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Sampling Volatile Oil Wells

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Abstract

Recombined surface samples are usually used for volatile oil laboratory fluid property studies. A procedure for stabilizing and surface sampling of volatile oil wells is currently used in the industry. However, no investigation of the quality of the samples resulting from this procedure has ever been published.

Typically, during surface sampling, bottom-hole flowing pressure is less than the bubblepoint pressure of the original reservoir oil. This causes gas to form in a cylinder of the reservoir around the wellbore. Understanding the dynamics of this cylinder of gas saturation is critical to obtaining a recombined surface sample representative of original reservoir oil. It is possible to obtain a representative sample if this cylinder is stable.

This paper presents the results of a study of the sampling procedure. The effects of production rate prior to and during the sampling process were quantified using radial compositional simulation. The buildup and stability of the ring of gas saturation were examined.

Guidelines for sampling volatile oil wells is presented. It is based on comparisons of the compositions of recombined surface samples with the compositions of original reservoir oils for various producing schemes. These guideline are expected to give the best chance of obtaining a representative sample from a volatile oil well.

Introduction

Several authors discussed resevoir fluid sampling[1-4]. A study on gas condensate reservoir sampling[5] has recommended that sampling should be done early in the life of the reservoir. The usual procedure of reducing the rate before sampling may be useful in increasing the chance of obtaining a valid fluid sample in gas condensate reservoirs. In this paper, we used compositional reservoir simulation to investigate sampling in volatile oil wells.

Simulation Model

We used a radial compositional simulation model to investigate the changes in composition for volatile oils and to understand the effect of these changes on fluid sampling. The results reported here are those obtained for fluid sample "Oil 2" of Coats and Smart[6].

PVT Modeling. We used an EOS model to match the PVT behavoir of a volatile oil sample[6]. The iso and normal components for C_4 and C_5 were lumped together and the C_{7+} fraction was split into three components using the Whitson's method[7]. This resulted in an eleven-component fluid system. We then used the Peng and Robinson EOS[8,9] to match the PVT data of the fluid sample.

Following Coats and Smart[6] procedure, We used Ω_A, Ω_B for C_1 and the three heavy components, accentric factors for the three heavy components, and the binary interaction coefficients for the three heavy components with C_1 as regression variables. The match with the laboratory data was satisfactory. Figs. 1-3 show the match between some simulated and actual PVT properties for differential liberation and constant volume depletion (CVD) data.

Radial Compositional Model. We constructed a radial simulation model and used it to investigate the near-wellbore compositional changes. The model had twenty-two grid blocks in the radial direction. The block sizes increased logarithmically from 0.5 ft (the wellbore) to 100 ft. and then uniforamlly to a reservoir radius of 1490 ft. (160 acres). Gas-oil relative permeability are shown in **Fig. 4**. Other reservoir and fluid data for the base case are given in **Table 1**.

Simulation Results

Several runs were made to investigate the compositional changes that can occur at different production rates and to study the effect of the common procedure of reducing the production rate before sampling[1-5]. In the following sections, we discuss the results of our compositional simulation experiments for five different cases. These cases show the effect of producing the at high rate, producing at low rate, reducing the rate from the high rate case before sampling, reducing the rate from the low rate case before sampling, and shutting-in the well before sampling.

We used the mole fraction of C_{7+}[11] in the well stream as indicator of compositional changes between the recombined surface sample and the original reservoir fluid. Effects of compositional changes are also reported.

Case 1: Production at High Rate. The well was produced at high rate of 1,000 STB/D. After 220 days of production at the high rate, the well could not maintain its rate because it reached a minimum bottom-hole pressure of 1,470 psia. The average field pressure, first model block pressure, and well bottom-hole flowing pressure are shown in **Fig. 5**. The change in slope of the field average pressure shows that the bubble point pressure was reached around 50 days. Accordingly, an increase in the producing gas-oil ratio (GOR) can be seen after 70 days of production (**Fig. 6**). Because of the high production rate, the GOR increased to very high levels.

