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Investigation of Well Productivity in Gas-Condensate Reservoirs

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Abstract

The productivity of the wells in a moderately rich gas condensate reservoir was observed to initially decrease rapidly and then increase as the reservoir was depleted. All wells in the field showed the same response. Compositional simulation explained the reasons for these productivity changes.

During early production, a ring of condensate rapidly formed around each wellbore when the near-wellbore pressures decreased below the dew point pressure of the reservoir gas. The saturation of condensate in this ring was considerably higher than the maximum condensate predicted by the PVT laboratory work due to relative permeability effects. This high condensate saturation in the ring severely reduced the effective permeability to gas, thereby reducing gas productivity.

After pressure throughout the reservoir decreased below the dew point condensate formed throughout the reservoir, thus the gas flowing into the ring became leaner causing the condensate saturation in the ring to decrease. This increased the effective permeability of the gas. This caused the gas productivity to increase as was observed in the field.

There were also changes in gas and condensate compositions in the reservoir which affected viscosities and densities of the fluids. These effects also impacted gas productivity.

This work is another step forward in our understanding of the dynamics of condensate buildup around wellbores in gas condensate fields.

Introduction

Wells in gas condensate reservoirs often experience rapid decline when the near wellbore pressure goes below the dew point pressure. Several investigators[1-6] have reported on well productivity of gas condensate reservoirs. Radial compositional simulation models were often used to investigate the problem of productivity loss[1-5]. These models clearly showed that the loss in productivity was due to liquid drop out around the wellbore. This so called condensate blocking (increase in condensate saturation around the wellbore) reduces the effective permeability to gas and results in rapid decline in well productivity once the near wellbore pressure drops below the dew point. The effect of condensate blocking is more evident in low permeability reservoirs. Barnum *et al*.[7] have noticed that the recovery factor of gas condensate wells is only affected by condensate blocking if the well's kh is less than 1,000 md-ft. For higher quality reservoirs, productivity loss is not very severe.

Figs 1, **2**, and **3** show the performance of three different wells producing from the same reservoir. They show the rapid decline common to most gas condensate wells when they go below the dew point. However, they all show approximately stable gas production after the period of initial decline and, more importantly, a subsequent increase in gas production rate. The increase in rate is not due to any improved recovery technique since no fluid injection and no changes in operating conditions have ever taken place in this reservoir.

History Match with a Compositional Simulation Model

We constructed a radial, single-well compositional model to investigate the behavior of one of the wells (well A). The model consisted of one layer with 36 grid blocks in the radial direction. We started with a 0.5 ft. grid block near the well, increased the size logarithmically to gird block 10, and then used uniform grids of 100 ft. afterwards. A 9-component equation of state (EOS) formulation was used. An imbibition gas-oil relative permeability data set in presence of irreducible water was used (**Fig. 4**). History matching was performed in an attempt to explain the uncommon behavior of the well. The model was constrained by gas rate while reservoir properties were changed to match average reservoir pressure and condensate production rate. **Fig. 5** shows the match between actual and simulated condensate production rate. Permeability, porosity, and permeability distribution of the model were altered to achieve this match.

Results

After the successful history match of well A, several reasons for the uncommon behavior became apparent. The initial well productivity declined when the near wellbore flowing pressure decreased below the dewpoint pressure. This was due to the increase in condensate saturation around the wellbore. **Fig. 6** shows condensate saturation versus time in three grid blocks representing near wellbore, middle of the reservoir, and far end of the reservoir.

The condensate saturation near the wellbore increased to almost 70 percent when the pressure dropped below dew point pressure. This increase is considerably above the maximum condensate saturation predicted by the constant volume depletion experiment (CVD). This high condensate saturation is determined by the relative permeability curve (the condensate saturation has to be high enough to ensure that the correct amount of condensate passes to the wellbore).

After pressure throughout the reservoir drops below dewpoint pressure, significant condensate saturation builds up in the reservoir. Thus, the gas that arrives to the wellbore is leaner and drops less condensate around the wellbore. This is seen in Fig.6 as the continuous decline in near-wellbore (cell 1) condensate saturation which allows partial recovery of gas production.

