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RESERVOIR ENGINEERING RESEARCH INSTITUTE

PROJECT 3

IMMISCIBLE GAS-OIL DRAINAGE IN LAYERED POROUS MEDIA

3Q.93

July 1, through September 30, 1993

**ABBAS FIROOZABADI
TORE MARKESET**

Immiscible Gas-Oil drainage Gravity Drainage in Layered Porous Media

SUMMARY

Layered reservoirs with distinct permeability for each layer may have certain characteristics similar to fractured reservoirs. The contrast in capillary pressure of different media, may have significant influence on oil recovery of the less permeable medium. In the experimental work to be presented in this report, it has been demonstrated that the less permeable layer may not reach gravity-capillary equilibrium in field scale time frame. Therefore, appropriate use of capillary pressure data in the study of layered reservoirs by a simulation model may be very important.

Another feature of gas-oil gravity in layered porous media is the downward gas fingering in the less permeable layer which is related to the permeability ratio, capillary threshold height of the less permeable layer, and thickness of the more permeable layer¹. The theory of downward gas fingering was introduced in Ref. 1. The experiments of this report verify the validity of theory.

We are currently measuring capillary pressure of the two types of media used for the two layers. With capillary pressure and relative permeability data, we can proceed to analyze the laboratory experiments. The next quarterly report will cover analysis of the experiments presented in this report.

INTRODUCTION

In a recent theoretical study on gas-oil gravity drainage in layered porous media, we have demonstrated that downward gas fingering may occur¹. Gas fingering can affect the production performance significantly; GOR may fluctuate and sweep efficiency may decrease. In Ref. 1, we have shown that in a two-layer media with a low permeability layer on top and a high permeability layer below, gas could finger downward through the less permeable top layer to reach more permeable bottom layer below. If the gas mobility is assumed to be infinity, gas would finger through the less permeable top layer instantaneously. The occurrence of downward gas fingering is related to layers' permeability ratio, threshold capillary pressure of the less permeable layer, and the thickness of the more permeable layer. Downward gas fingering could occur if $k_2/k_1 > 1 - h_2^0/h_1$, where k_2 and h_2^0 are the permeability and threshold height of the top layer, and k_1 and h_1 are the permeability and thickness of the bottom layer¹. Note that in downward gas fingering for layered media, capillary pressure is a key parameter, whereas in downward viscous fingering, capillary pressure is neglected². In

order to appreciate the concept of gas fingering for gravity drainage in layered media, the following schematic will be useful.

Through the use of Fig. 1, we want to show when to expect downward gas fingering in a two layer media. Assume initially both layers are saturated with a liquid. At time, $t=0^+$, liquid starts to drain and the gas enters from the top to replace the drained liquid. The gas could enter provided the liquid pressure at the top, P_l is equal to $-(P_c^0 + \rho_g gh)$. The dotted line in Fig. 1 represents gas phase pressure profile, and the dashed line represents the final equilibrium pressure when gravity/capillary equilibrium is established. The solid thick line connects the initial flowing liquid phase pressure at the top to the origin. It is assumed both the liquid and gas phase pressures are equal to zero at the outlet, and therefore $P_c=0$. If $k_2/k_1 < 1$, the liquid phase pressure profile should be to the left side of line OB. Now, let's draw from point B, line BC parallel to line AO, and connect point C to the origin. The shaded area between lines BO and BC, and CO, and the region to the left of BCO have an important characteristic. If the initial flowing liquid pressure profile is within the shaded are, downward gas fingering would not occur. However, if the initial flowing liquid pressure profile is to the left of BCO, gas will instantaneously finger through the top layer to reach the more permeable bottom layer. Ref. 1 provides the reasoning based on the assumptions of infinite gas mobility and an incompressible liquid. One of the goals of the experimental work presented in this report is to demonstrate the validity of the concept of downward gas fingering described briefly above and outlined in Ref. 1.