Fig. 7 shows the mole fraction of C_{7+} versus time. The original fluid C_{7+} mole fraction is also indicated on the plot. The figure shows that the C_{7+} mole fraction in the well stream is nearly the same as the original fluid C_{7+} mole fraction for at least the first 50 days of production. This suggests that a fluid sample taken early in the life of the reservoir (even when the bottom-hole pressure is slightly less than the bubble point pressure) will almost represent the original reservoir fluid. The sample will not be representative after depletion occurs in the reservoir.

Gas saturation builds up near the wellbore and in the reservoir as pressure declines (**Fig. 8**). The gas saturation can build up immediately around the wellbore if the bottom-hole pressure around the wellbore is less than the bubble-point pressure. This gas saturation reduces the relative permeability to oil and increases the relative permeability to gas, reducing the oil productivity index.

Case 2: Production at Low Rate. We produced the well at a lower rate this time (500 STB/D). This case has similar results to Case 1 except for the effect of lowering the pressure below the bubble-point pressure is delayed. **Fig. 9** shows the C_{7+} mole fraction for the produced well stream. Although the pressure near the wellbore goes immediately below the bubble-point pressure (and gas saturation builds up), there is a better chance of obtaining a representative sample than the case of high production rate. Other simulation runs, at even lower rates, supported this observation.

Case 3: Reducing the High Production Rate Before Sampling. In this case, the production rate was reduced from 1,000 STB/D to 200 STB/D after 180 days of production. **Fig. 10** shows the average reservoir pressure, bottom-hole flowing pressure, and the first simulation cell pressure. The near wellbore pressure is affected by the reduction in production rate. At 180 days, the near wellbore pressure jumps to around 3,800 psia and shows a more gentle decline at production rate of 200 STB/D. The effect of reducing the oil production rate can be also seen as sudden decrease in the producing GOR (**Fig. 11**). The GOR will go back to its normal increasing trend after the production rate is stabilized at 200 STB/D.

Fig. 12 (mole fraction of C_{7+}) shows that when the well production rate is suddenly decreased, a spike of C_{7+} can be detected in the well stream. A fluid sample taken at this time will not be representative of the reservoir fluid. **Fig. 13** shows the gas saturation developing near the wellbore and far in the reservoir. The figure indicates that the gas saturation around the wellbore will be affected by the reduction of rate.

Case 4: Reducing the Low Production Rate Before Sampling. In this case, the production rate was reduced from a low rate of 500 STB/D to a lower rate of 200 STB/D. **Fig. 14** is the C7+ mole fraction for the well stream fluid. At 180 days, the spike can be seen but with a lower magnitude when compared with Case 3 (Fig. 12). This suggests that production at low rate is desirable if a representative fluid sample is to be obtained.

Case 5: Shut-in Before Sampling. This case shows the effect of shutting-in the well before fluid sampling. The simulation model was run at production rate of 1,000 STB/D for 30 days, followed by a shut-in period for 10 days, then produced again at a reduced rate of 200 STB/D. **Fig. 15** shows the behavoir of C_{7+} mole fraction. The figure indicates that shutting the well in before sampling has a minimal effect on the quality of the sample.

Discussion

Obtaining a representative fluid sample is important to estimate the fluid PVT properties. These PVT properties are essential to almost all reservoir and production engineering calculations. Fluid sampling of volatile oil wells can be affected by the conditions of the well before sampling. In general, fluid samples should be taken before considerable depletion occurs in the reservoir. Ideally, the fluid sample will be representative of the original reservoir fluid if the pressure (both in the reservoir and near the wellbore) is not allowed to drop below the bubble-point. If the near wellbore pressure goes below the bubble point, a representative sample may still be obtained. However, if the reservoir pressure drops below the bubble-point, the fluid sample will not be representative of the original reservoir fluid.

