Production Forecasting in Shale Volatile Oil Reservoirs

A Thesis

Presented to

the Faculty of Department of Chemical Engineering

University of Houston

In Partial Fulfillment

of the Requirements for the Degree

Master of Science

in Chemical Engineering

by

Ibukun Makinde

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Ibukun Makinde

Approved:

Chair of the Committee
William John Lee, Professor,
Petroleum Engineering

Committee Members:

Guan Qin, Professor,
Petroleum Engineering

Robert Stewart, Professor,
Earth and Atmospheric Sciences

Suresh K. Khator, Associate Dean
Cullen College of Engineering

Michael Harold, Department Chair
Chemical Engineering

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Abstract

This thesis gives us a better understanding of the behavior of shale volatile oil reservoirs. The effects of fluid compositions as well as the sensitivity of certain variables on cumulative oil production and rates were analyzed using black-oil and compositional simulations. Two-phase (oil and gas) black-oil simulations gave better results than single-phase (oil) black-oil simulations. Compositional simulations were much better in comparison to two-phase black-oil simulations. Therefore, for thorough analysis of fluid composition effects and more accurate production forecasts (especially for reservoir fluids like volatile oils in shale formations), compositional simulations are necessary.

In this research, single-phase and two-phase black-oil simulations were run on a base case model and the results were compared. Sensitivity studies were carried out by varying certain parameters in the base case model, then single-phase and two-phase black-oil simulations were run and the results were compared to the base case model. This was followed by analyzing six different fluid samples through compositional simulations. Flash calculations were later done on the fluid samples to obtain inputs for two-phase black-oil simulations. Finally, the simulation results from the compositional and two-phase black-oil simulations were then compared.

The importance of shale oil and gas research cannot be over-emphasized, given the ever-rising global demand for energy. Research and studies like this, can lead to better well completions and design, improve reservoir management and economics as well as provide insight into potential alternative methods to enhance recovery from unconventional shale formations.

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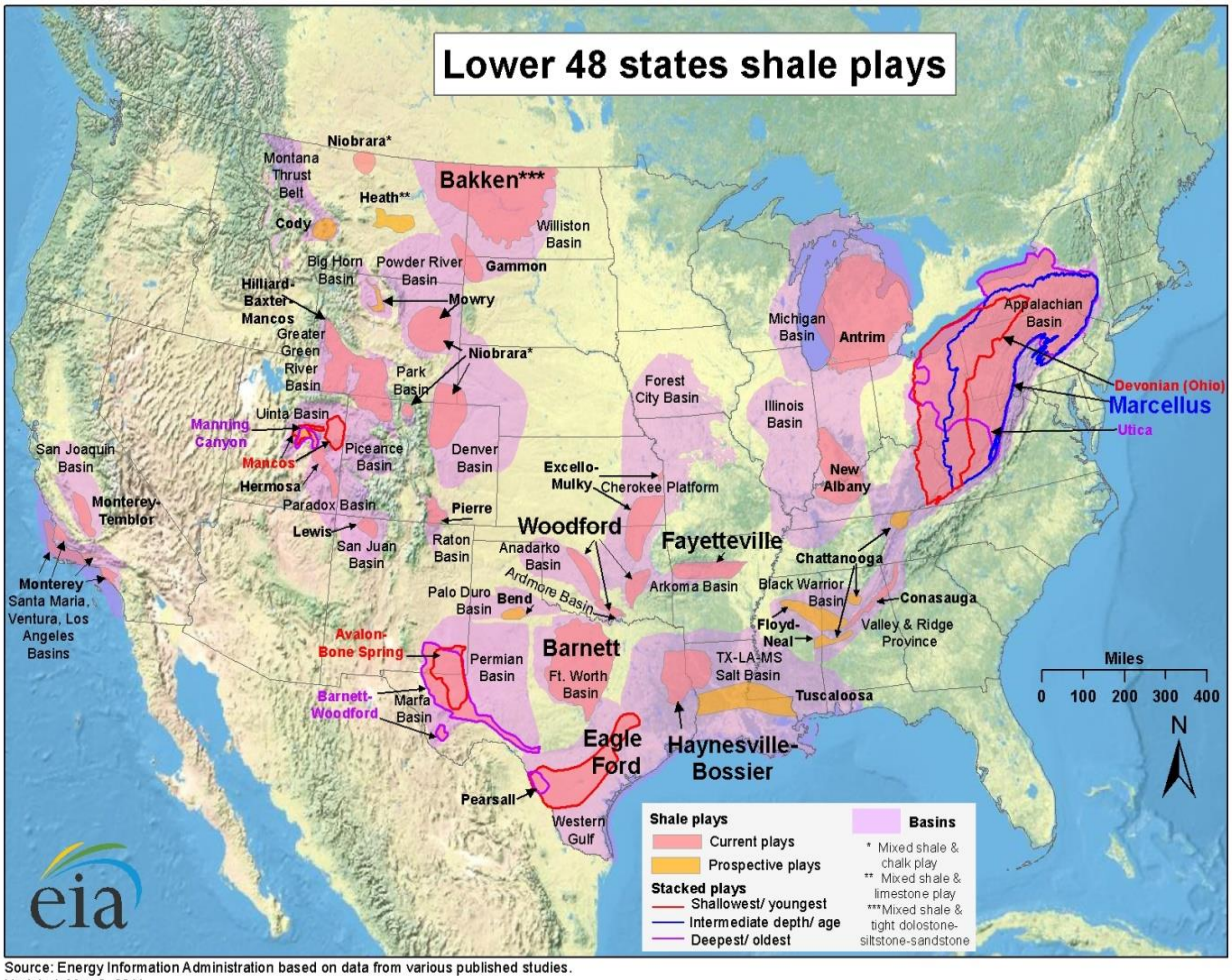
1. Introduction

Unconventional resources include hydrocarbon reservoirs that have very low permeability and porosity. They are therefore very difficult to produce compared to conventional plays. Approximately one-third of worldwide oil and gas reserves are conventional; the rest are unconventional resources. This fact coupled with rising global demand for energy underlies the importance of research into ways of enhancing productivity in unconventional plays. Examples of unconventional resources are tight gas, coal bed methane (CBM), shale gas, shale oil, heavy oil/tar sands and methane hydrates.

Shale reservoirs have emerged as extremely viable sources of producible hydrocarbon reserves. They do not produce economic volumes of oil and gas without some form of stimulation and or special recovery processes. Examples are the Eagle Ford and Bakken shale plays. There has been a steady increase in productivity of oil and natural gas from shale plays across the US, due to the use of multi-stage hydraulic fracturing and horizontal well drilling technologies. Even though performance may vary dramatically from play to play due to geological heterogeneities, drilling activities in US shale plays are generally producing more oil and natural gas than in the past. Figure 1-1 below is the map of the different shale plays in the United States while Figure 1-2 shows the growth in hydrocarbon productivity from various plays across the US for the past one year. While there has been a steady improvement in production from shale plays, recovery factors are still relatively low when compared to conventional formations. To improve on the existing technology and further increase recovery factors from shale formations, a

thorough and better understanding of reservoir fluid properties and phase behavior are highly important.



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 1-1 Map of Shale Plays in the United States (EIA, 2011)

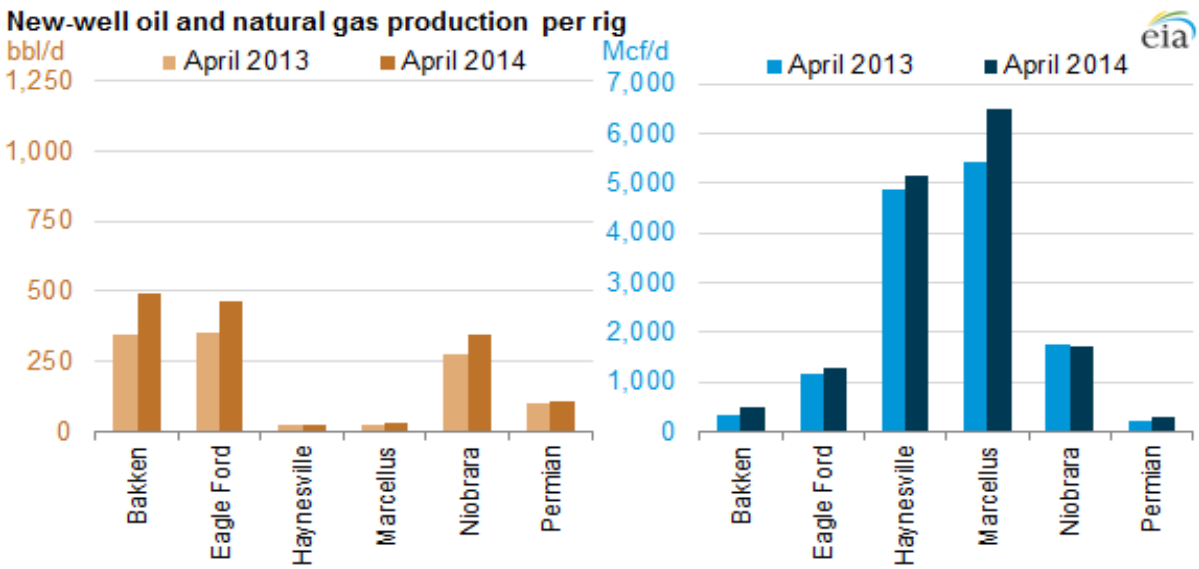


Figure 1-2 March 2014 Drilling Productivity Report (EIA, 2014)

1.1. Objective of Study

Most commonly found fluids in reservoirs are hydrocarbons (existing in either oil or gas phase or both) and water. Based on fluid properties, reservoirs are classified as: dry gas, wet gas, gas condensates, volatile oils, black oil and heavy oil reservoirs. The focus of the research done in this thesis is on shale volatile oil reservoirs. Why volatile oils? Volatile oils have complex fluid properties that are yet to be fully understood, and the behavior becomes even more complex in shales with nano-scale pores. This research attempts to better understand the behavior of shale volatile oil reservoirs as well as to study sensitivity to certain variables of cumulative oil production, oil rates and recovery factors; to determine optimal conditions for maximizing oil recovery in shale volatile oil reservoirs. Incorrect PVT data can lead to substantial errors in reservoir engineering calculations and forecasting. In order to accurately forecast production and find ways to enhance oil recovery in shale volatile oil reservoirs, a very good understanding of the

most favorable operational conditions, PVT properties and phase behavior of volatile oils is necessary.

1.2. Volatile Oils

Volatile oils are crude oils with typical oil API gravity ranging from 38° to 60° and gas-oil ratio (GOR) range of 1500 – 3300 scf/STB. This is a rule of thumb, i.e., values of oil API gravity and GOR for volatile oils can be higher or lower. To establish fluid type with some measure of accuracy, a representative sample of a reservoir fluid can be examined in a laboratory. Volatile oil fluid composition varies with reservoir location. However, volatile oils are typically richer in heavier hydrocarbon components (C_{7+}) compared to gas condensates and less rich compared to black oils. Hydrocarbons are primarily found in the liquid (oil) phase in a volatile oil reservoir. In Figure 1.2-1, we observe that the reservoir temperature is close to the critical temperature; hence volatile oils can also be called near-critical oils sometimes. The iso-volume lines are closer near the bubble point curve, indicating that a small drop below the bubble point pressure leads to vaporization of a considerable fraction of the oil. When the initial reservoir pressure falls below the bubble point pressure, an overlying gas cap may be formed. As production takes place, reservoir pressure drops and lighter hydrocarbon components evolve out of the liquid (oil) phase.

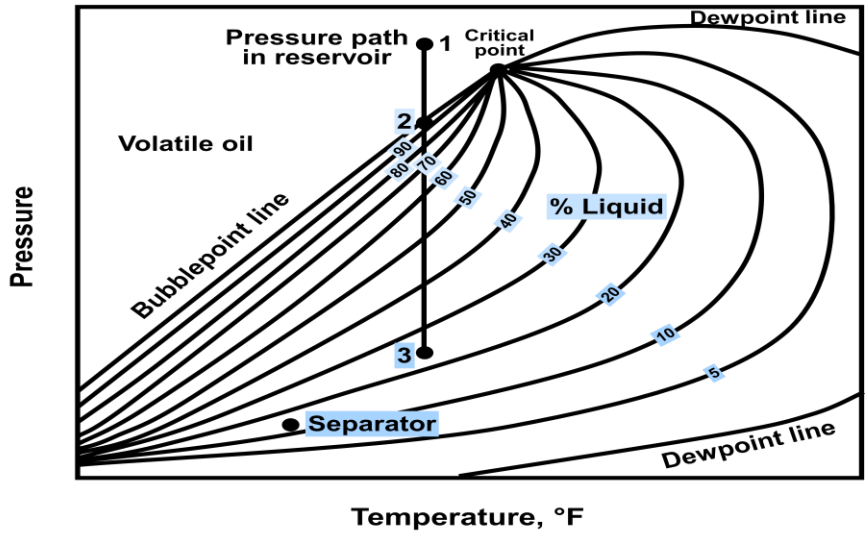


Figure 1.2-1 Phase Diagram of a Typical Volatile Oil (McCain Jr., 1990)

The gas that comes out of solution in a volatile oil reservoir as pressure drops is a retrogade gas – rich enough to release considerable quantities of condensate at surface conditions. Therefore, stock-tank liquid comes from the oil phase during the early life of the reservoir and, late in the life of the reservoir, stock-tank liquid is mostly condensate from reservoir gas. Oil API gravity increases steadily during the life of the reservoir due to the increasing amount of condensate in the production stream. Above the bubblepoint pressure, producing GOR's are generally constant for volatile oils. However, below the bubblepoint pressure, producing GOR's typically increase because of the existence of two phases (oil and gas). These are shown in Figure 1.2-2. The noticeable decrease in producing GOR towards the end of productiong period is a result of a sharp increase in gas formation volume factor (FVF) at low reservoir pressures, i.e., much higher gas volume at reservoir conditions as reservoir pressure decreases (McCain Jr., 1994).

Figure 1.2-2 Typical Production Trend (Oil API Gravity and producing GOR) for Volatile Oils (McCain Jr., 1994)

2. Fluid Flow

The study of fluid flow in porous media has advanced considerably over the years. It has been very applicable to the field of petroleum engineering, as petroleum reservoirs are typical examples of porous media. Fluid flow in reservoirs is largely controlled by two factors – microscopic and macroscopic (Gerritsen and Durlofsky, 2005). The microscopic factors include viscosity of the fluids and interfacial/surface tension existing between the fluid phases in the reservoir. The macroscopic factors are reservoir heterogeneity and differences in mobility between the fluids. Viscosity, which is the measure of resistance of fluids to flow, is an obvious and important factor that controls fluid flow in reservoirs; more viscous fluids tend to resist flow more than less viscous fluids. Interfacial/surface tension between reservoir fluids can lead to disconnection of fluids with lower saturation in the pores, thereby hindering their continuous flow path. Also, the existence of one fluid may inhibit the flow of the other, due to resistance to change of the interfacial shape. Reservoir heterogeneity leads to varying rock properties such as differences in permeability, porosity, etc., all of which affect the flow of fluids. These factors (apart from reservoir heterogeneity) are highly dependent on phase saturations, phase interactions at existing reservoir pressures and temperatures, as well as molecular composition of the phases. This underlies the importance of appropriately understanding phase behavior in volatile oil reservoirs and its corresponding effects on overall production performance.

A phase is part of a system that is physically different from other parts with distinct boundaries. It is matter that has homogenous chemical composition and physical state. Single-phase flow is the flow of a single-phase fluid (one component – oil in this case).

Two-phase flow (biphasic) is a type of multiphase flow, involving simultaneous flow of two immiscible fluid phases through a porous medium. In this case, the two phases are oil and gas. Flow equations through porous media are derived from material balance and Darcy's law. For a slightly compressible fluid, assuming that the system is homogenous (constant permeability and porosity), viscosity and fluid compressibility are constant, the following simplified one-dimensional form of the diffusion equation can be obtained:

$$\frac{\partial P}{\partial t} = \frac{k}{(\mu \varphi c_t)} * \frac{\partial^2 P}{\partial x^2}, \qquad (2-1)$$

where k is permeability, μ is viscosity, φ is porosity and c_t is total compressibility. The constant in equation (2 – 1), $k/(\mu\varphi c_t)$ is commonly referred to as hydraulic diffusivity; D_h. Equation (2 – 1) can then be rewritten as:

$$\frac{\partial P}{\partial t} = D_h * \frac{\partial^2 P}{\partial x^2}. \qquad (2-2)$$

The above equations are written in terms of pressure because that is what we most directly measure in a reservoir. As we can see, the simplified single-phase equation is a diffusion equation. This diffusive process depicts how pressure responses are propagated across an oil reservoir. For fractured reservoirs, flow is more rapid in the fractures than in the matrix. Therefore, we can assume that there is no flow from block to block; rather there is flow from one block (matrix) to fracture, then to another block. In this situation, there is an additional source term, q_{mf} that is added to equation (2 – 1), which describes flow from the matrix to the fractures (Zhangxin *et al*., 2006).

For a two-phase flow, key concepts like relative permeability, capillary pressure, formation volume factors and saturation of phases involved come into play. In this

research, the two phases to be considered are oil and gas[1]. Oil wets the porous medium more than gas, hence it is called the wetting phase and gas is called the non-wetting phase.

[1] An immobile water phase is always present, which affects total compressibility

3. Reservoir Simulation Models

A reservoir simulation model is a tool that helps to make informed decisions on oil and gas reserves estimates, reservoir performance, design and management. They are used to replicate field scenarios with the aid of reservoir simulation software. One of the major reasons for reservoir simulation is economics. We ultimately want to increase the net value of hydrocarbons we recover from reservoirs, and our ability to optimize production practices is enhanced by our ability to forecast future productions under different operating scenarios using simulators. For example, increasing the oil production rate for a field that is already producing at a minimum cost can be done with the help of reservoir simulation and management. This is illustrated in Figure 3-1 below.

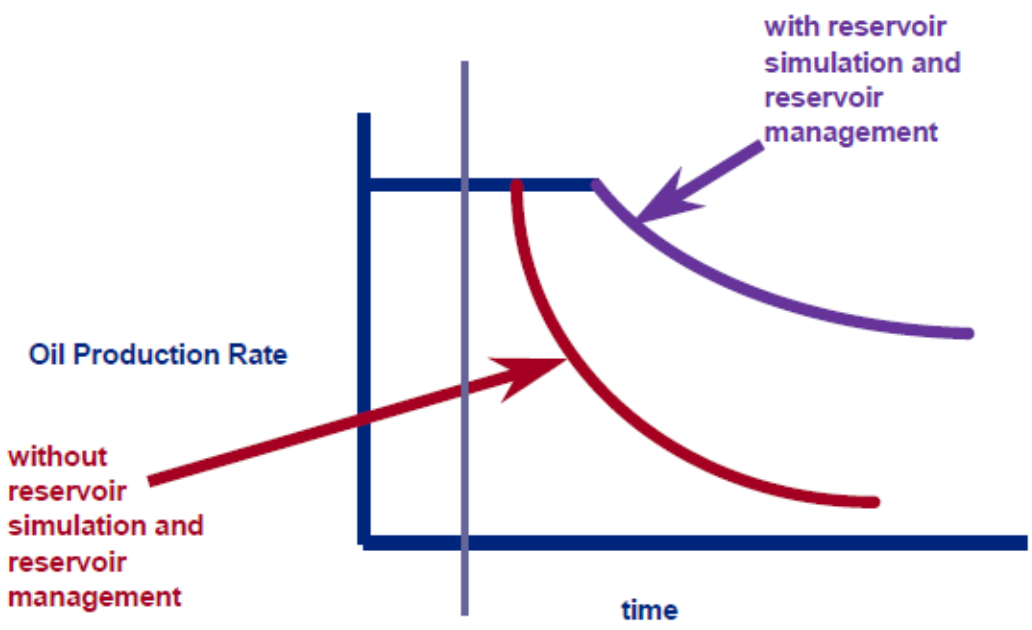


Figure 3-1 Advantage of Reservoir Simulation (Schlumberger, 2005)

Based on mode of application, model formulation and reservoir formation attributes, reservoir simulation models are classified into different types. Examples of reservoir simulation models are black-oil, thermal, compositional, IMPES (Implicit pressure, explicit saturations), single-porosity or dual-porosity, etc. In this research, the black oil and compositional simulation models were used.

3.1. Black-Oil and Compositional Simulation Models

Black-oil simulation has been commonly used for reservoir simulation. In black-oil models, oil and gas are represented by two components. One "component" called oil and the other "component" called gas, as shown below:

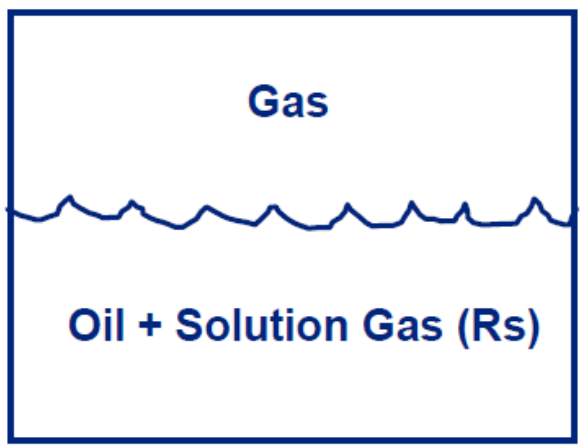


Figure 3.1-1 Oil and Gas phases – Black-oil model (Schlumberger, 2005)

Black-oil models assume that the dissolved gas (defined by the solution GOR, R_s), free gas in contact with oil, produced gas and gas injected into the reservoir all have the same physical properties. In black-oil simulation, PVT properties of fluid phases are calculated as a function of pressure only. Therefore, the only input necessary for black-oil

simulators is a table of PVT properties such as oil formation volume factor (FVF), gas FVF, solution gas-oil ratio, viscosity, etc. as a function of pressure.

In compositional models, oil and gas phases are represented as multi-component mixtures. Both the oil and gas phase are made up of different amounts of the same components. For instance, methane can be 60% in the gas phase and be 15% in the oil phase. A pictorial description is shown below:

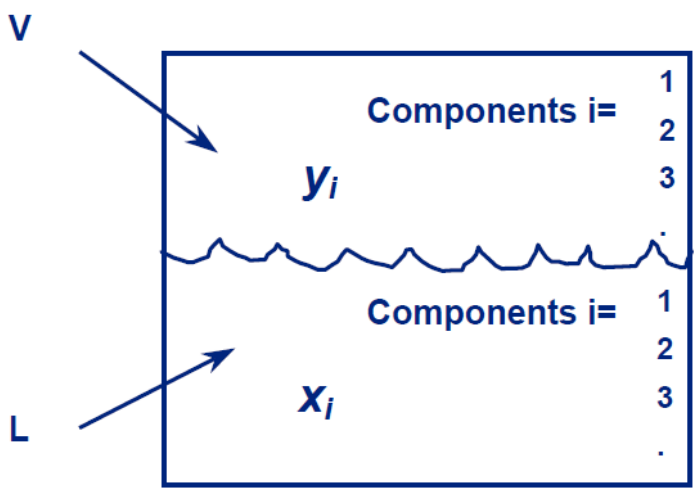


Figure 3.1-2 Oil and Gas phases - Compositional model (Schlumberger, 2005)

In these models, the composition of produced gas varies with time and the physical properties of the gases are different. Flash calculations have to be done to know how many phases are present. If both oil and gas phases exist, compositions of each phase are calculated. These compositions are then used to calculate the physical properties of the fluid. An equation of state is used in this case instead of simple PVT tables.

While black-oil simulation has a number of features in common with compositional simulation, it does not provide a good enough description of reservoir processes in a

number of situations. If the reservoir stays in a single phase, away from its critical point throughout its history, then a black-oil model can be suitable. However, when considering two-phase or multiphase flows in general, some compositional effects arise; hence, compositional models are preferable in this case. Compositional simulation gives a more accurate account of effects of composition on phase behavior, interfacial tension, viscosity and other composition-dependent properties, which are all very important factors affecting overall reservoir production performance. Despite its advantages, compositional simulation has difficulties, some of which are computing time, numerical dispersion and grid orientation (also common in black-oil models), phase composition calculation around the critical point, just to mention a few.

4. Research Hypothesis

A reservoir model consisting of multi-stage hydraulically fractured horizontal wells was set up using reservoir simulation software to simulate single-phase (oil) and two-phase (oil and gas) flows in order to answer the following pertinent hypothetical questions:

1. What are the important variables that affect cumulative oil production, oil rates and recovery factors in a hydraulically fractured shale volatile oil reservoir?
2. Can varying the oil API gravity and studying their effects on cumulative oil production, oil rates and recovery factors, give us a better understanding of volatile oil fluid properties?
3. Which other variables can enable us to better understand the PVT and fluid properties of volatile oils?
4. What is the impact of the second phase (gas) in the two-phase flow models (compared to the single-phase models) on overall reservoir production performance?

To find answers to these questions and more, sensitivity analysis was done to illustrate the important parameters affecting production and behavior of shale volatile oil reservoirs. This will be explained better later in this thesis. Furthermore, compositional simulations with fluids of different compositions were done and the results compared to black-oil simulations.

5. Base Case Reservoir Simulation

The KAPPA Ecrin 4.30 reservoir simulation software was used for black-oil simulation of single-phase (oil) and two-phase (oil and gas) flows in the base case model. Single-phase and multiphase flow analyses can be done with KAPPA – using black-oil simulations. For multiphase compositional flow simulations, the software relies upon the Peng-Robinson thermodynamic equation of state (EOS). It contains some constants and exponents which may require some calibration before use. It allows for simulations of an arbitrary number of components, with the Peng-Robinson EOS used for the hydrocarbon phases. However, compositional simulation using the KAPPA Ecrin 4.30 software is very time consuming. Water phase (if any) is treated separately with correlations, considering it immiscible with no gas dissolved in it. The boundary conditions are limited to the "no flow" and "constant pressure" type (KAPPA, 2013). The simulations for all models considered in this work are isothermal.

A reservoir model consisting of 8 horizontal wells, with 20 hydraulic fractures spaced 250 ft apart was used for the base case model. 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 5000 ft. Overall dimensions of the reservoir model are 7000 ft long, 7000 ft wide and 250 ft thick. The simulation model is a single porosity system.

The fractures are all infinitely conductive. Fracture width of 2 ft was used. This is mainly for calculation purposes. Actual fracture width is about 0.2 inches. Wider fractures are used to make simulation go more smoothly. Fracture permeability is correspondingly reduced in order to keep the product of width and permeability (of the fractures) at an appropriate level. Also, this is possible because reservoir models with the

same fracture conductivity but different fracture widths yield similar results (Alkouh *et al.*, 2012).

Automatic gridding was used for the model. The fine geometrical 3-D grid contains 39218 cells and 77748 vertices. The initial reservoir pressure is 5000 psia and the wells produce for 30 years at a minimum bottomhole pressure constraint of 1000 psia. Figure 5-1 shows the pictorial representation of the base case model after gridding. Tables 5-1 and 5-2 show the reservoir data and the base case model parameters used.

