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ENHANCED NATURAL GAS RECOVERY FROM LOW-PERMEABLE RESERVOIRS

1. INTRODUCTION

Growth of global trends of natural gas consumption on the background of the existing conventional fields depletion was a prerequisite of raising natural gas prices, which led to the development of new and improvement of existing technologies for its production. The dominant role of natural gas as the main source of energy will continue for the next decade. One of the main sources of additional gas production is unconventional natural gas deposits, which include deposits with low-permeable low-porous reservoirs [1].

According to the Energy Information Agency report (EIA, July 2013) technologically recoverable resources of shale gas in Ukraine equal 3.62 trln m^3 (1.75% of world reserves), and including resources of tight gas reach 7 trln m^3 [2]. Proven natural gas reserves of conventional deposits equal 1 trln m^3. Previously (in 2011) US Energy Information Administration estimated the technically recoverable resources of Ukrainian shale gas at 1.2 trln m^3 (0.6% of the estimated world reserves), and total – at around 5.6 trln m^3. According to the Dixi Group report, shale gas resources in Ukraine vary and range from 5 to 8 trln m^3, with technically recoverable 1–1.5 trln m^3 [3].

2. CRITICAL LITERATURE REVIEW

One of the main differences between the development of conventional and unconventional natural gas fields is the presence of the respective stages of production. In conventional gas fields development there are following periods of gas production: increasing gas production, constant gas production and production gas declining [4].

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In case of unconventional fields drop-down production is observed from the beginning of their development [5]. For example, production decline curves for Heynesville shale gas field are given below (see. Fig. 1), were estimated by Chesapeake Energy Company [6, 7].

As it can be seen from Figure 1, the flow rate drop for production wells is quite fast. During the first year well production rate may decrease to 65–80%, during the second year – 35–45%, in the third – 20–30%. After a sharp decline of production rate relatively stable plato at the site is observed, which is called the “tail” of development. During the final stage of development the percentage production decline is reduced and in average it can range 5–7% of the previous year. This “tail” can last for decades, but it is limited to cost-effective production rate (minimum reservoir pressure).

The foregoing features of unconventional natural gas fields development could be explained by the peculiarities of gas occurrence mechanism in low-porous low-permeable reservoirs. Natural gas contained in shale deposits and coal seams is in the free state in the pores of the rock matrix and in the adsorbed state on the surface of pores space [7–9]. As it was established according to the field data of unconventional natural gas deposits development the amount of adsorbed gas may reach 40–50% of the initial reserves. Consideration of adsorption processes in predicting development strategies will allow engineers to more accurately determine the reserves and predict the ultimate gas recovery factor [10]. Therefore, special attention should be given to the development of new methods for forecasting the indices of unconventional natural gas field development that will consider the peculiarities of unconventional natural gas fields and will give reliable results.

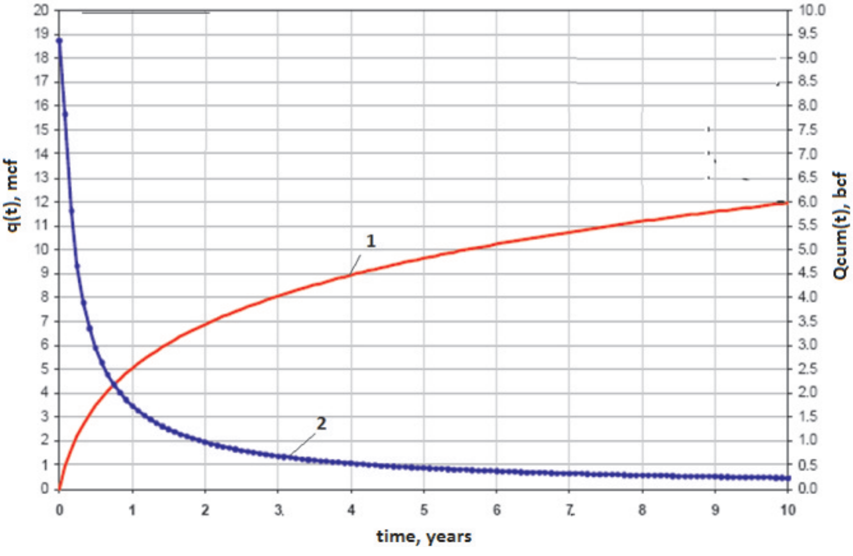

Fig. 1. Production decline curves for Heynesville shale:
1 – cumulative gas production, 2 – well flow rate

As it was established by the results of field research works and gained field experience of gas production from unconventional deposits, some amount of gas is in adsorbed state [11–13]. One of the possible and main ways of gas production increase from low-porous low-permeable reservoirs is gas desorption stimulation from the surface of the pore channels.

