

## POTENTIAL APPLICATION OF CO<sub>2</sub> FOR ENHANCED CONDENSATE RECOVERY COMBINED WITH GEOLOGICAL STORAGE IN THE DEPLETED GAS-CONDENSATE RESERVOIRS

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### Abstract:

CO<sub>2</sub> emissions are considered to be the main contributor to global warming and climate change. One of the ways reducing the emissions to atmosphere is a proper capture and further geological storage of the carbon dioxide. In the oil industry, CO<sub>2</sub> is used as one of the injection agents to displace oil and enhance its recovery. Due to the low multi-contact miscibility pressure between CO<sub>2</sub> and hydrocarbons, fully miscible condition is quickly reached, leading to efficient displacement and high recovery factors. The utilization of the depleted gas fields for CO<sub>2</sub> storage, however, is considered as the option that is more expensive compared to oil field, since the enhanced recovery of gas with CO<sub>2</sub> is not effective. For this reason, our study considers the potential use of CO<sub>2</sub> EOR in depleted gas-condensate fields. This potential is evaluated by performing numerical simulations for the typical-size gas-condensate reservoirs with no active aquifer, in order to estimate both the storage efficiency and the additional oil recovery from condensed C<sub>5+</sub> hydrocarbon fractions, that otherwise will be never recovered and lost in the reservoir. Obtained results indicate significant potential for CO<sub>2</sub> storage and additional condensate recovery from the typical gas-condensate field of Eastern Ukraine.

**Key words:** *Gas-condensate, EOR, EGR, CO<sub>2</sub> storage*

### INTRODUCTION

Anthropogenic emissions of carbon dioxide (CO<sub>2</sub>) are widely considered to be the main contributor to the increase of greenhouse gas concentrations in the atmosphere, leading to global warming and climate change [14]. Therefore, the reduction of CO<sub>2</sub> emissions is the key action to mitigate the impact of global warming in the upcoming years. Since the Kyoto protocol in 1992 [21], developed countries have agreed to emission reduction targets and on the governance system to achieve it; yearly Conferences of Parties (COP) are held to assess the progress towards these targets and update them, as was the case notably for the COP 21 in Paris in 2015 [22].

Carbon dioxide capture and geological storage (CCS) is one of the solutions proposed to achieve this reduction. The relevance of CCS in the portfolio of measures is increasing: it is commonly agreed that the targets in the Paris agreement cannot be met without CCS, especially if a temperature increase lower than 2°C is targeted [9], and at the same time, an increase in emissions is already observed a few years later [11].

The availability of CO<sub>2</sub> storage is a constraint to achieve greater abatements in CO<sub>2</sub> emissions without recurring to costlier and less mature technologies [12].

Based on the estimates by the IEA [10] and earlier by the IEA GHG program, notably their report on CCS in disused

fields [13], there is a huge potential for CO<sub>2</sub> storage (corresponding to a total capacity up to, or in excess of 900 Gt) in the depleted oil and gas reservoirs. Storage option in depleted gas fields is significantly higher (797 Gt) compared to CO<sub>2</sub>-EOR application in oil fields (129 Gt). However, another derived conclusion in the IEA GHG report [13] was that it is more expensive to store CO<sub>2</sub> in gas fields, because there is no increased revenue due to additional oil recovery. Detailed studies on the applicability of CO<sub>2</sub> for enhanced gas recovery in depleted gas fields [4] also point to the limited increase in recovery and to the increased challenges in reservoir characterization and well planning, on top of the infrastructural constraints. At the same time, typical disposal options for CO<sub>2</sub> include depleted oil and gas reservoirs, use in enhanced oil recovery in conventional and shale reservoirs, deep saline aquifers, deep unmineable coal seams, enhanced coal bed methane recovery, large voids and cavities, basalts, etc. (Fig. 1).

### REVIEW OF THE PREVIOUS STUDIES

Geological storage and sequestration of CO<sub>2</sub>, as any other mining activity, has their own specific associated risks; these risks can be characterized as “local” and “global” [17]. Examples of “local” risks include impact of elevated gas-phase in shallow subsurface and near-surface environment, induced seismicity, and effects of dissolved CO<sub>2</sub> on the groundwater chemistry and contamination of formations with fresh water, effects on human beings, animals and plants above surface. “Global” risks refer to release of carbon dioxide into the atmosphere that contradicts the idea of storage.