An important conclusion of the work in Ref. 1 which is of practical interest relates to the recovery sensitivity of some layered reservoirs to capillary pressure. Due to capillary pressure contrast between the layers, the liquid drainage in the less permeable layer becomes very slow. This characteristic of layered reservoirs is similar to fractured reservoirs. The demonstration that capillary/gravity equilibrium may not realize in any meaningful time frame is the second objective of the experimental work.

In this report, the experimental setup and procedure will be described first. The results will then follow. Analysis of experiments will be presented in the next quarterly report upon availability of capillary pressure and relative permeability data.

EXPERIMENTAL

Fig 2 shows the apparatus schematic. A 60 cm long Berea core, of 7.62 cm (3") diameter sits on top of 68.6 cm long sand layer. The transparent coreholder which houses the sand, has an internal diameter of 9.65 cm (3.8") in the top, 8.89 cm (3.5") in the middle which reduces to 7.62 cm (3.0"). The length of the 3.8", 3.5" and 3.0" diameter segments are 5.2, 2.5, and 60.4 cm, respectively. Details are shown on the right hand side of Fig. 2. The Berea was

covered with a layer of polyester casting resin (1/4" thick). The entire coreholder setup is transparent. But the gas-oil front could be viewed only in the sand layer. The piston-like setup shown in Fig. 2 allows to have capillary continuity between the Berea sandstone and the sandgrains at all times.

Permeability of the Berea sandstone, and the sandlayer are 950 md, and 46 darcy, respectively. The porosity of the Berea is 21.0 %. The porosity of the sand is around 38 %, and reduces slightly from one test to the next, due to compaction. For each test, the porevolume (PV) of the sandlayer is measured to account for PV reduction. The PV of the Berea is 574 cm³ and its threshold height for air/nC₁₀ system is 37 cm.

At the end of each test, by weighing both the Berea and sandpack core holders, liquid saturations are established. We are currently measuring capillary pressure and relative permeability of both layers to be used in the analysis of the experiments.

In all the tests, the two-layer porous media was saturated with liquid normal decane. Atmospheric air from the top provided the gas phase to drain the liquid.

RESULTS

A number of tests were performed to demonstrate the validity of theoretical arguments of Ref. 1. In all the tests, the thickness of the lower more permeable layer was varied by varying the position of the production outlet valve. Except in tests 15 and 16, all other tests were conducted under the condition of free flow of liquid. In tests 15 and 16, the rate of liquid production was controlled at a specified value.

Tests 2, 3, 15 and 16

In all four tests, the production outlet was fixed 1 cm above the bottom face of the sand layer (i.e., 67.1 cm below the Berea/sand interface). In tests 2 and 3, gravity drainage was allowed to take place. The top of the sand layer (i.e. the interface between the two layers) was watched carefully. After about 12 minutes, gas appeared at the interface for both tests 2 and 3. From then on, gas-liquid front in the sand layer moved downward; which implies production from both layers from $t=12$ min. Fig. 3 show the cumulative production and rate data. Prior to the arrival of the gas finger, the production rate is constant — around 182 cm³/hr, then increases gradually to 220 cm³/hr at $t=50$ min. A sharp rate increase to 280 cm³/hr at $t \approx 80$ min for test 2 is then followed. The production rate increase of test 3 has a similar trend. The trend of production rate increase is partly due to change in diameter of the coreholder housing the sand grains. Fig. 4 shows the position of the gas-liquid front in the sandlayer for test 3 (solid curve). The same figure also shows gas-liquid front when only sandlayer is drained (dashed curve). At the termination of this test, and removal of the Berea

layer on top, the sand was allowed to produce to equilibrium. A total of 136 cm^3 was produced in about 280 minutes, where still production rate was $2.5 \text{ cm}^3/\text{hr}$. Fig. 4 and drainage of the sandlayer imply that gas mobility is finite and that it affects the drainage in layered media much more than a homogeneous media. This important point will be discussed in detail in the next quarterly report.