To increase coal bed methane production non-hydrocarbon gas injection is widely used in order to reduce the methane partial pressure in the reservoir. In the same time reservoir pressure does not decrease, and may even increase. It allows maintaining a constant well flow rate without lowering the deposit energy potential. Injected CO_2 mainly adsorbed on the surface of the pore space, displacing CH_4 from coal. Displacement ratio of CH_4: CO_2 ranges from 2: 1 to 10: 1. In case of N_2 injection methane desorption increase not only due to substitution and nitrogen adsorption and by reducing the methane partial pressure. Reducing the CH_4 partial pressure provides the driving force for desorption. Implemented pilot projects of CO_2 and N_2 injection in order to improve gas recovery of coal deposits have shown successful results. Increasing coal bed methane recovery by carbon dioxide injection was considered in [14]. CO_2 injection in coal seams will not only increase the ratio gas recovery but also reduce the amount of greenhouse gases in the atmosphere through their underground sequestration. An analysis of the project in San Juan coal basin (USA) using well pattern with consist from 4 injection and 7 production wells shows its economic and technological effectiveness. In particular, injection of 56.6 million m^3 of carbon dioxide increase natural gas production by 150%, without CO_2 breakthrough to the production wells. For the successful usage of this technology the coal seam should have limited size, relatively high permeability and lithological irregularities and lack of significant natural fractures. Injection wells should be completed unstimulated, while production wells can be cavitated or hydraulically stimulated. In addition to CO_2 injection another possible method of increasing gas recovery is methane displacement by nitrogen. Using this method may be achieved final recovery factor near 90%. Sources of CO_2 for injection may become natural deposits. However, to improve the ecological situation a rational option could become it transportation from large factories, plants, etc., which is extremely expensive. Therefore, at the design stage of this method economic parameters should to be considered.

Coalbed methane production at depletion mode is relatively simple and cheap method. But it is produced only up to 50% of initial gas reserves [15]. In this situation, the authors examined the possibility of increasing gas recovery using nitrogen and helium. The physical essence of the process is that the pumping of non-hydrocarbon gas decreases the methane partial pressure, which in turn initiates its desorption without reservoir pressure reducing. As it was found in the result of experiments amount of adsorbed methane on the rock surface depends not only on temperature and pressure under which it is located, but also on its concentration in the gas. This conclusion is based on the results of the experiment on the methane and helium adsorption with different concentrations of different concentration on coal models surface. To investigate the influence of methane partial pressure on desorption, a series of experiments that included methane adsorption on the surface of coal was conducted. After reaching pressure equilibrium helium was injected to the model inlet while methane was produced from the model outlet into additional cell. The process was carried out in stages with maintaining constant pressure in the model (7 MPa). After a certain period of time the model was closed on both sides and pressure values have been recorded. Methane desorption was occurred in the model at this time, as was evidenced by pressure increasing. Knowing the amount of injected helium, methane, gas concentration at the model outlet and thermobaric parameters based on the material balance conditions the amount of additional extracted methane was determine. However, as helium is relatively expensive gas for industrial usage, a number of studies related to the nitrogen injection in order to intensify methane desorption by the foregoing method was conducted. It should be noted that the nitrogen adsorption capacity is 40% lower than methane. Amount of injected nitrogen equals about 3 pore volumes. In this case all free and about 80% of the adsorbed gas was produced. Laboratory experiments were conducted on sand packed and core models, and showed great efficiency of nitrogen injection in order to enhance gas recovery from coal bed methane fields.

In [16] the question of methane, nitrogen and carbon dioxide adsorption on coal samples from other deposits USA was studied. Before the experiments coal samples were crashed, purified and screened. After that 25 cm in length and 4.25 cm in diameter cylindrical container was filled by coal. Model porosity and permeability was measured using helium because it is not adsorbed on the coal surface. As it was measured porosity equal 37%, permeability – 31 mD. All studies were conducted at 22°C using gravimetric method. According to the experimental results, it was found that the coal from the field is absorbed three times more CO_2 than methane. Nitrogen adsorption capacity is lower than that of methane. An interesting fact is also that during desorption hysteresis was observed. And it was the largest for methane and CO_2. Some researchers attribute this phenomenon for measurement errors.

In order to determine the methane displacement ability by CO_2 and nitrogen the experiments were carried out at pressures of 2.9 and 4.1 MPa. For these experiments gases of different compositions were used (pure nitrogen, pure carbon dioxide and mixtures thereof). Thus displacement agent was injected at a constant flow rate. Based on the experiments results it was established that CO_2 breakthrough occurs after injection of 1.2 pore volume. In this case, the highest rate methane recovery is achieved after 1.5–1.8 pore volume of CO_2 injected. With regards to nitrogen, it breaks much sooner after injection of 0.5 pore volume. The maximum gas recovery reached after 2–2.5 pore volumes injection. When using a mixture of gases to methane displacement, regardless of the concentration of individual components of the first to exit the model breaks nitrogen, displacing of methane. However, the higher the concentration of nitrogen in the mixture, the sooner it breaks. Then CO_2 was break. Thus before CO_2 breakthrough jump in methane production was observed.

The hydrodynamic model of depleted shale gas with two horizontal wells with transverse multistage fracturing has been used to analyze the influence of parameters of adsorption of CO_2 and CH_4 on the accumulated gas production, total volume injected CO_2 and CO_2 breakthrough time in [17]. To determine the relative adsorption capacity of CH_4 and CO_2 was used replacement rate of methane with carbon dioxide or CO_2–CH_4 relative adsorption capacity is defined as:

$$\alpha_{CO_2-CH_4} = \frac{V_{L-CO_2} \cdot P_{L-CH_4}}{V_{L-CH_4} \cdot P_{L-CO_2}} \tag{1}$$

V_{L-CO_2}, V_{L-CH_4} – Langmuir volume for CO_2 and CH_4, m^3/t;

P_{L-CO_2}, P_{L-CH_4} – Langmuir pressure for CO_2 and CH_4, MPa.