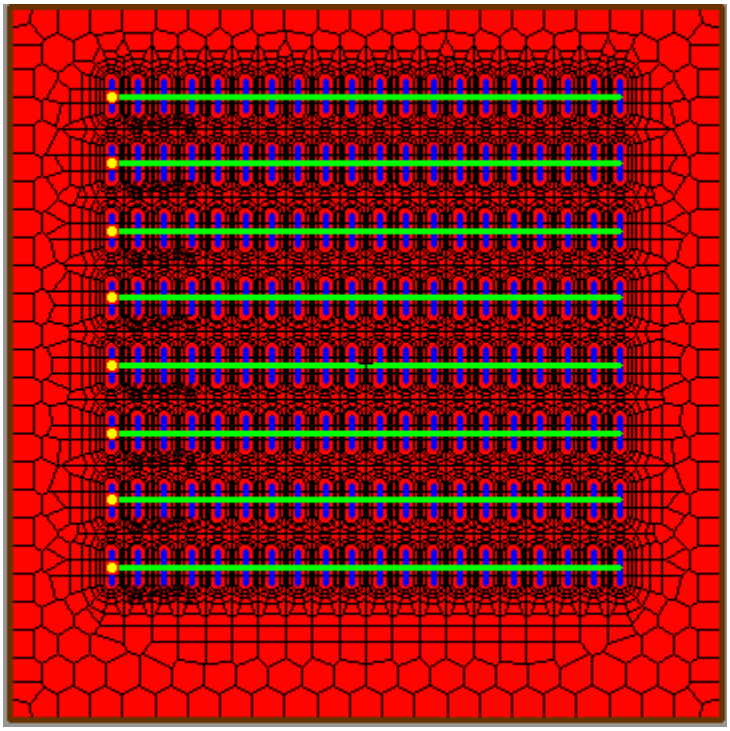


Figure 5-1 Base Case Model

Table 5-1 Reservoir Data for Base Case Model

Permeability	0.001 md
Porosity	0.06
Reservoir Temperature	250°F
Initial Reservoir Pressure	5000 psia
Depth to top of formation	10000 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 5-2 Parameters for Base Case Model

Number of wells	8
Distance between wells	660 ft
Horizontal well length	5000 ft
Fracture spacing	250 ft
Fracture half-length	150 ft
Fracture width	2 ft
Oil API gravity	42°API
Initial solution GOR	1500 scf/STB
Gas specific gravity (Air = 1)	0.75

Several correlations were used to generate values of PVT properties for oil and gas phases as a function of pressure. Table 5-3 shows the correlations used and properties calculated.

Table 5-3 Correlations Used for Black-Oil PVT tables - KAPPA Ecrin 4.30

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[2]
Oil formation volume factor, B_o	Standing	-	-
Oil compressibility, c_o	Vazquez - Beggs	-	-

5.1. Base Case Simulation Results

The reservoir model previously described was used to run single-phase and two-phase flow simulations for a period of 30 years. These were black-oil isothermal simulations. Simulation results for the single-phase flow case were then compared to results for the two-phase flow case. Figures 5.1-1 thru 5.1-4 show the base case simulation results comparing single-phase flow with two-phase flow for cumulative oil production, oil rates (semi-log plot), oil recovery factor and average reservoir pressure. It should be noted that the simulation results are for all the 8 horizontal wells combined. Figure 5.1-1 shows a higher cumulative oil production for the two-phase flow (oil and gas) case than the

[2] Internal correlations within the software

single-phase flow (oil) case. This is likely due to solution gas drive mechanism that drives production in the two-phase flow case. This is made possible by the presence of the second phase (gas) which is absent in the single-phase flow. The reservoir is initially in an under-saturated state, i.e., reservoir pressure is higher than bubble point pressure. No free gas exists until the reservoir pressure drops below bubble point. Before this occurs, production is mainly driven by the bulk expansion of reservoir rock and oil. When reservoir pressure drops below the bubble point, expansion of the dissolved gases in oil provide most of the reservoir drive energy. A higher cumulative oil production for the two-phase flow correspondingly leads to higher oil rate and oil recovery factor compared to the single-phase flow case. The oil recovery factor for the two-phase flow is about 7.6% compared to approximately 3.3% for the single-phase flow. These are evident in Figures 5.1-2 and 5.1-3.

There is a lesser pressure drop for two-phase flow than single-phase flow. During production, there is a fast decline in reservoir pressure above the bubble point. When reservoir pressure reaches the bubble point, pressure declines less rapidly due to formation of gas bubbles in the reservoir that expand and take up the volume exited by produced oil, hence protecting against pressure drops unlike in the single phase flow case. This is shown in Figure 5.1-4.

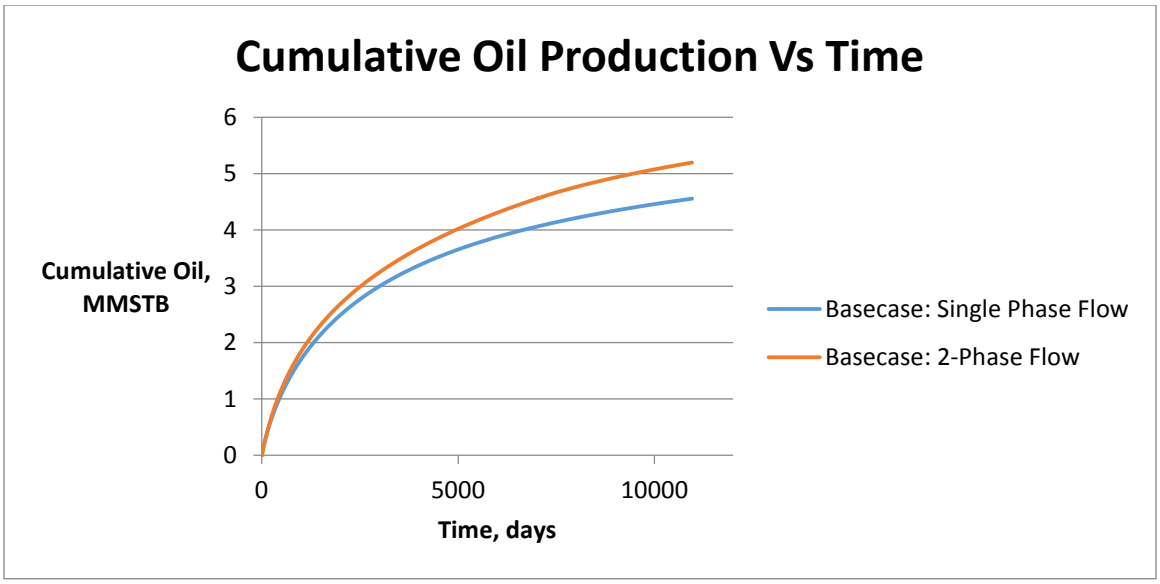


Figure 5.1-1 Base Case Comparisons - Cumulative Oil Production

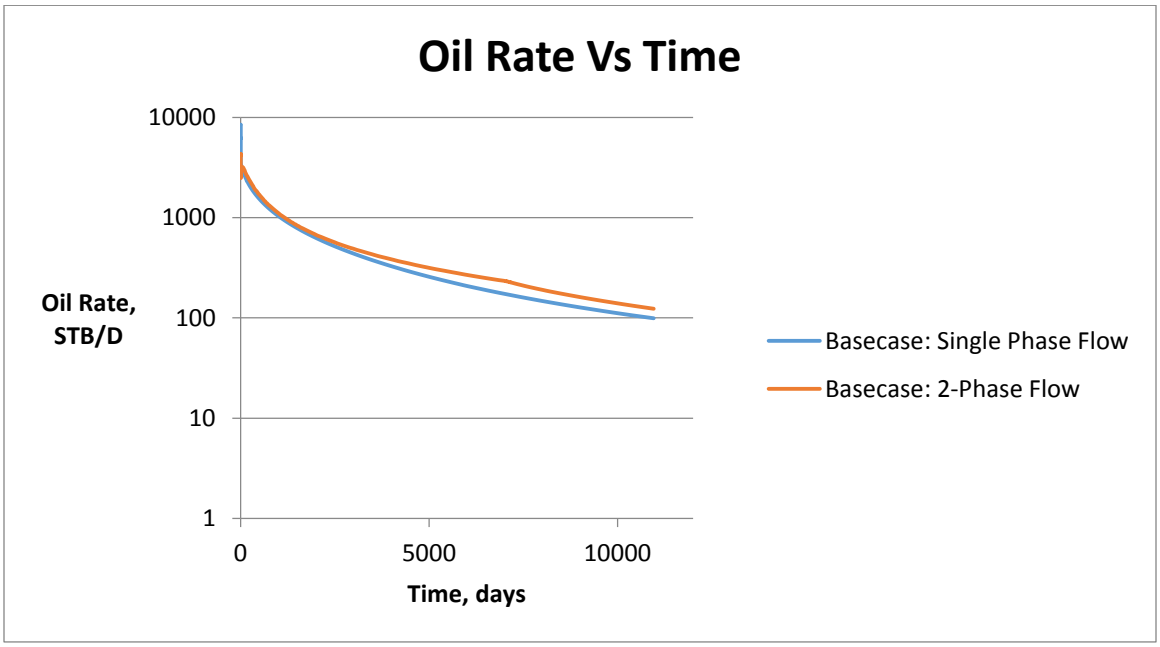


Figure 5.1-2 Base Case Comparisons - Oil Rate

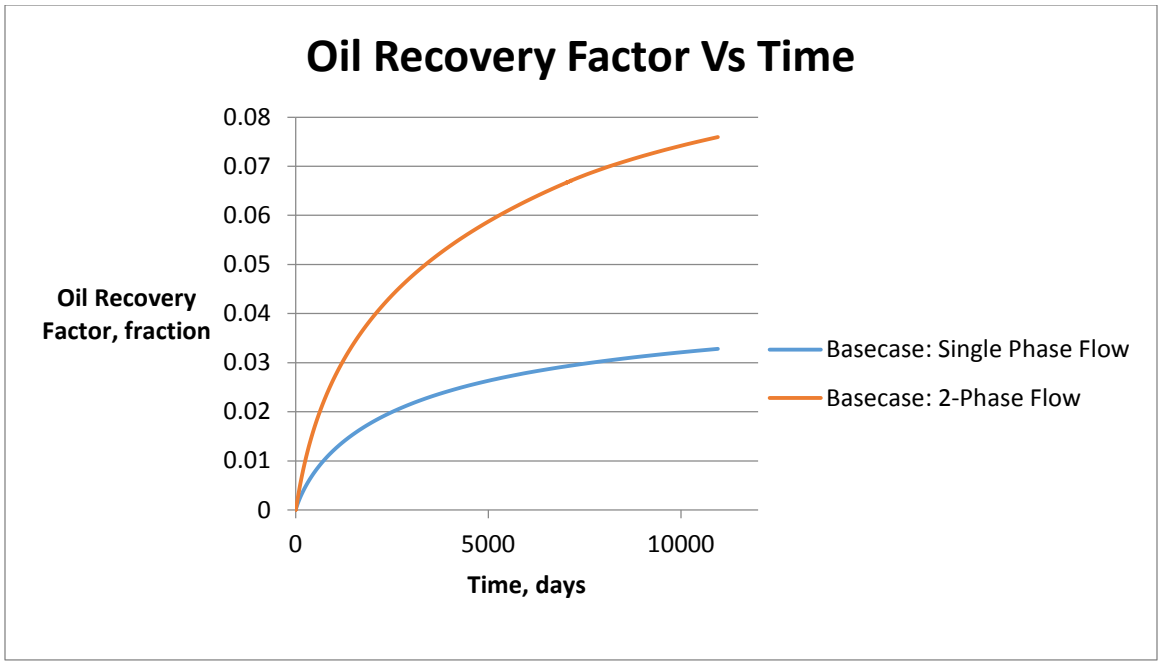


Figure 5.1-3 Base Case Comparisons - Oil Recovery Factor

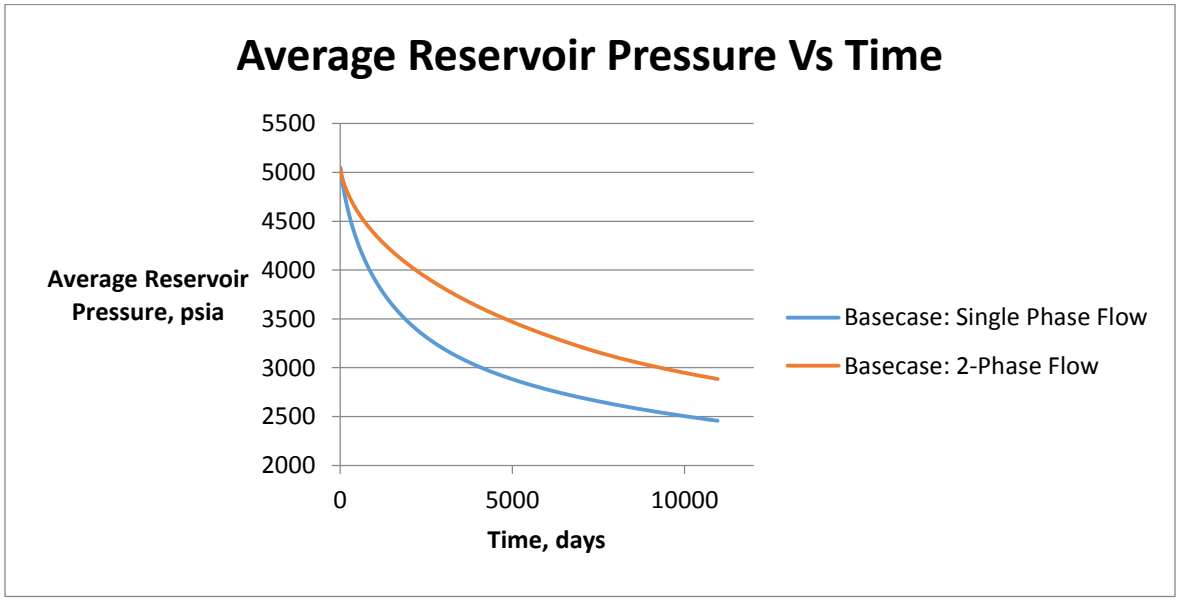


Figure 5.1-4 Base Case Comparisons - Average Reservoir Pressure

5.2. Base Case Diagnostic Plot

Log-log diagnostic plots were plotted for the base case model in order to identify the flow regimes that are present as production takes place in the reservoir. Figure 5.2-1 shows a log-log diagnostic plot of oil rate versus elapsed time. From the figure, an early transient bilinear flow (grey) was first observed, followed by a long period of linear flow (orange arrow with half slope) and some boundary dominated flow (blue arrow with unit slope) towards the end of production.

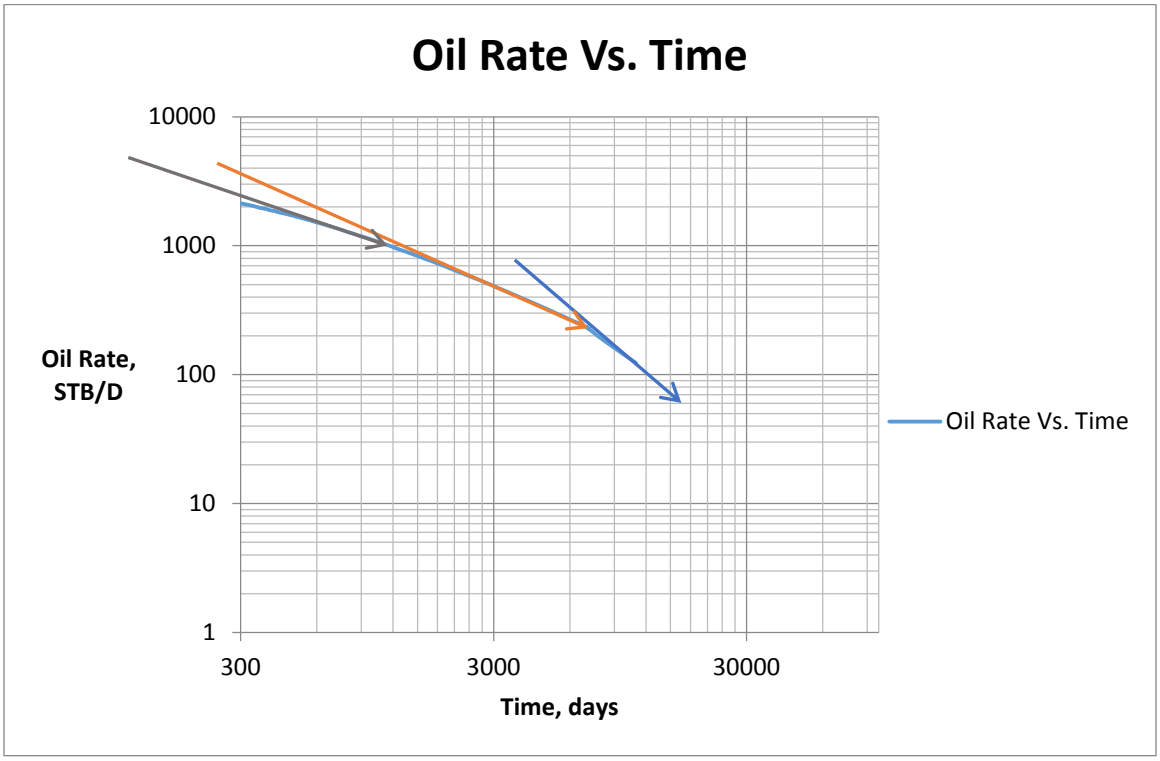


Figure 5.2-1 Log-log Diagnostic Plot of Oil Rate Vs Time - Base Case Model

Figure 5.2-2 shows a log-log diagnostic plot of oil rate versus material balance time. The material balance time (MBT) is calculated by dividing the cumulative oil production by oil rate. It is a superposition time function and it converts variable rate data into equivalent constant rate solution. From Figure 5.2-2, bilinear flow with a quarter slope

(light green arrow) was observed at early times, followed by a long period of transient linear flow (black and yellow arrows) and finally some linear flow (brown arrow with half slope) towards the end of production. Boundary dominated flow was not observed in this case, although the initial effects of boundaries caused the deviation from linear flow.

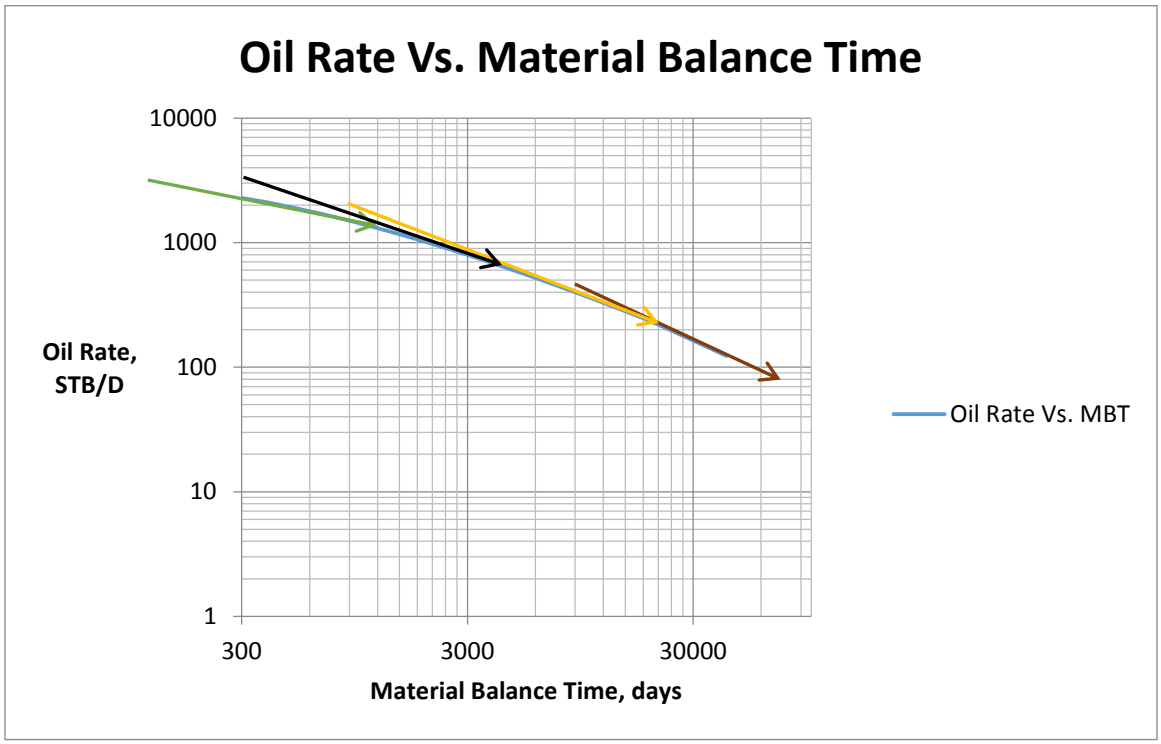


Figure 5.2-2 Log-log Diagnostic Plot of Oil Rate Vs Material Balance Time - Base Case Model

5.3. Simple Decline Models – Base Case Simulation

Decline curve analysis provides a means of predicting future production from a well or group of wells by extrapolating available field data. Simple decline models were tested on the base case simulation (oil rate) data to know which one fits. The simple decline models considered are the Arps decline model, the Stretched Exponential Production Decline (SEPD) model and the Duong's model. This was done with the aid of FEKETE reservoir simulation software.

The three types of Arps decline model equations are:

1. Exponential decline (b = 0), $q_t = q_i * exp[-D_i t]$; $(5.3 - 1)$
2. Hyperbolic decline (0 < b < 1), $q_t = \left[\frac{q_i}{(1 + bD_i t)^{\frac{1}{b}}}\right]$; $(5.3 - 2)$
3. Harmonic decline (b = 1), $q_t = \left[\frac{q_i}{(1 + bD_i t)}\right]$, $(5.3 - 3)$

where b is the Arps' decline constant, q_i is the stabilized rate at t = 0, q_t is the production rate at time t and D_i is the decline rate at flow rate q_i.

For the SEPD model, the following equation is used:

1. $q_t = q_i * \exp\left[\left(-\frac{t}{\tau}\right)^n\right]$, $(5.3 - 4)$

where q_i is the initial production rate, q_t is production rate that varies with time, n is the exponent parameter for the SEPD model and τ is a characteristic time parameter. The Duong's model equations are:

1. $q_t = q_1 t^{-n}$; $(5.3 - 5)$
2. $t_D = t^{-m} * \exp\left[\frac{a}{1-m}(t^{1-m} - 1)\right]$; $(5.3 - 6)$

3. $q_t = q_i t_D + q_\infty,$ $(5.3 - 7)$

where a and m are empirical constants, t_D is the dimensionless time, q_1 is the stabilized rate at time t = 1, q_t is the production rate at time t and q_∞ is the intercept of the plot q_t vs. t_D.

The first six months of the data was discarded and the start date was from the 7th month. The 30 years forecast was based on approximately 3 years of the simulated production (oil rate) data history. Figure 5.3-1 shows that the Arps decline model (red) shows an almost perfect fit with simulated data (green). The Arps' decline constant, b is equal to one. The SEPD model (blue) underestimated production while the Duong's model (yellow) overestimated production.

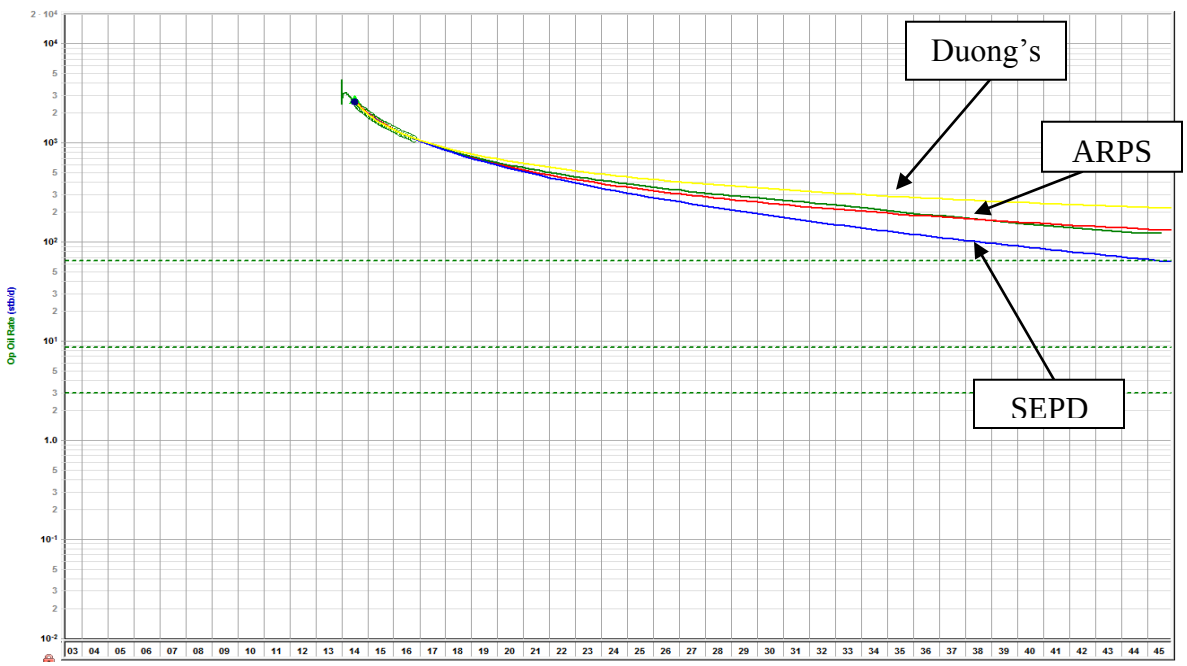


Figure 5.3-1 Comparison of Simple Decline Models - Base Case (Oil Rate Vs Time)

5.4. Four-Well Case

The base case simulation of single-phase and two-phase flows was repeated using 4 horizontal wells. The distance between the wells is twice that of the original base case model already discussed, i.e., 1320 ft (660 ft from one well to half adjacent distance of the other). All other parameters are the same as the original base case model. An illustration of the two models side by side is shown in Figure 5.4-1 below. The results of the simulation were compared to the original 8-well base case model. Figures 5.4-2 thru 5.4-7 show the simulation results for single-phase and two-phase flow compared to the original base case model.

For both the single-phase and two-phase flow cases, there is higher cumulative oil production, oil rate and oil recovery factor for the 8-well base case model compared to the 4-well case. This is an expected result, as there are more wells and more hydraulic fracture stages overall in the 8-well case than in the 4-well case. Also, closer distance between the wells in the 8-well case ensures a larger stimulated reservoir volume (SRV), which ultimately leads to more production.

