ | 8,977,000 | 9,299,000 | 9,910,000 | 10,225,000 | 10,512,000 | 10,853,000 | 11,149,000 | 11,697,000 | 11,993,000 | 12,208,000 |
| 9. Liberated gas per bbl. of original reservoir oil, bbl. 1/ $\frac{S_1 - S_2}{F_1 f_2}$ | 0 | .0219 | .0626 | .0848 | .1044 | .1286 | .1459 | .1826 | .2023 | .2157 |
| 10. Total liberated gas, bbl. 1/ $\frac{N_1(S_1 - S_2)}{F_1 f_2}$ | 0 | 899,980 | 2,573,000 | 3,484,900 | 4,290,000 | 5,285,000 | 5,996,000 | 7,504,000 | 8,314,000 | 8,865,000 |
| 11. Produced free and liberated gas, bbl. 1/ $\frac{g - nS_2}{f_2}$ | 0 | 283,000 | 1,225,000 | 1,753,000 | 2,148,000 | 3,007,000 | 3,478,000 | 4,446,000 | 5,342,000 | 6,067,000 |
| 12. Free and liberated gas in reservoir, bbl. 1/ $G_1 \frac{f_1}{f_2} + \frac{N(S_1 - S_2)}{F_1 f_2} - \frac{g - nS_2}{f_2} = G_2$ | 8,977,000 | 9,916,000 | 11,258,000 | 11,957,000 | 12,654,000 | 13,131,000 | 13,667,000 | 14,755,000 | 14,965,000 | 15,006,000 |
| 13. Total oil and gas in reservoir, bbl. 1/ $N_2 + G_2$ | 50,072,000 | 47,805,000 | 45,225,000 | 44,205,000 | 43,345,000 | 42,394,000 | 41,909,000 | 41,234,000 | 40,002,000 | 38,904,000 |
| 14. Volume of water entering reservoir, bbl. $G_1 + N_1 - G_2 - N_2 = We$ | 0 | 2,267,000 | 4,847,000 | 5,867,000 | 6,727,000 | 7,678,000 | 8,163,000 | 8,838,000 | 10,070,000 | 11,168,000 |
| 15. Cumulative water injected, bbl. $w$ | 0 | 177,700 | 358,600 | 417,900 | 458,000 | 648,000 | 774,000 | 1,032,000 | 1,410,000 | 1,778,000 |
| 16. Cumulative water injected, bbl. $I$ | | | | | | | | | 240,409 | 798,248 |
| 17. Net rate of water entry, bbl. per month $\frac{(We + w) - I}{\text{No. of months}}$ | 0 | 74,000 | 125,000 | 108,000 | 150,000 | 163,000 | 122,000 | 133,000 | 228,000 | 151,000 |
| 18. Net rate, bbl. per month per lb. per sq. in. pressure decline. $\frac{\text{Line 17}}{(P_1 - P_2)} = C$ | 0 | 525 | 338 | 224 | 262 | 242 | 162 | 148 | 235 | 148 |

1/ Volume measured at indicated pressure $P_1$, $P_2$, $P_3$, etc.

## Producing Equipment

In July 1947, most of the wells were still flowing through surface chokes that restrict the production to daily allowable rates. Whenever water production exceeded 10 percent of the total fluid, purgers were required to by-pass the choke periodically and permit the well to flow out accumulated water. Flow-valve systems have been used to keep water-producing wells flowing, but these valves were not entirely successful. Most wells ceased flowing and were put on the pump when water production exceeded 40 percent of the total liquid. A few wells with low water:oil ratios, that were in areas of low formation permeability, would flow only small quantities of oil, and these wells had to be pumped to recover sufficient oil for economical operation.

## Treating, Storage, and Sale of Oil

Fluids produced from wells in the Atlanta field move through buried 2-inch flow lines to gas-oil separators operated at pressures ranging from 10 to 500 pounds per square inch. Several leases had both high- and low-pressure separators. A loop field line connected gas vents of the high-pressure separators to provide fuel gas for drilling and service operations. Water-oil emulsions were "broken down" and separated in unit heat treators operated at temperatures of 120° to 140° F. Because of the sulfur content of the oil (about 0.5 percent) wooden storage tanks are preferred. In July 1947 all of 40° (or over) A.P.I.-gravity-oil was purchased by the Interstate Oil Pipeline Co. at a flat price of $1.86 per barrel. A few structurally high wells in the West field produced condensate of 56 to 59° A.P.I. gravity, and several wells with high gas:oil ratios produced mixtures of crude and condensate ranging in gravity from 42° to 50° A.P.I.

Analyses of several samples of crude oil from wells in the Atlanta field are given in table 9.

## Production Problems

Oil operators in the Atlanta field have several problems in connection with the production of oil from the Smackover limestone. Listed in the order of their importance they are:

1. Exclusion of water from oil-producing wells.
2. Removing paraffin from tubing, casing, and flow lines.
3. Excluding excess gas from wells.
4. Removing salt deposited in tubing.

### Excluding Water from Oil-Producing Wells

Water appearing in oil-producing wells is either formation water that replaces produced oil as a result of pressure differentials established during the production process, or is extraneous water that enters the well through leaking casing or casing seat.

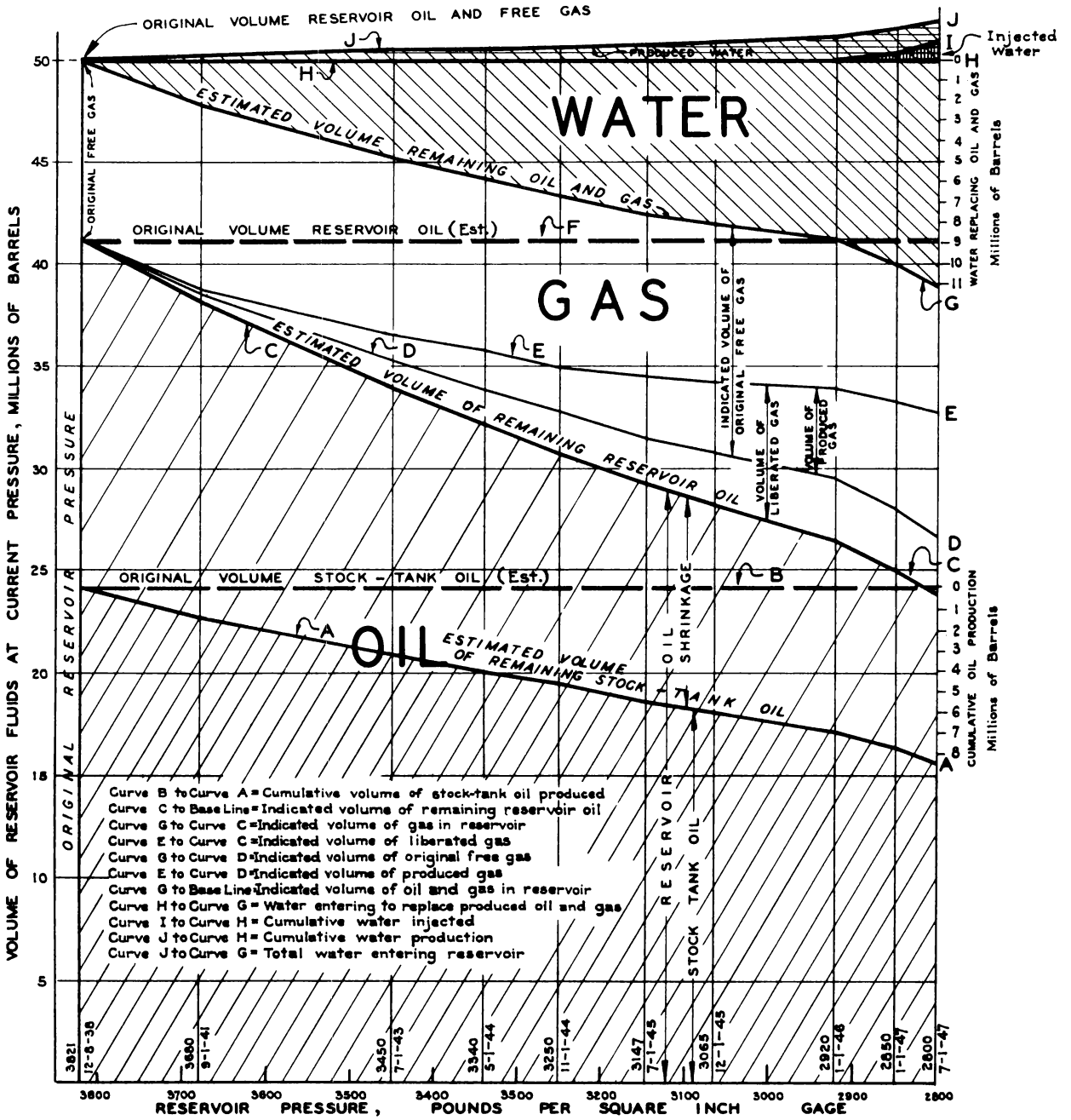


FIGURE 14– VOLUME OF RESERVOIR OIL AND GAS IN THE ATLANTA SMACKOVER LIMESTONE RESERVOIR AT SUCESSIVE PERIODS AND PRESSURES, AND THE VOLUME OF WATER ENTERING THE RESERVOIR, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

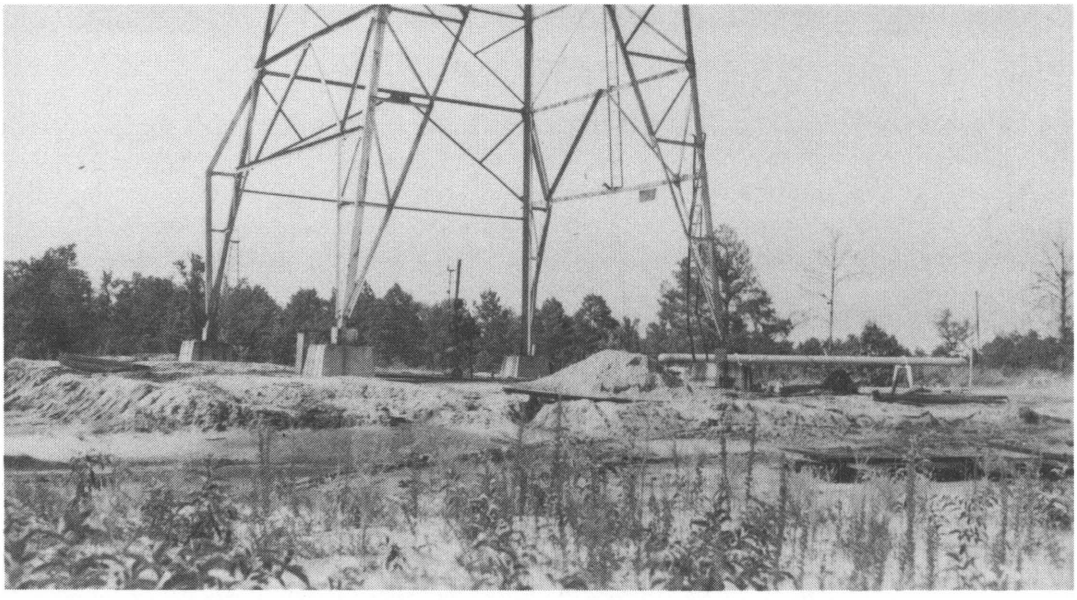

Figure 15. - Installation for injecting fresh water into casing of flowing well to prevent deposition of salt in tubing.

