Depletion of Gas - Condensate Low Permeability Reservoirs (Höflein Field, Vienna Basin)

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1. Abstract:

This paper combines theoretical, experimental and field data of a low permeable gas condensate reservoir. Static laboratory experiments - constant composition expansion (CCE) and constant volume depletion (CVD) - are compared with dynamic depletion experiments from artificial sandpacks. Additionally, calculations from a PVT package and field data from the production history are also included.

The mathematical model of phase behavior in a porous medium taking into account capillary forces and wettability was applied for the CVD prediction under the conditions of the Höflein field. The model is based on the asymptotic solution of the equations for the equality of the chemical potentials. This theory was included to investigate the influence of capillary forces in the case of Höflein.

2. Description of the field Höflein

The field Höflein is a gas condensate field located NW of Vienna (Fig.1) and was discovered in 1982. It first tested in 1984 and produced out of 9 wells since 1987. The reservoir was found to be at a pressure that corresponded to the dew point pressure of 285 bar and at a temperature of 78°C. The net pay lies between 28 - 55 m.

The geological structure and a cross section are shown in Fig.2 and Fig.3. The reservoir is located at an average depth of 2650 m below

sea level. It contains different reservoir rock types which occur at depths between 2550 - 2850 m below sea level in two connected but dislocated units. The reservoir rocks are of autochthonic mesozoic type and are located on a structural high on the basement. Two main pay zones can be distinguished: the upper unit (Höflein formation) consisting mainly of partially fractured sandy dolomite with porous chert nodules and the lower unit consisting of two main sandstone beds [1]. The properties of the different layers can be found in Tab.1. A wide range of porosities and permeabilities is observed. In the dolomitic Höflein formation, the average porosity around 10 % is mostly due to the porous chert content. Connection between the porous nodules is provided by a network of fractures through the sandy dolomite phase with associated permeabilities up to 1 (μm)².

In both sandstone intervals mainly subarkoses), porosity is intergranular and permeability trends are determined by quartz overgrowth and/or clay minerals (kaolinite, illite-mixed-layer minerals). Dissolved feldspar indicates some secondary porosity. The upper sandstone with the best reservoir properties in the uppermost parallel laminated beds also exhibits some partial dolomitic cementation. In the lower sandstone, coal seams and numerous pyrite nodules have been identified.

3. Experimental studies: CCE, CVD and dynamic depletion experiments

During the production test samples were taken for laboratory experiments. The composition of well Ho1 can be seen in Tab.2. A detailed picture of the hydrocarbon distribution is shown in Fig.4. The characteristics of this gas condensate are a relatively high content of CO₂ (15%) and a C5+ fraction of 3.7%. The standard PVT experiments (constant composition experiment - CCE and constant volume depletion CVD) were carried out in a Ruska window cell. The characteristic curves - the liquid drop out and the well stream composition - are presented in Fig.5 and Fig.6. All liquid drop out curves have a so called 'tail' by which the slow increase in liquid below the dew point is described before the massive drop out starts.

At a later stage investigations have been carried out in order to find out whether this field consists of different compartments. The same experiments were performed for the wells 3,6,9 and 12 as they were for well 1. It can be seen from Fig.7 that two characteristic groups exist: one that exhibits a maximum in the liquid drop-out and one that lacks it. This fact indicates a compartmentization which is not very pronounced.

Since the gas condensate contains quite a large percentage of CO₂ and also shows a significant water saturation, a CVD was performed with a water phase present in the cell in order to investigate the influence of the formation water on the quality of the well stream composition. The percentage of CO₂ decreased by 2%, which is in accordance with the solubility data for CO₂ in water. An increased percentage of CO₂ production can only be expected at rather low pressures.

A prime interest of our research was how much the porous medium influences the production of the gas condensate, or in other words how well does a CVD predict the production of a gas condensate. For this purpose depletion experiments (DE) were performed from artificial sand packs. The experimental setup is shown in Fig.8. At the time of design of the experiments it was only possible to manufacture sand packs with the following parameters:

length	10 m
inner diameter	1 cm
porosity	30 %
permeability	1 Darcy

Swi

0 %

The parameters achieved in the sandpacks reflect only the properties of the microfractures in the field Höflein. As a first step no initial water saturation was established in order to avoid problems with the separation of the water in the well stream.

In both experiments - CVD and DE - the well stream was cooled down to 20°C where gas and liquid separated. The gas was analyzed immediately in a gas chromatograph, the liquid in the liquid chromatograph.

