SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE 2814

A Study of Water Coning in the Oil Creek Reservoir, North Antioch Field, Oklahoma

By

J. M. Cutler and W. A. Rees, Members AIME, Coastal States Gas Producing Co.

This paper was prepared for the Second Symposium on Numerical Simulation of Reservoir Performance, to be held in Dallas, Tex., Feb. 5-6, 1970.

ABSTRACT

In reservoirs with bottom-water drives, water coning has historically been a producing problem. Prior to the use of high-speed computers, the coning problem practically defied solution. This paper discusses a study of water coning in the Oil Creek reservoir of the North Antioch field, which was made utilizing an r-z, two-phase compressible coning model. The model matches water-cut history and predicts future performance. The study points up the importance of variation in vertical permeability on the coning phenomenon. More particularly, it shows the effects of a continuous 4-ft zone of low permeability which occurs in the reservoir. Coning characteristics of wells in which the original oil-water contact was located above the zone are compared with those in which the original contact was below the zone. The study indicated that the reservoir could safely be produced at rates that would greatly increase the present worth value of the reserves without materially affecting the ultimate recovery.

INTRODUCTION

The North Antioch field is located in the northwest part of Garvin County, Okla. The field was discovered in May, 1965, with the drilling of Coastal States' J. R. Winchester No. 1. As the field developed, it became obvious that the oil reserves in the Oil Creek reservoir were of substantial proportions. Development was essentially complete by Oct., 1966. Because of a rather unusual combination of reservoir and fluid characteristics and the obvious possibilities for increasing recoverable reserves, reducing costs and increasing present worth value through proper operation, the decision was made to utilize some advanced forms of reservoir modeling to predict the results of various possible methods of operation of the field. This paper presents the results obtained from modeling and recommendations for future operations in the field.

References and illustrations at end of paper.

RESERVOIR CHARACTERISTICS

The Oil Creek reservoir of the North Antioch field is made up of approximately 108 ft of fairly uniform and clean Ordovician sandstone found at a depth of approximately 6,500 ft subsea or 7,500 ft subsurface. Through coring and analysis of logs, it was determined that the average porosity and permeability of the sand are 17.32 percent and 350 md, respectively. Fig. 1 is a portion of a typical electric log of the Oil Creek sand in the field. Table 1 shows the results of core analysis on two cores taken from the Oil Creek reservoir. The most striking of the characteristics of the sand is its uniformity as indicated by the SP portion of the log and the core analysis. There is one noticeable exception to the uniformity and that is the portion marked "barrier" on Fig. 1. This break in the sand is actually a zone of low permeability which can be correlated throughout the field and, as will be discussed later, has a marked effect on the producing characteristics of the individual wells in the field. Fig. 2 is a structure map of the North Antioch field showing the locations of the various wells and indicating the hydrocarbon trap to be an anticlinal structure with minor faulting. The field covers an area of about 600 acres and is bounded on the north, east and south by water, and on the west by a large regional fault. The numerous small faults that exist at the shallower horizons do not appear to extend into the Oil Creek zone. The only faulting of importance appears in the northern part of the reservoir where one well, the Winchester No. 2, was severely faulted. The Oil Creek sand is a blanket sand in the area in which the field is located and affords sufficient volume for a very large aquifer. The original oil-water contact in the reservoir was at 6,585 ft subsea with the result that bottom water underlies practically all of the reservoir. The entire sand is completely oil saturated in only a small area of the field in the vicinity of the Winchester No. 3.

DEVELOPMENT

Development was essentially complete by Oct., 1966, at which time 19 producing wells and six dry holes had been drilled. One additional well was drilled in April, 1969. All but two of the wells that have produced in the field were drilled by Coastal States. Wells were completed in the Oil Creek by perforating 5- to 10-ft intervals near the top of the sand. Fig. 3 is a fence diagram utilizing logs of all of the wells that have been productive in the Oil Creek reservoir. The diagram shows the position of the original oil-water contact and the current completion interval of each well. Once it was determined that the Oil Creek sand constituted a single reservoir, it became apparent that the interests of economics and conservation would both be best served by producing the reservoir as a unit. Unitization parameters were based an acre-ft, and, effective March 1, 1968, the Oil Creek reservoir was unitized. The map of Fig. 2 shows the unit outline. The original allowables in the field were set at 63 BOPD in accordance with the Oklahoma discovery allowable schedule. Prior to the expiration of the discovery allowable, the Conservation Commission granted a special allowable of 95 BOPD in order that the producing mechanism of the field could be determined at an early date. After unitization, the unit allowable was set at 2,750 BOPD. Effective June 1, 1968, the unit allowable was increased to 3,450 BOPD and effective Dec. 10, 1968, to 4,500 BOPD.

DATA COLLECTION

During the early producing life of the reservoir, data was collected and observations made for use in designing the method of operation for the field. Pressure surveys were run at 6-month intervals and samples of producing fluids were taken for analysis. The produced oil has an API gravity of 44.7° and an oil volume factor of 1.336 at original reservoir conditions of 3,329 psia and 148°F. The original solution GOR was 651 cu ft/bbl. PVT analysis indicates a bubble point at 2,239 psia. In addition to the pressures and analysis mentioned above, special core analyses were also run to give values of vertical permeability and relative permeabilities of gas, oil and water. The results of these analyses are given in Table 2.

RESERVOIR BEHAVIOR

The relatively large continuous sand interval together with the bottom water evident on electric logs gave reason to believe that a water drive would be a significant factor in the producing mechanism of the field. Subsequent pressure surveys indicated this to be the case. Material balance calculations utilizing the water-influx concepts of Hurst and van Everdingen indicated an aquifer of approximately 50 times the volume of the hydrocarbon reservoir. The primary producing mechanism calculated to be water expansion [91 percent] with the assistance of hydrocarbon expansion [9 percent]. Although these calculations were revealing as to the over-all reservoir volumes involved, they gave little insight into the behavior of individual wells or areas in the field.