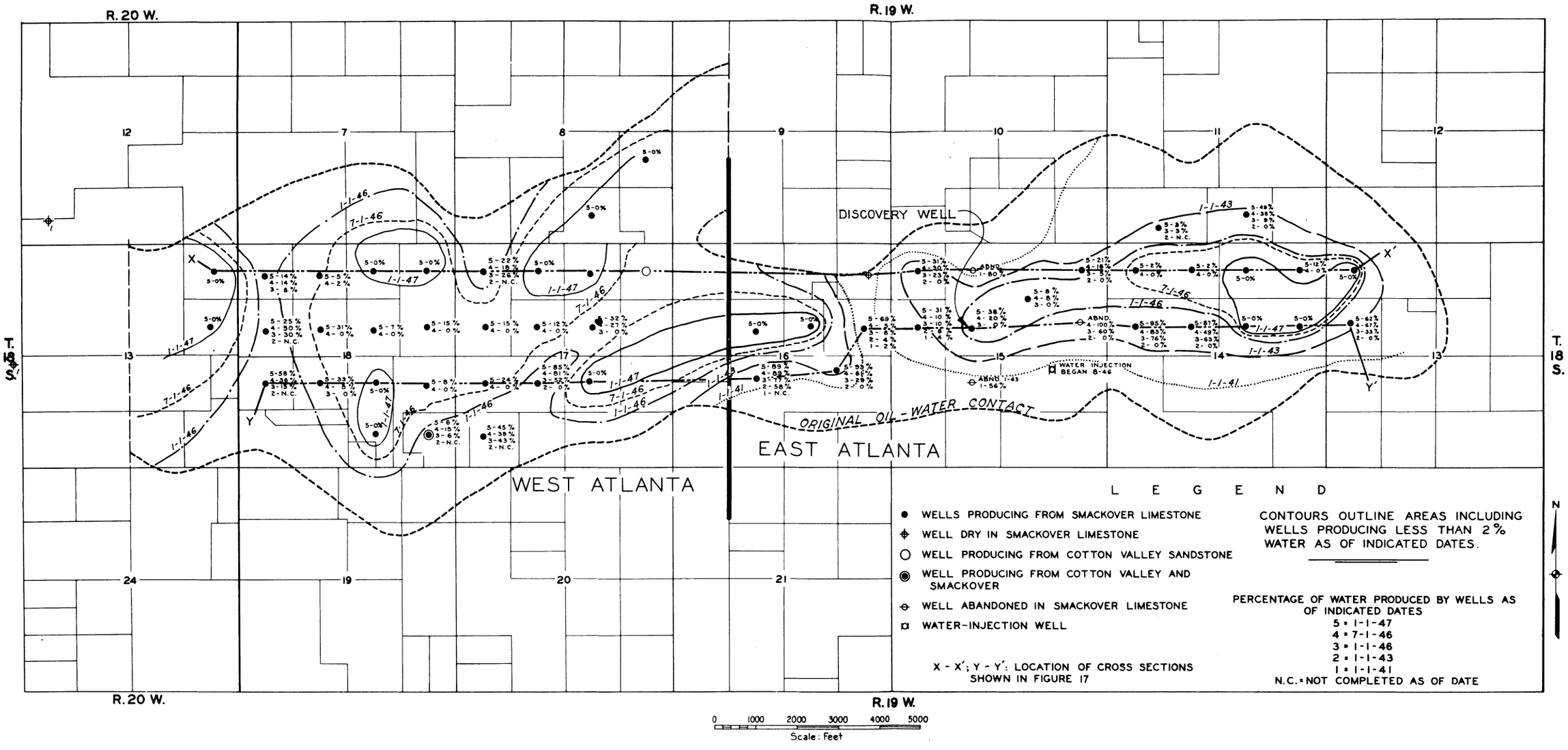


FIGURE 16 - MAP SHOWING PROGRESS OF ENCROACHING WATER INTO WELLS IN ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

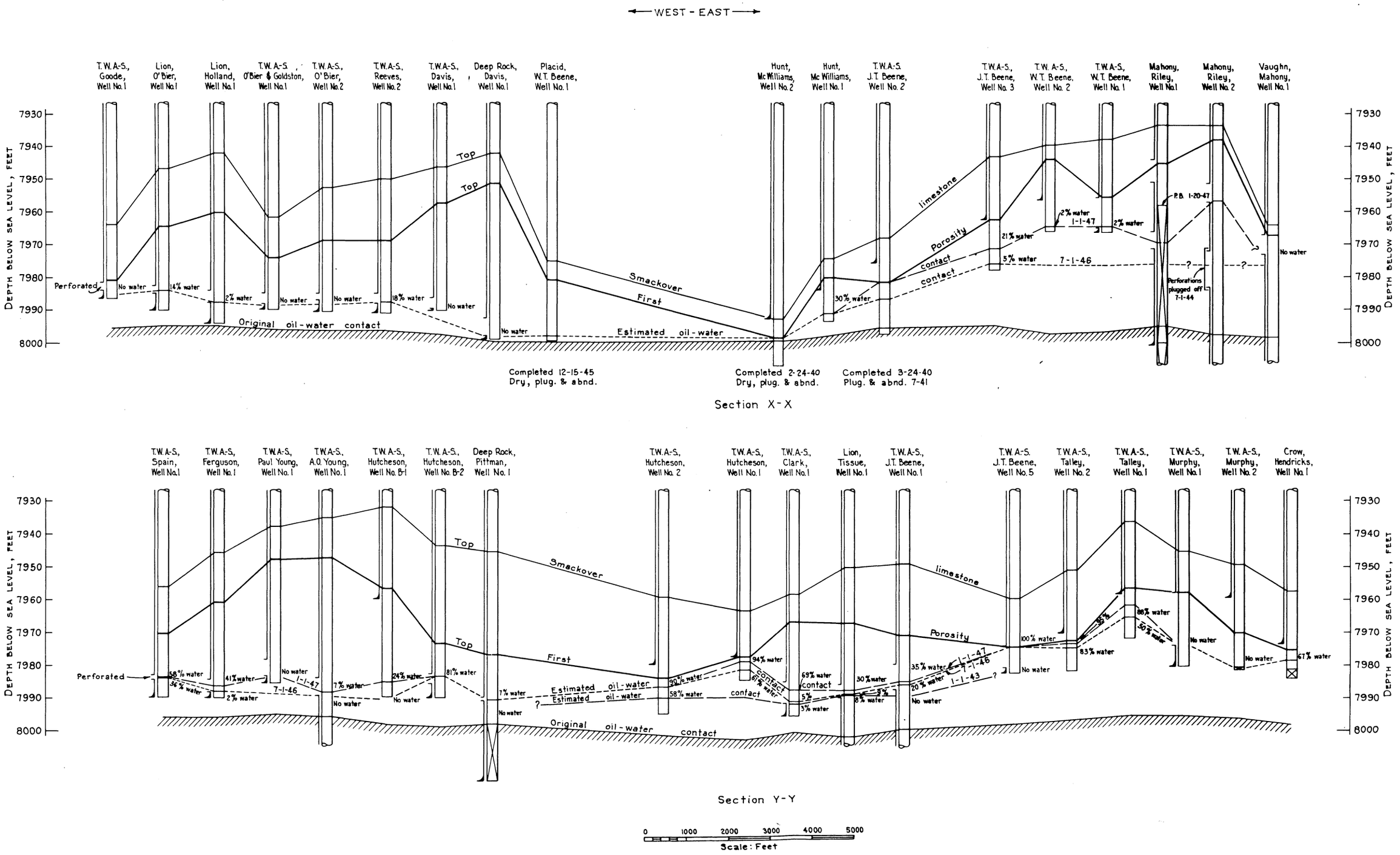


FIGURE 17. - CROSS SECTIONS X-X' AND Y-Y' SHOWING VERTICAL ADVANCE OF WATER INTO RESERVOIR, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

TABLE 9. - Characteristics of crude-oil samples from Atlanta oil field, Columbia County, Ark.

Part I. Analyses by Bureau of Mines routine method

Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware

| | J. T. Beene Well No. 1 | W. T. Beene Well Nos. 1,2 | Bonnie Davis Well No. 1 | Paul Young Well No. 1 |
|---|---|---|---|---|
| A.P.I. gravity, degrees | 42.6 | 45.2 | 49.0 | 51.1 |
| Sulfur, percent | .49 | .54 | .43 | .37 |
| Viscosity, S.U. at 100°F., sec. | 35 | 35 | 33 | 34 |
| Light gasoline, percent | 8.6 | 12.6 | 16.6 | 21.8 |
| Total gasoline, percent | 34.9 | 36.5 | 44.7 | 50.3 |
| Kerosine distillate, percent | 19.5 | 18.1 | 16.8 | 15.7 |
| Gas oil, percent | 13.2 | 11.8 | 12.0 | 9.3 |
| Nonviscous lubricating distillate, percent | 12.8 | 11.6 | 8.8 | 9.1 |
| Medium lubricating distillate, percent | 4.5 | 4.3 | 2.9 | 2.8 |
| Residuum, percent | 14.6 | 14.2 | 11.0 | 10.0 |
| Distillation loss, percent | 0.5 | 3.5 | 3.8 | 2.8 |

Part II. A.S.T.M. Distillation test by Core Laboratories Inc.

Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware

| | Murphy 1 | Hutcheson A-1 | W. Mack 1 | D. D. Goode 1 |
|---|---|---|---|---|
| Gravity, deg. A.P.I. | 42.7 | 44.7 | 56.6 | 49.0 |
| Initial boiling pt., °F | 131 | 115 | 105 | 114 |
| 5 percent distilled at °F. | 204 | 175 | 127 | 151 |
| 10 percent distilled at °F. | 245 | 218 | 148 | 185 |
| 20 percent distilled at °F. | 307 | 288 | 185 | 237 |
| 30 percent distilled at °F. | 369 | 350 | 223 | 287 |
| 40 percent distilled at °F. | 441 | 425 | 264 | 340 |
| 50 percent distilled at °F. | 517 | 509 | 315 | 410 |
| 60 percent distilled at °F. | 590 | 583 | 375 | 499 |
| 65 percent distilled at °F. | | | | 545 |
| 70 percent distilled at °F. | | | 477 | 594 |

Because of the wide range in permeability, formation water below the oil does not advance uniformly through the reservoir but cones or fingers around the wells. (See figs. 16 and 17.) Plastics have been used in three wells in an attempt to plug off water-saturated zones, and in seven wells perforations opposite water-saturated zones were cemented off and the casing was reperforated above. Because of the comparatively high vertical permeability these plug-back operations were only temporarily successful. In a few wells, the percentage of water produced with oil decreased following a decrease in the rate of daily oil production. The possibility that a water-saturated zone was underlain by oil-productive sands of low water saturation encouraged one operator to plug off the upper zone and to reperforate the casing below, but the test was inconclusive

In most wells water production increased uniformly and rapidly after the well was placed on the pump. Where the water production exceeded 95 percent of the total liquid produced, the wells could not be operated economically and were abandoned.

Corrosion of casing by hydrogen sulfide gas gave considerable trouble in the Magnolia field[26] and has caused some trouble in the Atlanta field. Inert fluids left in the annulus as a protective measure against corrosion have not proved wholly effective in the Atlanta field. In some pumping wells the fluid in the annulus was removed, and the casinghead was opened to the flow line to lower the back pressure on the producing formation. To determine whether or not casing was leaking, several operators periodically checked the chloride content of produced water. As water from the Cotton Valley formation behind the producing string of casing has a chloride content of 150,000 parts per million as compared with 200,000 parts per million for typical Smackover limestone water, the source could be determined easily. If leaking casing was indicated, the tubing was pulled and the location of the leak was determined with a formation tester. Cement was forced through the leak and distributed behind the pipe by pressure manipulation on the bradenhead. Extraneous water has been detected and successfully excluded from several producing wells by these methods.

Removing Paraffin

Paraffin that congeals in tubing and flow lines has proved troublesome on many wells in the Atlanta field. Usually paraffin is deposited in wells that produce little or no water with the oil, and its deposition becomes more serious when the rate of oil production is restricted. Paraffin in the tubing is removed periodically by chemical treatment or mechanical scrapers. In wells where tubing is not set on a packer, steam or hot water was injected into the casing to melt and displace the paraffin. Flow lines usually were cleaned by blowing with steam.

Excluding Excess Gas from Wells

To prevent waste of gas and conserve reservoir energy it is desirable to maintain gas:oil ratios as low as practical. Because of gas liberation accompanying decline in reservoir pressure in the Atlanta field, however, the gas:oil ratio of several wells increased greatly. Acid treatments were used with limited success to increase the permeability of the reservoir rock and to lower temporarily the produced gas:oil ratio. In some wells perforations opposite upper zones were cemented off, and the casing was reperforated at a lower level to reduce the volume of gas entering the well with oil. Wherever the casing was set above the gas sand a liner was set and cemented through the gas sand. These methods, however, were not entirely successful and many wells in the Atlanta field continued to produce with high gas:oil ratios.