Fig. 3 also reveals that the gas-oil gravity drainage in layered media could be unstable. The conditions of duplicate tests 2 and 3 were the same, but the cumulative production data is not reproduced. However, toward the capillary/gravity equilibrium, we expect the same recoveries for both tests.

Tests 15 and 16, are different from tests 2 and 3, with respect to the outlet boundary conditions. In tests 2 and 3, as mentioned above, $P_c = 0$ at the outlet. In tests 15 and 16, the production rate was controlled to a value of $60 \text{ cm}^3/\text{hr}$ by manual adjustment of a needle valve. At this rate, gas should not finger according to a criterion established in Ref. 1. Fig. 5 shows the production and rate data for these two duplicate tests. After 700 minutes, the production rate drops to less than $60 \text{ cm}^3/\text{hr}$ and the outlet valve was fully open. The production and rate data for these two tests reveal very similar behavior; the difference is a reflection of manual rate adjustment. In both tests, the gas front reached the interface at around 220 minutes, where production was about 220 cm^3 . Fig. 6 shows the gas-liquid front position at various times. Note that in tests 2 and 3, due to unstable flow conditions, gas appears at the interface after production of only 30 cm^3 .

Table 1 gives the final liquid saturation of the Berea and sand layers at the end of the tests. This table also provides other data such as test duration, and gas arrival time at the interface. The saturation data of Table 1 reveal that the bulk of the production for tests 2 and 3 is a result of simultaneous production from the Berea and sand layers.

Test 5 and 6

In these duplicate runs, the production outlet was fixed 33.6 cm below the interface. According to our criterion¹, the gravity drainage process should be stable. Fig. 7 shows the production and rate data for tests 5 and 6. The results are nearly the same and there is no gas arrival to the interface. Table 1 gives the saturation of the two layers at the end of tests 5 and 6. One would expect higher liquid saturations for the Berea layer for these two tests than tests 2, 3, 15, and 16. Capillary pressure contrast between the two layers slow down the establishment of gravity/capillary equilibrium.

Test 7 and 9

In these two test, the outlet valve was held at 44.6 cm below the interface. Therefore, according to the criterion of Ref. 1, the gas oil gravity drainage should be unstable. For both

tests, gas front reached the interface at $t \approx 105$ minutes implying that a quick gas fingering did not occur. Production and rate data are shown in Fig. 8. Production data imply an unstable gravity drainage process. From Table 1, it is seen that at the end of these two tests, the liquid saturations of the Berea layer is close to the previous test. The gas-liquid front position is shown in Fig. 9. At the end of tests 7, and 9, after removal of the top Berea layer, the sand layer was allowed to drain; 13.8 and 53.0 cm³ of liquid were produced. It took 80, and 50 minutes to produce these volumes where production rates were 0.4 and 0.1 cm³/hr at the end.

Test 10, 11, and 12

In these three tests, the production level was fixed at 78.1 cm below the interface. Fig. 10 shows the production and rate data. For all three tests, the rate is about 230 cm³/hr in the first ten minutes (decreases very slowly). Gas arrives at the interface at $t < 10$ minutes. The production rate increases gradually to about 300 cm³/hr at $t = 40$ minutes. There is a sharp rate increase at this time. Around $t = 50$ minutes, the production rate reaches 350 cm³/hr for test 12. Similar to other unstable tests, there is a difference in production data which is believed to be due to unstable flow conditions. It is interesting to note that the liquid saturations of the Berea layer is about the same as all other tests. Fig. 11 shows that the gas-oil front position in the sand layer moves slowly due to finite gas mobility.

Test 13

In this test, the production level outlet was fixed at 98.1 cm below the interface. The initial production rate was around 260 cm³/hr, but started to increase from $t \approx 3$ min. At time $t = 60$ minutes, the production rate reached maximum value of 535 cm³/hr, and then a decreasing trend started (see Fig. 12). The run was terminated when gas breakthrough occurred at the sand outlet. Gas appeared at the interface in about 10 minutes which signifies gas fingering through the top Berea layer. It is likely that gas arrival to the interface was earlier than ten minutes because we could only see the appearance of gas at the interface from the circumference.

