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Reservoir Simulation Models – Impact on Production Forecasts and Performance of Shale Volatile Oil Reservoirs

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Abstract- Reservoir simulation is an important tool that can be used to simulate as well as predict production from shale reservoirs. The type of reservoir simulation model used, is significant in this process. Black-oil and compositional simulators can be used for reservoir simulation. Black-oil simulations are easier and less time-consuming than compositional simulations. However, how accurate are black-oil simulation results compared to compositional simulation results? Can we afford to jeopardize the accuracy of production forecasts by using easier and less time-consuming reservoir simulation methods? Can the results be trusted to some extent? Single-phase and two-phase black-oil simulation results as well as compositional simulation results were analyzed and compared in this article.

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Reservoir Simulation Models – Impact on Production Forecasts and Performance of Shale Volatile Oil Reservoirs

Ibukun Makinde [α] & W. John Lee [σ]

Abstract- Reservoir simulation is an important tool that can be used to simulate as well as predict production from shale reservoirs. The type of reservoir simulation model used, is significant in this process. Black-oil and compositional simulators can be used for reservoir simulation. Black-oil simulations are easier and less time-consuming than compositional simulations. However, how accurate are black-oil simulation results compared to compositional simulation results? Can we afford to jeopardize the accuracy of production forecasts by using easier and less time-consuming reservoir simulation methods? Can the results be trusted to some extent? Single-phase and two-phase black-oil simulation results as well as compositional simulation results were analyzed and compared in this article.

Results show that the two-phase black-oil simulations are different and more accurate than single-phase black-oil simulations. As we have no field data to support our assumption, our opinion is based solely on the impact of the gas phase (for two-phase flow) on production performance. Sensitivity studies were carried out with the aid of isothermal single-phase and two-phase black-oil simulations to determine how certain parameters affect production performance of shale volatile oil reservoirs. Also, the effects of fluid compositions on cumulative oil production and oil rates were analyzed using compositional and two-phase black-oil simulations. Results from compositional simulations were different and presumably more accurate than two-phase black-oil simulations. This hypothesis is based on the fact that compositional simulation includes more of the physics that we assume are important in modeling reservoir fluids. Therefore, for thorough analysis of fluid composition effects and improved production forecasts (especially for reservoir fluids like volatile oils in shale formations), compositional simulations are necessary in most cases.

Keywords: reservoir simulation, black-oil, compositional, production forecasting, volatile oil, unconventional resources – shale reservoirs.

I. Introduction

Shale reservoirs, such as the Eagle Ford and Bakken, have emerged as extremely viable sources of hydrocarbon reserves. They do not produce economic volumes of oil and gas without some form of stimulation. There has been a steady increase in productivity of oil and gas from shale plays across the US, due to the emergence of multi-stage hydraulic fracturing and horizontal well drilling technologies. Despite this positive production trend, shale plays have been plagued by relatively low recovery factors in comparison to conventional plays.

This article discusses performance analyses of shale volatile oil reservoirs using different simulation models with the aim of improving production forecasts and overall reservoir management. Why the focus on volatile oils? It is because volatile oils have complex fluid properties that are yet to be fully understood, and the behavior becomes even more complex in shales with nanoscale pores. A better understanding of the fluid properties of volatile oils as well as an appropriate use of reservoir simulation models can help eliminate many errors in reservoir engineering calculations and forecasting. Apart from examining the influence of reservoir simulation models on production performance, Makinde and Lee (2016) also investigated the effect of fluid sampling errors on production forecasts.

As a result of the ever-rising global demand for energy, the importance of shale oil and gas research cannot be overemphasized. A better understanding of volatile oil fluid properties will be a major hurdle crossed in the race to further improve recovery in shale reservoirs. This, without doubt, will positively impact the oil and gas industry. Research and studies like this can lead to improved reservoir management and economics as well as provide insight into potential alternative methods to enhance recovery from unconventional shale formations.

II. Reservoir Simulation Models

In black-oil simulation models, oil and gas are represented by two components – one “component” called oil and the other “component”, gas. Here, there is an assumption that produced gas, solution gas, injected and free gas in contact with oil all have the same physical properties. In this model, PVT properties of fluid phases are calculated as functions of pressure only. Therefore, the only inputs necessary for black-oil simulators are tables of PVT properties such as oil

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formation volume factor (FVF), gas FVF, solution gas-oil ratio, viscosity, etc. as a function of pressure.

However, in compositional models, oil and gas phases are represented as multi-component mixtures. Both phases are made up of different amounts of the same components. For example, ethane can be 45% in the gas phase and 7% in the oil phase. Here, the physical properties of the gases are different and the composition of produced gas varies with time. An equation of state is used in this case instead of simple PVT tables.

III. Reservoir Model Description

A reservoir base case model consisting of 8 horizontal wells, with 20 hydraulic fractures spaced 250 ft apart was constructed. The distance between each well is 660 ft, i.e., 330 ft from one well to half adjacent distance of the other. The horizontal well lengths are 5,000 ft. Overall dimensions of the reservoir model are 7,000 ft long, 7,000 ft wide and 250 ft thick. The simulation model is a single porosity system. The fractures are all infinitely conductive. For computational purposes, a fracture width of 2 ft was used. Actual fracture width is about 0.2 inches, but wider fractures make simulation go more smoothly. Fracture permeability is correspondingly reduced to keep the product of width and permeability (of fractures) at an appropriate level. This approach is appropriate because reservoir models with the same fracture conductivity but different fracture widths yield similar results (Alkouh et al., 2012). The initial reservoir pressure is 5,000 psia and the wells produce for 30 years at a minimum bottom hole pressure constraint of 1,000 psia. Figure 1 is a pictorial representation of the base case model after gridding. Tables 1 and 2 show the reservoir data and the model parameters used. Correlations used to generate PVT properties of oil and gas phases, as a function of pressure are shown in Table 3.

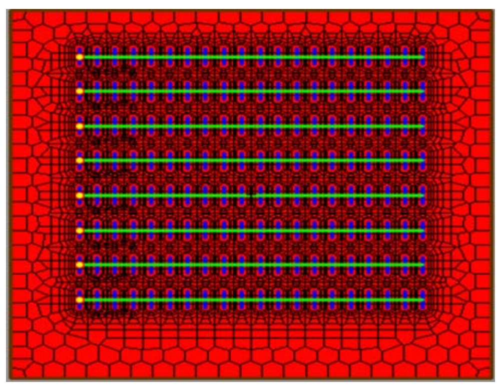


Fig.1: Reservoir Basecase Model (after gridding)

Table 1: Reservoir Data for the Reservoir Basecase Model

Permeability	0.001 md
Porosity	0.06
Reservoir Temperature	250°F
Initial Reservoir Pressure	5,000 psia
Depth to top of formation	10,000 ft
Reservoir Thickness	250 ft
Corey Relative Permeability Exponent	2.5
Critical gas saturation, S_{gc}	0.05
Residual saturation of oil (gas/oil displacement), S_{org}	0.2

Table 2: Parameters for the Reservoir Basecase Model

Number of wells	8
Distance between wells	660 ft
Horizontal well length	5,000 ft
Fracture spacing	250 ft
Fracture half-length	150 ft
Fracture width	2 ft
Oil API gravity	42°API
Initial solution GOR	1,500 scf/STB
Gas specific gravity (Air = 1)	0.75

Table 3: Basecase Correlations Used for Black-Oil PVT Tables

Oil		Gas	
Property	Correlation	Property	Correlation
Bubble point pressure, p_b	Standing	Z-factor	Dranchuk
Oil viscosity, μ_o	Beggs - Robinson	Gas viscosity, μ_g	Lee et al.
Solution GOR, R_s	Standing	Gas formation volume factor, B_g	Internal[1]
Oil formation volume factor, B_o	Standing	-	-
Oil compressibility, c_o	Vazquez - Beggs	-	-

IV. Single-Phase vs. Two-Phase Black-Oil Simulations

30 years of production was simulated using single-phase (oil) and two-phase (oil and gas) black-oil simulators. The simulations were isothermal and simulation results are for the 8 horizontal wells combined. Figures 2 to 4 show the simulation results comparing single-phase flow with two-phase flow for cumulative oil production, oil recovery factor and average reservoir pressure. There is larger cumulative oil production and oil rate for the two-phase flow than the single-phase flow case. This is likely due to the solution gas drive mechanism in two-phase flow, caused by the presence of the second phase (gas) which is absent in single-phase flow. A higher cumulative oil production correspondingly leads to a higher oil recovery factor for the two-phase flow case. Also, there is lesser pressure drop for two-phase flow compared to the single-phase flow case due to multiphase flow effects.