To calculate the baseline pressure and volume Langmuir methane amounted to 2 m^3/t and 5 MPa; for carbon dioxide under 3.4 m^3/t and 2.7 MPa. In order to determine the effect of these parameters on the extraction of gas from deposits held by individual launches hydrodynamic calculations stimulator for CO_2 and CH_4 for the basic version, and the parameters of the Langmuir 50% higher and lower than their value for the base case. By increasing the amount of methane Langmuir 50% final rate gas recovery increased by 3.4%, the amount of injected CO_2 is reduced by 12% and decreases the breakthrough of CO_2 and 8% decreases its production. The increase for CO_2 Langmuir 50% have no effect on the ratio of the final gas recovery, but can increase by 18.5% volume of injected CO_2 and reduce its production by 68%. Increased pressure Langmuir methane by 50% can increase gas production by 1.25% and the amount of injected CO_2 by 3.5%. However, it dramatically (by 51%) reduced time to breakthrough of CO_2 producing wells. An increase in the Langmuir pressure for CO_2 by 50% does not affect the increase gas recovery, but reduces the amount of CO_2 injected 5% significantly increases its production (69%).

3. PROBLEM FORMULATION

Although there are a large number of studies, known technology for natural gas desorption stimulation from shale gas deposits and coal bed methane fields using displacement agents, there are no studies specifically for tight low-porous low-permeable reservoirs. Also, it is not clearly established the dependence on porosity, permeability, pore size, rock grain size and its ability to adsorbed methane at different temperatures. Determination of these dependencies will improve current gas production and increase the final gas recovery possibly not only from unconventional deposits, but also from the conventional natural gas fields. Also, the impact of non-hydrocarbon gas injection pressure on the process of desorption stimulation from models with different permeability is not fully investigated.

4. GENERAL DESCRIPTION OF EXPERIMENTAL RESEARCH

Experimental studies were conducted, which provide the opportunity to establish regularities of adsorption-desorption processes in tight sands and develop methods (technologies) that leads to increase gas recovery factor from low-porous low-permeable reservoirs.

a)

b)

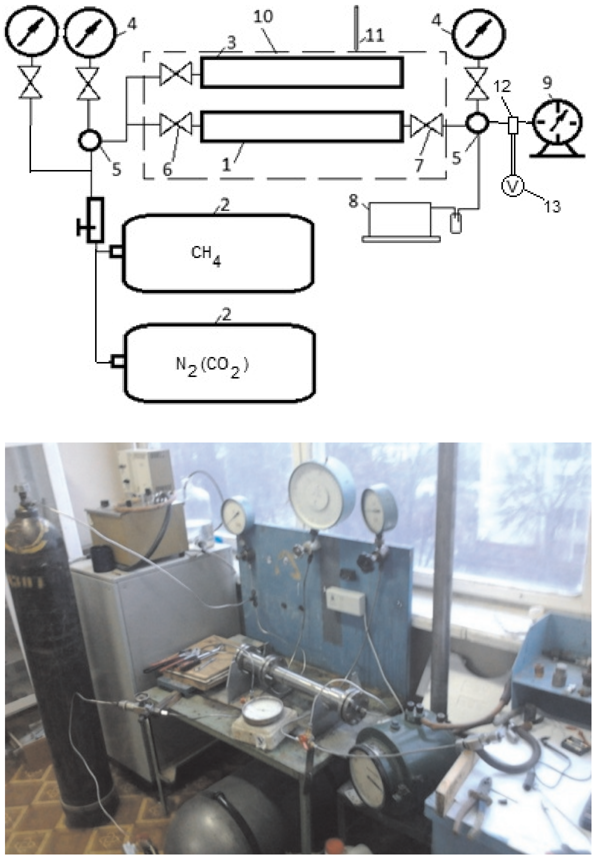

Fig. 2. Scheme (a) and general view (b) of experimental setup: 1 – model, 2 – gas source, 3 – reference cell, 4 – pressure gauges, 5 – manifolds, 6 – input valve, 7 – output valve, 8 – vacuum pump, 9 – gas meter, 10 – thermo bath, 11 – temperature sensor, 12 – methane sensor (Dynament MSH-P/HC/NC/5/V/P/F), 13 – voltmeter

To investigate the adsorption-desorption processes from low-permeable reservoirs the laboratory setup was developed. A schematic diagram and its general view are shown in Figure 2. The methodology of carrying out the experiments is as follows. Model is filled with the sand of selected fractions (0.125, 0.5, 1 and 2 mm). The porosity and absolute permeability, the volume of the model lines and additional cells are determined.

Model is evacuated for some hours maintaining a constant temperature, thereby releasing pore space of the model from previously adsorbed gas (including air). The temperature is maintained closes to 100°C. Some authors in their studies for model degassing evacuated it for 12 hours at 50°C. For rock samples with high clay content it is recommended to maintain a temperature of about 200°C [18].

At the beginning of the experiment a constant temperature is set, which will be maintained throughout the whole period of its duration. The experiments were conducted at temperatures 22°C, 40°C and 60°C. The model is filled with methane at a pressure P_1. The volume of methane in the model is determined by the equation of state of the gas in the pore volume for a particular temperature and pressure conditions. Pressures at the inlet and outlet of the model were measured. The model withstands some period of time to stabilize the pressure in it. This process can take from 4 to 8 hours. Throughout all period of time pressure is measured. Methane adsorption on the surface of the pore space is fixed as a result of the pressure drop in the model. According to studies after 3 hours the pressure in the model varies slightly, so stabilized value of pressure was determined in 4.5 hours. Amount of adsorbed gas is determined using the equation of its state. Then the experiment is repeated for the other values of the initial pressure. The data of studies were processed according to the known method [19].

The result of the construction of graphical dependence is checked by using the pressure drop method. To do this, valve 7 is opened and free gas is released for 4–5 s to receive atmospheric pressure at the model output. Then the valve at outlet 7 is closed and the liquid flow meter is attached. To determine the amount of desorbed gas valve 7 is slowly opened. The investigation continues for as long as the gas flow will not be less than 10 ml/d.