Compositional Changes. In volatile oil reservoirs, compositional changes affect the production behavoir. We used Case 2 simulation to show some of these effects. **Fig. 16** compares the relative permeability in the first grid block for oil and gas. Oil relative permeability goes down with time while gas relative permeability goes up. This is a direct result of the saturation changes occuring near the wellbore with production. With in the increase in gas saturation, more gas passes into the wellbore. As a result, productivity of the gas increases while productivity of the oil decreases.

Viscosity changes (**Fig. 17**) near the wellbore also increase the mobility of the gas (because gas viscosity decreases) and decrease the mobility of the oil (because oil viscosity increases). The changes in viscosity are a result of the gas becoming leaner (has less heavy components) and the oil becoming heavier as pressure declines.

Recommended Sampling Guidelines. Based on the work performed in this paper, we can suggest several guidelines to obtain the most representative sample of a volatile oil fluid.

1. Try to obtain the fluid sample before any significant production takes place.
2. Bring the well on production at the lowest possible rate prior to sampling.
3. If the well has been producing for some time before sampling, a rate reduction may help.
4. When the rate of the well is changed, the separator production should be stabilized over a period of days (rather than hours) to make sure that the C_{7+} spike has subsided.

Conclusions

We used compositional simulation for volatile oil reservoir fluids to investigate the compositional changes during production and the effect on fluid sampling. The following conclusions can be drawn from this work:

1. A representative fluid sample of volatile oil reservoirs can be taken even if the bottom-hole pressure of the well is less than the bubble-point pressure. The sample may not be representative if it is not taken early enough.

2. There is higher chance of obtaining a representative sample from a volatile oil well if it has been producing at lower rate. This is true whether the production rate is reduced before sampling or kept at its level.

3. A fluid sample taken immediately after reducing the production rate may not be representative. One needs to wait until the effect of reducing the rate dies out before obtaining a fluid sample.

4. Shutting-in the well before sampling will not significantly affect the fluid sample.

Nomenclature

GOR = producing gas-oil ratio

Ω_A, Ω_B = equation of state parameters

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TABLE 1 – Reservoir and fluid properties for the base case

Reservoir porosity = 0.2 fraction
Reservoir permeability = 10 md
Reservoir thickness = 50 feet
Reservoir temperature = 176 °F
Initial pressure = 4,800 psia
Bubble point pressure = 4,475 psia
Separator pressure = 300 psia
Separator temperature = 80 °F
Stock-tank pressure = 14.7 psia
Stock-tank temperature = 70 °F

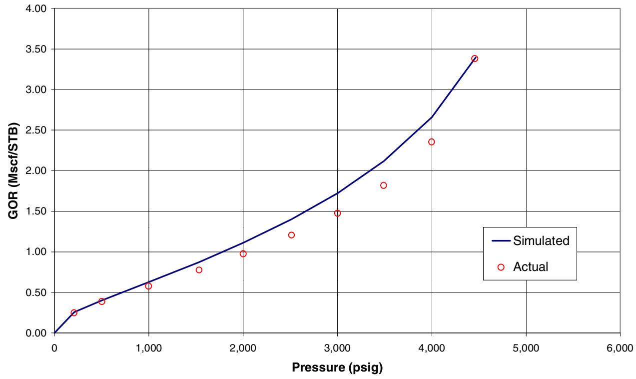

Fig. 1 – Match between actual and simulated gas-oil ratio from the differential liberation experiment.

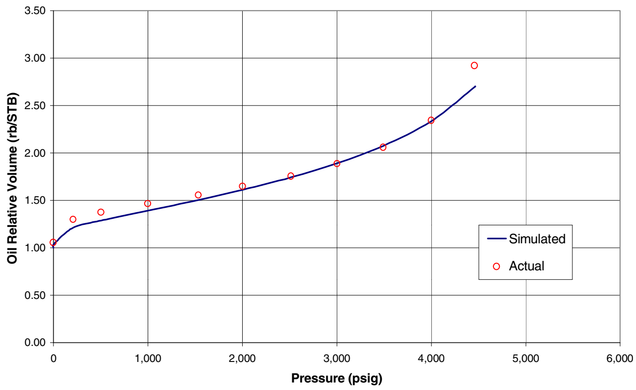

Fig. 2 – Match between actual and simulated oil relative volume from the differential liberation experiment.