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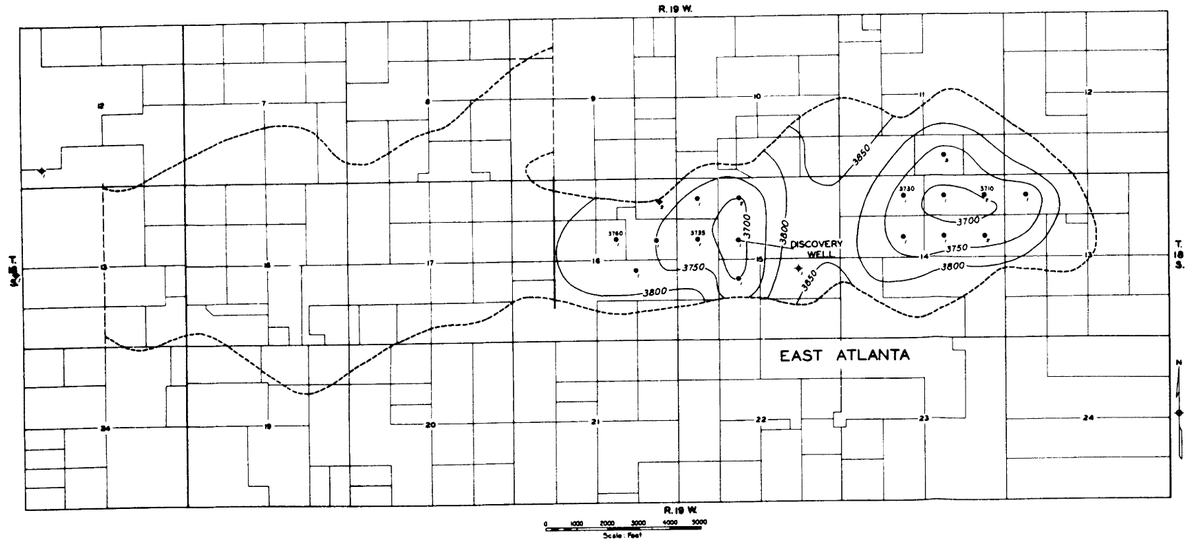
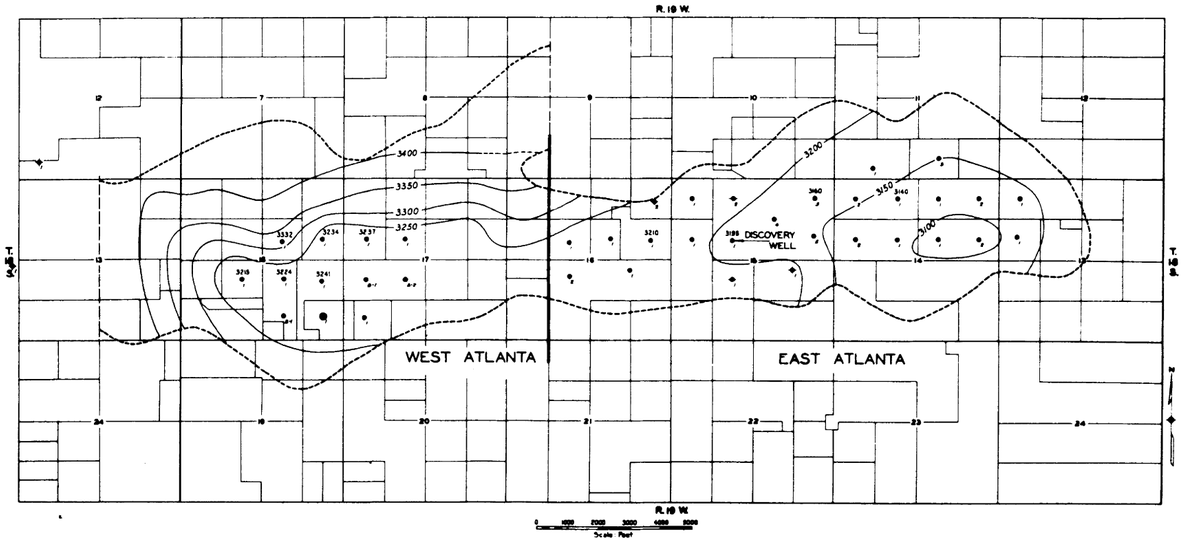
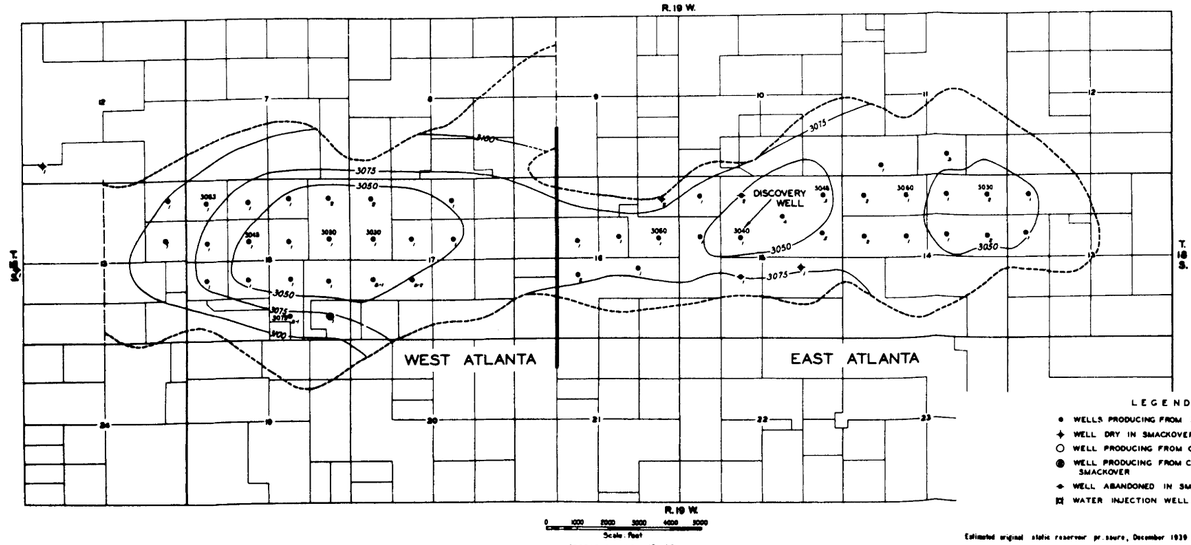
26/ Work cited in footnote 3.



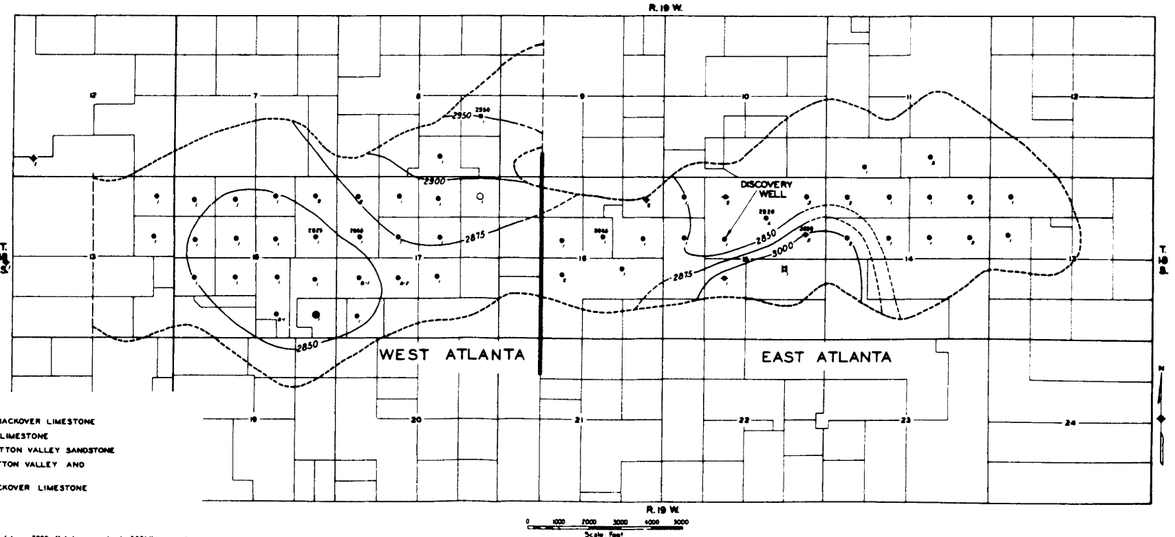

ISOBARIC MAP, 12-40
Estimated reservoir pressure at datum, 7900 ft. below sea level, { weighted average.....3791 / arithmetical mean.....3733 } lb. per sq. in.




ISOBARIC MAP, 11-44
Estimated reservoir pressure at datum, 7900 ft. below sea level, { weighted average.....3256 / arithmetical mean.....3219 } lb. per sq. in.




ISOBARIC MAP, 12-45
Estimated reservoir pressure at datum, 7900 ft. below sea level, { weighted average.....3059 / arithmetical mean.....3050 } lb. per sq. in.




ISOBARIC MAP, 1-1-47
Estimated reservoir pressure at datum, 7900 ft. below sea level, { weighted average.....2842 / arithmetical mean.....2887 } lb. per sq. in.

LEGEND
- WELLS PRODUCING FROM SMACKOVER LIMESTONE
- WELL DRY IN SMACKOVER LIMESTONE
- WELL PRODUCING FROM COTTON VALLEY SANDSTONE
- WELL PRODUCING FROM COTTON VALLEY AND SMACKOVER
- WELL ABANDONED IN SMACKOVER LIMESTONE
- WATER INJECTION WELL

Estimated original static reservoir pressure, December 1939 at datum 7900 ft below sea level, 3821 lb. per sq. in.

FIGURE 18.—PROGRESSIVE ISOBARIC MAPS OF RESERVOIR PRESSURES, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

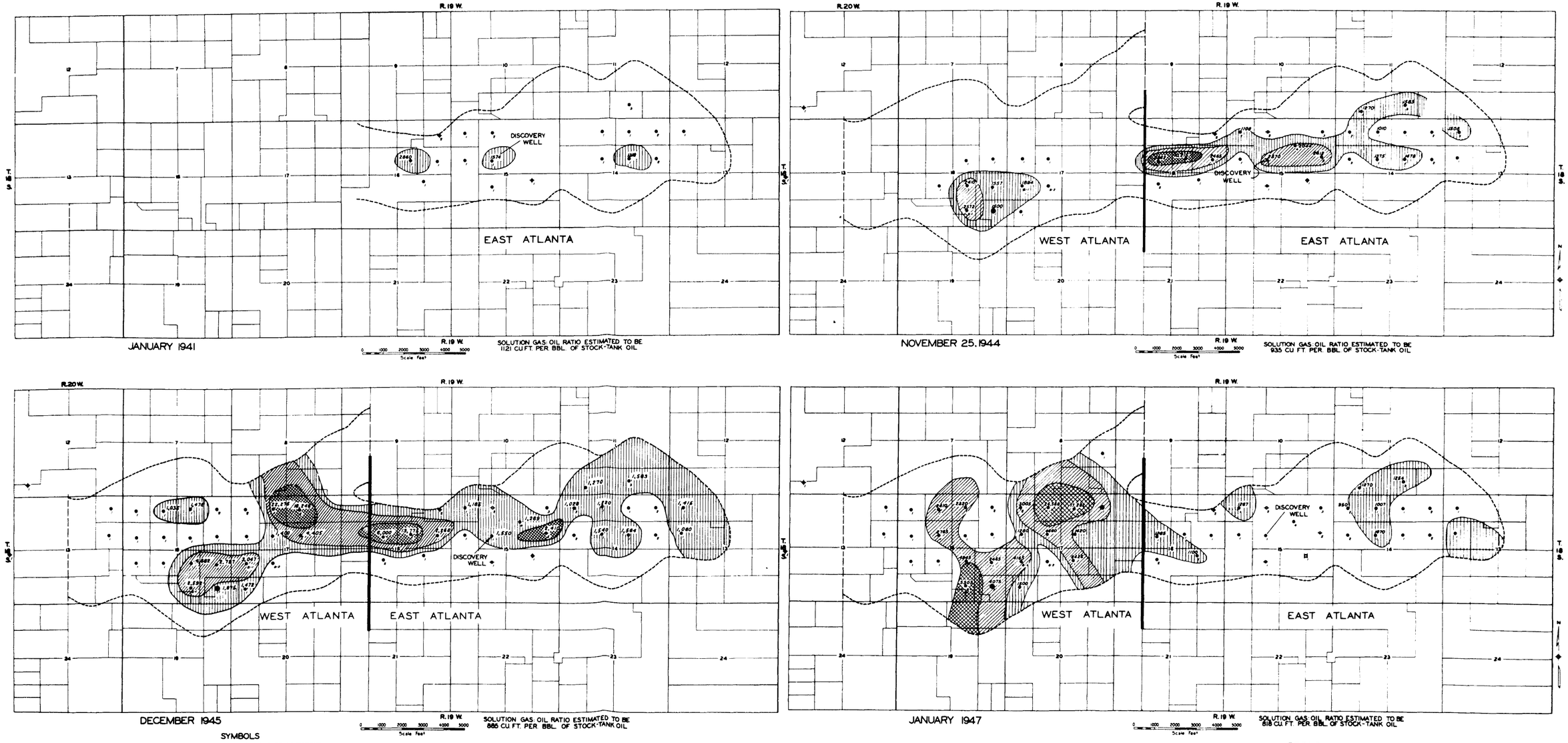



FIGURE 19.—MAPS SHOWING AREAS WITH GAS: OIL RATIOS ABOVE SOLUTION RATIO AT SUCCESSIVE DATES, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

## Removing Deposited Salt from Tubing

In one well in the West field, which produced considerable free gas and traces of water with the oil, difficulty was experienced with the tubing becoming plugged with salt crystals. Five months after the well was completed, the rate of oil flow from the well began to decrease rapidly, and within a few days the well stopped flowing. When pulled, 21 joints of tubing were found to be plugged with salt at a depth of approximately 5,900 feet below the surface. The casing was reperforated with five shots at depths between 8,294 and 8,295 feet opposite former perforations; cleaned tubing was rerun, and the well flowed normally again for about 4 months. In October 1946, flow ceased once more, and 21 joints of tubing at approximately 7,300 feet were found to be plugged with salt crystals. The crystals contained 99.65 percent sodium chloride, 0.15 percent calcium chloride, and 0.15 percent calcium bicarbonate.

