

A Novel Approach for Well-Test Analysis of Volatile Oil Reservoirs in Two-Phase Flow Conditions

Hamid Baniasadi and Fariborz Rashidi^{*,†}

Department of Petroleum Engineering, Amirkabir University of Technology, No. 424, Hafez Ave., Tehran, Iran

**Department of Chemical Engineering, Amirkabir University of Technology, No. 424, Hafez Ave., Tehran, Iran*

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Abstract – Two-phase flow near the wellbore in volatile oil reservoirs causes complications in well test analysis. In this study, the flow behavior of volatile oil reservoirs below the bubble-point pressure and the potential of radial composite model for interpretation of two-phase well test in volatile oil reservoirs was investigated. A radial composite model was used for two-phase well test analysis. A new procedure was developed to interpret well test data and estimate the radius of the two-phase region. The changes in fluid composition near the wellbore during drawdown test were found to increase the saturation pressure, which affects the saturation profile during build-up. Well test results showed that the radial composite method is a powerful tool for well test characterization and estimation of reservoir parameters. The proposed procedure was able to estimate the reservoir parameters and radius of the two-phase region with acceptable accuracy.

Key words: Radial composite model, Two-phase flow, Volatile oil reservoir, Well test analysis

1. Introduction

Hydrocarbon resources have been the most important source of energy in recent decades; and hence, many studies have been conducted on the discovery, production, processing and storage of these resources. Petroleum reservoirs are broadly classified as oil or gas reservoirs. The differences in phase behavior, coupled with the physical properties of reservoir rock that determine the relative ease with which liquid and gas are transmitted or retained, result in many diverse types of hydrocarbon reservoirs with complex behaviors [1-5].

In volatile oil reservoirs, when the bottomhole wellbore pressure (P_w) falls below the bubble point pressure of the reservoir fluid (P_b), dissolved gas in oil vaporizes and gas saturation increases near the wellbore. Initially, the liberated gas is immobile, but after a short period of time gas saturation increases and flows toward the well [6,7]. This behavior is similar to gas condensate systems with flowing wellbore pressure below the dew-point pressure. The existence of a two-phase flow region near the wellbore reduces the mobility of gas/oil and causes the log-log pressure derivative curve of a radial homogeneous reservoir to behave same as a “radial composite” system. The first region (Region 1) is the altered region with reduced effective permeability due to two-phase gas-oil flow. The second region (Region 2) is the virgin zone with original permeability (Fig. 1) [8].

There are two approaches that can be used for well test analysis of

volatile oil systems with $P_w < P_b$. In the first method, radial composite method, pressure data are directly used for well test analysis. This approach estimates effective permeability, skin, radius of gas bank, and distance to the fault/boundary. The important issue in using this method concerns the duration of test, which should be long enough such that the pressure response reaches beyond the two phase region [8]. In the second method, the Raghavan two-phase pseudo-pressure technique is employed. By two-phase pseudo-pressure approach, the near wellbore effects induced by the two phase flow will be eliminated. Therefore, it has been suggested that conventional methods developed for well test analysis of single phase oil reservoirs might be safely used [9,10]. However, two-phase pseudo-pressure method requires correct knowledge of the relative permeability of fluids which are usually not available.

Extensive published literature exists regarding behavior diagnosis and well test analysis of gas condensate systems by radial composite and two-phase pseudo-pressure methods [8,11-16]. However, only a few publications have dealt with volatile oil reservoirs below P_b [6,7]. Hence, the behavior of volatile oil reservoirs has not been well understood and pressure transient test analysis has not been well developed for reservoir characterization in two-phase volatile oil reservoirs.

The aim of this study was to investigate the behavior of volatile oil reservoir and characterize it through well test analysis. For this purpose, the flow behavior of volatile oil reservoirs near the wellbore and the saturation profile in drawdown and build-up tests below P_b were fully assessed. Subsequently, the radial composite model was used for two-phase well test analysis. A new procedure was presented for estimating the radius of two-phase region when the saturation profile is unknown. Synthetic test data generated by a commercial

[†]To whom correspondence should be addressed.