CONCLUDING REMARKS

Full analysis of the experimental work will be presented in the next quarterly report after availability of P_c and relative permeability data. However, certain conclusions can be drawn from the experiments.

1. Downward fingering in layered reservoirs could occur for gas-oil drainage process.
2. The recovery from the less permeable layer became very slow, and gravity/capillary equilibrium may not realize in a field scale time frame.

Conclusion 2 could be expanded after data analysis.

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Table 1 - Test Results

Test	2	3	15	16	5	6	7	9	10	11	12	13
Level from interface, cm	67.1	67.1	67.1	67.1	33.6	33.6	44.6	44.6	78.1	78.1	78.1	98.1
Test duration, min	7263	2628	7211	5743	4167	4110	9702	1407	1327	1776	5747	222
Final Rate, cm ³ /hr	0.34	3.07	0.17	0.18	0.41	0.21	0.15	6.53	4.35	1.93	0.19	132.6
PV, Sand, cm ³	1304	1305	1241	1234	1285	1275	1258	1244	1260	1222	1234	1246
S ₀ , Berea, %	47.3	48.6	45.8	45.9	47.4	48.2	46.2	49.4	49.6	47.8	48.1	55.4
S ₀ , Sand, %	30.5	39.4	30.9	31.2	100	100	59.8	64.9	28.7	26.4	18.2	22.8
Gas arrival at interface, min.	12	12	220	220	—	—	105	105	9	10	10	<10

Fig. 3 - Production and rate data for tests 2 and 3.

Fig. 4 - Fosition of gas-liquid front in the sand layer.

Fig. 5 - Production and rate data of tests 15 and 16.

Fig. 6 - Gas-liquid front from interface for test 15.

Fig. 7 - Production and rate data for tests 5 and 6.

Fig. 8 - Production and rate data for tests 7 and 9.

Fig. 9 - Gas-liquid front from interface for tests 7 and 9.

Fig. 10 - Production and rate data for tests 10, 11, and 12.

Fig. 11 - Gas-liquid front from interface for tests 10, 11, and 12.

Fig. 12 - Production and rate data for test 13.

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PROJECT 3

EXPERIMENTAL STUDY OF VISCOUS GAS-OIL DISPLACEMENT IN FRACTURED POROUS MEDIA

3Q.93

July 1, through September 30, 1993

**TORRE MARKESSET
ABBAS FIROOZABADI**

Experimental Study of Viscous Gas-Oil Displacement in Fractured Porous Media

SUMMARY

Six experiments have been carried out to study the influence of viscous forces on gas-oil displacement in fractured porous media. In these experiments, two different matrix/fracture configurations have been used. Two types of experiments were conducted: 1) constant injection rate, and 2) constant pressure drop. Comparison of the gravity drainage performance and the viscous displacement in the same matrix/fracture configuration reveals a strong effect of viscous forces.

INTRODUCTION

Gravity drainage in fractured porous media has been studied mainly by examining the influence of gravity and capillary forces. In fractured porous media comprised of matrix blocks and fracture network, these two forces affect the two-phase flow in both the matrix blocks and the fractures. Capillary forces also play a major role in interaction between the blocks via the capillary continuity mechanism. Both the capillary pressure and the gravity forces affect the crossflow between the matrix blocks. There is no published work on the effect of viscous forces on gas-oil flow in fractured porous media. Viscous forces are believed to cause crossflow between the fractures and the matrix blocks. Stated simply, imposing a high gas pressure gradient across fractured porous media could lead to improved recovery performance. The first phase of the work on this topic will be limited to experimental research. Theoretical analysis will be the second step.

In the following, the experimental setup, matrix-fracture configuration, and properties, and test procedure will be described. Then, the results will be presented.

