025 EXPERIMENTAL DETERMINATION OF THE MOBILITY OF HYDROCARBON LIQUIDS IN GAS CONDENSATE RESERVOIRS — THREE ACTUAL CASES

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Abstract

The experimental results of three long core, low rate, reservoir condition gas condensate depletion tests are presented in this paper. The three cases exhibited very different PVT and rock properties. Early production of the condensed phase was observed, with CCS in the range of 0 to 11 %. Condensed phase recoveries varied from a few percent to 25% during these experiments.

The three tests were simulated with a compositional reservoir simulation model. Relative permeability needed to be varied with interfacial tension in order to represent the early mobility of the deposited condensed phase. The interfacial tension threshold below which relative permeability begin to change was in the range of 0.5 to 1 dyne/cm.

The calculation of the inverse of the Bond number, involving rock and fluid properties, was a valuable preliminary tool to evaluate the possible mobility of the condensed phase, when maximum liquid deposit is lower than the black oil residual oil saturation.

Introduction

Gas condensate reservoirs are becoming more common place as exploration objectives are encountering greater depths, higher pressures, and higher temperatures. This is particularly true for the North Sea fields. Such reservoirs present specific problems, as their development depends on both gas and condensate production profiles.

A basic understanding of phase and flow behavior interrelationships is required to model the mobility of the condensed phase which drops out during depletion. Two different flow regime zones may be identified in the field : the well bore region where large pressure gradients and high flow rates (1) are to be met, the far field region characterized by slow depletion rates and small flow rates.

In the well bore zone, liquid drop-out may impair the well productivity (2-3).

In the far field region, the entrapment or mobility of the deposited condensate govern the reserves of the field under depletion.

This paper addresses a better understanding of the behavior of gas condensate fluids in the far field region.

Specific long core low rate reservoir conditions depletion experiments (4-5) have been developed in order to measure CCS and relative permeability of condensed phase and to be able to represent the mobility of the deposited condensed phase. This paper describes the results obtained on three different North Sea fields. A summary of the experimental results are given on these three cases. The history match of the experiments with the Eclipse 300 (version 96a) simulator, is detailed .

Experimental procedure

Method

The aim of the experiment is to perform a depletion under conditions as close as possible to those encountered in the reservoir. Scaling up laboratory results to provide field estimations may be performed.

A composite reservoir core is assembled by selecting individual core pieces and stacking them vertically. Connate water saturation (from log interpretation and capillary pressure measurements) is established with a synthetic brine, by methane displacement and vaporization. Reservoir fluid saturation at field pressure and temperature is achieved through successive miscible displacements.

The pressure is then slowly decreased in the core by producing fluids from the bottom. The produced fluids are stored at bottom hole conditions so that the volumetric proportion of each phase may be determined (Figure 1) and condensed phase production is directly measured. This is a major improvement, when compared to classical reservoir conditions experiments where a back pressure valve is used. Reservoir conditions liquid and gas flow rates are readily available from the experiment, instead of being deduced from flash measurements.

Each produced phase has also its formation volume factor and gas oil ratio measured and is analyzed with gas chromatography for lighter components (up to decane), and gel permeation chromatography for the C11+ fraction.

Reservoir fluid properties

Three North Sea gas condensate reservoir fluids were prepared. Two of them were recombined from separator oil and synthetic gas. The third one was a bottom hole sample taken under single phase production. Reservoir fluid compositions and main PVT properties are detailed in Tables 1 and 2. The dew point pressures were 330 bars at 186°C for Fluid A, 570 bars at 126°C for Fluid B and 425 bars at 125°C for Fluid C.

Constant composition expansions were performed for each fluid at reservoir temperature. As plotted in Figure 2, the three fluids demonstrate very different behavior. Maximum liquid deposit were similar for fluids A and B (20.1% and 21.3% respectively), but a much smoother curve was obtained on fluid B (maximum 410 bars below P_{dew}). Fluid C was a near critical fluid with a maximum liquid drop out equal to 42.4%, 30% being deposited within the first 20 bars below the dew point.

