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Volatile Oil. Determination of Reservoir Fluid Composition From a Non-Representative Fluid Sample

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Abstract

Volatile Oil reservoir are sometimes evaluated as gas and condensate systems when pressure in the well neighborhood reaches values fairly below saturation pressure. This pressure drop is common in almost all reservoirs at late depletion stages or from the beginning in tight formations. When this situation occurs, it does not matter how carefully the sample is taken, it always leads to non-representative PVT analysis. Based on a real case study on a tight formation, sampled at the beginning of production history, a dynamic data integration between petrophysical and thermodynamic information was conducted in order to understand overall reservoir behavior. As part of this integration, a compositional material balance was developed in order to describe the reservoir performance against pressure. A sensitivity case to relative permeability curves was run with the material balance. The fairly good matching of the material balance model with the production test allowed us to determine the most probable reservoir fluid composition. It was also noted that the relationship between *GOR* and separator fluid composition had negligible dependence on relative permeabilities.

Introduction

The evaluation of PVT properties of reservoir fluid becomes a fundamental step during the initial reservoir characterization stage. Initial forecasts are made based on usually few and often uncertain data, by means of simple calculation tools like material balance and correlations. Because of its influence in the calculations, and mainly on the economics of a project, the type of fluid and its behavior constitutes one of the most important overall information.

The determination of reservoir fluid type (Black Oil, Volatile Oil, Gas, etc) seems to be a simple task after initial production data are collected (Stock Tank Oil Gravity, *GOR*, etc.). General “thumb” rules have been developed to accomplish this job¹⁻², but they require to have representative samples. In this way, the same causes that affect sample representativity, can affect correct reservoir fluid type identification.

Among the most common causes of non-representative sampling, the following can be mentioned:

1. Low permeability or formation damage that generates significant pressure drop during production tests.
2. Non-stabilized production tests. This situation is common in “off shore” wells where test duration should be minimized due to the high costs involved.
3. Commingled production from more than one formation with different fluids.

The present paper is based on a real case study where it was difficult to establish the type of fluid, based on the available information. Moreover lab tests, conducted on the samples, indicated their lack of representativity. Using the general characteristics of the real case, an illustrating example is presented herein.

Available Information

The following information, which was used as basic data in our example, contains the general characteristics of the real case:

- **Reservoir.** A tight formation field with just one well completed in one productive layer. The initial pressure, which corresponds with the hydrostatic one, is around 6.000 psia and the average formation temperature, extrapolated from the value recorded during logging, is about 248 °F.
- **Production Test.** A less than 24 hours draw-down test was conducted on the well. Although results did not show signs of stabilization during the last test hour, the test was stopped because the results obtained during it, discouraged further investigation at the test costs. Flowing pressure was around 2.500 psia, generating gas and oil to flow in the well neighborhood.
- **Sampling.** In a separator at last test hour conditions. The compositions of gas and liquid from the separator sample

and the separator conditions are presented in Table 1.

- **PVT Analysis.** The gas and oil recombination performed at lab with the last test hour separator *GOR* (11.229 scf/bbl) allowed us to conclude the lack of representativity of the sample due to the coexistence of important volumes of gas and liquid at reservoir pressure and temperature.
- **Further Lab Work.** Further recombinations of gas and liquid sampled during the last hour of the test were conducted in order to obtain a fluid which has the same saturation pressure as the static one. In this way a couple of fluid were obtained:
 - A Volatile Oil Fluid with *GOR* around 3.930 scf/bbl.
 - A Condensate Fluid with *GOR* around 28.072 scf/bbl.

As during the test, *GOR*s between 6.737 scf/bbl and 16.843 scf/bbl where observed, these recombinations seemed to be out of the logical range suggested by the well test. On this point, it should be noted that as no pseudo-steady state could be reached, and there are important volumes of flowing gas and liquid in the neighborhood of the well perforations, the production of gas and oil is strongly influenced by the relative permeability curves of the system.

With all of this incompatible and apparently useless information, the reservoir engineer is confronted with the need to solve the following dilemmas:

1. Decide what type of fluid is present in the reservoir knowing that :
 - 1.1. The production *GOR* indicates a gas and condensate field.
 - 1.2. The physical aspect of the surface sample (colour, viscosity, etc.) suggests a Volatile Oil system.
 - 1.3. The well test and logs run do not allow to discriminate if there was, originally, two possible flowing phases in the system (sample contamination) or not.
2. Recommend future actions based on fluid type selection.
3. Generate representative and adequate thermodynamic information for reservoir engineering tools such as Numerical Simulation, Material Balance and Volumetric Analysis.

