Laboratory modelling on enchanced gas and condensate recovery

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Abstract

Gas condensate fields produce gradually less condensate because of retrograde condensation when pressure drops beneath the dewpoint pressure. Gas injection counter-balances pressure drop, decreases dewpoint pressure and dilution of gas decreases condensation. Wide range of laboratory tests demonstrates the effect of gas injection on the reservoir fluid phase behaviour and the produced gas properties. These tests simulate the different industrial EGR scenarios like dry gas, carbonated gas or nitrogen injection; pressure maintenance, wellbore treatment (huff and puff) and CO_2 sequestration. The effect of gas replacement, the enhanced propane, butane and pentane+ production and the condensate revaporization can be quantitavely predicted.

Összefoglalás

Növelt hatékonyságú gáz- és csapadék-kihozatalok laboratóriumi modellezése: Gázkondenzátum tárolókban a telep nyomásának harmatpontnyomás alá csökkenésével – a kitermelés szempontjából veszteséget jelentő – csapadékkiválás (retrográd kondenzáció) történik. Laboratóriumi modell-kísérleteink ennek a veszteségnek a csökkentésére irányulnak: a telepek kondenzátum-tartalmának kihozatalát gázbesajtolással növeljük meg, esetenként a tárolóban található értékes gázkomponensek egy részét a besajtológáz értéktelen komponenseire cseréljük. A közleményünkben ismertetett modellkísérletek alapján a gázbesajtolásos EGR módszerek a kondenzátumveszteség jelentős csökkentésére alkalmasak. Besajtológázként szén-dioxidos gázokat alkalmazva a többletkihozatal mellett a szén-dioxid klímavédelem szempontjából kívánatos elhelyezése is megtörténik.

Introduction

Depleted gas condensate reservoirs can be revitalized by gas injection. Depending on objective and availability, different injection gases have been suggested and tested for gas injection Enhanced Gas Recovery (EGR), most frequently dry hydrocarbon gas, carbon dioxide (or carbonated natural gas) and nitrogen are considered.

Reservoir pressure maintenance preventing or reducing condensate dropout benefits from dry gas EGR.

Carbon dioxide EGR is recently becoming predominant in combination with CO_2 sequestration [1-3] in condensate bank revaporization and displacement of original hydrocarbon gas phase.

Nitrogen EGR is considered when neither

hydrocarbon nor CO_2 injection is regarded feasible or economical [4] and it is available as the byproduct of the air liquefaction.
Researchers equivocally emphasize that phase behavior and other laboratory tests must precede any EGR field application.
The purpose of this paper is to show laboratory tests performed on several Hungarian gas condensate systems using a variety of injection gases (Table 1 summarizes the investigated reservoir fluids and applied injection gases).

	pipeline gas	separator gas	carbonated natural gas	nitrogen natural gas
Szeghalom		•	•	•
Ederics			•	
Őri-D	•	•	•	

Table 1. Examined fields and injection gases

Our injection gases are regularly multicomponent mixtures. Their composition is carefully adjusted to reach best possible match with that of the gas reserves dedicated to EGR application. As a consequence, the output of these EGR tests are realistic input data of reservoir engineering model computations in contrast to laboratory tests carried out with pure CO_2 [2].

Experimental

PVT (Pressure-Volume-Temperature) tests are conducted in conventional windowed PVT apparatus. Observed characteristics are dewpoint pressure, condensate dropout profile and compositional variations. Complex phase behavior, including revaporization effects, is presented providing foundation for pilot testing and large scale deployment of EGR.
Several EGR scenarios are elaborated: different abandonment pressures, changing injection/displacement ratios; reservoir pressure buildup and drowdown.

Gas injections

Part of the condensate remains in the reservoir during the exploitation and is lost to the production. (That's why it's called condensate loss.) The maximum amount of condensate can be produced only if the reservoir pressure is maintained above the dewpoint all over the production period. (This case is represented by the hypothetical "no condensation" line in Figures 1 and 6.)
Laboratory CVD (Constant Volume Depletion) test quantitatively reveals the condensate buildup affected by the pressure drop in the gas condensate system. Figure 1 shows that the produced condensate varies between 40 and 60 per cent of the theoretical maximum.