[1] Internal correlations within the software

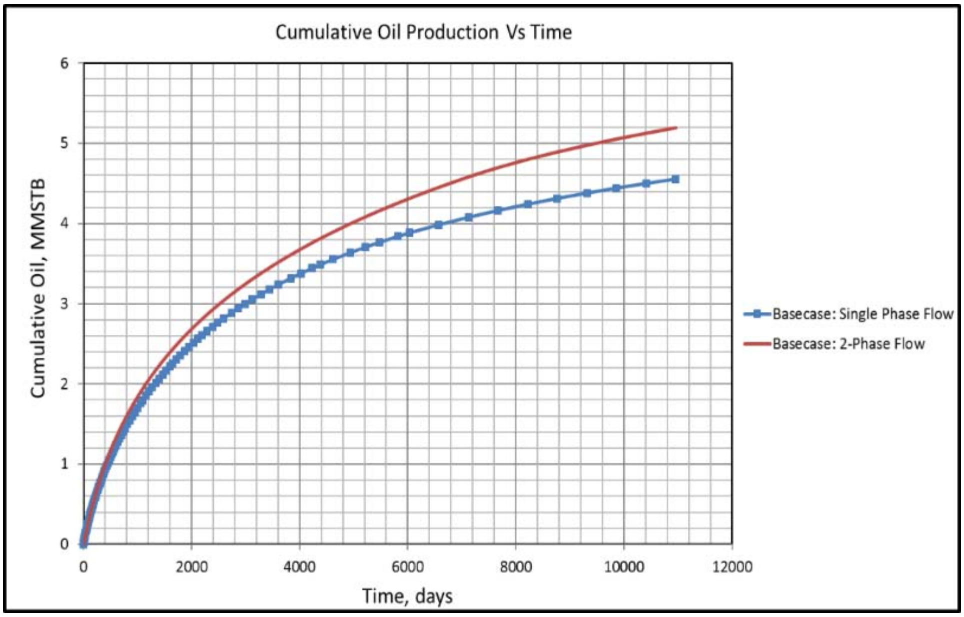


Fig. 2: Single-Phase Flow vs. Two-Phase Flow – Cumulative Oil Production

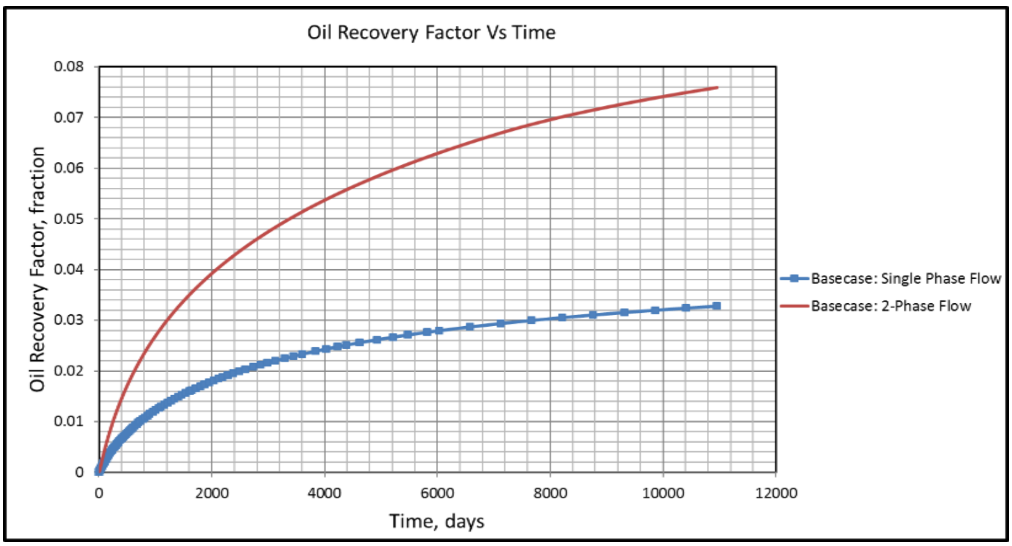


Fig. 3: Single-Phase Flow vs. Two-Phase Flow – Oil Recovery Factor

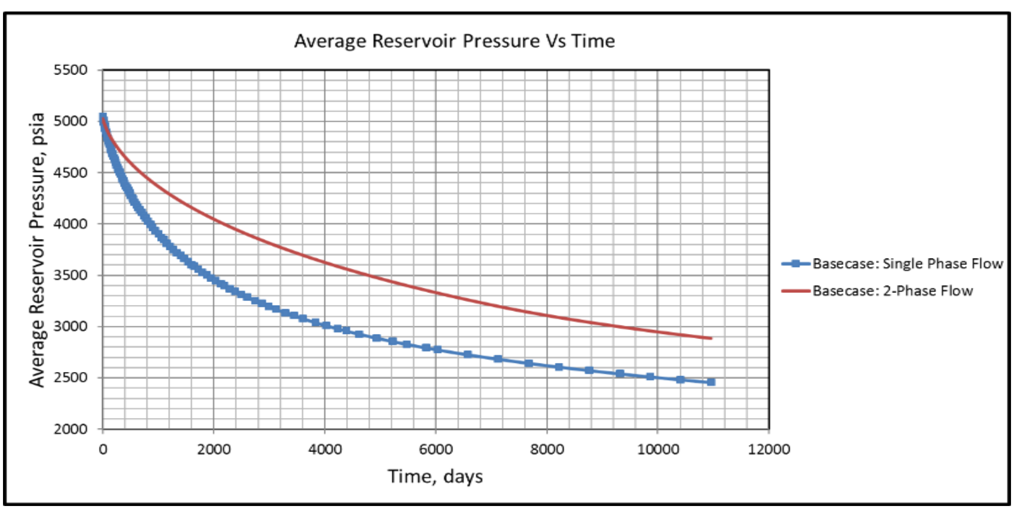


Fig. 4: Single-Phase Flow vs. Two-Phase Flow – Average Reservoir Pressure

V. Sensitivity Analyses – Single-Phase Flow vs. Two-Phase Flow Comparisons

How do certain parameters affect the production performance of shale volatile oil reservoirs when single-phase and two-phase black-oil simulators are used to simulate production? Are the results comparable or do they differ? Sensitivity studies were carried out with the aid of isothermal single-phase and two-phase black-oil simulations. The parameters studied include fracture spacing, fracture half-length, oil API gravity and critical gas saturation. These parameters were varied with other variables in the base case model kept constant.

a) *Fracture Spacing – Single-Phase Flow vs. Two-Phase Flow Comparisons*

Fracture spacing is an important well completion parameter. The fracture spacing used for the base case model is 250 ft (20 hydraulic fractures). Two other cases were considered – 100 ft (50 hydraulic fractures) and 500 ft (10 hydraulic fractures). Figures 5 to 8 show the effect of fracture spacing on cumulative oil production, oil rates, oil recovery factors and average reservoir pressure for single-phase and two-phase flow cases. Simulation results show that closer fracture spacing leads to higher cumulative oil production, higher initial oil rates and higher oil recovery factor for both single-phase and two-phase flow cases. For the oil rate cases, we can observe higher oil rates toward the end of the production period as fracture spacing widens. This is because there is faster drainage of the reservoir with closer fracture spacing, thereby leading to lower oil rates toward the end of the production period in comparison to cases with wider fracture spacing. There is a quicker pressure drop at the beginning of the production period for single-phase flow than for two-phase flow cases. Oil recovery factors, cumulative oil production and oil rates are generally higher for two-phase flow than for single-phase flow cases.

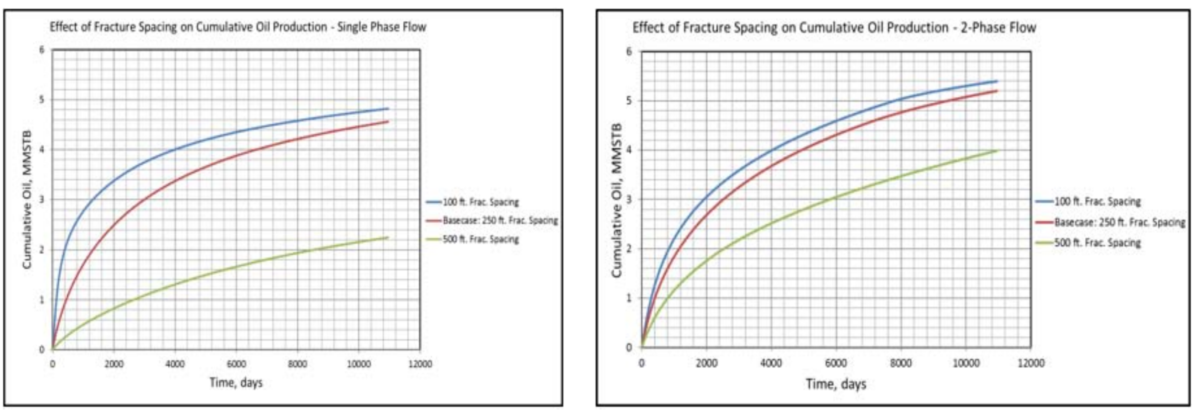


Fig. 5: Effect of Fracture Spacing on Cumulative Oil Production – Single-Phase and Two-Phase Flow Cases.