In this paper a practical working methodology is presented in order to reasonably reconstruct the reservoir fluid characteristics for a correct reservoir modeling.

Working Methodology

The proposed methodology includes a qualitative stage followed by a quantitative stage. The fundamental decisions are made in the first stage.

Qualitative Stage. In this part all the basic assumptions are set and general guidelines for the study are proposed. For the analyzed case, the following assumptions were made:

- The original fluid, in the perforated interval, is present in only one phase. As there would be infinite solutions (saturation values and relative permeabilities) for the case where two mobile phases were present in the perforated

interval, this situation was excluded. All the remaining available information was used as basic evidence to support this idea.

- All the values recorded and reported during the field and lab tests were assumed to be valid. The authors consider a popular bad practice to neglect some part of the information on the solely basis that it presents an apparent inconsistency with the rest of the data. Prior to its rejection, the origin of this inconsistency should be carefully analyzed.

Once all the assumptions were made, the type of fluid present in the reservoir was analyzed.

- Assuming a gas and condensate system is present in the reservoir, on the surface sampling, a higher *GOR* value that the one measured should have been recorded. This should occur because gas has a greater mobility than liquid and, once liberated, it moves easier to the wellbore than the oil in the reservoir giving, as a result, a higher production *GOR*. As a result, the liquid accumulation in the wellbore neighborhood should give a production *GOR* above 28.072 scf/bbl, value measured in the lab tests.
- A Volatile Oil system should be compatible with the information measured during the production test.
- The case where two mobile phases originally exists at the perforations has been previously discarded because there is no available information that points towards this situation. On the other hand, if this condition is presented in real life, the problem turns out into an inverse problem. In addition, the inverse problem encountered during dynamic data integration are ill-posed by essence, that is the solutions of such problems can have existence, uniqueness or stability difficulties.³

Quantitative Stage. Once accepted the presence of a Volatile Oil fluid as the most probable situation, it is necessary to determine its composition and thermodynamic behavior.

It is important to clarify that the lab recombination at a *GOR* of 3.930 scf/bbl is not representative of the reservoir fluid because the formulation of the problem indicates that if the test *GOR* was higher than its Volatile Oil lab *GOR* it indicates that there should have been an independent supply of free gas coming from the wellbore neighborhood. This free gas has a different composition from the total gas liberated from the original oil, so the gas at the separator has an altered composition.

In order to obtain a representative composition and its thermodynamic behavior, the following task were performed:

1. A thermodynamic model was adjusted in order to adequately describe the lab test corresponding to the Volatile Oil system. The adjusted thermodynamic parameters were the ones used in the subsequent compositional simulation stages.
2. Separator gas and liquid was numerically recombined based on the production test *GOR*.
3. Due to the presence of a gas cap in nearby areas, an originally saturated fluid was assumed. So, using the

adjusted parameters from the first step, thermodynamic equilibrium, at a saturation pressure equal to the static pressure, was obtained.

4. Once equilibrium was reached, the remaining free gas was liberated
5. The liquid phase left was used to simulate the Volatile Oil behavior at reservoir conditions.

Simulation was performed by using the liquid phase left as entry stream of a compositional material balance (CMB), trying to obtain, as the simulation output, a similar production (*GOR* and composition) as the one recorded during well test.

The CMB used in this study is based on reference 4 and calculates the produced stream through the following scheme:

- The volume of each phase is determined through thermodynamic equilibrium at each stage of depletion.
- Gas and oil production is calculated using relative mobility of each phase, based on relative permeability curve, phase viscosity and average saturation.

Result Analysis

Applying the previous mentioned steps 1 through 4, on the available information, the reservoir fluid composition presented at Table 2 was obtained. The thermodynamic simulation of this fluid indicates that the representative flash *GOR* of the original fluid at test separator conditions should be 2526 scf/bbl. This value is clearly different from the *GOR* measured at test conditions.

To obtain gas and liquid production from the material balance at different average reservoir pressures, a relative permeability curve was needed as input. The employed curve was considered as “base” curve and is presented in Table 3 and Figure 1.