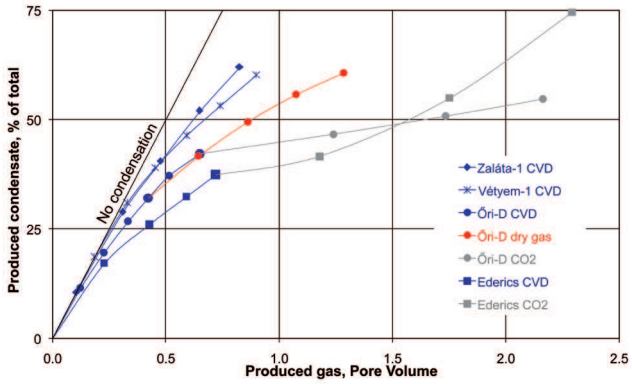

Fig. 1. Comparison of produced condensate in different fields

The purpose of an EGR project can be either the pressure maintenance, early in the production period, or revaporization of the condensate left behind in the reservoir.
Our simulation aims at predicting the response of the system to the planned EGR treatment or gas sequestration.

The gas injection can alter the phase behavior in several ways:
1. the dewpoint pressure decreases by mixing with the dry injection gas,
2. the retrograde condensation diminishes (because of the pressure maintenance effect),
3. the injected gas can revaporize the condensate in the reservoir.

The first and the second responses are demonstrated by declining dew point pressure and diminishing retrograde condensation data in an EGR study for Halom reservoir. Reservoir fluid and the carbonated gas mixing effect can be found in Figure 2. Original GCR (Gas/Condensate Ratio) 2400 std m^3/m^3 was elevated by the gas mixing to 7200 std m^3/m^3.

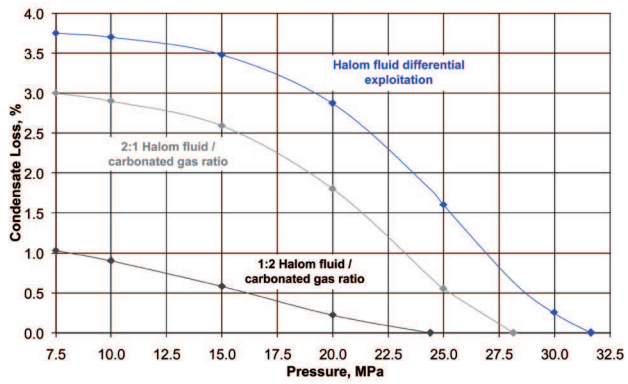

Fig. 2. Szeghalom reservoir fluid mixed with 54% CO_2-content gas

The blue curve shows the condensate loss during the differential depletion of the original reservoir fluid (CVD test). Mixing the reservoir fluid in 2:1 total gas volume ratio with carbonated gas of 54 percent carbon dioxide, the dewpoint decreases from 31.5 MPa to 28 MPa and the condensate loss by approximately 20 per cent. Increasing the volume of the injected gas from 2:1 to 1:2 ratio gives a similar decrease in the dew point, but the drop in the condensate loss is greater, it goes down to 1.0 percent of reservoir volume.
Analogous results are obtained by Shtepani and Thomas [2], who investigated 20, 40, 60 and 80 mole% mixtures of a 4555 m^3/m^3 GCR reservoir fluid and pure CO_2. Other system properties were 23.5 MPa dewpoint pressure at 100 °C, 3.4% maximum dropout at CDV test. This type of research is called P-x (pressure-concentration) experiment. Dewpoint pressure and condensate bank gradually reduced in the order 20-40-60% while 80% mixture had no dewpoint, its cricondenterm fell below reservoir temperature. From the tendency of diminishing condensate volumes it is estimated that a 73% mixing with CO_2 represents a limiting dilution for the system, where criocondenterm just reaches reservoir temperature (100 °C). In our situation this figure is about 78-80% mixing. This points out to the phenomenon that higher temperature (127 °C) imposes stronger vaporization on the originally richer gas condensate system, thus the extent of dilution that eliminates the retrograde condensation eventually becomes quite alike for both systems.

The efficiency of the EGR also depends on the quality of the injected gas. Figure 3 shows the effect of replacing the gas cap of the Halom field with different types of gases.