E-mail: rashidi@aut.ac.ir

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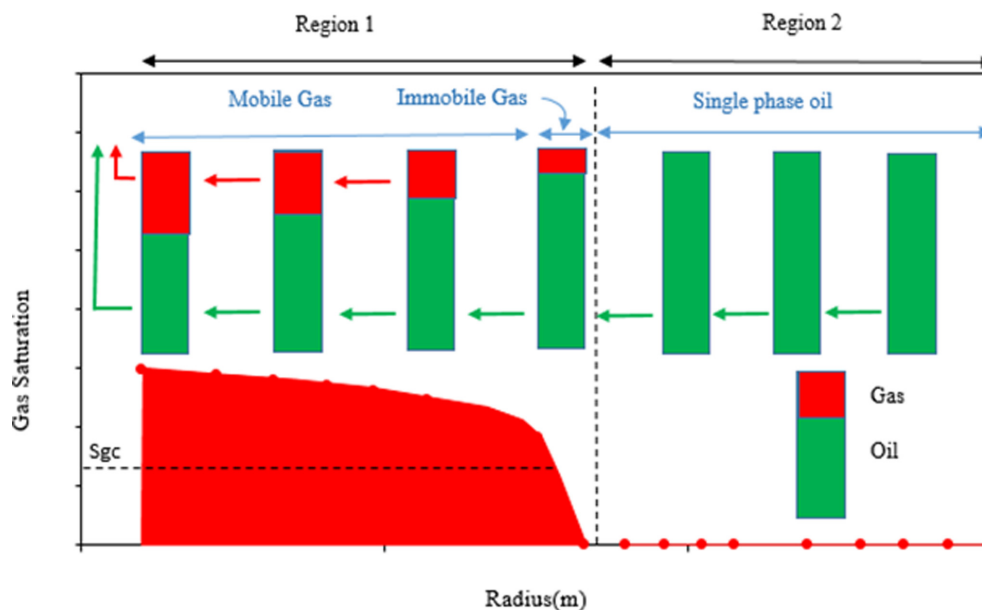


Fig. 1. Gas saturation profile near the wellbore.

reservoir simulator were used to check the applicability of the proposed method and investigate the flow behavior.

2. Theory and background

The well test interpretation model for volatile oil reservoirs with $P_w < P_b$, is a two-region radial composite model to represent the two-phase (oil and gas) region around the wellbore (Region 1) and a single-phase oil region away from the well (Region 2). This model is characterized by mobility and storativity changes in the radial direction, resulting in two radial flow stabilizations on the log-log pressure derivative curve. Therefore, interpretation of test data in a volatile oil reservoir that shows a composite behavior will yield the inner and outer zone effective permeabilities (K_{eff1} and K_{eff2}), the wellbore skin (S_w), the total skin (S_t), the mobility ratio between various regions $(kh/\mu)_{1/2}$ and the outer radius of two-phase region (R_i) [8].

To determine the two-phase radius (R_i) from well test data, different methods have been proposed [17-22], all of which require evaluation of the total compressibility in the two-phase region around the wellbore [11]. Bozorgzadeh and Gringarten [11] proposed a procedure to characterize the condensate bank from pressure build-up test data and interpret well test data in gas condensate systems. We employed this procedure (which will be referred to as Analysis#1 herein) to analyze the pressure build-up data in a volatile oil reservoir. To use the above method for characterizing volatile oil reservoirs, oil saturation of the two-phase region near the wellbore at the time of shut-in must be determined.

However, in some cases, there is not enough data to estimate the oil saturation of two-phase region near the wellbore. Therefore, in this study, another procedure has been also presented for estimation of the total compressibility and interpretation of well test data. This method (which will be referred to as Analysis#2 herein) is based on

the fact that the mobility ratio (M) and diffusivity ratio (D) described by Eqs. (1) and (2) are both independent of viscosity and compressibility. Therefore, they can be estimated from the log-log pressure derivative plots, through type curve matching without calculation of the total compressibility and viscosity of fluids in the two-phase near-wellbore region.

$$M = \frac{\lambda_1}{\lambda_2} = \left(\frac{k_1}{\mu_1} \right)_{\text{two phase}} / \left(\frac{k_2}{\mu_2} \right)_{\text{single phase}} \quad (1)$$

$$D = \left(\frac{k_1 h}{\mu_1 \phi C_{t1}} \right)_{\text{two phase}} / \left(\frac{k_2 h}{\mu_2 \phi C_{t2}} \right)_{\text{single phase}} \quad (2)$$

Thereafter, the two-phase total compressibility could be calculated from the mobility ratio (M), diffusivity ratio (D), and single-phase total compressibility (C_{t2}). The following steps have been proposed for well test analysis using this method:

1. Calculate the mobility of the single-phase outer region (λ_2) from well test data using the fluid properties of single-phase oil at average reservoir pressure.
2. Estimate the mobility ratio (M) and diffusivity ratio (D) through matching pressure and derivative data with a radial composite model.
3. Calculate the two-phase total compressibility (C_{t1}) using the mobility ratio (M), diffusivity ratio and single-phase total compressibility (C_{t2}):

$$C_{t1} = C_{t2} * M / D \quad (3)$$

4. Calculate the mobility of the two-phase region (λ_1) using the mobility ratio and the mobility of the single-phase oil region.

$$\lambda_1 = M * \lambda_2 \quad (4)$$

5. Calculate the radius of the two-phase region from well test data, based on the total compressibility of two-phase region.

