A Reservoir Study of the West Edmond Hunton Pool, Oklahoma

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WITH DISCUSSION

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ABSTRACT

The West Edmond pool of Central Oklahoma, a limestone reservoir, has an area in excess of 29,000 acres and as of Sept. 15, 1946, had produced 53 million barrels of oil from 731 wells at an average depth of 6900 ft. Water has encroached into the reservoir along the west side of the pool and although the area of water invasion is large the net volume of water influx is small, because encroachment has been primarily into a fracture system.

The most significant part of this study concerns the character of the Hunton reservoir. Geological study of cores of the producing section was made to supplement core-analysis data. It was determined that approximately 90 pct of the pore volume was contained in intergranular or sand-like porosity and 10 pct in fractures (intermediate porosity). The porous limestone is divided into blocks by the fractures, although in the strongly dolomitic parts of the producing section, fractures are less well developed. The low-permeability intergranular porosity, largely subsidiary to the high-permeability fractures, will produce oil into the fractures by evolution of solution gas. The fractures in effect serve as drainage channels for production of oil from the intergranular porosity. Because of such a large difference in permeabilities of the two components, a high degree of by-passing will occur, and, accordingly, the economics involved in undertaking full-scale high pressure gas injection operations have been seriously questioned.

INTRODUCTION

The West Edmond Hunton pool, which covers portions of Canadian, Logan, Oklahoma, and Kingfisher Counties in Central Oklahoma, is the largest reservoir producing oil from a limestone in the state. The total area of the pool comprises about 29,240 acres and development is considered to be essentially complete.

In all, 731 producing wells have been completed in the Hunton reservoir at an average depth of approximately 6900 ft, and have yielded a cumulative oil production in excess of 53 million barrels as of Sept. 15, 1946. In addition to wells completed in the Hunton limestone, 21 wells have been completed in the Bartlesville sand at a depth of approximately 6500 ft, which have produced a total of 730,000 bbl of oil. One small producer has been completed in the Cleveland sand at a depth of 5700 ft. However, a study of only the Hunton limestone reservoir will be presented in this paper.

The most significant phase of this study concerns the special type of geological core examination that was made in an effort to ascertain the type and degree of porosity in the rock in accordance with lithologic types. Results of this geological study showed the West Edmond pool to be of such a complex nature as to appreciably affect the behavior normally associated with homogeneous reservoirs. Recognition of this condition in the
reservoir essentially eliminates the prediction of performance histories by rigorous calculation, thus no predictions of gas-oil ratio and bottom-hole pressure behavior are made.

**Development**

The discovery well, which was drilled in the NW-NW-SW of sec. 32-14N-4W by Ace Gutowsky and other interests, had the Wilcox sand as an objective. Failing to find production in this sand at a depth of 7690 ft, the operator perforated the Bois d'Arc section of the Hunton limestone from 6938 to 6956 ft and obtained an initial production of 535 bbl of 41°API gravity oil per day through a 5/8-in. choke in April 1943.

Development in the field was rather slow at first when it was discovered that the entire Bois d'Arc section was cut out by an old stream channel less than a mile north of the discovery well. However, when good production from the Bois d'Arc section of the Hunton limestone was found north of the old stream channel, the development program gained momentum and reached a peak in February 1945, when 62 wells were completed during the month. As of Sept. 15, 1946, there were 731 Hunton wells completed in the pool with little prospect for much additional development.

The West Edmond pool is approximately 17 miles long and 5 miles wide at its widest part, which is through the northern half of the reservoir. The pool is only some 2 to 3 miles wide in the southern portion. An old stream channel, which passes through the middle of the pool in an east-west direction, completely segments the Bois d'Arc section of the Hunton limestone into two parts. The pool is bounded on the east by the truncation of the upper part of the Hunton and on the north by a thinning of the section. A water table at approximately -5930 ft subsea limits the pool on the west, as well as on the south.

**Geology**

Many engineering problems that arise during the producing life of a reservoir are solved by application of knowledge concerning the characteristics of the reservoir rock. Perhaps the most important characteristic is porosity, and attempts are continually being made to obtain more data on the areal and vertical distribution of porosity in quantitative terms of degree and continuity. This geological discussion of the West Edmond field emphasizes the factor of porosity. The evidence bearing on the manner of development of porosity is discussed, but more attention is given to the evidence concerning the physical characteristics of the producing porosity as it now exists. The West Edmond pool, which is a stratigraphic trap, is on the flank of a large structure on the "Granite Ridge Trend." The axis of the "Ridge" passes through the older Edmond pool 5 miles east of the West Edmond pool and continues southward below Oklahoma City and northward into Nebraska. The major structures along this trend have the common characteristics of pre-Pennsylvanian uplift and erosion followed by differential uplift during the Pennsylvanian and westward tilting in post-Pennsylvanian time.

Fig 1 is a cross section of the field by McGee and Jenkins. The Pennsylvanian lies across an erosional surface of Mississippian lime, Woodford shale, and Hunton lime in the limits of the West Edmond field. To the east the overlap continues to the Wilcox. The evidence of the extent and degree of pre-Pennsylvanian erosion has been shown by McGee and Jenkins. The maximum uplift was in the Oklahoma City field some 12 miles to the southeast. West Edmond is well down

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1 References are at the end of the paper.
Fig 1—East-west cross section, West Edmond field. (McGee and Jenkins.)
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KINGFISHER COUNTY

CANADIAN COUNTY

LOGAN COUNTY

OKLAHOMA COUNTY

WEST EDMOND FIELD
OKLAHOMA

SCALE
1 MILE

STRUCTURAL MAP
TOP OF THE HUNTON GROUP
CONTOUR INTERVAL = 50 FEET

AFTER B. N. GREER - UNPUBLISHED MASTERS THESIS - OKLAHOMA STATE UNIVERSITY

FIG 2.
PRE-PENNSYLVANIAN SECTION

MISSISSIPPIAN LIMESTONE
0-220'

WOODFORD SHALE
0-60'

HUNTON GROUP
225'-360'

SYLVAN SHALE
100'

VIOLA LIMESTONE
75'

UPPER SIMPSON
250'-275'
(LIMESTONE, DOLOMITE, LIMY SAND AND SHALE.)

"SECOND WILCOX" SAND

HUNTON SECTION

FRISCO LIMESTONE
0-40'
FRAGMENTS OF FOSSILS WITH CALCITE MATRIX, GLAUCONITE.

BOIS D'ARC LIMESTONE
0-95'
FRAGMENTS OF FOSSILS WITH OR WITHOUT MATRIX (0-70').
MIXTURES OF FRAGMENTS OF FOSSILS AND FINELY CRYSTALLINE CALCITE AND DOLOMITE (6-25).

OOLITES WITH INCOMPLETE MATRIX OF CRYSTALLINE CALCITE (3-14).

HARAGAN-HENRYHOUSE LIMESTONE
190'
MIXTURES OF FINELY CRYSTALLINE CALCITE AND DOLOMITE (5-25).

ARGILLACEOUS FINELY CRYSTALLINE CALCITE

MIXTURES OF FRAGMENTS OF FOSSILS AND FINELY CRYSTALLINE CALCITE.

FRAGMENTS OF FOSSILS WITH MATRIX OF FINELY CRYSTALLINE CALCITE.

FRAGMENTS OF FOSSILS WITH CRYSTALLINE CALCITE MATRIX

CHIMNEYHILL LIMESTONE
30'-40'
FRAGMENTS OF FOSSILS WITH MATRIX OF FINELY CRYSTALLINE CALCITE

MIXTURES OF FINELY CRYSTALLINE CALCITE AND DOLOMITE

FRAGMENTS OF FOSSILS WITH FINE SAND, GLAUCONITE, CLAY AND CHERT.
CRYPTOCRYSSTALLINE CALCITE WITH SCATTERED OOLITES

Fig 3—Sections West Edmond Field, Oklahoma.
the flank of the northward-plunging end of this uplift. The area can be assumed to have been topographically high during exposure with westward drainage, which crossed the outcrop of the Hunton.

An earlier erosional surface is that overlain by Woodford shale. This pre-Mississippian erosion surface shows some degree of truncation on the members of the Hunton with greater erosion to the
north and northeast. The combined results of solution during these two periods of erosion are significant in the development of porosity in the Hunton limestone.

Fig 2 shows the structure of the field on the paleotopographic surface of the top of the Hunton group. The total closure between water level, at approximately -5930 ft, and the highest production is about 560 ft. The structure is a monocline. Northeast closure is the pre-Woodford edge of the Bois d'Arc and east closure is the pre-Pennsylvanian edge of the Bois d'Arc. The pool is separated into two parts by a narrow canyon-like valley of an old stream course. The maximum depth of this valley is 140 ft and the Bois d'Arc section is entirely eroded. The development of this channel by erosion furnished a topographically low outlet for ground water and thus facilitated movement of ground water down to the level of the drainage channel.