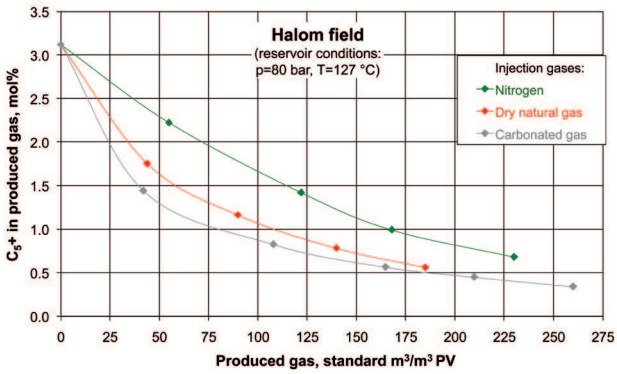

Fig. 3. Gas cap replacement test

In these series the injected gas replaces the gas cap above the condensed liquid at constant pressure. In this case nitrogen proved to be a better injection gas than carbon dioxide giving higher pentane plus concentration in the produced gas. The explanation of these results is the following. Injecting the gas, liquid components start to vaporize and the quality and quantity of the dissolved gas changes in the liquid phase. Nitrogen has a very low solubility, so a relatively high mole fraction of the pentane plus in the liquid phase is in equilibrium with the vapor at the experimental conditions. On the other hand, the condensate dissolves a great amount of carbon dioxide, therefore the mole fraction of the pentane plus decreases. The lower pentane plus concentration in the liquid gives a lower pentane plus concentration in the vapor, that is, the increase of the equilibrium constant is overcompensated by the change in the pentane plus concentration in the liquid phase. Summarizing, the effect of the change in the concentrations is higher than the effect of the change in the equilibrium constants. For producing the condensate, the nitrogen is a better agent than carbon dioxide because less volume of injection gas is sufficient to the same production of richer gas.

Őriszentpéter-D (South) field is an example of gas injection and displacement, and it is a current issue. During the exploitation the pressure decreased and it caused condensate buildup in the reservoir, especially at the wellbore. In Figure 4 two gas injection and displacement simulations are presented, one with a dried separator gas and another one with a carbonated gas.

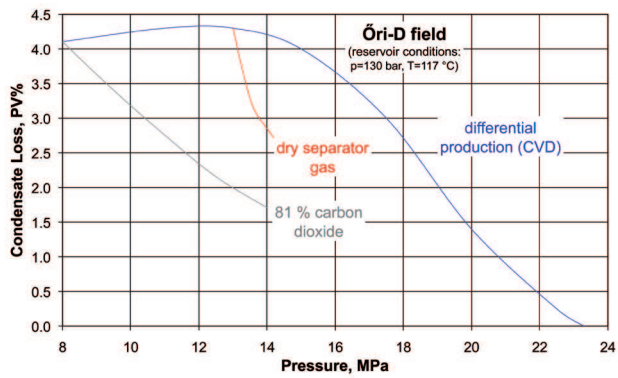

Fig. 4. Gas injection and displacement

The blue curve shows the condensate loss during the constant volume depletion down to 8 MPa anticipated abandonment pressure. The current 13.0 MPa reservoir pressure has been chosen for the start of injection of the dry separator gas. The gas was injected in four steps, each step was approximately one quarter of a pore volume (PV), the total injected volume being 0.9 PV. Reservoir pressure

was slightly increased by producing less gas as compared to the amount of injected gas. This gas replacement course resulted in a 40 percent revaporization of the condensate bank.

With carbon dioxide the injection started at the estimated depletion pressure of 8 MPa. The injected volume was higher, about 2 PV. The reduction in condensate volume is less intensive than with dry separator gas. This can be explained with the swelling of the liquid phase upon the more extensive dissolution of CO_2. The CO_2 dissolution suppresses the liquid component concentration, which in turn reduces the degree of revaporization.

The third scenario is the huff and puff wellbore treatment (Figure 5). The huff and puff is a one-well method: injection ("huff" stage) and production ("puff" stage) takes place in the same well. While the gas is injected in the reservoir, the pressure increases and the condensate bank diminishes due to the revaporization. When the gas production starts, the pressure decreases and the condensate volume slightly increases. This treatment is repeated three times with gradually increasing both the upper limit of the injection pressure and the final pressure of the production period. After the third treatment the depletion pressure is again lowered to 8.0 MPa. The whole treatment results in more than 60% revaporization of the initial condensate content. As the same well is used for both injection and production, the huff and puff revaporizes the condensate mainly from the wellbore region.