4. Experimental results:

The CVD allows in contrast to the DE to measure the liquid drop out directly. What can be compared is the well stream in quality and quantity. From the produced moles versus pressure one can see that the CVD over estimates the production (Fig.9). The reason for this is the fact that liquid in the porous medium is evidently held back by capillary forces. Another difference exists in the fact that the phase transitions can be enhanced by stirring in the PVT cell. On the other hand, if the richness of the gas condensate were such that the liquid drop out exceeds the critical saturation and becomes mobile then the CVD would underestimate the produced amount of higher hydrocarbons. The composition of the well stream is presented in Fig.6.

5. Comparison with calculations from a PVT package

The experimental results were checked with a commercial PVT-package in which the temperature dependence of the interaction term was modified to get a better fit [7]. The dew point could be matched very well at the cost of accuracy in the pressures down to the maximum drop out in the CCE, while the calculated CVD curve is off at the maximum liquid drop out. In this manner it was possible to model some of the tailing effect.

6. Influence of capillary pressure

In this section we want to investigate the physical basis for condensation of gases in a porous medium. For gas-condensate systems the calculation of the phase distribution in 'dry' cores is straight forward: the liquid phase occupies thin pores, the gas is located in the thick ones. The interphase mass transfer provides equality of curvature for all gas-liquid menisci and excludes effects of inaccessible

pores. This means that the gas phase is connected throughout the porous medium.

The presence of water makes the physical picture more complex. The distribution of the liquid phases depends on the wettability of water and condensate. In the water-wet case the water fills the smallest pores, next comes the condensate and the gas is always found in the biggest pores.

The general theory is elaborated for the Appendix A. In order to give a first understanding of the effect the water free case is treated there. For practical cases an asymptotic theory with the small parameter being the ratio of the capillary forces and the pressure in the gas phase yields a system of linear equations (Appendix B).

7. Influence of capillary pressure, numerical results

Model calculations were carried out under the assumption that the water is the most wetting fluid in the pore space. Generally the influence of the porous medium on the liquid saturation vanishes with increasing size of the pores. The capillary forces become negligible if the permeability exceeds 10 mD. In the Höflein field the reference pore radius is 0.3 μm which corresponds to 8.5 mD, so the effect of the capillary medium should be small. Although the number of small pores is considerable it can be neglected because of the assumption that the rock is water wet and the small pores are already filled with water (Tab.1).

For field production purposes the most interesting quantity is the liquid saturation. It was found to be only marginally different at low pressures (Fig.11) compared to the case without capillary forces.

8. Summary

- The influence of the capillary pressure on the liquid drop out due to the presence of a porous medium can be neglected if the reservoir rock is water wet.
- Comparing the static (CVD) and dynamic (DE) experiments is only justified if the initial water saturation is established and the permeability is in the same range as the one of the reservoir. In the case $S_{wi}=0$ the CVD over estimates the production of condensate in comparison with the DE.

- The solubility of the high CO_2 content leads to a higher production of this component in a later stage of the life of the reservoir, as it is released from the water phase.
- The CDV results can be matched fairly well with a modified equation of state.

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10. Symbols:

C.....curvature of the interface
 g_iGibbs potential
 JLeverett function
 kpermeability
 ppressure of the phase
 p_ccapillary pressure
 Ssaturation
 x_imass fraction of the i-th component
 θcontact angle
 ϕporosity
 ϵparameter
 ρdensity
 σsurface tension

subscripts:

D.....dimensionless
 mmass

superscripts:

0.....no porous medium
 ggas phase
 lliquid phase

11. Literature:

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Appendix A: General theory of phase equilibrium in a porous medium

The investigation of thermodynamic equilibrium conditions for 2P multicomponent mixtures in porous media is of critical importance for the description of physical processes in oil-gas-condensate fields in order to estimate reserves, to screen recovery methods and to predict the recovery factor. The description of phase equilibrium in porous media requires to take into account capillarity and wettability. Capillary effects lead to the formation of a dispersed liquid phase (condensate) in thin capillaries. This phase can contain a considerable amount of heavy hydrocarbons which is necessary to take into account in reserves estimation. The presence of capillary forces also causes depth spreading of the gas oil contact in a thick reservoir resulting in the formation of a gas-oil transition zone. In this zone because of a heterogeneity of the reservoir any distribution of liquid saturation can be observed.