It became apparent that, if oil production was to be maximized and cost minimized, it would be necessary to study in more detail the effects of natural depletion and of several possible methods of pressure maintenance at various producing rates on individual well recoveries. These studies were accomplished with a two-dimensional, three-phase, unsteady-state reservoir simulator utilized on Coastal's IBM 360-50 computer.[1] First it was necessary to provide the model with all known data and estimates of unknown data and to then vary the unknown data until the actual pressure history of the reservoir could be matched. In actual operations, a considerable amount of data had been collected so that history matching was quite a simple matter. Once the program matched the 3-year pressure history of the reservoir, the simulator could then be utilized to predict future field behavior under various operating conditions. Depletion of the reservoir was simulated utilizing the natural mechanism, and also utilizing pressure maintenance by both water and gas injection.

Due to the type of energy present in the Oil Creek reservoir, theoretically there should be little difference in ultimate oil recovery utilizing either pressure maintenance or normal depletion. However, there is an appreciable difference in present worth value. The well producing rates remain high if the reservoir pressure is maintained while the well rates drop appreciably as the pressure declines under natural conditions. As a practical matter, the low producing rates encountered with natural depletion would result in the economic limit being reached while considerable recoverable oil remained in the reservoir. Results obtained from this model study confirmed that the reservoir was, for all practical purposes, continuous and that any faulting that was present did not materially affect the transmissibility of pressures or fluids. The high rate of transmissibility prevents the buildup of large pressure gradients in the reservoir even with relatively high producing or injection rates.

Although the model employed was a two-dimensional areal model, the mathematics are so arranged that a three-dimensional effect is seen in the water saturation buildup in the vicinity of the producing wells due to movement of the bottom water in the reservoir. This particular feature, although not rigorously correct, does yield estimates of the effect of coning and was sufficiently indicative to point out the importance that water coning might have on the ultimate production from the reservoir. In other words, although the horizontal model gave indications that excellent sweep efficiencies would be experienced from the natural water drive or any supplement thereto, it was unable to predict accurately the effects of vertical water coning around the individual wells. Since the ultimate reservoir recovery must, of necessity, be the sum of the individual well's recovery, the study of individual well behavior became extremely important.

CONING HISTORY MATCH

Arthur[2] and Muskat[3] have presented theoretical treatments of water coning. Many authors[4-13] have discussed various aspects of water coning. For this study of individual well behavior, an r-z, two-phase compressible, single well simulator was utilized.[14] The pressure distribution was calculated implicitly and the saturation distribution was calculated explicitly by the alternating direction technique over the integration net to obtain a numerical integration. For the producing block and those blocks surrounding the producing block, the implicit saturation method was employed to reduce instabilities and computer time required to calculate the saturations.

As in the case of the areal simulator, the first requirement was to provide the program with sufficient data so that the prior producing history could be matched. As of Aug., 1969, two wells had substantial water producing histories. One well was the W. N. Park No. 1 in the south part of the reservoir, and the other was the R. B. Jones No. 3 located in the northeast part of the reservoir. As can be seen in the fence diagram of Fig. 3, the original water contact was 3 ft below the bottom of the perforations in the Park well while the original oil contact was approximately 16 ft below the bottom of the producing perforations in the Jones well. Each of the wells produced substantial amounts of water and were taken off production when water cuts approached 80 percent. At the time they were removed from production, accumulated oil production for the Park well was 45,156 bbl and for the Jones well was 44,463 bbl. Since the Jones well had the longer interval between the perforations and the water contact, it was decided that history matching for the coning model would be based primarily on the Jones well. Fig. 4 is a plot of percentage water-cut and oil production vs time for the R. B. Jones No. 2.

In arriving at a history match, only a small adjustment in the relative permeability to water curve, as determined in the laboratory was necessary. The relative permeability to water measured in the laboratory was adjusted upward in order to match the history of the Jones well. This adjustment may have been necessary due to inaccuracies in field measurements of the actual water-cut history. The upward adjustment of the water-relative permeability curve will, if anything, result in indicating the water coning problem to be more severe than it actually is.

Actual capillary pressure data measured in the laboratory was modified from a curvelinear relationship to a straight-line relationship. The capillary pressure data is employed by the model to obtain a transition zone between the oil and water legs. This transition zone is used only to get the initial phase distribution of the fluids in the reservoir. After the fluids start their movement, the capillary forces are negligible compared to the driving forces of viscous and gravity flow.

The actual water producing history of the Jones No. 3, as shown on Fig. 4, shows a fairly uniform increase in water production up to about 20 percent water. At this point, the water percentage increased quite rapidly up to about 75 percent water when the well was taken off production. The history match supplied by the coning model departed from the actual history at approximately the 20 percent water-cut level. This condition was primarily due to the fact that in the history match the model size used resulted in essentially a stationary oil-water contact for the reservoir; whereas, as a practical matter, the oil-water contact in the reservoir was rising at a rate of approximately 2.5 ft/year due to production from the rest of the wells in the field. Departure also could have been caused by a hysteresis effect which has been observed in actual field behavior which results in water saturations around a wellbore failing to decrease with a reduction in producing rate as the theory would indicate it should do. The coning model follows the theory, and so, as the producing rate in the Jones well decreased, the model allowed the water cone to fall back and decrease the water saturation and, as a result, the producing water-cut in the well. This departure in history matching was not believed to be of particular importance because the actual history indicated that approximately 76 percent of the well's ultimate oil recovery was obtained at a water-cut of less than 20 percent.

Since the model was a one-well closed system, it was important that it be sized so that a reasonable match of pressure history would result. The pressure match needed to be close enough so that no appreciable deviation in fluid characteristics occurred. In this case, the pressures checked within 55 psi over the producing life of the well being matched. Since the pressures were well above the bubble-point pressure, the pressure match was considered to be adequate.