A graphic section of the West Edmond pool is illustrated in Fig 3. The pre-Pennsylvanian section is shown on the left side. Although the Hunton group is commonly spoken of as a unit, the "Hunton lime," it is made up of several limestone members, which have physical differences marked enough to affect the porosity. Basically the Hunton was originally made up of two types of component particles, fragments of fossils (4 to 1/16 mm) and finely crystalline calcite and dolomite (3/16 to 1/64 mm). With these were deposited slight admixtures of oölites, silt, clay, and glauconite. Some of the depositional mixtures of these component particles were modified, during consolidation, by the addition of clear crystalline calcite. The essential physical differences of the size of component particles, arrangement in space, and degree of cementation, are factors that affected the action of the subsequent porosity-making processes of solution, dolomitization, and fracturing.

Fig 4 is a detailed graphic log of Gulf-Streeter No. 1, showing both the intergranular and intermediate porosity. The entire Hunton group in this well was cored with a diamond bit with 97 pct recovery. This figure shows only the upper, or so-called Bois d'Arc, producing section. Production is also obtained from the lower Hunton, particularly in the northeastern part of the field. The porosity is divided into two types, intergranular and intermediate. Bulnes and Fitting define intergranular rocks as "those in which the size, shape, and spatial distribution of the pores, and the way they are interconnected, are determined essentially by the number, the geometric properties and the distribution of the sedimentary units. In the intermediate type, in addition to the intergranular openings, cavities occur, whose size, shape, and position in the rock bear no direct
relationship to the number, to the geometric properties, or to the spatial distribution of the sedimentary units."

In rocks that are considered as intermediate porous media, but that also have an intergranular character, the terms intergranular and intermediate can be applied to the void space, as intergranular and intermediate porosity. Although mathematical treatment alone serves to point out the broader characteristics of porosity, it is also necessary to give detailed attention to the rocks themselves. Observations, microscopic or otherwise, should be stated in terms of physical properties, preferably in quantitative terms, rather than in the qualitative descriptive manner that geologists require for the purposes of identification and correlation. Statement in quantitative terms requires close attention to the actual specimens used in laboratory tests of porosity and permeability. Such attention usually suggests the making of additional tests to isolate and evaluate individual factors that affect porosity and permeability. Moreover, it is necessary to evaluate critically the limitations of laboratory tests in the determination of true porosity and permeability and to give similar critical attention to the problems involved in obtaining and selecting representative samples.

On the left of the graphic log in Fig 4 are data on intergranular porosity and permeability. Both porosity and permeability represent laboratory determinations. The solid black represents complete oil stain, the diagonals represent partial oil stain, the dotted areas show traces of stain, and the porosity lacking oil stain is shown in outline only. In the West Edmond reservoir, oil stain is present in only a part of the intergranular porosity shown by laboratory determinations. Permeabilities below one milidarcy were not determined. All plugs with permeabilities of one milidarcy or more were in oil-stained rock, so permeabilities are also shown in solid black. On the right side of the graph are data on intermediate porosity and permeability. The porosity data are based on measurement of fractures in 3-in. cores. The percentages of seams and fractures that are nonporous by reason of filling with clay, calcite, pyrite, or dolomitic lime are shown by the outline alone. Those which are open and oil stained are shown as solid black percentages. The permeabilities shown are laboratory measurements of observable seams in the test plugs. Obviously, only the smaller seams can be retained intact in a test plug. These permeabilities are not considered to be representative of the permeability in the 3-in. core and have little meaning in relation to the reservoir as a whole.

The Frisco member of the Hunton group, illustrated in Fig 5, is a limestone made up of fragments of fossils cemented with calcite. The laboratory tests show from 0.5 to 2.0 pct porosity. The voids are mainly hollow fossils or isolated interfragment interstices, which were not completely filled. The intergranular permeability is negligible and the intergranular porosity, from a producing standpoint, is also negligible, as only the smaller seams can be retained intact in a test plug. These permeabilities are not considered to be representative of the permeability in the 3-in. core and have little meaning in relation to the reservoir as a whole.

The intermediate porosity consists of two types of fractures. One type is of irregular, vertically oriented voids filled with clay and silt. The continuity, the irregular walls that show local evidence of solution, and the fact that the filling is similar to the insoluble residue of the limestone, are evidence that these are solution-enlarged fractures. Although there is now no appreciable void space, these filled fractures afford clues to the original magnitude and distribution of the solution channels. The other type of fracture also tends to be vertical, has matching walls, and cuts across the solution-enlarged
fractures. The clayey filling of the solution-enlarged fractures was compressed when fractured, which is strong evidence that the later fracturing occurred after a

section accounts for virtually all of the oil-stained intergranular porosity. Rock areas showing as much as 3 pct primary porosity show no evidence of solution and

considerable load of sediment had accumulated above the Hunton. The continuity of the late fractures within a 3-in. core was shown by forcing colored liquid paraffin into the core through a hole drilled through the vertical axis of the core. After cooling, the core was sawed longitudinally to intersect the fractures that were filled with paraffin.

Referring again to the cored section of Streeter No. 1, Fig 4, the greater part of the Bois d'Arc is made up of fragments of fossils with several degrees of interstitial filling. The upper part is calcite-cemented and is similar to the overlying Frisco. In the middle part are individual layers, which were incompletely cemented. Some layers have fine interstitial fragments of fossils, some have finely crystalline calcite, and some may have had little or no interstitial filling.

Solution in the fragmental Bois d'Arc no oil staining. Evidence as to the degree of solution can be seen adjacent to the solution-enlarged fractures. The process started by the opening of the seams along the contacts between component particles or along contacts between component particles and the cement. In some cases partial solution of the matrix was accompanied by differential solution of some of the fragments of fossils. Frequently there is difficulty in determining the degree of primary interstitial porosity, because such porosity is commonly affected by solution. Solution progressed through complete removal of interstitial material and partial removal of component particles. In advanced stages of solution the porosity in some instances was decreased as removal of lime at contact points permitted compaction. About 15 pct intergranular porosity appears to be the upper limit in solution riddled fragmental limestones.
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Figs 5 and 6 illustrate the fracture porosity in the fragmental Bois d'Arc section. The courses of solution-enlarged fractures in the partially cemented frag-

Table 1 shows the relationships of intergranular porosity and permeability to details of lithology. Fragmental limes tend to develop permeability as porosity increases. Finely crystalline rocks develop permeability as the dolomite content increases. The sum of solution porosity and primary porosity (Table 1) does not always equal the average laboratory test porosity because the laboratory data include fracture porosity. The values estimated for primary porosity may in some cases be low, such as the 5 pct shown for dolomite, but all of this porosity is considered to be nonproductive.

The Streeter No. 1 core has no highly dolomitic rocks in the section shown in Fig 4. Fractures are less abundant in the finely crystalline rocks. Solution-enlarged, filled fractures are present but open frac-

ture porosity.

Fig 6—Porosity in Bois d'Arc limestones. Heavy lines show fractures in Bois D'Arc limestones containing intergranular porosity. Specimen at right is finely crystalline limey dolomite.

mental limes range from single fractures to ramified rifts in the less competent zones of high primary porosity. Solution, instead of concentrating on the walls of the fracture, tended to disseminate through the rock and encompass the limits of the core. In some cases the ramified rifts are seen only when preserved by filling, the present porosity being greater outside the rift than within. Late fractures intersect both solution-enlarged fractures and solution porosity.