As part of the scope of the study, sensitivity to the quality and quantity of produced fluids was also tested. This analysis was achieved by changing the shape and extreme points of the relative permeability curve. In this way, an “alternative” relative permeability curve, which results significantly different from the “base” curve, was utilized.. The “alternative” curve is presented as Table 4 and Figure 2.

A notable alteration on the relative permeability curve, **for a given *GOR***, produces important changes in the average reservoir pressure at sampling time, but only generates a small variation in the composition of the production streams. This behavior is presented in Tables 5, 6 and in Figure 3.

The small difference in compositions among the production streams presented in Table 6 indicates some kind of independence between composition and porous media. On the other hand, if production composition, given a *GOR* value, was dependent of the relative permeability curves, the system should have multiple solutions. For this “dependent” situation, the representative pseudo relative permeability of the system is needed to know in order to univocally establish the original fluid composition. Also in this particular case, it is very important to have reliable measured test in order to conduct a posterior history matching using a CMB or numerical simulation.

The results of the study allowed us to conclude with a high degree of confidence that the reservoir fluid composition found with this methodology is adequate.

Conclusions

1. A valid working methodology to dynamically integrate the reservoir model with the available information of non-representative Volatile Oil samples is presented.
2. Producing *GOR* in a Volatile Oil system could be misleading, especially at flowing pressures below saturation pressure. The representative *GOR* of the system, as is the case of the example presented herein, can be very different from the sampling value registered.
3. Lab test over non-representative samples can be re-evaluated, once the cause of non-representativity has been established. The results obtained on the case presented are of extreme importance for the reservoir characterization of a Volatile Oil reservoir.
4. For the present work, once the production *GOR* is fixed and using a CMB, a small dependence between the effluent composition and the relative permeability curve was observed. This point is of extreme importance to sustain the conclusions herein presented. The small influence of the relative permeability curves over the effluent composition for a given *GOR*, allow to postpone a detailed evaluation of the porous media.

Nomenclature

GOR = Gas Oil Ratio, L³/L³, scf/bbl

References

1. Moses, P.L.: “Engineering Applications of Phase Behavior of Crude Oil and Condensate System,” *JPT* (July 1986) 715.
2. Mc Cain Jr., W.D.: “Reservoir-Fluid Property Correlations – State of the Art,” *SPE* (May 1991) 266.
3. Hadamard, J.: *Lecons sur la Propagation des Ondes et les Equations de l’Hydrodynamique*, Chelsea Publication Co., New York (1949)
4. Reudelhuber, F.O. and Hinds, R. F.: “A Compositional Material Balance Method for Prediction of Recovery from Volatile Oil Depletion Drive Reservoirs,” *Trans. AIME* (1957), **210**, 19.

SI Metric Conversion Factors

$$\begin{aligned} &^{\circ}\text{F} \text{ } (^{\circ}\text{F}-32)/1.8 &= &^{\circ}\text{C} \\ \text{scf/bbl} \times 1.781 \text{ } 130 & & \text{E } -01 &= \text{m}^3/\text{m}^3 \\ \text{psi} \times 6.894 \text{ } 575 & & \text{E}+00 &= \text{kPa} \end{aligned}$$

TABLE 1 – SEPARATOR SAMPLING CONDITIONS AND STREAM COMPOSITIONS

Separator Pressure, psia	79.7
Separator Temperature, °F	55.4
Separator <i>GOR</i> , scf/bbl	11,229

Separator Gas Sample

COMPONENT	MOLE PER CENT	COMPONENT	MOLE PER CENT
N ₂	1.316	C ₁₀	0.004
CO ₂	0.692	C ₁₁	
C ₁	83.637	C ₁₂	
C ₂	8.160	C ₁₃	
C ₃	3.252	C ₁₄	
i-C ₄	0.830	C ₁₅	
n-C ₄	1.129	C ₁₆	
i-C ₅	0.321	C ₁₇	
n-C ₅	0.265	C ₁₈	
C ₆	0.202	C ₁₉	
C ₇	0.124	C ₂₀₊	
C ₈	0.054	TOTAL	100.000
C ₉	0.014		