At the same time, it can be argued, that CO<sub>2</sub> storage will not have any impact on groundwater, since its production

normally takes place from depth above 300 m, while storage formations are deeper than 800 m [8]. Considering the deep depleted gas-condensate reservoirs, the risks are minimized here due to the presence of well-defined geological traps related to previously formed gas reservoirs. Unfortunately, the risk of migration from the target storage formation cannot be eliminated completely, particularly due to the re-pressurization and change of the stresses and the long-term well integrity issues of the casing and cement. A good analysis of the CO<sub>2</sub> sequestration concepts and problems is presented by Liebscher and Muench [15]; also Ganguli [7] well described an integrated reservoir study approach for CO<sub>2</sub> enhanced oil recovery and sequestration applied to the Indian mature oil field of Ankleshwar.

Al-Hashami et al. [1] evaluated the applicability of CO<sub>2</sub> injection for EGR and geological storage using conceptual reservoir simulation, particularly studying the effect of diffusion, solubility in water, start of the injection related to the level of reservoir depletion and injection rates, applying basic economic analysis. Incremental gas recovery due to CO<sub>2</sub> injection can account up to 11% and economic profitability is very sensitive to the gas price, CO<sub>2</sub> cost and original gas composition. Diffusion is an important factor for CO<sub>2</sub> mixing with reservoir gas, but if diffusion coefficient is less than 10<sup>-6</sup>m<sup>2</sup>/s, its impact is minimal and can be ignored. Solubility of CO<sub>2</sub> in formation water delays the breakthrough time. Injection of CO<sub>2</sub> at a later depletion stage is more favorable for economics and incremental gas recovery. It is necessary to point, that the obtained results are very sensitive to in-place gas composition, and since it is not provided in the cited paper, it is hard to conclude how CO<sub>2</sub> improves the condensate recovery.

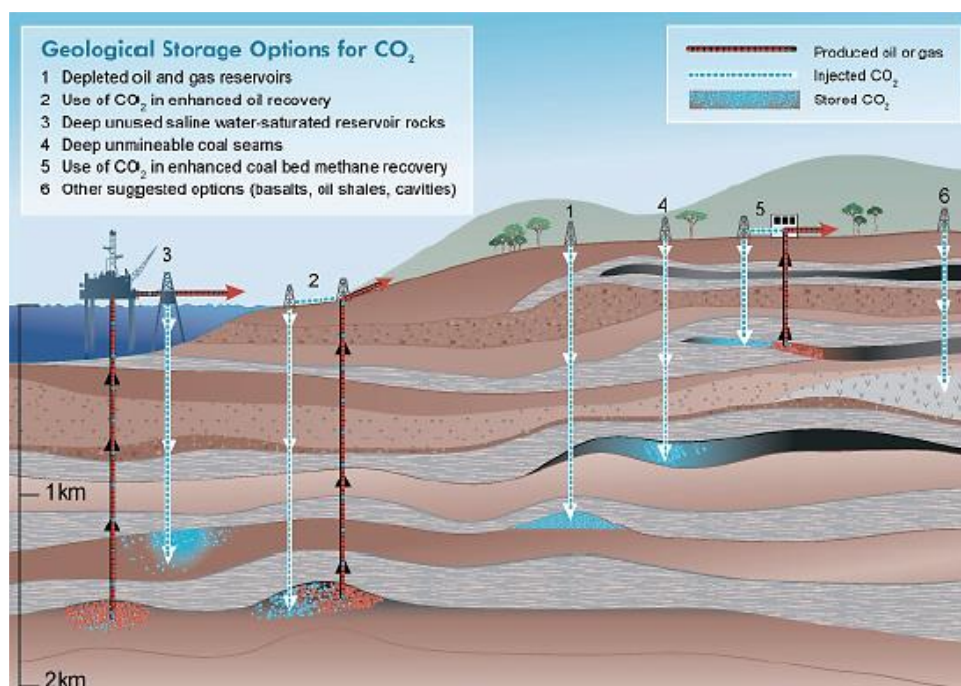


Fig. 1 Options for CO<sub>2</sub> sequestration and geological storage  
Source: [24].