The factors controlling the second set of fractures, even in zones in which the earlier solution-enlarged fractures are open, are believed to have been late structural movement, compression due to 6000 ft of overburden and changes in competence due to solution.
field, where dolomitic rocks are present in greater proportion than in the central and southern part, probably has a less continuous fracture system. Late fractures calcite. Solution has affected both the matrix and the oolites, and frequently secondary dense argillaceous dolomite material fills a part of the intergranular

<table>
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<tr>
<th>Material</th>
<th>Condition</th>
<th>Footage of Core, Ft</th>
<th>Number of Test Plugs</th>
<th>Average Lab. Test Porosity, Pct</th>
<th>Estimated Primary Porosity, Pct</th>
<th>Estimated Solution Porosity, Pct</th>
<th>Estimated Intergranular Permeability Based on Lab. Tests, Md</th>
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<td>Fragmental lime, with calcite cement</td>
<td>Little solution</td>
<td>41.7</td>
<td>62</td>
<td>1.93</td>
<td>1.42</td>
<td>0.36</td>
<td>0.66</td>
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<tr>
<td>Fragmental lime with partial cement either crystalline or granular calcite</td>
<td>Little solution</td>
<td>49.7</td>
<td>59</td>
<td>2.54</td>
<td>1.73</td>
<td>0.62</td>
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<td></td>
<td>Considerable solution</td>
<td>81.25</td>
<td>114</td>
<td>7.84</td>
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<td>Mixtures of fragments of fossils and granular calcite and dolomite</td>
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<td></td>
<td>Matrix mainly calcite</td>
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<td>37</td>
<td>2.42</td>
<td>2.42</td>
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<td>Matrix mainly dolomite</td>
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<td>10</td>
<td>7.35</td>
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<td>0.98</td>
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<tr>
<td></td>
<td>Predominantly granular</td>
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<td>Groundmass mainly calcite</td>
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<td>3.81</td>
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<td>Groundmass mainly dolomite</td>
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<td>5.00</td>
<td>9.18</td>
<td>8.20</td>
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<td>Oolitic fragmental lime</td>
<td>Considerable solution</td>
<td>34.05</td>
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<td>1.38</td>
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<td>Groundmass of granular calcite and dolomite with scattered fragments of fossils</td>
<td>Groundmass mainly calcite. Little oil-stain</td>
<td>36.6</td>
<td>46</td>
<td>6.77</td>
<td>6.77</td>
<td>0</td>
<td>0</td>
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<tr>
<td></td>
<td>Groundmass calcite and dolomite. Diss. oil-stain</td>
<td>34.2</td>
<td>60</td>
<td>8.62</td>
<td>5.00</td>
<td>3.62</td>
<td>0.14</td>
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<tr>
<td></td>
<td>Groundmass mainly dolomite. Strong oil-stain</td>
<td>28.7</td>
<td>38</td>
<td>16.67</td>
<td>5.00</td>
<td>11.07</td>
<td>0.73</td>
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are present and show no mineralization. Some of the finely crystalline calcitic rocks show late fractures, which have no oil stain. These fractures can be followed downward into lines of weakness, which will split when tapped with a hammer. Such unstained fractures are considered to have occurred along lines of weakness during drilling. Other lines of weakness can be discovered by hammer blows. Virtually all limestones tend to fracture more selectively in some one direction perpendicular to the bedding planes.

The oolitic limestone is a fragmental lime with a complete or partial matrix of crystalline calcite or finely crystalline solution porosity. Both solution-enlarged fractures and late open fractures cut the oolitic lime.

In the north central part of the field the Woodford shale lies directly on the lower part of the Bois d'Arc fragmental lime and some 60 to 90 ft of the section present at Streeter No. 1 is missing. The finely crystalline limes between the fragmental member and the oolitic member are thicker and more dolomitic. The beds below the oolitic limestone are also strongly dolomitic. As compared with Streeter No. 1, the bulk of the porosity is in finely crystalline beds. Fractures are present in all beds but in general the volume of
the fractures is less in the finely crystalline beds. In the north and northeast portions of the pool the amount of dolomitization tends to increase and to extend downward in the section. Because dolomite beds do not appear to retain fractures it is probable that the degree and extent of fracturing is less in that area. However, evidence from cuttings suggests vugular voids, which may introduce another type of intermediate porosity.

Values of intergranular porosity and intermediate porosity for eight cored wells are shown in Fig 7. In wells from which core recoveries were less complete, cores of 2 to 3-ft intervals enabled the bracketing of core losses into lithologic and porosity types. Quantitative figures obtained from laboratory tests of subjacent and superjacent rocks were used. This procedure is believed to be conservative, as it is probable that losses were greater in rocks of higher porosity. In determining intergranular porosity, units of similar lithology that have similar types, or similar degrees of the same type of porosity, are averaged, both for over-all porosity from laboratory analysis and for oil-stained or “producing” porosity. The permeabilities shown are laboratory figures from fracture-free plugs.

Intergranular porosity is variable in distribution and degree. The Frisco shows a zone of intergranular porosity in Anna Paul No. 2. The fragmental member of the ‘Bois d’Arc shows porous zones in all wells. The finely crystalline beds between the fragmental and oolitic members show relatively low oil-stained porosities. This is due to higher primary porosity and less fracturing. The oolitic limestone shows consistently high porosity. The beds below the oolitic have relatively high primary porosity and considerable oil stain. The self-potential of the electric log shows a minor bulge opposite the lowest producing porosity, regardless of the porosity type or stratigraphic position.

The vertical distribution of porosity is far from uniform.

The intermediate porosity values indicate the average of open-fracture porosities. Estimates of widths of fractures were based on evidence seen in the complete cores of Streeter No. 1 and are considered to be conservative. As representative intermediate permeability figures are impossible to obtain by laboratory methods, the indicated permeabilities shown represent estimates of well to well permeability based on the number and degree of fractures. The maximum range is shown as 0 to 1000 md, which implies connecting, rather than continuous, fractures from well to well.

Table 2 shows a recapitulation of the over-all averages of intergranular and intermediate porosities for the Frisco, Bois d’Arc, and Haragan. The capacity of the Frisco is clearly limited but fractures make up about 20 pct of the total porosity. In the Bois d’Arc there is considerable variation in average porosity between wells. The averages show intermediate porosity to be slightly less than 10 pct of total porosity. In the Haragan (below the oolitic member) both intermediate and intergranular porosities are variable. It is probable that some fractures, partially sealed by recrystallization, may be included in the intergranular porosity. These may be permeability channels of limited extent but are not true intermediate porosity. The footage of total void space is also highly variable from well to well because of differences in both average porosity per foot of pay and total pay thickness.

In summary, it has been found from geological examination of the cores secured in the West Edmond pool that porosity is of two general classifications; namely, intergranular and intermediate or fracture porosity. Void space contained in the fracture system has been approximated to be on the order of 10 pct of the total
### Table 2—Summary of Porosity and Permeability Data from Hunton Cores of Eight Wells, West Edmond Field, Oklahoma

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<td>Gulf Streeter No. 1, 20-13N-4W</td>
<td>32</td>
<td>0.07</td>
<td>0.03</td>
<td>77</td>
<td>0.46</td>
<td>3.63</td>
<td>2</td>
<td>0.4</td>
<td>0</td>
<td>111</td>
<td>2.88</td>
<td>0.3832</td>
</tr>
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<td>Gulf Flynn No. 1, 21-13N-4W</td>
<td>36</td>
<td>0.01</td>
<td>0</td>
<td>66½</td>
<td>0.60</td>
<td>3.72</td>
<td>2</td>
<td>0.05</td>
<td>0</td>
<td>94½</td>
<td>3.04</td>
<td>0.4051</td>
</tr>
<tr>
<td>Gulf Anna Paul No. 2, 8-13N-4W</td>
<td>43</td>
<td>0.18</td>
<td>0.88</td>
<td>78½</td>
<td>0.70</td>
<td>0.73</td>
<td>4½</td>
<td>0.0</td>
<td>0</td>
<td>118</td>
<td>5.43</td>
<td>0.6128</td>
</tr>
<tr>
<td>Gulf Messenbaugh No. 2, 20-14N-4W</td>
<td>35</td>
<td>0.18</td>
<td>0.88</td>
<td>45½</td>
<td>0.90</td>
<td>3.81</td>
<td>10½</td>
<td>0.06</td>
<td>0.42</td>
<td>56</td>
<td>3.93</td>
<td>0.4193</td>
</tr>
<tr>
<td>Gulf Wright No. 1, 17-14N-4W</td>
<td>42</td>
<td>0.77</td>
<td>6.54</td>
<td>20</td>
<td>0.39</td>
<td>6.16</td>
<td>62</td>
<td>0</td>
<td>6.99</td>
<td>363½</td>
<td>7.11</td>
<td>0.3798</td>
</tr>
<tr>
<td>Gulf Wright No. 3, 17-14N-4W</td>
<td>40</td>
<td>0.55</td>
<td>7.90</td>
<td>18</td>
<td>0.03</td>
<td>4.34</td>
<td>54</td>
<td>7.94</td>
<td>4.05</td>
<td>55</td>
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<td>0.4190</td>
</tr>
<tr>
<td>Gulf Christner No. 1, 2-14N-4W</td>
<td>35</td>
<td>0.33</td>
<td>6.43</td>
<td>20</td>
<td>0.0</td>
<td>9.91</td>
<td>54</td>
<td>7.94</td>
<td>4.05</td>
<td>55</td>
<td>4.05</td>
<td>0.3798</td>
</tr>
<tr>
<td>Sohio Lynch No. 4, 18-14N-4W</td>
<td>40</td>
<td>0.77</td>
<td>6.54</td>
<td>20</td>
<td>0.03</td>
<td>4.34</td>
<td>54</td>
<td>7.94</td>
<td>4.05</td>
<td>55</td>
<td>4.05</td>
<td>0.3798</td>
</tr>
<tr>
<td>Average per foot</td>
<td>0.09</td>
<td>0.34</td>
<td>5.20</td>
<td>0.09</td>
<td>5.45</td>
<td>4.01</td>
<td>75.9</td>
<td>5.17</td>
<td>3.0932</td>
<td>3.0932</td>
<td>3.0932</td>
<td></td>
</tr>
<tr>
<td>Average per well</td>
<td>0.03</td>
<td>0.11</td>
<td>5.33</td>
<td>0.11</td>
<td>4.01</td>
<td>3.92</td>
<td>75.9</td>
<td>5.17</td>
<td>3.0932</td>
<td>3.0932</td>
<td>3.0932</td>
<td></td>
</tr>
</tbody>
</table>
FIG 76—INTERGRANULAR POROSITY AND PERMEABILITY OF PRODUCING SECTION OF HUNTON IN EIGHT CORED WELLS, WEST EDMOND FIELD.