Separator Liquid Sample

COMPONENT	MOLE PER CENT	COMPONENT	MOLE PER CENT
N ₂	0.049	C ₁₀	5.445
CO ₂	0.080	C ₁₁	6.946
C ₁	3.265	C ₁₂	5.283
C ₂	2.090	C ₁₃	5.059
C ₃	3.267	C ₁₄	4.317
i-C ₄	2.103	C ₁₅	2.441
n-C ₄	4.006	C ₁₆	2.221
i-C ₅	2.731	C ₁₇	1.498
n-C ₅	2.950	C ₁₈	1.114
C ₆	6.435	C ₁₉	0.933
C ₇	10.620	C ₂₀₊	8.180
C ₈	11.551	TOTAL	100.000
C ₉	7.416		

TABLE 2 – RESERVOIR FLUID CONDITIONS AND MOST PROBABLE COMPOSITION

Reservoir Pressure, psia	6,000.0
Reservoir Temperature, °F	248.0

COMPONENT	MOLE PER CENT	COMPONENT	MOLE PER CENT
N ₂	0.739	C ₁₀	1.110
CO ₂	0.623	C ₁₁	1.534
C ₁	65.105	C ₁₂	1.264
C ₂	8.134	C ₁₃	1.296
C ₃	3.892	C ₁₄	1.171
i-C ₄	1.163	C ₁₅	0.695
n-C ₄	1.718	C ₁₆	0.658
i-C ₅	0.650	C ₁₇	0.459
n-C ₅	0.683	C ₁₈	0.351
C ₆	0.930	C ₁₉	0.300
C ₇	1.451	C ₂₀₊	2.678
C ₈	2.010	TOTAL	100.000
C ₉	1.386		

TABLE 3 – “BASE” RELATIVE PERMEABILITY CURVE

S_w+S_g [%]	K_{rg}	K_{ro}
39.70	0.000	1.000
41.92	0.000	0.799
44.41	0.000	0.597
46.35	0.021	0.396
48.56	0.028	0.215
50.78	0.035	0.156
52.99	0.043	0.113
55.21	0.053	0.083
57.42	0.062	0.056
59.64	0.073	0.039
61.85	0.085	0.026
64.07	0.098	0.017
66.28	0.112	0.011
68.50	0.127	0.007
70.71	0.143	0.004
72.93	0.157	0.002
75.14	0.172	0.002
77.36	0.188	0.001
79.57	0.205	0.001
81.79	0.221	0.001
84.00	0.237	0.000

TABLE 4 – “ALTERNATIVE” RELATIVE PERMEABILITY CURVE

S_w+S_g [%]	K_{rg}	K_{ro}
35.00	0.000	0.984
36.50	0.000	0.935
38.00	0.000	0.885
39.50	0.000	0.836
41.00	0.009	0.787
42.50	0.024	0.738
44.00	0.039	0.689
45.50	0.055	0.639
47.00	0.072	0.590
48.50	0.090	0.541
50.00	0.108	0.492
51.50	0.127	0.443
53.00	0.147	0.393
54.50	0.167	0.344
56.00	0.188	0.295
57.50	0.210	0.246
59.00	0.233	0.197
60.50	0.256	0.148
62.00	0.286	0.098
63.50	0.325	0.049
65.00	0.361	0.000

TABLE 5 – VARIATION OF SEPARATOR GOR AGAINST AVERAGE RESERVOIR PRESSURE FOR DIFFERENT RELATIVE PERMEABILITY CURVES.

“Base” Kr		“Alternative” Kr	
Avg. Res. Pressure [psia]	Separator GOR [scf/bbl]	Avg. Res. Pressure [psia]	Separator GOR [scf/bbl]
6,000	2,526	6,000	2,526
5,853	2,323	5,790	2,308
5,707	2,617	5,580	2,698
5,560	3,771	5,370	3,882
5,414	5,284	5,160	5,305
5,267	6,967	4,950	6,980
5,122	8,977	4,740	8,931
4,976	11,229	4,530	11,229

TABLE 6 – VARIATION OF STREAMS COMPOSITIONS FOR DIFFERENT RELATIVE PERMEABILITY CURVES @ GOR = 11,229 scf/bbl.