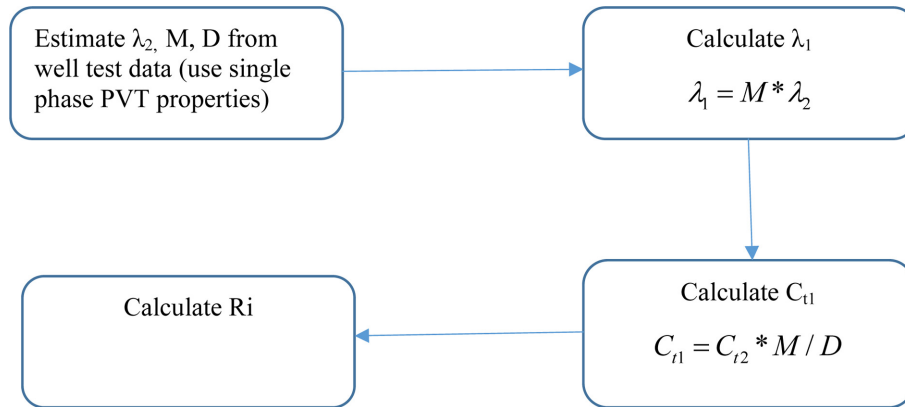


Fig. 2. Proposed procedure for determination of well test parameters.

Table 1. Model parameters (base model)

| Parameter | Value | Parameter | Value |
|---|----------|----------------------------------|-------|
| Porosity (%) | 9 | Reservoir temperature (°C) | 146 |
| Absolute permeability (m ²) | 4.93E-15 | Initial reservoir pressure (MPa) | 34 |
| Net to-Gross ratio | 1 | Initial water saturation | 0 |
| Wellbore radius (m) | 0.08 | Residual oil saturation | 10% |
| Top depth (m) | 3048 | Critical gas saturation | 5% |
| Reservoir thickness (m) | 30.48 | | |

Fig. 2 presents the proposed procedure for determination of well test parameters.

3. Model construction

In the present study, simulations were carried out to investigate the well test behavior of volatile oil systems with $P_w < P_b$, and to identify the challenges in well-test analysis of these reservoirs. In all cases, the reservoir was single-layer, isotropic and homogeneous with constant thickness. Gravitational and frictional effects along with wellbore storage were neglected. Furthermore, near-wellbore effects were ignored, except for the cases that these effects are mentioned. The data used for the simulation model are summarized in Table 1.

A single-layer simulation model was built with 48 cells. To simulate various phenomena occurring around the wellbore accurately, the grid size was logarithmically increased in the radial direction, with larger grid cells away from the wellbore and finer ones around it. The outer radius of the model was considered to be large enough to ensure that the outer boundary effects do not affect the transient well test data. High resolution time steps were used specially at the beginning of each test duration.

Two volatile oil samples, A and B, with different volatility criteria were used in this study. Fluid properties are listed in Table 2. Modified Peng-Robinson equation of state (EOS) with three parameters was

Table 2. Fluid properties

| Properties | Fluid A (base) | Fluid B |
|---|----------------|---------|
| P_b (MPa) | 33.58 | 28.47 |
| R_s (m ³ /m ³) | 311.33 | 505.65 |
| B_o at P_b (m ³ /Sm ³) | 2.08 | 2.53 |

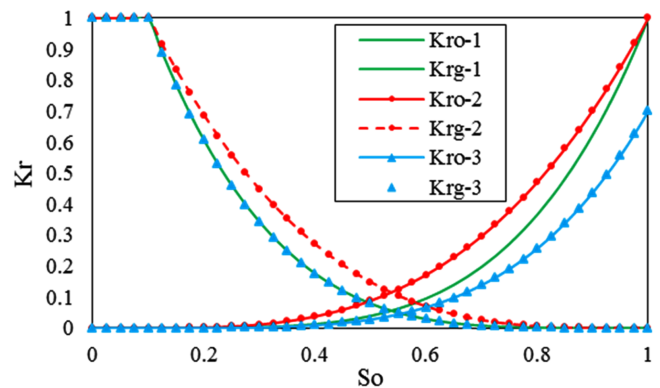


Fig. 3. Relative permeability curves.

used to model PVT properties of the reservoir fluids. Three different relative permeability curves were employed to estimate the interrelation of relative permeability and saturation (see Fig. 3).

4. Results and Discussion

To investigate the impacts of various reservoir conditions on well test behavior, successive 5-days drawdowns and 5-days build-ups (DD1, BU1, DD2, and BU2) were designed and simulated to generate synthetic test data. Fig. 4 presents the pressure and rate histories for a typical simulation run (Case 1). Seven runs were implemented using different rates, initial pressures, wellbore skins, fluid compositions, and gas-oil relative permeability models (see Table 3).