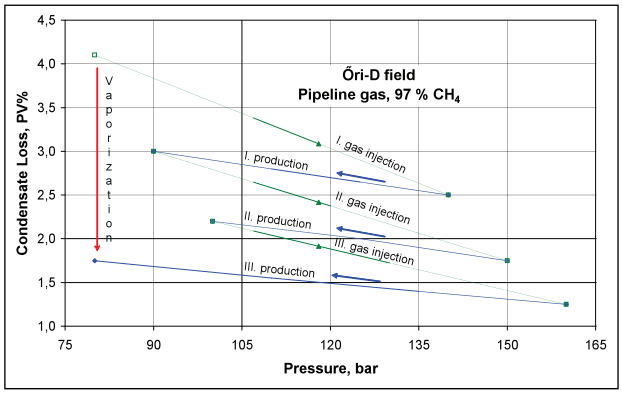

Fig. 5. Huff and puff wellbore treatment

Discussion

Figure 6 shows the pentane plus production. Both (dry gas and carbonated gas) injections resulted in approximately 20% increment in the pentane plus production. The dry gas injection started at 13.0 MPa and finished at 14.3 MPa. The carbonated gas injection started at 8.0 MPa and finished at 14.0 MPa. The quantity of the carbonated gas used in the experiment is twice as much as the quantity of the dry gas. The C_5+ production is about the same, but the liquid phase is significantly less in case of the carbonated gas injection. Similarly to the situation of the Halom field, C_5+ concentration in the liquid phase is reduced in line with the good solubility of carbon dioxide. The lower pentane plus concentration in the liquid entails a lower pentane plus concentration in the vapor. This is the reason why pentane plus production with carbonated gas falls behind that of with separator gas (see Figure 1).

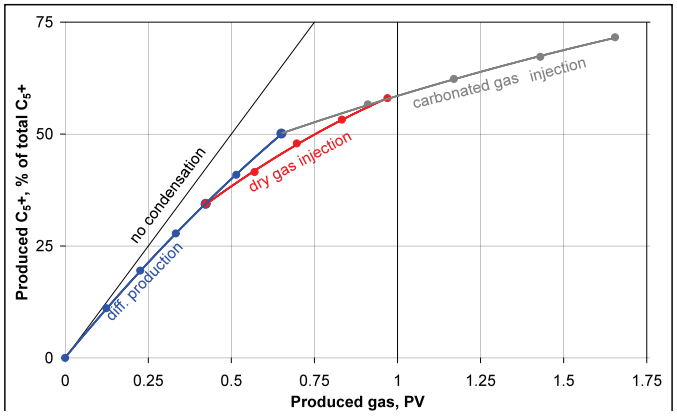

Fig. 6. The production of C_5+ in Őri-D field

Pipeline gas turned out to be an efficient agent for huff and puff wellbore treatment. Limited amount of injection gas, without contaminating the reservoir fluid, was able to revaporize 60% of the condensate bank, improving flow conditions for subsequent reservoir gas production.

Gas phase volumetric behavior is governed by pressure, temperature and composition. The reservoir volume occupied by unit amount of gas at standard condition can be calculated using compressibility factor z. Figure 7 presents all of the Őri-D experimental z factors related to different gas injections. The impact of every manipulation on the gas volumetric behavior can be followed on this chart.

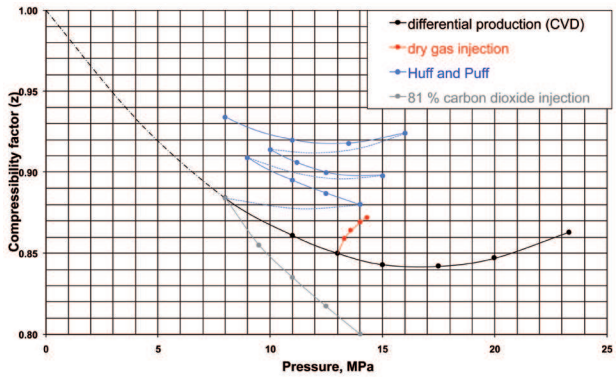

Fig. 7. Variation of z factor in Őri-D field

Separator gas injection involves minor compositional variation, therefore corresponding z factor (red line) changes moderately. Carbon dioxide injection implies more profound compositional variation, especially due to the greater pressure boost. In consequence a significant decrease in z factor takes shape, which is an advantage at CO_2 sequestration. The increase of z factor at pipeline gas injection is also significant (blue line). Gas phase volumetric properties are approaching underground gas storage conditions, offering orientation to that direction.

Conclusions

Laboratory tests with injection gases of different compositions identical with accessible injection gas reserves provide realistic input database for industrial EGR reservoir engineering computations.

The simulation of gas displacement type enhanced gas recovery can be used to determine the efficiency of condensate recovery and for the utilization in gas storage and pressure maintenance. One of the possible benefits is the replacement of the valuable components (rich or hydrocarbon gas) for less valuable components (dry or inert gas) in the reservoir.

The carbon dioxide geosequestration is a core business of the near future. CO_2 injection into a depleted gas condensate reservoir implies an excess benefit by improved condensate and rich gas recovery.

References

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Keywords: PVT laboratory test, Enhanced Gas and Condensate Recovery, revaporization, carbon dioxide sequestration, wellbore treatment

Reviewed by Péter Kalocsai