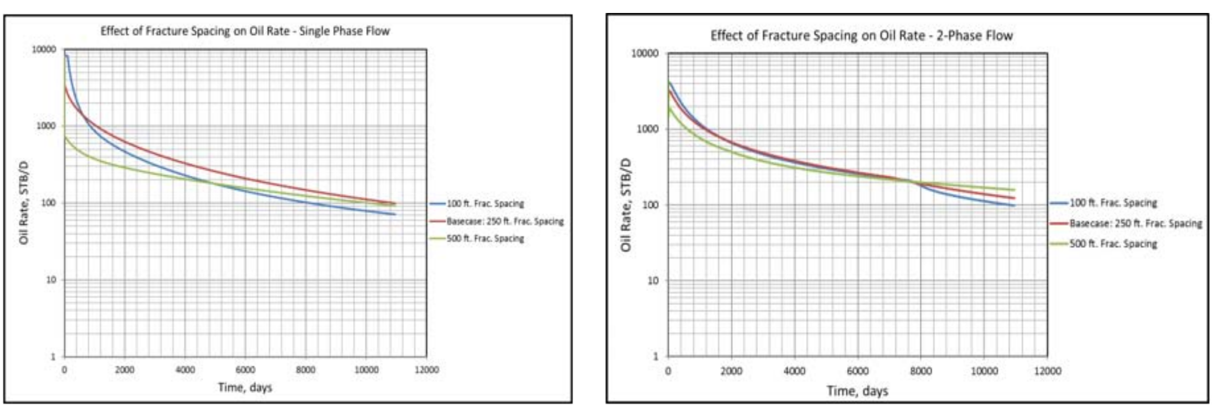


Fig. 6: Effect of Fracture Spacing on Oil Rates – Single-Phase and Two-Phase Flow Cases.

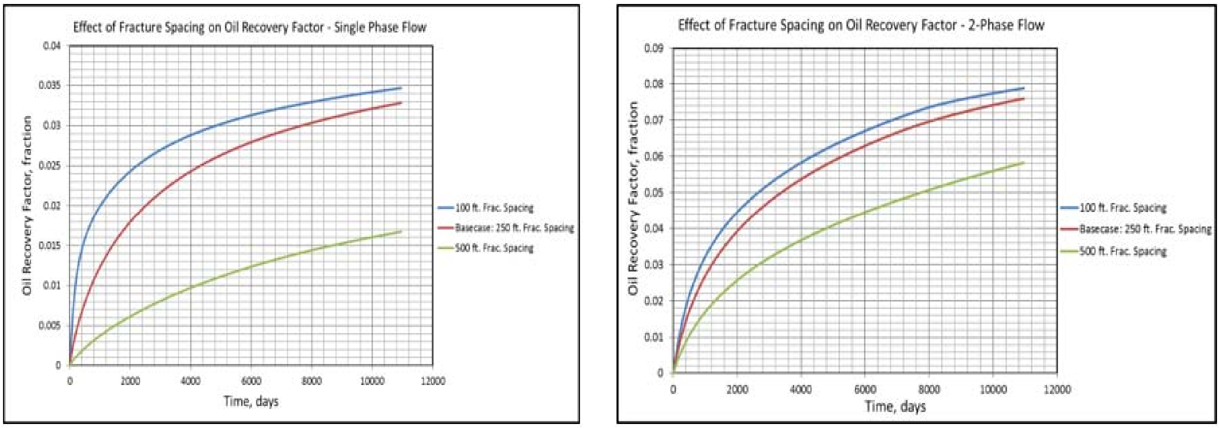


Fig. 7: Effect of Fracture Spacing on Oil Recovery Factor – Single-Phase and Two-Phase Flow Cases.

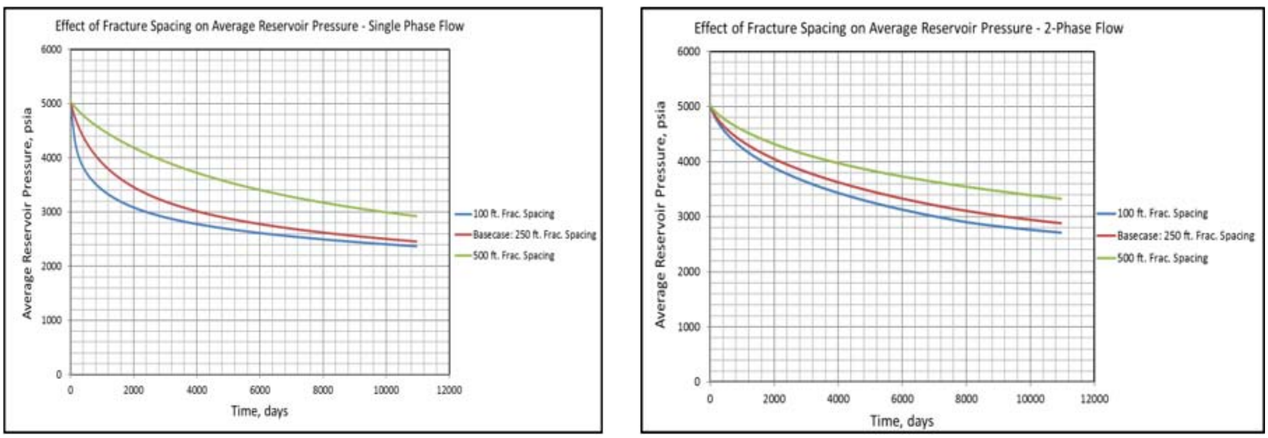


Fig. 8: Effect of Fracture Spacing on Average Reservoir Pressure – Single-Phase and Two-Phase Flow Cases

b) Fracture Half-Length – Single-Phase Flow vs. Two-Phase Flow Comparisons

Fracture half-length is the distance from the wellbore to the outer tip of a fracture. Three scenarios were considered here – fracture half-lengths of 100 ft, 200 ft and 300 ft. In the base case model, the fracture half-length is 150 ft. Figures 9 to 12 show the effect of fracture half-length on cumulative oil production, oil rate, oil recovery factors and average reservoir pressure for single-phase and two-phase flow cases. Results show that the larger the fracture half-length, the higher cumulative oil production, oil rate and oil recovery factor for both single-phase and two-phase flow simulations. There is a more rapid pressure drop (that later flattens out) early in the production period for single-phase flow than for the two-phase flow cases. Oil recovery factors, oil rates and cumulative oil production are mostly higher in two-phase flow than the single-phase flow cases.

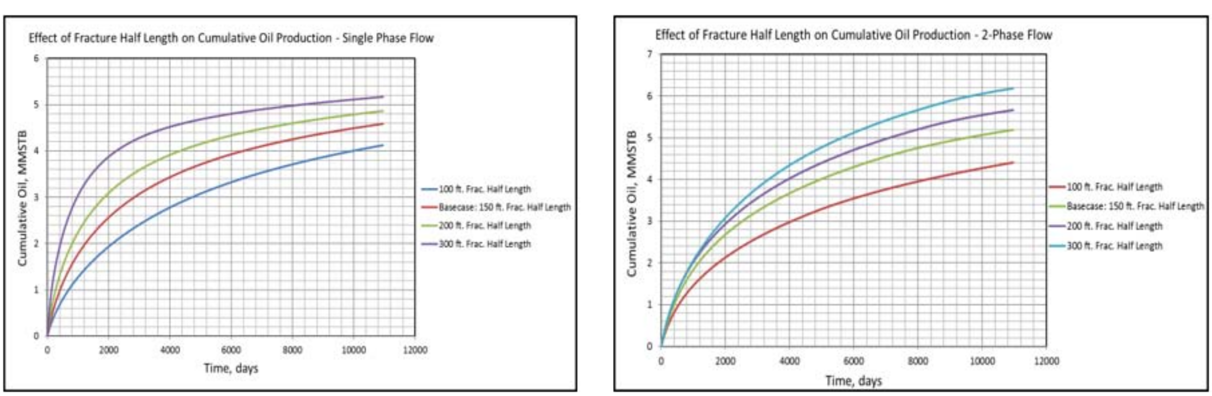


Fig. 9: Effect of Fracture Half-Length on Cumulative Oil Production – Single-Phase and Two-Phase Flow Cases

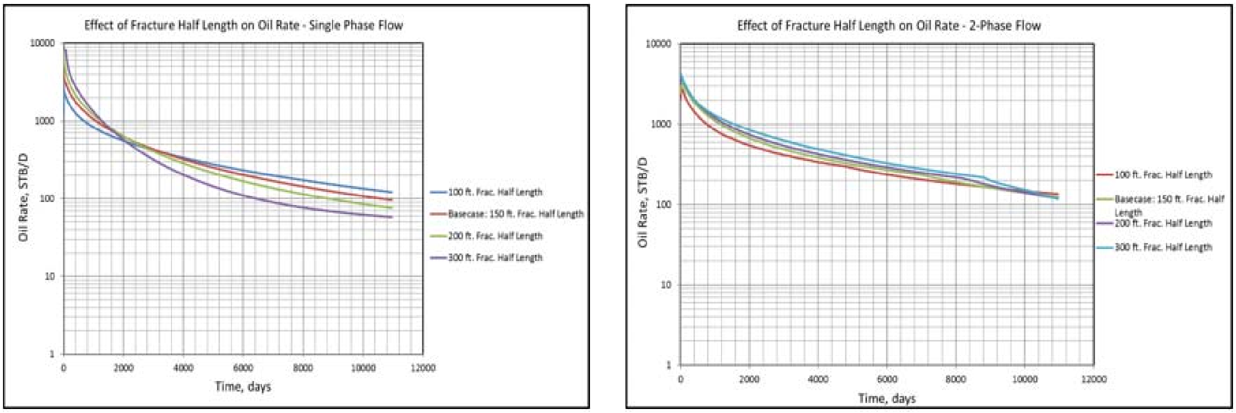


Fig. 10: Effect of Fracture Half-Length on Oil Rates – Single-Phase and Two-Phase Flow Cases