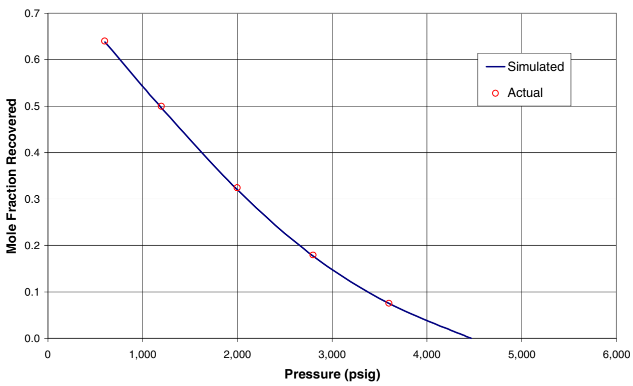

Fig. 3 – Match between actual and simulated mole fraction recovered from the constant volume depletion experiment.

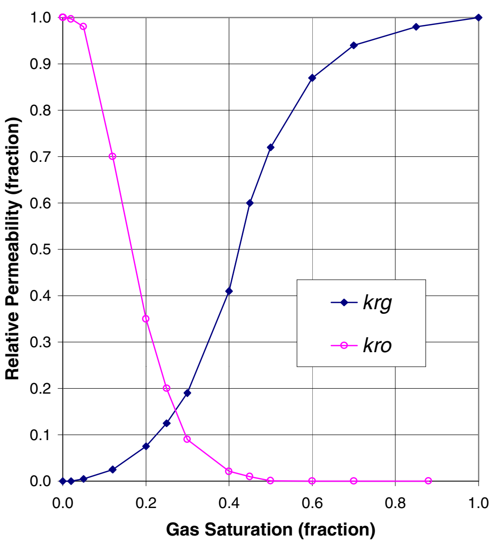

Fig. 4 – Gas-oil relative permeaility data.

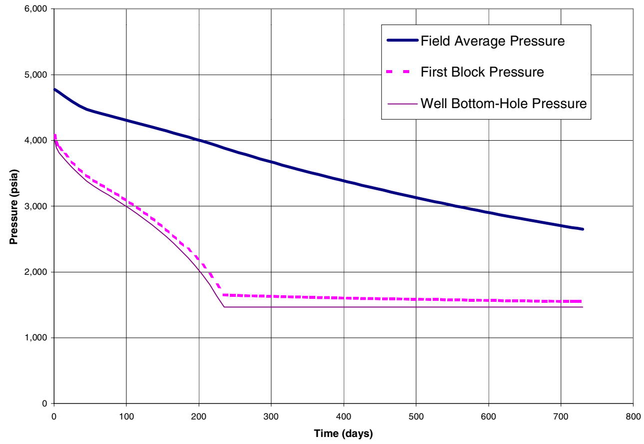

Fig. 5 – Field and well pressures for Case 1.

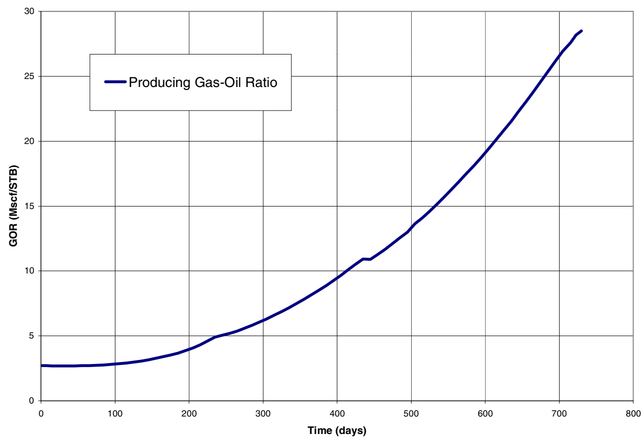

Fig. 6 – Producing gas-oil ratio for Case 1.