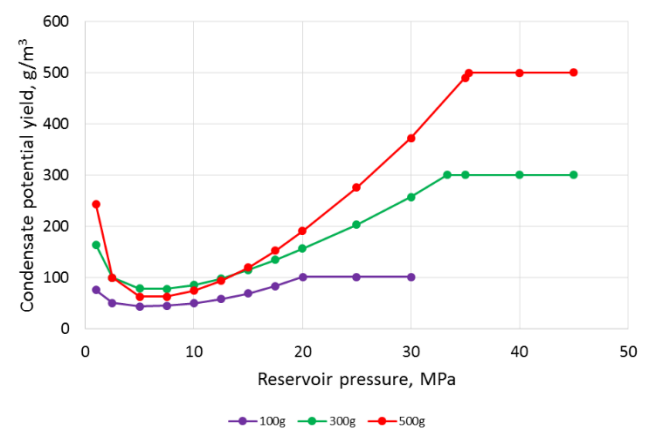
Use of the CO<sub>2</sub> to increase condensate production was studied before. Gachuz-Muro et al. [6] performed laboratory experiments for condensate displacement in naturally fractured reservoirs at high pressures and high temperatures. According to their results, injection of CO<sub>2</sub> showed little difference to natural depletion and natural gas injection is a preferred agent resulting in maximum condensate recovery. Soroush et al. [19] performed conceptual EOR simulation study for dipping gas-condensate layered model with pure CO<sub>2</sub> and CO<sub>2</sub> WAG both in up-dip and down-dip miscible conditions. Down deep CO<sub>2</sub> WAG and pure CO<sub>2</sub> injection resulted in the same values of ultimate condensate recovery around 81% while up-dip case recovered only 60%. Uchenna [20] studied application of CO<sub>2</sub> injection on condensate recovery for the publicly available reservoir model PUNQ-S3 and condensate composition from Whitson et al. [23]. Two cases were evaluated: pressure maintenance, when CO<sub>2</sub> was injected from the beginning of the production and delayed pressure maintenance, when CO<sub>2</sub> injection started after 4 years of depletion. Continuous injection of CO<sub>2</sub> resulted in increased CO<sub>2</sub> production that has a positive effect on condensate banking removal from the production near wellbore areas, resulting in higher gas-rates and higher ultimate recovery of condensate of 70%. The most efficient case represents the delayed pressure maintenance, for which the maximum gas recovery factor of 89% and condensate recovery is just 4% smaller than in the case of continuous injection, but with significantly higher NPV obtained from cumulative probability distribution. Shtepani, 2006 reviewed the possibility of CO<sub>2</sub> sequestration in depleted gas/condensate reservoirs, indicating that injection of CO<sub>2</sub> may allow enhanced gas recovery by liquid re-vaporization and pressure maintenance. Moreover, there are additional favorable features of CO<sub>2</sub>, like higher density at reservoir conditions relative to gas-condensate will force CO<sub>2</sub> to migrate downwards; larger viscosity will ensure that displacement of condensate will be better in comparison to hydrocarbon gases due to more favorable mobility ratio. Core flood experiments indicated that already at three pore volumes injected significant volume of condensate could be displaced and produced. Narinesingh and Alexander [16] published the only paper that has a similar objective, as in the current study, was done by, in which they tried to optimized the well placement and injection pattern in a simple cuboid type 3D grid model for EGR and CO<sub>2</sub> sequestration of depleted gas-condensate reservoir. From the simulations, over 60% of the injected CO<sub>2</sub> remained in the reservoir, 20% trapped due to hysteresis and 40% remained in supercritical state; and the maximum incremental condensate recovery over primary production only accounted to 6.9%, while the main CO<sub>2</sub> trapping mechanism is hysteresis. Unfortunately, it is not clear from the paper how the hysteresis was modeled exactly.

The only study that considered the application of CO<sub>2</sub> for both EGR and sequestration was done on a simple shoebox grid model using different commercial simulator (CMG-GEM). In the current study we evaluated the combined synergetic effect of possible CO<sub>2</sub> application for enhanced condensate recovery coupled with long-term geological storage in the depleted gas-condensate reservoir based on the realistic geological model and with different reservoir fluid compositions.