4-1. Phase behavior

In a volatile oil reservoir, during a drawdown test, when P_w drops

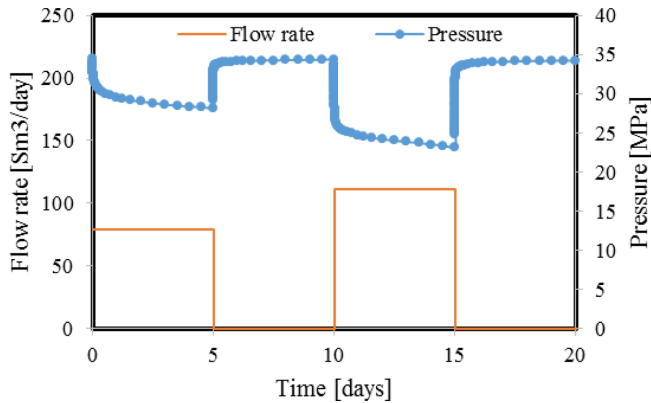


Fig. 4. Pressure and rate histories (case 1).

Table 3. Simulation runs used in this study

| Case No. | Changed parameter |
|----------|-------------------|
| 1(Base) | - |
| 2 | $P_i=38$ MPa |
| 3 | Fluid B |
| 4 | Kr2 |
| 5 | Kr3 |
| 6 | $S_w=5$ |
| 7 | $S_w=10$ |

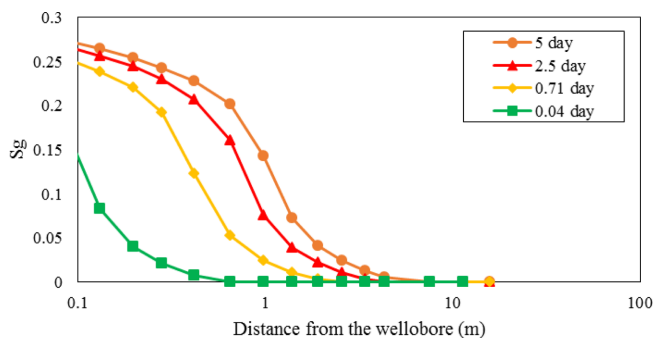


Fig. 5. Gas saturation profile near the wellbore in the DD1 test at different times from the beginning of production (Case 1).

below P_b , a two-phase (oil and gas) flow zone is created near the wellbore with high gas saturation level, whereas the single-phase oil remains away from the wellbore. The size of the near wellbore region with high gas saturation increases with duration of drawdown

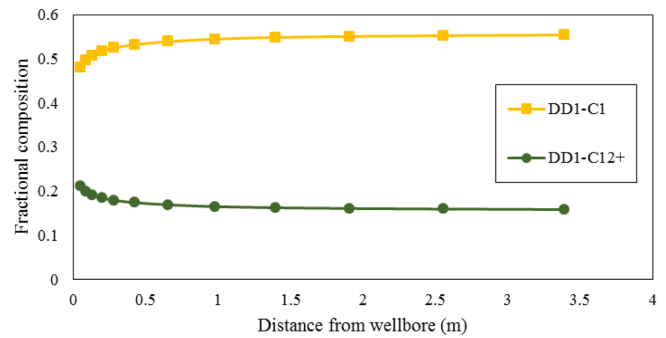
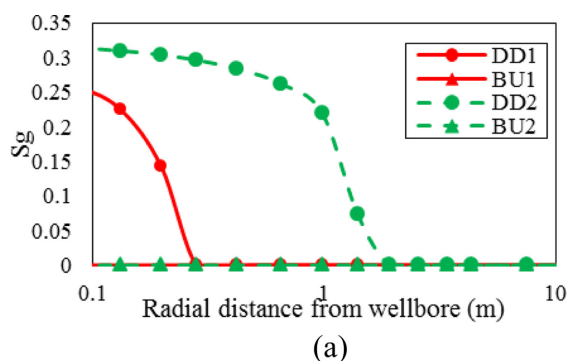


Fig. 6. Fluid fractional composition of light and heavy components at the end of the DD1 test (Case 1).

test, as shown in Fig. 5. Moreover during the test, the amounts of heavy end components in oil increase and those of light end components decrease towards the wellbore (see Fig. 6). The fluid composition of near-wellbore region cannot return to the original fluid composition due to the loss of light components.

During the subsequent build-up, dissolution of the free gas near the wellbore (remained from the previous drawdown) depends on the difference between the average reservoir pressure and P_b . If this difference is high enough (like Case 2 with an initial pressure of 38 MPa), the liberated gas condenses into the oil and the near-wellbore gas saturation returns to the initial gas saturation during build-up, as shown in Fig. 7(a). But if the two pressures are close to each other (like Case 1 with an initial pressure of 34 MPa), the liberated gas cannot condense into the oil and remains as a separate phase, as shown in Fig. 7(b). In fact, the above-mentioned behavior depends on the saturation pressure of fluid near the wellbore, which varies due to fluid composition changes during production (Fig. 8). Therefore, if the build-up pressure is above the saturation pressure of near-wellbore fluid, the liberated gas dissolves into oil during the build-up test; otherwise, it remains as a separate gas phase.