It seemed probable that some of the brine produced with the oil was being evaporated by expansion of gas in the flow string to cause deposition of the salt. As a remedial measure, tubing was rerun without a packer and, with the aid of a horizontal lubricator (fig. 15), 5 to 8 barrels of fresh water was injected daily into the annulus between tubing and casing and was produced through the tubing with the reservoir fluids. An analysis of produced water showed that formation water was diluted about one-third by the injected water - enough apparently to prevent crystallization of salt, because during the next 10 months no difficulty was experienced with plugging.

## Remedial Work on Wild Well

All wells in the Atlanta field were drilled and completed safely: but during some repair work, 3 years after completion, one well blew wild for 2 days. The well had been "killed" preparatory to resetting a tubing packer, and the tubing had been lifted 5 feet to open the circulating ports in the packer, when the well suddenly started to flow through the casing. Attempts were made to close the rams on the blow-out preventer and the mastergate, but both were cut out immediately. Wild-well specialists were called out, the old mastergate was removed, and a new one was installed and closed. While flowing wild, the well produced only gas for nearly 24 hours; then the rate of flow declined from 40 to 25 million cubic feet of gas daily, and the well began to produce oil at an estimated rate of 75 barrels per hour. Approximately one-half of the oil produced while the well was out of control was caught in a pit, from which 688 barrels of pipeline oil was salvaged.

## Fluid Withdrawals and Pressure History

Regulations of the Arkansas Oil and Gas Commission provide for monthly reports of oil, gas, and water production from individual wells, and these reports were the basis of production studies. Many additional production tests were made by Commission and Bureau of Mines engineers. Since September 1940, shut-in bottom-hole pressure tests have been made on representative wells at intervals of 3 or 4 months. Based upon these data, isobaric, water-production, and gas:oil ratio maps were prepared and studied to interpret pressure changes and the movement of fluids in the reservoir. Some of these maps are shown in the report as figures 16, 17, 18, and 19.

The initial reservoir pressure in the discovery well, Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware, J. T. Beene No. 1, SE NW sec. 15, T. 18 S., R. 19W., was 3,821 pounds per square inch gage. Twelve months later bottom-hole pressure in the well diagonally offsetting it to the northwest was 3,810 pounds per square inch, indicating very little drop in reservoir pressure during this initial period when 167,000 barrels of reservoir fluid was produced. An abnormally low bottom-hole pressure recorded in a well in sec. 14, T. 18 S., R. 19 W., is not considered to be representative of reservoir pressure in that area because of the very low permeability of the reservoir rock surrounding the well.

By January 1941, 16 oil wells and 2 dry holes had been completed in two separated areas in the eastern part of the Atlanta field. In these areas (see fig. 18) reservoir pressure, as indicated by shut-in bottom-hole pressure tests, had declined from 3,821 to 3,700 pounds per square inch. Total reservoir fluid withdrawals were highest in the neighborhood of the discovery well.

The initial oil-water contact in the discovery well was at 7,999 feet below sea level, but the north offset, J. T. Beene well No. 2, completed 3 months later, produced initially 30 percent of water with the oil from a water-saturated zone between depths of 7,995 and 7,997 feet below sea level, indicating a somewhat higher oil-water contact in this area. In March 1940, 1 month after completion of J. T. Beene No. 2, the south offset to the discovery well, J. A. Price well No. 1, began to produce water through perforations between subsea depths of 7,992 and 7,998 feet. By January 1941, two other wells in this vicinity were producing small quantities of water, and water production from the J. T. Beene well No. 2 had increased to 80 percent, indicating edgewater advance from the north and south.

The tested initial gas:oil ratio of the discovery well was 1,608 cubic feet per barrel as compared with an estimated solution ratio of 1,146 cubic feet per barrel obtained by differential gas-liberation of a reservoir sample at 216° degrees F. The next few wells completed produced gas in volumes approaching the solution gas:oil ratio. Figure 19 shows that, by January 1941, three wells were producing gas at ratios appreciably above the solution ratio. The comparatively high gas:oil ratio of the most westerly well may have been caused by gas drainage from the West Atlanta field, since the base of the casing in that well was above the level of the gas-oil contact in the West field. High gas:oil ratios of the Murphy well No. 1, SW-1/4NE-1/4 sec. 14, T. 18 S., R. 19 W., reflects the comparatively impermeable producing formation surrounding the well which permits gas to enter the well more readily than oil. In October 1940, maximum allowable oil production per well was decreased from 200 to 180 barrels daily. Nevertheless, gas:oil ratios of the most westerly wells continued to increase, and in July 1941 the limiting gas:oil ratio for maximum oil allowables was raised from 2,000 to 3,000 cubic feet per barrel - approximately three times the solution gas:oil ratio.

Nearly all wells in the East field had been completed by May 1942. Reservoir pressures were higher in the western part of the field, where total fluid withdrawals per acre-foot of reservoir voids were least.

By January 1943 the oil-water contact in the vicinity of wells along the south edge of the field had risen approximately 10 feet. (See fig. 17.) Two wells in sec. 15, T. 18 S., R. 19 W., which produced large quantities of water, were abandoned early in 1943. The West Atlanta field was discovered in July 1943, but total oil production from the two fields increased very little until early in 1944. (See fig. 13.)

The estimated horizontal and vertical position of the oil-water contact in the vicinity of the wells at different periods is shown in figures 16 and 17. The estimated vertical position of the oil-water contact as shown in figure 17 is based on the relative percentages of oil and water which entered the casing through perforations at the indicated depths; it does not imply, however, that the oil-water contact between wells, where no information is available, is at the depth indicated by the straight line between wells. The advance of water through the producing formation is controlled by a number of factors, including differences in relative permeability and effective pressures in the various zones, and these factors are too complex to be shown diagrammatically in figure 17.

By November 1944 rates of gas and water production from wells along the south edge of the field had increased greatly and thirteen wells were producing more than 2 percent water with oil. To decrease water production, perforations between 7,972 and 7,984 feet below sea level in J. K. Mahony, E. Riley No. 2 well (fig. 17) were plugged off and the casing was reperforated above. Thirteen wells in the East field and five wells in the West field were producing gas at ratios above the solution gas:oil ratio. (See fig. 19.)The highest gas:oil ratios were recorded on wells at the west end of the East Field in front of edge-water advancing from the south. The reservoir pressure was lowest in the East field, away from areas into which edgewater was advancing, and highest in recently completed wells along the north edge of the East field. (See fig. 18.) As a result of large gas and water withdrawals from the reservoir, the bottom-hole pressure along the south edge of the West field in November 1944 had declined 240 pounds per square inch in the preceding 16-1/2 months.

Early in 1945 the maximum daily oil allowable per well was decreased to 100 barrels daily, but after a temporary drop, gas and water production continued to increase. (See fig. 13.) By December 1945, pressure in the West field had declined so that, with the exception of some low-pressure, water-free areas in the center of the field, bottom-hole pressures were fairly uniform. (See figs. 16 and 19.) Large volumes of gas being produced through perforations at subsea depths between 7,980 and 7,990 feet in a well in N-1/2 sec. 17, T. 18 S., R. 19 W., indicated that the gas cap was expanding vertically in some areas of the field.

Water began to advance into wells along the north edge of the field during 1945, and by January 1946 six wells in that area were producing more than 2 percent of water with the oil. The volumes of water produced with oil increased rapidly during 1946 and by January 1, 1947, only 10 of the older wells were producing water-free oil. Two recently completed wells along the north edge of the West field also were water-free. Production from Tide Water Associated

Oil Co. and Seaboard Oil Co. of Delaware, J. T. Beene well No. 5, was discontinued because of increased water production. Lower perforations in two other wells were plugged off to decrease water production and casing was reperforated at a higher level. Gas:oil ratios had declined on many wells in the East field as free and liberated gas in the reservoir was exhausted and the producing mechanism changed from solution-gas to water-drive. The volume of fluid produced per pound per square inch of reservoir pressure decline increased markedly and was approximately 2,100 barrels from the entire field in 1946 as compared with about 1,470 barrels in 1945.

During the first 6 months of 1947 water continued to move into the reservoir along the south edge of the field and production from another well was discontinued after remedial work failed to reduce water production. Reservoir pressure in some areas of the East field was raised slightly by water injected into the disposal well along the south edge of the field. Recently completed wells along the north edge of the field were water-free, and these wells produced gas and oil at ratios close to the solution gas:oil ratio. In June 1947, several structurally high wells in the West field still were producing much free gas with the oil.

## Production and Pressure History of Three Individual Areas

The production history of three individual areas are shown graphically in figure 20. The first group includes five wells on the Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware, J. T. Beene lease, near the center of the East field. These wells have produced some free gas during most of their productive lives but except for short periods during 1941 and 1946 have produced little water.

The relationship between free gas and water production is indicated in the graph. Some free gas was produced in 1939 and 1940 but the rate of gas production declined as water production increased late in 1940. Free gas production increased again in 1941 about the time well No. 2, large water producer, was abandoned. Production of free gas declined to zero in 1946, when advancing water became the effective medium in oil production.

Curves E and F are based on the respective volumes of reservoir oil and total fluid produced per pound per square inch of bottom-hole pressure decline at the represented wells. Drainage area, sand thickness, and porosity were not uniform at the several wells, and to compare leases it was desirable to divide the production per pound of pressure decline by the volume of the reservoir drained by wells in the group. For wells in group 1, total reservoir fluid produced per pound of pressure decline, per unit reservoir volume varied between 1.00 and 2.00, until late in 1946 when it increased as injected water raised the reservoir pressure. The total production of fluid and production of oil per unit were greatest when total fluid withdrawals did not exceed 30,000 barrels per month and declined sharply following periods of high fluid-withdrawal rates. In 1946, oil production per unit of pressure decline represented a larger percentage of the total fluid production than in earlier years.

The second group includes five wells near the west edge of the East field in section 16. These wells produced large volumes of free gas between 1941 and

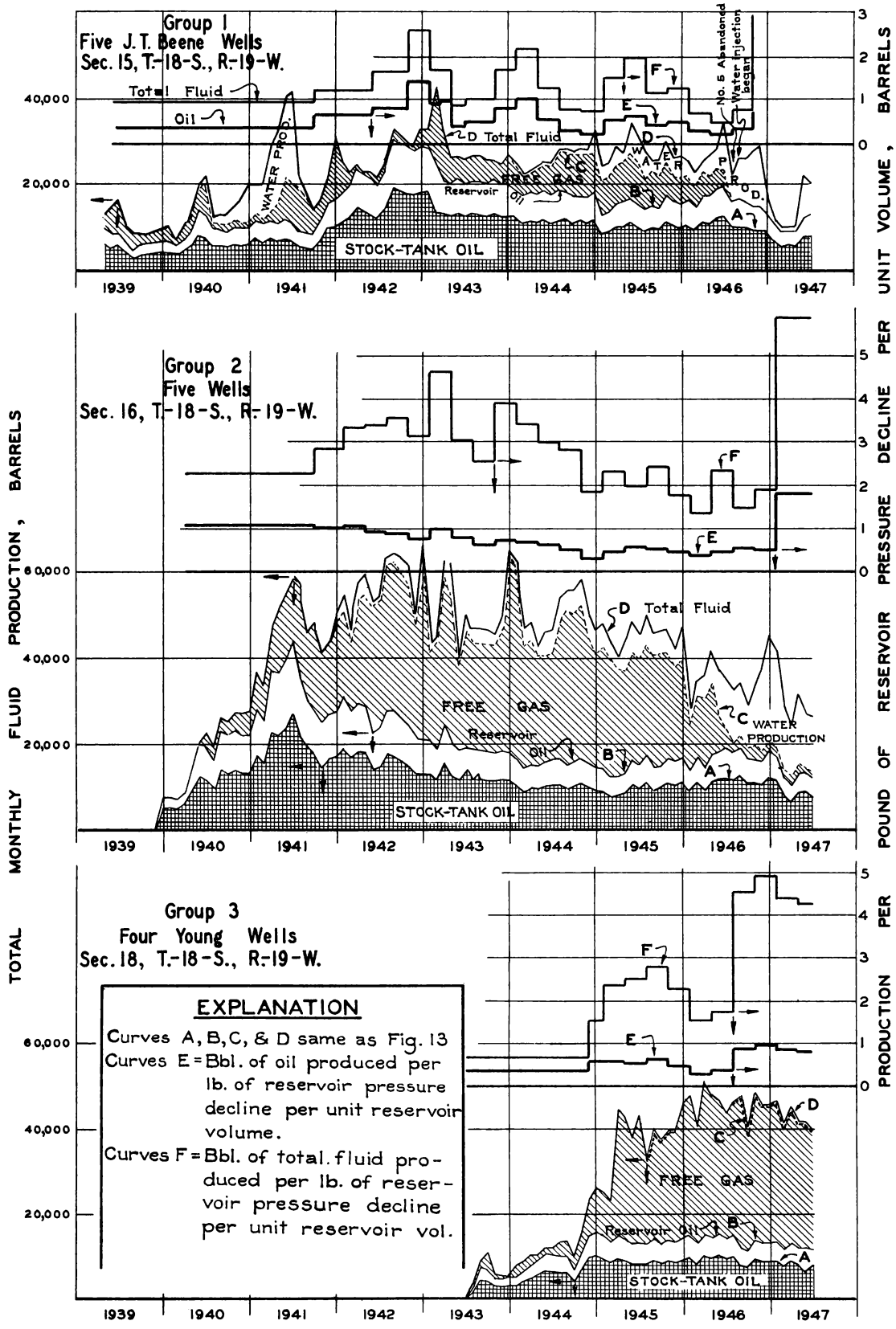



FIGURE 20.-FLUID PRODUCTION AND PRESSURE HISTORY OF THREE SEPARATED AREAS, ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