From our in house experience, the first « guess » of IFT values, as calculated from correlations, might be within a few percent of the experimental values or one order of magnitude higher or lower.

The falling drop method was used to measure reservoir condition gas oil interfacial tensions under equilibrium. A reliable evaluation of the interfacial tension is a key issue in these experiments as the interpretation strongly depends on the IFT values.

Very different IFT curves versus pressure were obtained, well correlated with the liquid drop out curves (Figure 3). Dew point pressure IFT's were respectively equal to 0.045, 0.22 and 0.0012 dyne/cm (obtained by extrapolation of experimental results).

Composite core properties

For each depletion test, seven to eleven vertically full-size core plugs, 7.3cm (or 6.0 cm for case C) in diameter, and 6cm to 30cm long, were selected to build the composite core. They were cleaned, dried, X-ray scanned and their average porosity and permeability were measured (Table 3). Each core plug was metal alloy sealed before stacking under triaxial stress in order to ensure good capillary continuity in the composite core. The highest permeability core plugs were systematically located at the bottom of the stacking.

The average properties of the three composite cores are detailed in Table 4. Total length was respectively 166.5cm, 130.4 cm and 155.33 cm, for reservoirs A, B and C. Average dry permeability, and permeability at initial water saturation were very similar for reservoirs A and B, whereas composite core C underwent a five fold permeability reduction when saturated with water. At start of depletion, permeability was 17mD for case A, 53.5mD for case B and 3.5 mD for case C.

Depletion results

Very low flow rates were used for the three tests. Average depletion rates were respectively, 0.54, 1.51 and 0.93 bar/day for Cases A, B and C. The liquid fractional flows of the three depletion tests are plotted on Figure 4. As bottom hole sampling was a batch procedure, bottom hole condition liquid fractional flow was determined as a series of averages over discrete time intervals. Critical condensate saturation (CCS) was deduced from the fractional flow curves and the liquid drop out curves to lie in the saturation intervals : [0-4%] for fluid A, [0-2%] for Case B and [4-11%] for fluid C.

Two important comments have to be made. First, in all three cores the CCS is very low. Second, the CCS depends on both rock and fluid properties, as the CCS was slightly higher for Case C : near critical fluid (IFT = 10-3 at dew point), but low permeability core, 4.5 mD, than the CCS for Case B, IFT = 0.2 dyne/cm at dew point, average permeability equal to 53.5 mD.

If liquid deposit is high enough, condensed phase flow rate is a « two flow regimes » curve in each case. The first regime is interpreted as a « miscible » regime, when gravity forces override capillary forces (high Bond number). The second regime, when existing, corresponds to a black-oil maximum, when liquid saturation is higher than the black-oil residual saturation measured with high IFT fluids on neighboring cores.

Low CCS did not necessarily imply that large quantities of condensed phase were produced in our experimental conditions. Cumulative productions (Figure 5), were 15 cm³ for case A, 5.8 cm³ for case B and 107 cm³ for case C, corresponding to deposited condensed phase recoveries of 9.2%, 2.8% and 25% respectively.

As discussed in the simulation results paragraph, these recoveries would depend on the depletion flow rate.

They could suggest that fluid properties are more important than rock properties for total recovery of condensates. In fact they depend on the ratio of black oil residual oil saturation, versus maximum liquid saturation due to retrograde condensation.

Simulation procedure

The three experiments have been history matched with the full field compositional simulator Eclipse 300.

The main steps of the procedure were as follows :

- determination of EOS parameters for the compositional description of the PVT behavior of the fluid
- conventional gas-oil relative permeability measurement on neighboring cores
- mercury injection imbibition capillary pressure curve measurement
- adjustment of the function which defines the variation of relative permeability with interfacial tension on the bottom hole conditions production of condensed phase.

PVT behavior

The Peng - Robinson equation of state was used to represent the thermodynamic properties of the three fluids. Pseudo components were optimized (number and properties), in order to achieve the best fit of experimental data with a reasonable number of pseudos. It was found that the heaviest fraction systematically had to be split in two. 6 pseudos were used for fluid A, 5 for Fluid B and 6 for Fluid C. The parachors for the pseudo components were adjusted to match actual bottom hole condition interfacial tension measurements.