A RESERVOIR STUDY OF THE WEST EDMOND HUNTON POOL, OKLAHOMA.
FIG 7b—Intermediate porosity and permeability of producing section of Hunton in eight cored wells, West Edmond field.
void space; thus most of the oil is contained in the intergranular or tight porosity. Permeabilities may also be classified as to intergranular and intermediate. The fracture system is characterized by high permeabilities, whereas the intergranular system is characterized by low permeabilities. Accordingly, the West Edmond reservoir is a complex interrelated system of reservoirs, the fracture system having extremely good communication and the remainder having practically no intercommunication.

**STATE REGULATIONS**

As provided by regulations of the Oklahoma Corporation Commission, the pool was developed on 40-acre spacing with wells located at or near the center of each 40-acre tract. The only exception to this pattern was the discovery well, which was located on 10-acre spacing in a 40-acre unit.

State regulations regarding casing programs and completion methods required that at least 300 ft of surface casing be set and cemented to the surface. The original rules provided that the oil string be set on bottom and cemented to at least 2800 ft above the casing shoe; however, the rules were changed in December 1943, to allow the casing to be set not higher than the top of the producing formation and cemented to a point not less than 2700 ft above the casing shoe. It is required that all production be through tubing not to exceed 2 1/4 in. and set not higher than the top of the casing perforation. Special applications for larger tubing have been granted for some of the pumping wells, which produce water.

The pool is prorated on an individual well basis and no well is given an allowable in excess of its ability to produce. The allowable for the first well completed in the pool was set at 400 bbl per day, but upon completion of the second well the top allowable was reduced to 300 bbl per day. The maximum gas-oil ratio permitted without penalty was 2000 cu ft per barrel. In May 1944 the top daily allowable was reduced to 200 bbl per well with the same penalty attached to any well with a gas-oil ratio exceeding 2000 cu ft per barrel. The adjusted allowable of a well penalized for high gas-oil ratio is determined by multiplying the normal allowable of such well by 2000, divided by the actual gas-oil ratio for that well. In December 1944 the daily well allowable was reduced to 150 bbl with the same gas-oil ratio penalty applied. In December 1945 a pool allowable of 80,000 bbl per day was established, which was distributed among the active wells in the pool. From December 1945 to September 1946 the pool allowable has varied from 70,000 to 80,000 bbl per day and on Sept. 1, 1946, the pool allowable was reduced to 40,000 bbl per day. The top well allowable during September 1946 was 64 bbl per day. Beginning Jan. 1, 1946, the gas-oil ratio allowable without penalty was established on the basis of the arithmetical average gas-oil ratio of all wells tested plus the amount of gas remaining in solution in the reservoir oil at that time. Gas-oil ratio and bottom-hole pressure surveys are now taken semiannually and the present allowable gas-oil ratio without penalty is 7203 cu ft per barrel, based on the August 1946 surveys.

**METHOD OF COMPLETION**

All wells in the pool were drilled and completed with rotary tools and only two strings of casing were used. Generally 10 3/4-in. surface pipe was run and, in accordance with State regulations, the pipe was cemented to the surface. Common practice was to use 7-in. casing for the oil string, which was set on bottom and cemented with 700 to 1000 sacks. Some operators preferred to perforate the entire pay section, whereas others perforated selectively in accordance with electrical
log and geological data. After the State regulations were revised in December 1943, a number of wells were completed with the oil string on top of the Hunton formation. Practically all wells were acidized with 1000 to 1500 gal of acid and natural flow was obtained in nearly all completions. All wells are produced through 2-in. or 2½-in. tubing with the exception of a few pumping wells for which exceptions to the State rules were made and 3-in. tubing was allowed.

**Reservoir Fluid**

A number of bottom-hole samples were obtained at pressures approximating 3000 psia, and analyzed for solubility, viscosity, and shrinkage. As shown on Fig 8, the average saturation pressure was determined initially to be 2770 psia, and the volume of gas originally dissolved in the oil was 1010 cu ft per barrel. The reservoir had no free gas cap initially and the reservoir oil was slightly undersaturated, since the initial reservoir pressure was 3145 psia. At original conditions the residual oil shrinkage was determined to be 48 pct and the oil viscosity at saturation pressure was 0.58 centipoises. The oil viscosity at atmospheric pressure was 2 centipoises.

From analyses of Hunton water samples, the formation water has a specific gravity of 1.129 and a total solids content of 187,500 milligrams per liter.

**Performance of Reservoir**

In Table 3, statistics on reservoir performance, such as average static bottom-hole pressure, cumulative oil, gas, and water production, cumulative pressure drop, cumulative oil produced per cumulative pressure drop, average gas-oil ratio, and cumulative gas-oil ratio, are presented for 11 periods in the history of the reservoir. These data, along with other pertinent information such as number of wells and daily oil and water production rates, are shown graphically on Figs 11, 12, and 13. As of Sept. 15, 1946, produc-
tion had been 53,178,000 bbl of stock-tank oil, 122.5 billion cu ft of gas, and 5,220,000 bbl of water. During this period of production the reservoir had undergone a pressure decline of 1243 psi, which amounts to an average of 42,700 bbl of oil production per pounds per square inch drop in pressure. The August 1946 weighted average gas-oil ratio extrapolated to Sept. 15, 1946 indicated 5600 cu ft per barrel, and the cumulative gas-oil ratio was 2305 cu ft per barrel.

The original bottom-hole pressure in the Hunton reservoir was 3145 psia. The first general pressure survey made in March 1944 on 19 wells showed an average pressure of 2984 psia at a subsea datum of -5864 ft. Since March 1944 periodic pressure surveys have been made at intervals of 3 to 6 months on approximately 25 pct of the wells in the field, generally the same wells being tested on each survey. The last survey was made in September 1946, at which time the average bottom-hole pressure was 1902 psia for the 180 wells tested. Pressures have declined continually throughout the producing history of the pool. Fig 9 is an isobaric map constructed on the last general pressure survey of September 1946.

The first general gas-oil ratio survey made between Oct 14 and Nov 15, 1944, showed an average gas-oil ratio for the 199 wells tested of 1007 cu ft per barrel of oil. This average gas-oil ratio is nearly the same as the original solution ratio of 1010 cu ft per barrel. Gas-oil ratios have increased with each quarterly survey and by Sept. 15, 1945, the average ratio was 1950 cu ft per barrel, with approximately 35 pct of the wells tested having a ratio in excess of 2000 cu ft per barrel. The last gas-oil ratio survey was completed in August 1946, at which time 713 wells were tested and found to have a weighted average gas-oil ratio of 5180 cu ft per barrel. Of the wells tested, 583, or 81.8 pct, had a ratio in excess of 2000 cu ft per barrel, and 184 wells, or 25.8 pct of those tested, had a ratio in excess of 7203 cu ft per barrel, which is the present maximum gas-oil ratio allowed without penalty.

The first water production was reported on Jan. 31, 1944, in the Schmitz-Specht No. 1-B, SE NE sec. 36-14N-5W, and 7 months later 10 wells were producing water with a cumulative water production of 36,497 bbl. By March 1, 1945, the number of water-producing wells along the west side of the pool had increased to 42, with a cumulative water production of 247,504 bbl. On April 1, 1946, 132 wells were producing water with a cumulative water production of 2,677,228 bbl, and as of Sept. 15, 1946, there were 157 wells.
Fig 9.
Fig 10.
producing 15,500 bbl of water daily, with producing clean oil. A water-encroachment map, Fig 10, shows the chronological history of the advancing water front by yearly intervals. At the present time 71 wells in the pool are equipped to pump, most of which are producing water. However, a number of these wells flow at least a portion of their production.

A series of interference tests was made on three offsetting wells in secs. 7 and 18-14N-4W to determine what effect the operation of two wells would have on an offsetting well. The three wells selected for study had productivity indexes of 2.8, 5.0, and 45.0. It was found that when the two higher capacity wells were produced at rates of 800 to 1100 bbl per day, the bottom-hole pressure in the third well dropped 30 psi from a static condition.