In the experiments the model with the length of 16.7 cm and the diameter of 2.6 cm was used. The experimental setup was pressure-tested to one half of the working pressure (20 MPa). The pressure in the experiments varied from 1 to 8.9 MPa, and the maximum value of 16 MPa was achieved. Pressure measurement during the experiments was carried out with pressure gauges with accuracy class 0.15. Studies were conducted using experimental design theory. As a source of methane gas cylinders were used. According to the passport of natural gas quality for compliance with GOST 27577:2005 methane content equals 97%, hexane+ 0.004%, non-hydrocarbon components of about 0.8%. Gas specific gravity is 0.574, dew point temperature – minus 35.5°C. To prevent uncontrolled gas leakage on laboratory setup alarm methane gas detector "Leleka" was installed, with operating boundary 0.75% of methane concentration in air, which corresponds to 5% of the lower limit of explosion.

5. RESULTS DISCUSSION

Experimental results of the dependence of methane adsorption from porosity, permeability, pressure and temperature is shown in Figure 3.

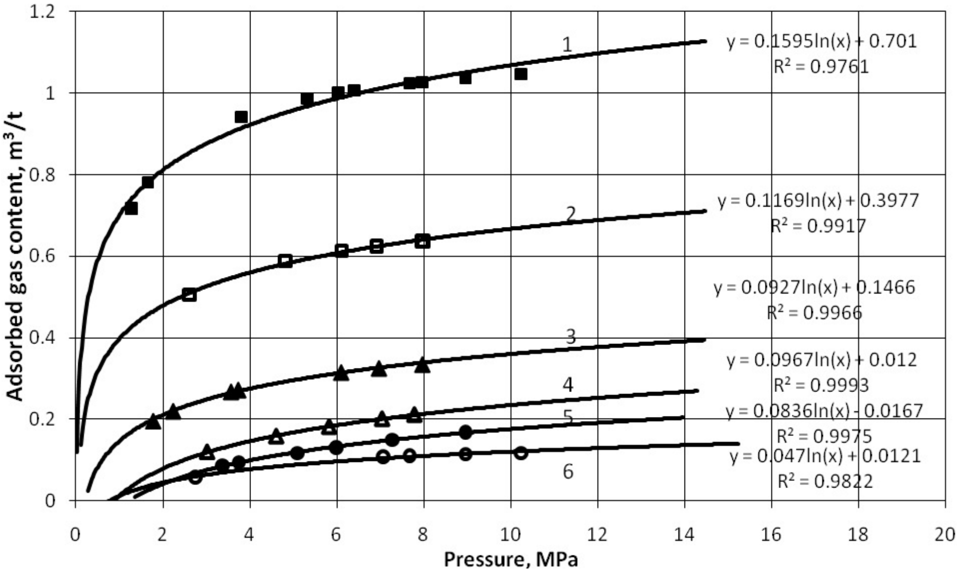

Fig. 3. Graphical dependences of adsorbed gas content from pressure (adsorption isotherm) for models with different permeability at different temperatures: 1, 2 – adsorption isotherms for the model with permeability of 9,7 mD at temperature 40°C and 60°C respectively, 3, 4 – adsorption isotherms for the model with permeability of 29 mD at temperature 40°C and 60°C respectively, 5, 6 – adsorption isotherms for the model with permeability of 93 mD at temperature 40°C and 60°C respectively

The maximum adsorbed gas content on the pore space surface with the temperature increase from 40°C to 60°C decreases by 1.5 times (from 1.2 m^3/t to 0.75 m^3/t) for model with permeability of 9.7 mD, by 1.2 times (from 0.43 to 0.35 m^3/t) for model with permeability of 29 mD and by 1.5 times (from 0.25 to 0.15 m^3/t) for model with permeability of 93 mD. Moreover, at constant temperature with increasing the model permeability the amount of adsorbed gas reduces by about 80% (from 1.2 m^3/t for model with permeability of 9.7 mD to 0.22 m^3/t for model with permeability of 93 mD).

It can be concluded that at constant pressure with increasing the temperature the amount of adsorbed gas decreases. However, when the temperature 80°C amount of adsorbed gas is weakly dependent on pressure, and an average equal 0.35–0.45 m^3/t for model with permeability of 9.7 mD. With the permeability increasing by 3 times the amount of adsorbed gas is reduced by about 2 times. This suggests that even in deep deposits with high reservoir temperatures adsorption processes occurs.

The dependence of the adsorbed gas content from the model permeability shows that even when the model permeability reach 100 mD amount of adsorbed gas ranges 0.065–0.1 m^3/t, and a further permeability increasing has virtually no effect on the adsorption capacity.

It is also worth noting that with permeability increasing the absolute dependence of the amount of adsorbed gas on temperature decreases. If for model with permeability

9.7 mD with increasing temperature from 40°C to 60°C the amount of adsorbed gas is reduced from 0.95 to 0.5 m^3/t (by 1.9 times), for model with permeability of 93 mD the amount of adsorbed gas decreases from 0.1 to 0.065 m^3/t (by 1.5 times). Thus, with increasing permeability by 10 times the amount of adsorbed gas is reduced to about 7–8 times. In this regard, it can be concluded that natural gas is adsorbed on the surface of the pore space even in conventional highly permeable layers, but its amount is much less than in unconventional low-porous low-permeable reservoirs.

It should be noted that the amount of adsorbed gas increases with pressure rising. However, at high pressure values the amount of adsorbed gas does not increase with pressure growing up. This effect can be explained by the fact that all adsorption centers are occupied and further adsorption is not possible.