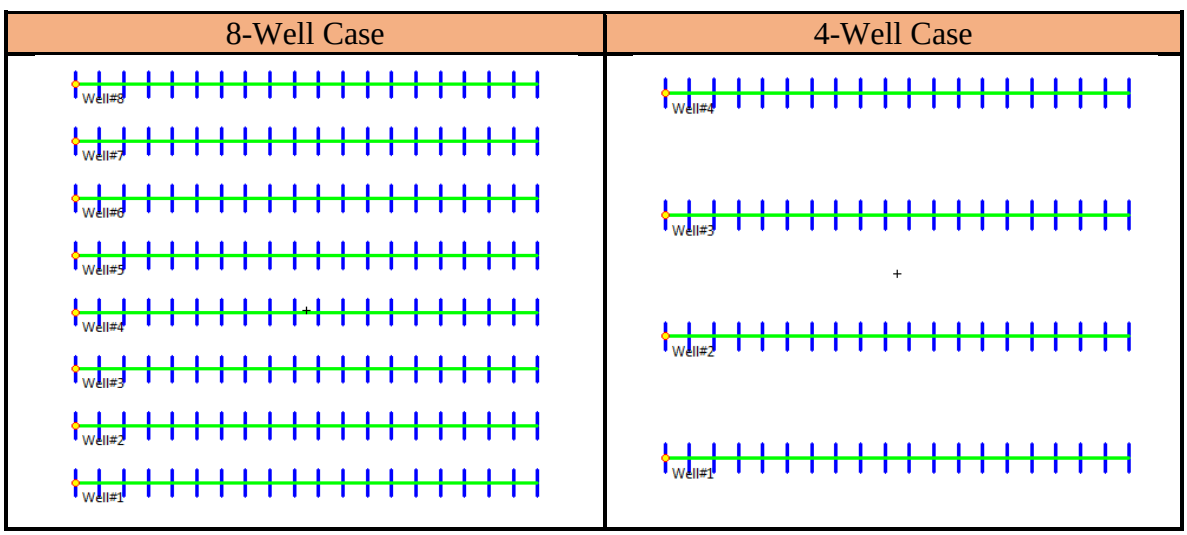


Figure 5.4-1 Pictorial representation of 4-Well and 8-Well Cases

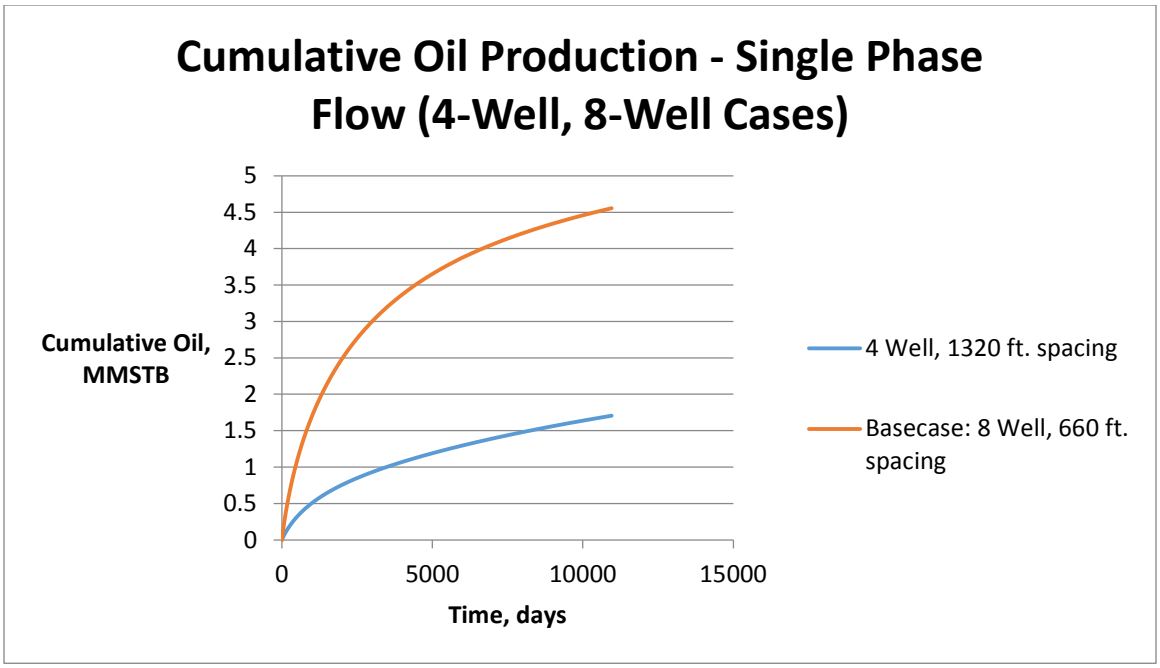


Figure 5.4-2 Four-Well Single-Phase Case Comparisons - Cumulative Oil Production

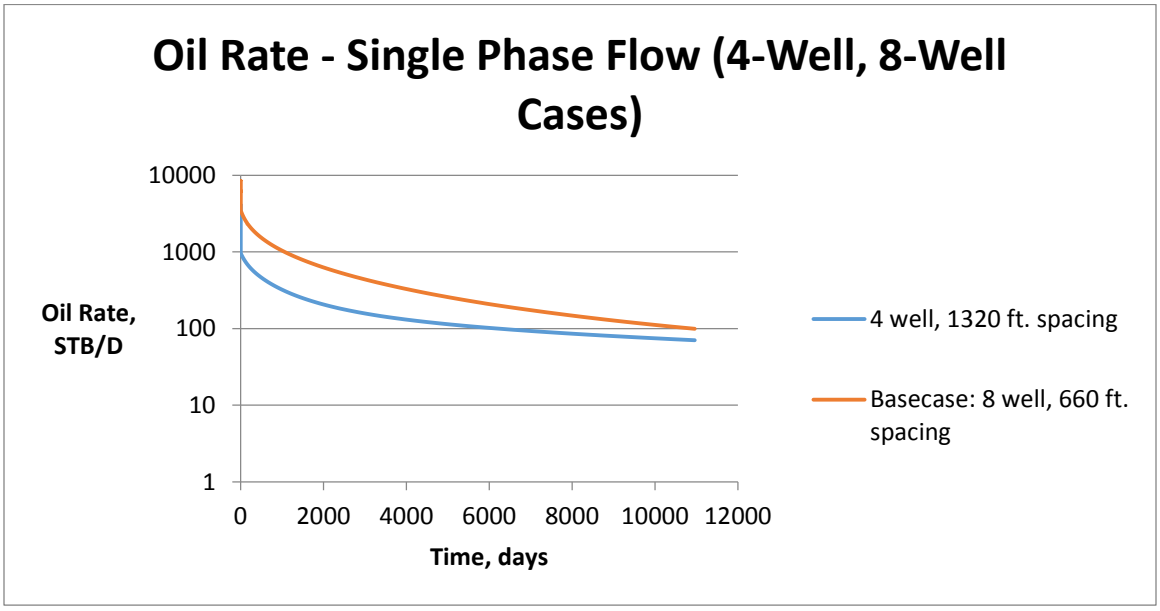


Figure 5.4-3 Four-Well Single-Phase Case Comparisons - Oil Rate

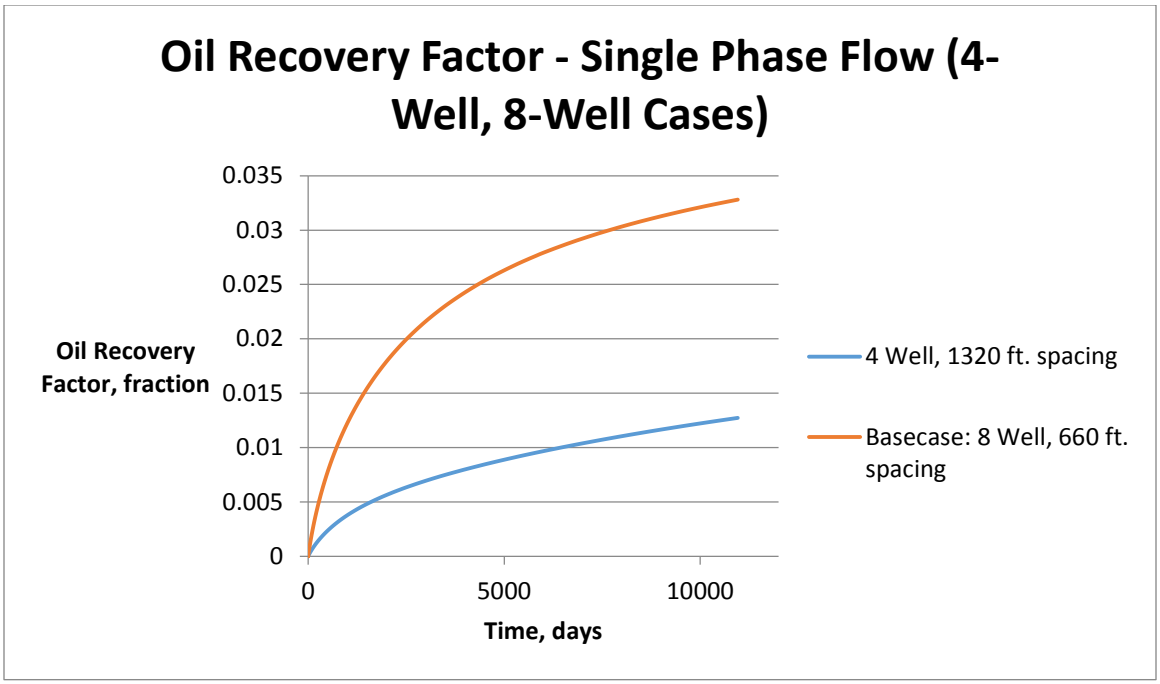


Figure 5.4-4 Four-Well Single-Phase Case Comparisons - Oil Recovery Factor

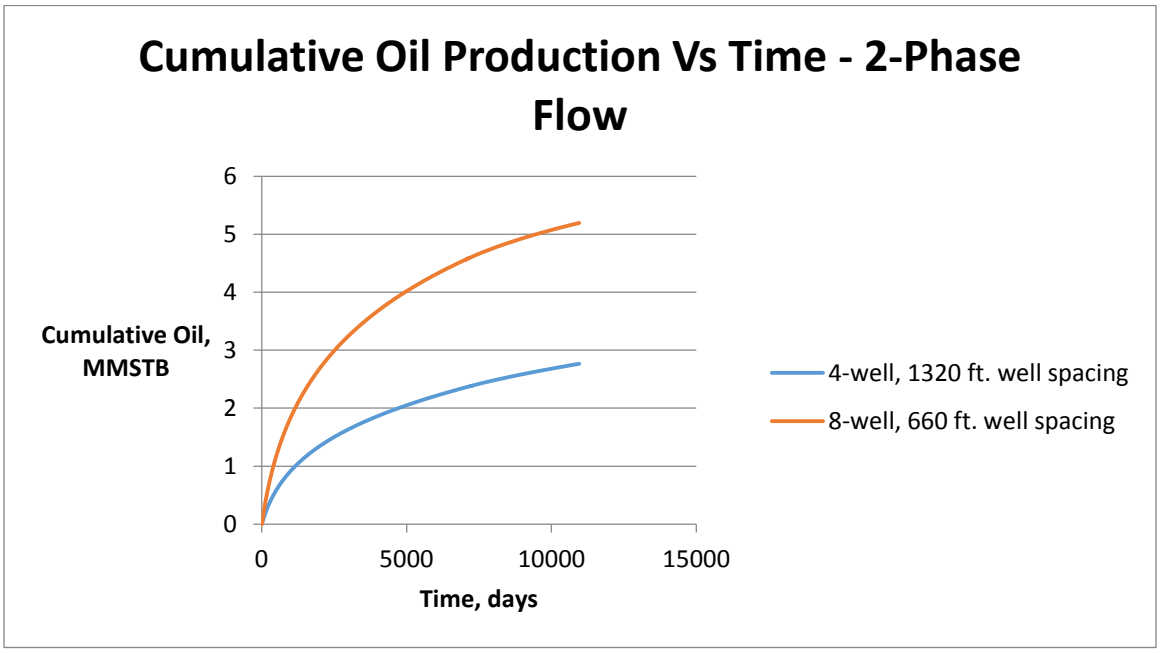


Figure 5.4-5 Four-Well Two-Phase Case Comparisons - Cumulative Oil Production

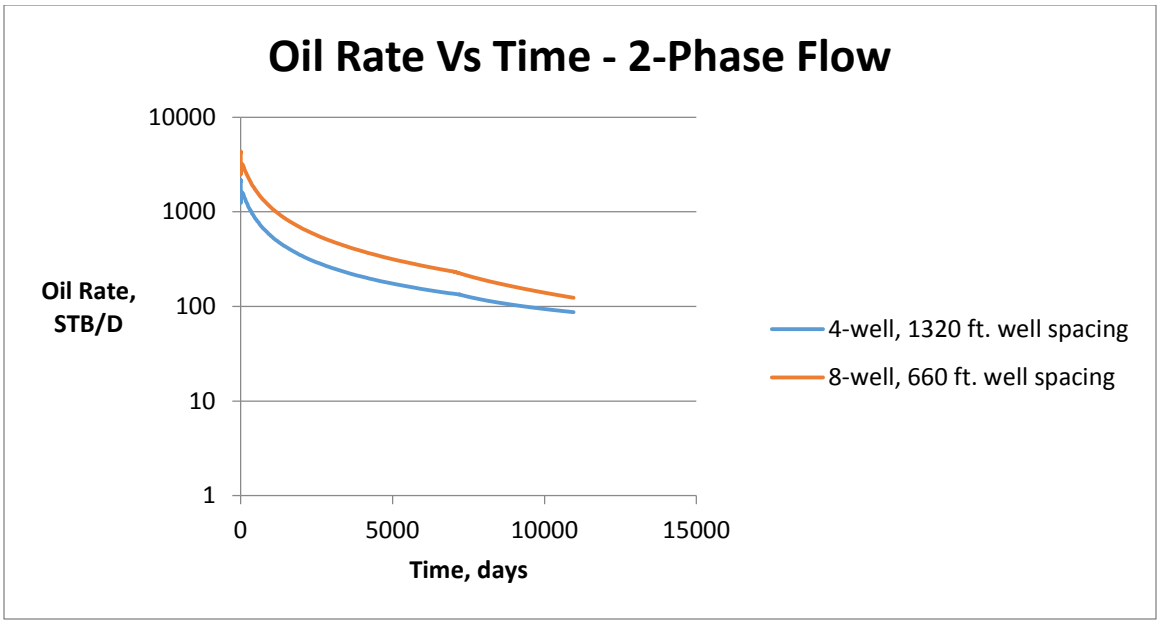


Figure 5.4-6 Four-Well Two-Phase Case Comparisons - Oil Rate

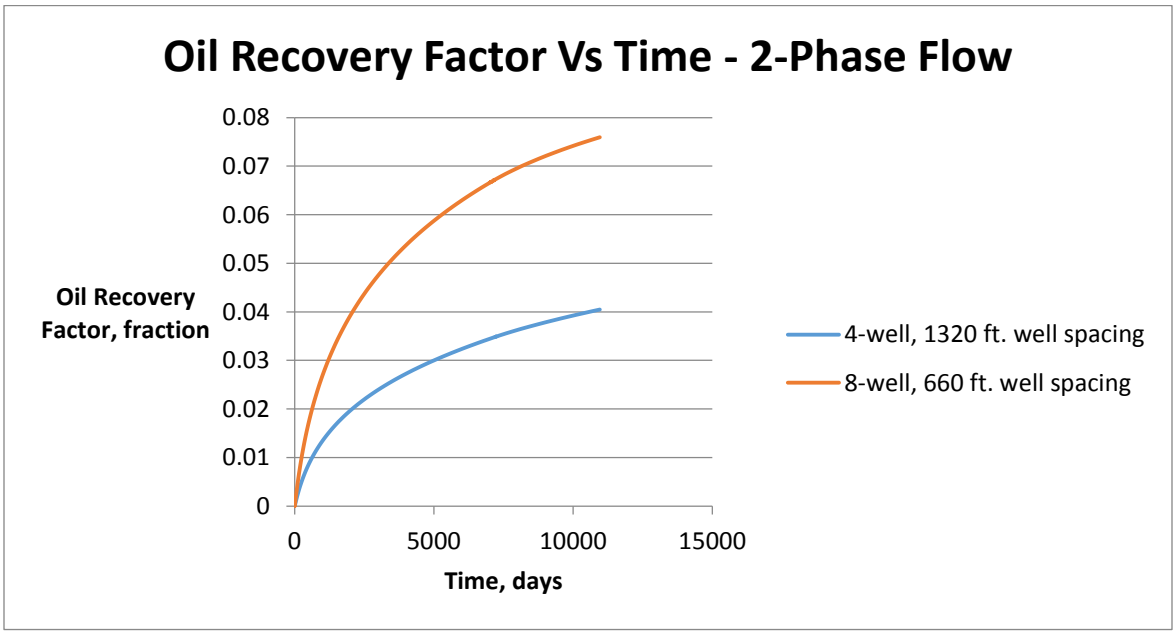


Figure 5.4-7 Four-Well Two-Phase Case Comparisons - Oil Recovery Factor

6. Sensitivity Studies

Sensitivity studies were carried out to ascertain the important parameters that affect production performance in shale volatile oil reservoirs. 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. The results can help us understand the behavior of shale volatile oil reservoirs, as well as make better well completion methods and design possible. All the simulations were isothermal black-oil simulations of single-phase and two-phase flows using KAPPA Ecrin 4.30. All the results were compared to the base case simulation results.

6.1. Fracture Spacing

Fracture spacing is a key parameter to be considered during well completions. Reservoir engineers can generate different scenarios to help completion engineers find the optimum spacing necessary for their operations.

The fracture spacing used for the base case simulation is 250 ft (20 fractures) on horizontal wells of 5000 ft length. Two other scenarios were considered – 100 ft (50 fractures) and 500 ft (10 fractures). Figures 6.1-1 thru 6.1-6 show the effect of fracture spacing on cumulative oil production, oil rate and oil recovery factor for the 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. Even though closer fracture spacing (more fracture stages) requires a higher completion cost per well, it eventually means better drainage of the SRV within

a shorter period of time. A detailed net present value (NPV) analysis can be done to determine the optimum fracture spacing.

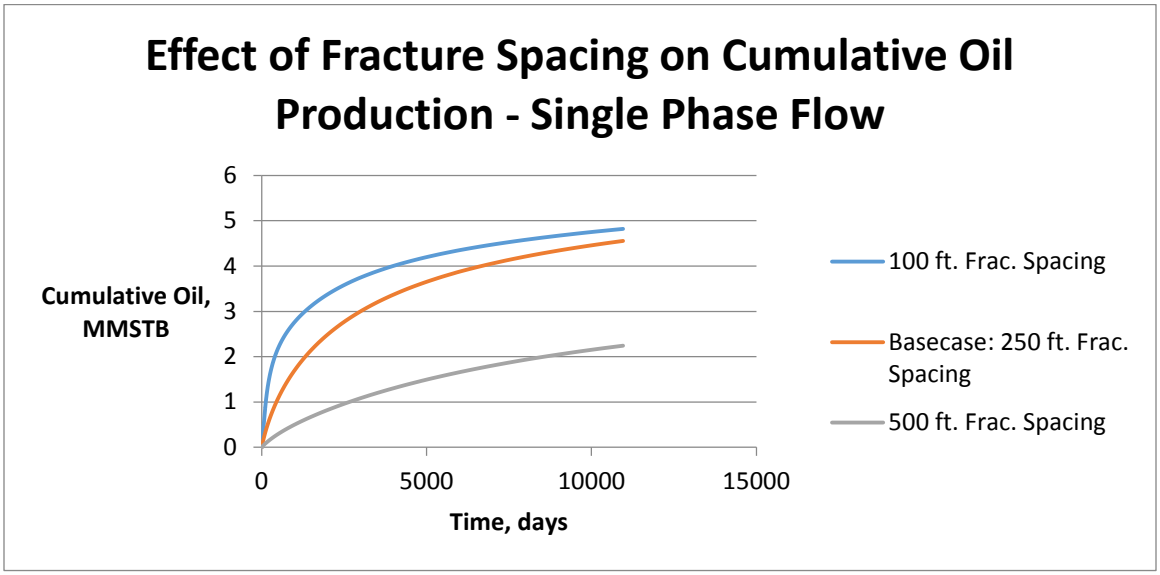


Figure 6.1-1 Fracture Spacing Single-Phase Case Comparisons - Cumulative Oil Production

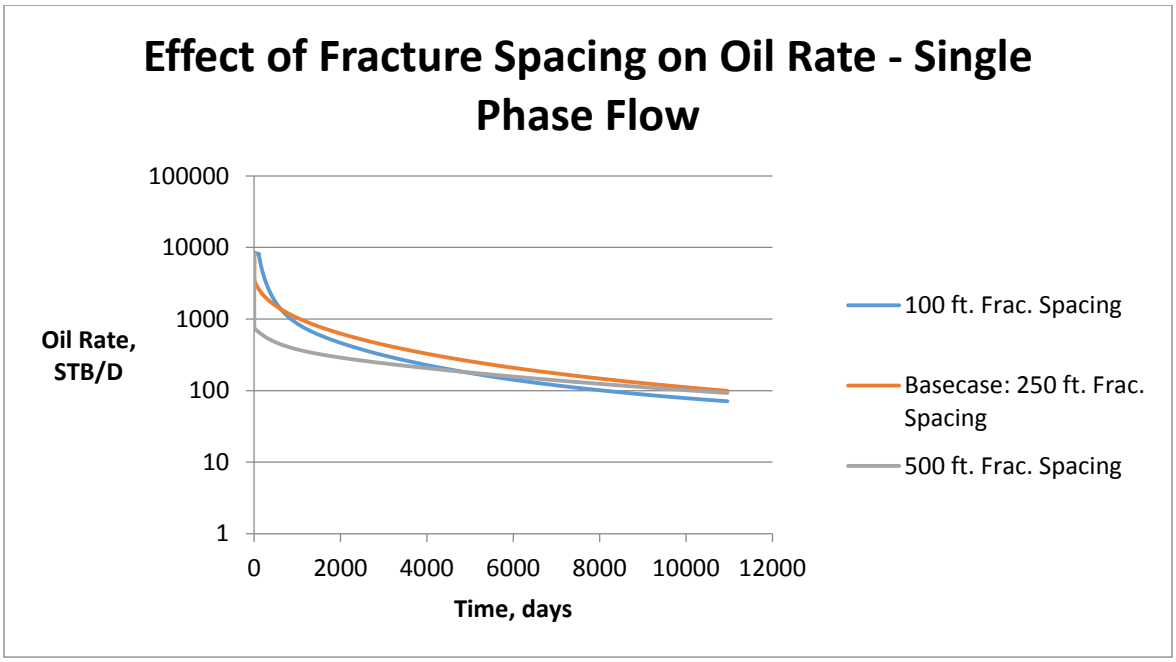


Figure 6.1-2 Fracture Spacing Single-Phase Case Comparisons - Oil Rate

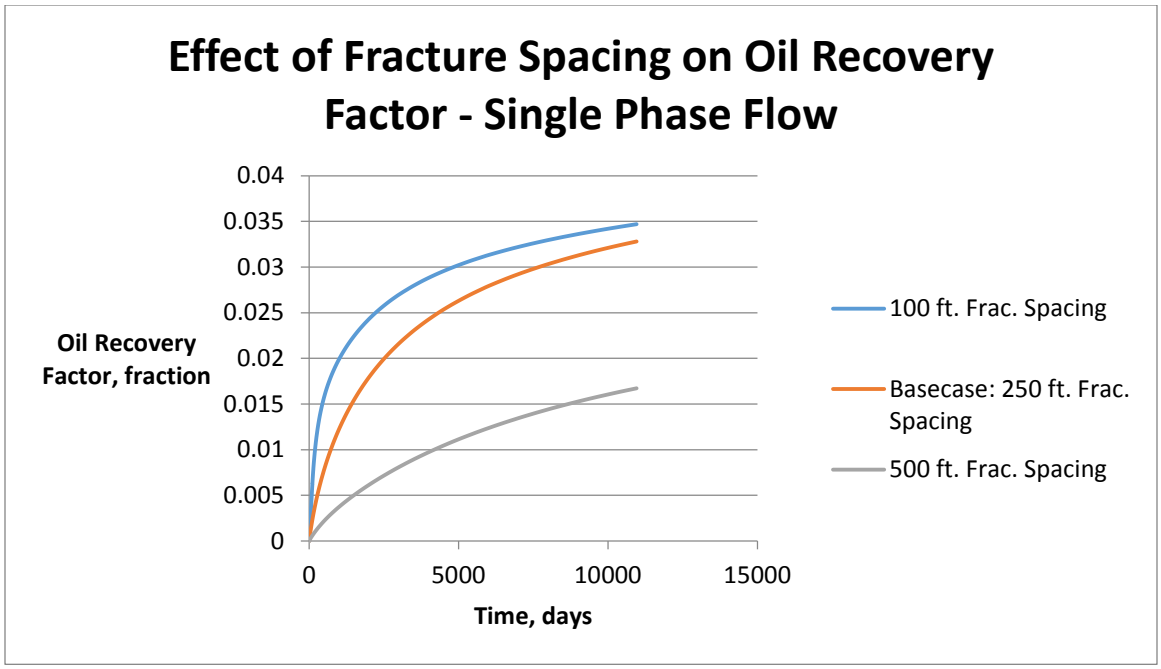


Figure 6.1-3 Fracture Spacing Single-Phase Case Comparisons - Oil Recovery Factor

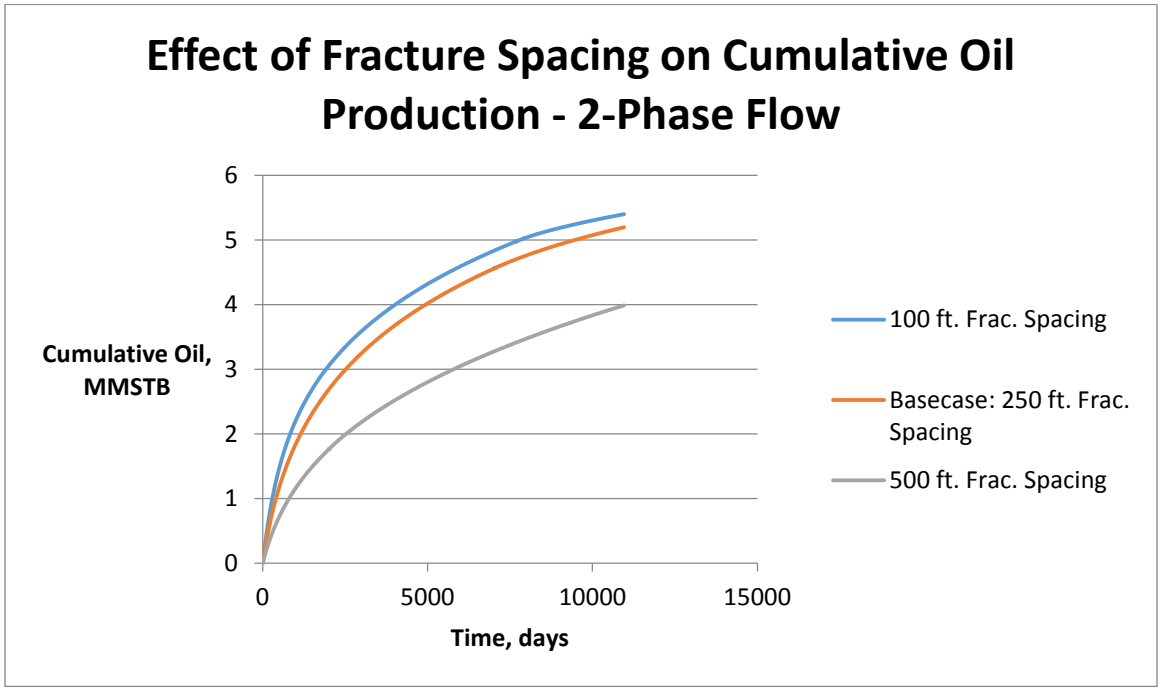


Figure 6.1-4 Fracture Spacing Two-Phase Case Comparisons - Cumulative Oil Production

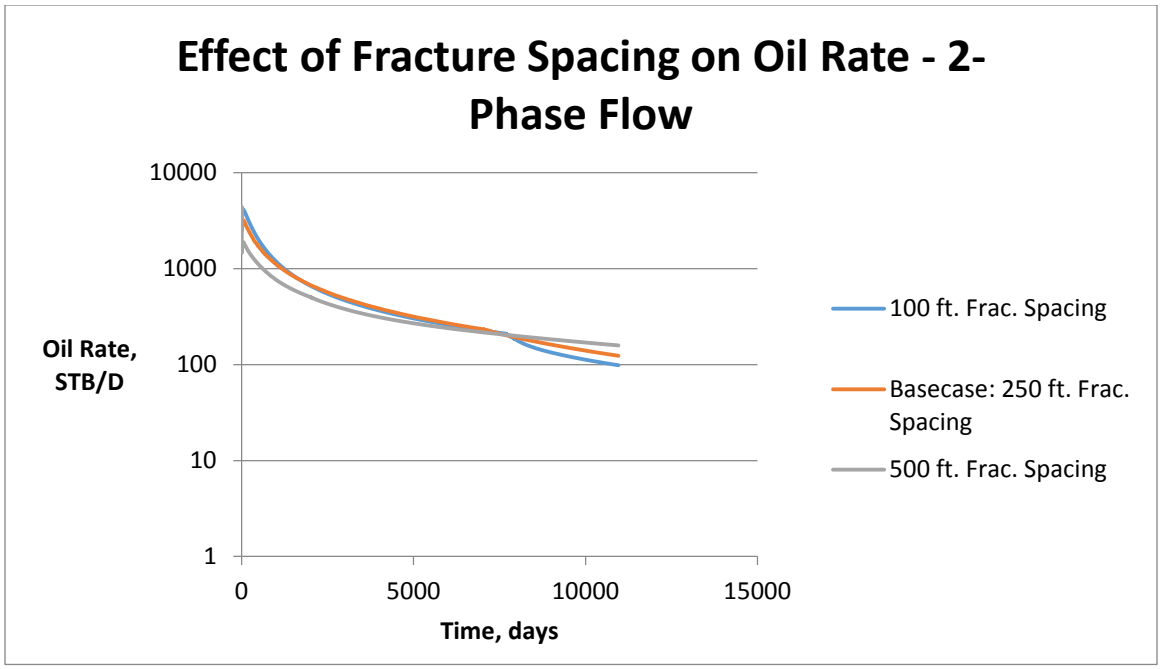


Figure 6.1-5 Fracture Spacing Two-Phase Case Comparisons - Oil Rate

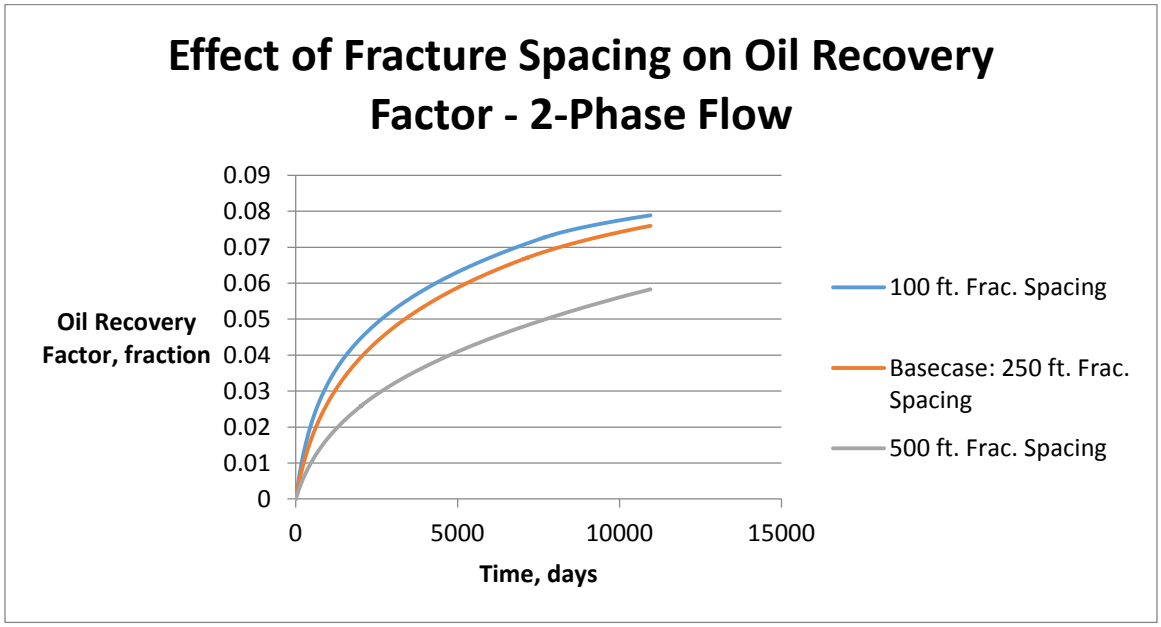


Figure 6.1-6 Fracture Spacing Two-Phase Case Comparisons - Oil Recovery Factor

6.2. Fracture Half-Length

Fracture half-length is the distance from the well to the tip of the fracture. It is also a vital parameter for well completions and design especially in shale formations. Three scenarios were considered – fracture half-lengths of 100 ft, 200 ft and 300 ft. The fracture half-length used for the base case simulation is 150 ft. Figures 6.2-1 thru 6.2-6 show the effect of fracture half-length on cumulative oil production, oil rate and oil recovery factors for single-phase and two-phase flow cases.