1946, after which the production of water increased rapidly. The rate of gas production was highest at wells immediately ahead of the advancing edgewater front and decreased sharply as the wells came directly under the influence of the water drive. Considerably more fluid and slightly more oil per unit of pressure decline (curves F and E, fig. 20) were produced from wells in group 2 than from those in group 1. Probably much of the free gas produced from these wells came from the West Atlanta field. The volume of oil produced per unit of pressure decline, as shown in curve E, decreased more or less regularly until 1946, when a slight increase was apparent. In 1947 this ratio increased rapidly as injected water caused an increase in the reservoir pressure.

The third group of wells, in section 18 of the West Atlanta field, produced large quantities of free gas and comparatively little water. By July 1947, water production still was comparatively low, although it was increasing steadily from several wells. Oil production per unit of reservoir pressure decline was comparable to that of the other groups, but total fluid production shown by curve F was comparatively high. Both oil and total fluid production (curves E and F) increased rapidly in 1946 as advancing water became more effective in the production of oil.

## Efficiency of Natural Water Drive

In an attempt to evaluate the efficiency of the natural water drive in "watered-out" areas of the Atlanta field, a drainage area based on the proximity of other wells was assigned to each of several abandoned wells, and the recoverable oil originally present was compared to that produced from the wells before abandonment. For practical purposes it may be assumed that by water displacement the residual oil saturation of the pore spaces in the reservoir rock cannot be reduced below 19 percent and that only the oil above that degree of saturation is recoverable. The first step in the calculation of recoverable oil originally in place in the drainage areas assigned to each of the wells was to compute, from the isovol work map, the reservoir voids above the water table in each of these areas. The computed volumes are shown in the second column of the table. The estimated original water saturation in each of these drainage blocks shown in column 3 varied, depending upon the structural position and average permeability of the reservoir rock. Recoverable stock-tank oil shown in column 4 is the product of the voids, the recoverable oil saturation (100 - (connate water + 19) ), and the barrels per acre-foot (7,758), divided by the formation volume factor of the reservoir oil (1.695). The ratio of the produced oil to the recoverable oil originally in place is defined as the efficiency of the production mechanism. Wells shown in table 10 were abandoned because of high water incursion, and natural water drive is assumed to have been the active production mechanism.

These data indicate much variation in the percentage of oil recovered from the different wells and emphasize the probability of oil drainage from adjacent areas.

TABLE 10. - Recovery of oil from several abandoned wells in Atlanta oil field

| Well name and number Tide Water Assoc. and Seaboard Oil | Reservoir voids, acre-ft. | Connate water, percent | Recoverable stock-tank oil originally in place, bbl. | Total stock-tank oil production, bbl. | Date abnd. | Recovery, percent |
|---|---|---|---|---|---|---|
| J. T. Beene 2 | 53.4 | 42 | 95,300 | 29,705 | 7-41 | 31.16 |
| J. T. Beene 5 | 123.8 | 35 | 261,000 | 167,534 | 7-46 | 64.1 |
| J. A. Price 1 | 53.7 | 45 | 78,000 | 88,505 | 12-42 | 113.4 |
| Hutcheson 1 | 71.9 | 20 | 202,000 | 279,134 | 6-47 | 138.1 |
| 3 S. edge wells | 249.5 | 33 | 596,000 | 552,993 | | 92.7 |

It is apparent from a study of current and past produced water:oil ratios and from present and past casing-perforation depths that a lower portion of the oil reservoir over the entire field has been flooded by advancing water and is lost to economical oil production through the present wells. Water did not advance uniformly through the reservoir, either vertically or horizontally (see figs. 16 and 17), and oil in less permeable zones was bypassed. Whether bypassed and trapped oil below water-saturated zones can be produced economically through the present wells is extremely problematical, and for the purposes of this report the recovery of such oil is assumed to be economically impossible. Likewise oil trapped between wells could be recovered only by drilling additional wells. By July 1947 a lower zone 2 to 15 feet thick, which originally contained about 15,735,000 barrels of recoverable reservoir oil, was thus lost to economical oil production. By material-balance calculations it is shown that only 11,168,000 barrels of water entered the entire reservoir to that date. (See table 9.) If this water entered only the lower zone and if each barrel of encroaching water displaced a barrel of reservoir oil into the wells to be produced, the maximum efficiency of this natural water flood would be the ratio of the displaced oil (11,168,000 barrels) to the original recoverable oil (15,735,000 barrels), or 71 percent. Under actual reservoir conditions the encroaching water probably was not confined to the lower zone and may have displaced gas as well as oil so that the actual efficiency would be less than the maximum cited above.

## Production and Sale of Gas

Approximately 12.5 billion cubic feet of free and dissolved gas was produced from the Smackover limestone in the Atlanta field to July 1947. Some of this gas was used in drilling wells and some in service operations, but because of the sulfur content (860 grams per 100 cubic feet), there was no ready market for the remainder.

The natural-gasoline content of the gas varies widely, depending upon the gas:oil ratio of the producing well and upon the pressure and temperature of the gas-oil separation. The average gasoline content of all gas produced in 1947 was about 5 gallons per M cubic feet. During the summer of 1947, the Hiwan Oil & Gas Co. began construction of a natural-gasoline plant in the West Atlanta field. (See fig. 21.) Plans were underway to process and extract liquid hydrocarbons from the gas, and to sell all residue gas not required for plant operation. The reinjection of gas into the reservoir has not been contemplated.

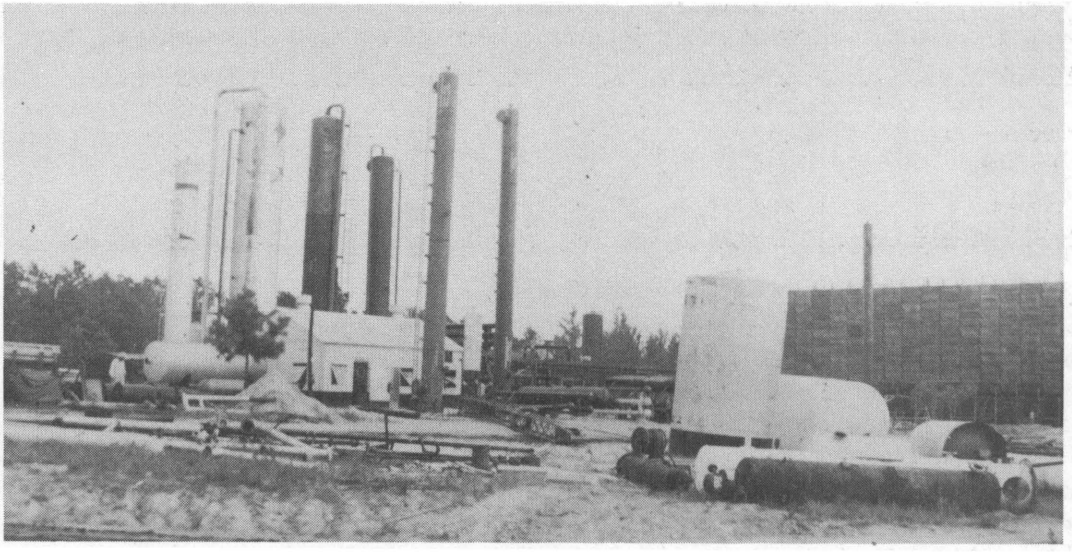


Figure 21. - Natural-gasoline plant under construction, Atlanta oil field.

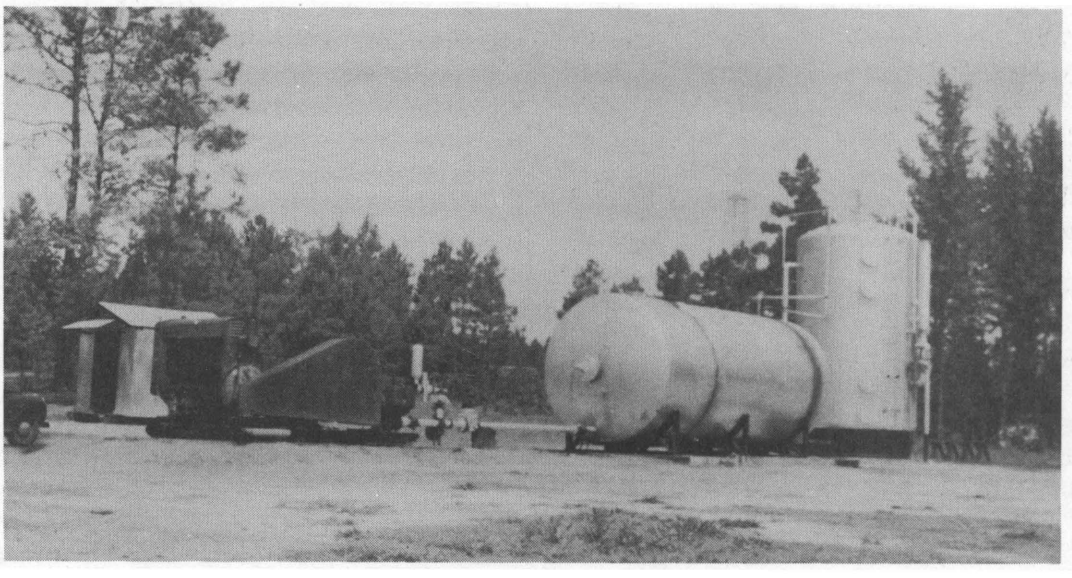


Figure 22. - Water-treating and injection equipment, Atlanta oil field.