4-2. Well test behavior

In volatile oil reservoirs with $P_w > P_b$, the mobility of volatile oils can be evaluated using a method similar to that employed for black oils, because they exhibit the same trends in drawdown and build-up tests. Below P_b , at the beginning of build-ups, oil exhibits a lower relative

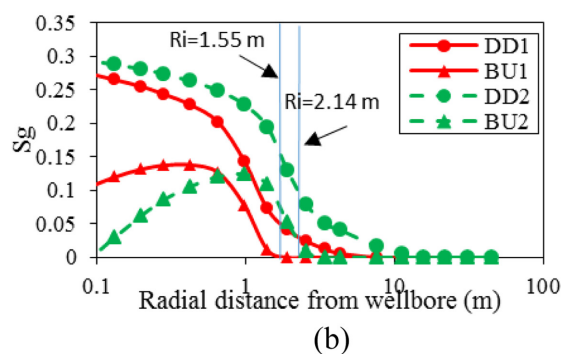


Fig. 7. Gas saturation profiles at the end of drawdown and build-up tests below P_b : (a) Case 2: $P_i=38$ MPa (b) Case 1: $P_i=34$ MPa.

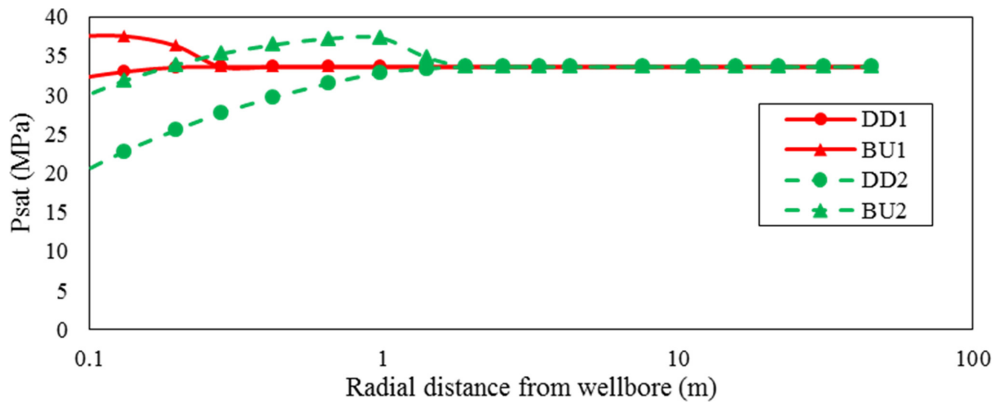


Fig. 8. Saturation pressure profile for flow periods at the end of drawdown and build-up tests (Case 2).

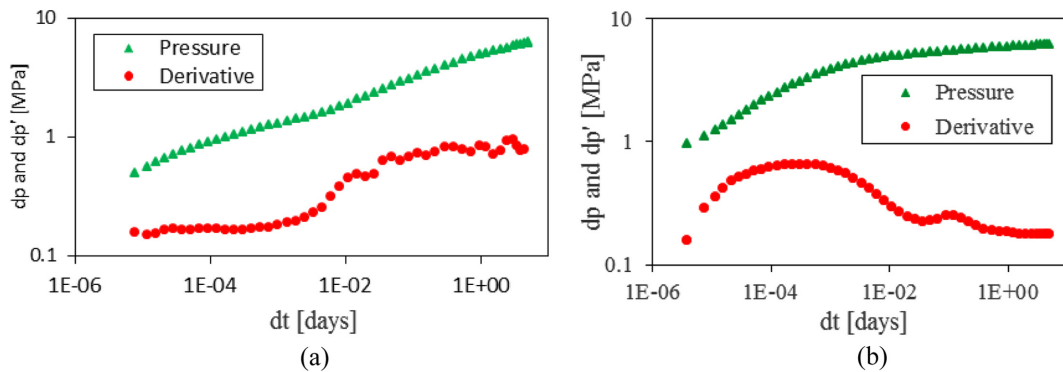


Fig. 9. Log-log pressure and derivative in (a) DD1 test and (b) BU1 test for Case 1.

mobility, as shown in Fig. 9(b), with higher early time derivative stabilizations during the build-up test. This behavior corresponds to the lower mobility at the end of previous drawdown, i.e., higher late time derivative stabilizations of drawdown test as shown in Fig. 9(a). Consequently, the log-log pressure-derivative behavior of volatile oil reservoirs below P_b corresponds to a radial composite model, with decreasing mobility during drawdowns and increasing mobility during build-ups (Fig. 9).