The results of this series of tests show that communication does exist in the reservoir and it is interpreted that communication through fractures rather than the low-permeability intergranular porosity. Bottom-hole-pressure build-up tests secured on a large number of wells in the pool indicate, in general, a rather rapid stabilization of bottom-hole pressure.

**INTERPRETATION OF DATA**

As evidenced by the data presented in the geological section of this paper, the geology of the West Edmond pool is somewhat unique, at least for pools in this area. Many significant interpretations of performance are based directly upon this geological study. The study showed that the pool contained two general classes of porosity; namely, intergranular and intergranular and...
fracture porosity. Moreover, it was determined that the fracture pore volume was on the order of 10 pct and the intergranular pore volume on the order of 90 pct of the total pore volume. Geological interpretations are that the high-permeability fracture system substantially isolates the very low-permeability intergranular system. The fractures, in effect, serve as drainage channels for production of oil from the intergranular porosity. If no fractures had existed in the Hunton reservoir, well capacities would have been small, probably less than 300 bbl per day. Since well capacities are relatively large, it is interpreted that the fracture system is the greatest contributing factor to well potentials. Because it is very difficult to measure fracture permeabilities in the laboratory, the laboratory data alone may be very misleading. Such a condition cannot be blamed on "core loss." As the fracture system is three dimensional, it is interpreted that very good communication exists throughout the various producing sections in the fracture system. Moreover, from the geological information supplied it must be interpreted that a very small degree of communication can exist within the intergranular system, except as this system communicates directly with the fractures.

Although there has been some discussion among operators in the West Edmond pool as to whether or not the Hunton reservoir initially contained saturated oil, the evidence from a considerable number of bottom-hole samples indicates an original saturation pressure of 2770 psia, as compared with a bottom-hole pressure of about 3000 psia at the time of sampling and a pressure of 3145 psia at original conditions. Accordingly, it is interpreted that the pool was producing in the early stages as a result of expansion of the liquids in the reservoir plus some water encroachment. At the present time the reservoir is producing oil primarily by the solution gas-drive type of mechanism. There has been some water encroachment into the reservoir along the west side of the pool, which has made some contribution toward retarding the pressure decline.

Present indications are that total water influx into the reservoir is on the order of 20 to 25 million barrels, including water already produced. There are in excess of 6000 acres that actually produce water and more than 10,000 acres from the pool boundary into which water has encroached. Net oil-saturated pore volume in this area is calculated to be on the order of 200 million barrels. Accordingly, the net volume of water intrusion estimated for the pool (20 to 25 million less 5,220,000 bbl produced) is less than 10 pct of the oil-saturated pore volume within the area of water encroachment. The fact that the total area of water encroachment and the pore volume within that area is quite large, as compared with the volume of water intrusion, indicates that water entered the reservoir through permeable streaks (fractures), thus bypassing the majority of the intergranular void space. From geological concepts of the characteristics of the Hunton reservoir, this type of performance should be anticipated. A relatively limited water encroachment is indicated and it is predicted that pressures will continue to decline.

Because of the relatively small volume of the fracture system, as compared with the pore volume of the intergranular system, the most efficient recovery can be realized only if the field is produced in such a manner as to obtain maximum recovery from the intergranular porosity. It appears that the only process by which the intergranular porosity will produce oil is by the evolution of gas from solution and subsequent expansion. Further, it appears that the only means of utilizing the energy within the intergranular system is by creating a differential pressure
between the fracture system and the intergranular system. Oil will be produced from the intergranular system into the fracture system, which affords essentially the only means of communication to the well bore. Since gas injected into the reservoir would essentially fill only the high-permeability fracture system, bypassing the majority of the oil in the low-permeability intergranular system, it is believed that such gas injection would not materially contribute to the production of additional profitable oil from the reservoir. At the present time gas-oil ratios are 5.6 times the initial solution ratio. This very rapid growth of the gas-oil ratio, with a corresponding relatively small system at this stage. Certainly, if the reservoir were acting as one homogeneous body, gas-oil ratios would have been substantially less at this period in the life, because this type of performance would indicate a rather limited reservoir and small ultimate recovery when other data point to a much larger pool and greater recovery.

It is predicted that in most cases wells that produce water will also continue to produce oil for a considerable period of time. Such oil production will be due to
the bleeding of the intergranular porosity into the fracture system as the pressure continues to decline. Oil will be produced from the fractures along with water, although in many cases water-oil ratios will be quite high.

From volumetric calculations it is estimated that approximately 600 million barrels of stock-tank oil was originally in place in the West Edmond pool, and that fractures contained about 60 million barrels of this total. It should be anticipated that the percentage of oil recovery from the fracture system will be high because the fractures serve as good channels for gravity drainage. On the other hand, it is anticipated that the percentage of oil recovery from the intergranular porosity will be relatively small. Estimating that 70 pct will be recovered from the fractures, and that the intergranular recovery will be limited by a final free gas saturation of 32 pct at 200-psi reservoir depletion pressure in the intergranular porosity, the ultimate recovery for the West Edmond pool is estimated to be on the order of 165 million barrels by primary methods of operation. Although some economic benefit could probably be realized by unitized operation of the reservoir, permitting selective well production, it is not believed that the injection of gas into a reservoir such as this could materially increase the ultimate recovery. With such a wide difference between permeabilities of the fracture system and the intergranular system, and assuming good communication throughout the fracture system, it seems logical that gas injected into the reservoir would be recycled through the fractures at considerable expense without contributing much toward additional oil recovery. It is believed that this condition will prevail regardless of the amount of oil that ultimately may be produced from the reservoir. Therefore, the production of the estimated 165 million barrels of oil is not essential to the conclusions reached regarding the value of gas injection. Near the end of the producing life of the pool at a time when oil production from the intergranular porosity has become small and pressure in the fracture system is low, it is believed that it would be economically feasible to sweep the remaining oil out of the fractures by a gas-injection program. Such a program would require only a very small outlay of investment as compared with an expenditure necessary for gas injection at much higher pressures.

ACKNOWLEDGMENTS

Acknowledgment is made to Mr. P. H. Bohart, Mr. S. G. Sanderson, Mr. P. H. Reisher, Mr. J. T. Richards, Gulf Oil Corporation, and Dr. Morris Muskat, Gulf Research and Development Co., for encouragement and valuable assistance in the preparation of this paper; to other members of the Production and Geological Departments, Gulf Oil Corporation, for their aid; and to the management of the Gulf Oil Corporation for permission to present this paper.

REFERENCES


DISCUSSION

L. E. Elkins*—The authors of this paper have made an excellent study of the lithological and physical characteristics of the reservoir rock in the West Edmond Hunton limestone pool. Their qualitative interpretation of the types of porosities and permeabilities that exist in the reservoir are believed to be well founded;

* Stanolind Oil and Gas Co., Tulsa, Oklahoma.
however, there is considerable differences of opinion among engineers and geologists as to the quantitative interpretation of the porosity, permeability and extent of the so-called fracture system. The writers have laid particular emphasis on the occurrence of fractures in the reservoir rock, and point out that approximately 10 pct of the total porosity exists in the fracture system. It is my opinion that fractures occur, but the evidence supporting a connected fracture system throughout the field is far outweighed by other evidence to the contrary.

1. The bottom-hole pressure map of the West Edmond field, as shown in Fig 9, indicates a variation of bottom-hole pressure of approximately 1800 psi and a variation between wells located 1320 ft apart by as much as 600 lb. It is not believed that such a pressure condition could exist with any type of connected fracture system.

2. The productivity indexes of wells in the field vary considerably from less than one to more than 50. This also indicates the lack of a field-wide fracture system but confirms the presence of both intermediate and intergranular porosity.

3. There is approximately 600 ft of structural closure in the field, and if continuous fracturing existed to any substantial degree, gas segregation would occur in the upper part of the reservoir. While some high gas ratios are found upstructure there are just as many high ratio areas in other parts of the field.

4. The writers have concluded that the limestone in West Edmond is divided into something in the order of 6-in. cubes on the basis of a few scattered cores, each of which represents only a hole of 3-in. diameter cut in the center of a 40-acre tract. While fracturing is noted in some of the cores, the composite summary of all available evidence does not support blocks of intergranular dolomite of this dimension.

Granting that complications are introduced by the geometry of the so-called blocks of intergranular limestone as related to more permeable channels surrounding these blocks, there are, in my mind at least, three factors that have not been given the consideration due when drawing conclusions that gas injection, for example, would probably be of no value in such a reservoir. These factors are as follows:

1. Every block of intergranular limestone as described in the paper will, in itself, operate as a single reservoir and will be subjected to depletion, both as to degree and rate, depending upon the geometry of the particular block as well as the fluid and pressure conditions within the block and in the permeable channels adjacent to and surrounding such block.