### NUMERICAL MODEL DESCRIPTION

A typical deep gas-condensate field of Dnieper-Donetsk Basin (Eastern Ukraine) was chosen as a geological setting. A synthetic numerical model was created, with non-uniform pattern of 14 producers spaced within an anticline structure. Three different PVT systems with potential condensate yield of 100, 300 and 500 g/m<sup>3</sup> were evaluated in the study. The field first was depleted until the point when maximum liquid saturation of condensed hydrocarbons was reached; the CO<sub>2</sub> injection started into the six additionally placed injectors. The neighboring producers are shut, once the CO<sub>2</sub> breaks to them, when the mole fraction in the production stream reaches 70%.

Synthetic numerical grid representing the typical geological setting of deep gas-condensate reservoirs of Dnieper-Donetsk Basin (Eastern Ukraine) was used, the same one as in the study of chemical enhanced oil recovery methods (CEOR) by Burachok et al. [2]. The model of the reservoir (6.7x2.0 km) was constructed with uniform lateral gridding of 40x40 m and vertical thickness between 0.5 and 5.0 m, resulting in 188000 active cells. The reservoir was divided into three communicating compartments split by transmissible faults. Rock-types are represented by three sands: coarse (majority of the cells – 56%), fine (20%) and very fine (13%), with permeabilities ranging from 0.1 up to 110 mD. Three different synthetic PVT models with potential yield of 100, 300 and 500 g/m<sup>3</sup> were developed to evaluate incremental condensate recovery from CO<sub>2</sub> injection (Fig. 2) and respective fluid compositions in Table 1.



**Fig. 2 Potential condensate yield for the reservoir fluids in the study**

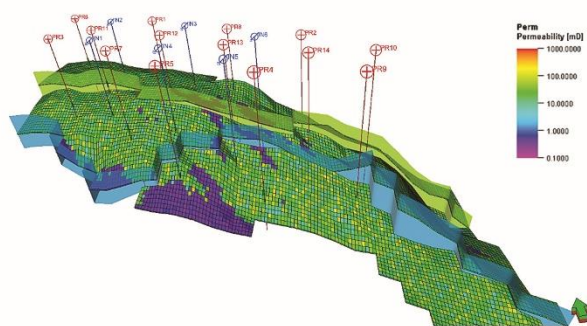
**Table 1**  
*Initial reservoir fluids compositions for different potential condensate yields*

Component	Potential condensate yield, g/m <sup>3</sup>		
	100	300	500
Mole fraction			
N <sub>2</sub>	0.0050	0.0040	0.0045
CO <sub>2</sub>	0.0500	0.0401	0.0400
C <sub>1</sub>	0.8500	0.8340	0.8213
C <sub>2</sub>	0.0500	0.0420	0.0401
C <sub>3</sub>	0.0150	0.0150	0.0140
C <sub>4</sub>	0.0050	0.0040	0.0045
C <sub>5+</sub>	0.0150	0.0330	0.0350
C <sub>10+</sub>	0.0092	0.0190	0.0260
C <sub>15+</sub>	0.0008	0.0089	0.0146

**Table 2**  
*Initial fluids in place for the models in study*

PVT model with potential yield of C <sub>5+</sub> , g/m <sup>3</sup>	Average reservoir pressure, MPa	Gas initially in place, bln. m <sup>3</sup>	Condensate initially in place, mln. m <sup>3</sup>
100	39.41	44.172	6.728
300	39.31	42.598	16.146
500	39.21	40.416	25.737

The reservoir was produced by 14 non-uniform well pattern with distances between the wells ranging from 550 up to 750 m (Fig. 3). All the wells were completed in the coarse sands and are under group control with daily rate of gas 7 million m<sup>3</sup>.



**Fig. 3** Example of permeability variation for one of the layers in the model

Reservoirs are depleted until the moment when average reservoir pressure is equal to the pressure of maximum liquid dropout that represents maximum liquid (condensate) phase saturation in the reservoir, after which CO<sub>2</sub> injection is started into 6 injection wells placed in the crest of the anticline. Production wells are shut once the produced CO<sub>2</sub> mole fraction reaches 70% and injection is stopped when all the producers are closed. After that, the migration of CO<sub>2</sub> plume was monitored for another 100 years.

The following CO<sub>2</sub> injection scenarios were evaluated:

- injection with reservoir voidage replacement at 150%;
- continuous injection at the rate of 750 k m<sup>3</sup>/day (approximately 150 kt a year);
- continuous injection at the rate of 1500 k m<sup>3</sup>/day (approximately 300 kt a year).