Results indicate 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. Each well can drain more volume of the reservoir with larger fracture half-lengths.

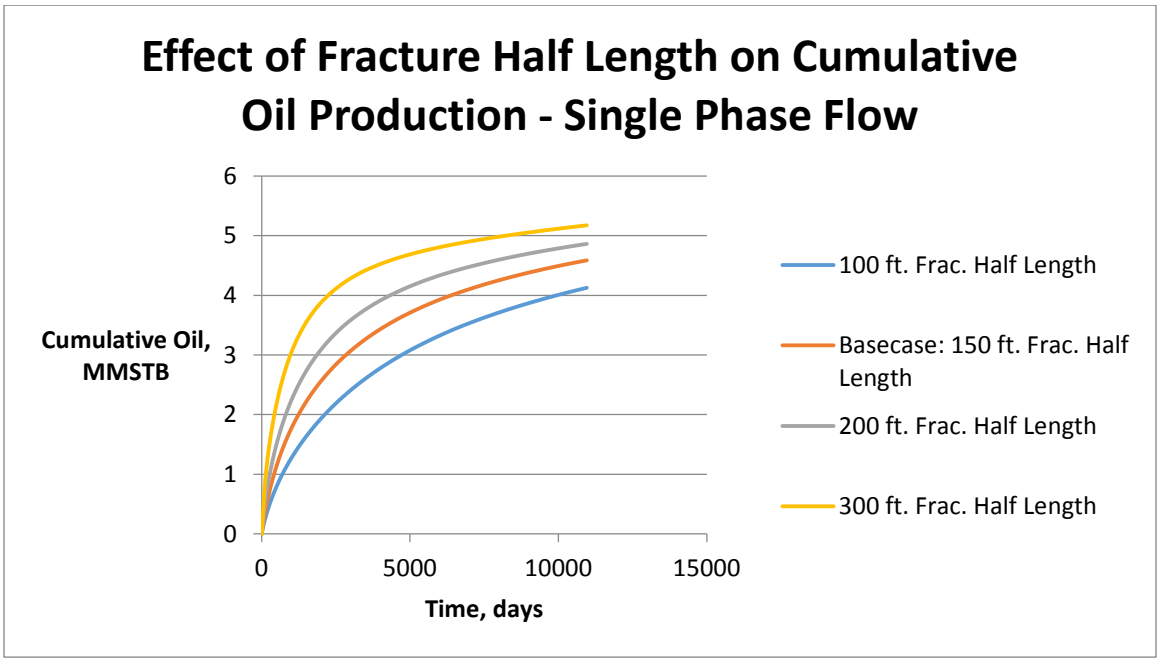


Figure 6.2-1 Fracture Half-Length Single-Phase Case Comparisons - Cumulative Oil Production

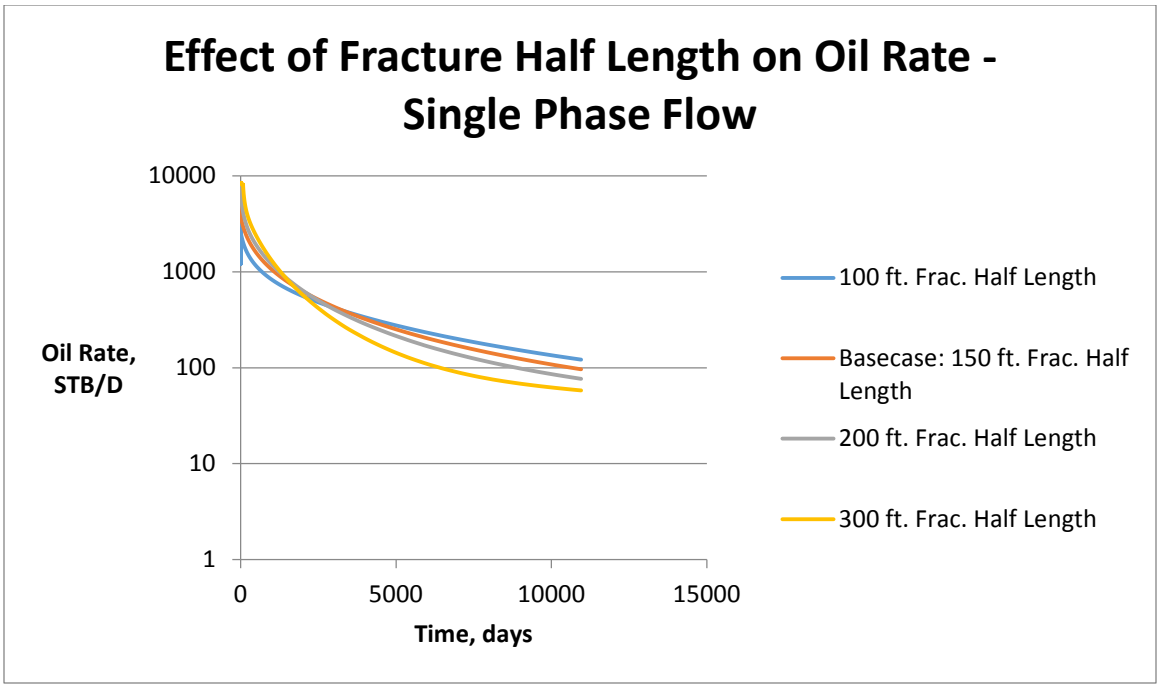


Figure 6.2-2 Fracture Half-Length Single-Phase Case Comparisons - Oil Rate

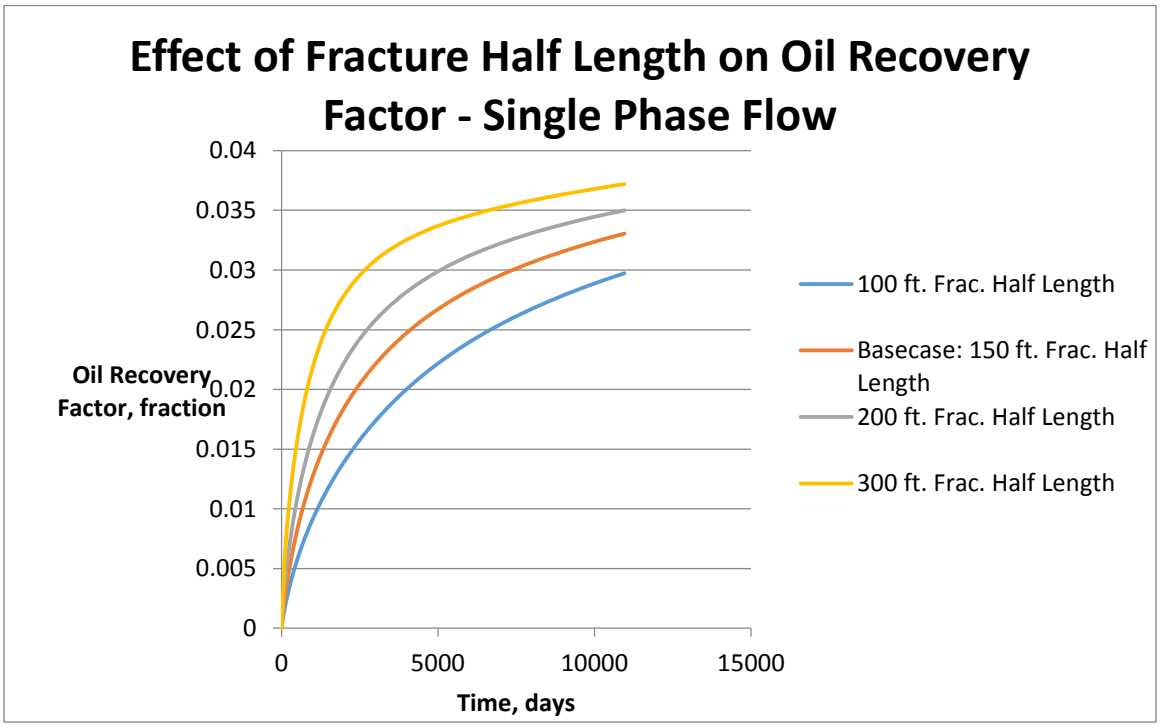


Figure 6.2-3 Fracture Half-Length Single-Phase Case Comparisons - Oil Recovery Factor

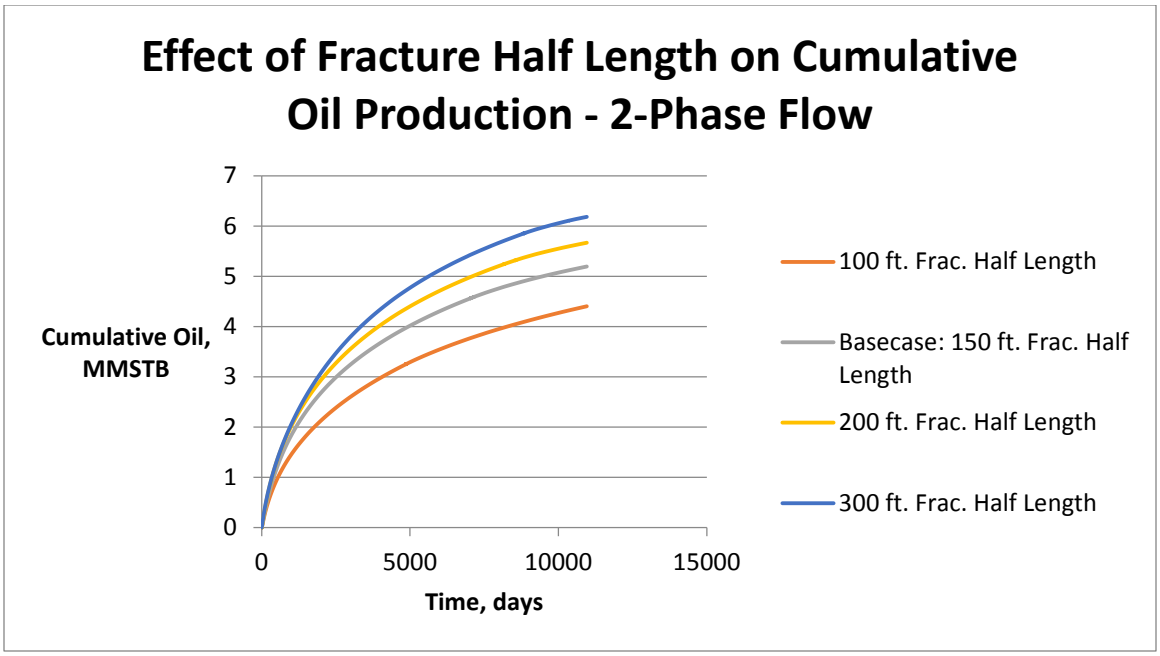


Figure 6.2-4 Fracture Half-Length Two-Phase Case Comparisons - Cumulative Oil Production

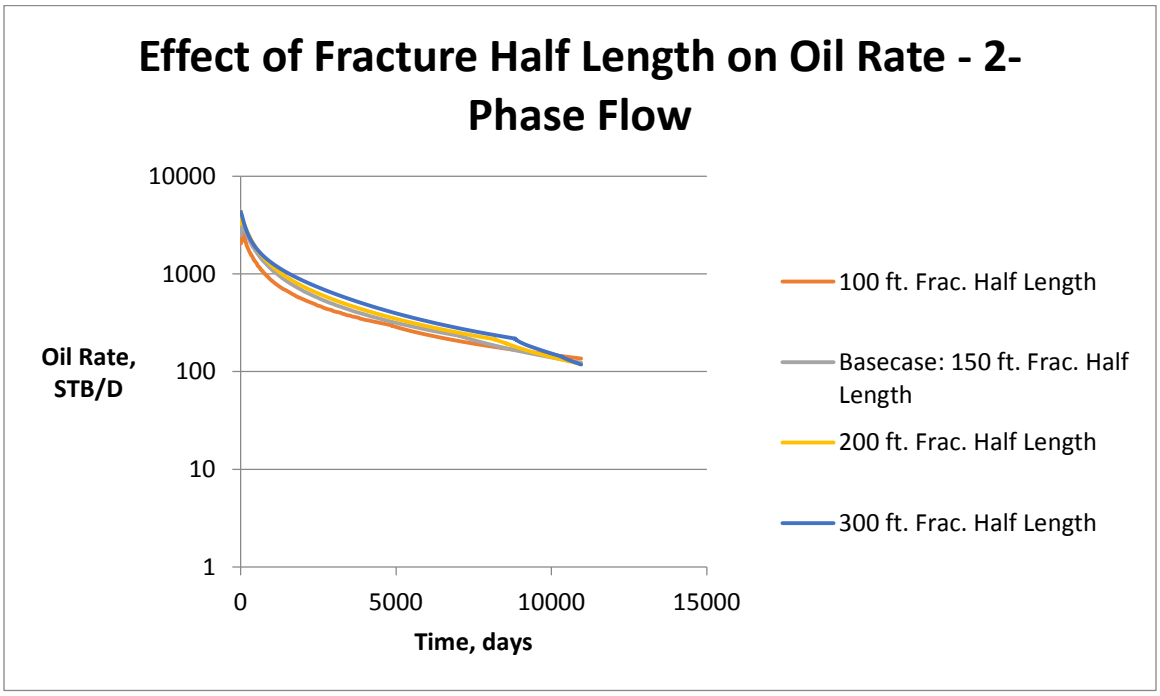


Figure 6.2-5 Fracture Half-Length Two-Phase Case Comparisons - Oil Rate

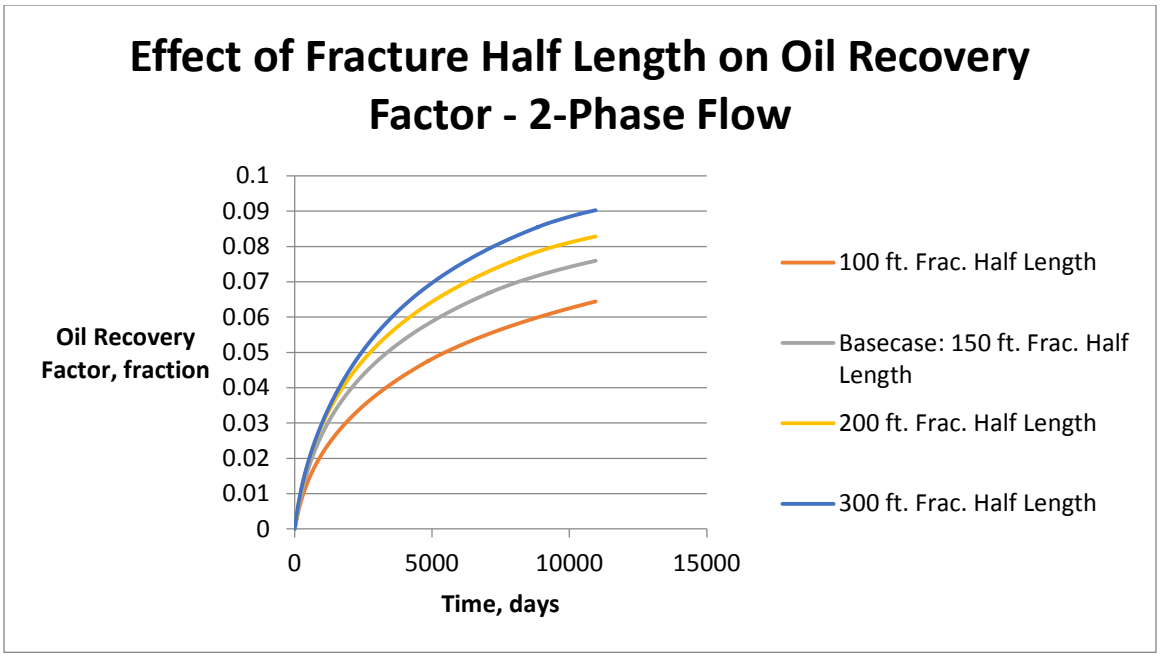


Figure 6.2-6 Fracture Half-Length Two-Phase Case Comparisons - Oil Recovery Factor

6.3. Oil API Gravity

The following sensitivity study was done in order to understand how shale volatile oil reservoir performance is influenced by fluid properties. The oil API gravity is considered in this case. Oil API gravity is inversely correlated to the specific gravity of oil; hence heavier oils have low API gravities and lighter oils, higher API gravities. The viscosity of oil increases with lower API gravity and it decreases with higher API gravity. Simulations were run for both single-phase and two-phase flow scenarios. 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 considered. Two additional cases were added for the two-phase flow simulations in order to better illustrate the impact of this vital fluid property on the behavior of shale volatile oil reservoirs. Oil API gravity of 42° was used for the base case simulations. Figures 6.3-1 thru 6.3-8 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 simulations, the higher the oil API gravity, the higher the cumulative oil production. This is because the higher the oil API gravity, the lighter the oil and the lower the viscosity – indicating higher oil mobility. Similarly, the study shows that the higher the oil API gravity, the higher the oil recovery factor. Further, the single-phase flow simulation sensitivity study indicates that the initial oil production rates are higher, with higher oil API gravity. Also, the lower the oil API gravity, the slower the rate of decline of average reservoir pressure and vice versa.

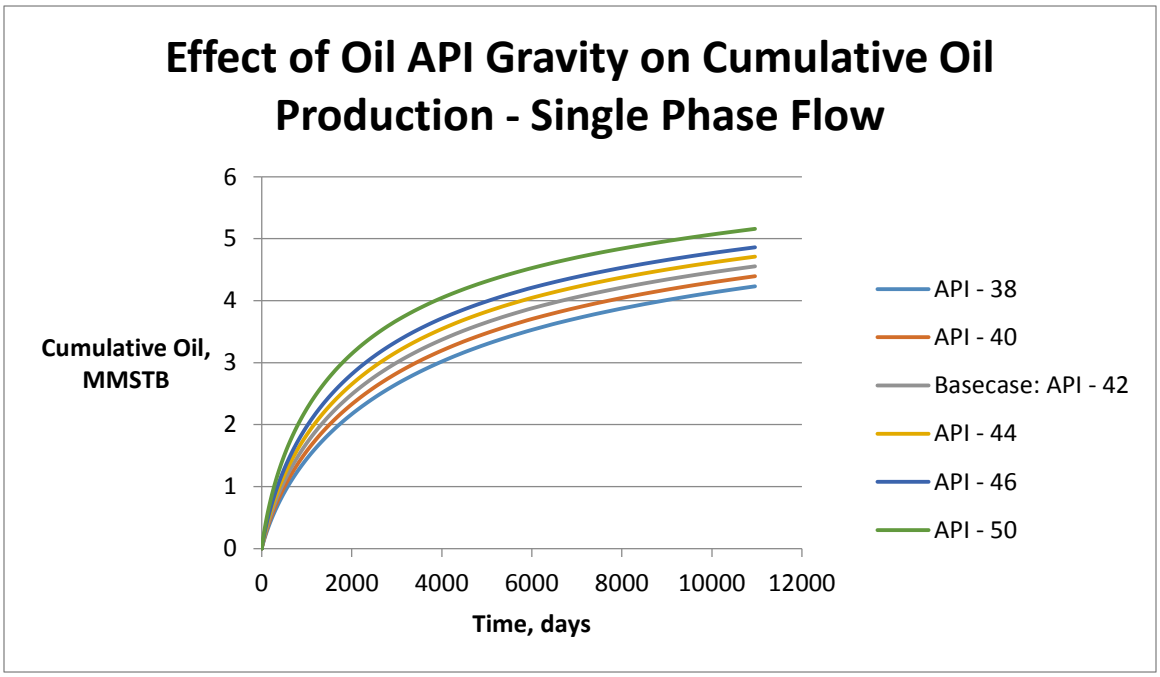


Figure 6.3-1 Oil API Gravity Single-Phase Case Comparisons - Cumulative Oil Production

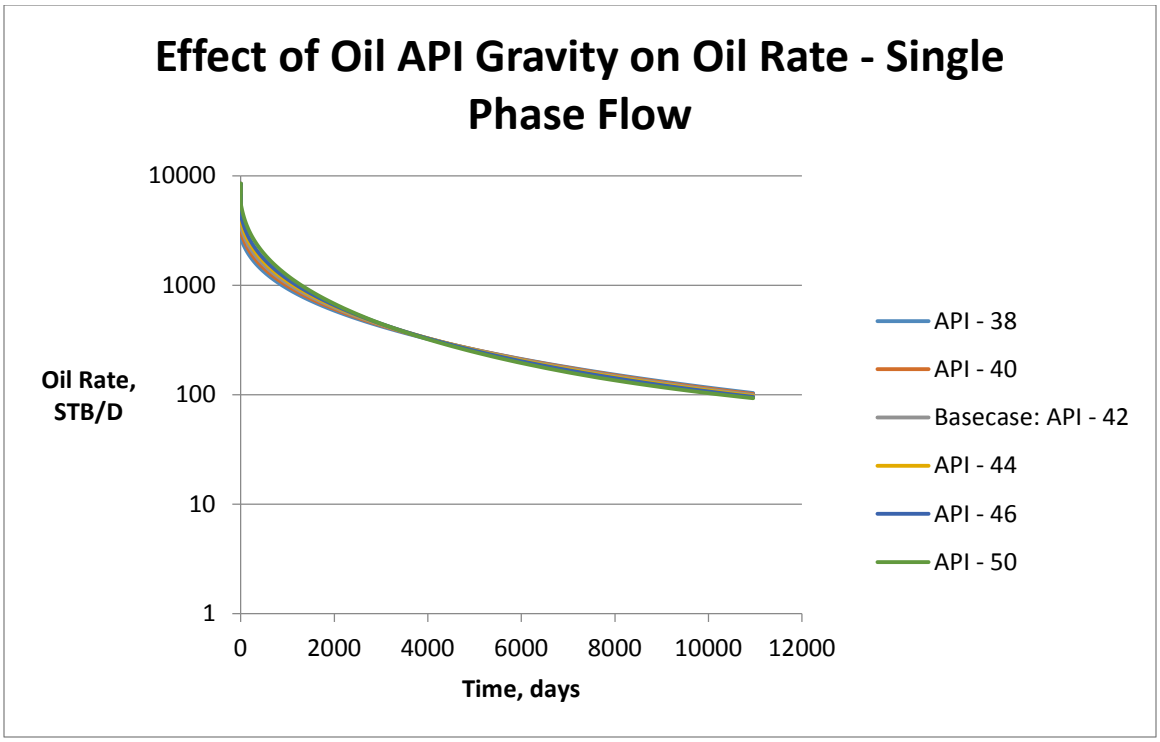


Figure 6.3-2 Oil API Gravity Single-Phase Case Comparisons - Oil Rate

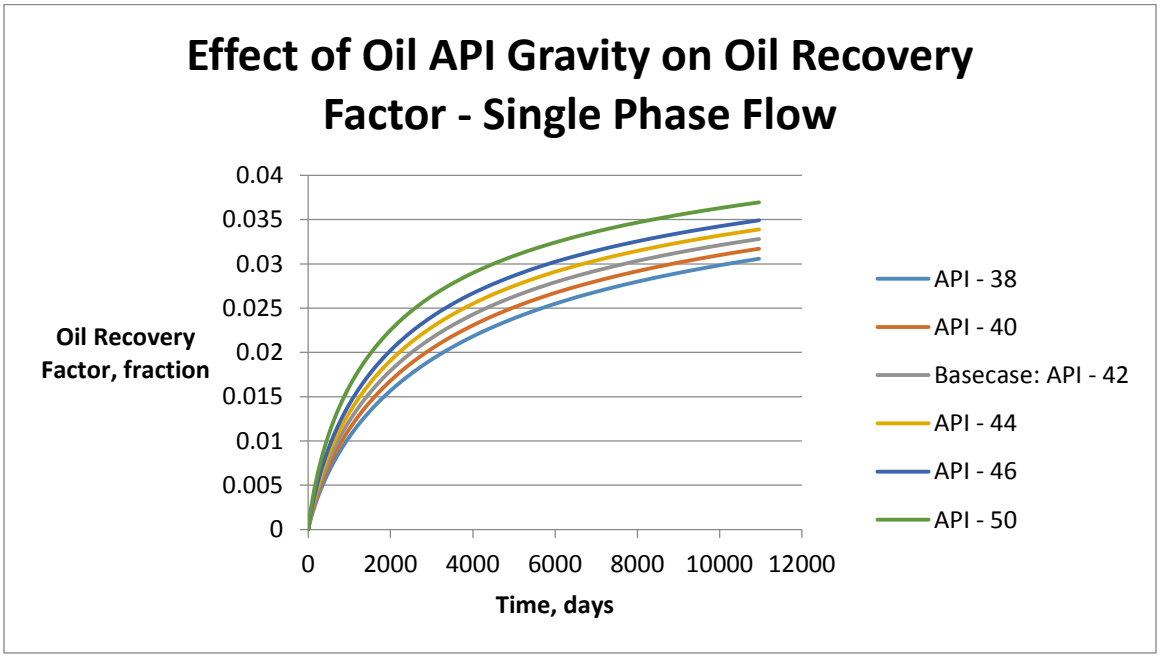


Figure 6.3-3 Oil API Gravity Single-Phase Case Comparisons - Oil Recovery Factor

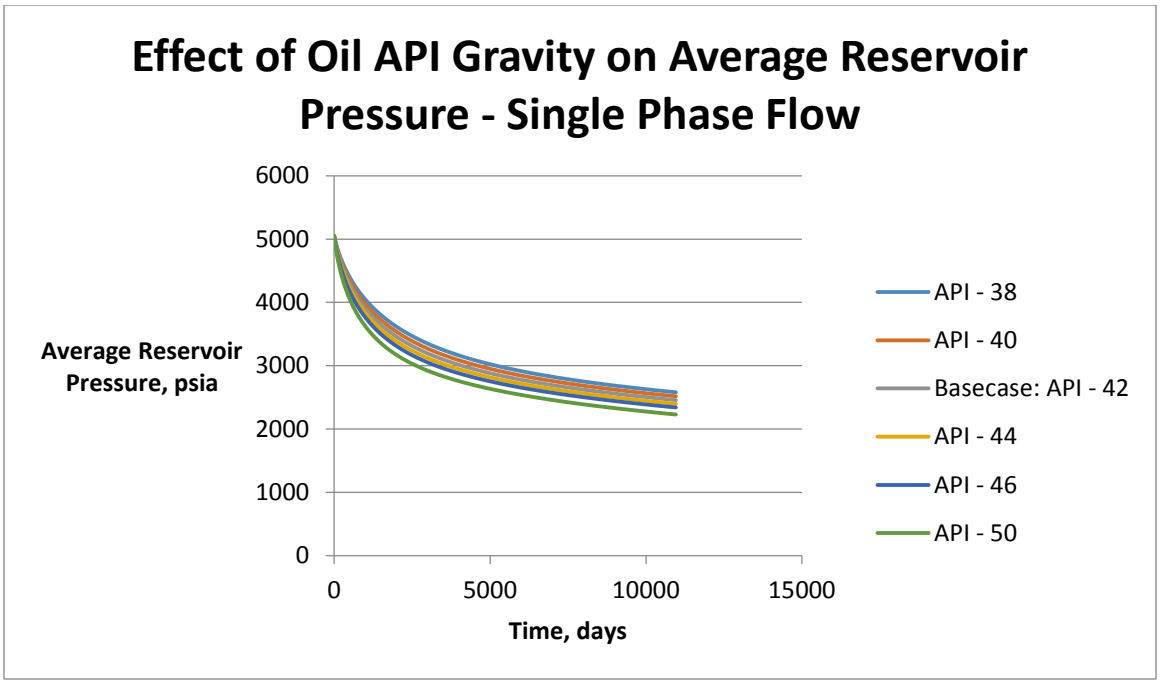


Figure 6.3-4 Oil API Gravity Single-Phase Case Comparisons - Average Reservoir Pressure