4-3. Well test analysis

The procedure described in the theory and background section

was implemented with computer generated build-up data, as depicted in Fig. 4. Analysis was performed on pressure data using the two-zone radial composite model and the two mentioned procedures (Analysis#1 and Analysis#2). It is notable that well-test analysis is usually conducted on build-up test data, since drawdown data may be altered by rate fluctuations and wellbore dynamics [12]. In the following section, discussions focus on analyzing build-up tests.

Fig. 10 shows analysis of build-up test (BU1) following drawdown with 79 Sm³/day oil rate in Case 1. In this figure, two radial-flow stabilizations are visible on the pressure derivative curve, indicating a two-region radial-flow composite behavior. Therefore, the radial

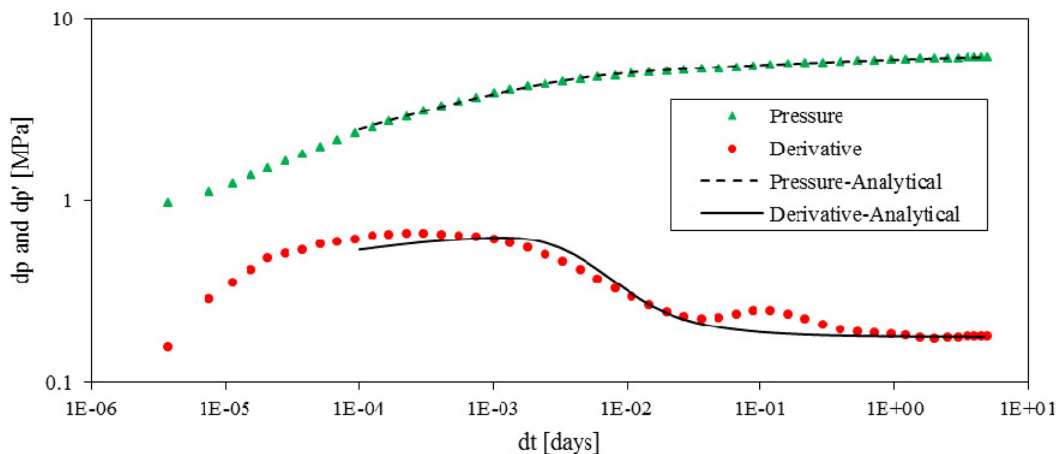


Fig. 10. Log-log pressure and derivative matching of the BU1 test (Case 1).

Table 4. Results of BU1 test using radial composite model (Case 1)

| Parameters | Model values | Analysis#1 | Analysis#2 |
|------------------|--------------|------------|------------|
| $K_{eff1} (m^2)$ | | 1.32E-15 | 1.30E-15 |
| $K_{eff2} (m^2)$ | 4.93E-15 | 4.91E-15 | 4.91E-15 |
| Sw | 0 | 0.53 | 0.50 |
| St | | 9.61 | 9.61 |
| Ri (m) | | 1.51 | 1.55 |
| M | | 0.274 | 0.274 |
| D | | 0.075 | 0.079 |

composite model was used for well test interpretation. Table 4 presents the results of build-up test analysis using Analysis#1 and Analysis#2 procedures. As can be seen, the calculated wellbore skin and permeability of single-phase region are close to the actual values. Moreover, the calculated mobility and diffusivity ratios in both analyses are almost the same, confirming the applicability of the second analysis method (analysis#2) for well test analysis of volatile oil reservoirs.

The slight difference between actual and calculated wellbore skins shown in Table 4 is due to the formation of gas bank around the

Table 5. Results of BU1 test using radial composite model in different cases

| Parameter | Model parameters | Case 3 (Fluid B) | Case 4 (Kr2) | Case 5 (Kr3) | Case 6 (Sw=5) | Case 7 (Sw=10) |
|------------------|------------------|------------------|--------------|--------------|---------------|----------------|
| $K_{eff1} (m^2)$ | | 1.12E-15 | 2.40E-15 | 1.47E-15 | 1.11E-15 | 1.12E-15 |
| $K_{eff2} (m^2)$ | 4.93E-15 | 4.90E-15 | 4.81E-15 | 4.67E-15 | 4.80E-15 | 4.78E-15 |
| Sw | 0 | 0.40 | 0.22 | 0.41 | 6.83 | 13.3 |
| St | | 9.87 | 3.39 | 10.40 | 33.30 | 57.10 |
| Ri (m) | | 1.58 | 2.14 | 3.03 | 1.93 | 1.94 |
| M | | 0.243 | 0.498 | 0.249 | 0.315 | 0.315 |
| D | | 0.058 | 0.166 | 0.063 | 0.098 | 0.098 |