EXPERIMENTAL

Apparatus

The apparatus schematic is depicted in Fig. 1. It consists of a glass-walled case with metal top and bottom plates supported by a metal framing. The metal framing allows the 0.95 cm thick glass plates to be forced against the rock faces. Design allows the setup to be tilted through 240° about a central horizontal axis. The glass case was sealed using fuel resistant room temperature vulcanizing fluorosilicone rubber. The bottom and the top end plates were made of 2.54 cm and 0.64 cm thick aluminum plates, respectively. Both plates were provided with connections for vacuum, ventilation, gas injection, fluid loading and drainage (see Fig. 1). A valve mounted 6 cm above the bottom face of the coreholder

allows gas to flow out freely without interfering with liquid flow. The liquid is produced from the outlet at the bottom plate.

Peripheral accessory equipment consists of vacuum pump, vacuum gauge, heat tapes, balance, gas bottle, gas mass flowmeter and controller, pressure transducer, multiloop controller with proportional, integral, and derivative (PID) control capabilities, resistance temperature detector (RTD), air conditioning unit, convection oven, and two personal computers (PC). The RTD, air conditioning unit, convection oven, pressure transducer, and the gas massflow meter and controller are interfaced to the multiloop controller. The multiloop controller is interfaced to one of the PCs. A computer program in C language allows logging of pressure, gas flowrate, and temperature. The same program also simultaneously provides temperature control of the laboratory room ($76 \pm 0.3^\circ\text{F}$). The balance is interfaced to the other PC. A Quick-Basic program allows logging of mass data. Constant gas flowrate is provided by the gas mass flow meter and controller. By utilizing the PID control capacity of the multiloop controller, the injection pressure can be also held constant while the gas injection flow rate varies.

Matrix-Fracture configurations and properties

Two different matrix-fracture configurations are used to study viscous displacement in fractured porous media (see Fig. 2). Both configurations are assemblies of matrix blocks and matrix slabs of Berea sandstone. Block areal dimensions are 15 x 30 cm, and 60 cm in height. Slab dimensions are 3.75 x 30 cm areal, and 60 cm in height. In both configurations (see Fig. 2a and Fig 2b), the rock faces are in direct contact. To ensure uniform fractures and tight mounting in the coreholder, the rock material is grinded to a dimensional tolerance of ± 25 microns. Care is taken to ensure all faces are normal (90°) to adjoining faces.

In Fig. 2a, the slabs in the middle contain 7 vertical fractures; three fractures from the space between the opposing faces of the matrix slabs and four fractures in the space between the glass walls and the slab faces. Visual observations lead us to conclude that the four fractures between the glass walls and matrix slabs are thinner than the fractures between matrix slab faces. For the top and bottom matrix blocks of Fig. 2a, in each four corners a large channel allows free flow of injected gas without any appreciable pressure drop. These channels have a prism shape; the base triangle dimensions are 4 x 4 x 5.6 mm. Therefore, both top and bottom matrix blocks are only subject to gravity drainage.

For Fig. 2b, the fractures for the top and bottom matrix slabs are similar to the fractures of the middle slabs of Fig 2a. The middle matrix block is surrounded by four large corner fractures to allow free flow of gas.

The effective permeability of the fracture/matrix configurations of Fig. 2a is 6.3 darcy and that of Fig. 2b is 4.2 darcy. The effective permeabilities were measured by single phase liquid flow of normal decane. Since the effective permeability across the matrix blocks are very large (due to channels), we may imply that these effective permeabilities correspond to the slab/fracture assemblies.

The porevolume of the matrix/fracture configurations of Figs. 2a and 2b, are 17,827 cm³, and 18,151 cm³ respectively. The deadvolume including, corner channels, valve, fittings and tubing, and deadspace at the outlet is estimated to be 70 cm³. The fracture volumes (includes horizontal and vertical fracture between rock and slabs, and vertical fractures between rock and glass) are 164 and 208 cm³ for configurations 2a and 2b, respectively. We have not yet measured permeability of the Berea sandstone slabs and blocks. They will be measured soon. From previous data, we expect permeabilities in the range of 600 to 900 md.