PROTOTYPE MODEL

In applying the coning model to the study of individual well behavior, the existence of the low permeability sand stringer located about 36 ft below the top of the sand is of utmost importance. This interval appears in every well in the field as can be seen on the fence diagram of Fig. 3. The model was set up with the grid system shown in Fig. 5, which consists of eight intervals in a vertical direction and 10 intervals in a horizontal direction. The vertical intervals include the entire 108 ft of the sand and are so arranged that the perforated interval, which is fairly uniform in size and location for all wells in the field, is located in the second interval and the hard sand barrier is located in the fifth interval. The 10 horizontal intervals represented a distance of 1,731 ft.

Since the model was to be used to design an operating method for the field, the model was designed to conform as nearly as possible to the actual physical conditions that would exist as the reservoir is depleted. The model was arranged so that water could be injected into the bottom portion of the grid system to simulate the rise of bottom water as a result of field production and water injected for pressure maintenance. The external radius of coning model was set at 1,731 ft and water was injected at the base of Layer 8. Water injected was proportioned so that every concentric ring along the base had the same rate of rise. The rate of rise of the water table assigned to the model was 2.5 ft/year based upon the actual rise of water in the Oil Creek reservoir. To make sure the water level moved at the prescribed rate for various rates of withdrawal, the porosity was ratioed to producing rates. Varying the porosity values does not affect the results in coning or pressure calculations. The volume of water injected simulated a reduction in reservoir pressure from original down to a pressure of 2,850 psi and then pressure maintenance at 2,850 psi. The grid block that was monitored for pressure maintenance was located at r = 10 and z = 1.

The injection rate together with the physical parameters used in the model could simulate the production interval, lithology, water encroachment and reservoir pressure behavior for any well in the field. The plan called for a series of prediction runs using different producing rates for representative wells throughout the field. These predictions would include wells in which the original oil-water contact was located above and below the hard sand barrier. It was thought that, if the coning tendency was dependent on rate and if the water-cut history could be predicted, then it should be possible to develop a relationship between producing rates and production to 20 percent water-cut for various water level locations. It would then be a simple matter to schedule the production for any well and determine which rate would yield the highest present worth value.

Three case examples that best describe the effect of water coning in the Oil Creek reservoir are presented below. The first case involved placing the contact at 20 ft below the top of the sand, which is 20 ft above the base of the sand barrier; the second case at 40 ft below the top of the sand, which is at the base of the sand barrier; and the third case is the same as the second case except there is no hard sand streak. Table 3 summarized the computer runs that were made for each case.

CASE 1

For Case 1, a water contact was placed 9 ft below the bottom perforation and 16 ft above the barrier. A number of computer runs were made with production varying from 50 to 200 BOPD. Table 4 gives the results of this case and shows the accumulated producing time in days for various water-cuts to be reached at various producing rates. Fig. 6 is a graph of producing rate vs time for various producing water percentages. Utilizing these curves, a number of rates were selected and the production to 20 percent water-cut determined. These data were then utilized to determine the rate that would give the greatest present worth value. Fig. 7 is a graph of producing rate vs present worth value. It was found that the maximum present worth value was indicated at a rate of 16 1/2 BOPD. It will be noted, however, that most of the data used to arrive at this conclusion were the result of extrapolation from points actually determined. Although the determination of 16 1/2 BOPD as the optimum rate for a well with the water-oil contact located above the barrier may be open to question because of the extrapolation, it is obvious that the optimum producing rate is considerably below the lowest rate [50 BOPD] actually computed.

CASE 2

This case was modeled so that the original water-oil contact was located 29 ft below the bottom perforation which put the contact at the base of the hard sand barrier. Table 5 gives the time required to arrive at the various water-cuts for various producing rates. Fig. 8 is a graph of producing rate vs time for various producing water percentages. It will be noted that, in both Case 1 and Case 2, the time required to arrive at a 20 percent water-cut is inversely proportional to the producing rate. However, the effect of the hard sand barrier can be seen by noting the variation of cumulative production at 20 percent water-cut for the two cases. In the case with the water contact above the barrier, cumulative production to 20 percent water-cut decreases as the rate increases. However, with the water contact located below the hard sand barrier, the cumulative production increases as the rate increases. As can be seen from Table 5, the rate which will maximize the present worth value for a well with the water contact located below the sand barrier is considerably greater than the highest rate [800 BOPD] computed. Although the original plan was to make a number of computer runs with the water contact at various positions below the barrier, Case 2 gave such a high optimum producing rate that additional runs were unnecessary as they would yield even higher rates.

CASE 3

This case is similar in all respects to Case 2 except that the hard sand barrier was removed. The producing rate was set at 400 BOPD. The results indicated that water breakthrough would occur in 7.25 days and would reach 20 percent water-cut in 130 days after accumulated production of 52,000 bbl. This can be compared with Case 2 at the same 400-BOPD rate in which water breakthrough occurred in 58 days and 20 percent water-cut reached in 1,280 days after production of 512,000 bbl [Fig. 9].

Because the continuous sand barrier exists over the entire Oil Creek reservoir, the majority of the wells are almost completely immune from the effects of water coning. Since the pressure in the Oil Creek reservoir can be maintained at any desired level by the injection of the proper amounts of water, the most efficient producing rate for the reservoir then becomes a function of pressure drawdown around the individual wells.

WELL RATES

In order to maintain the maximum saturation of oil and, therefore, the maximum relative permeability to oil in the vicinity of the well, the flowing bottom-hole pressure for an individual well should not be allowed to drop below the bubble-point pressure [2,239 psia]. A multiphase vertical flow computer program was utilized to determine conditions within the producing wellbores for various producing rates and wellhead pressures.[15-16] The characteristics of various wells as determined by well tests were utilized in the computer program and flowing bottom-hole pressures corresponding to rates and wellhead pressures in individual wells in the field were determined. Table 6 was constructed from data obtained on recent well tests and utilizing the computer program where necessary. The table shows individual well productivity index [PI], bottom-hole flowing pressure at tested rate of production, and the rate of production that will result with a bottom-hole flowing pressure of 2,239 psia and a shut-in bottom-hole pressure of 2,900 psia. Note that it would be possible to produce 14,624 BOPD from the existing Oil Creek completions in the North Antioch field without lowering the flowing bottom-hole pressure of any well below the reservoir bubble point.