Relative Permeability Effects. The relative permeability to both condensate and gas is determined from condensate and gas saturation. **Fig. 7** shows the relative permeability of the condensate near the wellbore (cell 1) and deep in the reservoir (cell 36). The figure shows that the relative permeability to condensate near the wellbore continuously declines as the incoming gas becomes leaner. Around the end of the run (7,000 and 7,600 days), the two blips in relative permeability curves are due to shut-ins and sudden changes in production rate. The figure also shows that the condensate far in the reservoir (cell 36) does not move since its saturation does not become high enough to build any relative permeability.

Fig. 8 shows the relative permeability to gas in both cells 1 and 36. After the initial drop near the wellbore when pressure goes below dewpoint pressure, the relative permeability to gas increases with time. This increase in near-wellbore gas productivity is due to decrease in near-wellbore condensate saturation shown in **Fig. 6**.

Compositional Changes. The simulation results show that the compositions of both the condensate and the gas in the reservoir change with decreasing reservoir pressure. The compositional changes around the wellbore are more dramatic than in the reservoir. This is shown by surface tension[8] plot (**Fig. 9**). The surface tension reflects the closeness of the composition of the condensate and the gas. Around the wellbore (cell 1) higher surface tension reflects considerable difference between condensate and gas compositions. Whereas in the reservoir (cell 36), the surface tension is much lower than near the wellbore.

The compositional changes affect the viscosities of both the condensate and the gas. **Figs. 10** and **11** show the viscosity of the condensate and the gas (calculated from their compositions[9]). The two figures show that condensate viscosity increases while gas viscosity decreases as reservoir pressure decreases. This results in increased gas mobility.

Condensate Ring Development. **Fig. 12** illustrates the buildup of condensate around the wellbore and shows the way the condensate saturation profiles change with time. Initially the condensate saturation builds to nearly 70 percent near the wellbore when the pressure near the wellbore drops below the dewpoint pressure of the gas. This maximum condensate saturation is considerably higher than predicted in the static laboratory PVT work. This condensate saturation decreases to zero a short distance away from the wellbore and is zero throughout most of the reservoir (where pressures are above dewpoint pressure). The diameter of the ring grows with time but as long as most of the reservoir has pressures above dewpoint the maximum concentration of condensate near the wellbore remains near 70 percent. After six years of production the condensate ring has expanded to about 300 feet into the reservoir (**Fig. 12**).

Between the sixth and seventh years of production the pressure throughout the reservoir drops below dewpoint pressure. Condensate saturation builds in the reservoir to the level predicted by the laboratory PVT results; leaner gas approaches near wellbore, and the near wellbore condensate saturation decreases.

Through the next seven years the condensate saturation throughout the reservoir increases as pressure decreases according to the PVT results and the condensate saturation near the wellbore decreases. This, of course, results in an increase in gas saturation near the wellbore which increases the gas productivity. At year 20 some revaporization occurs and the condensate saturation in the reservoir decreases slightly.

Discussion

Production data for the wells in this field were rather unusual. The gas production rates initially declined rapidly, then stabilized, and for over ten years have regularly increased. The time at which the gas production rates stabilized coincided with the start of the decline in condensate yield (approximately 2000 days in **Figs. 1** and **3**). Thus, the gas productivities appeared to be related to the dewpoint pressure of the reservoir gas.

Compositional simulation showed that the fairly severe gas productivity decline early in the life of the wells was caused by the buildup of a ring of condensate near the wellbore when the pressure near the wellbore dropped below dewpoint pressure. Note the subtle decline in yield in the production data (**Figs. 1, 2** and **3)** during this period as the diameter of ring increases. The condensate saturation in this ring of condensate had to build to a level high enough to allow the condensate lost from the gas entering the ring to pass into the wellbore.

In this example the condensate saturation near the wellbore built to about 68 percent which with an irreducible water saturation of 20 percent reduced the effective permeability of the gas to less than 0.1. When the pressure in the bulk of the reservoir fell below the dewpoint condensate dropped throughout the reservoir. The saturation of this condensate did not increase to a high enough value for the condensate to flow, however the gas flowing to the wellbore was leaner and thus had less condensate to drop in the ring. This allowed the condensate saturation in the ring to decline to about 55 percent. Although this change does not appear to be dramatic it did result in a gas saturation of 25 percent which increased the relative permeability of gas to about 0.2, more than double the value when the ring first formed. This, of course, resulted in the increase in gas productivity.