Results of the two-phase flow simulations give us a good illustration 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 impede oil flow to the wellbore – ultimately leading to a decline in cumulative oil production. This study shows that the higher the oil API gravity, the lower the cumulative oil production. This is illustrated in Figure 6.3-5. The higher the oil API gravity, the more lighter components the fluid contains. These lighter components of the fluid contribute to gas saturation around the wellbore, thereby decreasing cumulative oil production with time. Table 6.3-1 shows actual production forecast data from simulation 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 however, increases with increasing oil API gravity. Furthermore, Figure 6.3-9 shows how

average gas saturation increases with increasing oil API gravity. This further corroborate the explanations above on how increasing oil API gravity decreases cumulative oil production.

In addition, two-phase flow simulation results 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 illustrated in Figure 6.3-7, 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 6.3-8.

Table 6.3-1 Forecast after 30 years 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

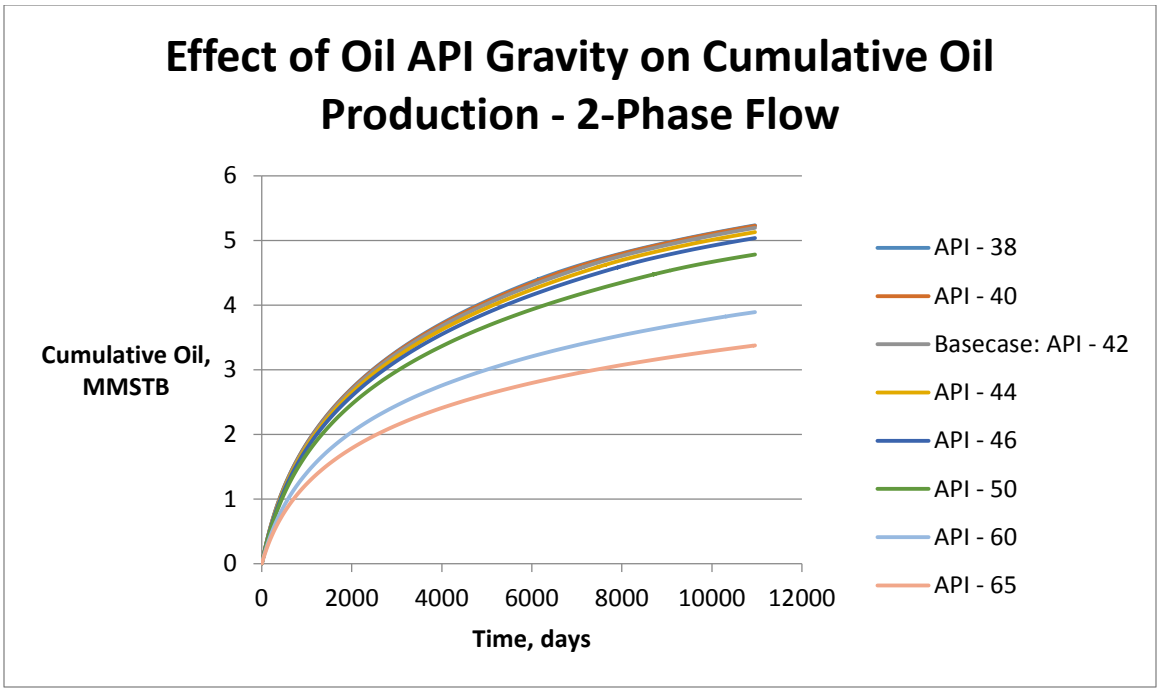


Figure 6.3-5 Oil API Gravity Two-Phase Case Comparisons - Cumulative Oil Production

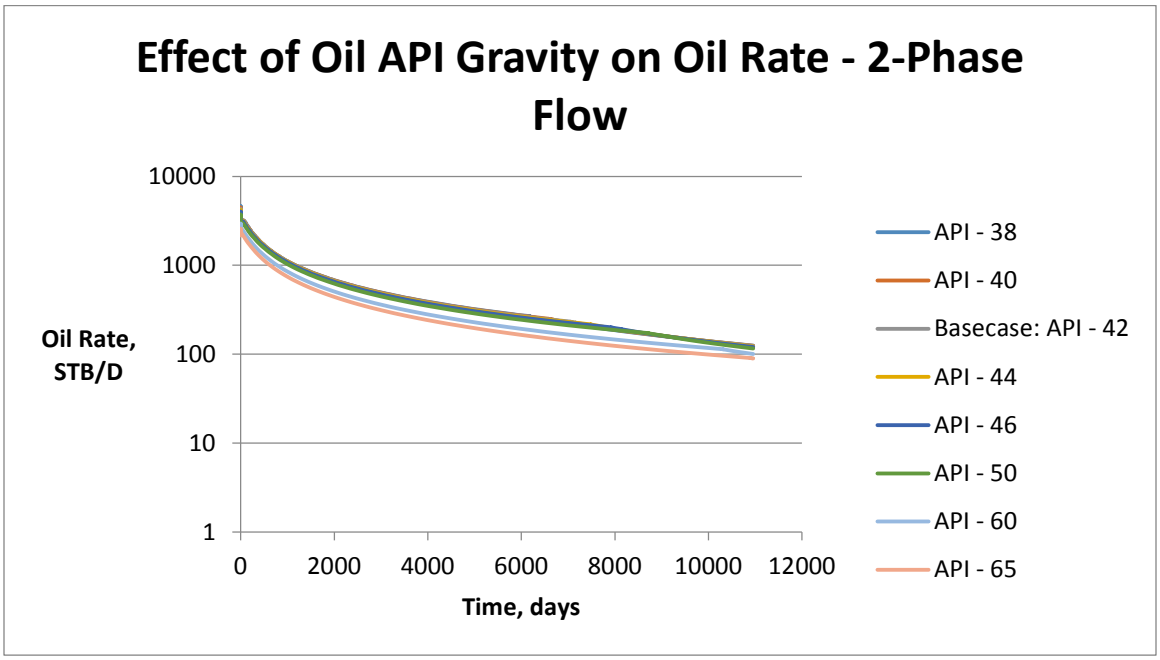


Figure 6.3-6 Oil API Gravity Two-Phase Case Comparisons - Oil Rate

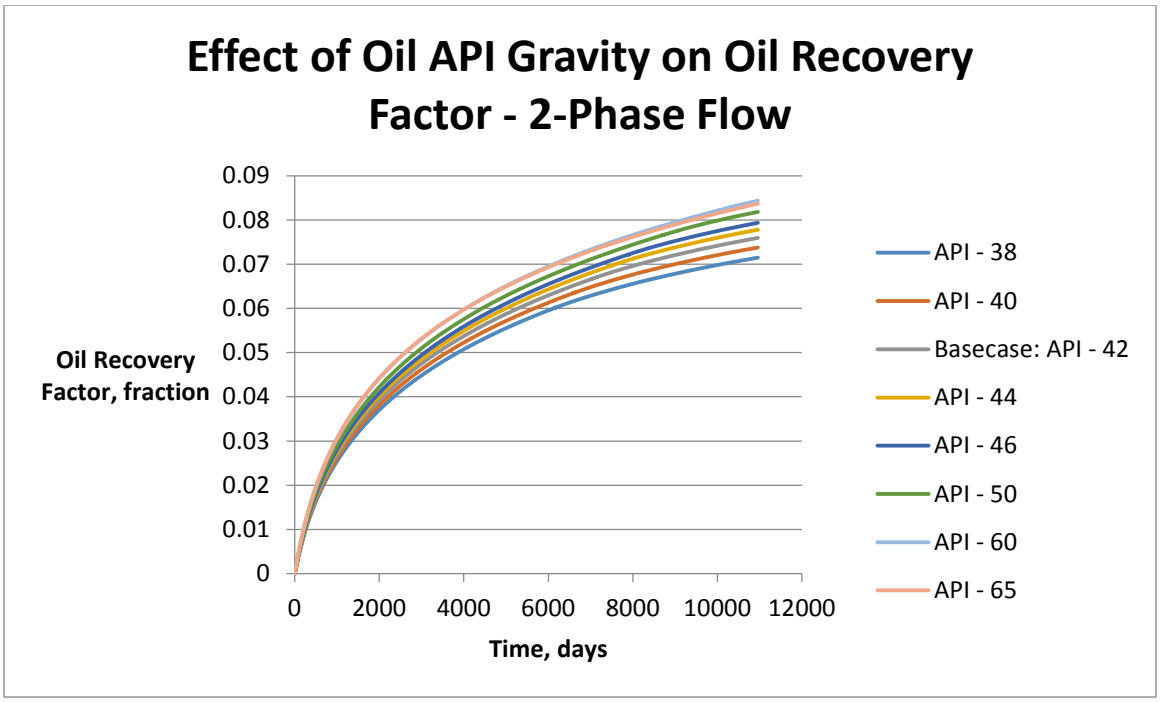


Figure 6.3-7 Oil API Gravity Two-Phase Case Comparisons - Oil Recovery Factor

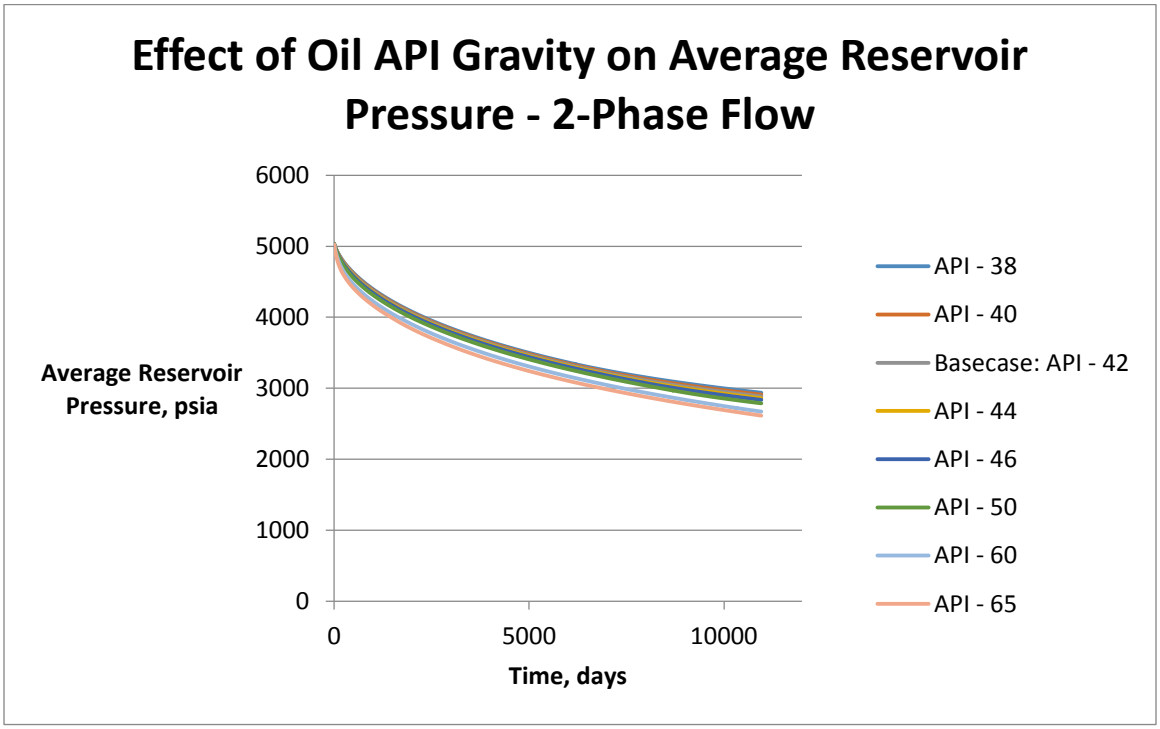


Figure 6.3-8 Oil API Gravity Two-Phase Case Comparisons - Average Reservoir Pressure

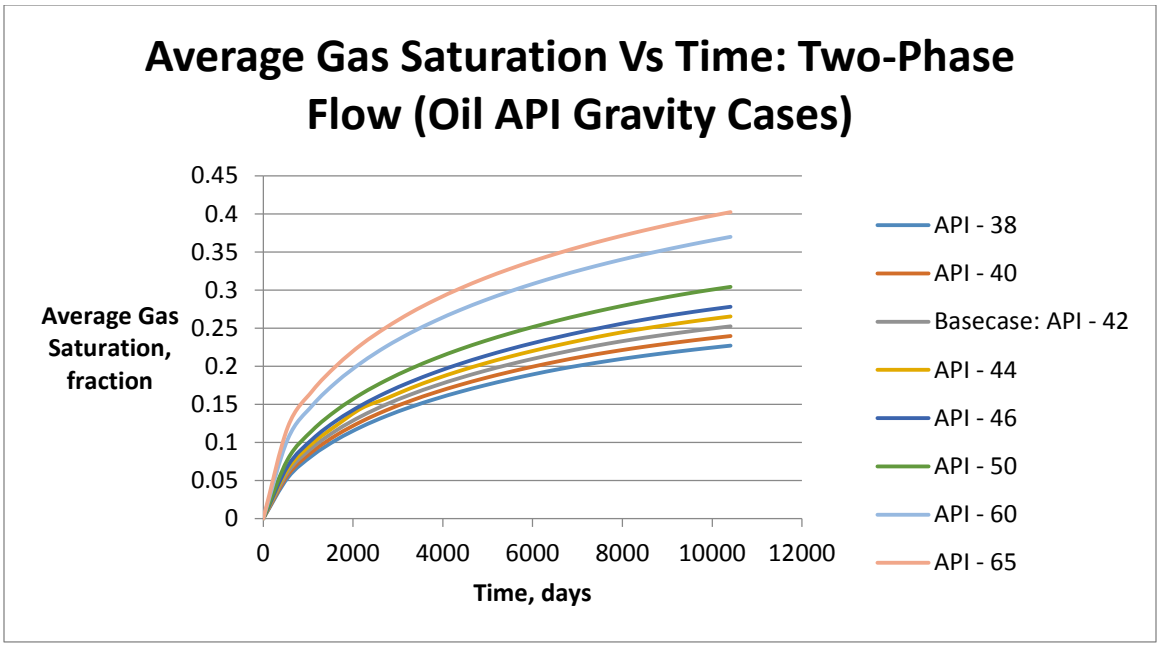


Figure 6.3-9 Oil API Gravity Two-Phase Case Comparisons - Average Gas Saturation

6.4. Critical Gas Saturation

When reservoir pressure drops below the bubble point in an oil reservoir, gas evolves out of solution. This gas is immobile until it builds up to a certain threshold value called the critical gas saturation. At and above the critical gas saturation, the gas phase becomes mobile and begins to flow towards the wellbore. This sensitivity analysis studies the effect of critical gas saturation on shale volatile oil reservoir performance. Simulations were run for two-phase flow cases. Critical gas saturations of 2%, 10%, 15% and 20% were considered. 5% critical gas saturation was used for base case simulations. Figures 6.4-1 thru 6.4-4 show the effect of critical gas saturation on cumulative oil production, oil rate, oil recovery factor as well as average reservoir pressure.

Simulation results show that cumulative oil production increases with increase in critical gas saturation. This can be seen in Figure 6.4-1. The higher the critical gas

saturation, the longer the gas stays in the pore spaces, thereby pushing out more oil before it becomes mobile and starts to flow. This can also explain why oil recovery factor increases with increase in critical gas saturation. For 20% critical gas saturation (highest case considered), oil recovery factor is almost 12%, while it is almost 7% for the lowest case considered – 2% critical gas saturation. Figure 6.4-3 shows this.

In Figure 6.4-2, results show that at early times, a constant production rate was observed at the maximum constrained value (20% critical gas saturation case), before decline starts to occur. From the figure, 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 result is reversed as critical gas saturation gets higher. It also explains why there is a relatively faster decline in average reservoir pressure as critical gas saturation gets lower. This is observed in Figure 6.4-4.

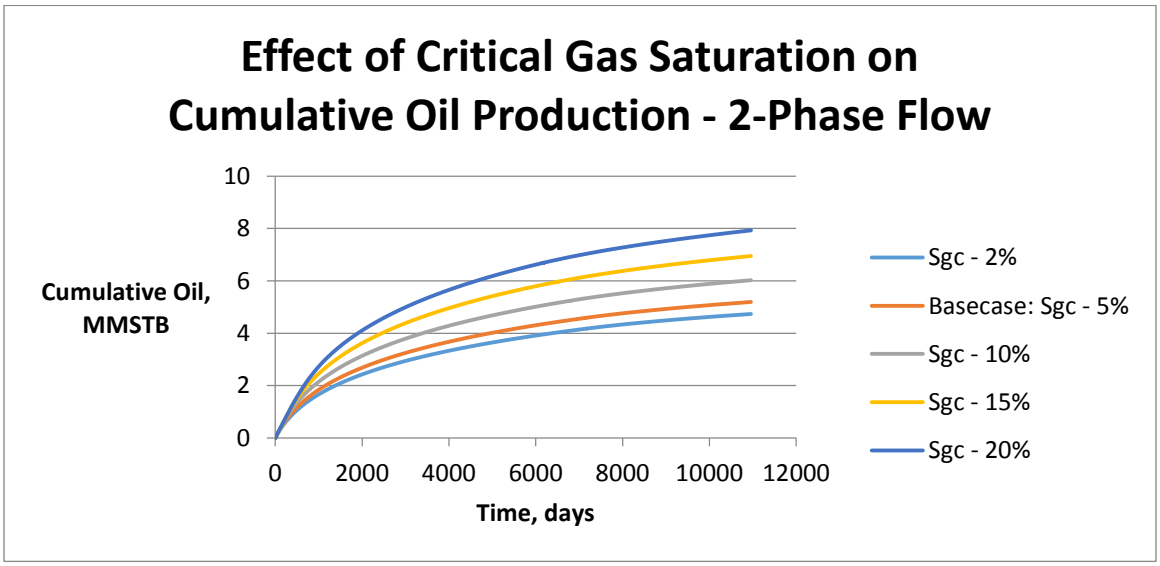


Figure 6.4-1 Critical Gas Saturation Two-Phase Case Comparisons - Cumulative Oil Production

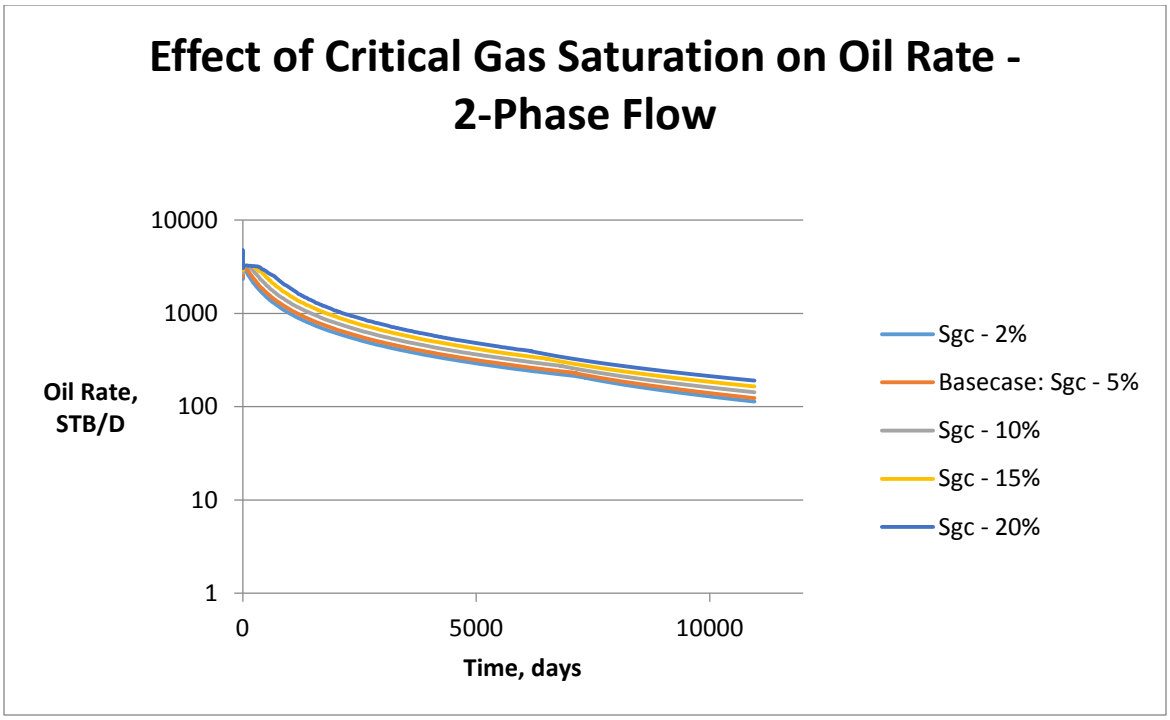


Figure 6.4-2 Critical Gas Saturation Two-Phase Case Comparisons - Oil Rate

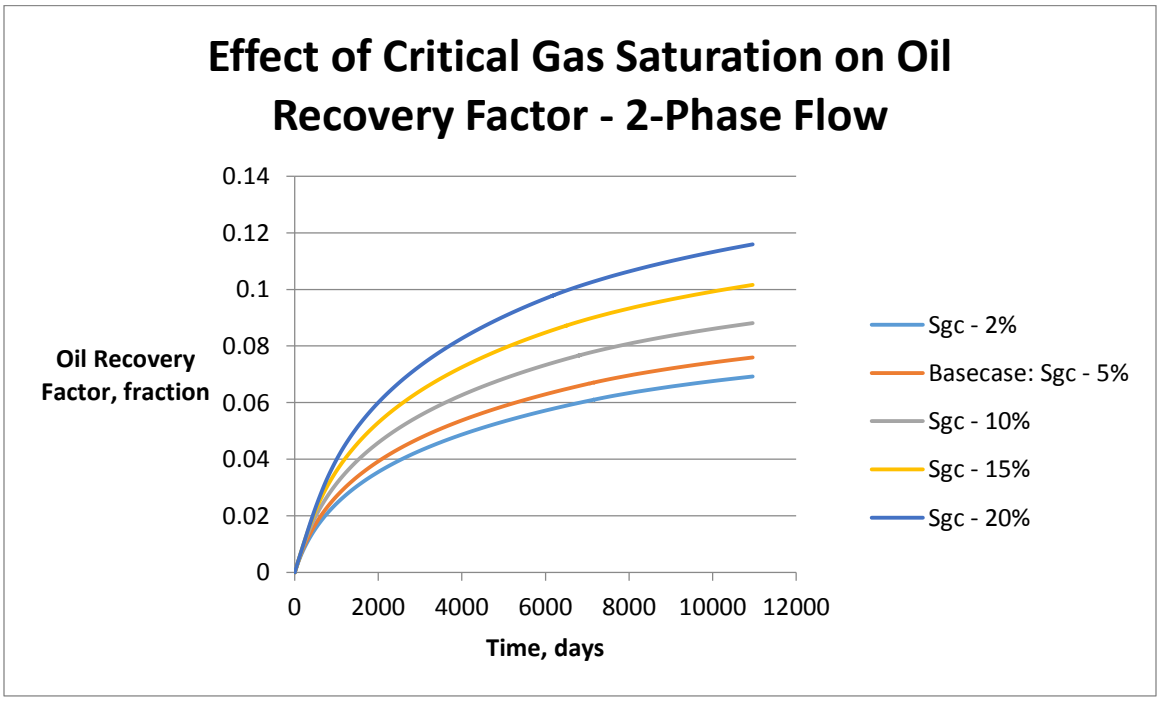


Figure 6.4-3 Critical Gas Saturation Two-Phase Case Comparisons - Oil Recovery Factor

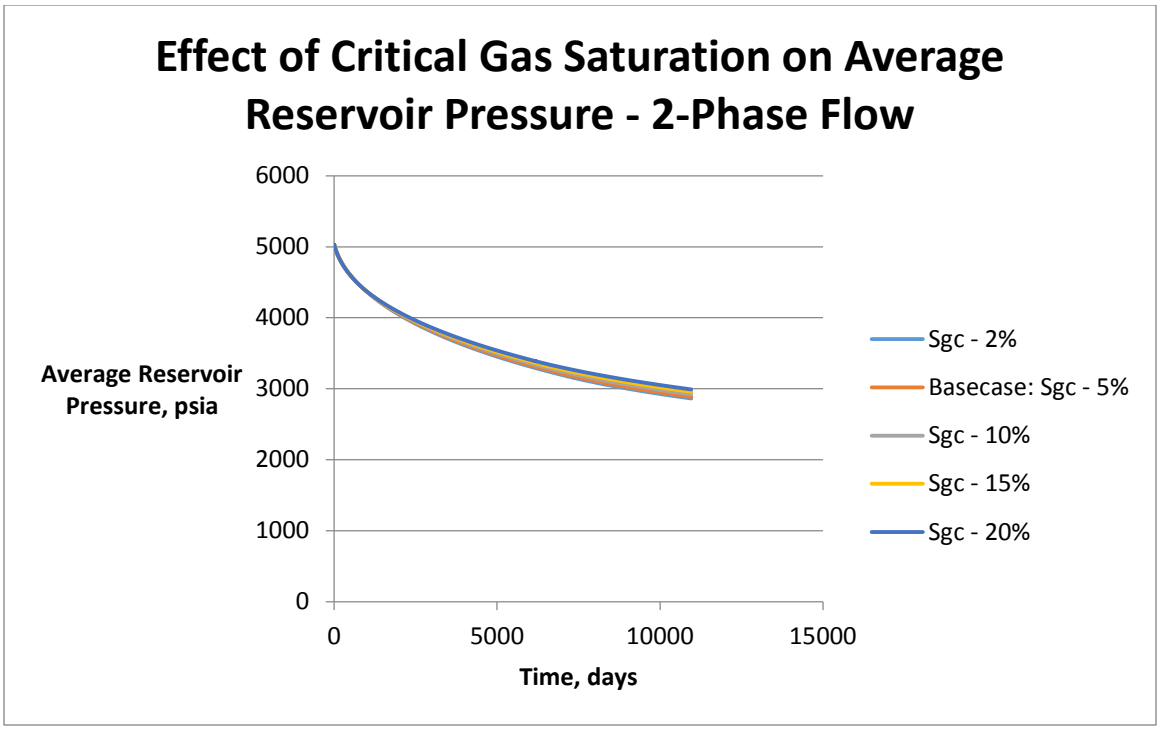


Figure 6.4-4 Critical Gas Saturation Two-Phase Case Comparisons - Average Reservoir Pressure

7. CMG - KAPPA Base Case Compositional and Black-Oil Simulations

Compositional and black-oil simulations were done using CMG (for compositional simulation) and KAPPA (for black-oil simulation) software, taking into consideration six different reservoir fluid compositions. Fluid 1 (Gong *et al.*, 2013), fluid 2 (CMG, 2013), fluids 3 and 4 (Whitson and Sunjerga, 2012) as well as fluids 5 and 6 (Sanni and Gringarten, 2008) were used in the simulations. Separator tests were done with the aid of CMG Winprop and the results of the flash calculations were used as inputs for the black-oil simulations in the KAPPA software. This was done in order to somewhat provide a fair basis for comparison of the CMG compositional simulation results and the KAPPA black-oil simulation results. Compositional simulation would have been done with KAPPA; however, it was very time-consuming (simulation took several days and could not be completed). The fluid compositions are shown in Table 7-1. Figures 7-1 thru 7-6 show the corresponding P-T diagrams for each of the different fluid compositions. The green curves represent the two-phase boundaries; the red lines are the isothermal lines and the blue points are the critical points on the diagrams. The P-T diagrams were generated using the CMG Winprop software. The positions of the isothermal lines sometimes enable us to make initial guesses on the reservoir fluid type. In many instances, the isothermal line depicts 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. In Figures 7-1 thru 7-6, it is observed that fluid 1 is most likely a gas condensate (the critical temperature is less than the reservoir temperature), fluids 2, 3 and 6 are almost certainly volatile oils, while fluids 4 and 5 are near-critical fluids (fluid 5 – most likely volatile oil).