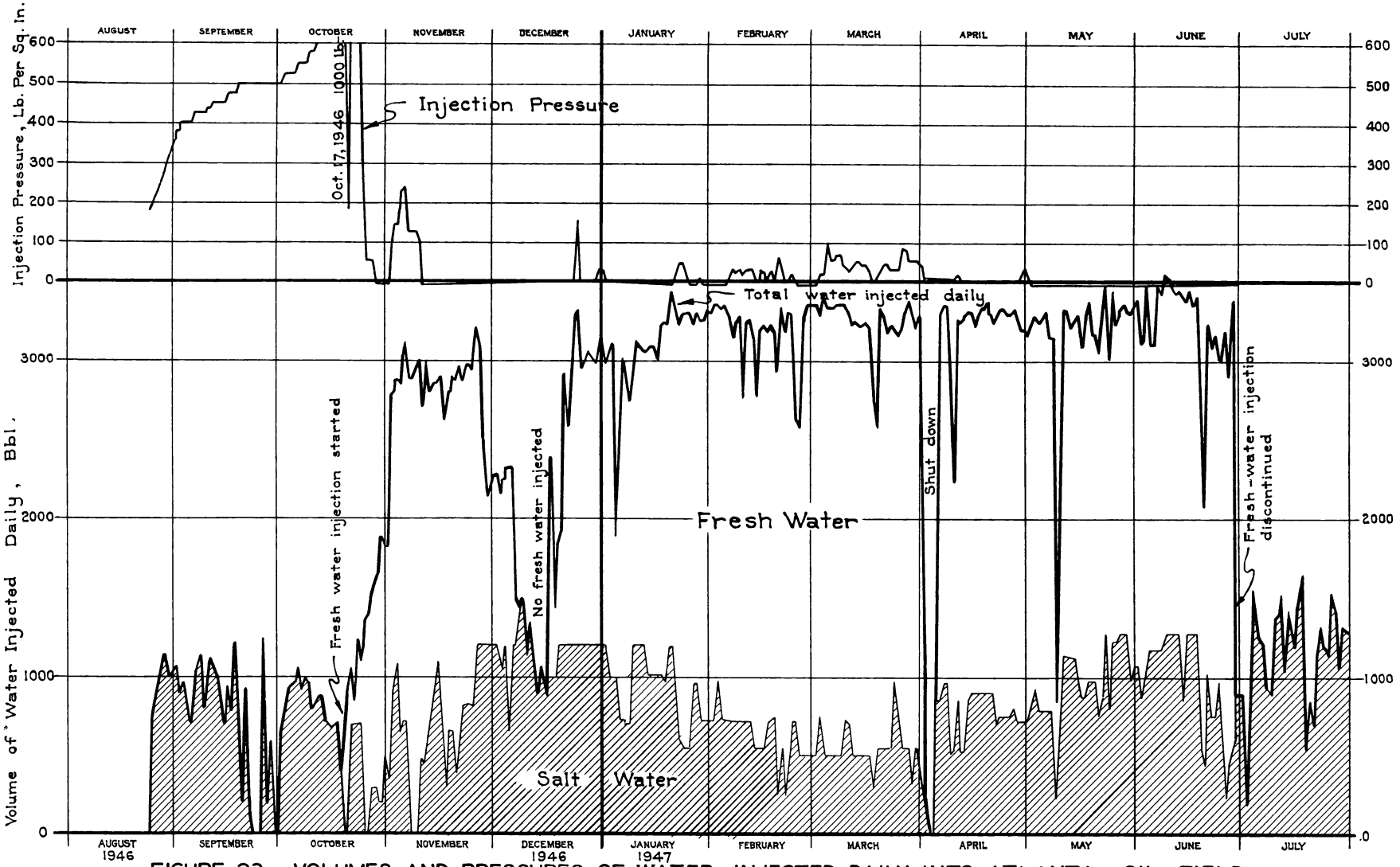



FIGURE 23.- VOLUMES AND PRESSURES OF WATER INJECTED DAILY INTO ATLANTA OIL FIELD, COLUMBIA COUNTY, ARK.

## WATER INJECTION

### Purpose

The success of pressure maintenance in the Midway pool[27] and the beneficial results obtained by injecting salt water into flank wells in the Magnolia field, Columbia County, Ark.,[28] encouraged operators to consider water injection in the Atlanta reservoir. As the pressure-production behavior of the Atlanta field was similar to that of the Midway field before water injection started, comparable, beneficial results from water injection in the Atlanta field might be expected. Injection of produced salt water would serve the dual purpose of brine disposal and reducing the rate of pressure decline.

### Injection Well

The Tide Water Associated Oil Co. and Seaboard Oil Co., of Delaware, largest operators in the Atlanta field, acquired a dry hole drilled on the Talley lease in the N-1/2 SE-1/4 sec. 15, T. 18 S., R. 19 W., for water injection. When the well was completed in 1940 it produced water and a show of oil from porous zones between 8,214 and 8,220 feet below the surface. To prepare the well for water injection, it was cleaned out, deepened to 8,302 feet, and a casing leak at 4,549 feet was squeeze-cemented. Two-inch tubing with a hold-down packer at 8,113 feet was set inside of the 5-1/2-inch casing at 8,206 feet. During a preliminary test early in 1946, 1,936 barrels of salt water was injected daily into the well. Regular water-injection was begun August 25, 1946, and to July 1, 1947, approximately 521,000 barrels of fresh water and 277,000 barrels of salt water had been injected into the Smackover limestone reservoir.

### Treatment of Injected Water

Salt water for injection was obtained from oil-water separating tanks on three leases in the East Atlanta field. The water moves under a small pressure and without aeration through a carborundum filter to a volume tank where it is picked up by a 4- by 10-inch pump and delivered to the injection lines. The salt water header, filter tank, volume tank, meter run, pump and six cylinder gasoline engine are shown in figure 22. Fresh water for injection was obtained from a shallow well and entered the system through the filter tank. Injection pressures at the pump varied from a partial vacuum to 1,000 pounds per square inch depending somewhat on the ratio of salt water to fresh water being injected. (See fig. 23.) Water-injection lines originally were 2-inch tubing, but later this was replaced with 4-inch Transite pipe. At the injection well, water passes through a small trap to remove salt crystals or pipeline scale.

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27/ Horner, William L., Pressure Maintenance by Water Injection, Midway Field, Arkansas; Drilling and Production Practice: Am. Petrol Inst., 1945, pp. 27-34.

28/ Work cited in footnote 3.

## History of Water Injection

Figure 23 shows the volumes of fresh water and salt water injected daily and the injection pressures at the pump. During the first 8 weeks of water injection, 800 to 1,000 barrels of salt water was injected daily into the well and injection pressures increased steadily to a maximum of 1,000 pounds per square inch. When fresh water alone was injected, October 19 and 20, the injection pressures dropped sharply to 175 pounds per square inch, but increased again on October 22 when salt water was added to the injected water. By controlling the relative injected volumes of fresh and salt water, the injection pressure was lowered to atmospheric pressure by the end of October. Early in November 1946, when the ratio of salt to fresh water was increased, the injection pressures increased to 240 pounds per square inch. After another short period of injecting only fresh water, both salt and fresh water were injected for several months at satisfactory pressures. Late in June 1947 fresh-water injection was discontinued, and during July about 1,200 barrels of salt water was injected daily under vacuum.

A satisfactory explanation is not available as to why the disposal well would take fresh and not salt water at satisfactory pressures in September and October 1946 but did take salt water under vacuum after about 75,000 barrels of fresh water was injected. In an attempt to determine the cause of high injection pressures, Bureau of Mines engineers made tests of the iron content, carbonate stability, and pH value of the water at successive points in the course between water production and injection. The tests showed a small variation (4.9 to 5.4) in the pH value of the water. Carbonate stability and to a lesser extent the bicarbonate content of the water varied somewhat, being higher when pressure was higher and more $CO_2$ and $H_2S$ were retained in solution. These tests, however, were of little practical value in determining definitely the cause of the higher pressures required to inject salt water.

It was suggested that the Smackover limestone might contain naturally some salt crystals that were dissolved by injected fresh water to increase the permeability of the rock to both fresh and salt water. In an attempt to determine the presence and importance of salt crystals in the virgin reservoir rock, samples from the inside of cores were ground to grain size, and the lighter -weight minerals were separated from the calcite by flotation on a solution of bromoform and carbon tetrachloride having a specific gravity of 2.45. In this determination, cores from several wells were combined in groups, depending upon their stratigraphic position. Upper rocks contained about 0.01 percent of floating minerals as compared with 0.03 percent for the stratigraphically lower beds. Microscopic examination of the light-weight minerals under polarized light revealed almost no crystals of halite (mineral salt). Although some crystals in open channels might have been dissolved during coring, the virtual absence of halite in the cores indicated that any increase in permeability due to solution of this mineral would be negligible.

## Results of Water Injection

The first noticeable effect of water injection in the Atlanta field was to increase bottom-hole pressure in the temporarily abandoned J. T. Beene well

No. 5, from 2,865 pounds per square inch in August to 3,000 pounds per square inch in December 1946. By April 1947, bottom-hole pressures over most of the East field had increased slightly. Pressure measurements made in July 1947, after water-injection rates had been reduced from 3,200 barrels daily to 1,200, showed lower average pressures than in April. The bottom-hole pressure on the J. T. Beene well No. 5 in July 1947, was 2,998 pounds per square inch.

In an attempt to understand the movement of injected water through the reservoir rock, measurements were made of the chloride content and specific gravity of the water produced from wells surrounding the injection well. Comparative specific gravities are shown below.

| Tide Water Associated Oil Co. | Specific gravity at 60° F. | | | |
|---|---|---|---|---|
| | 7-30-46 | 12-10-46 | 5-10-47 | 7-31-47 |
| J. T. Beene No. 1..... | ? | 1.221 | 1.217 | 1.217 |
| J. T. Beene No. 3..... | ? | | 1.222 | 1.221 |
| Talley No. 1..... | 1.228 | ? | 1.224 | 1.221 |

These data tend to show progressive dilution of the water produced from these wells. Other factors[29], however, affect the specific gravity of produced water and the cited data are too incomplete to be used to make quantitative measurements of the volumes of injected water produced from these wells. These analyses and the recent increase in water production from the J. T. Beene wells (fig. 20, group 1) suggest that injected water is moving towards producing wells.

On April 30, 1947, 50 grams of fluorescence dye was added to the injection water at the injection well. Careful examinations to May 5, 1947, and casual observation subsequently did not reveal the presence of dye in the produced water. This test, however, is not considered conclusive evidence that injected water did not move to the producing wells, since many factors may affect the appearance of the dye.[30] [31]

In July 1947, it was still too early to determine the beneficial effects of water injection in the Atlanta field. Although reservoir pressure was raised in some areas and the rate of pressure decline for the entire field has decreased slightly, the injection of more water at other points would be required to prevent continued pressure decline.

## Recommended Changes in Water-Injection Program

The writer thinks that most beneficial results in additional oil recovery could be obtained by injecting substantial quantities of water along the edges of the field adjacent to low-pressure areas not under the immediate influence of the natural water drive. Probably several such wells, receiving both salt and fresh water, would be required to maintain the reservoir pressure uniformly over the entire field. The volumes of water to be injected into each well should be determined by bottom-hole pressure tests on key wells.

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29/ See discussion under section "Interstitial Water."

30/ Ambrose, A. W., Underground Conditions in Oil Fields: Bureau of Mines Bull. 195, 1921, pp. 107-110.

31/ Plummer, F. B., Engineering Fundamentals: Oil and Gas Jour., vol. 44, Feb. 29, 1945, p. 141.

The total volume of water required to stabilize the reservoir pressure at any particular value can be calculated from data shown in figure 13 and table 8. Based upon changes in the viscosity of the reservoir oil with pressure (fig. 12), upon difficulties experienced in keeping low gas:oil ratio wells flowing, and to prevent irregular water encroachment and bypassing of oil, it would seem desirable to stabilize the reservoir pressure as high as practical. To maintain reservoir pressure the total water entering the reservoir, both naturally and by injection, must balance the total fluid withdrawals. Total fluid withdrawals for the first 6 months of 1947 averaged about 348,000 barrels per month (see fig. 13), whereas natural water entry during the same period averaged only 151,000 barrels per month. (See table 8, line 17.) To maintain reservoir pressure at these withdrawal rates would require the injection of an additional 197,000 barrels of water monthly to replace the produced fluids.

To raise the reservoir pressure from 2,800 pounds per square inch to 3,000 would require compression of the 15,006,000 barrels of free gas remaining in the reservoir as of July 1, 1948. Assuming that liberated gas in the reservoir would not return to solution in the reservoir oil; and, neglecting the compressibility of the oil and water, the higher pressure would be obtained by injecting an additional 1,007,000 barrels of water into the reservoir. Table 8 shows that when the reservoir pressure was 3,000 pounds per square inch, about 127,000 barrels of water per month entered naturally. At this natural rate of water entry, an additional 221,000 barrels per month of injected water would be required to balance total fluid withdrawals of 348,000 barrels per month.

Free-gas withdrawals through high-gas:oil-ratio wells represents a substantial portion of the total fluid withdrawals. Free-gas production is a matter of individual well withdrawal rates and depths of perforations and cannot be forecast by material-balance calculations. Gas production decreased during the early part of 1947, and under stabilized pressures the volume of free gas produced with the oil should continue to decrease, because additional gas would not be liberated from unproduced oil in the reservoir. At reduced gas- and total fluid-withdrawal rates, the volume of injected water required to maintain reservoir pressure would be correspondingly less.

## OTHER RESERVOIRS IN ATLANTA FIELD

### Cotton Valley Sands

In the West Atlanta field, oil production has been obtained from two separated Cotton Valley sands. The upper sand was penetrated by 21 wells at depths between 6,820 and 6,870 feet below sea level. The thickness of the sand in these wells ranged from 5 to 38 feet. The top of this sand is structurally highest in the Placid Oil Co. W. T. Boone well No. 1, NE-1/4 NE-1/4 sec. 17, T. 18 S., R. 19 W., from which oil is produced through casing perforations between a depth of 6,825 and 6,831 feet below sea level. Electric logs indicate that oil production may be obtained from this sand in 3 other wells. The initial oil production of the Placid Oil Co. W. T. Boone well No. 1 was 144 barrels of 35° A.P.I. gravity oil daily through 9/64-inch choke. By June 1947, daily oil production had declined to about 8 barrels, and the production of water had increased to 10 barrels a day. Total oil production from January 1946 to July 1947 was 10,847 barrels.