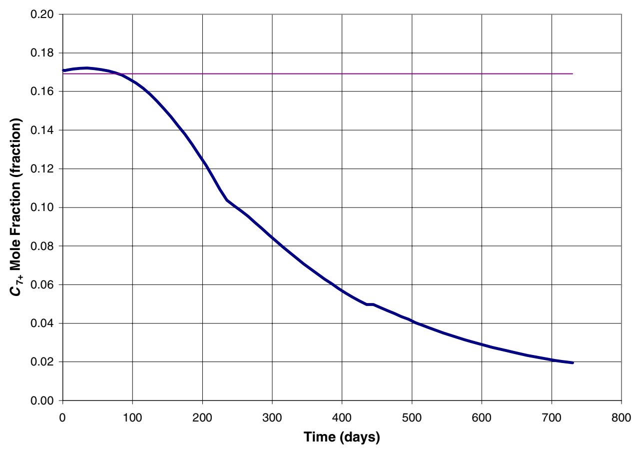

Fig. 7 – C_{7+} mole fraction in the total production stream for Case 1.

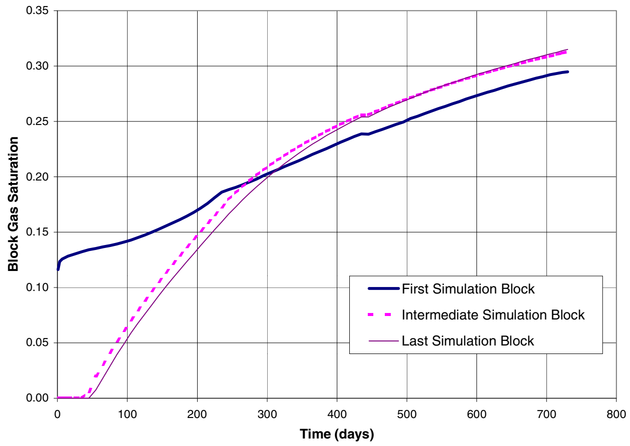

Fig. 8 – Simulation block gas saturation for Case 1.

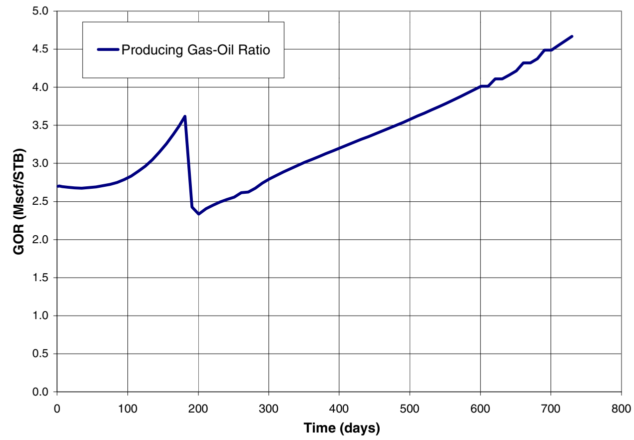

Fig. 11 – Producing gas-oil ratio for Case 3.