Test procedure

The case and rock material were evacuated to remove adsorbed fluid and then saturated with normal decane (see Figure 1). A period of two days was allowed to achieve full saturation with normal decane liquid. The rock matrix was submerged in the liquid with about 2 cm of excess liquid (≈ 900 cm³) above the horizontal face of the top block. Downward flow of this liquid, until the liquid level reached the horizontal face of the top block, gives the effective permeability of the matrix-fracture system. Negligible resistance in the inlet and outlet connections was assumed. Gravity drainage by atmospheric pressure was allowed until both the vertical space between the rock and the glass, was empty before nitrogen gas injection was initiated. The produced liquid was accumulated in a container and recorded on the PC. Liquid and gas have separate outlet. Gas injection pressure was measured at the inlet of the system and recorded on a PC (the outlet pressure was assumed atmospheric).

RESULTS

Six tests have been performed. In the first four tests, the matrix-fracture configuration of Fig 2a was used. The last two tests were conducted with the configuration of Fig. 2b. The results will be presented in the following.

Test 1 – Gravity drainage—Gravity drainage performance provides a basis for comparison for the other test on the same setup. Figure 3 displays the production and rate data. Fig. 4 displays the same data on a different scale. The flowrate at the start of the experiments is around 3,200 cm³/hr. After 3 minutes the drainage rate has decreased to

approximately 1,640 cm³/hr. During this period, the fluid in the vertical space between the glass and the rock face, and the fluid from the three vertical fractures between the four slabs and the two horizontal fractures, is drained (in addition to the drainage from the matrix). The fractures are now empty except for film flow along the vertical walls. The film flow continues until about 15 minutes (see Fig. 3). The rate at time t=15 min is approximately 735 cm³/hr. At t=500 min the drainage rate is 169 cm³/hr. At t=3,000 min the cumulative production is 5,041 cm³; corresponding to an average matrix saturation of 71.7%. The drainage rate is 17.5 cm³/hr.

At t=18,509 min (about 12.8 days) the flowrate is around 2.8 cm³/hr. The cumulative production at this time is 6,549 cm³, corresponding to an average liquid saturation of 63.3%.

Test 2 – Gas Injection at 1000 cm³/min and later drainage—In this test, nitrogen was injected at a constant flowrate of 1,000 cm³/minute, from t=0.5 min to t=5,432 min. In the first half a minute gravity drainage was allowed to take place and most of the liquid in the fracture was produced. At t=5,432 min the gas injection is terminated and the system is allowed to drain by gravity until t=8,372 min. The production and rate data versus time are shown in Figs. 3 and 4. Figure 5 shows injection pressure versus time on a logarithmic scale.

The initial production rate is 4,212 cm³/hr. An increase in the flowrate, caused by the sudden injection of gas, is observed. After the initial increase, the production rate decreases rapidly to 1,439 cm³/hr at t=6 min. At t=15 min the drainage rate is 1,284 cm³/hr. The production rate decreases to 168 cm³/hr at t=500 min. As observed in Fig. 3, the flowrate is higher than that of the gravity test during the first 500 minutes. Thereafter, the flowrate is almost identical to the gravity drainage rate (see Figure 4). The pressure decreases rapidly from a maximum of 1.27 psig at t=1.2 minute to 0.51 psig at 4.1 minutes. From then on, the pressure decreases rather uniformly to 0.33 psig at 5,432 minutes when the gas injection is terminated. (Pressure measurement accuracy is around 0.0013 psi.) The production rate at the end of gas injection is 8.6 cm³/hr. At t=3,000 min the cumulative production is 6,005 cm³, corresponding to an average matrix saturation of 66.3%, and drainage rate is 16.1 cm³/hr.

The system is allowed to drain by gravity from 5,432 to 8,372 minutes; when the experiment is terminated. From t=5,432 to t=6,092 min there is no production. The system starts to produce at t=6,092 min at a low rate of 1.9 cm³/hr. At t=6,213 min, the rate is 3.5 cm³/hr. When the experiment is terminated, at t=8,372 min, the rate is 3.1 cm³/hr.