Separator Gas Sample

COMPONENT	SAMPLED [%]	BASE KR [%]	ALTERNATIVE KR [%]
N ₂	1.316	1.221	1.187
CO ₂	0.692	0.707	0.714
C ₁	83.637	83.706	83.756
C ₂	8.160	8.237	8.269
C ₃	3.252	3.293	3.283
i-C ₄	0.830	0.840	0.830
n-C ₄	1.129	1.138	1.120
i-C ₅	0.321	0.319	0.312
n-C ₅	0.265	0.272	0.268
C ₆	0.202	0.156	0.152
C ₇	0.124	0.079	0.077
C ₈	0.054	0.025	0.025
C ₉	0.014	0.005	0.005
C ₁₀	0.004	0.001	0.001
C ₁₁	-	0.001	0.001
C ₁₂	-	-	-
C ₁₃	-	-	-
C ₁₄	-	-	-
C ₁₅	-	-	-
C ₁₆	-	-	-
C ₁₇	-	-	-
C ₁₈	-	-	-
C ₁₉	-	-	-
C ₂₀₊	-	-	-
TOTAL	100.000	100.000	100.000

TABLE 6 Cont. – VARIATION OF STREAMS COMPOSITIONS FOR DIFFERENT RELATIVE PERMEABILITY CURVES @ GOR = 11,229 scf/bbl.

Separator Liquid Sample

COMPONENT	SAMPLED [%]	BASE KR [%]	ALTERNATIVE KR [%]
N ₂	0.049	0.011	0.011
CO ₂	0.080	0.071	0.072
C ₁	3.265	2.862	2.864
C ₂	2.090	1.663	1.669
C ₃	3.267	2.120	2.113
i-C ₄	2.103	1.531	1.513
n-C ₄	4.006	3.081	3.032
i-C ₅	2.731	2.324	2.270
n-C ₅	2.950	2.652	2.618
C ₆	6.435	6.545	6.376
C ₇	10.620	10.418	10.101
C ₈	11.551	11.868	11.737
C ₉	7.416	7.503	7.425
C ₁₀	5.445	5.510	5.471
C ₁₁	6.946	7.072	7.061
C ₁₂	5.283	5.491	5.519
C ₁₃	5.059	5.375	5.440
C ₁₄	4.317	4.691	4.779
C ₁₅	2.441	2.710	2.777
C ₁₆	2.221	2.516	2.591
C ₁₇	1.498	1.728	1.787
C ₁₈	1.114	1.307	1.356
C ₁₉	0.933	1.109	1.154
C ₂₀₊	8.180	9.842	10.264
TOTAL	100.000	100.000	100.000

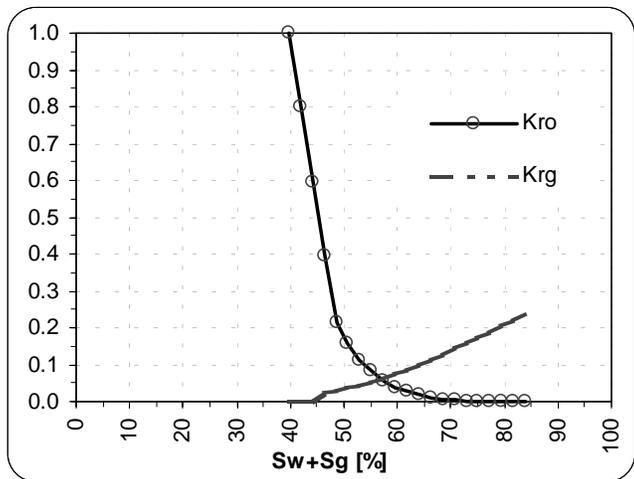


Figure 1 - "Base" Relative Permeability Curve.

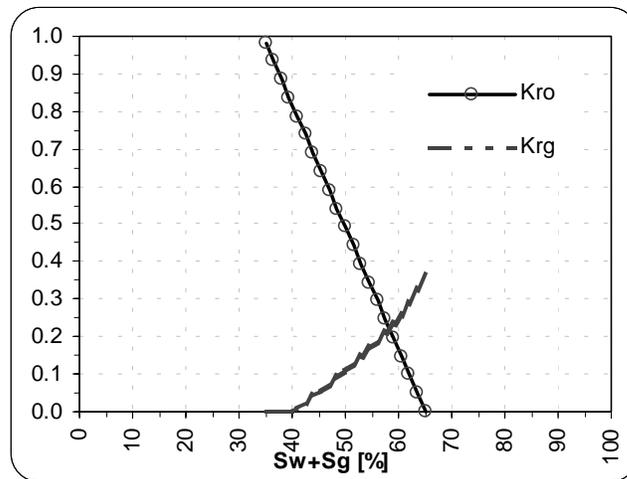


Figure 2 - Alternative Relative Permeability Curve.