Relative permeability

Gas oil relative permeability were measured on neighboring cores, with high interfacial tension fluids, by injection of gas in an oil saturated core. Oil relative permeability curve was extrapolated from the experimental cut-off of 10^{-4} down to 0.

In the low interfacial zone, relative permeability was allowed to vary with interfacial tensions according to the Coats (6) model which is implemented in Eclipse 300.

In this model interpolation between miscible and immiscible curves is achieved with a control

function F.

$$K_{r_{og}} = F K_{r_{og}}^{\text{immiscible}} + (1-F) K_{r_{og}}^{\text{miscible}} \quad (1)$$

In the Eclipse model, miscible and immiscible curves are scaled so that they both have the same critical saturation, defined by $F_{scr}^{\text{immiscible}}$. The miscible relative permeability of each phase is equal to its saturation (straight line relative permeabilities).

F may be a tabulated function of pressure, or of interfacial tension, or may be given by :

$$F = (\sigma/\sigma_0)^N \quad (2)$$

σ_0 is the threshold interfacial tension beyond which immiscible relative permeabilities are used. Exponent N (defaulted to 0.25), and threshold value σ_0 are supplied to the simulator.

Capillary pressure

In a process such as gravity segregation of condensed phase, capillary trapping may be of major importance at the interface between cores and at the bottom, and capillary pressures need absolutely to be taken into account.

The depletion process involves hysteretic phenomena. Nevertheless condensed phase mobility is generally low, and the simulations have been achieved, using imbibition capillary pressures.

As interfacial tensions vary by an order of magnitude of 2 to 3, variation of capillary pressure with interfacial tension must be modeled. Capillary pressures must also go to zero when the interfacial tension vanishes. Linear dependence is implemented in the simulator :

$$P_{cog} @ \sigma = (\sigma/\sigma_0) P_{cog} @ \sigma_0 \quad (3)$$

The mercury imbibition capillary pressure curve was scaled to the maximum interfacial tension met in each depletion test. As rock properties are significantly varying within the composite core, conventional $(\phi/K)^{0.5} P_c$ scaling was introduced for each plug.

Boundary conditions

Using a full field model to simulate an experiment makes it difficult to correctly represent the production outlet of the core.

Two extra cells have been added to the long core gridding, in order to correctly represent the outlet boundary conditions. The long core is represented as follows :

cells 1 to n core relative permeabilities and core capillary pressures (1 to 2cm vertical grid size was used).

cell n+1 core relative permeability and $P_c=0$

cell n+2 specific relative permeability and no P_c (production well is in cell n+2)

The specific relative permeability of cell n+2 are calculated so that the mobility of each fluid in this cell be equal to its saturation (pseudo cross relative permeability).

The validity of this representation was checked on conventional gas oil displacement by comparison with our in-house laboratory simulator. Both production history and saturation profiles were satisfactorily represented.

F function adjustment

A history match was obtained in each case by adjusting the function F controlling the variation of relative permeability with IFT. This is the only parameter in the simulation model that is not independently measured. Initial attempts to obtain matches using the formula (2) were unsuccessful. F was entered as a function of IFT in tabular form.

Simulation results and discussion

History match

When considering the experimental bottom hole production of condensed phase, two parameters are important : the onset of production which determines the CCS, and the subsequent daily flow rates which determine the total production of bottom hole liquid.

For cases A and C a very good agreement was obtained on both the onset of production and the bottom hole daily flow rate of the condensed phase produced (Figures 6 and 7). For case B (Figure 8) the adjustment was more difficult to obtain. Down to 200 bars below the dew-point, the agreement between calculated and experimental results was fair. Beyond 200 bars below the dew point, the

depletion rate was accelerated and the calculated liquid production was overestimated. It should be noted that although the reservoir liquid flow rate region is highest in this region, the liquid fractional flow is low, as shown on Figure 9. Condensed phase accumulated at the bottom of the core when IFT's were low is partially produced, but condensed phase in the upper part of the core is trapped.