The fluid characteristics and the pressure gradients set up between the center of the block and the outside dimensions of block to which oil will move may vary considerably within each of these literally millions of blocks. Two important factors controlling the rate and ultimate depletion of each block are the effective permeability to oil within the block, and the pressure differential employed from within the center of the block to adjacent relatively permeable channels. It is obvious that a pressure differential has to exist in order for this flow to take place. There is one school of thought that would create maximum pressure differentials at all times. This, on the face of it, might indicate that depletion from each of these blocks might proceed at a relatively higher rate. On the other hand there might be some optimum pressure differential. For example, if pressures at the outer dimensions of each block are at some intermediate value the effective permeability to oil at the boundary of each of these blocks may be substantially higher than it would be if the pressures in the permeable channels surrounding the blocks are kept reduced to an absolute minimum. In this respect, it may be possible that oil would move out faster with some intermediate pressure differential than could be possible at absolute minimum differentials and absolute maximum differentials.

Petroleum technology at this time has not proved either by research or by field performance just where, in range of pressure differentials, this optimum might be. Thus, we have no proof whether or not pressures should be sustained at intermediate positions or permitted to decline relatively fast in order to most successfully deplete the type of reservoir described in this paper.

2. One other important factor is with respect to supplying the energy required to ultimately deplete the relatively permeable channels of the oil that will “seep” out of the tight intergranular limestone into those per-
meable channels. It is recognized that the return of all gas to a field such as West Edmond might not be desirable, depending upon the storage capacity of the permeable channels and depending upon the rate of oil seepage into those permeable channels under the conditions imposed upon the reservoir. Nevertheless, long after the major source of gas energy has been depleted, and after the more permeable channels have been exhausted of their normally recoverable oil, there will be oil seeping into these channels along with the solution gas that comes with it out of intergranular limestone. The permeability to oil in the more permeable channels will be relatively low because of early depletion, and the solution gas itself probably will not be adequate to move that oil to well bores at existing low pressure differentials at such rates that wells can be operated economically. At that time the cycling of gas through those channels would result probably in a substantial increase in ultimate recovery from the reservoir by: (1) maintenance of economic producing rates, (2) keeping the permeable channels stripped to a minimum degree of the oil that continually will seep into that channel until the reservoir approaches its ultimate equilibrium. Here it is difficult to anticipate early in the life of a field just how much gas should be stored in the reservoir in order to save this reserve of gas for recycling in the final stages of depletion. Too much gas stored will impose a terrific load on gas-handling facilities; too little gas stored will lead to a sacrifice in ultimate oil recovery.

There has been some comment on the fact that not much gas can be stored in the permeable channels in a pool like that described in this paper. From the standpoint of storing free gas, that is correct; but engineers should bear in mind that a large portion of the gas normally produced as free gas with decline in pressure can be stored as gas in solution by maintaining pressure at relatively higher levels. In other words, storage of gas by gas injection is accomplished both by maintaining higher pressures in the gas phase of the reservoir and by keeping gas in solution until a later stage of depletion where pressures would be permitted to decline to relatively low levels, and this gas can then become available as free gas and used as such for energy within the reservoir.

Here again, because of the complex nature of the geometry of a reservoir such as West Edmond, not only the reservoir as a whole but each local area in the field must be evaluated with respect to the factors mentioned above. This evaluation can be made best by actually attempting to conserve gas by shutting in the high-gas-oil ratio wells and by injecting some gas, endeavoring to keep conditions in each area in such a manner that the maximum gas can be saved for ultimate depletion purposes without imposing an undue load on gas-handling facilities that might economically be justified in the operating program of the field.

3. Another important factor that cannot be overlooked in a reservoir such as exists at West Edmond is related to the amount of water encroachment into the field, which is a function of the reservoir pressure maintained in the field. If the author’s picture of the nature and distribution of the porosity is at all correct, it is a foregone conclusion that when edge water moves clear through the reservoir oil is bound to be trapped in the intergranular spaces. At least this oil is trapped to the degree that its removal by handling of water production is probably limited by economic considerations. Therefore, an optimum condition exists somewhere between two extremes—maintenance of relatively high pressures with a parallel necessity of handling relatively large volumes of gas as contrasted with allowing pressure to decline rather sharply and permitting a substantial influx of water from the surrounding aquifer.

Operators should not overlook the possibility of using two-stage or possibly three-stage separation in a field such as West Edmond, whereby gas might be taken from producing wells at pressures of 500 lb or greater, and returned directly to the reservoir at relatively low expense. Gas coming off the low-pressure separators and from relatively low-ratio wells could be used to keep the normal gasoline plant loaded with relatively rich gas without requiring them to compress large volumes of gas from near atmospheric pressure to field pressure for injection purposes.

JACK TARNER*—The first part of the paper presented consists of a lithologic study of the

* Phillips Petroleum Co., Bartlesville, Oklahoma.
Hunton formation, with a quantitative evaluation of the fractures present in cores. The second part of the paper is an engineering study presenting "many significant interpretations based directly upon this geologic study."

The authors have concluded, by "assuming good communication throughout the fracture system," that gas injected into the reservoir would be recycled through the fractures at considerable expense without contributing much toward additional oil recovery. This is a very important conclusion, which has for its foundation an assumed condition as to the persistence of fractures between all wells. This pool has been producing for almost four years. Well and pool performance data show that fractures do not communicate between wells.

Fractures found in cores have often been formed in the coring process. In the reservoir, subjected to approximately 10,000 lb of overburden pressure, seams can be insignificant and only become appreciable in size when that pressure is removed. Large fractures are shown in the core specimen in Fig 5 of this paper, but these fractures have been filled by secondary deposition. The later fracture system, which cuts the older system, and which appears in the specimen in Fig 6, is limited in vertical extent. The fractures terminate vertically in the small core specimen shown. When this condition is considered along with the statement "virtually all limestones tend to fracture more selectively in some one direction perpendicular to the bedding planes," it seems unreasonable to assume that they will connect some 1320 ft between wells.

The fractures present in the specimen in Fig 6 appear to carry through the massive, dense limestone and terminate as they enter the more porous limestone. It seems quite fortunate that this condition exists. The fractures could act as passageways for the injected gas to move through the dense limestone areas to the porous limestone, which is expected to yield the increased oil recovery resulting from unitized gas-injection operations.

It is not necessary to speculate as to the persistence of fractures found in cores when actual pool and well-performance data are available. Actual field performance has indicated that the fractures are not continuous between all wells. The pressure map shown in Fig 9 uses a contour interval of 200 psi. It is apparent that 200 psi difference in pressure exists between many offset wells and that differences of 1000 psi occur over distances of approximately one mile. These pressure differences could not exist in any completely fractured reservoir.

The same condition applies to producing gas-oil ratios. Many local areas of high gas-oil ratios have been formed. Under present producing conditions, this gas is only slowly migrating to the structurally high positions in the reservoir. Many offsetting wells are producing with gas-oil ratios that differ by 10,000 cu ft per barrel. If the reservoir were extremely fractured, migration of gas to the structurally high part of the reservoir would be rapid and offset wells would be producing with almost equal gas-oil ratios.

Pressure "build-ups" in the various wells have indicated large differences in formation conditions. Of 13 wells tested, three have had pressure "build-up" to static in less than 10 hr, the remaining 10 wells had pressure increases of from 100 to 430 lb during the second 24 hr of "shut-in" time. Two wells on which pressures were measured for four days had pressure increases of 100 and 200 lb the fourth day. These wells do not indicate any extreme fracture condition in the reservoir.

Productivity index tests do not indicate all wells to be fractured. Early in the producing life of this pool productivity index tests were made in 34 wells. Their indexes were divided as shown in Table 4.

<table>
<thead>
<tr>
<th>Productivity Index</th>
<th>Per Cent</th>
<th>Cumulative</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 0.5</td>
<td>11</td>
<td>11</td>
</tr>
<tr>
<td>0.5-1.0</td>
<td>24</td>
<td>35</td>
</tr>
<tr>
<td>1.0-1.5</td>
<td>26</td>
<td>61</td>
</tr>
<tr>
<td>1.5-2.0</td>
<td>11</td>
<td>72</td>
</tr>
<tr>
<td>2.0-3.0</td>
<td>10</td>
<td>82</td>
</tr>
<tr>
<td>3.0-4.0</td>
<td>4</td>
<td>86</td>
</tr>
<tr>
<td>4.0-5.0</td>
<td>3</td>
<td>89</td>
</tr>
<tr>
<td>Over 5.0</td>
<td>11</td>
<td>100</td>
</tr>
</tbody>
</table>

Approximately three fourths the number of wells tested had productivity indexes of less than 2.0, and only 11 pct were over 5.0. The indicated productivity index for the field is only 2.1. The thick producing sections in these wells would need only 10 to 20 md
permeability to have this productivity index. Only a relatively few wells have indexes indicative of even a small amount of fracturing.