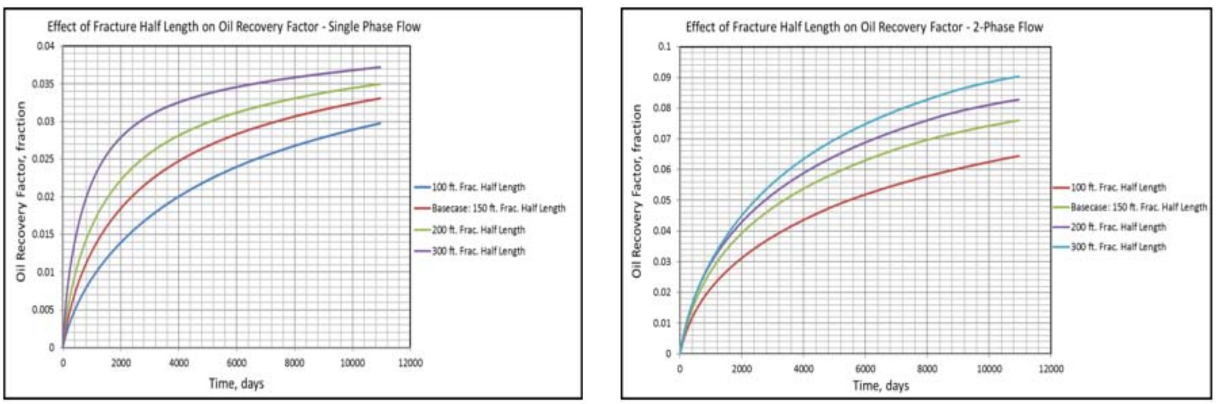


Fig. 11: Effect of Fracture Half-Length on Oil Recovery Factor – Single-Phase and Two-Phase Flow Cases

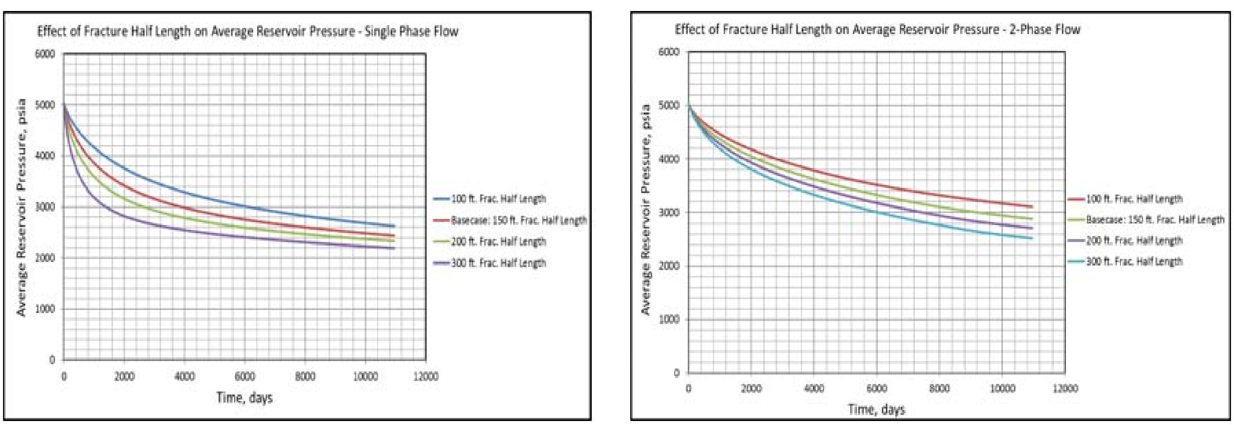


Fig. 12: Effect of Fracture Half-Length on Average Reservoir Pressure – Single-Phase and Two-Phase Flow Cases

c) Oil API Gravity – Single-Phase Flow vs. Two-Phase Flow Comparisons

Oil API gravity is a very important fluid property. It measures the heaviness or lightness of a petroleum liquid in comparison to water. Oil API gravity is inversely correlated to the specific gravity of oil; therefore, heavier oils have low API gravities and lighter oils, higher API gravities. Oil viscosity increases with lower API gravity and it decreases with higher API gravity. Oil API gravity of 42° was used for the base case model. The following oil API gravities were considered for the single-phase flow cases - 38°, 40°, 44°, 46° and 50°API. For the two-phase flow simulations - 38°, 40°, 44°, 46°, 50°, 60° and 65° oil API gravities were used. Two additional cases were added for the two-phase flow simulations in order to further demonstrate the impact of this fluid property on the behavior of shale volatile oil reservoirs. Figures 13 to 16 show the effect of oil API gravity on cumulative oil production, oil rate, oil recovery factor and average reservoir pressure for both single-phase and two-phase flow cases.

For the single-phase flow cases, the higher the oil API gravity, the higher the cumulative oil production and the initial oil production rates. This is because the higher the oil API gravity, the lighter the oil and the lower the viscosity – indicating higher oil mobility. Likewise, the analyses show that the higher the oil API gravity, the higher the oil recovery factor. Also, the lower the oil API gravity, the slower the rate of decline of the average reservoir pressure and vice versa.

Results of the two-phase flow cases provide a good demonstration of shale volatile oil reservoir behavior. As production occurs and reservoir pressure falls below the bubble point, gases start to build up around the wellbore. With time, the increasing gas saturation starts to hinder oil flow to the wellbore – eventually leading to a decline in cumulative oil production. This study illustrates that the higher the oil API gravity, the lower the cumulative oil production. This is shown in Figure 13. The higher the oil API gravity of fluids, the more the lighter components they contain. These lighter components of the fluid contribute to gas saturation around the wellbore, thus decreasing cumulative oil production with time. Table 4 shows actual production forecast data from two-phase black-oil simulations after 30 years of production. This table clearly shows the numerical value of cumulative oil production decline with increasing oil API gravity. Cumulative gas production on the other hand, increases with increasing oil API gravity. Furthermore, Figure 17 shows how average gas saturation increases with increasing oil API gravity. This also corroborates the explanations above on how increasing oil API gravity decreases cumulative oil production. In addition, results from two-phase flow cases show that oil production rates drop with increasing oil API gravity. However, there was an increase in oil recovery factor with increase in oil API gravity, even though above 60°API there was a slight drop in oil recovery factor for the 65°API case. This is shown in Figure 15, indicating that with further increase in oil API gravity above 60°API, oil recovery factor will most likely begin to decline. It is also observed from this study that the average reservoir pressure declines at a faster rate with increase in oil API gravity and vice versa. This is illustrated in Figure 16.

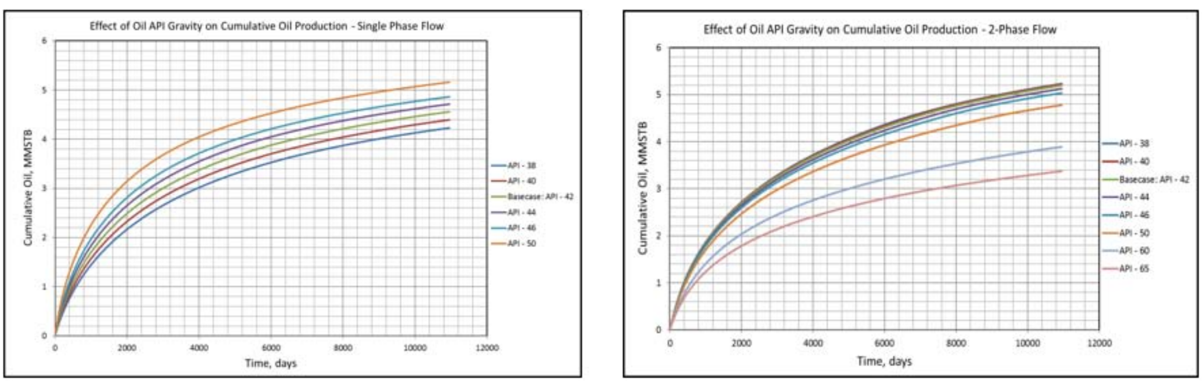


Fig. 13: Effect of Oil API Gravity on Cumulative Oil Production – Single-Phase and Two-Phase Flow Cases