Table 7-1 Fluid Compositions

	Fluid 1	**Fluid2**	**Fluid 3**	**Fluid 4**	**Fluid 5**	**Fluid 6**
Components	**Composition (%)**	**Composition (%)**	**Composition (%)**	**Composition (%)**	**Composition (%)**	**Composition (%)**
CH_4	62.54	58.77	58.07	61.82	53.47	49.43
C_2H_6	11.76	7.57	7.43	7.91	11.46	7.28
C_3H_8	5.59	4.09	4.16	4.42	8.79	8.02
I-C_4H_{10}	1.36	0.91	0.96	1.02	-	2.31
N-C_4H_{10}	2.32	2.09	1.63	1.74	4.56	3.61
I-C_5H_{12}	1.17	0.77	0.75	0.80	-	1.80
N-C_5H_{12}	1.10	1.15	0.80	0.86	2.09	1.79
C_6H_{14}	1.55	1.75	1.14	1.21	1.51	2.32
C_{7+}	11.36	21.76	22.59	17.59	16.92	22.41
CO_2	1.26	0.93	2.32	2.47	0.90	0.16
N_2	-	0.21	0.15	0.16	0.30	0.87

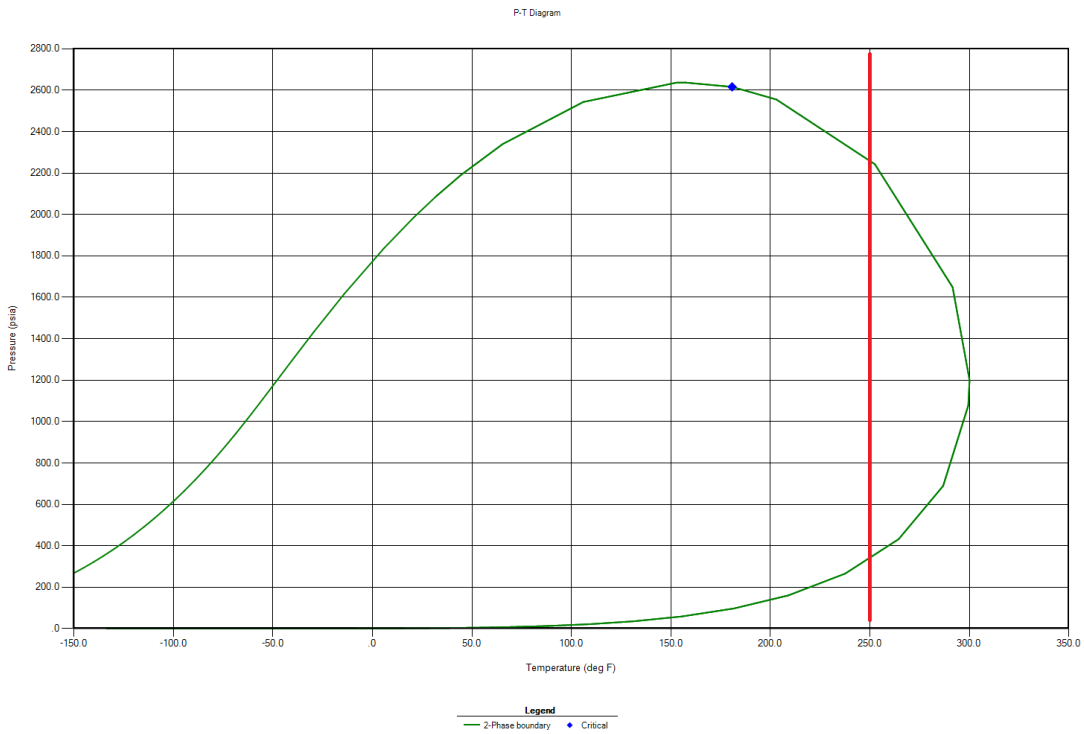


Figure 7-1 Fluid 1: P-T Diagram

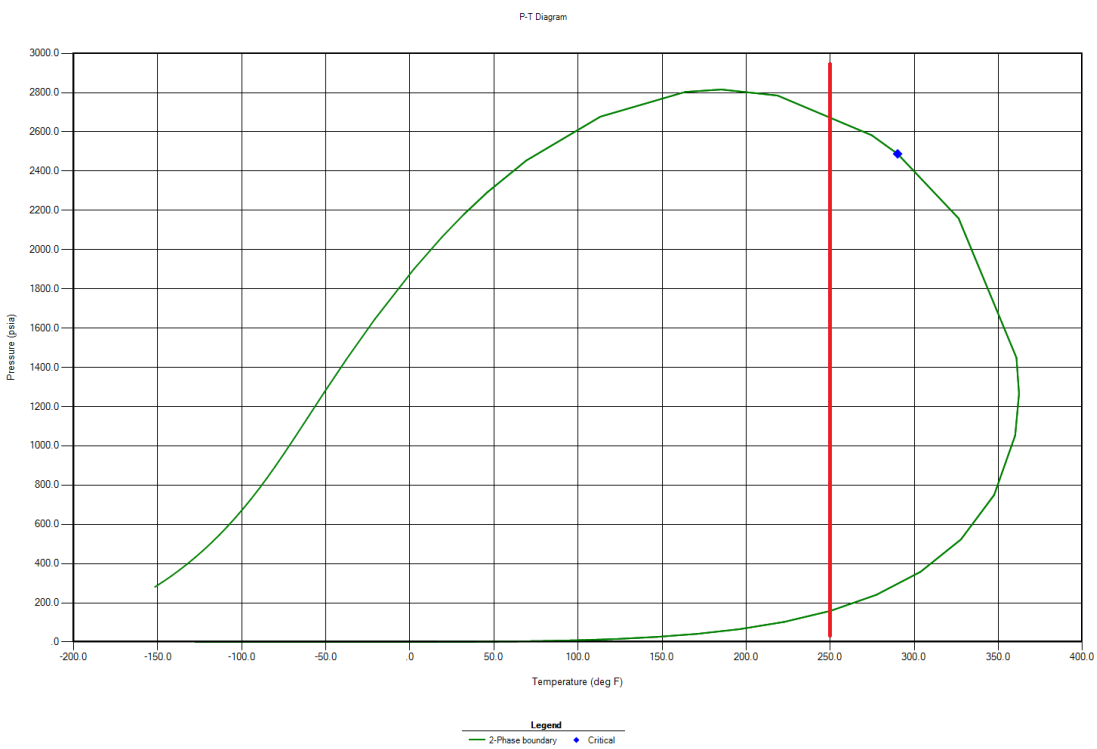


Figure 7-2 Fluid 2: P-T Diagram

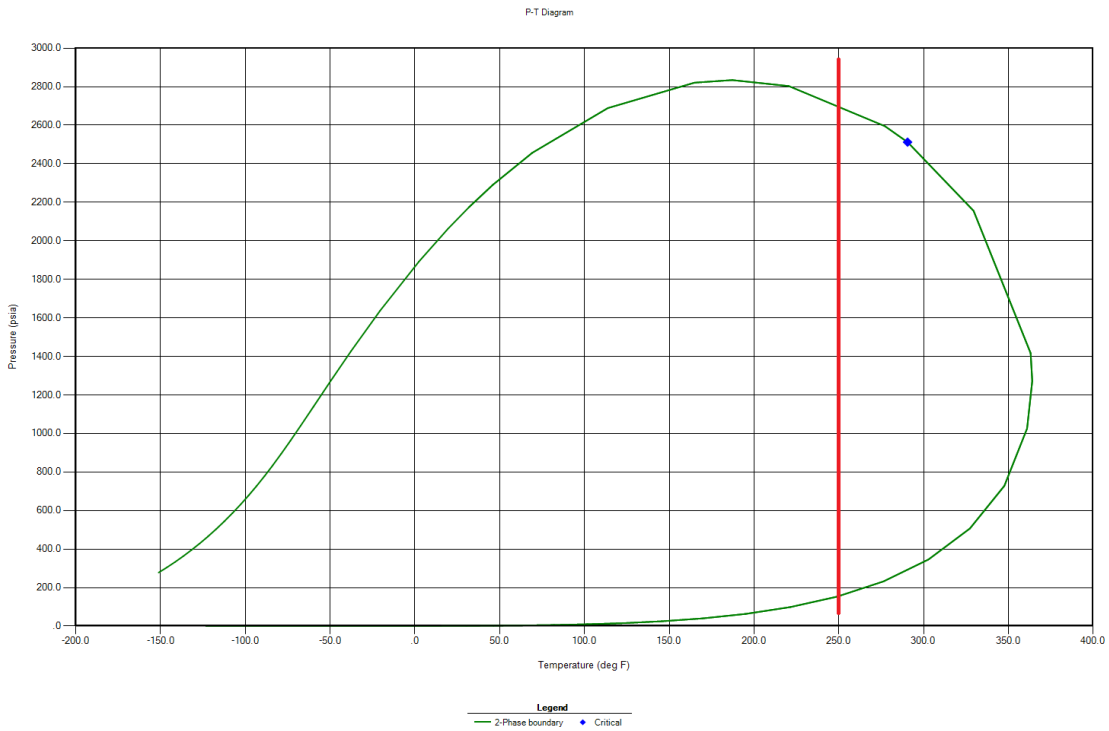


Figure 7-3 Fluid 3: P-T Diagram

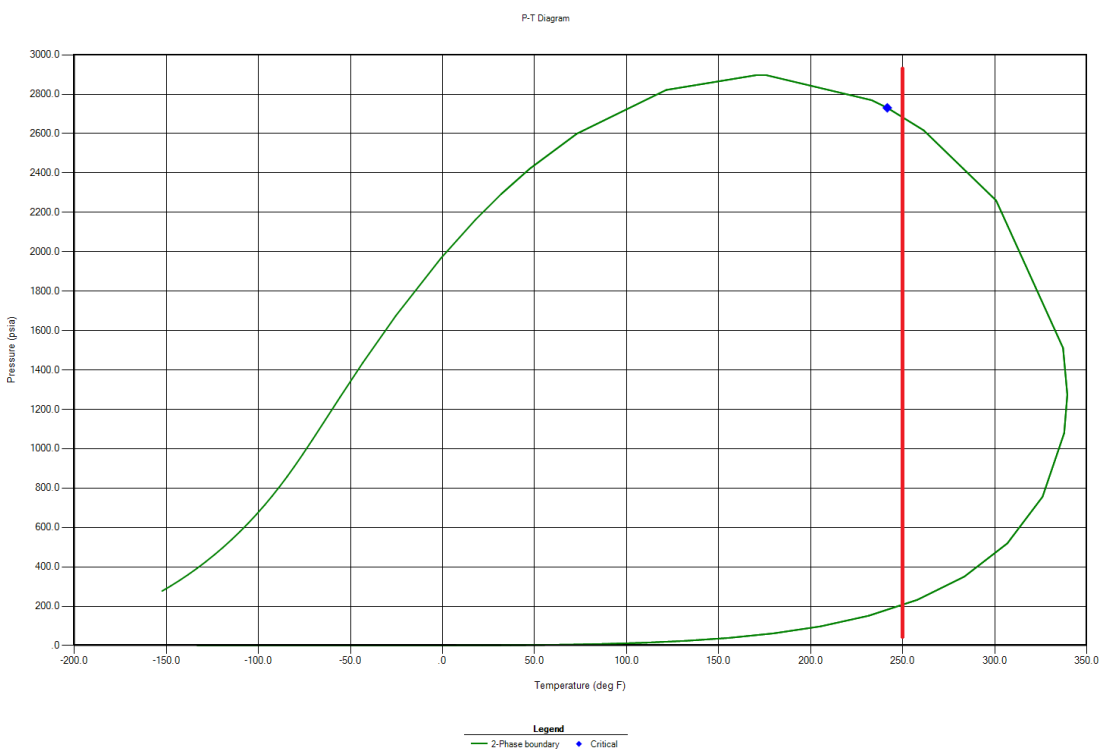


Figure 7-4 Fluid 4: P-T Diagram

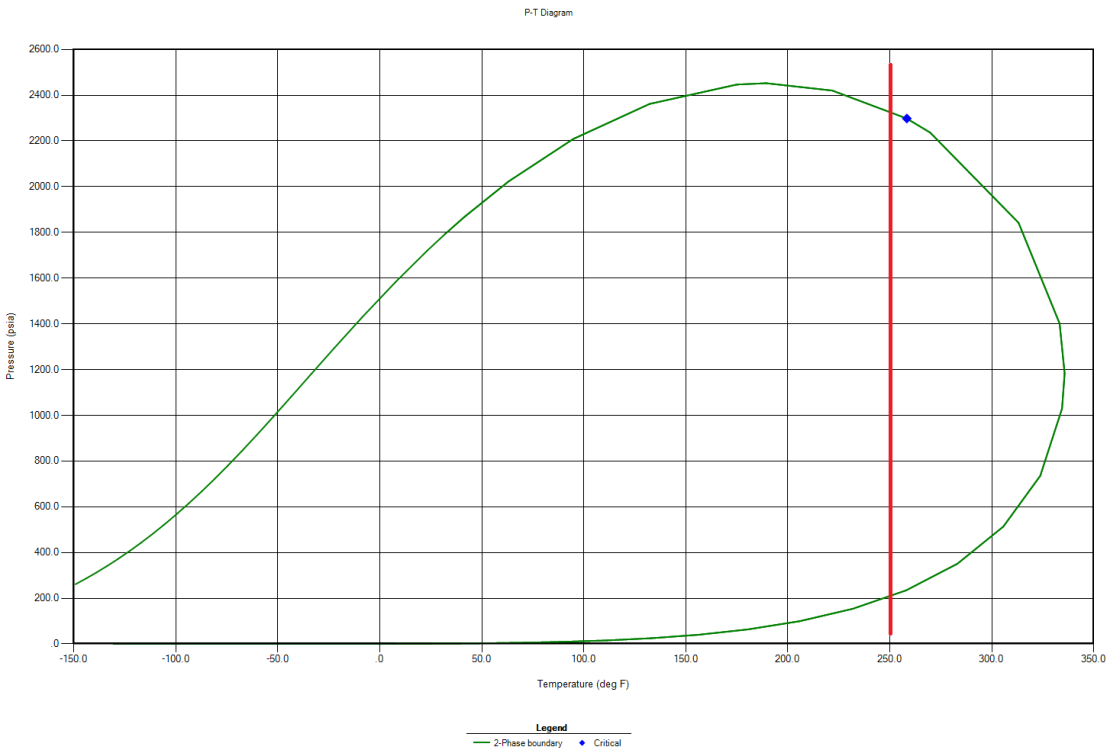


Figure 7-5 Fluid 5: P-T Diagram

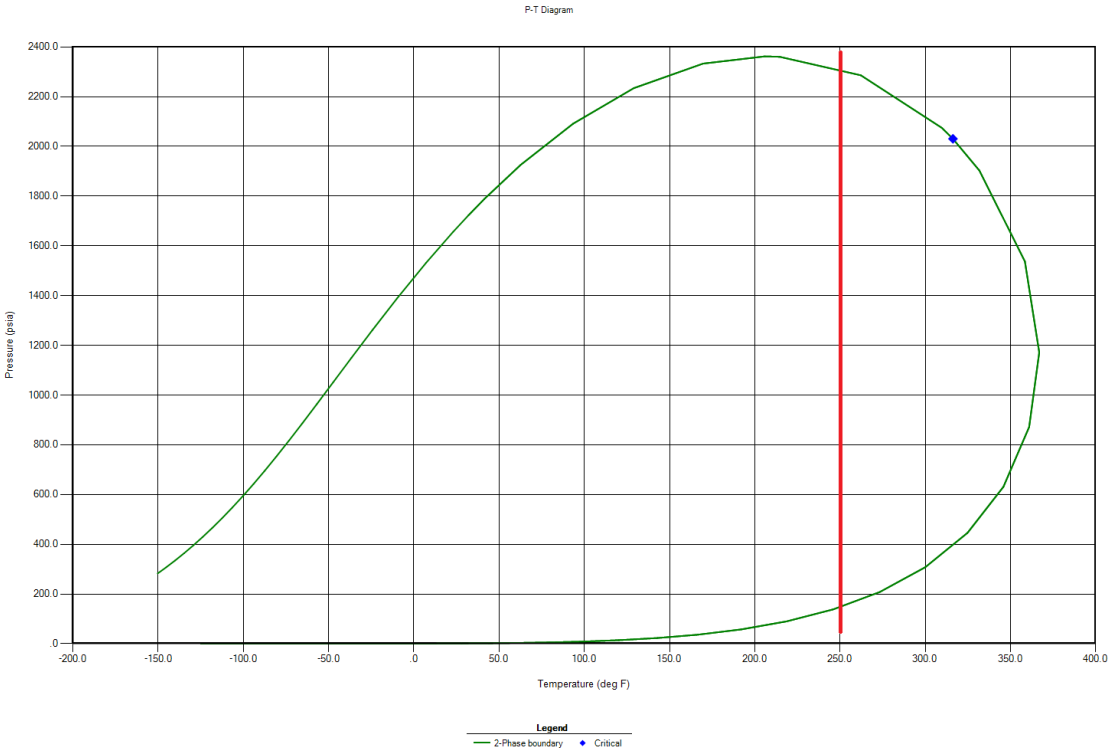


Figure 7-6 Fluid 6: P-T Diagram

7.1. CMG Base Case Compositional Simulations

The same reservoir model considered earlier for the base case simulation was replicated using the CMG-GEM reservoir simulation software. All parameters were the same, but the Peng-Robinson equation of state was used for the PVT. Compositional simulation was done considering six different fluid compositions. Simulation results were compared to show the effect of fluid composition on shale volatile oil reservoir performance. This is shown in Figures 7.1-1 and 7.1-2.

It was suggested that the heavy components in petroleum mixtures have the strongest effect on fluid characteristics (McCain Jr. 1994). Results of this study, however, show the importance of not only the heavy components, but also light components, especially methane. Figures 7.1-1 and 7.1-2 illustrate the effect of fluid composition on cumulative oil production and oil rates. Fluid 6, with the lowest percentage of methane component and relatively high percentage (22.41%) of C_{7+} components has the highest cumulative oil production and oil rate whereas fluid 1, with the highest percentage of methane component and lowest percentage of C_{7+} components has the lowest cumulative oil production and oil rate. Fluids 2 and 3 are similar in composition (percentage of methane components are almost the same and the percentage of C_{7+} components are slightly different) – they therefore have almost the same cumulative oil production and oil rates. Fluid 3, with a slightly lesser percentage of methane component and slightly higher percentage of C_{7+} components have a slightly higher cumulative oil production and oil rate than fluid 2. Fluid 5 has lower percentages of methane and C_{7+} components than fluid 4; however cumulative oil production and oil rate are higher for fluid 5 than for fluid 4. The trend generally shows that the lower the percentage of methane component,

the higher the cumulative oil production and oil rate. This clearly shows the importance of the effect of the percentage of methane component in reservoir fluid compositions on shale oil reservoir performance.

The heavy components affect cumulative oil production and oil rates because the higher the percentage of heavy components in reservoir fluid compositions, the more the contribution to the oil phase and consequently the higher the cumulative oil production and oil rate. Nevertheless, results of this study have shown that apart from the heavy components, the methane component has a big role to play as well. It should be noted that the spikes in the oil rate curves might have been due to little glitches caused by the numerical solver (in the software) used for the simulation, leading to repetition of multiple time steps. However, ignoring the spikes, the trend can be clearly observed.

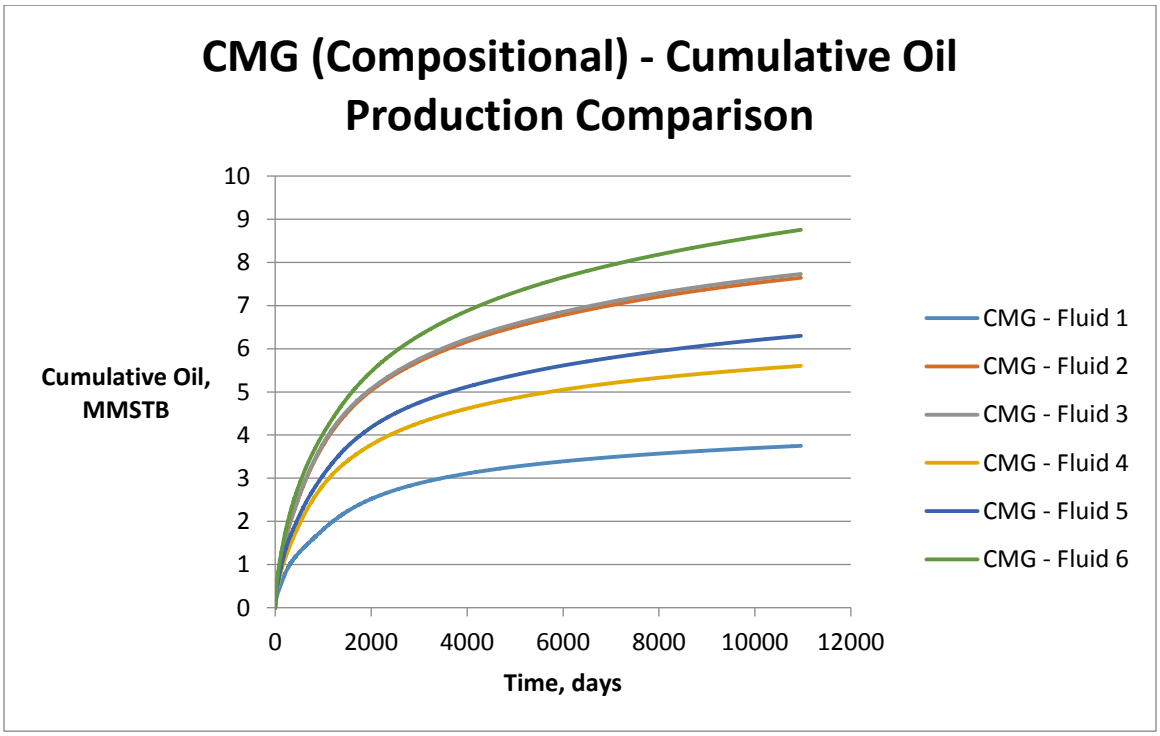


Figure 7.1-1 CMG (Compositional) - Cumulative Oil Production Comparison

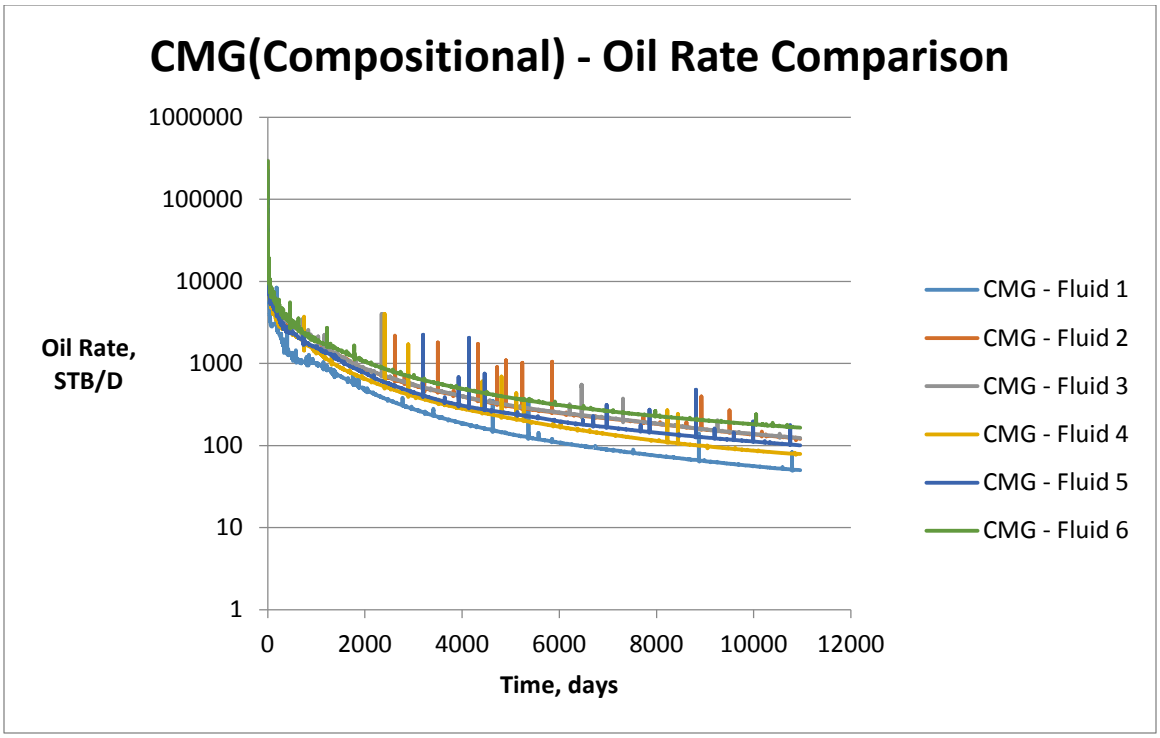


Figure 7.1-2 CMG (Compositional) - Oil Rate Comparison

7.2. KAPPA Base Case Black-Oil Simulations – Standing Correlation

As already mentioned, flash calculations were done with separator tests using CMG Winprop and the results were used as inputs for the KAPPA black-oil simulation. Two separators were used, with the stock tank acting 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 7.2-2.