Remedial work in the field has proved that the fractures do not extend vertically to join zones of high permeability. In one instance selective acidizing of the lower of two perforated intervals resulted in a decrease in the producing water-oil ratio. In another well, it was possible to isolate production from two different intervals by using a tubing packer. These results could not have been obtained in any completely fractured reservoir.

The authors conclude that "some economic benefit could probably be realized by unitized operation of the reservoir permitting selective well production." Selective production is employed in order to produce only the wells that have low producing gas-oil ratios. The high-gas-oil ratio wells are "shut in," and the gas that normally they would produce is made to travel through the reservoir to areas capable of yielding oil with low gas-oil ratios. An increased oil recovery is thus obtained. If this reservoir is of a nature that will permit the natural energy in the reservoir gas to be directed toward an increased oil recovery, those same high-gas-oil ratio wells could be converted to gas-injection wells and the injected gas could be directed through the reservoir in much the same manner to bring about an even greater increase in ultimate recovery.

L. F. Elkins*—This paper has presented a very interesting discussion of the fractured condition of the West Edmond Hunton limestone and has indicated the limitations this condition places on oil recovery by means of an external displacing fluid. I should like to make some comments about material-balance estimate of water encroachment, which the authors presumably used in comparing reservoir performance with geologic analysis of cores, and also about the inferences this water encroachment has in terms of gas-storage volumes and gas-oil ratios accompanying gas injection.

The authors used an initial saturation pressure of 2770 psia, average of a number of subsurface samples, but indicated that some operators believed the oil to be initially gas-saturated based on high initial gas-oil ratios of some upstructure wells. Since 514 ft of oil-filled closure exists between extreme top of known oil reservoir and the (-) 5864-ft pressure datum, actual pressure in vicinity of a possible initial gas cap was about 2990 psia. This is the highest saturation-pressure theory requires for equilibrium between oil and free gas. Two early subsurface samples from high P.I. wells had saturation pressures of 2902 and 2952 psia, respectively, and had very good checks between laboratory and field determined gas-oil ratios. Further proof of high saturation pressure is early pressure-production performance. Production by March 15, 1944, had averaged 6500 bbl per psi pressure drop with all measured top of pay pressures in excess of 2885 psia. Dividing by expansibility of undersaturated oil would indicate an initial oil content of 450 million barrels, an apparent good check between a very early material-balance estimate and later volumetric estimate of 600 million barrels. The only catch is that measured pressures were necessarily confined to the small developed area comprising only about 15 pct of the finally developed area. That and subsequent pressure surveys showed undeveloped area to have much higher pressure. Thus the 450-million-barrel figure must be multiplied by a factor of maybe as much as 4 or 5, which no longer is in agreement with volumetric data. Consideration of this and later data indicates that water influx was probably too small to account for production in excess of liquid oil expansion. This leaves only gas expansion as it is released from solution in oil as an explanation. These various factors all indicate a saturation pressure in excess of 2900 psia and probably as high as 2950 psia. More than likely some of the low-saturation-pressure samples had been exposed to large pressure drawdown in wells.

In addition to saturation pressure, the distribution of actual formation pressure must also be considered in material-balance calculations. To my knowledge this latter feature has never been discussed in literature on material-balance principles. It can be of considerable importance when large differences in actual formation pressure exist because of unequal unit fluid withdrawals or large

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Since water has encroached over a considerable part of the reservoir, it can only be concluded that initial oil content was less than 600 million barrels, that considerably more gas has been produced than reported, or that well pressures are not representative of reservoir pressures. Fifty per cent more cumulative gas production, or reservoir pressures about 200 psi in excess of well pressures, or some combination of the two, is necessary for a 600-million-barrel initial oil content and a reasonable amount of water influx.

Material-balance calculations are thus of little value in calculating water influx, but fortunately in this case one other method can be used. In the past few months water production has leveled off at about 15,000 bbl per day, and many wells previously making small amounts of water now have water-free production. Thus current water influx is probably of the order of 15,000 bbl per day. It may have been slightly higher during the period of very high fluid-withdrawal rates just prior to the allowable reduction in September 1946, but probably has not averaged more than 15,000 bbl per day during the 3½-year producing life prior to Jan. 1, 1947. Probably not over 19 million barrels of water has thus encroached into the oil reservoir, 7 of which have been produced, leaving about 12 million barrels spread over an area of at least 7400 acres, since some 185 wells have produced water. This is an average of 1600 bbl per acre, or only 5 to 6 pct of the initial oil-filled reservoir in the invaded area. Ninety-four per cent of the water production for December 1946 was concentrated in 108 wells, making over 25 pct water. Assuming bulk of encroached water to be concentrated in 4300-acre area of these wells, the average fraction of initial oil-filled reservoir invaded by water is increased to only 9 pct.

Although a few cases exist where water...

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Structural relief. The Schilthuis form of material-balance equation for a reservoir containing no initial free gas is:

\[
\text{Expansion} = \text{Production} - \text{Water Encroachment}
\]

\[
\begin{align*}
\Delta n &= \frac{(u - u_0)}{n} \\
\Delta u &= \frac{u}{n} \\
\Delta v &= \frac{v}{n} \\
\Delta Z &= \frac{Z}{n}
\end{align*}
\]

The usual procedure is to insert the factors \((u - u_0), u, v\) corresponding to average datum pressure and solve for the initial oil content, or, in this case, net water influx. Since these factors are nonlinear with pressure, however, proper average values cannot correspond to average pressures. Until cumulative free gas production measured at reservoir conditions predominates over oil production, the balance is most sensitive to \((u - u_0)\). Thus weighting \((u - u_0)\) rather than pressures should give a more reliable result.

Values of \((u - u_0)\) calculated from mid-pay pressures for each well for the March 15, 1946, survey and 2950 psia saturation pressure were multiplied by the corresponding pay thicknesses to determine weighted average value of \((u - u_0)\). Values of \(u\) and \(v\) for pressure corresponding to the average value of \((u - u_0)\) were used to complete the calculation. The maximum initial oil content calculable, assuming no water influx, is 540 million barrels. Corresponding initial oil content using weighted average mid-pay pressure in the material-balance equation is 635 million barrels, and using weighted average datum pressure, the usual procedure, oil content is 690 million barrels. Approximately the same percentage divergences, 19 and 28 pct, respectively, occur assuming any likely quantity of water encroachment; and the calculated initial oil content is, of course, correspondingly reduced. Regional migration of fluids in the reservoir introduces error, since it is implicitly assumed in this method of calculation that the proper values of \((u - u_0)\) can be determined from pressures alone. Since, in general, fluids migrate from high to low pressures, error is toward the high side. This causes even more divergence from the “average” pressure method.
has fingered ahead completely by passing some wells, each of these has had only small water production. No cases exist of continued low water percentage production behind.

Considering only this area invaded by a net 12 million barrels of water and having wells producing in excess of 25 pct water, it is well to consider equivalent performance of gas injection. During December 1946 these wells produced about 6300 bbl of oil per day and 14,000 bbl of water per day. It is reasonable to assume that the rock would have about the same effective permeability to gas as it does to water if free gas were to occupy the same position in the pore space. Reference to Leverett and Lewis' (Fig 14) three-phase fluid-flow study, the only published data,

**Fig 14—Relative Permeability of Unconsolidated Sands to Oil, Gas and Water.**
(Data from Leverett and Lewis Petr. Tech., 1940)
shows this to be true for sands. At current pressures, the 12-million-barrel pore space would hold about 9 billion standard cubic feet of gas. Gas production equivalent to 14,000 bbl of water per day, after correcting for pressure and for the different viscosities of gas and water, would be about 300 million cubic feet per day at a gas-oil ratio of 47,000 cu ft-per barrel. Thus if all wells were operated the same as current conditions, the entire stored gas would have to be cycled every 27 days. Extending this to the entire field with equivalent percentage pore space in fractures occupied by free gas, the current gas-injection volume would have to be about 2 billion cubic feet per day.

If these volumes of gas were not injected, lower gas-oil-ratio oil production from the intergranular porosity into the fractures would reduce the gas saturation to that necessary to balance gas-flow capacity to the gas-injection volume.

Of course, conditions with gas injection would not be quite as serious as this implies, since many wells producing large volumes of water would not be operated with equivalent gas production. At least the water invasion and production performance points to serious difficulties in control of gas production with a full-scale gas-injection program.