As a result of theoretical research the mathematical model between the adsorbed gas content depending on permeability, reservoir temperature and pressure conditions was obtained:

$$V_{ads} = \frac{20.23 \cdot (9.7 + P)}{k \cdot (t - 7.1)} + \frac{(1-P)^2 + e^{-1.346}}{2} \cdot \frac{1}{e^k} + \frac{2 \cdot (P - 3.2)}{(0.696 - k) \cdot \left(\frac{k + 5.373}{2} + \frac{1}{t} \right)} \tag{2}$$

where:

V_{ads} – adsorption capacity, m^3/t,
P – reservoir pressure, MPa,
t – reservoir temperature, °C,
k – reservoir permeability, mD.

This model can be used for the rapid determination of adsorption capacity depending on the temperature and pressure conditions and reservoir permeability.

Taking into account the fact that one of the methods of enhanced gas recovery (EGR) from shale, coal seams and tight sands is desorption stimulation of previously adsorbed gas, the research of the desorption stimulation methods was conducted. For example, there are the following known methods of desorption stimulation [20]:

1) pressure reduction,
2) inert gas stripping,
3) thermal desorption,
4) displacement desorption.

According to the features of gas fields development with low-permeable reservoirs the research of displacement desorption and inert gas stripping were conducted. These experimental studies were carrying out using methane (CH_4), nitrogen (N_2) and carbon dioxide (CO_2). According to the experimental results of relative adsorption capacity determination it can be concluded that the carbon dioxide usage as displacement agent can lead to produce for about 30% of adsorbed gas more than using nitrogen.

To quantify the feasibility of non-hydrocarbon gas injection in order to stimulate gas desorption and increase gas recovery the laboratory research were conducted on a sand packed reservoir model with fractional composition of 0.127 mm, 0.2 mm, 0.5 mm, 1 mm, 2 mm and 3 mm, length 450 mm and diameter of 40 mm. Model permeability equal 9.1 mD, porosity 27.99%.

To study the mechanism and characteristics of the process of natural gas desorption stimulation by inert gas stripping the following series of experimental studies were carried out:

1) nitrogen injection before methane concentration in the model reduce to 0% (full displacement), followed by a gradual pressure reduction to atmospheric (depletion);
2) nitrogen injection before its breakthrough, followed by a gradual depletion.

Analysis of experimental results shows that nitrogen injection method before its breakthrough is more efficient compared with the method of full methane displacement. Therefore, the rest of the research was conducted for the condition of nitrogen injection stops at his breakthrough to the model outlet.

For further research the following methods of nitrogen injection were selected:

1) the method of full voidage replacement (injection ratio) – with maintaining constant pressure in the model, before nitrogen breakthrough, followed by a gradual depletion;
2) the method of higher voidage replacement – with a gradual pressure increase in the model, but not higher than initial pressure, before nitrogen breakthrough, followed by a gradual depletion;
3) the method of partial voidage replacement – with a gradual pressure reduction in the model, before nitrogen breakthrough, followed by a gradual depletion.

Figures 4–6 show the results of the studies.

As it can be seen from Figure 7 the greatest growth of gas recovery factor can be achieved using the method of full voidage replacement. Therefore, further studies to determine the nitrogen injection pressure were conducted for that method for different value of injection pressure ranges from 0.3 to 1 of initial pressure (P_{in}).

For grounding the EGR method, which provides the highest impact on technical, technological and economic indices it is necessary to minimize specific injection ratio and maximize gas recovery factor:

$$T = F\left(\min\left(\Delta V\right), \max\left(\beta_{г}\right)\right) \tag{3}$$

Specific injection ratio (ΔV) – this is the ratio of the volume of injected agent to additional methane production. In other words it is the amount of nitrogen (carbon dioxide) that needs to be injected into the reservoir to produce additional unit of methane volume.

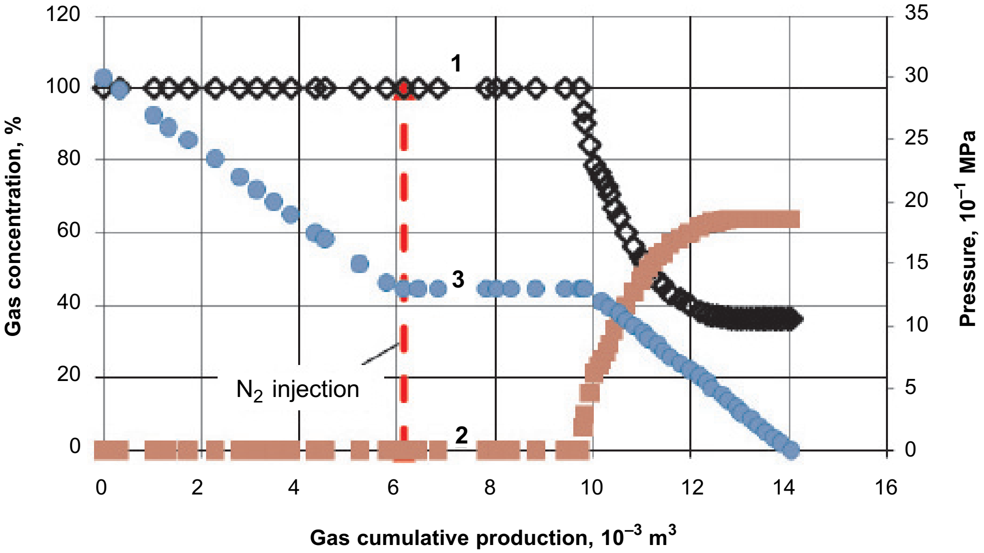

Fig. 4. The dynamics of pressure and components concentration in produced gas during the implementation of the method of full voidage replacement at the pressure of 0.4 from initial pressure: 1 – methane concentration, 2 – nitrogen concentration, 3 – pressure in the model