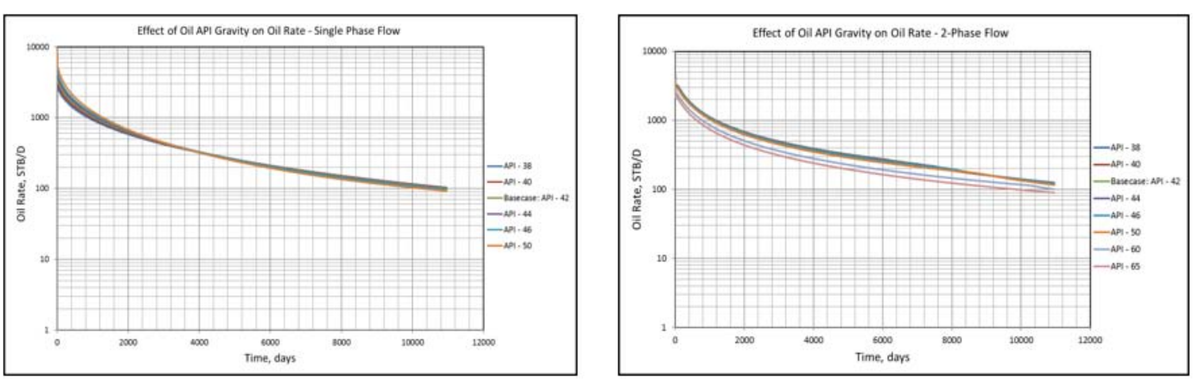


Fig. 14: Effect of Oil API Gravity on Oil Rates – Single-Phase and Two-Phase Flow Cases

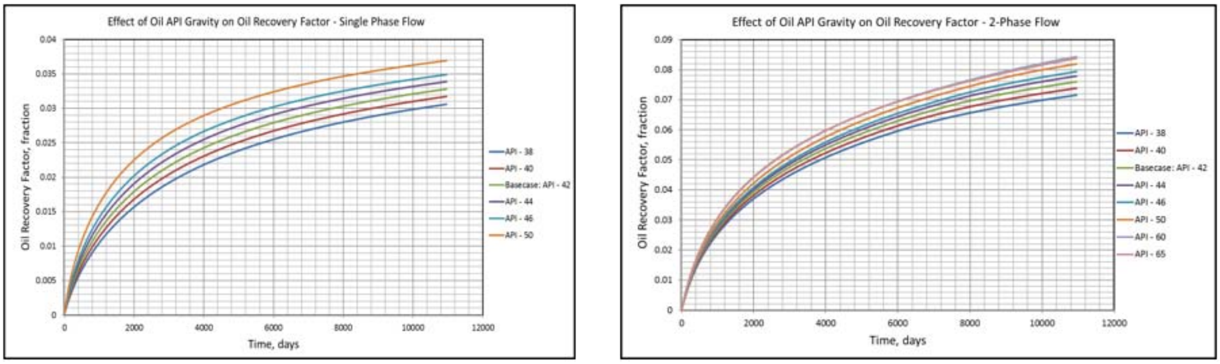


Fig. 15: Effect of Oil API Gravity on Oil Recovery Factor – Single-Phase and Two-Phase Flow Cases

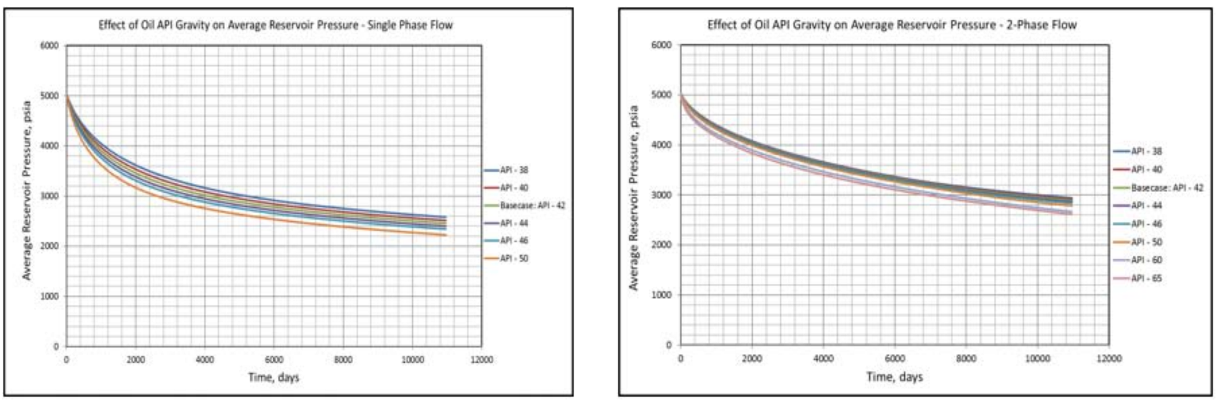


Fig. 16: Effect of Oil API Gravity on Average Reservoir Pressure – Single-Phase and Two-Phase Flow Cases

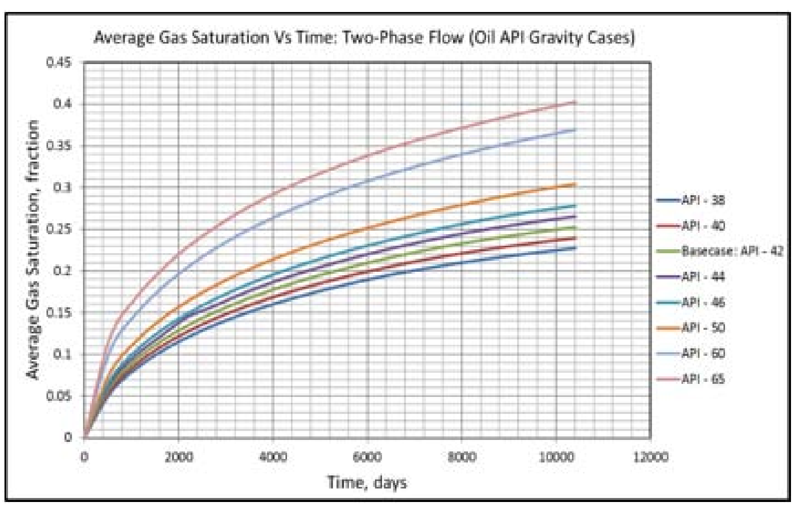


Fig. 17: Average Gas Saturation – Two-Phase Flow Cases

Table 4: Forecast after 30yrs. of Production for Two-Phase Flow (Oil API Gravity Cases)

Oil API Gravity	Cumulative Oil Production, MMSTB	Cumulative Gas Production, bscf
38°API	5.2336	27.4234
40°API	5.2257	28.7767
Base case: 42°API	5.1926	30.1184
44°API	5.1287	31.4301
46°API	5.0368	32.7155
50°API	4.7822	35.1055
60°API	3.8913	39.9792
65°API	3.3757	41.6698

d) Critical Gas Saturation – Two-Phase Black-Oil Simulation Cases

In an oil reservoir, gas evolves out of solution when the reservoir pressure drops below the bubble point. The gas is immobile until it reaches a threshold called the critical gas saturation. At and above the critical gas saturation, the gas phase becomes mobile and begins to flow towards the wellbore. Two-phase black-oil simulations were run with critical gas saturations of 2%, 10%, 15% and 20%. A critical gas saturation of 5% was used for the base case model. Figures 18 to 21 show the effect of critical gas saturation on cumulative oil production, oil rate, oil recovery factor as well as average reservoir pressure.

Results indicate that cumulative oil production increases with increase in critical gas saturation. This can be seen in Figure 18. The higher the critical gas saturation, the longer the gas stays in the pore spaces, thus pushing out more oil before it becomes mobile and starts to flow. Oil recovery factor also increases with increase in critical gas saturation. For the case with 20% critical gas saturation, the oil recovery factor is almost 12%, while it is approximately 7% for the case with 2% critical gas saturation. Figure 20 shows this.

In Figure 19, results show that at early times, a constant production rate was observed for the 20% critical gas saturation case, before decline starts to occur. From the graph, it is also observed that oil production rates decline earlier as critical gas saturation decreases. This is because at lower critical gas saturations, evolved gas becomes mobile earlier, leading to earlier decline in oil rate. This phenomenon is vice versa as critical gas saturation gets higher. It also explains why there is a slightly faster decline in average reservoir pressure as critical gas saturation gets lower. This is observed in Figure 21.