The same base case reservoir model was used and black-oil simulations done with KAPPA Ecrin 4.30 software. Results of the flash calculations were used as inputs in the software. Correlations were then used to calculate fluid PVT properties as a function of pressure only. The Standing correlation was used for bubble point pressure estimation –

Table 5-3. All other parameters were the same as in the base case simulation in Chapter 5. The Standing correlation formulas along with the PVT properties calculated are shown in Table 7.2-1.

Table 7.2-1 Standing Correlations

PVT Property	Formula
Bubble Point Pressure	$p_b = 18.2\left(\left(\frac{R_s}{\gamma_g}\right)^{0.83} \cdot \frac{10^{0.00091\,T}}{10^{0.0125\,\gamma_{API}}} - 1.4\right)$
Solution Gas – Oil Ratio	$R_s = \left(\left(\frac{p}{18.2} + 1.4\right) \cdot \frac{10^{0.0125\,\gamma_{API}}}{10^{0.00091\,T}}\right)^{\frac{1}{0.83}} \cdot \gamma_g$
Oil FVF - Saturated	$B_o = 0.972 + 1.47 * 10^{-4}\left(R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25 \cdot T\right)^{1.175}$
Oil FVF – Under-saturated	$B_o = B_{ob} \cdot e\left(c_o(p_b - p)\right)$

Table 7.2-2 Flash Calculation Results

	Fluid 1	Fluid 2	Fluid 3	Fluid 4	Fluid 5	Fluid 6
Gas-Oil Ratio, SCF/STB	6200.39	3023.99	3043.25	4081.12	3967.16	2560.88
API @STC	65.05	63.50	63.04	63.52	64.94	65.22
Average Gravity of Total Surface Gas (Air = 1)	0.7895	0.7434	0.7533	0.7564	0.8407	0.8507
Oil FVF, RB/STB	-	3.558	3.551	-	4.806	3.529
Condensate-Gas Ratio, STB/MMSCF	161.280	-	-	245.031	-	-
Dry Gas FVF, (ft^3/SCF)	$7.26*10^{-3}$	-	-	$6.46*10^{-3}$	-	-
Wet Gas FVF, (ft^3/SCF)	$6.18*10^{-3}$	-	-	$5.12*10^{-3}$	-	-
Well Stream Gas Gravity (Air = 1)	1.1253	-	-	1.2463	-	-

Simulation results were different from the ones obtained from the compositional simulations. The results show no particularly observable trend. Fluid 2, in this case, has the highest cumulative oil production and oil rate, while fluid 6 has the lowest. These were shown in Figures 7.2-1 and 7.2-2. Incorrect bubble point pressure estimates calculated with the correlations might have led to the discrepancies in the results. This also supports the fact that full compositional simulation is necessary for analyzing and forecasting volatile oil production.

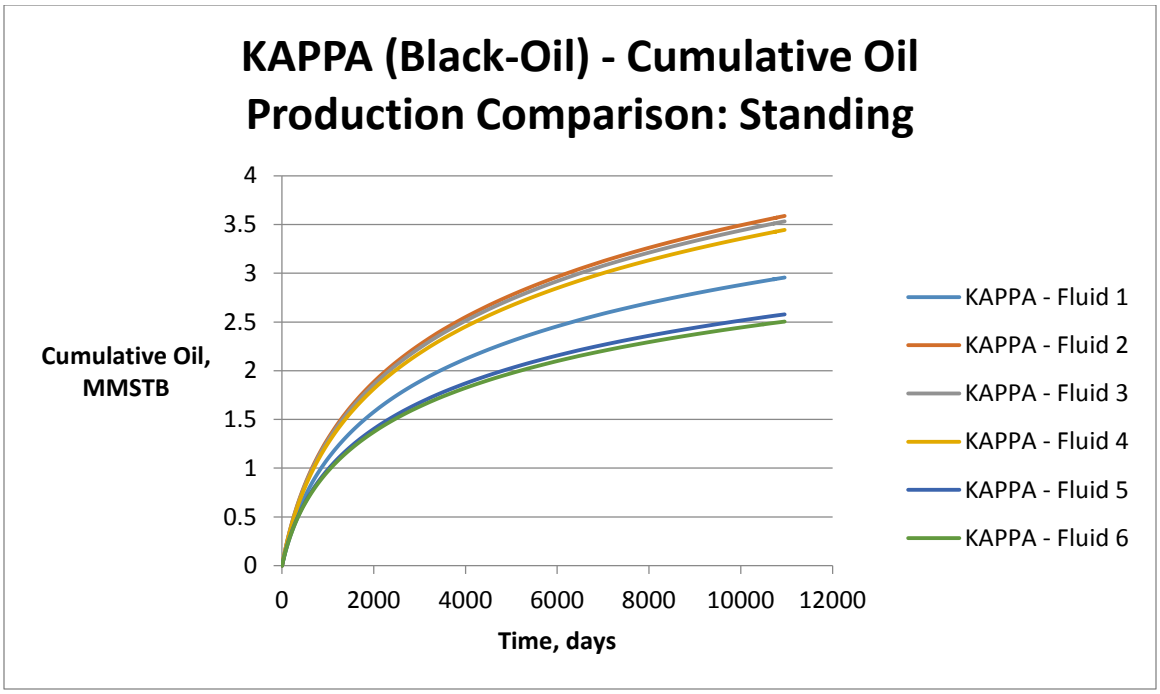


Figure 7.2-1 KAPPA (Black-Oil) - Cumulative Oil Production Comparison: Standing

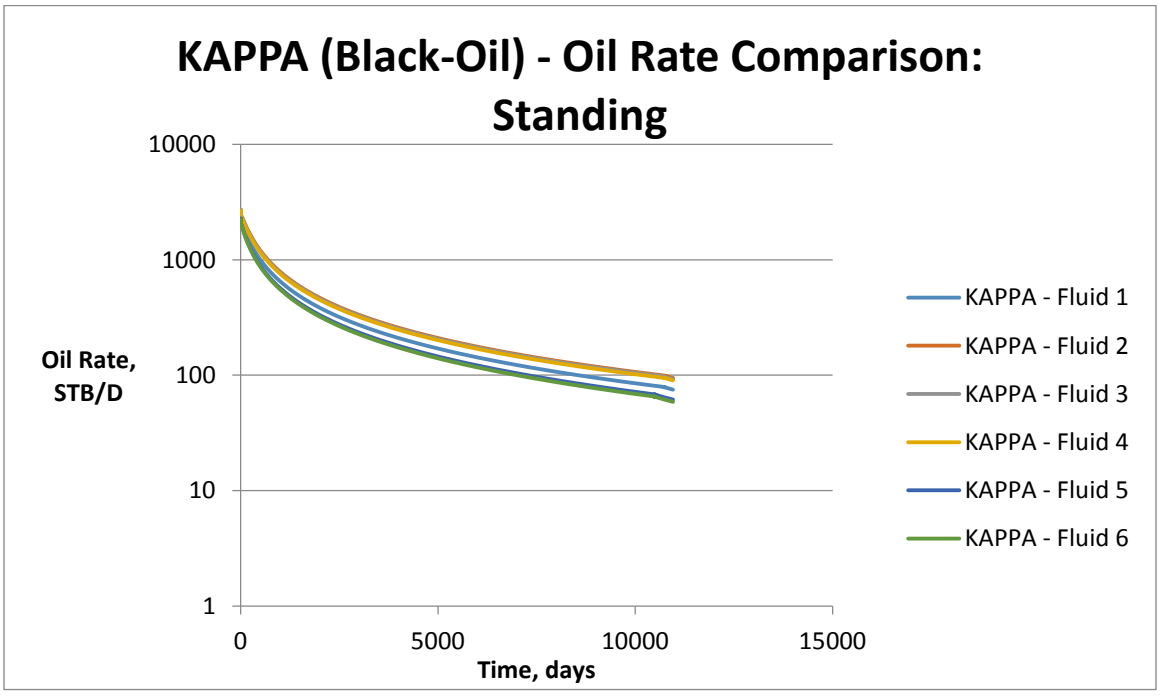


Figure 7.2-2 KAPPA (Black-Oil) - Oil Rate Comparison: Standing

7.3. KAPPA Base Case Black-Oil Simulations – Vazquez-Beggs Correlation

Black-oil simulations using KAPPA 4.30 Ecrin software was repeated using the Vazquez-Beggs correlation for calculating bubble point pressure estimates. Vazquez-Beggs correlation is a generally applicable correlation. The data used in the development of the correlation covers a wide range of temperatures, pressures and oil properties. The Vazquez-Beggs correlation formulas along with the PVT properties calculated are shown in Table 7.3-2. The summary of the correlations used for these simulation cases are shown in Table 7.3-1. Simulation results show a similar trend (Fluid 2 – highest cumulative oil production and oil rate and fluid 6 – lowest cumulative oil production and oil rate) to cases where Standing correlations were used to calculate most of the oil PVT properties. However, the values of the cumulative oil production and oil rates were relatively higher in this case.

Table 7.3-1 Correlations Used for Black-Oil PVT Tables 2 - KAPPA Ecrin 4.30

Oil		**Gas**	
Property	**Correlation**	**Property**	**Correlation**
Bubble point pressure, P_b	Vazquez - Beggs	Z-factor	Dranchuk
Oil viscosity, μ_o	Beggs - Robinson	Gas viscosity, μ_g	Lee et al.
Solution GOR, R_s	Vazquez - Beggs	Gas formation volume factor, B_g	Internal[3]
Oil formation volume factor, B_o	Vazquez - Beggs	-	-
Oil compressibility, c_o	Vazquez - Beggs	-	-

[3] Internal correlations within the software

Table 7.3-2 Vazquez - Beggs Correlations

PVT Property	Formula
Bubble Point Pressure	$p_b = \left(\frac{R_s}{C_1\, \gamma_g \cdot e\left(C_3 \left(\frac{\gamma_{API}}{(T + 459.67)} \right) \right)} \right)^{\frac{1}{C_2}}$
Solution Gas – Oil Ratio	$R_s = C_1\, \gamma_g\, p^{C_2} \cdot e\left(C_3 \left(\frac{\gamma_{API}}{(T + 459.67)} \right) \right)$
Oil FVF - Saturated	$B_o = 1 + A_1\, R_s + A_2 (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right) + A_3\, R_s (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right)$
Oil FVF – Under-saturated	$B_o = B_{ob}\, e\big(c_o (p_b - p)\big)$
Compressibility – Saturated	$c_o = \frac{-1433 + 5R_{sb} + 17.2T - 1180\gamma_g + 12.61\gamma_{API}}{10^5 p} + \frac{\frac{B_g}{B_o} \cdot \frac{dR_s}{dp}}{5.6145835}$
Compressibility – Under-saturated	$c_o = \frac{\left(-1433 + 5 \cdot R_{sb} + 17.2 \cdot T - 1180 \cdot \gamma_g + 12.61 \cdot \gamma_{API}\right)}{10^5 p}$

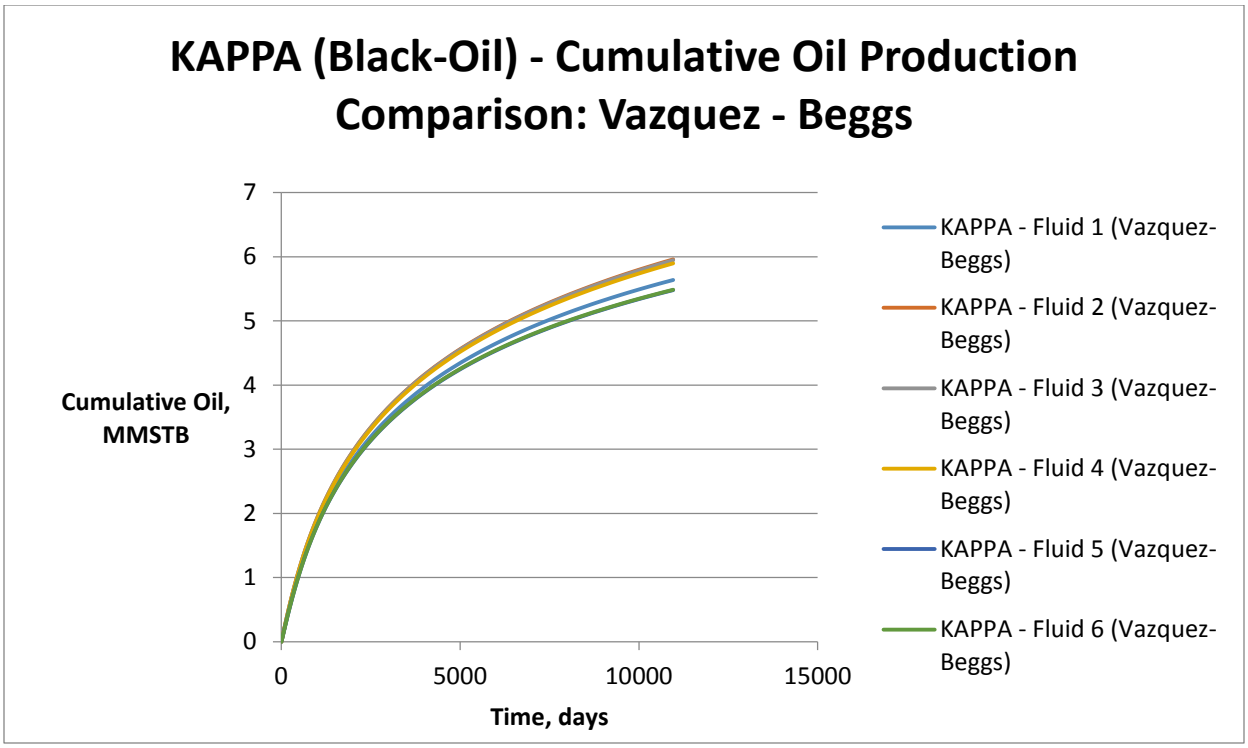


Figure 7.3-1 KAPPA (Black-Oil) Cumulative Oil Production Comparison: Vazquez-Beggs

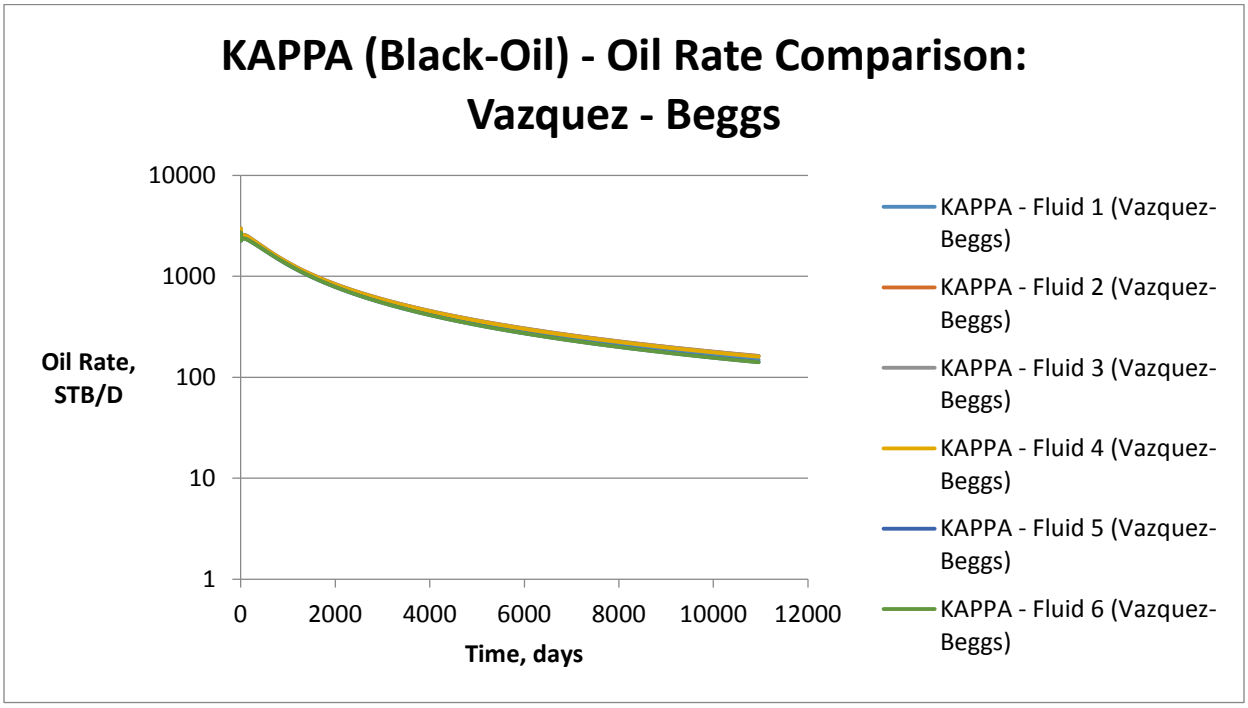


Figure 7.3-2 KAPPA (Black-Oil) Oil Rate Comparison: Vazquez-Beggs

The inconsistencies in the results for the black-oil simulations are most likely due to inaccurate bubble point estimates calculated with the aid of the empirical correlations. In Table 7.3-3, the approximate bubble point estimates calculated with the Standing and Vazquez-Beggs correlations are shown. It should be noted that the initial reservoir pressure is 5000 psia. Therefore, the bubble point estimates calculated are higher or 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 Jr. *et al.*, 1998). This definitely affects the accuracy of production forecasts.

Table 7.3-3 Approximate Bubble Point Estimates

	Standing	**Vazquez – Beggs**
Fluid 1	8020 psia	7650 psia
Fluid 2	4870 psia	4650 psia
Fluid 3	4870 psia	4650 psia
Fluid 4	6150 psia	5850 psia
Fluid 5	5270 psia	5020 psia
Fluid 6	3570 psia	3450 psia

7.4. CMG (Compositional) Vs. KAPPA (Black-Oil) Base Case Simulations

Simulation results from both CMG compositional and KAPPA black-oil simulations were compared for each of the fluid compositions under consideration. The results are displayed in Figures 7.4-1 thru 7.4-12. As earlier mentioned, fluid 1 was suspected to be

a gas condensate and fluid 4, a near-critical fluid (maybe gas condensate due to the P-T diagram – critical temperature less than reservoir temperature); therefore, additional simulations were run by modeling the two fluids as gas condensates using KAPPA modified black-oil simulations. Well stream gas gravity was used instead of specific gas gravity to estimate pseudo-critical properties in these cases. The modified black-oil (MBO) simulation of gas condensates in KAPPA takes into consideration the condensate-gas ratio, R_v which is the amount of vaporized oil in gas. This is not the case for simulation of bubble point fluids in KAPPA, i.e., black-oil simulation is used unless of course there are available laboratory data which can be used to specify the PVT of the particular fluid under consideration. The results were included for comparisons with the other compositional and black-oil simulations of these fluid compositions.

Results generally show higher cumulative oil production and higher initial oil rates when CMG compositional simulation was used compared to the KAPPA black-oil simulations. Black-oil simulations using Vazquez-Beggs correlation for calculation of most of the oil PVT properties give results that are closer to the compositional simulation results than black-oil simulations where Standing correlations were used. For fluid 1, when modeled as a gas condensate using KAPPA modified black-oil simulation; cumulative oil production was almost as high as the CMG compositional simulation case. When modeled as a bubble point fluid using Vazquez-Beggs correlation (black-oil simulation in KAPPA), cumulative oil production and oil rate were much higher than the compositional simulation case. This indicates that our suspicion that fluid 1 is a gas condensate is almost certain. It is therefore vital to identify fluid type properly prior to modeling and simulation. For fluid 4 (modeled as a gas condensate) however, the results

were similar to the original (when modeled as a bubble point fluid using Standing correlation) KAPPA black-oil simulation case. When modeled as a bubble point fluid using Vazquez-Beggs correlation, the cumulative oil production is a little close to the compositional simulation case except towards the end of production period. Oil rate is higher than the compositional simulation case for most of the production period. This highlights the difficulties inherent in modeling near-critical fluids, especially when using black-oil simulations with dependence on empirical correlations.