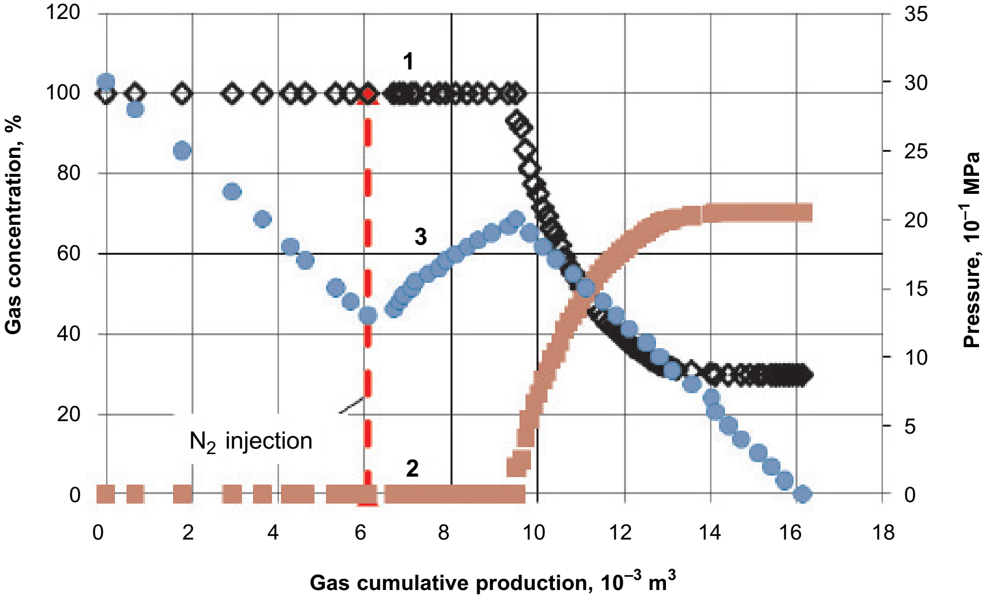

Fig. 5. The dynamics of pressure and components concentration in produced gas during the implementation of the method of higher voidage replacement at the pressure of 0.4 from initial pressure: 1 – methane concentration, 2 – nitrogen concentration, 3 – pressure in the model

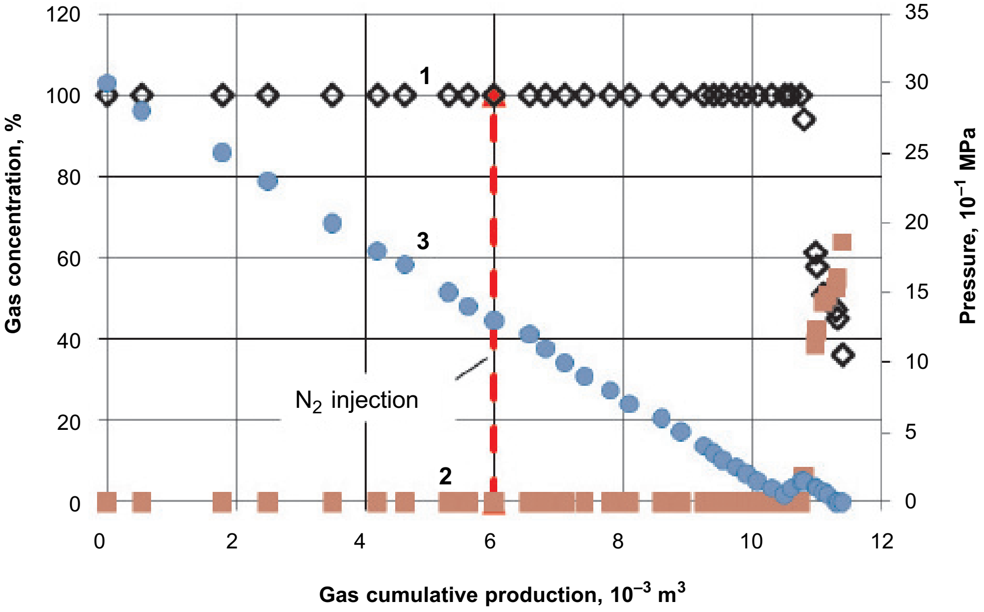

Fig. 6. The dynamics of pressure and components concentration in produced gas during the implementation of the method of partial voidage replacement at the pressure of 0.4 from initial pressure: 1 – methane concentration, 2 – nitrogen concentration, 3 – pressure in the model

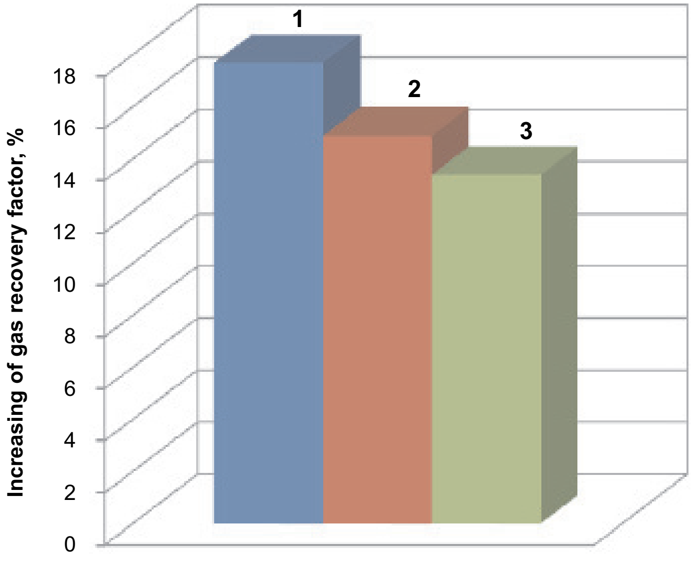

Fig. 7. Comparison of different methods of methane displacement by nitrogen: 1 – full voidage replacement, 2 – partial voidage replacement, 3 – higher voidage replacement