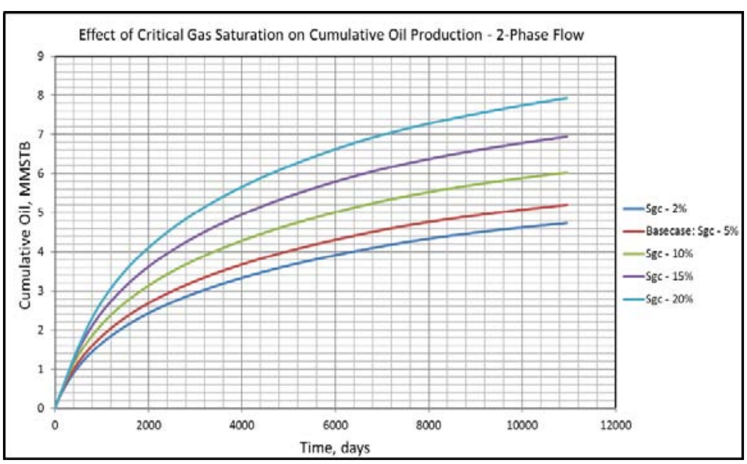


Fig. 18: Effect of Critical Gas Saturation on Cumulative Oil Production – Two-Phase Flow Cases

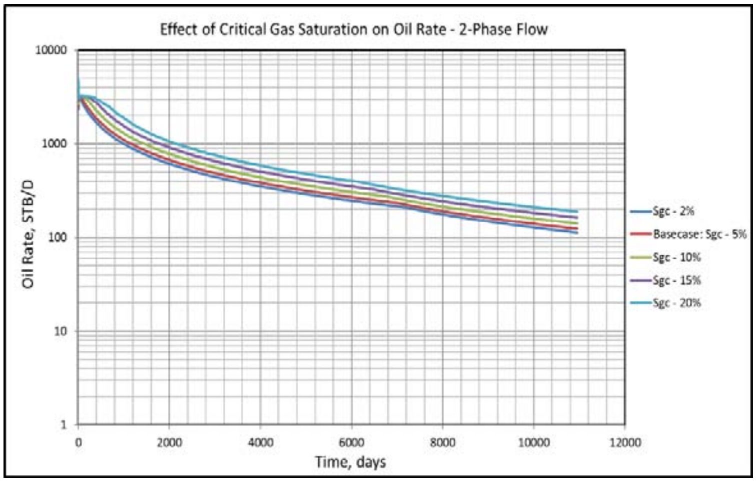


Fig. 19: Effect of Critical Gas Saturation on Oil Rates – Two-Phase Flow Cases

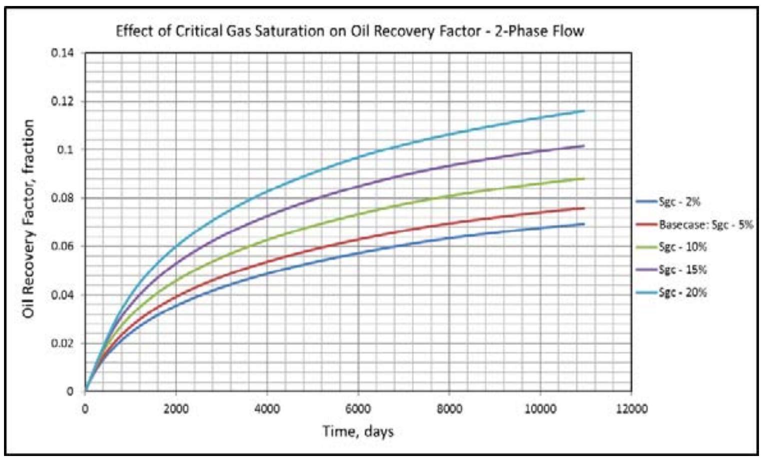


Fig. 20: Effect of Critical Gas Saturation on Oil Recovery Factor – Two-Phase Flow Cases

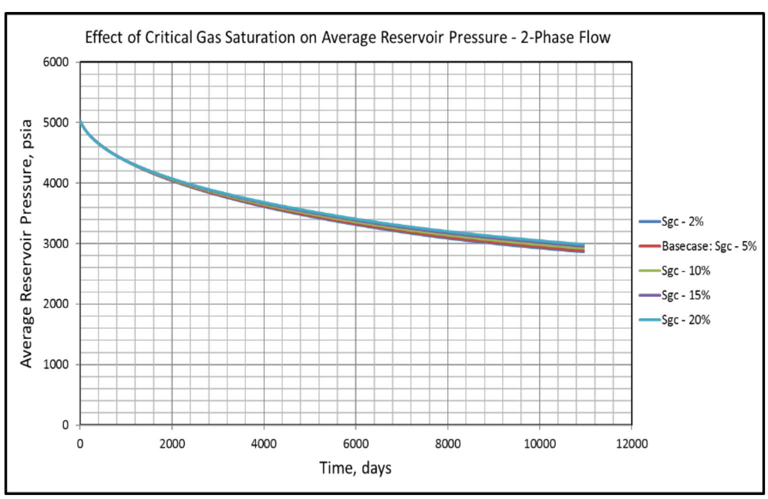


Fig. 21: Effect of Critical Gas Saturation on Average Reservoir Pressure – Two-Phase Flow Cases

VI. Compositional Simulations

Compositional simulations using different 5 different reservoir fluid samples were run for a period of 30 years. All reservoir parameters remain the same, except that in this case, the Peng Robinson equation of state was used for the PVT instead of correlations. The fluid compositions are shown in Table 5. The fluid samples are volatile oils (Fluids 3 and 4 are near-critical fluids). Figures 22 and 23 show the corresponding P-T diagrams for each of the different fluid compositions. The curves represent the two-phase boundaries; the straight lines going through the curves are the isothermal pressure decrease paths during production and the points on the curves are the critical points. The P-T diagrams were generated using the CMG Winprop software. The positions of the isothermal lines usually help us to determine the reservoir fluid type. In many instances, the isothermal line shows the pressure path in the reservoir. In this case, however, the lines just indicate the positions of the reservoir temperature compared to the critical points. Simulation results were compared to determine the effects of fluid composition on production performance of shale volatile oil reservoirs.

Table 5: Fluid Compositions

	Fluid 1	Fluid 2	Fluid 3	Fluid 4	Fluid 5
Components	Composition (%)	Composition (%)	Composition (%)	Composition (%)	Composition (%)
CH_4	58.77	58.07	61.82	53.47	49.43
C_2H_6	7.57	7.43	7.91	11.46	7.28
C_3H_8	4.09	4.16	4.42	8.79	8.02
$I\text{-}C_4H_{10}$	0.91	0.96	1.02	-	2.31
$N\text{-}C_4H_{10}$	2.09	1.63	1.74	4.56	3.61
$I\text{-}C_5H_{12}$	0.77	0.75	0.80	-	1.80
$N\text{-}C_5H_{12}$	1.15	0.80	0.86	2.09	1.79
C_6H_{14}	1.75	1.14	1.21	1.51	2.32
C_{7+}	21.76	22.59	17.59	16.92	22.41
CO_2	0.93	2.32	2.47	0.90	0.16
N_2	0.21	0.15	0.16	0.30	0.87