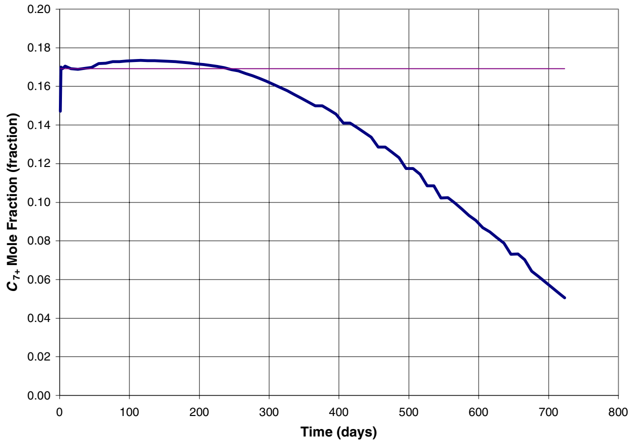

Fig. 9 – C_{7+} mole fraction in the total production stream for Case 2.

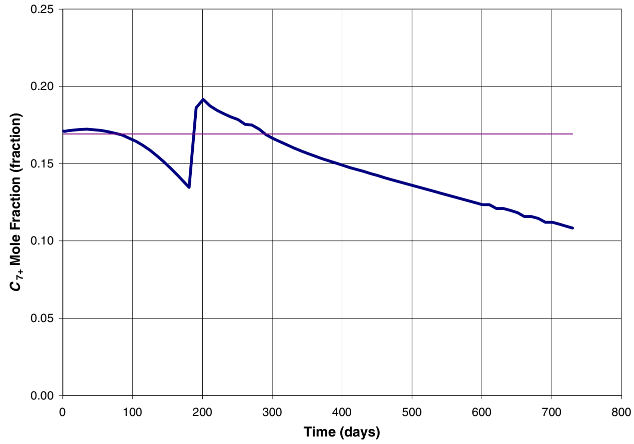

Fig. 12 – C_{7+} mole fraction in the total production stream for Case 3.

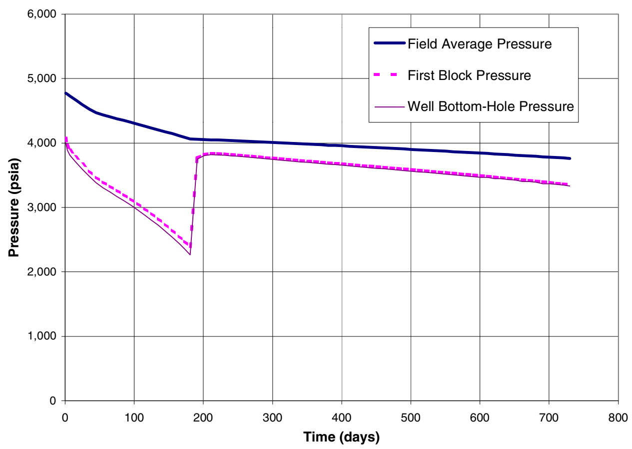

Fig. 10 – Field and well pressures for Case 3.

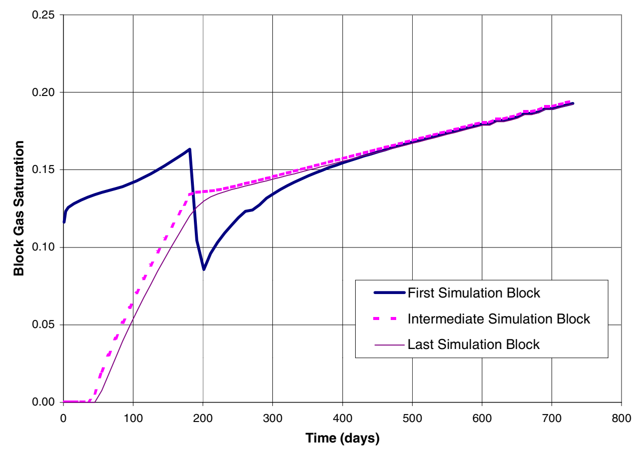

Fig. 13 – Simulation block gas saturation for Case 3.