## SOLUTION AND MODELING METHOD USED

ECLIPSE compositional, a general-purpose 3D reservoir simulator, was used in the study. Three different options for CO<sub>2</sub> geological storage are implemented in the simulator [5]. Below we provide a short description of each and explanation on the one selected for this study.

### 1. CO2STORE

Considers three phases: a CO<sub>2</sub>-rich phase (labeled gas phase), H<sub>2</sub>O-rich phase (labeled liquid phase) and a solid phase. The option allows accurate mutual solubilities of CO<sub>2</sub> in water and water in CO<sub>2</sub>. Simplified geochemistry accounts for dissolution of three salts (NaCl, CaCl<sub>2</sub>, CaCO<sub>3</sub>) in water and could be modeled as solid phase as well. The option is based on the internal correlations with minimum input from the user and applicable up to 250 degrees C and 600 bar. It does not allow presence of hydrocarbons and is best suited for storage in aquifers. Therefore, it is not applicable for our study.

### 2. GASWAT

The option is based on a gas/aqueous phase equilibrium. The liquid mole fractions of CO<sub>2</sub> are accurately predicted, but the gas phase mole fractions of H<sub>2</sub>O are not as accurate. Gas composition can include hydrocarbon gases, which can be soluble in water. This option is suited for depleted dry gas reservoirs, but not for the case when liquid hydrocarbon phase is present in the reservoir.

### 3. CO2SOL

The water is not considered in the oil or gas phase but the option allows simulation of CO<sub>2</sub> solubility in water phase. Reservoir can contain any hydrocarbon components for gas and oil but only CO<sub>2</sub> can be soluble in water. This option is most suited for EOR projects in depleted oil reservoirs and, therefore, was used in the current study.

The option is based on the method proposed by Chang et al. [3], in which fugacity of the liquid phase CO<sub>2</sub> is computed from the gas fugacity of pure CO<sub>2</sub>, which is predicted by EOS together with CO<sub>2</sub> solubilities defined as functions of pressure. Chang et al. developed correlation based on data from several different authors with temperature range up to 100 degrees C, which is a significant limitation, especially for very deep reservoirs, where temperatures could be significantly higher. Because water is only present in the liquid phase, therefore dry-out effect in the vicinity of the CO<sub>2</sub> injectors cannot be modeled. For CO<sub>2</sub> EOR this may have insignificant effect, but it may become important for pure CO<sub>2</sub> sequestration projects.

**RESULTS DISCUSSION**

For all evaluated cases with potential condensate yield of 100, 300 and 500 g/m<sup>3</sup>, the same operating constraints were applied, which allowed proper comparison of the results.

Injection of CO<sub>2</sub> significantly extended the operating time of the field for low injection rate case of 750 k m<sup>3</sup>/d by 12 years and by 5 years for voidage. In the case of 1500 k m<sup>3</sup>/d injection rate, earlier breakthrough leads to same operating time as for the base case (Fig. 4).

In addition, there is a clear trend of earlier CO<sub>2</sub> breakthrough time with increase of potential condensate yield in the reservoir gas for the same injection conditions.

CO<sub>2</sub> injection has positive effect on the incremental condensate recovery (Fig. 5 and Table 3).

recovery profiles follow the same pattern, indicating that slower injection is preferred towards higher condensate recovery. Another important observation, the smaller the condensate yield, the higher the incremental recovery, with a maximum of 5.2% obtained for 100 g/m<sup>3</sup> and 750 k m<sup>3</sup>/d injection (Table 3).

Change of the produced total mole fractions for liquid components (C<sub>5+</sub>, C<sub>10+</sub>, C<sub>15+</sub>) clearly shows the effect of condensate displacement by increased mole fraction, when condensate bank approaches production wells with further rapid decline due to CO<sub>2</sub> break-through and well shut-ins (Fig. 6).

CO<sub>2</sub> injection summary is given in the Table 4. Total injection varied between 4.0 and 5.1 Mt. Due to the high mole-fraction (70%) for production wells shut-in, significant amounts of carbon dioxide (between 28 and 56%) were recycled, resulting in sequestration between 1.7 and 3.6 Mt.