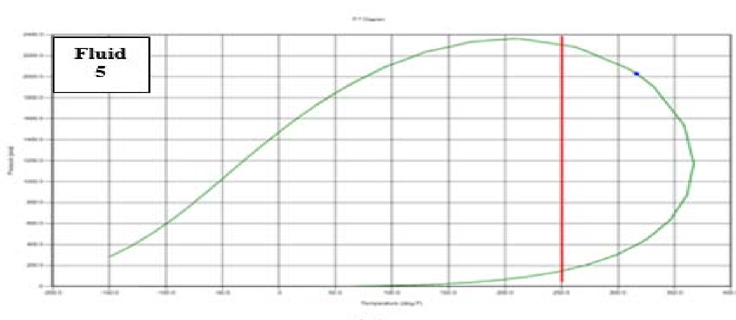


Fig. 22: P-T Diagram – Fluid 5

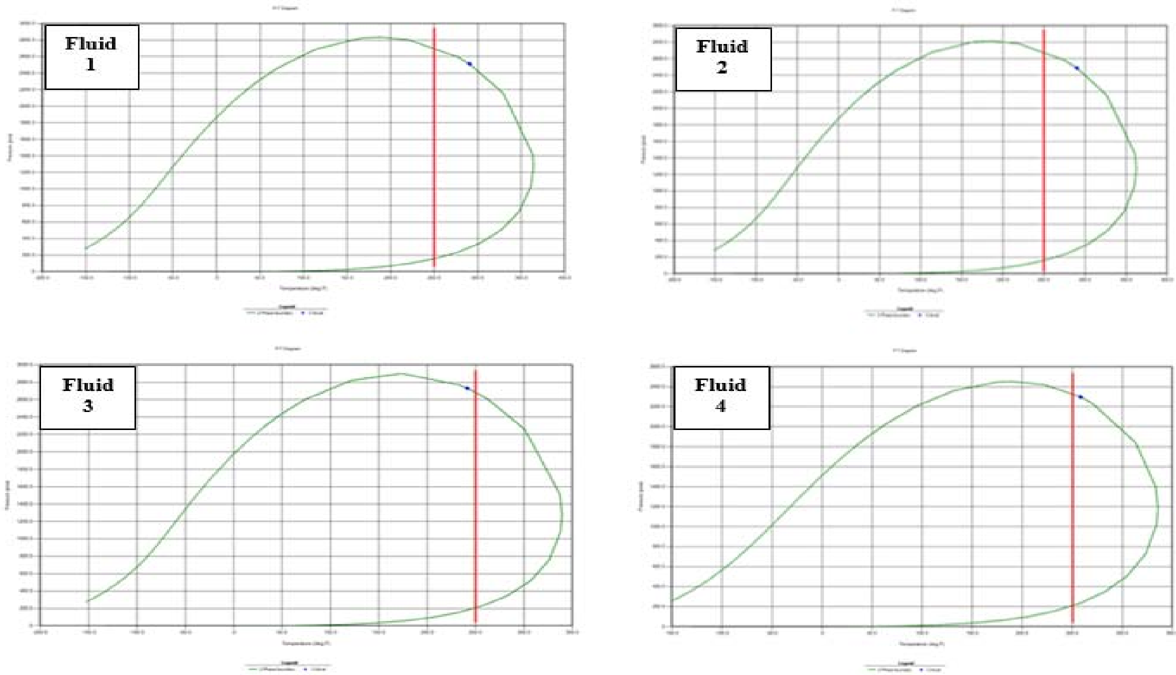


Fig. 23: P-T Diagram – Fluids 1-4

McCain (1994) suggested that the heavy components in petroleum mixtures have the greatest effect on fluid characteristics. Results of this study, however, show the importance of not only the heavy components, but also of the light components, especially methane. Figure 24 illustrates the effect of fluid composition on cumulative oil production and oil rates. Fluid 5, with the smallest methane composition and relatively high (22.41%) C_{7+} composition has the largest cumulative oil production and oil rate whereas Fluid 3, with the largest methane composition and relatively low C_{7+} composition (though not lowest – Fluid 4 has the least C_{7+} composition), has the smallest cumulative oil production and oil rate. Note that, despite the fact that Fluid 4 has a smaller C_{7+} composition than Fluid 3, cumulative oil production and oil rate for Fluid 4 is higher than for Fluid 3. This indicates that the methane composition plays a major role in reservoir performance. Fluids 1 and 2 are similar in composition (methane compositions are almost the same and the C_{7+} compositions are slightly different) – they therefore have almost the same cumulative oil production and oil rates. Fluid 2, with a slightly smaller methane composition and slightly larger C_{7+} composition, has a slightly higher cumulative oil production and oil rate than Fluid 1. Also, Fluids 5 and 2 have almost the same C_{7+} composition (Fluid 5 – 22.41% and Fluid 2 – 22.59%); however, there is a considerable difference in their methane composition [less – (49.43%) in Fluid 5 than in Fluid 2 – (58.07%)] and results indicate much higher cumulative oil production and oil rate for Fluid 5 than for Fluid 2. The trend generally indicates that the smaller the methane composition, the larger the cumulative oil production and oil rate. This clearly demonstrates the importance of the effect of the methane composition on production performance.

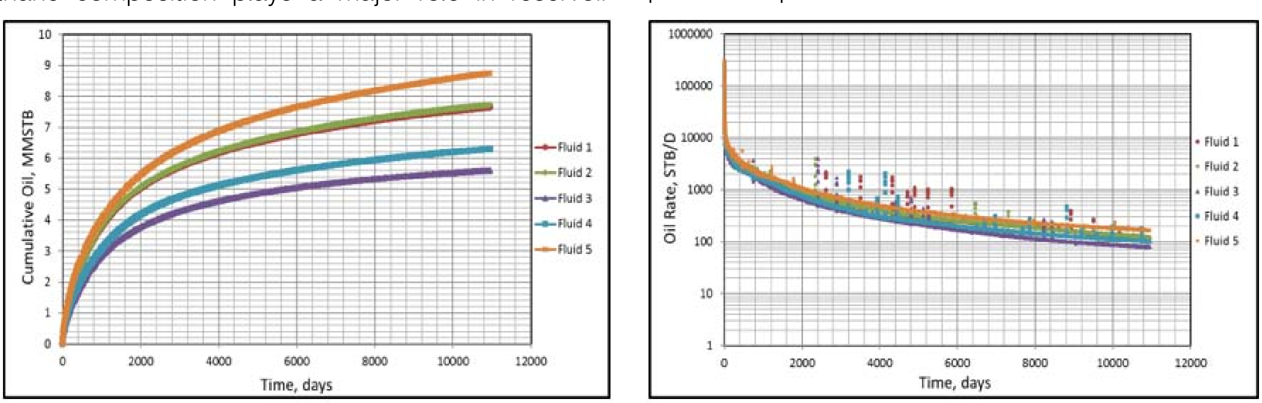


Fig. 24: Compositional Simulations – Cumulative Oil Production and Oil Rate Comparisons

The heavy components affect cumulative oil production and oil rates because the larger the heavy component composition in the reservoir fluid, the more it contributes to the oil phase production and consequently increases the cumulative oil production and oil rate. However, results of this study indicated that apart from the heavy components, the methane component has a large role to play as well. Note that the spikes in the oil rate curves are probably artifacts due to the numerical solver (in the software) used for the simulation. However, disregarding the spikes, the trends can be clearly observed.

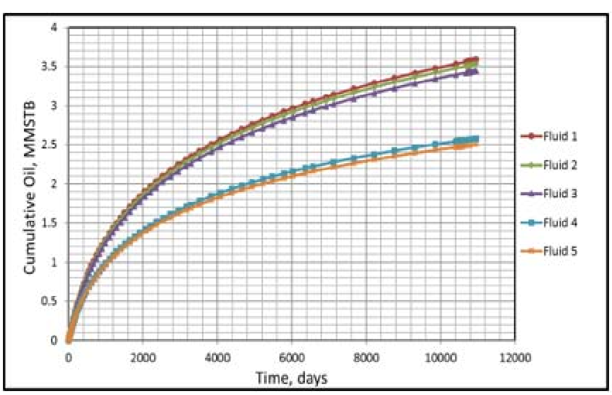
VII. Two-Phase Black-Oil Simulations – Standing Correlation

Separator tests were done on the fluids and the results of the flash calculations were used as inputs for two-phase black-oil simulations. Two stages of separation were used, with the stock tank as one of the separators. Separator pressure and temperature were 400 psia and 100°F, while the stock tank conditions were 14.7 psia and 60°F respectively. The results of the flash calculations are shown in Table 6. This was done to provide a reasonable basis for comparison of the compositional simulation and the black-oil simulation results.

Table 6: Flash Calculation Results

	Fluid 1	Fluid 2	Fluid 3	Fluid 4	Fluid 5
Gas-Oil Ratio, SCF/STB	3,024	3,043	4,081	3,967	2,561
API @STC	63.50	63.04	63.52	64.94	65.22
Average Gravity of Total Surface Gas (Air = 1)	0.743	0.753	0.756	0.841	0.851
Oil FVF, RB/STB	3.558	3.551	-	4.806	3.529
Condensate-Gas Ratio, STB/MMSCF	-	-	245.0	-	-
Dry Gas FVF, (ft^3/SCF)	-	-	6.5E-3	-	-
Wet Gas FVF, (ft^3/SCF)	-	-	5.1E-3	-	-
Well Stream Gas Gravity (Air = 1)	-	-	1.246	-	-

First, a case where Standing's correlation was used for bubble point pressure estimates was considered. The simulation results were different from those obtained in the compositional simulations and show no notably observable trends. Figure 25 shows the results for cumulative oil production and oil rates. Fluid 1, in this case, has the largest cumulative oil production and oil rate, while Fluid 5 has the smallest. Incorrect bubble point pressures estimated with the correlations might have led to discrepancies in the results.



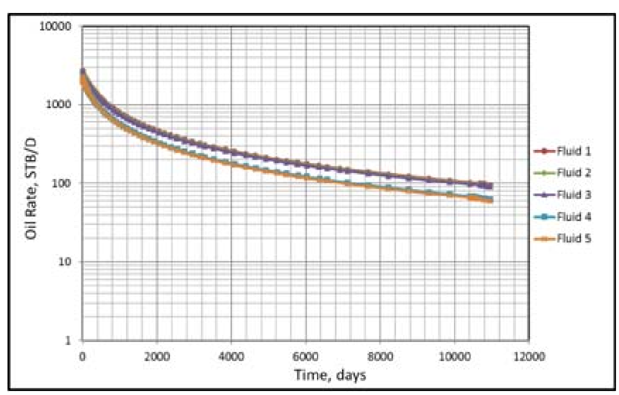


Fig. 25: Two-Phase Black-Oil Simulations – Standing: Cumulative Oil Production and Oil Rate Comparisons

VIII. Two-Phase Black-Oil Simulations – Vazquez-Beggs Correlation

Black-oil simulations were repeated using the Vazquez-Beggs correlation to estimate bubble point pressure. The Vazquez-Beggs correlation is generally applicable and the data used in the development of the correlation covers a wide range of temperatures, pressures and oil properties. Simulation results show similar trends (Fluid 1 – largest cumulative oil production and oil rate and Fluid 5 – smallest cumulative oil production and oil rate) as in cases where Standing's correlation was used to calculate the bubble-point pressure. However, the values of the cumulative oil production and oil rates were relatively larger in this case. The results for cumulative oil production and oil rates are shown in Figure 26.