The cumulative production at this time is $6,602 \text{ cm}^3$. This corresponds to an average liquid saturation of 63.0%.

The production pause after the termination of gas injection and subsequent production at a low rate are indications that the four middle slabs have desaturated substantially due to gas injection. The gas injection does not affect the desaturation of the top and bottom matrix blocks directly, due to big vertical channels across these two blocks.

Test 3 – Gravity drainage and gas injection at $1,000 \text{ cm}^3/\text{min}$ —The system is allowed to drain by gravity until $t=3,217$ minutes, when nitrogen was injected at a constant flowrate of $1,000 \text{ cm}^3/\text{minute}$. Cumulative production and rate data are displayed in Figs. 3 and 4. The injection pressure is shown in Fig. 5. During the gravity drainage period, the drainage performance almost duplicates that of the first gravity drainage experiment. In Figs. 3 and 4, we observe that the drainage rate closely follows that of test 1. At $t=3,000$ min the cumulative production is $4,854 \text{ cm}^3$, corresponding to an average matrix saturation of 72.8% and drainage rate is $16.7 \text{ cm}^3/\text{hr}$. At $t=3,217$ min, (the start of gas injection), the drainage rate is $14.9 \text{ cm}^3/\text{hr}$. The cumulative production is $4,913 \text{ cm}^3$. When gas injection starts the rate rapidly increases to $332 \text{ cm}^3/\text{hr}$. The pressure initially increases to 0.37 psig, then after 5 minutes stabilizes at 0.36 psig; which is about 0.02 psig higher than test 2 at the same time. The pressure decreases to 0.34 psig at $t=6,000$ minutes, and decreases very slowly towards the end. The production rate at the termination of the experiment is $4.6 \text{ cm}^3/\text{hr}$. The cumulative production is $6,707 \text{ cm}^3$, corresponding to an end saturation of 62.4%.

In Figs. 3 and 4 we see that at the end, the drainage performance approaches that of test 2, in which gas was injected at $1,000 \text{ cm}^3/\text{min}$ from the beginning of the test. If we extrapolate the drainage performance of test 2 to 10,000 minutes, the difference between test 2 and 3 would be approximately 180 cm^3 , or 1% of PV.

Test 4 – Gas injection at $\Delta P=0.3 \text{ psi}$ —Instead of gas injection at a constant rate, the inlet pressure is kept constant at 0.3 psig while the rate varies (the outlet pressure is atmospheric). In test 4 this pressure is 0.03 psig lower than the pressure at the end of test 2. Figs. 3 and 4 depict the cumulative production and rate data versus time. The injection rate and the pressure are shown in Fig. 6.

As can be observed in Fig. 6, the pressure oscillates around the set value of 0.3 psig in the beginning of the experiment. After 1,500 minutes the pressure stays nearly constant. The oscillations in the pressure is caused by the resistance change in the system as the time elapses (time variant system). The control parameters are set by calibrating the

controller to control gas injection flowrate into the matrix-fracture system when it is dry. As the system is depleted, the resistance changes and the control parameters become off. The controller compensates by varying the flowrate too fast. This can be seen on the gas injection rate curve in Fig. 6. During the first 1,200 minutes, when rock still drains at a high rate, the resistance in the system is high. After 1,200 minutes the resistance changes slowly and the injection rate is nearly constant. The average gas injection rate is about 850 cm³/minute.

In the first 10 minutes, liquid drains at a high rate due to production from the vertical and horizontal fractures, and the matrix drainage. The initial rate is 3,903 cm³/hr. At t=6 minutes, the production rate is 1,311 cm³/hr. The rate reduces to 1,109 cm³/hr at t=15 min. The drainage rate is lower than test 2 in the first 200 minutes, (see Fig. 3). From 500 minutes, the production rate for all four tests, 1, 2, 3, and 4, is nearly the same.