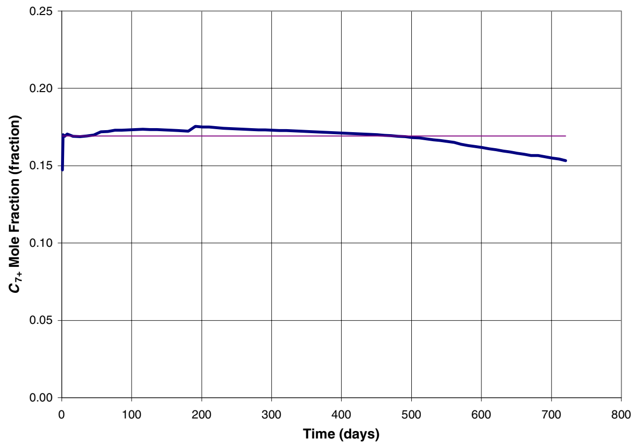

Fig. 14 – C_{7+} mole fraction in the total production stream for Case 4.

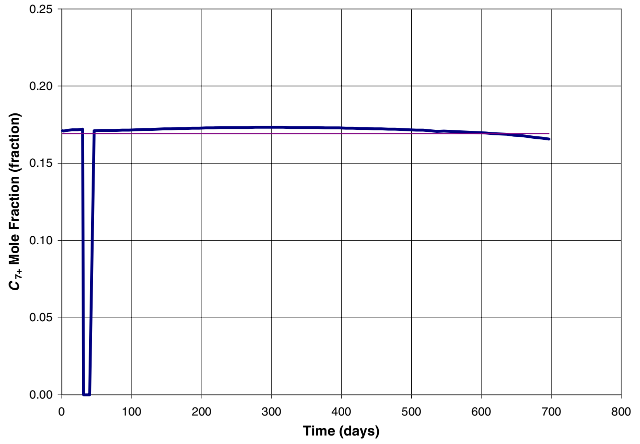

Fig. 15 – C_{7+} mole fraction in the total production stream for Case 5.

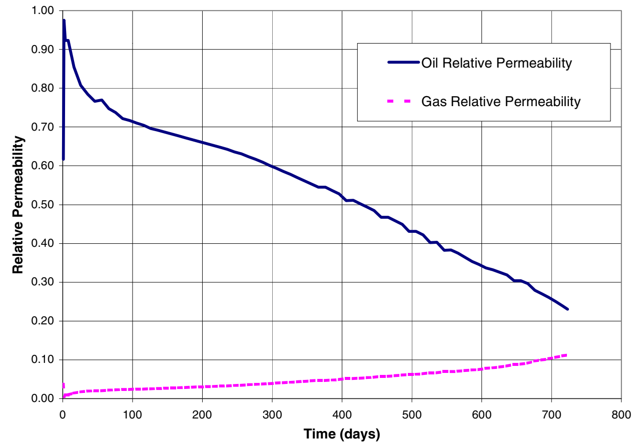

Fig. 16 – Oil and gas relative permeability in the first simulation grid block (Case 2).

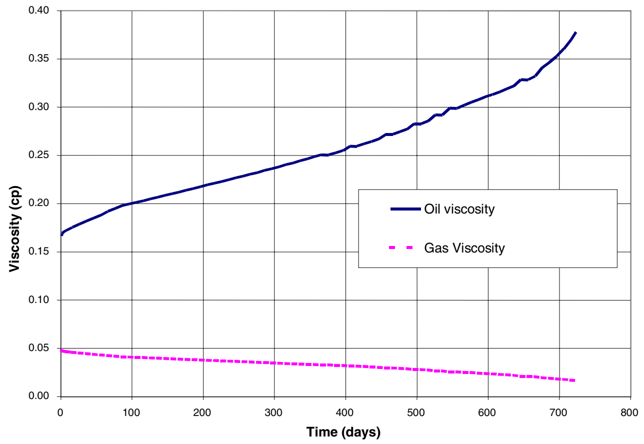

Fig. 17 – Oil and gas viscosity in the first simulation grid block (Case 2).