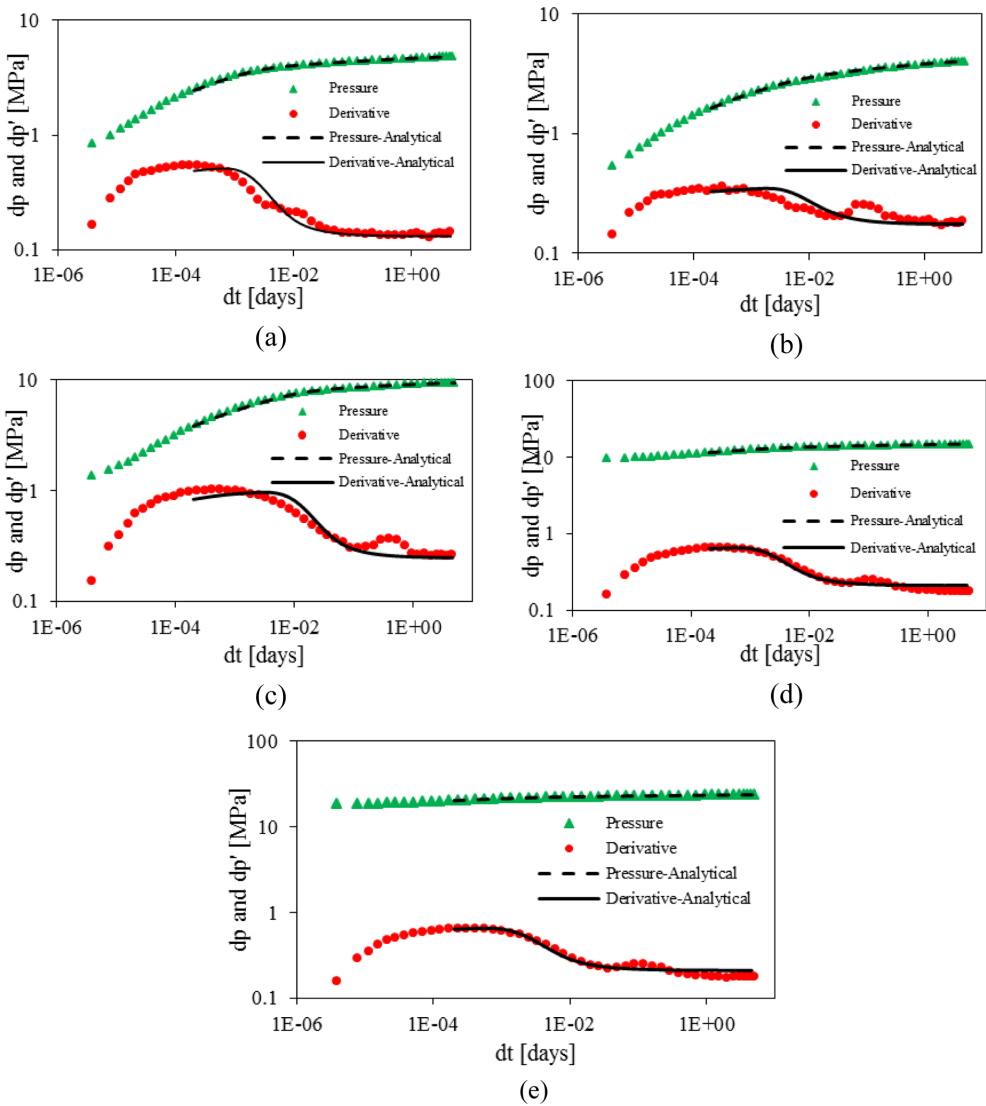


Fig. 11. Analysis of volatile oil reservoir with radial composite model: (a) Case 3: fluid B (b) Case 4: Kr2 (c) Case 5: Kr3, (d) Case 6: Sw=5, (e) Case 7: Sw=10

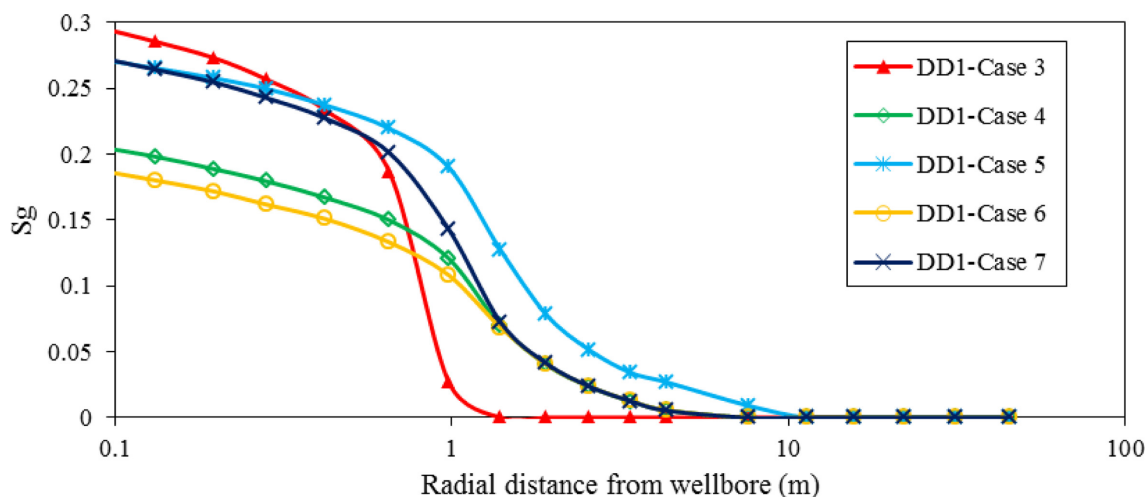


Fig. 12. Saturation profile at the end of DD1 in different cases.