Based upon the results obtained from the coning and PI studies, Table 7 was prepared so that an oil rate could be assigned to each well producing from the Oil Creek reservoir at a particular unit allowable. This rate schedule would allow those wells with their oil-water contacts located above the sand barrier to produce at the optimum rate calculated from the present worth value. For those wells with the oil-water contact located below the base of the sand barrier, the rates would gradually increase with increased oil leg below the sand barrier until they reached the limit imposed by the flowing bottom-hole pressure.

CONCLUSIONS

The various simulator studies described in the report indicate that the Oil Creek reservoir in the North Antioch field can be produced at rates in excess of the current 4,500 BOPD without affecting the ultimate recovery from the reservoir. More specifically, the following conclusions have been reached.

1. The Oil Creek reservoir behaves as a single reservoir with excellent transmissibility of fluids and pressures throughout the system.

2. The Oil Creek reservoir is connected to an aquifer approximately 50 times the size of the hydrocarbon reservoir.

3. The reservoir pressure can be maintained at any point desirable by injecting a volume equal to the withdrawal. The Oil Creek reservoir pressure should be maintained at approximately 2,900 psi by the injection of water.

4. The existence of bottom water under a large portion of the reservoir would cause severe coning problems in many of the wells if it were not for a thin hard sand barrier located approximately 36 ft below the top of the sand. The sand barrier results in a distribution of pressure which, for all practical purposes, prevents water coning in wells that are perforated above the barrier and which have the water contact located below the barrier.

5. In wells with the water contact below the barrier, producing rates in excess of 1,000 bbl/well/day will not result in an appreciable increase in water coning.

6. It would be possible to produce the Oil Creek reservoir at a rate of 14,624 BOPD through existing completions without lowering the bottom-hole flowing pressure of any well below the reservoir bubble point.

7. Mathematical models used to simulate reservoir performance are proven tools to assist the petroleum engineer. Management should continue to encourage their use.

As a result of the findings of this study, the Conservation Department of the Corporation Commission of Oklahoma was petitioned on Nov. 19, 1969, to increase the existing allowable of the Oil Creek unit to 6,500 BOPD. The Commission has granted the increased allowable. Although the studies indicated that a much higher rate was possible without endangering the ultimate recovery, only a 2,000-BOPD increase was requested at that time so that the effect of the rate increase could be observed and correlated with the results of the model studies.

ACKNOWLEDGMENTS

The authors express their appreciation to the management of Coastal States Gas Producing Co. for its permission to publish this paper. The authors would also like to thank Intercomp, Austin, Tex., for technical aid during the initial phases of the coning study.

REFERENCES

1. Fagin, R. G. and Stewart, C. H.: "A New Approach to the Two-Dimensional Multiphase Reservoir Simulator", Soc. Pet. Eng. J. [June, 1966] 175-182.
2. Arthur, M. G.: "Fingering and Coning of Water and Gas in Homogeneous Oil Sands", Trans., AIME [1944] 155, 184-201.
3. Muskat, M.: Physical Principles of Oil Production, McGraw-Hill, New York [1949] 226-236.
4. Sobocinski, D. P. and Cornelius, A. J.: "A Correlation for Predicting Water Coning Time", J. Pet. Tech. [May, 1965] 594-600.
5. Howard, G. C. and Scott, P. P., Jr.: "Plugging Off Water in Fractured Formations", Trans., AIME [1954] 201, 132-133.
6. Meyer, H. I. and Searcy, D. F.: "Analog Study of Water Coning", Trans., AIME [1956] 207, 302-305.
7. Elkins, L. F.: "Fosterton Field - An Unusual Problem of Bottom Water Coning and Volumetric Water Invasion Efficiency", Trans., AIME [1959] 216, 130-137.
8. Karp, J. C., Lowe, D. K. and Marusov, N.: "Horizontal Barriers for Controlling Water Coning", J. Pet. Tech. [July, 1962] 783-790.
9. Chierici, G. L., Ciucci, G. M. and Pizzi, G.: "A Systematic Study of Gas and Water Coning by Potentiometric Models", J. Pet. Tech. [Aug., 1964] 923-929.
10. Welge, H. J. and Weber, A. G.: "Use of Two-Dimensional Methods for Calculating Well Coning Behavior", Soc. Pet. Eng. J. [Dec., 1964] 345-355.
11. Givens, J. W.: "A Practical Two-Dimen Dimensional Model for Stimulating Dry Gas Reservoirs with Bottom Water Drive", J. Pet. Tech. [Nov., 1968] 1229-1233.
12. Muskat, M. and Wyckoff, R. D.: "An Appropriate Theory of Water-Coning in Oil Production", Trans., AIME [1935] 114, 144-163.
13. Chaney, P. E., Noble, M. D., Henson, W. L. and Rice, J. D.: "How to Perforate your Well to Prevent Water and Gas Coning", Oil and Gas J. [May 7, 1956] 54, No. 53, 108.
14. Spivak, A. and Coats, K. H.: "Simulation Techniques for Two and Three Phase Coning Studies", Paper SPE 2595 presented at 44th Annual SPE Fall Meeting, Denver, [Sept. 28-Oct. 1, 1969].
15. Hagerdorn, A. R. and Brown, K. E.: "Experimental Study of Pressure Gradients Occurring During Continuous Two-Phase Flow in Small-Diameter Vertical Conduits", J. Pet. Tech. [April, 1965] 475-484.
16. Brill, J. P., Doerr, T. C. and Brown, K. E.: "Practical Use of Recent Research in Multiphase Vertical and Horizontal Flow", J. Pet. Tech. [April, 1966] 502-512.