The top of the lower Cotton Valley sand was penetrated in 24 wells in the West Field at depths between 6,866 and 6,950 feet below sea level. The top of the sand is structurally highest in a narrow ridge running northeast through the center of sec. 17, T. 18 S., R. 19 W. Oil production from this sand was obtained through casing perforations in two dually completed wells in the SE-1/4 of sec. 18. A study of electric logs indicates that eight wells in an area of about 400 acres penetrated oil-productive sand averaging 10 feet in thickness. No core analyses are available from Cotton Valley sands, but side-wall cores taken in this zone in the dually-completed Skelly Oil Co., R. M. Young well No. 1, are described as dense to medium-grained slightly calcareous sandstone.

A sample of reservoir oil from the Cotton Valley sand was taken from the Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware, A. O. Young well No. 1, NE-1/4 SE-1/4 sec. 18, T. 18 S., R. 19 W., at a depth of 6,739 feet below sea level and at a pressure of 3,019 pounds per square inch. A sample of separator gas containing 93.75 percent methane, 2.73 percent ethane, 1.54 percent propane, and 1.98 percent of heavier components was combined with the subsurface oil sample to simulate original reservoir conditions. When the oil sample was flashed from above its saturation pressure to atmospheric pressure, 655 cubic feet of gas per barrel of stock-tank oil was liberated, while 1 barrel of reservoir oil shrank to 0.694 barrel of stock-tank oil. The viscosity of the oil at the reservoir temperature of 202° F. increased from 0.50 centipoise to 1.65 centipoises with the decrease in pressure.

Casing in the Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware, A. O. Young well No. 1 was perforated with 36 shots at a depth of 7,222 to 7,224 feet below the surface. The initial oil production was 356 barrels of 40.7° A.P.I. gravity oil daily through a 1/4-inch choke, and the gas:oil ratio was 750 cubic feet per barrel. At that rate of flow, bottom-hole pressure declined rapidly from 3,080 to 2,290 pounds per square inch for a productivity index of 0.45 barrel of oil daily per pound of pressure drop. The initial oil production from the Skelly Oil Co., R. M. Young well No. 1, in which the casing was perforated between 7,210 and 7,222 feet with 36 shots, was 254 barrels daily of 41.8° A.P.I. oil through 3/16-inch choke.

The production of oil from Cotton Valley sands in the A. O. Young well was discontinued in October 1944 after a work-over job failed to yield lasting results. The cumulative oil production was 23,779 barrels. Cotton Valley production from the Skelly Oil Co., R. M. Young well No. 1 declined to about 4 barrels of oil daily in June 1947 and was discontinued in July after 53,817 barrels of oil had been produced. Electric logs indicate the possibility of other oil-productive Cotton Valley sands in the Atlanta field at depths of about 6,740 and 7,130 feet below sea level. The lower sand in the Tide Water Associated Oil Co. and Seaboard Oil Co. of Delaware, E. M. Hutcheson B-1 well was tested through gun perforations between depths of 7,294 and 7,308 feet. After 3,300 feet of oil and 1,900 feet of salt water had been swabbed from the casing, perforations were cemented off, and the well was completed in the Smackover limestone.

In the East Atlanta field, Cotton Valley sands were cored at about 7,050 feet below sea level in three wells. These cores were described as "hard to

medium-fine-grained sandstone with thin streaks of shale." The porosity of the core samples ranged from 15 to 22 percent and permeability from 14 to 500 millidarcys. The saturations of the cores from the oil-bearing zones ranged from 7 to 13 percent of the total pore space. After the J. A. Price well No. 1 was abandoned in the Smackover limestone, Cotton Valley sands at depths between 6,775 and 6,780 feet were tested in the well. During the test very little gas, no oil, and 900 feet of water were swabbed from the hole, and the well was abandoned. No other tests of Cotton Valley sands in the East Atlanta field have been made, although electric logs and core analyses indicate the possibility of oil production from several zones.

### Jones Sand

The Jones sand at the base of the Cotton Valley series, which is an important oil reservoir in the nearby Schuler field, has been identified in electric logs of several wells in both the East and West Atlanta fields. In the G. H. Vaughn, Mahony well No. 1, NW-1/4 NW-1/4 sec. 13, T. 18 S., R. 19 W., the Jones sand was tested through casing perforations between depths of 7,936 and 7,943 feet below sea level, but no oil, gas, or water was produced during a 14-hour test.

### Upper Sands

As yet no tests have been made in the Atlanta field of possible oil-producing formations above the Cotton Valley series. All beds between the mid-Cretaceous unconformity and the top of the Smackover limestone are expected to conform more or less with structures in the lower bed (fig. 2), although the axis of structures in the upper beds may shift somewhat. Structures favorable to oil accumulation probably do exist in some of these lower Cretaceous beds. In the Rodessa field the Gloyd zone, Dees and Young lime, of the Rodessa group have proved productive.[32] The James lime and sands of the Hosston group are oil-productive in the nearby Stephens field.

## SUMMARY AND CONCLUSIONS

The Atlanta field was discovered in 1938 as a result of seismograph surveys made in 1937. The western part of the field was discovered independently in 1943, and drilling in 1946 and 1947 resulted in important extensions. The principal oil reservoir is an oolitic limestone near the top of the Smackover formation of Jurrassic age. Core records, electric logs, and fluid samples permit reasonably accurate analyses of reservoir conditions.

The structure is a narrow east-west anticline with two main east and west domes and minor cross folds. The original oil-water contact was close to 8,000 feet below sea level; and the productive area, as determined by intersection of the oil-water interface surface with the structure of the top of the porous and permeable limestone, includes an area of 4,172 acres. Between the top of the

32/ Hill, H. B., and Guthrie, R. K., Engineering Study of Rodessa Oil Field in Louisiana, Texas, and Arkansas: Bureau of Mines Rept. of Investigations 3715, 1943, 126 pp.

porosity and the oil-water contact are numerous tight zones from which essentially no oil could be produced before water advancing through permeable strata reached producing wells in such large quantities as to make oil production unprofitable. On this basis all zones with measured or indicated permeabilities of less than 10 millidarcys were not considered to be reservoir rock. The top of the west dome was saturated with gas, and the original gas-oil contact was at about 7,972 feet below sea level. The gas-producing reservoir rock in the West field included about 18,638 acre-feet, and the oil-producing reservoir rock in both East and West fields included about 53,171 acre-feet.

The porosity of the reservoir rock varies widely between wells and between zones in the same well. Void spaces in each zone around each well were calculated separately, and from the sum of the voids in each well the total voids in the gas reservoir were calculated to be 1,630 acre-feet and the total voids in the oil reservoir 8,042 acre-feet. Weighted average porosity of the rock of the gas reservoir was 15.81 percent and of the oil reservoir 15.125 percent.

Connate water content was calculated from determinations by the restored-state method to average 25 percent in the gas reservoir, 26 percent in the main body of the oil reservoir, and 42 percent in a transition zone 13 feet thick above the oil-water contact.

At the original pressure of 3,821 pounds per square inch gage and temperature of 218° F., the reservoir oil was saturated with 1,146 cubic feet per barrel of stock-tank oil, and the shrinkage of reservoir oil to standard conditions was from 1.695 to 1.000. The gas reservoir originally contained approximately 15 billion cubic feet of gas measured at standard conditions and the oil reservoir about 24 million barrels of stock-tank oil.

To promote efficient use of natural reservoir energy, the rate of oil production and the relative volumes of gas and water produced with the oil were controlled by the Arkansas Oil and Gas Commission. Depending on reservoir behavior, the maximum gas:oil ratio, without further oil curtailment, was limited to 3,000 cubic feet per barrel of oil. Since 1946 fluid withdrawals from the reservoir have ranged between 300,000 and 400,000 barrels per month. Free or liberated gas, produced through a few high gas:oil ratio wells, has represented a substantial portion of the total fluid withdrawals. Because of high sulfur content, no ready market for the gas was available until recently, and the greater part of the gas was vented to the air. Without unitization of operations and selective low-gas:oil-ratio production, this waste could not have been eliminated.

A natural water drive is most active along the south edge of the field, and three wells in that area have been abandoned because of water incursion. The natural water drive, however, has not been sufficient entirely to replace produced fluids; and by July 1, 1947, the reservoir pressure had declined from 3,821 to 2,800 pounds per square inch, with a consequent loss of reservoir energy and increase in viscosity of the reservoir oil.

Since August 1946, produced and extraneous water has been injected into the Smackover limestone reservoir through one well along the south edge of the field. The rate of pressure decline in the reservoir was decreased, but the volume and locale of water injection were not favorable to maintaining pressure uniformly over the field. The volumes of injected water necessary to maintain pressure at any given withdrawal rate can be approximated by material-balance calculations.

When water production from wells in the Atlanta field increased to 95 percent or more of the liquid produced, it was considered unprofitable to operate the well, although only the more permeable zones may have been oil-depleted and water-saturated. The efficiency of oil recovery thus depended upon the relative speed at which the water advanced through the several strata penetrated by the well; because greatest efficiency and less trapping of oil would result when water advanced uniformly through each of the penetrated strata. The rate of water advance through the rock is proportional to the difference in pressure between water-saturated zones and the well bore. Rapid water advance may result in trapping of oil in the less permeable zones and areas. Better equalization of pressure between wells by selectively curtailing withdrawal rates, particularly gas withdrawals, might have resulted in more uniform pressure distribution and water encroachment. The injection of water into edge areas not under the immediate influence of the water drive might serve to maintain a more uniform front of advancing edge water and so decrease the tendency of the water drive to finger and bypass oil. Pressure maintenance by the reinjection of produced gas might result in greater recovery, but without unitization of the reservoir it would not be practical.

Oil production from the Smackover limestone in the Atlanta field has been profitable, but production from Cotton Valley sands has been disappointing. Upper sands in the Atlanta field area have not been tested, but these offer little promise of substantial reserves.

## APPENDIX

## RULES, REGULATIONS, AND ORDERS OF THE ARKANSAS OIL AND GAS COMMISSION PERTAINING TO THE ATLANTA OIL FIELD

### Permission to Drill

General Rules - January 1944

RULE B-1 - Before any person, firm or corporation shall spud in and begin the actual drilling of any well in search of oil and/or gas in the State of Arkansas, such person, firm or corporation shall file with the Oil and Gas Commission its application in such form as the Commission shall require for a permit to drill said well. The application shall be accompanied by the sum of $50.00, which sum is fixed as the fee for granting of a permit. The permit so issued by the Commission shall be in such form as it may by its rules and regulations prescribe, and the number of said permit shall at all times be prominently displayed upon the derrick used in drilling of the well.

RULE B-2 - Before any person shall begin drilling of any well in search of oil or gas in the State of Arkansas, said person, firm or corporation shall file with the Oil and Gas Commission a bond, payable to the State of Arkansas in the principal sum of twenty-five hundred ($2,500.00) dollars, executed by said person, firm or corporation, as principal, and some surety approved by said Commission, as surety, conditioned that the said person, firm or corporation, shall plug said well in compliance with all of the rules and regulations of the Commission and with the laws of the State of Arkansas, in event said well does not produce oil or gas in commercial quantities or ceases to produce oil or gas in commercial quantities within one year of the date of filing of said bond.

In lieu of furnishing the bond above required for each particular well drilled by any person, firm or corporation, said person, firm or corporation may file with the Commission a blanket bond in the sum of ten thousand dollars ($10,000.00), executed in the same manner as the bond mentioned in the preceding paragraph, conditioned that said person, firm or corporation shall plug any well drilled by it within the State of Arkansas, in compliance with all of the rules of the Commission, and the laws of the State of Arkansas.

## Spacing of Wells

General Rules - January 1944.

RULE B-3, A. The spacing of wells in proven oil and gas fields, or in areas that the Commission may designate, shall be governed by special rules for that particular field or area, adopted after notice and hearing.

Order No. 14-39 - March 31, 1939

RULE II.-No well shall hereafter be drilled for oil or gas at any point less than 1,320 feet from any spudded, drilling, or completed well, or less than 660 feet from any property line or division line.

Order No. 15-45, July 26, 1945

RULE II.-No well shall hereafter be drilled in the Lime Pool of the Atlanta field at a point more than 100 feet from the center of a governmental forty-acre drilling unit.