At t=3,000 min, the cumulative production is 5,771 cm³, corresponding to an average saturation of 67.6%. The production rate at this time is 16.3 cm³/hr. The test is terminated at t=11,575 min, with cumulative production of 6,775 cm³. The final liquid saturation is 62.0%. The rate prior to test termination is 3.7 cm³/hr.

At termination, the experimental setup is dismantled, and the slabs weighed. The liquid saturation of three of the slabs are found to be 46.7, 45.0 and 44.0, percent. (The last slab was not weighed). Assuming a threshold capillary height of 40 cm, the liquid saturation of the bottom block is 90 percent. From material balance, the liquid saturation of the top matrix block is estimated to be 50.8 percent which is 5.5 percent more than the average saturation of the middle slabs. The saturation data imply the strong influence of the viscous displacement in fractured porous media.

Test 5 – Gas injection at 1000 cm³/min—In this experiment, nitrogen gas was injected at a constant rate of 1,000 cm³/minute in matrix-fracture configuration of Fig. 2b. Cumulative production and rate data are displayed in Figs. 7 and 8. Fig. 9 depicts the injection pressure on a linear scale.

Gravity drainage is allowed to take place in the first minute. The initial production rate is 4,749 cm³/hr. Gas injection is started when the liquid/gas interface reaches the bottom face of the lower slabs. After the initial rate increase due to injection, the production rate decreases rapidly to 1,753 cm³/hr at t=6 min. At t=15 min, the drainage rate is 1,489 cm³/hr. The production rate decreases to 219 cm³/hr at t=500 min. At t=3,000 min, the cumulative production is 8,129 cm³, corresponding to an average matrix saturation of 55.2%. The drainage rate is 23.5 cm³/hr.

The pressure data shows a rapid pressure decrease from a maximum of 1.6 psig at $t=1.6$ min to 0.83 psig at $t=4.8$ min. From then on, the pressure decreases very slowly to 0.51 psig at 20,216 minutes when the experiment is terminated. The final drainage rate is $2.3 \text{ cm}^3/\text{hr}$. The cumulative production at this time is $10,186 \text{ cm}^3$. This corresponds to an average liquid saturation of 43.9%.

Test 6 – Gravity drainage—In this experiment, the system is allowed to drain by gravity. Figs. 7 and 8 display the cumulative production and drainage rate data. The initial drainage rate is $4,415 \text{ cm}^3/\text{hr}$. In the initial period, similar to other tests, the fluid in the vertical space between the glass and the rock face, and the fluid from the three vertical fractures between the four slabs and the two horizontal fractures is drained (in addition to the drainage from the rock matrix). The rate at time $t=15$ min is approximately $813 \text{ cm}^3/\text{hr}$. At $t=500$ min, the drainage rate is $217 \text{ cm}^3/\text{hr}$. At $t=3,000$ min, the cumulative production is $6,210 \text{ cm}^3$; corresponding to an average matrix saturation of 65.8%, and the drainage rate is $21.8 \text{ cm}^3/\text{hr}$.

At $t=11,473$ min the flowrate is around $6.0 \text{ cm}^3/\text{hr}$. The cumulative production at this time is $7,697 \text{ cm}^3$, corresponding to an average liquid saturation of 57.6%. Comparison of the results from tests 5 and 6 shows a substantial effect of viscous forces.

CONCLUDING REMARK

The tests described above have to be analyzed in order to gain insight and understanding of viscous displacement in fractured porous media. However, the saturation data of the matrix slabs reveals that there is a strong influence of viscous forces on gas-oil displacement in fractured porous media.

Figure 1 - Viscous displacement experimental setup.

Fig. 2 - Matrix-fracture configuration.

Fig. 3 - Production and rate data for tests 1, 2, 3, and 4.

Fig. 4 - Production and rate data for tests 1, 2, 3, and 4.

Fig. 5 - Injection pressure data for tests 2, and 3.

Fig. 6 - Injection pressure and injection rate data for test 4.

Fig. 7 - Production and rate data for tests 5, and 6.

Fig. 8 - Production and rate data for tests 5, and 6.

Fig. 9 - Injection pressure data for test 6.

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