Table 1 - Conventional core analysis.

Sample Number	Depth Feet	Horizontal Permeability Millidarcys	Vertical Permeability Millidarcys	Porosity Percent
E. P. Lippert No. 1-C				
1	7513 - 58	187.4	-	17.6
2		355.5	-	20.2
3		161.8	-	16.8
4		907.4	-	19.6
5		1044.3	-	22.3
6		573.5	-	21.9
7		530.7	-	22.9
8		573.5	-	19.1
9		813.2	-	18.7
10		246.5	-	17.6
11		678.0	-	18.2
12		573.5	-	19.1
13		487.9	-	20.3
14		274.5	-	17.2
15		339.0	-	16.3
16		318.4	-	15.9
17		226.0	-	14.3
18		445.8	-	19.4
19		117.5	-	16.3
20		428.0	-	18.5
21*		32.4	-	15.0
22*		85.7	-	14.2
23*		38.1	-	10.3
24*		15.2	-	10.8
25*		10.5	-	11.9
26*		24.8	-	13.4
27		233.7	-	15.4
28		421.1	-	15.4
29		328.7	-	19.3
30		333.8	-	17.6
31		256.8	-	23.6
32		568.9	-	22.5
33		547.8	-	22.5
34		89.9	-	16.9
35		426.3	-	21.4
36		187.4	-	11.3
37		233.7	-	14.0
38		297.9	-	15.3
39		410.9	-	17.8
40		380.0	-	20.8
41		505.0	-	18.9
42		380.0	-	20.4
43		205.4	-	17.6
44		277.3	-	17.8
45		113.0	-	20.1
State Tract 4 - 3				
1	7496 - 536	518	539	21.3
2		424	337	19.8
3		338	267	15.3
4		362	370	15.6
5		265	173	14.5
6		192	324	16.0
7		437	413	19.3
8		UNC	401	26.3
9		UNC	389	25.1
10		UNC	87	24.0
11*		56	6.9	14.1
12*		18	4.8	9.0
13*		7.4	0.7	5.8
14*		28	2.5	11.5
15*		8.2	0.9	8.7
16*		11	18	11.8
17		102	12	18.1
18		139	48	13.3
19		154	165	18.0
21		363	263	20.2
22		233	235	18.3
23		229	370	18.2
24		538	372	19.8
25		630	224	19.1
26		342	41	17.5
27		881	39	17.3
28		276	219	17.0
29		399	321	20.6
30		416	367	20.3
31		512	54	18.2
32		195	282	18.5
33		444	448	20.9
34		396	355	18.9
35		235	132	17.3
36		453	53	19.6
38		191	56	14.4
40		205	56	15.0

* Hard Sand Barrier

Table 2 - Basic input data for water coning study.

Number grids in the radius direction	12
Number grids in the Z direction	8
Water density, lbs./cu. ft	71.00
Oil density, lbs./cu.ft	46.84
Water viscosity, cps	0.600
Oil viscosity, cps	0.390
Orig. water volume factor, Res. Bbls./STB	0.9990
Orig. oil volume factor, Res. Bbls./ STB	1.336
Water compressibility, psi^{-1}	0.00000319
Oil compressibility, psi^{-1}	0.00001130
Rock compressibility, psi^{-1}	0.00000390
Initial Pressure, psia	3311
Bubble point pressure, psia	2239
Orig. solution GOR, SCF/STB	651
Wellbore radius, feet	0.3300

Saturation Table

Water Saturation, Fraction	Capillary Pressure PSI	Relative Permeability To Water	Relative Permeability To Oil
.10150	1.00000	.00000	.92997
.20000	.89037	.05000	.57200
.30000	.77908	.10200	.36000
.30475	.77379	.10400	.35000
.40000	.66778	.15300	.19900
.50000	.55648	.20400	.07730
.60000	.44519	.25500	.01720
.69525	.33918	.30300	.00000
.70400	.32918	.31000	.00000
.80000	.22259	.31000	.00000
.90000	.11130	.31000	.00000
1.00000	.00000	.31000	.00000

Block Properties

Layer Number	Layer Permeability Mds.	Vertical Permeability Mds.	Porosity Fraction	Layer Thickness Feet
1	350	300.0	.1732	5
2	350	300.0	.1732	6
3	350	300.0	.1732	9
4	350	300.0	.1732	16
5	21	2.5	.1000	4
6	350	300.0	.1732	20
7	350	300.0	.1732	30
8	350	300.0	.1732	18

Table 3 - Summary of computer runs.

Case	Initial OWC Position, Feet	Daily Oil Rate, BPD	Water Breakthrough Time (fw=.01), Days	Producing Time, Days	Water Cut at Producing Time, Fraction
1	20	50	<10	400	.21
1	20	100	< 3	500	.33
1	20	150	< 2	250	.33
1	20	200	< 2	10	.16
2	40	200	94	1759	.20
2	40	300	66	1425	.20
2	40	400	58	1276	.20
2	40	800	46	1058	.20
3	40	400	7.25	130	.20

Table 4 - Case 1.

Water Cut, Percent	Cumulative Producing Time, Days 50 BPD	100 BPD	150 BPD	200 BPD
1	<10	<3	<2	<2
5	18.5	5.2	2.8	1.9
10	49	12	6.0	3.8
15	145	30	13.7	8.5
20	330	58	25.5	15.5 est.
Cum. Prod. to 20% water cut	16,500	5,800	3,825	3,100

Table 5 - Case 2.

Water Cut, Percent	Cumulative Producing Time, Days 200 BPD	300 BPD	400 BPD	800 BPD
1	94	66	58	46
5	295	239	211	176
10	660	520	460	390
15	1,150	890	780	660
20	1,760	1,430	1,280	1,060
Cum Prod. to 20% water cut	352,000	429,000	512,000	848,000

Table 6 - Well tests and PI.