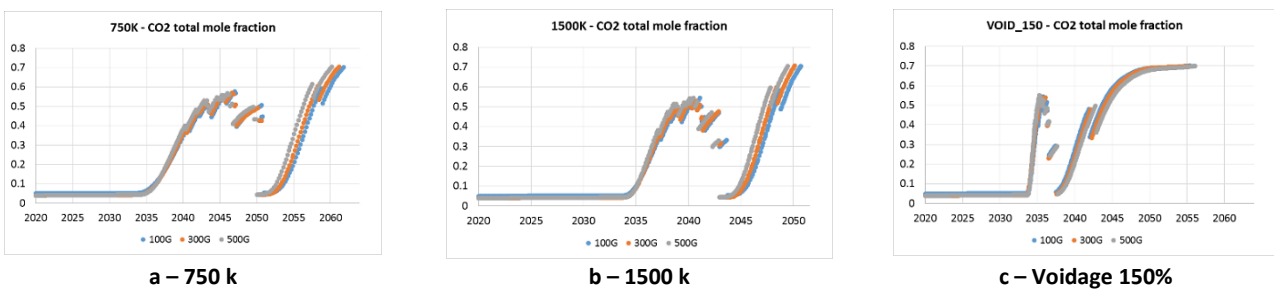
**Table 3**  
**Incremental condensate recovery**

Case	Incremental condensate, %		
	100 g	300 g	500 g
750 k	5.18	3.21	3.08
1500 k	4.65	2.78	2.70
Voidage	4.34	2.54	2.66

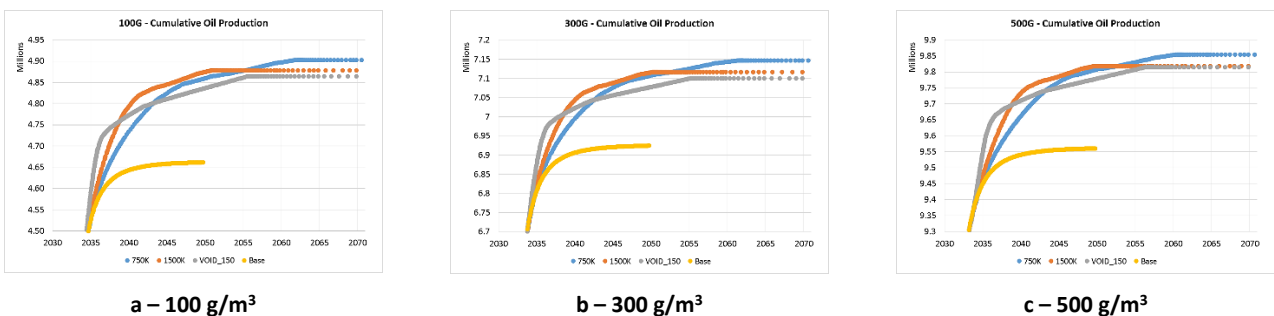
**Table 4**  
**CO<sub>2</sub> total injection and sequestration summary**

Case	Injected, Mt			Re-cycled, Mt			Stored, Mt		
	100G	300G	500G	100G	300G	500G	100G	300G	500G
750 k	4.218	4.125	3.981	1.760	1.804	2.270	2.458	2.320	1.711
1500 k	5.150	4.975	4.776	1.521	1.534	1.910	3.629	3.441	2.867
Voidage	5.104	4.717	4.260	1.441	1.441	1.737	3.663	3.277	2.523

For the voidage case, due to the high volume compensation at the beginning of the injection, the condensate recovery is much higher than for the other cases, leading to minimum ultimate recovery due to shut-in of the wells in the vicinity of the injectors. The minimum injection rate case (750 k) on a long-term produces maximum volume of incremental condensate because of good sweep, longer pressure maintenance and slower break-through of CO<sub>2</sub>. Independent from the condensate yield, all condensate



**Fig. 4 Comparison of total produced CO<sub>2</sub> mole fraction for different injection rates (100 g/m<sup>3</sup> – blue, 300 g/m<sup>3</sup> – orange, 500 g/m<sup>3</sup> – grey)**