Other changes in the gas after reservoir pressure declines below dewpoint pressure also aid in the improvement of gas productivity. These changes are not as significant as the improvement in relative permeability to gas. However the leaner gas has a measurably lower viscosity which improves productivity. And the production of leaner gas reduces both the hydrostatic and friction components of the pressure drop through the tubulars. This effect also tends toward productivity improvement.

Conclusions

Compositional simulation was used to investigate the productivity of gas condensate wells. This work resulted in the following conclusions.

1. Production rate of gas condensate wells in low permeability reservoirs declines because of liquid drop out around the wellbore, once the near wellbore pressure drops below the dewpoint pressure.
2. Condensate builds up in the reservoir as the reservoir pressure drops below the dewpoint pressure. As a result, the gas moving to the wellbore becomes leaner.
3. The gas production rate may stabilize, or possibly increase, after the period of initial decline. This is controlled primarily by the condensate saturation near the wellbore.
4. Both the liquid and gas around the wellbore change in composition. The liquid becomes heavier and the gas becomes leaner.
5. Viscosity of the liquid becomes higher and viscosity of the gas becomes lower with production. This improves the mobility of the gas with respect to the oil.

Nomenclature

h = net pay thickness, L, ft
k = reservoir permeability, L^2, md

Acknowledgements

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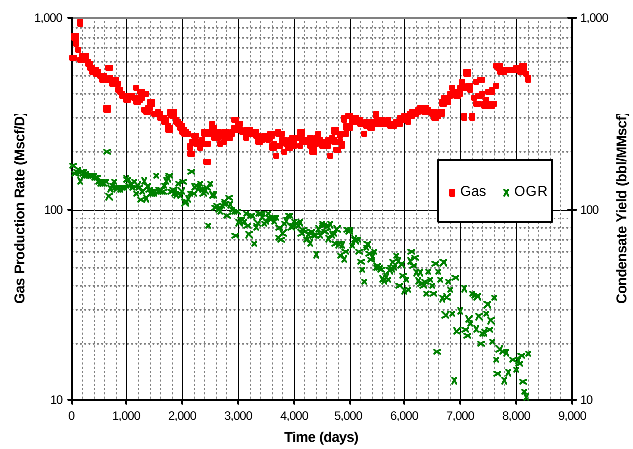

Fig. 1 - Gas production rate and condensate yield (Well A)

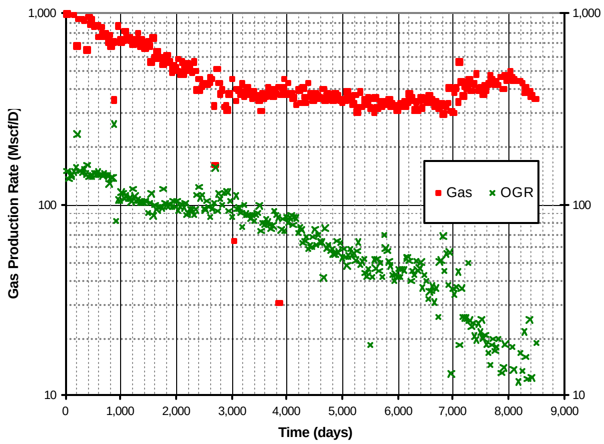

Fig. 2 - Gas production rate and condensate yield (Well B)