wellbore and subsequent reduction in oil relative permeability. The other reason for this mismatch arises from model assumptions. The radial composite model assumes average values for the inner zone. However, as shown in Fig. 1, the gas saturation in the near wellbore zone is increasing toward the well bore.

The outer radius of the two-phase region was calculated using the obtained storativity ratios. The obtained radius was within an acceptable range compared to the actual radius of two-phase region that can be calculated from gas saturation profile in Fig. 7(b) for Case 1. The slight difference between the actual radius and predicted one might be due to the changes in saturation profile during build-up, compared to that in the preceding drawdown (Fig. 7(b)), which has been already stated for gas condensate systems. This difference could be reduced if accurate PVT properties of the produced well stream at the time of production are used for calculations [11].

To check the validity of the described method, other models were analyzed using different parameters. As presented in Table 3, Case 3 included a different fluid, (Fluid B) with higher volatility, while in Cases 4 and 5, relative permeability was changed. In Cases 6 and 7, wellbore skin was changed to 5 and 10, respectively. In all models, other parameters were similar to Case 1. Results of two-phase well test analysis of these cases are presented in Fig. 11(a) for fluid B (Case 3), Figs. 11(b) and 11(c) for models with different relative permeabilities (Cases 4 and 5), and Figs. 11(d) and 11(e) for different wellbore skins ($S_w=5$ Case 6, $S_w=10$ Case 7). In all cases, two stabilizations were observable on the pressure derivative response. Therefore, the two-region radial composite model was selected for well test analysis. Table 5 represents the actual parameters and the predicted ones represents the actual parameters and the predicted ones. As can be seen, in all cases, the actual and estimated values of permeabilities and wellbore skins were within acceptable ranges.

Fig. 12 indicates the saturation profiles of the mentioned cases at the end of drawdown. Comparison between the actual and predicted radius of two-phase regions shows that the predicted ones were in acceptable ranges. The radius was underestimated in some cases,

which could be attributed to the saturation changes in drawdowns and build-ups, as previously discussed.

5. Conclusion

Well test behavior of volatile oil reservoirs below P_b was investigated based on synthetic generated data. The potential of radial composite method in the interpretation of two-phase volatile oil well test data was examined. The following conclusions were also drawn:

- (1) Saturation profiles in the drawdown and build-up tests in a two-phase flow near the wellbore revealed that the liberated gas in the drawdown test of volatile oil reservoirs may completely condense into the oil during subsequent build-up, if the average reservoir pressure is much higher P_b . However, if the reservoir pressure is close to P_b , the liberated gas cannot condense into the oil and remains as a separate phase.
- (2) Well test analysis using pressure data shows a composite behavior for volatile oil reservoirs below the P_b due to the presence of a high gas saturation zone around the wellbore with decreasing mobility during drawdowns and increasing mobility during build-ups.
- (3) Radial composite models could be successfully employed for well test interpretation and estimation of reservoir parameters including permeability, wellbore skin and radius of the two-phase region, provided that test duration is long enough to reach the single-phase oil region.
- (4) The new procedure developed in this study estimates the radius of the two-phase region with acceptable accuracy and therefore, can be very useful when saturation profile near the wellbore is not available.

Nomenclature

Variables

BU : Buildup test

Bo : Oil formation volume factor [m^3/Sm^3]

C_t : Total compressibility [1/Pa]
 D : Diffusivity ratio
 DD : Drawdown test
 h : thickness [m]
 k : Permeability [m^2]
 K_{eff} : Effective permeability [m^2]
 K_r : Relative permeability
 K_{rg} : Gas Relative permeability
 K_{ro} : Oil Relative permeability
 M : Mobility ratio
 P : Pressure [pa]
 P_b : Bubble point pressure
 P_i : Initial pressure
 P_w : Wellbore pressure
 R_i : Two-phase outer radius [m]
 R_s : Solution gas oil ratio [m^3/m^3]
 S_w : Wellbore skin
 St : Total skin

Greek letters

λ : Mobility
 μ : Viscosity [kg/m·s]
 ϕ : porosity

Subscripts and Superscripts

b : bubble point
 i : initial
 g : gas
 o : oil
 r : relative
 t : total
 w : wellbore

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