M. LITTLEFIELD, L. L. GRAY and A. C. GODBOLD (authors reply)—Most differences of opinion as to the physical character of the West Edmond pool arise from two basic misconceptions. The first misconception is that the total “pay” section is uniform in character and is all effective “pay” section. As shown in Fig 7, this is not the case. Study of cores with particular attention to the relation of oil stain to porosity and permeability shows considerable vertical variation in the distribution of “producing” porosity and permeability. In general, the vertical distribution of fracture porosity is more uniform than is the distribution of oil-stained intergranular porosity. The second misconception is that no fractures are present or, if present, are not connected because the reservoir does not perform as it should if all “producing” porosity was contained in large fractures, amounting to cavernous voids. If such were the case, uniformity of pressures and gas-oil ratios, as well as gravity segregation would be expected. Fracturing of this magnitude did not occur at West Edmond, nor was such implied in the paper. It is not necessary that such a condition exist in order to have bypassing. The important point is the contrast between permeabilities of intergranular and fracture porosity. If one component had an effective permeability of 50,000 md (and the other 500 md), the tendency for bypassing would be substantially the same as if they were respectively 100 md and 1 md, or 10 md and 0.1 md. However, in the former case, uniformity of performance might be expected, whereas the latter two examples would undoubtedly give variations between wells. Rock study indicates that about 10 pct of the producing porosity is in fractures and 90 pct is made up of intergranular voids. The infinite variations of combinations of these two types or porosity are apparent in Fig 7. One constant factor is the fracturing of rock with intergranular porosity. Fracturing of the limestone into blocks of the order of 6 in. is indicated by the incidence in cores of fractures of various types, including bedding planes. The latter are not included in computations of void space. Actually, the range in size of fractured limestone blocks is probably considerable. In the dolomites, sealing of fractures by recrystallization may introduce irregularities of fracture permeability, irrespective of the size of fracture blocks.

From rock study alone, proof of interconnection of fractures is the presence of oil stain in them in parts of the section where both the rock itself and the filling of the solution-enlarged fractures is unstained.

In commenting on the discussion offered by Mr. L. E. Elkins, of Stanolind Oil and Gas Company, we find that there is not too much disagreement in our viewpoints, the major difference apparently being in the degree of connection within the fracture system. Mr. Elkins states that the cycling of gas through the channels would probably result in substantial increased recovery by (1) “maintenance of economic producing rates,” and (2) “keeping the permeable channels stripped to a minimum degree of the oil that continually will seep into that channel until the reservoir approaches its ultimate equilibrium.” In this connection, Mr. Elkins is referring to
recycling in the final stages of depletion. Certainly, if gas were recycled in the permeable channels (fractures) as suggested, a considerable degree of communication would have to exist within the permeable channels between wells, and between groups of wells. If good connection in the fracture system extends over such an area as this, then it appears likely that it might extend over very large areas as we have indicated. After the reservoir has been depleted to the point where the seepage of oil into the channels controls the rate of recovery, it does not appear evident how gas recycling will yield oil at a greater rate than provided by the bleeding of oil from the intergranular rock.

The injected gas would merely be sweeping out the oil bled into the channels, and could have no effect on the rate of bleeding except perhaps to retard it to the extent that the pressure decline is arrested. Possibly Mr. Elkins is referring to alternate recycling and shutdown periods at a low stage of depletion. Such a program might have considerable merit. As stated in the paper, the authors believe that a recycling program at depletion of the intergranular porosity would probably be feasible.

In regard to the suggestion that oil may move out faster at some optimum intermediate pressure differential in place of absolute minimum differentials and absolute maximum differentials, the basic principles of reservoir mechanics are contradicted because it is required that flow rates increase with decreasing outflow pressure.

Mr. Jack Tarner, of Phillips Petroleum Company, does not agree that fractures, as such, exist in the reservoir, but suggests rather that fractures observed in cores were formed in the coring process by the release of overburden pressure. Although some fractures do result from mechanical stresses along previous lines of weakness, such fractures are easily recognizable, and none of these were included in computation of void space.

In commenting further on Mr. Tarner's discussion, no claim is made by the authors that filled fractures contribute to production and they are not included in computations of void space. As a matter of interest, they are shown in Fig 4, on the right side of the lithologic column under intermediate porosity. The legend shows this to be nonproductive. Filled fractures are common in the Frisco member, amounting to more than 5 pct of the volume in some layers. The computed figure for open fractures for the Frisco in the Streeter well is .07 pct.

In Fig 6, both the left-hand and center specimens have open vertical fractures which extend the full length of the specimen. It is true that some late fractures do terminate vertically on bedding planes. It is also true that some continue through the core, the maximum observed distance being 5 ft, on a nearly vertical break which came in one side of the core and out on the other side. The right-hand specimen in Fig 6 shows a pattern of echelon fractures in dolomite. The fact of fewer fractures in dolomite and of the tendency toward sealing by recrystallization is stated in the paper.

The center specimen of Fig 6 has a flat fracture face the whole length of the core. This represents a late fracture which cuts both early solution-enlarged fractures and the solution-made intergranular porosity. Without question, fractures through relatively dense limestone into limestone of good intergranular porosity do afford channels of communication to areas of fine porosity which are otherwise virtually isolated.

Mr. Tarner concludes that the average productivity index for the field is on the order of 2:1 and further concludes that the producing section would need from only 10 to 20 md permeability to have this productivity index. Obviously, Mr. Tarner is assuming that the "thick producing sections" are all effective pay. As stated previously, this was one of the "misconceptions" as core studies showed. Actually, the measured intergranular permeabilities, as shown in this paper, have only \( \frac{1}{10} \) of the value necessary to obtain a P.I. of 2:1. It was essential that a very substantial contribution by a fracture system would have been necessary in order to obtain the productivities that actually existed. Submitted in Fig 7 in the paper is a summary of the core data as evidence that the actual millidarcy feet obtained were only a small fraction of the minimum required for a P.I. of 2:1.

It was thought that some economic benefit might possibly be realized by unitized operation, permitting selective production. Certainly the uncontrolled advance of water through the fracture system is not good practice and under unitized operations it is believed
that water could be kept from advancing much farther if water-producing wells could be operated even beyond their economic limits. Moreover, we have made no claim that gas injection would not give some additional recovery. However, we do believe that the large projected investment and operating costs necessary to full-scale high pressure pool-wide gas injection would not be profitable, or at best it would be highly questionable. Whereas gas injection is an expensive process, selective well production is not. Actually, selective production, including operation of the water-producing wells, would cost less than competitive operations, because the total well-months operated should be substantially less than well-months operated under normal competitive operations.

We have stated in general terms that communication existed within the fracture system, admitting at the same time, however, that the degree of communication within the fracture system was highly variable, particularly in the northern portion of the pool which is largely dolomite. We have no cores from this area, but have recognized the probability that fewer fractures exist. This, of course, results in greater pressure differentials between wells and lower P.I. values. No statement has been made in the paper that the fracture system is of uniform continuity throughout. Continuity from any given well may be appreciable in one direction, as evidenced from interference tests, but of much smaller degree in the opposite direction. Accordingly, this would not necessitate that all wells in the pool have the same bottom-hole pressure, the same gas-oil ratio, the same P.I. and the same incidence of fractures in order for the fracture system to be communicating throughout a large portion of the pool. Again the important point is the ratio of permeabilities between the two components and not absolute values of permeability. There are very large areas in the pool which have had similar pressure declines and small pressure differentials between wells.

Irrespective of the rock study made on cores from eight wells located generally down the central portion of the reservoir, it is not possible to hide from the fact that water encroachment to date has illustrated perfectly the point the authors wish to make. As Mr. L. F. Elkins, of Continental Oil Company, expresses it in his discussion, “Thus, not only does the water-encroachment performance confirm existence of quite low volume highly permeable streaks indicated by fractures in cores, but in addition it proves a reasonable degree of continuity of these streaks throughout the reservoir, a factor that can only be inferred by the frequency of fractures in cores examined.” This area of water encroachment represents a considerable portion of the pool. Certainly, it is logical to reason then that by-passing of gas injected would largely duplicate the by-passing evidence already obtained by the manner of water encroachment.

The performance of the West Edmond Hunton reservoir will furnish data on the behavior of a combination of intermediate and intergranular porosity and permeability. Even though that combination seems almost hopelessly complex, possibly the effect of some factors may be judged by comparison with the behavior of reservoirs composed only of fracture porosity and with reservoirs made up entirely of low-permeability, intergranular, limestone porosity. Essential differences between intergranular limestone permeability and intergranular dolomite permeability suggest that they should be considered separately in attempts to analyze the factors which affect reservoir performance. Study of carbonate reservoirs should progress from those with a single type of porosity to those in which various types are combined.

Inasmuch as the success or failure of a pressure maintenance project from an economic standpoint is largely dependent upon the degree of by-passing to be expected, it is clear that a thorough knowledge of the reservoir rock is essential. The authors wish to take this opportunity to thank those who have given their time to discuss this paper. Moreover, we hope that further work of this nature on limestone and dolomite reservoirs will be done as a supplement to core analysis and performance data.