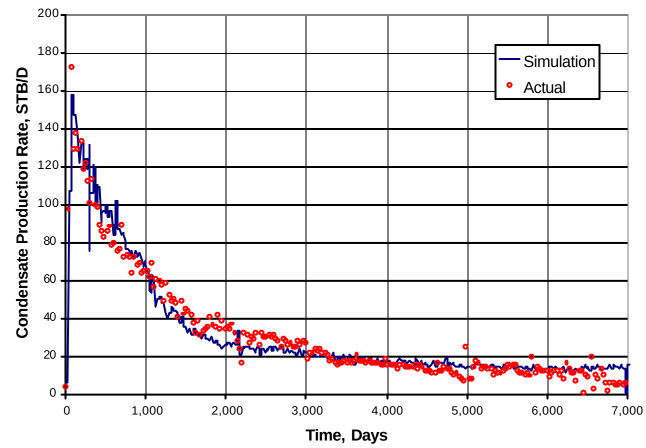

Fig. 5 - History match of condensate production rate

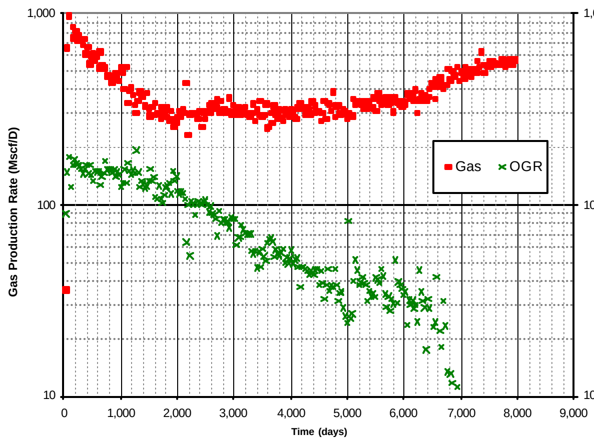

Fig. 3 - Gas production rate and condensate yield (Well C)