The discrepancies between calculated and experimental curves are probably due to the very flat liquid deposit curve and the particular shape of the interfacial tension variation versus pressure.

Calculated ultimate cumulative production of condensed phase is 14% higher than the experimental one. This is within the experimental precision of a 400 bars depletion test.

In all three cases A, B or C, it was absolutely necessary to vary relative permeability with interfacial tensions to history match the production of condensed phase.

But in the case of near critical fluid C, a correct onset of production was simulated even with black-oil relative permeabilities. Flow rate and cumulative volume of condensed phase were much too low in that black oil simulation.

Figure 10 shows the F functions which gave the best match in each case, initial F value is never equal to 0 (fully miscible curve), even for the near critical fluid. For each case, initial value is equal to 0.75, the shape of the F function versus interfacial tension is very steep at the lower IFT's, and undergoes a sudden break for a first IFT transition respectively equal to 0.06, 0.4 and 0.004 dyne/cm. Beyond this value a very gradual increase of the F function was observed up to the ultimate threshold value where black-oil relative permeabilities became valid for IFT's equal to 1, 0.58 and 1 dyne/cm. The slope of the miscible function between the first transition, and the ultimate threshold is lower for low IFT fluids.

Due to this particular shape of the F function the analytical formula (2) is clearly inadequate.

Value of σ_0

We have tried to correlate the ultimate threshold with rock and fluid properties. In the poster of K.Hartman (7), a correlation was proposed :

$$\sigma_0 = -0.5 + \log[(K/\phi)^{0.5}] \quad (4)$$

According to this formulation the threshold IFT for cases A, B, C should be equal to 0.48, 0.64 and 0.13 dyne/cm. Except for Case B, this is significantly different from the value of the simulations of this paper, but the threshold value is dependent on the model of miscibility of the simulator.

According to Schechter et al (8), the inverse of the Bond number has been evaluated with the formula :

$$N_B^{-1} = C \sigma (K/\phi)^{0.5} / \Delta \rho g H \quad (5)$$

where $C=0.4$ for the capillary tube model, and H is the height of the model. When N_B^{-1} is large, capillary forces dominate and condensate remains trapped. When N_B^{-1} approaches zero, gravity forces dominate the flow. As the initial mobility or trapping of the condensed phase is basically due to the competition between capillary and gravity forces, N_B^{-1} could be a good correlation parameter. It is also a combination of rock and fluid properties, and the strong interaction between the two is demonstrated by our results.

At the threshold IFT's N_B^{-1} for Cases A and B were very similar $0.2 \cdot 10^{-3}$ and $0.14 \cdot 10^{-3}$, whereas a higher value was obtained for Case C $0.6 \cdot 10^{-3}$. In fact in Case C as large quantities of condensate are deposited (42%), liquid mobility does not only depend on capillary/gravity equilibrium, and it is not surprising that this case did not compare with Case A or B.

As a preliminary screen tool, in the case of fluids where maximum liquid deposit is below the black-oil residual oil saturation, the calculation of the inverse of the Bond number should give information on the possible mobility of the condensed phase, the threshold number being in the range of $0.2 \cdot 10^{-3}$, when calculated with formula (5). Such an interpretation was already suggested in the paper of Haniff et al (9). The comparison of the evolution of IFT and gas oil gravity difference with pressure (5-10) was a qualitative equivalent to the Bond number evaluation.

Further work should be implemented on other actual depletion cases in order to obtain a more reliable quantitative interpretation.

It should be pointed out that this result is related to the miscibility model implemented in Eclipse E300, and that the shape of the F function has to be adjusted on experimental results.

Conclusions

Long composite core, low rate, vertical depletion test under reservoir conditions (temperature, pressure, core and fluid samples) is an appropriate tool to evaluate the far field mobility of condensed phase in gas condensate reservoirs.

Very low critical condensate saturations are observed (0 to 11%), for each of the three actual cases presented, for dew point interfacial tensions varying from 0.001 to 0.2 dyne/cm, and average permeability varying from 3.5 mD to 53.5 mD

Experimental recovery of condensed phase varies from a few percent to 25%.