Provided: That the Commission may grant such exceptions, after notice and upon hearing, as may be reasonably necessary where it is shown, and the Commission finds, that a well drilled in accordance with the stated spacing rule would be outside the pool or topographical conditions are such as to make drilling difficult. However, whenever an exception is granted, the Commission shall take such action as will offset any advantage which the person securing the exception may have over other producers by reason of the drilling of the well as an exception.

RULE III.-Not more than one well shall be drilled on any forty acres, or forty-acre subdivision of a lease, owned on the effective date of this order by

one person, or by persons in moiety. To a well which is drilled upon such forty-acre unit, the forty acres upon which it is drilled shall be assigned to that particular well. If, however, a well is drilled on a lease covering more than forty acres, owned by one person, or by persons in moiety, the acreage in excess of 40 acres, but in no event more than 10 acres in excess of 40 acres, upon which such well is drilled, shall be used for the purpose of allocating production.

## Drilling of Wells

General Rules

RULE B-30 - In order to prevent encroachments on or injury to neighboring leases or property, all wells drilled at a distance of less than one hundred fifty (150) feet from the nearest property line shall not deviate more than three (3) degrees from vertical at any point in the hole; all wells drilled at a distance of less than three hundred (300) feet and more than one hundred fifty (150) feet from the nearest property line shall not deviate more than four (4) degrees from vertical at any point in the hole; wells drilled at a distance of more than three hundred (300) feet from the nearest property line shall not deviate more than five (5) degrees from vertical at any point in the hole. The Commission shall have the right to make, or to require the operator to make a directional survey of the hole, at the request of an offset operator and at the expense of said offset operator prior to the completion of the well; make a directional survey of the hole at any time, and at the expense of the operator, in order to ascertain that the well has not deviated beyond the boundaries of property on which well is located.

RULE B-5 - During the drilling of every well, the owner, operator, contractor, driller, or other person responsible for the conduct of drilling operations, shall keep at the well a detailed and accurate record of the well, reduced to writing from day to day, which shall be accessible to the Commission and its agents at all reasonable times. A copy of the record shall be furnished to the Commission upon form prescribed by the Commission, within fifteen days after the completion of any well, but shall be kept confidential, if the operator so requests in writing, for a period not to exceed ninety days after the completion of the well, provided that the report or data there, when pertinent, may be introduced in evidence in any public hearing before the Commission or any Court, regardless of the request that the report be kept confidential. The well record shall describe progressively the strata, water, oil or gas encountered in drilling a well with such additional information as to gas volumes, pressures, rate of fill-up, water depths, caving strata, casing record, etc., as is usually recorded in the normal procedure of drilling.

Any electrical logging or surveying of the well shall also be recorded and copy furnished the Commission, within 30 days after completion.

RULE B-17 - At the time of drilling any well, the operator shall continuously maintain in the hole, from top to bottom, good mud-laden fluid of the weight of not less than nine and one-half (9-1/2) pounds per gallon; tested in accordance with A.P.I. specifications now existing, and shall test the blowout preventer on said well at intervals of not more than eight hours apart. Fluid specifications can be changed by special order.

Casing and Cementing

Order No. 15-45

RULE IV. - The casing program of all wells hereafter drilled to the Lime Pool in the Atlanta field shall be as follows, unless otherwise ordered.

(a) A minimum of 100 feet of surface casing shall be set and cemented with not less than fifty sacks of cement. Cementing shall be done by the pump and plug method. Cement shall be allowed to set a minimum of twenty-four (24) hours.

(b) A second string of casing shall be set at a minimum depth of 2,200 feet and shall be cemented with sufficient cement to fill the annular space back of the casing up into the surface casing, using not less than five hundred (500) sacks of cement. Cementing shall be done by the pump and plug method. Cement shall be allowed to set a minimum of twenty-four (24) hours under pressure before drilling the plug or initiating tests. Said second string of casing shall be new casing or reconditioned casing which has been tested to thirteen hundred (1,300) pounds per square inch pressure subject to reconditioning.

Before drilling the plug in the second string of casing, the casing shall be tested by pump pressure in the presence of an offset operator or an agent of the Commission, or both. After the mud-laden fluid in the hole has been displaced by clear water, pump pressure of at least eight hundred (800) pounds per square inch shall be applied. If at the end of thirty minutes the pressure gauge shows a drop of one hundred fifty (150) pounds or more, the operator shall do that which is necessary to cause the second string of casing to be set and cemented so that it will hold said pressure for thirty (30) minutes without a drop of more than one hundred fifty pounds in pressure.

(c) The producing string of casing shall consist of new casing, mill-tested to at least two thousand (2,000) pounds pressure per square inch, which shall be set below the gas-oil contact of, or set completely through and perforated below the gas-oil contact of the oil saturated formation. Cementing shall be done by the pump and plug method. Said producing string shall be cemented with not less than five hundred (500) sacks of cement and shall be allowed to stand a minimum of twenty-four hours under the pressure required to pump the plug to bottom and a minimum total of seventy-two hours before drilling the plug and the casing.

Before drilling the plug in the producing string of casing, the casing shall be tested by pump pressure in the presence of an offset operator or an agent of the Commission or both. After the mud-laden fluid in the hole has been displaced by clear water, a pump pressure of fifteen hundred (1500) pounds per square inch shall be applied. If at the end of thirty minutes the pressure gauge shows a drop of fifty pounds or more in pressure, the operator shall do that which is necessary to cause said string of casing to be so set and cemented that it will hold said pressure for thirty minutes without a drop of more than fifty pounds in pressure.

## Completion

Order No. 15-45

RULE V. - Each operator shall notify the Commission in writing, at least twenty-four (24) hours before completing a well, the time at which said well will be completed. If said well be completed by the operator in conformity with the regulations of the Commission, a completion certificate shall be issued to such operator. Completion certificates shall be withheld until the well has been completed in accordance with the rules of the Commission. Pipe line companies and all other purchasers or carriers are forbidden to accept oil or gas from any well until the completion of such well is approved by certificate of compliance.

General Rules

RULE B-18 - Christmas tree fittings or well head connections shall have a working pressure or a test pressure in keeping with the expected depth of the well.

RULE B-23 - All wells shall be equipped with, and produced through, tubing of not more than two and a half (2-1/2) inches in diameter. Bottom of tubing on flowing wells shall not be higher than top of producing sand. If tubing is perforated, the perforations shall not extend above the top of the sand. Tubing shall be free from obstructions, and have orange peel weld or bar on bottom in order to permit free entrance of bottom hole instruments.

RULE B-24 - All wells shall be equipped with adequate chokes, or beans, to properly control the flow thereof.

RULE B-25 - All flowing wells must be produced through an approved oil and gas separator.

RULE B-14 - Meter settings of adequate size to measure the gas efficiently for the purpose of obtaining gas-oil ratios shall be installed on the gas vent line of every separator. Well-head equipment shall be installed and maintained in first-class condition so that static bottom hole pressures may be obtained at any time by duly authorized agent of the Commission. Valves shall be installed so that pressures can be readily obtained on both casing and tubing.

## Production

Order No. 15-45

RULE VI - The total quantity of crude oil which may be lawfully produced each day from the Lime Pool of the Atlanta field shall be determined by the Commission. The said total quantity of oil which may be lawfully produced daily from the Lime Pool is hereinafter that amount as shown on the Commission's schedule of Allowed Production.

RULE VII - Production from the field shall be upon a volumetric basis, giving equal weight to the production of oil, gas and/or water. Each well each day shall be given the opportunity to void the common reservoir in proportion to each surface acre assigned on a basis of not in excess of 3,000

cubic feet of gas measured under atmospheric conditions for each barrel of stock tank oil produced.

Current Allowables

Reference No. 16-47, April 28, 1947

WHEREAS, the Commission finds from the evidence adduced at the hearing on Tuesday, April 8, 1947, that rate of production of oil, gas and condensate which will be conducive toward obtaining the greatest ultimate recovery of oil, gas and condensate from each of the pools or fields operating under regulation in this state--as nearly in the practical daily amount as can be averaged over the months of May, June and July, 1947, except as herein provided, and until such time as new evidence can be gathered--to be:

Atlanta-Limestone 4,269 barrels daily.

WHEREAS, the Commission finds that in order to prorate the above stated amount of oil daily to each individual pool and to the various operators in these pools so as to (1) prevent the drilling of an additional well or wells on any tract in addition to such well or wells as can without waste produce the operator's just and equitable share of oil and gas; (2) provide that each operator in each pool shall be allowed to recover substantially that amount of recoverable oil and gas which the amount of recoverable oil and gas under his tract bears to the amount of recoverable oil and gas in the total developed area of the pool, insofar as these amounts can be practically ascertained; (3) prevent or minimize reasonably avoidable net drainage from across property lines; (4) provide that each operator in each pool shall have the opportunity to use his just and equitable share of the reservoir energy; and (5) prevent or minimize unnecessary storing of oil above ground that the daily production from each well in each pool should be allocated in the manner herein stated, which the Commission finds to be reasonable, practical and equitable.

PROVIDED, that in order to provide working stock of oil or condensate and facilitate the producing and gathering of oil and in order to recognize the practical difficulty of producing the allowable to the exact number of barrels permitted herein, it shall not be considered in violation of this order for the allowable as set out for each such well to be exceeded for any one month by not more than one day's allowable production for such well, and such one day's production over the scheduled allowable shall be considered as legal oil produced under the terms of this order and within the allowable for such well.

PROVIDED, HOWEVER, that the tolerance of overproduction not to exceed one day's allowable production, as herein provided for, shall be deducted from the scheduled allowable production for such well for the succeeding month.

Monthly certified gas-oil ratio tests, of at least three hours' duration, are to be furnished the Commission on the Commission's Form 10-1/2. These monthly tests for each pool or field shall be made after each well has been permitted to flow until stabilized at its daily allowable rate of production. It is ordered that each well be tested after stabilization and produced at that rate which results in the most efficient gas-oil or gas-condensate ratio.

Where the most efficient rate is above the daily oil or condensate allowable, the well shall be produced at its most efficient rate until the oil or condensate allowable is made for this period, then closed to production. All measurements shall be made with an orifice meter, either permanent or portable.

ATLANTA-Limestone Pool - Production from this pool shall be upon a volumetric basis, giving equal weight to the production of oil, gas and/or water. Each well each day shall be given the opportunity to void the common reservoir, in proportion to each surface acre assigned it 2.75 barrels of oil and/or water, and 8,250 cu. ft. of gas as measured under atmospheric conditions. Provided, however, that no well shall be allowed to produce in excess of 2.75 barrels of stock tank oil for each assigned acre in any one day or 24 hours.

IT IS ORDERED that the allowed oil, when computed, shall be 100% net oil or condensate measured on 100% tank tables and corrected to 60 degrees Fahrenheit All production, runs to storage and deliveries are to be based on 100% tank tables, with proper adjustments for temperature, B. S. and water, when reported to the Commission.

Each well in this pool is hereby allowed to void the reservoir per acre per day the space occupied in the reservoir by 2.75 barrels of net stock tank oil and 8,250 cu. ft. of gas measured at atmospheric conditions. However, no well shall be allowed to produce in excess of 2.75 barrels of stock tank oil per acre per day.

ATLANTA FIELD — May, 1947

"LIMESTONE POOL" — SCHEDULE NO. 149

Reservoir pressure = 2,837 lb. absolute

Free gas deviation factor = 0.966

Shrinkage factor = 1.44 barrels of reservoir = 1 barrel of surface oil

Solution gas = 1000 cu. ft. per bbl. of surface oil

$$\frac{14.65}{2837} \times \frac{666}{520} \times \frac{1}{5.61} \times 0.966 = 0.001138812$$

$$\text{Daily oil allowable} = \frac{ARV}{RV} \times \text{acres assigned to unit}$$

ARV = Allowed reservoir voidage per acre day.

RV = Reservoir voidage per barrel of stock-tank oil produced.

ARV = (2.75 x 1.44) + 5,500 x 0.001138812) = 10.2

$$RV = 1. + 0.44 + (\text{Free Gas} \times 0.001138812) + \frac{\text{Percent water}}{100 - \text{percent water}}$$

Total field allocation.....4,269 Barrels

SAMPLE CALCULATION

| Acreage | G.O.R., cu. ft. per bbl. | Water, percent | Maximum daily res. voidage, bbl. | Bbl. fluid per bbl. stock tank oil | Allowable | |
|---|---|---|---|---|---|---|
| | | | | | Daily | Monthly |
| 39.2 | 3,000 | 33 | 400 | 4.202 | 95 | 2,945 |
| 40.0 | 868 | 0 | 408 | 1.440 | 110 | 3,410 |
| 40.0 | 4,000 | 6 | 408 | 4.908 | 83 | 2,573 |