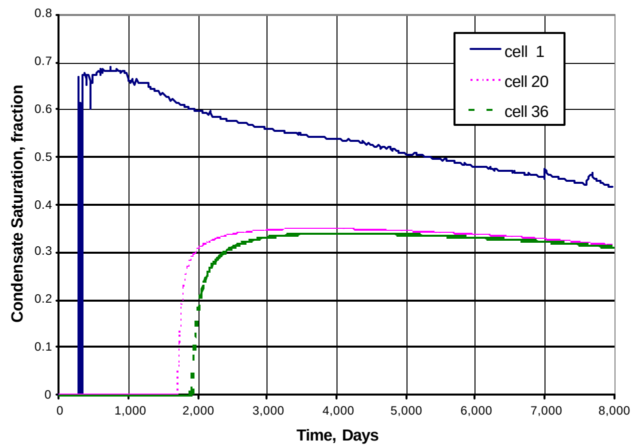

Fig. 6 - Reservoir condensate saturation versus time

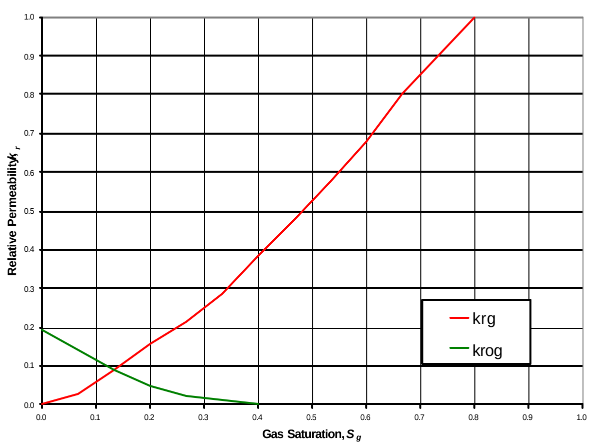

Fig. 4 - Relative permeability curves used in simulation model

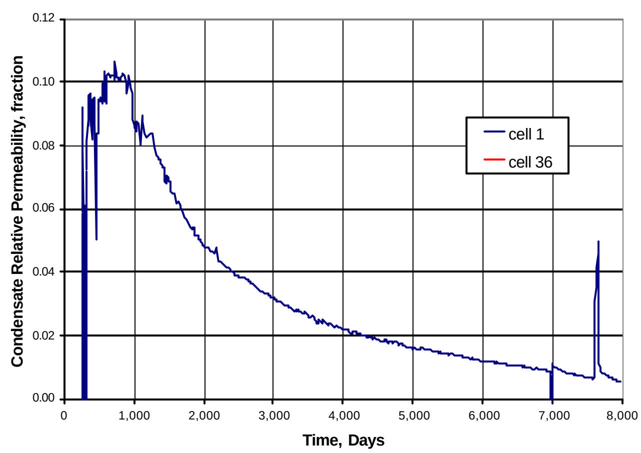

Fig. 7 - Reservoir condensate relative permeability

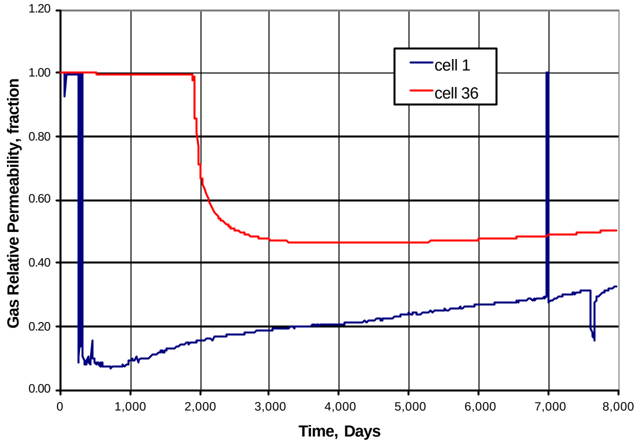

Fig. 8 - Reservoir gas relative permeability

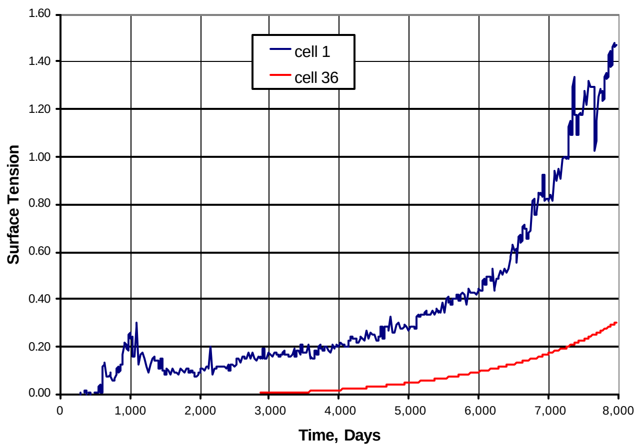

Fig. 9 - Reservoir fluid surface tension

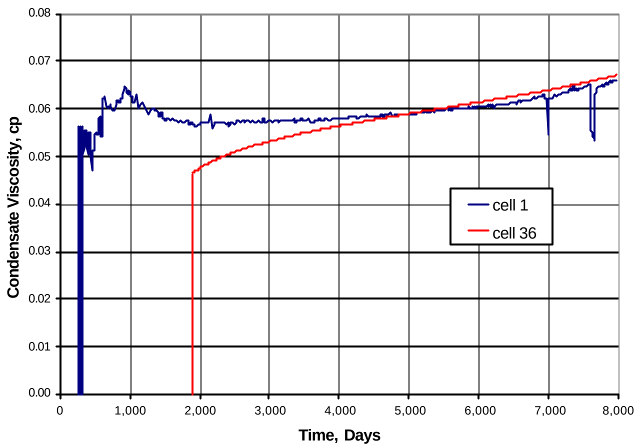

Fig. 10 - Reservoir condensate viscosity

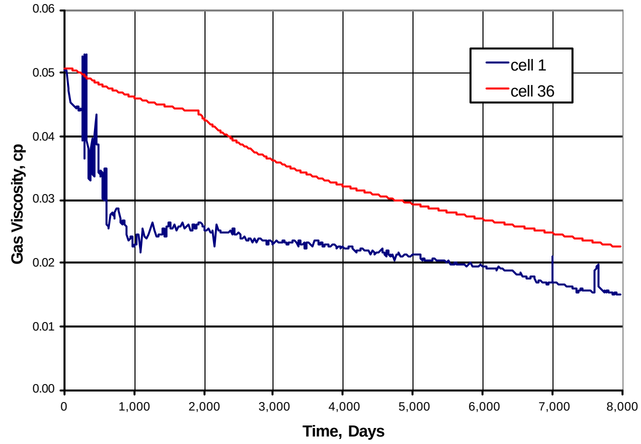

Fig. 11 - Reservoir gas viscosity

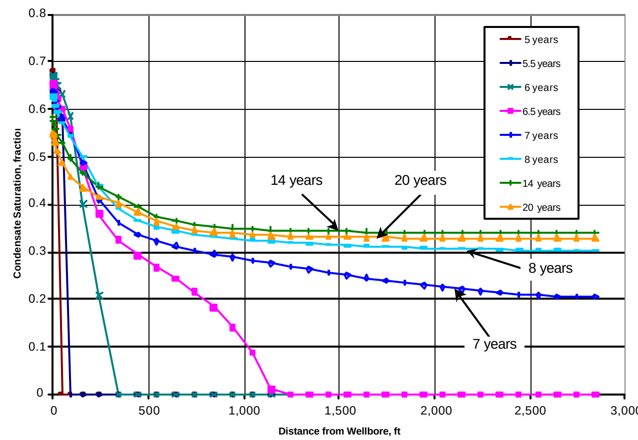

Fig. 12 - Condensate saturation profile change with time