Well	Distance from Orig. OWC: To Base of Barrier*, Ft.	To Base of Perf., Ft.	Recent Well Tests: Oil Rate BPD	FTP psia	FBHP psia	Productivity Index BFPD/psi	Oil Rate @ FBHP of 2239 psia ** BPD
R. G. Anderson No. 1	+ 5	24	128	575	2,000	0.124	82
Comm. Min. Inc. No. 1	- 5	25	242	835	2,690	0.768	507
M. B. Harris No. 1-C	-27	51	288	550	2,180	0.356	235
G. B. Holt No. 1	-26	48	318	805	2,680	1.013	669
G. B. Holt No. 2	-33	60	320	675	2,455	0.596	393
G. B. Holt No. 3	- 7	34	184	525	2,020	0.207	136
G. B. Holt No. 4-C	-50	77	285	295	1,690	0.219	145
F. P. Hope No. 1-T	-26	48	444	865	2,840	3.731	2,100
R. B. Jones No. 3	+14	17	-	-	-	-	-
E. P. Lippert No. 1-C	-56	86	576	815	2,820	3.388	2,100
McKeown No. 1	+19	13	208	275	1,545	0.169	112
J. McPherson No. 1-C	-48	76	520	715	2,620	1.405	927
W. S. Merrick No. 1-T	-22	56	408	725	2,610	1.074	709
W. N. Park No. 1	+32	3	-	-	-	-	-
J. C. Pritchard No. 1	-22	46	360	775	2,670	1.286	849
Pritchard Oil Unit 1-T	- 1	26	361	815	2,740	1.444	953
NAOCU Tract 4-3	-51	81	553	805	2,780	2.633	1,738
H. B. Williams No. 1	-19	45	370	765	2,665	1.152	760
J. R. Winchester No. 1-T	- 8	36	228	875	2,740	0.970	640
J. R. Winchester No. 3-C	-82	105	618	735	2,730	2.377	1,569
Total			6,411				14,624

* + Above, - Below
** SIBHP = 2900 psia

Table 7 - Well rates.

Well	Daily Oil Rate, BOPD: Unit Allowable 4500 BOPD	Unit Allowable 6500 BOPD	Unit Allowable 8500 BOPD	Unit Allowable 10,500 BOPD
R. G. Anderson No. 1	38	38	38	38
Comm. Min. Inc. No. 1	42	42	42	42
M. B. Harris No. 1-C	235*	235*	235*	235*
G. B. Holt No. 1	239	372	516	669*
G. B. Holt No. 2	331	390*	390*	390*
G. B. Holt No. 3	80	80	80	80
G. B. Holt No. 4-C	140*	140*	140*	140*
F. P. Hope No. 1-T	239	372	516	742
R. B. Jones No. 3	-	-	-	-
E. P. Lippert No. 1-C	589	914	1,268	1,822
McKeown No. 1	-	-	-	-
J. McPherson No. 1-C	478	744	927*	927*
W. S. Merrick No. 1-T	301	469	651	709*
W. N. Park No. 1	-	-	-	-
J. C. Pritchard No. 1	223	347	481	691
Pritchard Oil Unit 1-T	46	46	46	46
NAOCU Tract 4-3	533	829	1,150	1,652
H. B. Williams No. 1	213	331	459	660
J. R. Winchester No. 1-T	88	88	88	88
J. R. Winchester No. 3-C	685	1,063	1,473	1,569*
Total	4,500	6,500	8,500	10,500

* Maximum Rate by P.I.

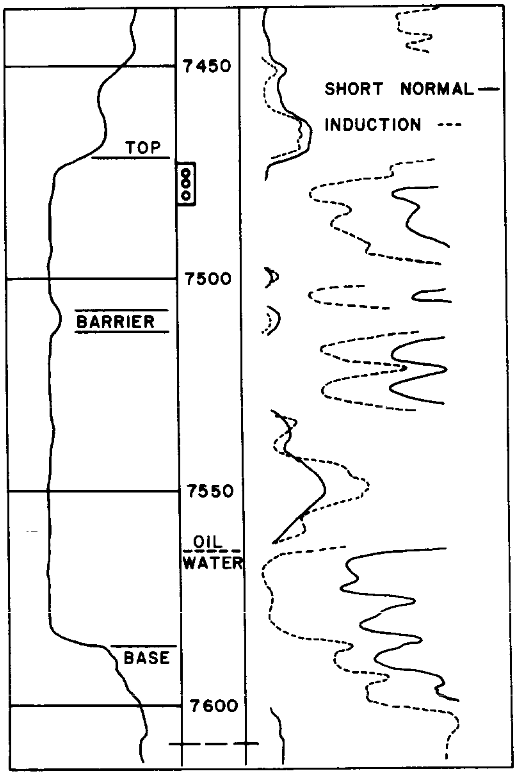

Fig. 1 - Type log of the Oil Creek reservoir.

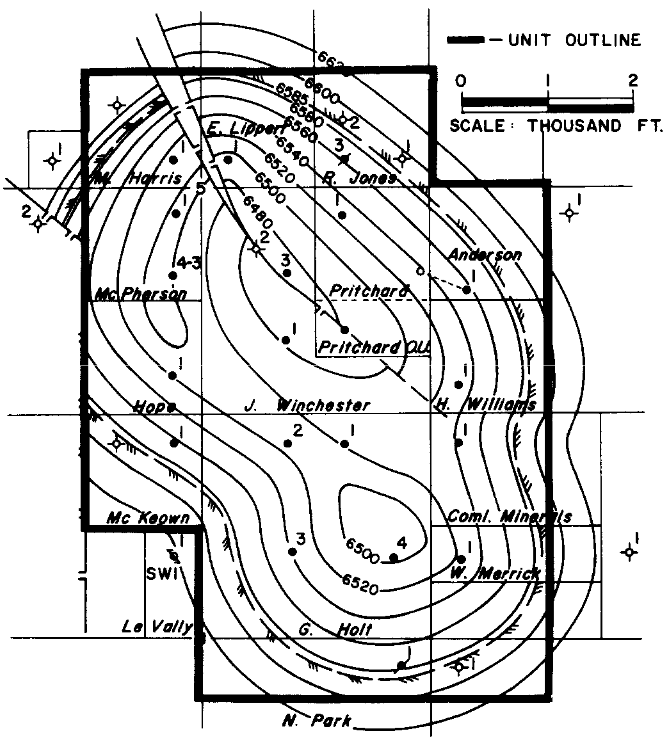

Fig. 2 - Structure map of the top of Oil Creek reservoir, North Antioch Field, Garvin County, Okla.