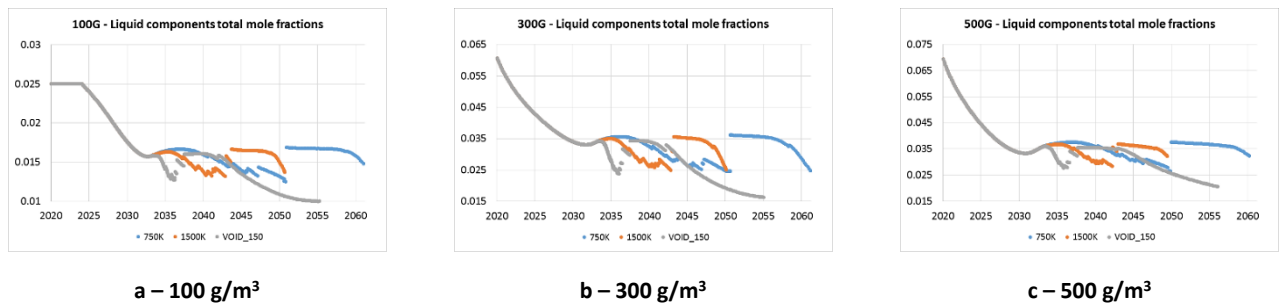
**Fig. 5 Comparison of cumulative condensate production (750 k m<sup>3</sup>/d – blue, 1500 k m<sup>3</sup>/d – orange, Voidage 150% – grey; base depletion case – yellow)**

Once the injection is stopped, gravity and diffusion drive the CO<sub>2</sub> plume expansion by increasing the solubility in connate formation water, clearly seen in the change of total (Fig. 7) and aqueous (Fig. 8) mole fractions. The majority of the sequestered CO<sub>2</sub> remains in the vapor phase (Table 5), between 70.0 and 74.5%, caused by significant reservoir depletion and pressures being subsequently lower, with reservoir pressure lower than critical 73.8 bar and supercritical state observed only in the vicinity of the injection wells influenced by pressure increase.