During the depletion of a gas condensate field the increase of the dew point pressure due to capillary effects leads to earlier separation of the condensed liquid which negatively effects the production of heavy hydrocarbon components. Capillary and wettability forces also greatly effect the displacement of the gas condensate mixture by lean or enriched gas. These forces cause phase distributions between thick and thin capillaries. This finally leads to a change in relative permeabilities. Thus the action of capillary forces governs the recovery of the gas condensate.

From general considerations one can conclude that the condensation starts already above the experimentally determined dew point in a PVT cell. Experimental observations confirm this conclusion [2], [3].

We now turn to the mathematical basis of the phase equilibrium of a 2P multicomponent fluid in a porous medium taking into account wettability and capillary forces. The general conditions for the equilibrium of connected liquid and gas regions having mutual boundaries are defined by the minimum of one of the thermodynamic potentials. For example, if we use temperature and pressure as primary intensive variables, the Gibbs potential is one of the options. Its derivative with respect to the concentrations of the components - which is an intensive quantity - has to be equal in the gas and in the liquid phase [4], [5], [6]

$$g_i^l(p^l, x_j^l) = g_i^g(p^g, x_j^g), \quad i, j = 1, n, \dots \quad (A1)$$

$$\sum_{j=1}^n x_j^g = \sum_{j=1}^n x_j^l = 1, \dots \quad (A2)$$

$$p^g - p^l = p_c = \sigma(g_i) C, \dots \quad (A3)$$

where g_i are the Gibbs potentials and x_j the mass fraction of the i -th component, p is the pressure of the phase, p_c the capillary pressure, σ is the surface tension, C is the curvature of the interface. The superscripts g and l refer to the gas and to the liquid phase, respectively. When writing equation (A3) we tacitly assumed that the liquid phase is the wetting phase.

If pressure and composition of, for instance, the gas phase are known then (A1) may be considered as a system of n independent equations from which n intensive quantities of the liquid phase $p^l, x_1^l, \dots, x_{n-1}^l$ may be uniquely determined. The composition of the liquid phase will be the same in every pore. From the fact that the pressure in the phases are equal follows that the curvature of the gas-liquid interface is the same throughout the porous medium.

The condensation in a capillary initially filled with gas begins with the formation of a thin liquid film on its walls. This film exists due to Van der Waals forces between the solid surface and the gas molecules. As the thermodynamic conditions approach the dew point, the film thickens. At some moment the film becomes unstable and the capillary becomes abruptly filled with liquid. This process can be labelled 'condensation from the wall'.

In the opposite case of evaporation there is no thin layer on the wall but rather a filled capillary. The interface is the place where the

phase transition takes place. Therefore, one can speak of an 'evaporation from the meniscus'.

Since evaporation and condensation follow different regimes, a hysteresis is expected so that in the case of a strong influence of the porous medium (small pore radii) the actual liquid drop out curve will differ from the one determined in the CVD.

The influence of the porous medium on the thermodynamic system (phase transition enters into the system of equation (A1)-(A3) via the capillary pressure

$$p_c = \sigma \cos \vartheta \sqrt{\frac{\phi}{k}} J(S) \dots\dots\dots (A4)$$

The saturation has to be expressed by the concentrations x_j^g and x_j^l

$$x_j = x_j^l S_m + x_j^g (1 - S_m) \dots\dots\dots (A5)$$

where x_j is the known mass fraction of the j-th component of the 2P mixture, S the volume saturation of the liquid phase and S_m the mass saturation of the liquid phase. The two saturations are connected through the following formula

$$S_m = \frac{\rho^l S}{\rho^l S + \rho^g (1 - S)} \dots\dots\dots (A6)$$

here ρ^g and ρ^l are the densities of the gas and liquid phase.

The graphical interpretation of this problem is that in the space p, x_i the dewpoint line is shifted towards lower pressures while the bubble point line is shifted towards higher pressures. The compositions of two coexisting phases are located on the mutual tangent line to a curve $g = g(p = \text{const}, x_i)$.