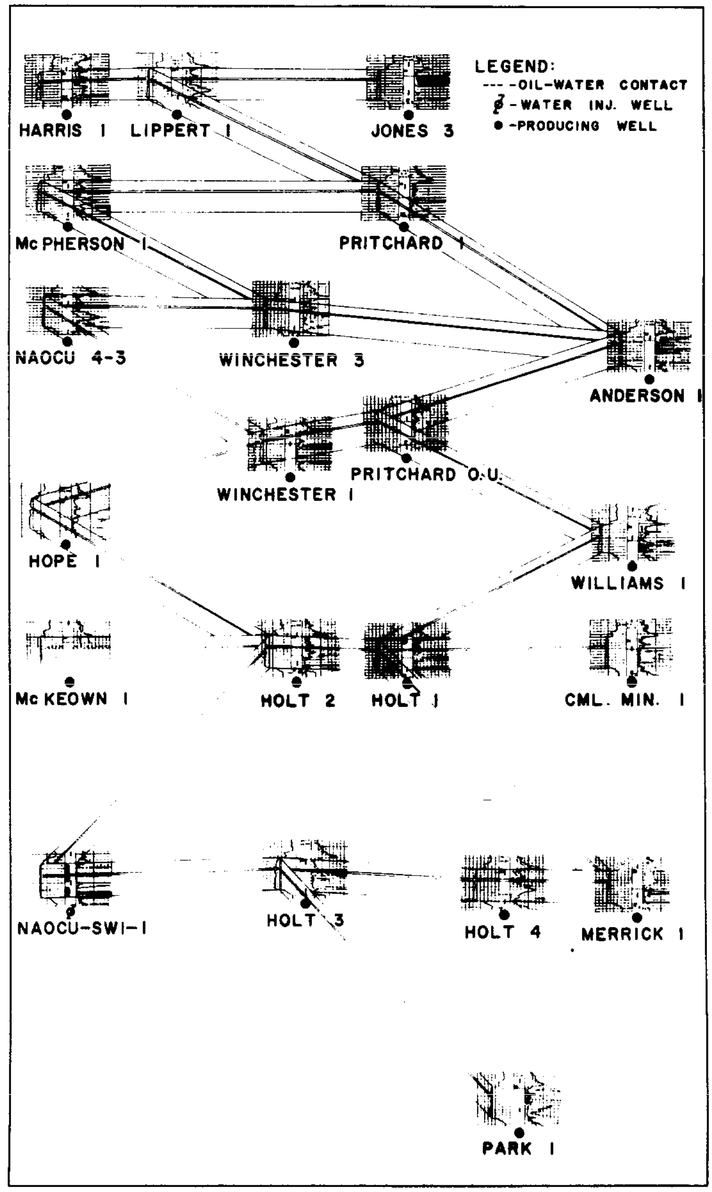

Fig. 3 - Fence diagram.

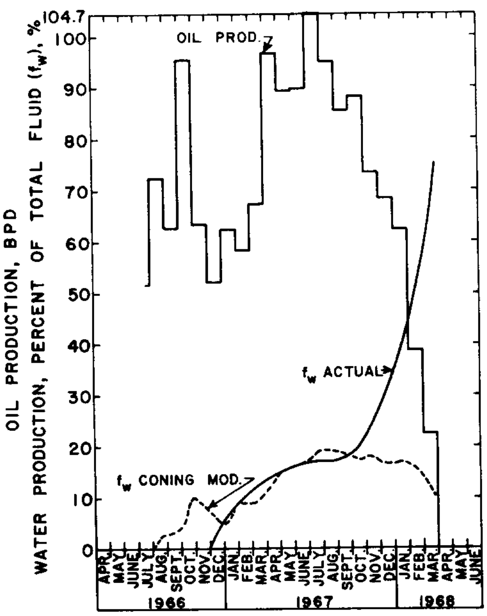

Fig. 4 - History match for the R. B. Jones No. 3.

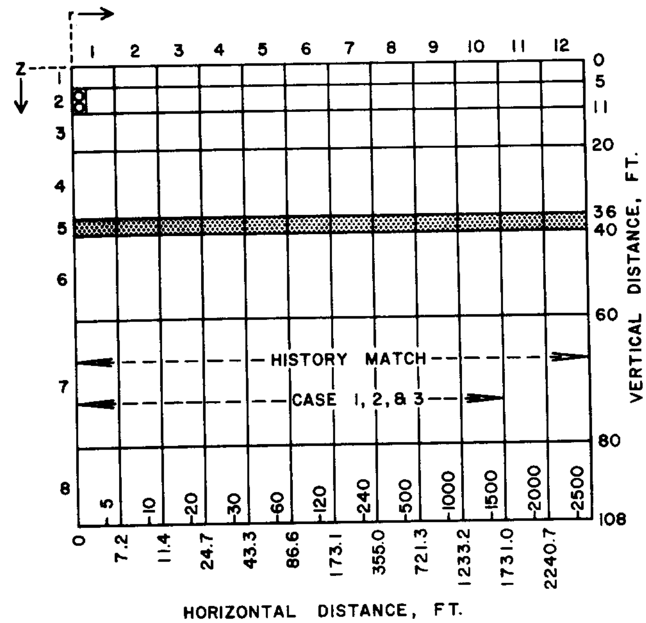

Fig. 5 - Grid system for the r-z, two-phase compressible coning model.