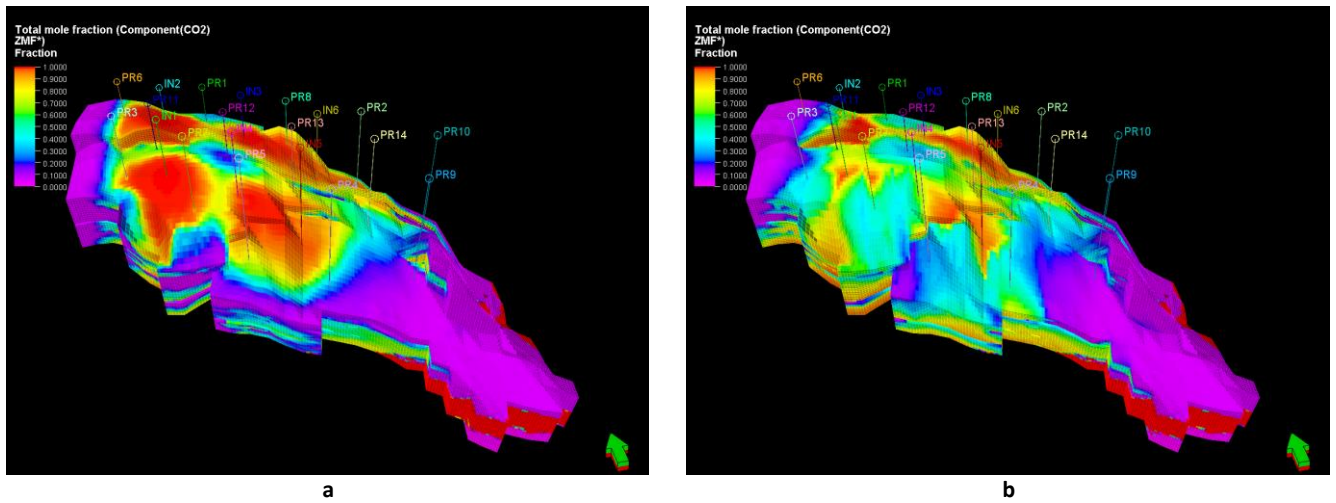
**Table 5**

**Split of sequestered CO<sub>2</sub> volumes in different phases**

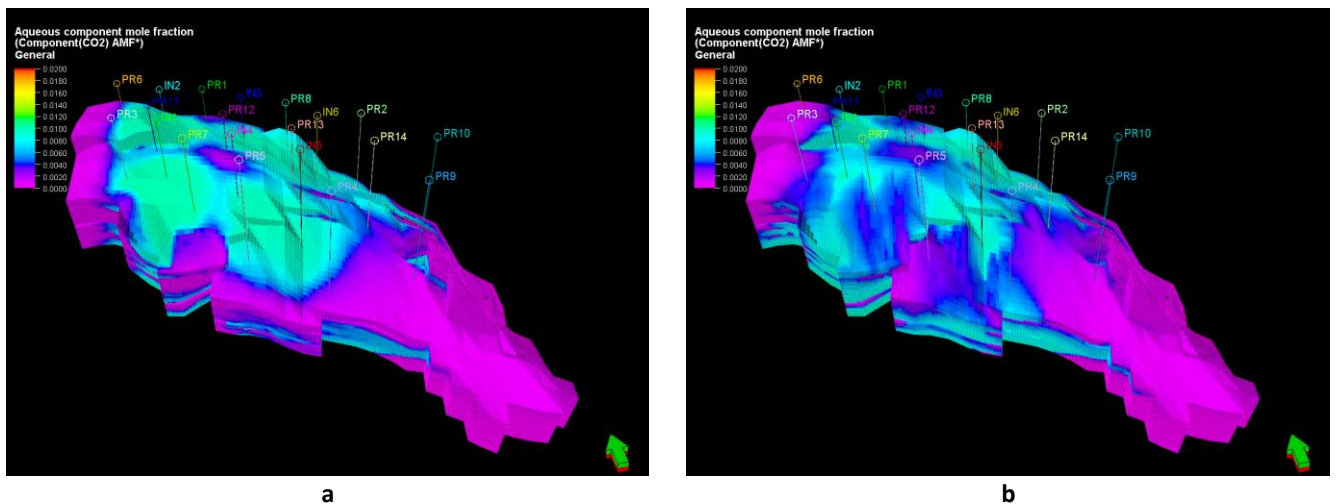
Case	100 g		300 g		500 g			
	% in water	% in supercrit.	% in vapor	% in water	% in vapor	% in water	% in supercrit.	% in vapor
750 k	0.64	25.59	73.76	0.65	24.84	74.51	0.64	25.60
1500 k	0.69	28.69	70.62	0.70	27.11	72.19	0.68	28.68
Voidage	0.68	29.32	70.00	0.68	26.80	72.52	0.66	26.73



**Fig. 6 Comparison of liquid components (C<sub>5+</sub>, C<sub>10+</sub>, C<sub>15+</sub>) total mole fractions (750 k m<sup>3</sup>/d – blue, 1500 k m<sup>3</sup>/d – orange, Voidage 150% – grey)**



**Fig. 7 CO<sub>2</sub> total mole fraction for 100 g/m<sup>3</sup> voidage case after the end of the injection in 2060 (a) and after 100 years (b)**



**Fig. 8 CO<sub>2</sub> aqueous mole fraction for 100 g/m<sup>3</sup> voidage case after the end of the injection in 2060 (a) and after 100 years (b)**

## CONCLUSIONS

Synthetic numerical simulation study was performed for the typical conditions of deep gas-condensate reservoirs of Dnieper-Donetsk basin in Eastern Ukraine with application of commercial general-purpose 3D reservoir simulator. The key objective of the study was to evaluate potential applicability of CO<sub>2</sub> injection for enhanced condensate recovery and geological sequestration in depleted gas-condensate reservoir with three different PVT models, representing small (100 g/m<sup>3</sup>), medium (300 g/m<sup>3</sup>) and high (500 g/m<sup>3</sup>) potential condensate yields. For each PVT model, three injection rates were tested (low, high and 150% voidage replacement). Incremental condensate recovery is a function of both injection rate and potential yield, with maximum incremental oil recovery up to 5%, when both are at their smallest values. Injection of CO<sub>2</sub> extended the reservoir development by 10-15 years, in comparison to the base primary depletion case. About 70% of the sequestered CO<sub>2</sub> remains in the vapor state, which is related to the high level of depletion and reservoir pressures being lower than the critical. Less than 1% of the CO<sub>2</sub> is stored in the connate formation water. Simulated cases showed the possibility to store only between 1.7 and 3.6 Mt, while the injected volume was between 4.0 and 5.1 Mt. Significant re-cycled volumes of CO<sub>2</sub> are due to high shut-in mole fraction of 70%. Considering that many gas-condensate reservoirs observe natural water-drive, additional studies could be done to evaluate the storativity for these types of reservoirs including different mole-fraction limits for wells shut-in.

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