Table 1

Experimental results of methane desorption by nitrogen

Injection pressure from initial pressure	Volume of produced methane until nitrogen breakthrough		Volume of totally produced methane		Volume of injected nitrogen		ΔV
	l	% from base variant	l	% from base variant	l	pore volume	–
1	7.7	74.4	12.726	106.35	7,7	0.6	10.13
0.9	8.3	79.88	12.369	119.1	7.55	0.61	3.815
0,8	8,86	86,02	12,57	122,1	6.76	0.65	2.91
0.7	8.84	85.41	12.194	117.7	5.78	0.47	3.14
0.5	9.62	91.36	13.815	115.1	4.3	0.41	2.72
0.4	9.73	94.74	11.863	114.9	3.7	0.31	2.38
0.3	9.75	96.15	11.503	113.4	3	0.26	2.20

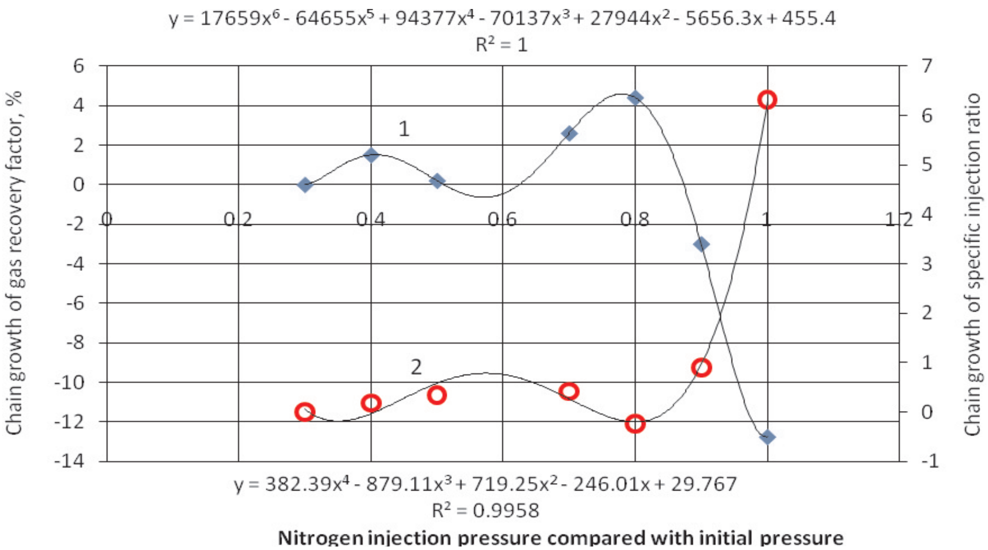

Fig. 8. Relative experimental results of methane desorption by nitrogen: 1 – chain growth of gas recovery factor, 2 – chain growth of specific injection ratio

Analysis of the obtained results (Tab. 1, Fig. 8) shows that the maximum increasing of gas recovery factor (for about 23%) can be achieved as a result of nitrogen injection with pressure of 0.8 P_{in}. This pressure is high enough, initiating more extensive methane desorption, and reduces nitrogen breakthrough time. This variant allows maximizing gas recovery factor while minimizing the amount of injected agent. With injection pressure decreasing gas recovery factor reduces.

In our point of view the physical meaning of this process explains by the mechanism of adsorption-desorption processes and nitrogen stripping and displacement characteristics. In particular, as a result of nitrogen injection methane partial pressure reduces initiates CH_4 desorption. The higher is nitrogen injection pressure, the more methane will desorb.

Also it can be concluded that with increasing the nitrogen injection pressure decreases it breakthrough time. This explains the inefficiency of higher voidage replacement method for desorption stimulation and relatively high efficiency of nitrogen injection at low pressure.

Using the same algorithm the laboratory experiments of methane displacement desorption by carbon dioxide was conducted. The results analysis shows that the method of full and higher voidage replacement leads to greater gas recovery factor increasing compared with partial voidage replacement method (Fig. 9). Therefore, further studies were carried out for these two methods in order to determine optimal carbon dioxide injection pressure.

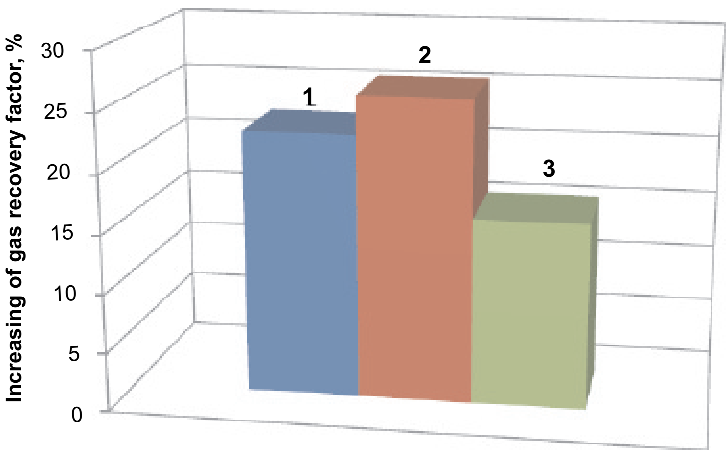

Fig. 9. Comparison of different methods of methane displacement by carbon dioxide: 1 – full voidage replacement, 2 – partial voidage replacement, 3 – higher voidage replacement

As it was established, with CO_2 injection pressure increasing gas recovery factor growth, which is not observed using nitrogen. This is because CO_2 displacement properties improve at high pressure. Also at higher pressure increases the amount of absorbed CO_2, and hence the greater amount of methane released in the pore space.