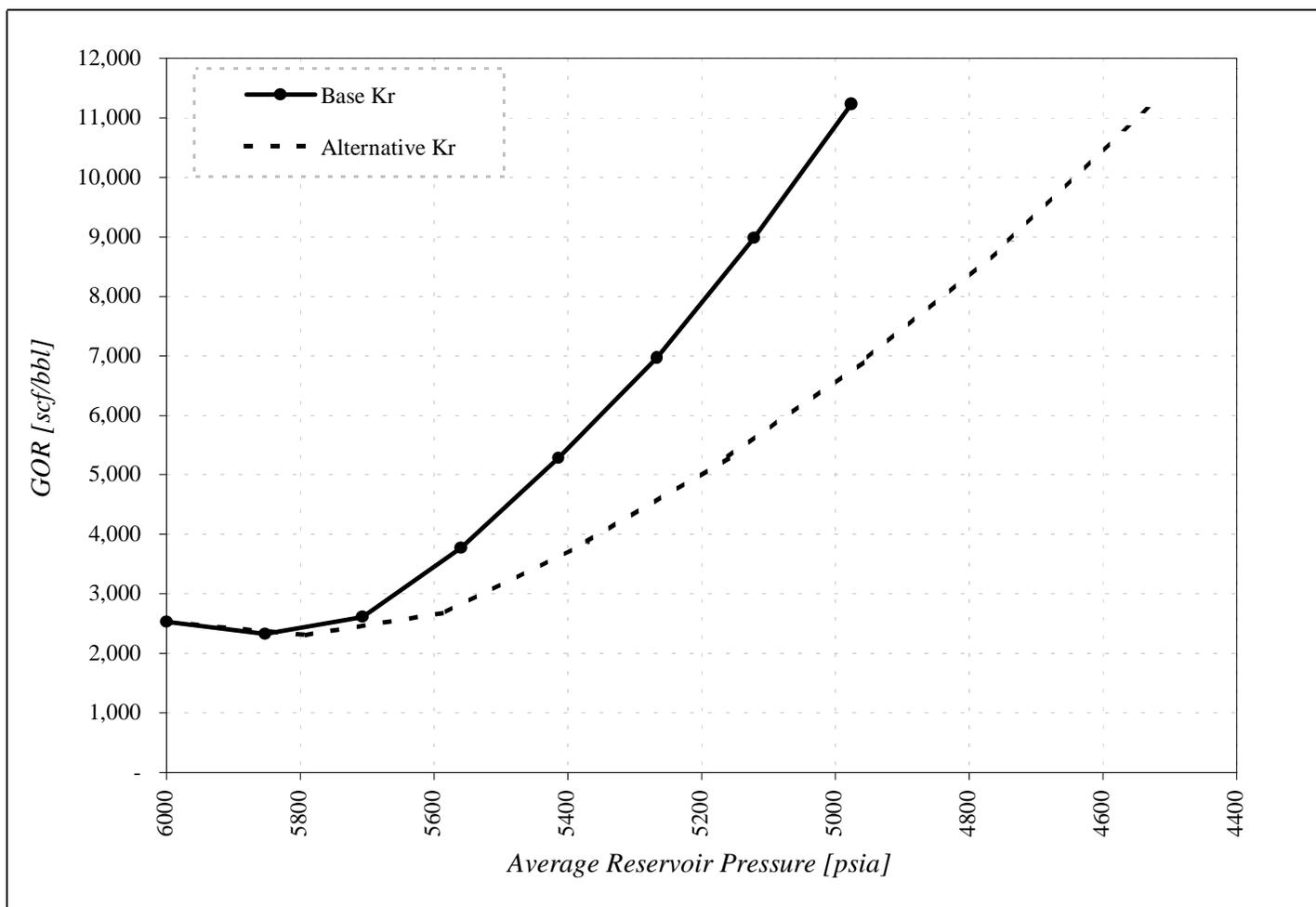


Figure 3 - GOR vs. Average Reservoir Pressure for the different permeability curves analyzed.