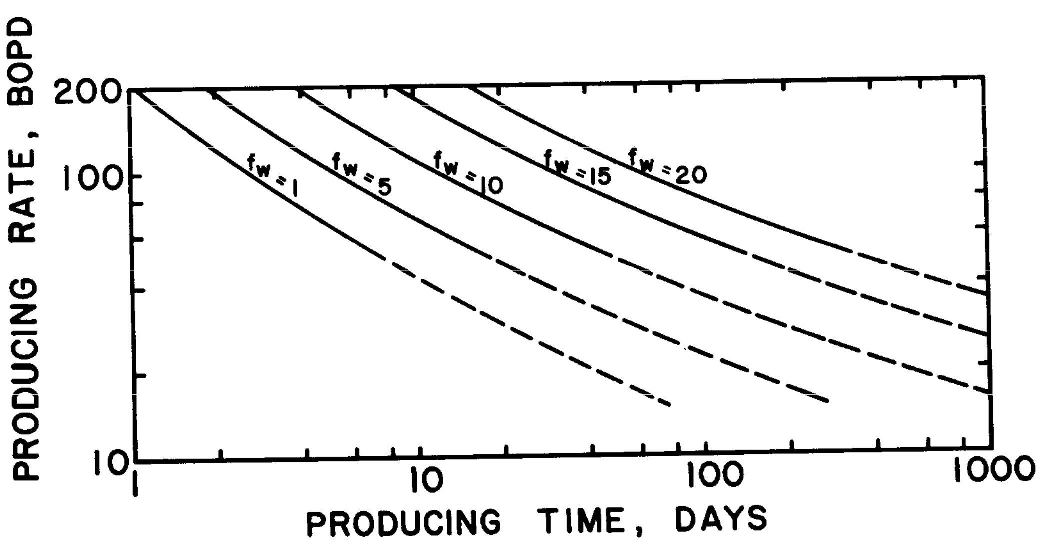

Fig. 6 - Producing rate vs time for Case 1 where the original contact is above the sand barrier.

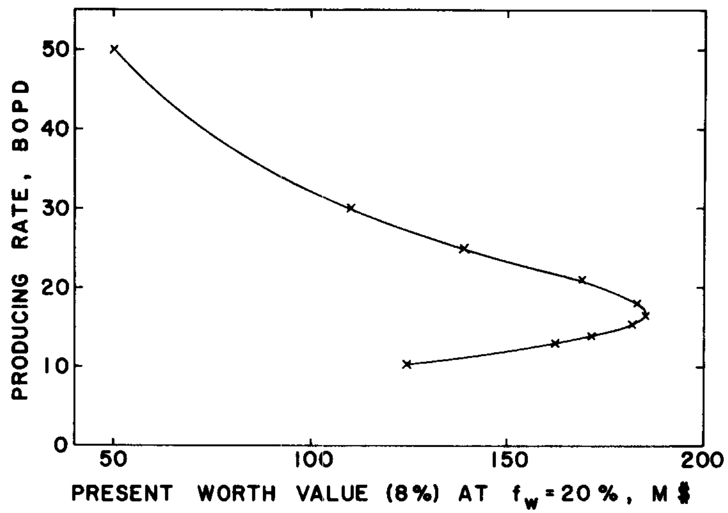

Fig. 7 - Producing rate vs PW value for Case 1.

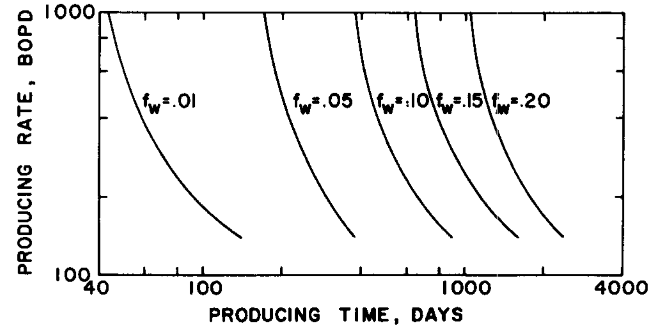

Fig. 8 - Producing rate vs time for Case 2 where the original contact is below the sand barrier.

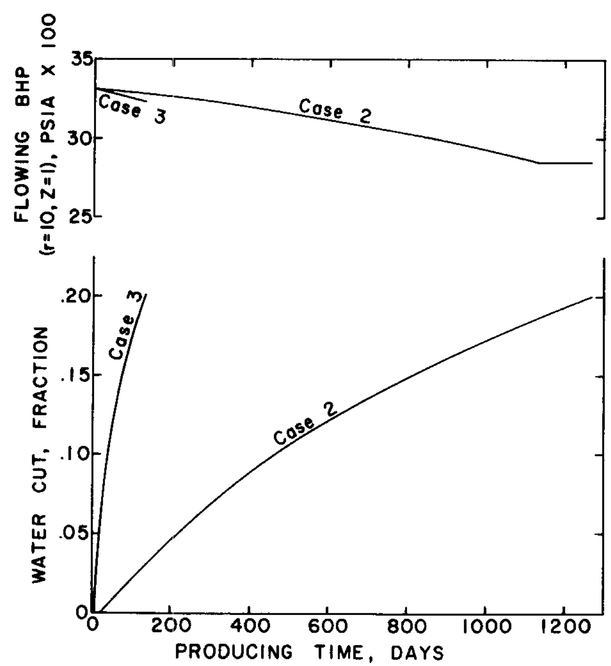

Fig. 9 - Comparison of Case 2 (with barrier) with Case 3 (with no barrier) at 400 BOPD.