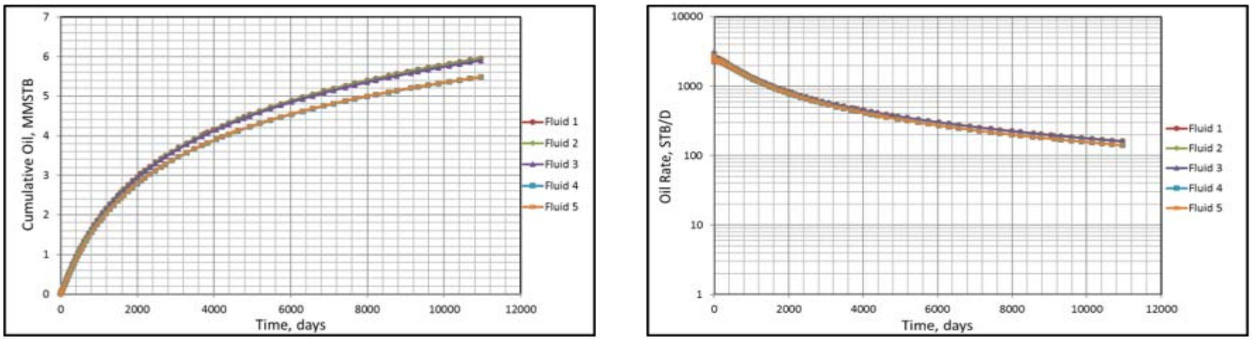


Fig. 26: Two-Phase Black-Oil Simulations – Vazquez-Beggs: Cumulative Oil Production and Oil Rate Comparisons

The inconsistencies in the results for the black-oil simulations are most likely due to inaccurate bubble point estimates using empirical correlations. In Table 7, the approximate bubble point estimates calculated with the Standing and Vazquez-Beggs correlations are shown. Note that the initial reservoir pressure is 5,000 psia. Therefore, the bubble point pressure estimates calculated are higher and lower than the initial reservoir pressure depending on the fluid type considered. Predicted values of bubble point pressure (using correlations) could be in error by 25 percent or more depending on the circumstance (McCain *et al*., 1998). This definitely affects the accuracy of production forecasts.

Table 7: Approximate Bubble-Point Estimates

	Standing	Vazquez – Beggs
Fluid 1	4,870 psia	4,650 psia
Fluid 2	4,870 psia	4,650 psia
Fluid 3	6,150 psia	5,850 psia
Fluid 4	5,270 psia	5,020 psia
Fluid 5	3,570 psia	3,450 psia

IX. Compositional vs. Two-Phase Black-Oil Simulations

Simulation results from the compositional and black-oil simulations were compared for each of the fluid samples under consideration. Results generally show greater cumulative oil production and greater oil rates from compositional simulation than from black-oil simulations. Black-oil simulations using Vazquez-Beggs correlation for calculation of most of the oil PVT properties produced results that are closer to the compositional simulation results than black-oil simulations in which Standing's correlations were used. Therefore, we conclude that proper use of correlations or the development of better correlations for black-oil simulations can lead to results that are close to or almost the same as compositional simulation results. Results of cumulative oil production and oil rate comparisons for Fluid 1 are shown in Figures 27. Results for other fluid samples (except for Fluid 3) are similar to that of Fluid 1.

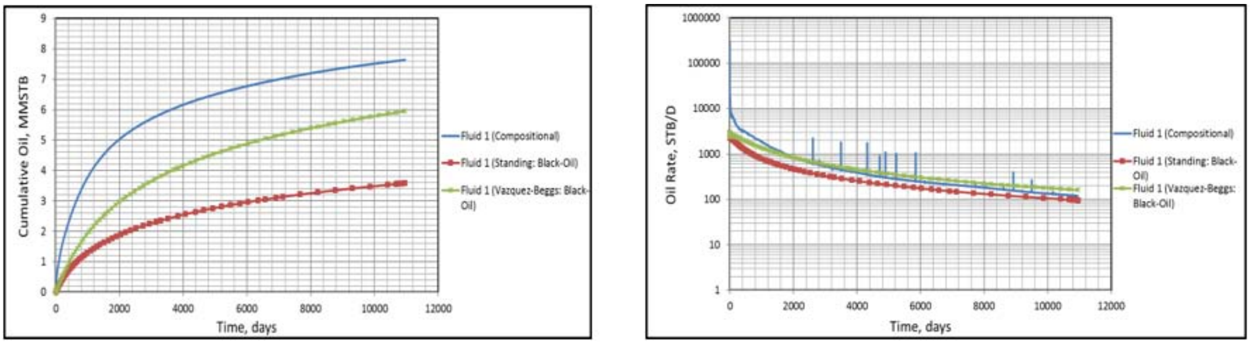


Fig. 27: Compositional vs. Two-Phase Black-Oil Simulations – Fluid 1 Cumulative Oil Production and Oil Rate Comparisons

a) *Near-Critical Fluid: Fluid 3 Case*

Fluid 3 is a near-critical fluid; therefore, an additional simulation was run by modeling it as a gas condensate using modified black-oil (MBO) simulation. MBO simulation of gas condensates takes into consideration the condensate-gas ratio, R_v, which is the amount of vaporized oil in gas.

When Fluid 3 was modeled as a gas condensate (using MBO), the result was similar to the original black-oil simulation case (when modeled as a bubble point fluid using Standing's correlation). When modeled as a bubble point fluid using the Vazquez-Beggs correlation, the cumulative oil production is a little closer to the compositional simulation case except toward the end of the production period. This highlights the difficulties inherent in modeling near-critical fluids, especially when using black-oil simulators with illustrates the results for the cumulative oil production and oil rates.

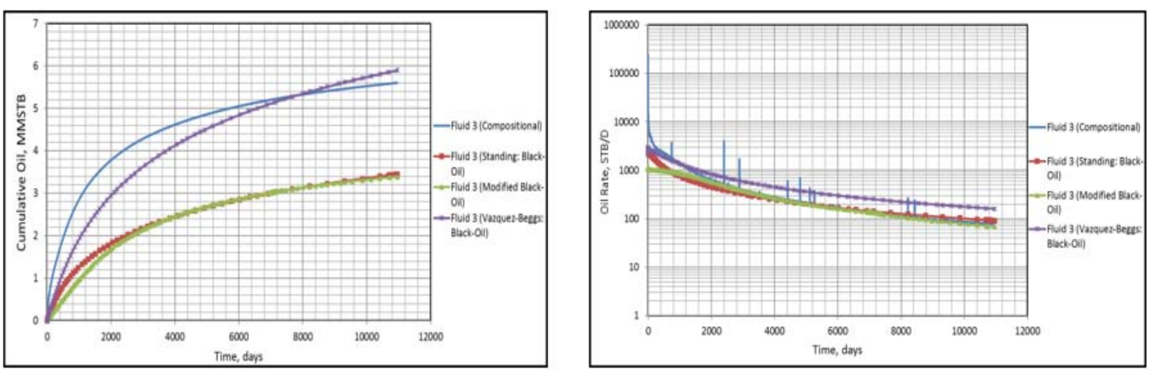


Fig. 28: Compositional vs. Two-Phase Black-Oil Simulations – Fluid 3 Cumulative Oil Production and Oil Rate Comparisons

X. Conclusions

1. Sensitivity studies done with the aid of single-phase and two-phase black-oil simulators, showed that fracture spacing, fracture half-length, oil API gravity and critical gas saturation are important parameters that affect oil production and oil rates in shale volatile oil reservoirs;
2. From the analyses of the oil API gravity cases, it is obvious that imperfect fluid samples (errors in calculation of fluid properties) can have significant impact on oil recovery estimates;
3. The gas phase in two-phase flow has a considerable effect on oil production in shale volatile oil reservoirs;
4. Results from black-oil simulations are markedly different from compositional simulations. Compositional simulations are more accurate than two-phase black-oil simulations, while two-phase black-oil simulations are more accurate than single-phase black-oil simulations;
5. Volatile oil production cannot be properly modeled using black-oil simulations (especially when PVT properties are estimated with empirical correlations);
6. Inaccurate bubble point pressures and PVT properties estimated using correlations can have huge impacts oil production forecasts, whereas identification and use of more appropriate correlations for PVT property estimates can lead to production estimates that can be almost the same as those obtained from compositional simulations;
7. Reservoir engineering calculations for volatile oils should treat the reservoir fluid as a multi-component

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mixture, i.e., compositional simulation is necessary for thorough analysis of volatile oil production, especially in shale volatile oil reservoirs;
8. Light components, particularly methane composition in reservoir fluids, can have a substantial effect on shale volatile oil reservoir production performance;
9. Proper identification and classification of fluid samples prior to modeling and simulation is important (especially for black-oil simulations);
10. Near-critical fluids are very difficult to model.

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