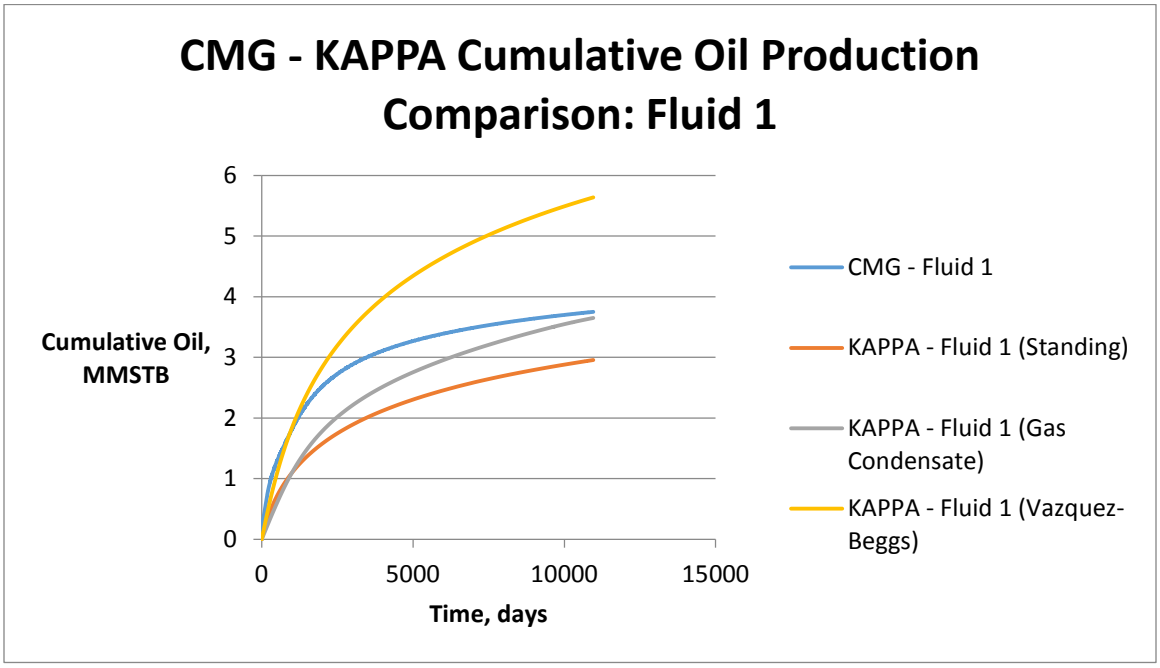


Figure 7.4-1 Fluid 1: CMG - KAPPA Cumulative Oil Production Comparison

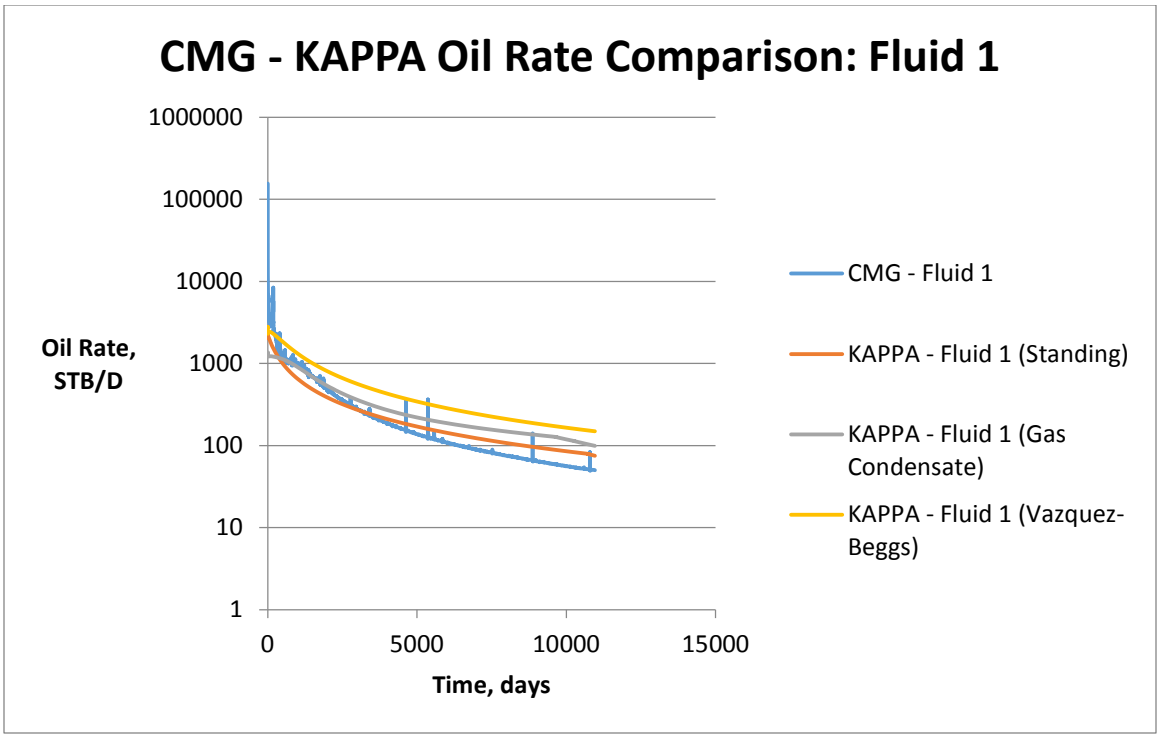


Figure 7.4-2 Fluid 1: CMG - KAPPA Oil Rate Comparison

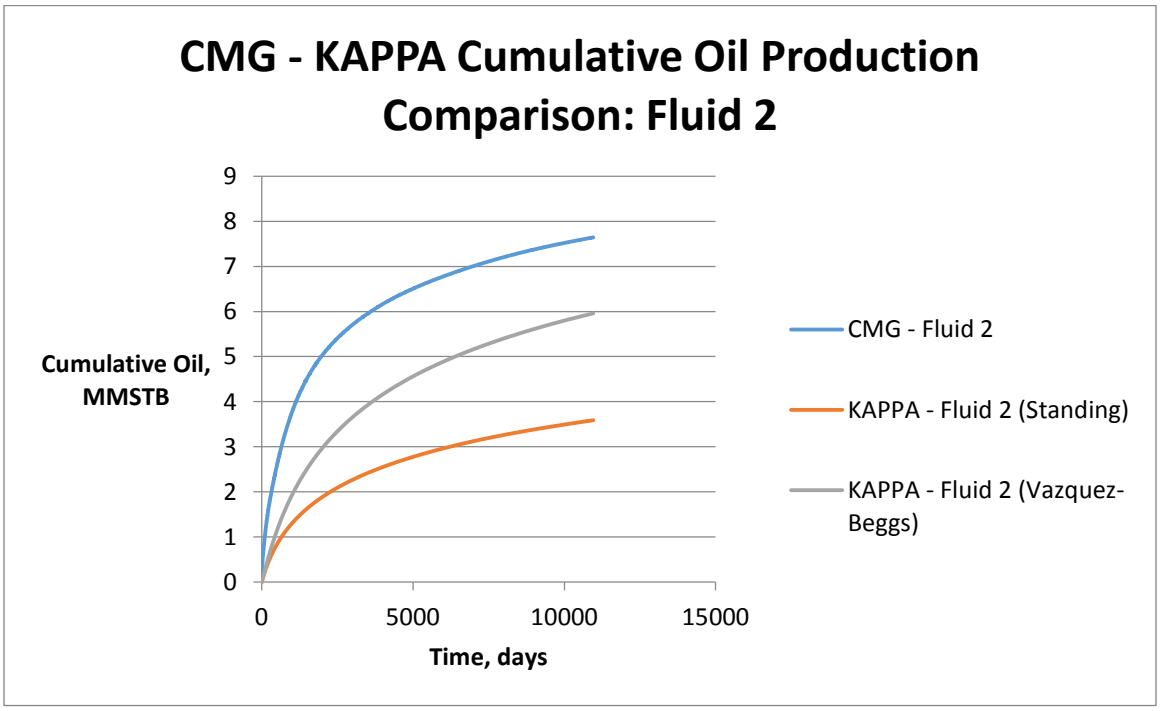


Figure 7.4-3 Fluid 2: CMG - KAPPA Cumulative Oil Production Comparison

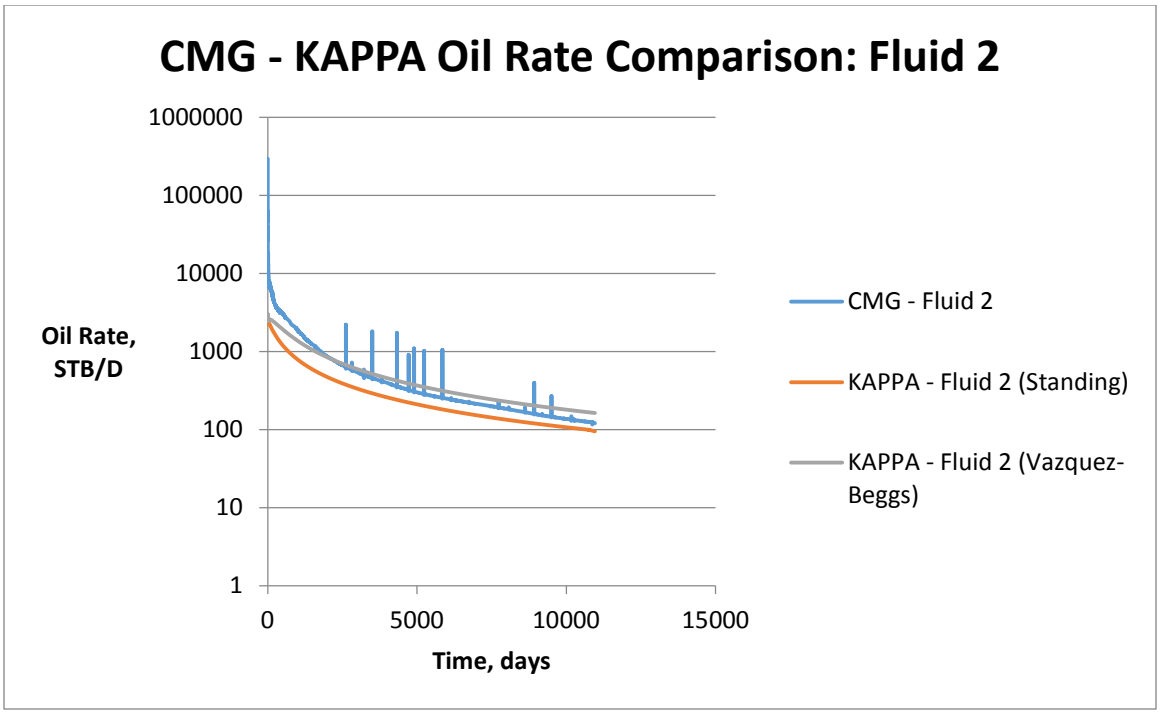


Figure 7.4-4 Fluid 2: CMG - KAPPA Oil Rate Comparison

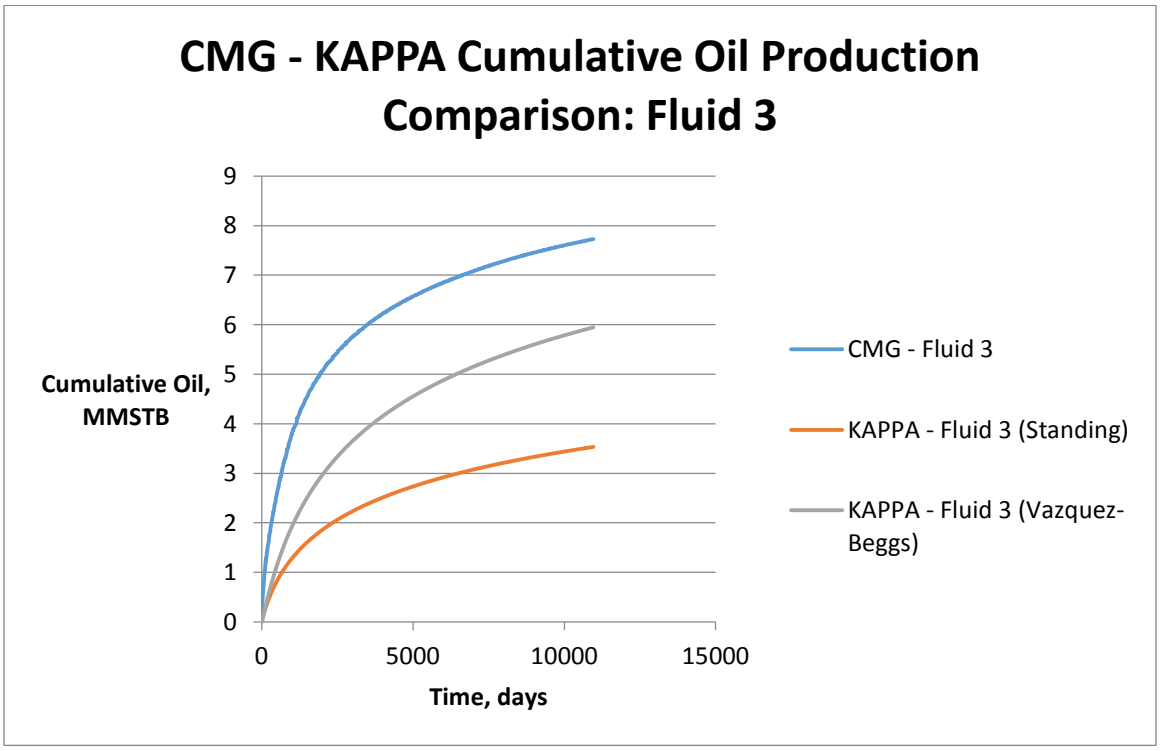


Figure 7.4-5 Fluid 3: CMG - KAPPA Cumulative Oil Production Comparison

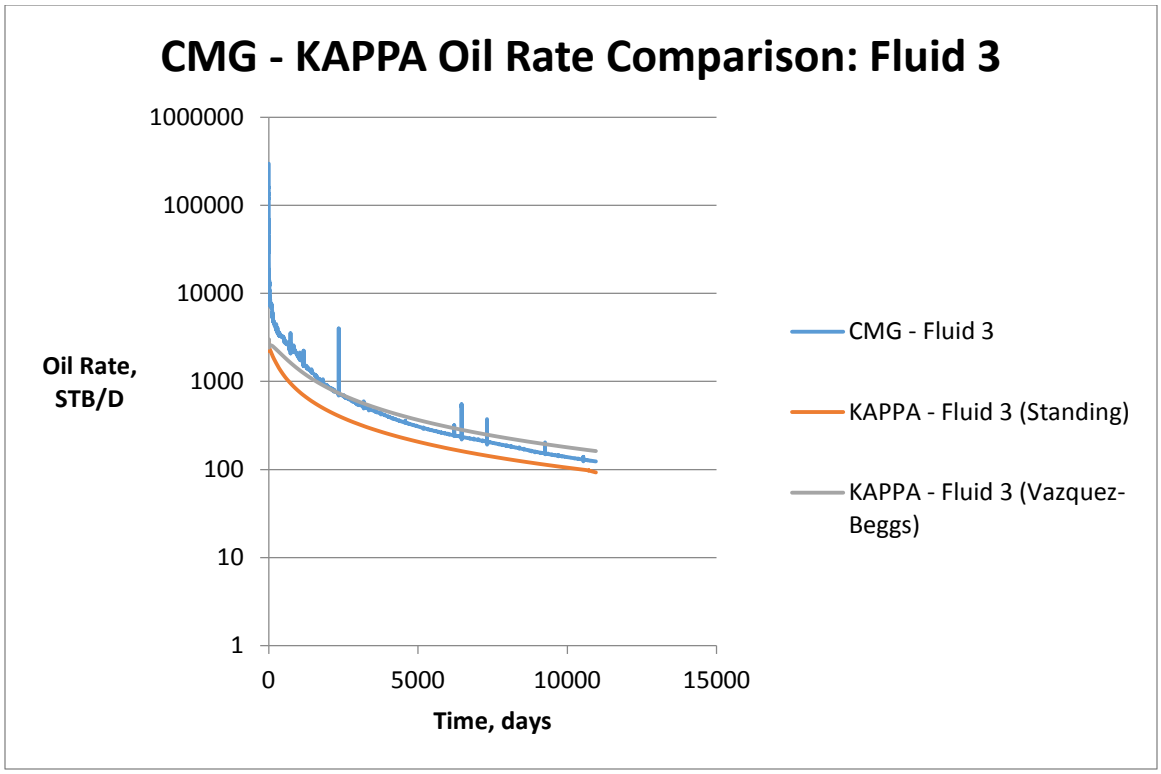


Figure 7.4-6 Fluid 3: CMG - KAPPA Oil Rate Comparison

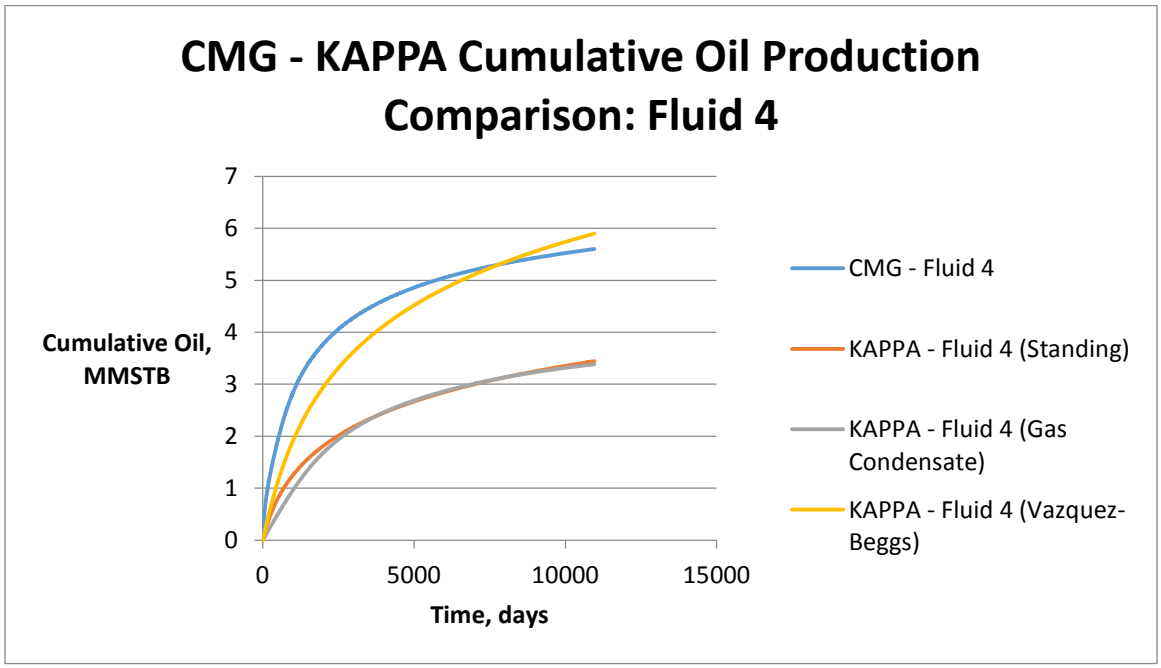


Figure 7.4-7 Fluid 4: CMG - KAPPA Cumulative Oil Production Comparison

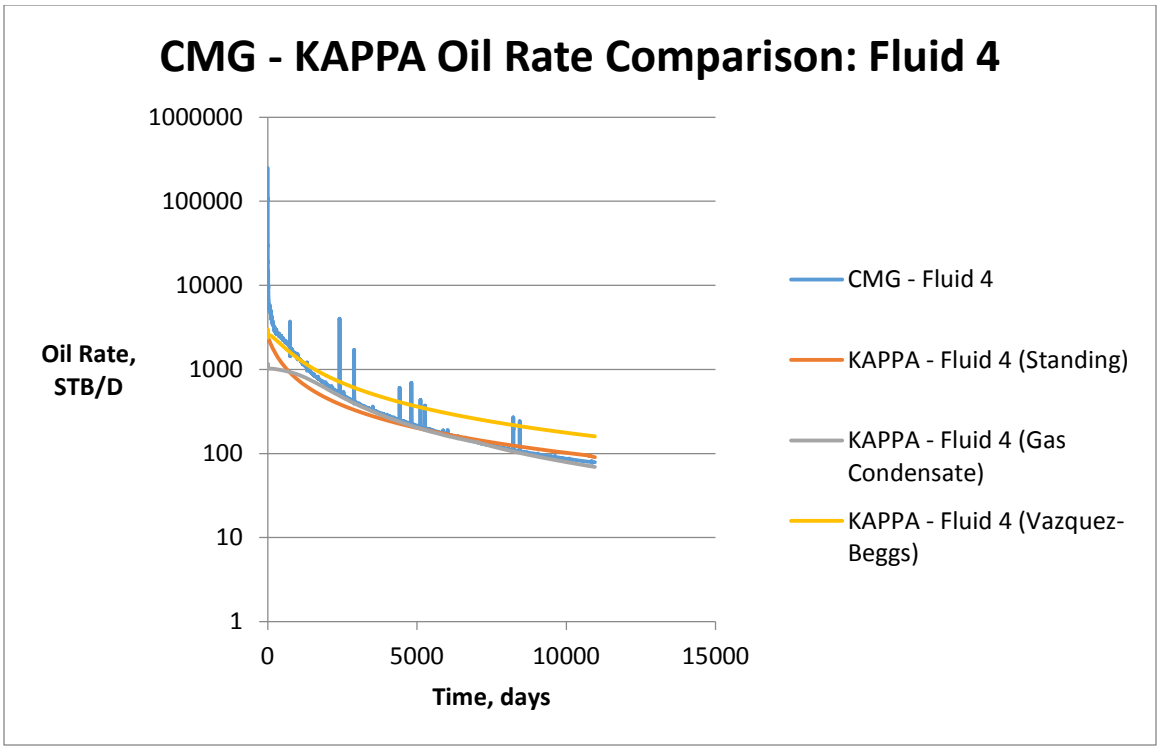


Figure 7.4-8 Fluid 4: CMG - KAPPA Oil Rate Comparison

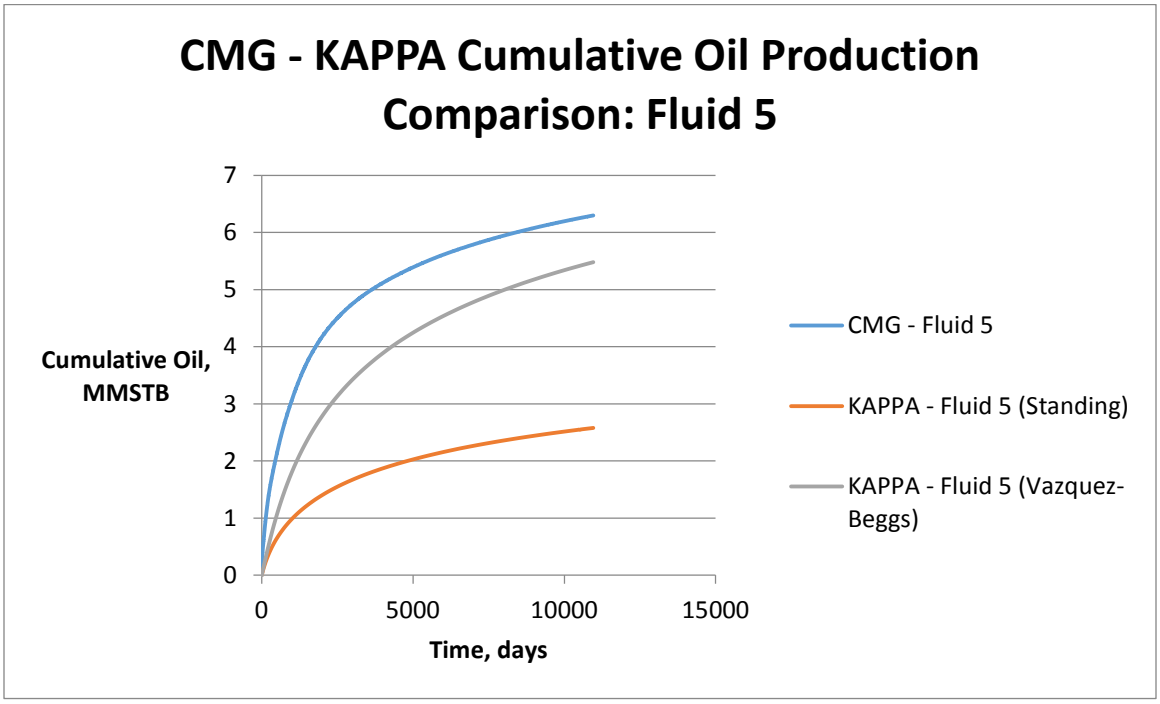


Figure 7.4-9 Fluid 5: CMG - KAPPA Cumulative Oil Production Comparison

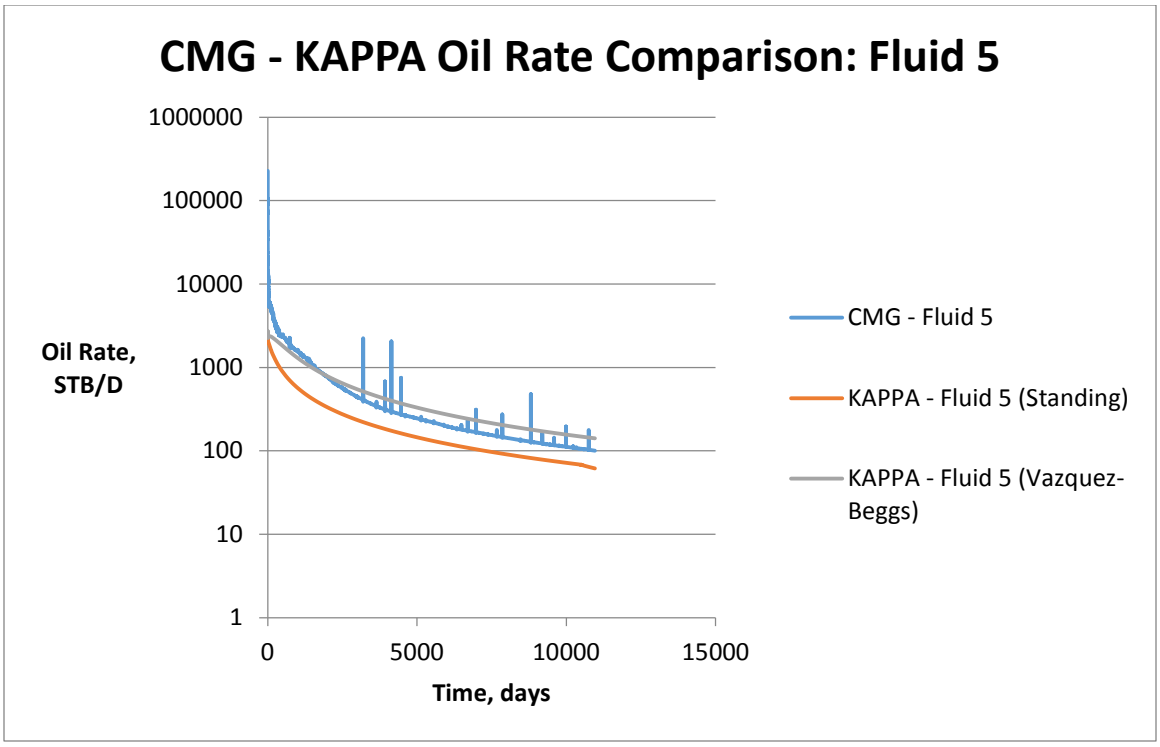


Figure 7.4-10 Fluid 5: CMG - KAPPA Oil Rate Comparison

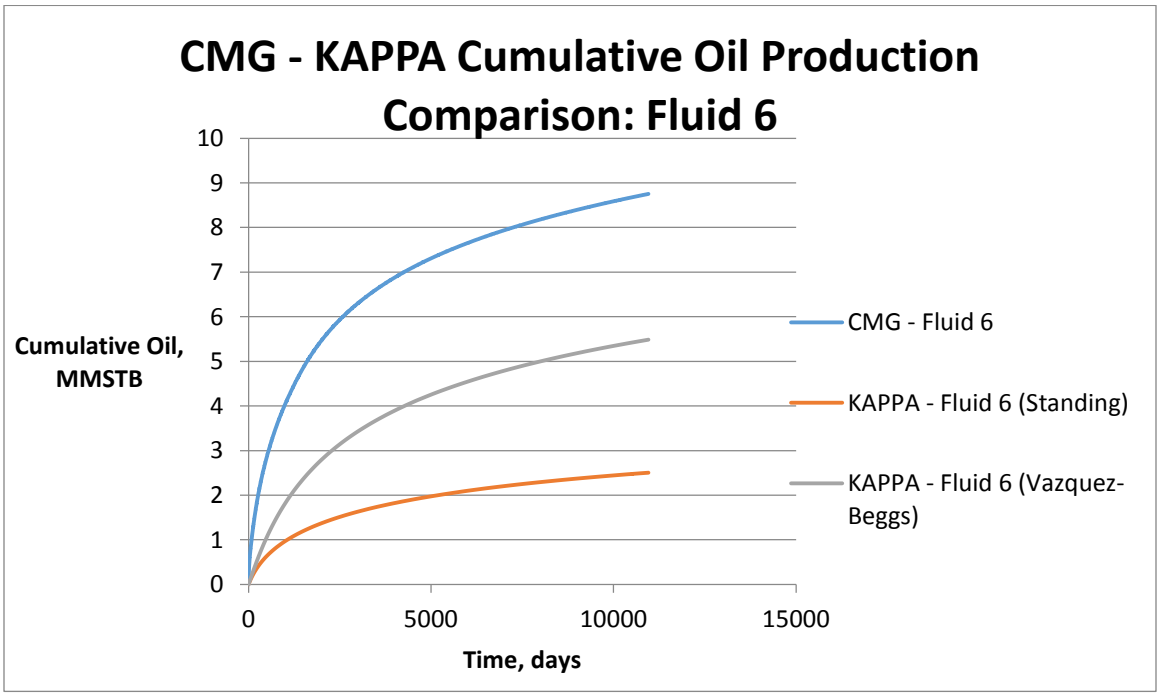


Figure 7.4-11 Fluid 6: CMG - KAPPA Cumulative Oil Production Comparison

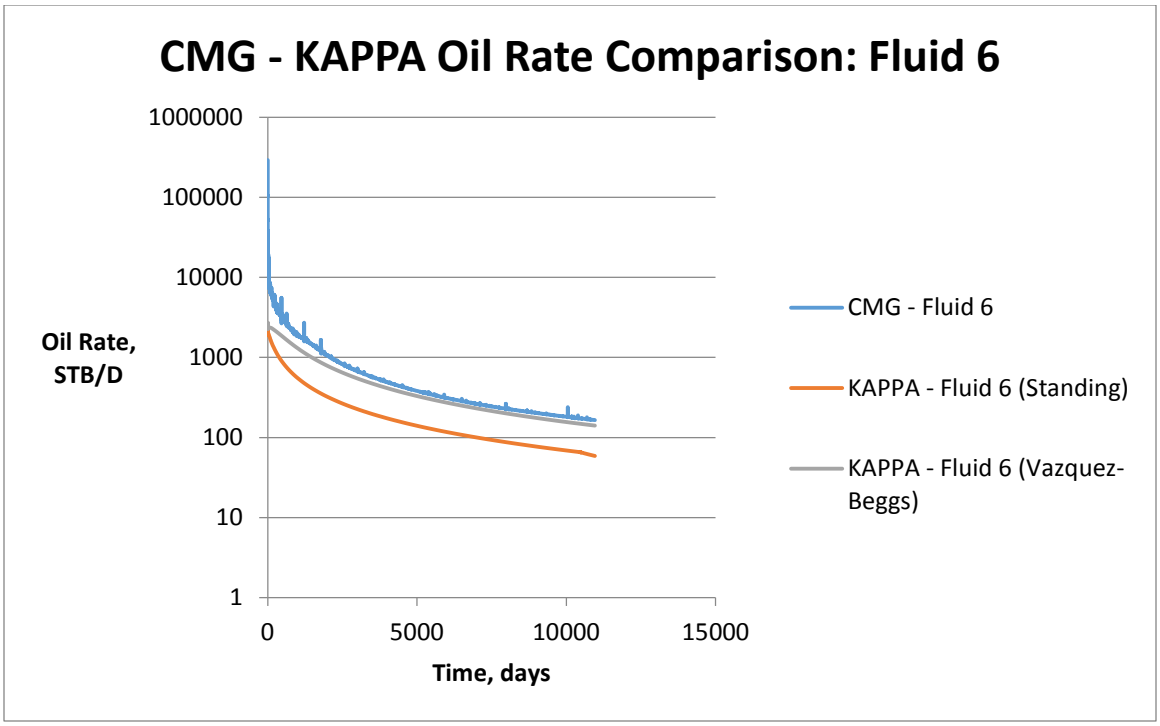


Figure 7.4-12 Fluid 6: CMG - KAPPA Oil Rate Comparison

8. Conclusions

The following conclusions can be drawn from this study:

a. The gas phase in the two-phase flow has considerable effect on oil production in shale volatile oil reservoirs;

b. Sensitivity studies 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;

c. From the study of oil API gravity, it is evident that imperfect fluid samples (errors in calculation of fluid properties) can have significant impact on oil recovery estimates;

d. There is need for proper identification and classification of fluid samples prior to modeling and simulation (especially for black-oil simulations);

e. Near-critical fluids are very difficult to model due to their complexity;

f. Volatile oils cannot be properly analyzed with classic material balance equations (i.e., black-oil simulations), as the assumption that free gas in the reservoir remains as gas through the separator contradicts the behavior of gases released from volatile oils during production (i.e., when pressure drops below bubble point);

g. Reservoir engineering calculations for volatile oils must treat the fluid mixture as a multi-component mixture (i.e., compositional simulation is necessary in this case), so that the total composition of the production stream is known and separator calculations done to ascertain the amounts of liquids and gas at the surface;

h. Inaccurate bubble point pressure and PVT property estimates calculated using correlations can have huge impacts on oil production forecasts;

i. Correct use of correlations for PVT property calculations in black-oil simulations can lead to better production estimates that can be almost or as good as those obtained from compositional simulations.

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