Appendix B: Asymptotic theory for phase equilibrium

We assume that the pressure p^g and the component concentrations of phase equilibrium in the absence of capillary forces may be written as

$$g_i^l(p^0, x_j^l) = g_i^g(p^0, x_j^g), \quad i, j = 1, n \dots\dots\dots (B1)$$

For given initial compositions of the gas and liquid phase an initial pressure p^0 we introduce the following designations:

$$p_D^g = \frac{p^g}{p^0}, \quad p_D^l = \frac{p^l}{p^0}, \quad p_D = \frac{p^0 - p^g}{\varepsilon p^0} \dots\dots (B2)$$

$$\varepsilon = \frac{\sigma \cos \vartheta}{p^0} \sqrt{\frac{\phi}{k}}$$

Under ordinary conditions (pressure 100 bar, pore radius 1 μm , IFT 1 mN/m) the parameter ε can be considered small, in the just mentioned particular case 10^{-4} . Hence the solution of (B2) can be found as a small disturbance around the point (p^0, x^0) . The pressures and compositions are expanded into a series and only the linear term in ε will be kept

$$x_j^l = x_j^0 + \varepsilon x_j^1 \dots\dots\dots (B3)$$

$$p_D^g = 1 - \varepsilon p_D \dots\dots\dots (B4)$$

$$p_D^l = 1 - \varepsilon (p_D + J(S)) \dots\dots\dots (B5)$$

Estimates show that higher orders are negligible. Inserting the expressions (B3)-(B5) into (B1) and ordering the terms according to powers of ε one gets for the zeroth approximation the phase equilibrium in the absence of capillary forces which can be determined by the usual methods [4], [5], [6]. the first approximation is a system of n linear equations for n values of x_j^1, J in the form

$$\sum_{j=1}^{n-1} \frac{1}{p^0} \frac{\partial g_i^l}{\partial x_j^l} - \frac{\partial g_i^l}{\partial p^l} J = \left(\frac{\partial g_i^l}{\partial p^l} - \frac{\partial g_i^g}{\partial p^g} \right) p_D \dots\dots (B6)$$

After solving this system the saturation can be found via the Leverett fuction $J(S)$. In the case of the Höflein field the J-function and the average pore radius distribution are shown in Fig.10.

Fig.1: location of the field Höflein

Fig.2 structural map of the field Höflein

Fig.3 cross-section of the field Höflein (NW-SE), simulation model

Fig.4 hydrocarbon distribution

Fig.5 liquid drop out, CVD, CCE

Fig.6 Composition of well streams CVD, DE
(symbols:full = CVD, empty = DE)

Fig.7 liquid drop out (CVD) of various well samples

Fig.8 experimental setup of the DE

Fig.9 cumulative production, CVD, DE

Fig.10 J-function and pore radius distribution

Tab.1: Reservoir parameters of the field Höflein

depth	2550-2850	m		
net pay	28-55	m		
temperature	78	°C		
initial presssure	285	bar		
	ϕ	k	Sw	
	%	mD	%	
Höflein series	DQS	1,3-24,3	0,1-1119	33
upper sandstone	OQS	0,1-21,2	0,1-3236	55
lower sandstone	UQS	0,4-16,6	0,1-516	56

Fig.11 Influence of the porous medium on the liquid drop out

Tab.2: Composition of field Höflein, different wells

component	well 1 mol%	well 3 mol%	well 6 mol%	well 9 mol%	well 12 mol%
CO2	16,612	17,511	17,267	14,768	15,406
N2	2,313	2,235	2,286	2,212	2,366
C1	63,654	67,148	67,003	66,954	68,377
C2	6,713	5,290	4,906	5,704	5,124
C3	3,328	2,595	2,617	3,610	2,675
i-C4	0,838	0,670	0,785	0,871	0,665
n-C4	1,144	0,924	1,082	1,149	0,932
i-5	0,531	0,448	0,442	0,585	0,416
n-C5	0,453	0,390	0,499	0,465	0,394
C6	1,891	0,034	0,038	0,663	0,582
C7	0,239	0,118	0,152	0,866	0,670
C8	0,664	0,374	0,385	1,259	1,445
C9	0,568	0,322	0,330	0,321	0,340
C10	0,475	0,266	0,263	0,257	0,273
C11	0,297	0,207	0,166	0,139	0,148
C12	0,162	0,101	0,082	0,086	0,091
C13	0,078	0,048	0,037	0,056	0,060
C14	0,029	0,013	0,012	0,028	0,030
C15	0,013	0,005	0,005	0,004	0,004
C16	0,004	0,001	0,001	0,001	0,001
C17+	0,001	0,000	0,000	0,002	0,002
pd [bar]	265	274	278	256	254
rho liq stc. [kg/m³]	761,3	764,6	775,6	761,3	761,3