Two different flow regimes are identified on the condensed phase flow rate curve versus pressure. The first one corresponds to early mobility of condensed phase due to low IFT values, and weak capillary trapping. The second maximum is observed if average liquid saturation is sufficiently high to get « black-oil » mobility despite more important capillary trapping.

Relative permeability must be varied with interfacial tensions to simulate the production of bottom hole condensed phase. In each case, a history match is obtained by adjusting a miscibility function.

The inverse of the Bond number could be a valuable preliminary tool to evaluate the possible mobility of the condensed phase, when liquid deposit is below the black oil residual oil saturation.

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TABLE 1 - Fluid Compositions

Component	Fluid A	Fluid B	Fluid C
N2	0.26	0.56	0.26
CO2	3.05	2.11	2.43
C1	69.47	76.29	65.51
C2	8.31	7.71	9.45
C3	4.10	3.53	6.02
C4	2.74	1.83	2.99
C5	1.66	1.17	1.44
C6	2.11	1.27	1.63
C7	1.09	1.11	1.42
C8	1.05	0.63	1.26
C9	0.84	0.32	0.98
C10	0.68	0.29	0.85
C11	0.78	0.45	0.70
C12-13	1.16	0.70	1.15
C14-15	0.79	0.54	0.76
C16-17	0.55	0.38	0.56
C18-19	0.38	0.28	0.44
C20-24	0.55	0.41	0.89
C25-29	0.24	0.22	0.53
C30-39	0.15	0.15	0.51
C40-49	0.03	0.04	0.16
C50-74	0.01	0.01	0.07
MW (g/mole)	36.55	29.78	42.6

TABLE 2 - FLUID PROPERTIES

	Fluid A	Fluid B	Fluid C
Pd @ Tres (bar)	330	570	425
Tres (°C)	186	126	125
GOR (m3/m3)	1118	1946	800
Density @Tres, Pref (kg/	348	384	466
Pref (bar)	350	609	450

TABLE 4 - Composite core properties

	Case A	Case B	Case C
Total length (m)	166.5	130.4	155.33
Section (cm2)	28.27	41.85	41.85
Total pore volume* (cm3)	885	1497	1272
Average porosity* (%)	18.8	27.4	19.6
Average permeability	25.6	57.3	17.8
Initial water saturation	0.052	0.159	0.143
Kg* @ Swi (mD)	17	53.5	3.5

* measured under stress

TABLE 3 - Individual core properties

N°	Case A			Case B			Case C		
	L(cm)	Φ (%)	k(mD)	L(cm)	Φ (%)	k(mD)	L(cm)	Φ (%)	k(mD)
1	10.60	18.9	13.6	15.53	26.47	22.30	27.67	20.09	21.46
2	12.19	18.2	16.1	16.92	27.87	42.30	6.64	18.36	7.34
3	21.94	19.2	20.6	12.33	27.24	46.00	27.13	19.92	8.93
4	8.64	22.2	23.3	18.93	28.77	68.30	12.51	18.70	9.58
5	21.23	21.0	20.9	29.25	28.08	98.70	8.45	18.72	9.98
6	20.00	18.0	27.0	17.82	29.45	103.90	7.70	19.40	13.94
7	19.97	18.9	55.8	19.63	29.58	117.70	12.24	18.76	52.24
8	11.83	21.3	58.9				14.00	20.10	56.40
9	21.21	23.1	36.6				11.20	18.42	91.28
10	5.91	24.3	134.2				27.79	22.61	140.51
11	12.99	20.1	273.7

Figure 1 : Experimental setup

Figure 2 - Constant composition liquid drop out curves

Figure 3 - Interfacial Tensions

Figure 4 - Bottom hole conditions condensed phase production

Figure 5 - Bottom hole conditions condensed phase production

Figure 6 - Fluid A Condensed phase production

Figure 7 - Fluid C Condensed phase production

Figure 8 - Fluid B Condensed phase production

Figure 9 - Fluid B Condensed phase production