Experimental results show that the maximum gas recovery factor achieves using higher voidage replacement method of carbon dioxide injection at pressure of 0.8 from the initial reservoir pressure (Tab. 2).

Table 2

Experimental results of methane desorption by carbon dioxide

Injection pressure from initial pressure	Volume of produced methane until carbon dioxide breakthrough		Volume of totally produced methane		Volume of injected carbon dioxide		ΔV
	l	% from base variant	l	% from base variant	l	pore volume	–
Full voidage replacement technology							
1	9.317	89.16	13.09	125.3	9.6	0.733	3.62
0.8	9.648	92.77	12.74	122.5	7.65	0.6	3.27
0.6	9.99	95.51	12.58	120.3	5.8	0.46	2.73
0.4	10.35	97.83	12.20	115.4	4	0.327	2.46
0.2	10.57	101	11.64	111.2	2.15	0.18	1.83
Higher voidage replacement technology							
0.8	9.32	89.16	13.09	125.3	9.6	0.733	3.62
0.6	9.64	90.26	13.43	125.8	10	0.744	3.63
0.4	9.69	92.46	12.99	124	9	0.69	3.58
0.2	10.1	95.26	12.52	118.8	5.7	0.455	2.87

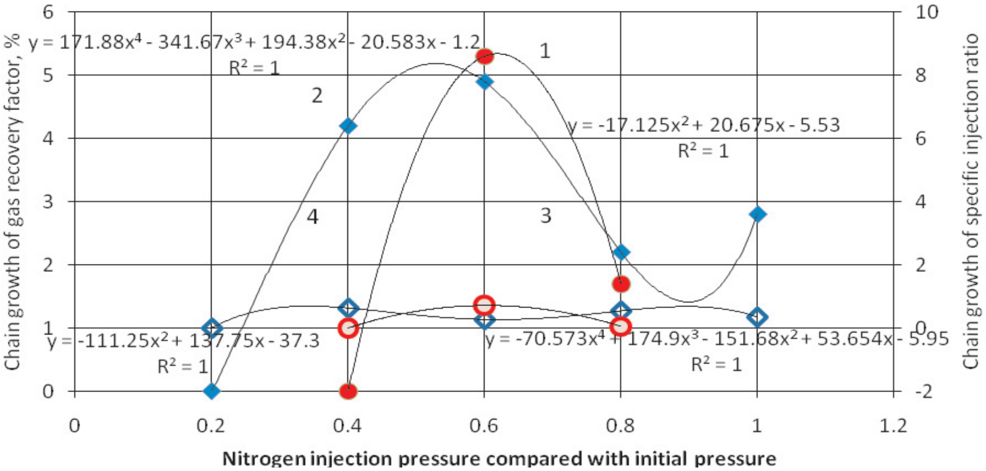

Fig. 10. Relative experimental results of methane desorption by carbon dioxide: 1, 2 – chain growth of gas recovery factor for higher voidage replacement and full voidage replacement technologies respectively, 3, 4 – chain growth of specific injection ratio for higher voidage replacement and full voidage replacement technologies respectively

However, full voidage replacement method at pressure of 0.6 from the initial reservoir pressure corresponds to the condition of minimizing the volume of injected carbon dioxide and maximize ultimate gas recovery factor (Fig. 10). Therefore, it is recommended for further implementation.

The physical essence of EGR by carbon dioxide displacement desorption is that CO_2 is better absorbed on the rocks surface releasing methane in the pore space. Considering the adsorption isotherms of methane and CO_2 can conclude that with injection pressure increasing greater amount of CO_2 is adsorbed, initiates methane desorption. This explains the efficiency of the high voidage replacement method.

6. CONCLUSIONS

1. To remove the adsorbed gas just reservoir pressure lowering is not enough due to the nature of adsorption isotherms. Particularly at pressure decreasing by 8–10 times compared to initial reservoir pressure only about 30–40% of the total amount of initially adsorbed gas is desorbed. And at considerable reservoir pressure reduction the further deposit development is not economically profitable.
2. For the first time the effect of temperature, pressure and reservoir permeability on methane adsorption capacity were determined. The mathematical model was developed that allows estimating adsorbed gas content depending on the reservoir permeability, pressure and temperature.
3. For the first time experimental studies were conducted and the relative adsorption of methane, nitrogen and carbon dioxide on the surface of tight sands were specified. EGR methods by methane desorption stimulation were substantiated.
4. The influence of injection pressure of the displacement agent on gas recovery factor was experimentally proved. It was grounded the physical sense of the processes that occur during natural gas desorption stimulation using non-hydrocarbon gases.
5. According to the research results it was found that in the case of nitrogen usage the most effective method is full voidage replacement at injection pressure of 0.8 from the initial reservoir pressure, and in case of carbon dioxide usage – full voidage replacement method at pressure of 0.6 from the initial reservoir pressure. Taking into account known methods of N_2 and CO_2 production nitrogen injection is recommended for further implementation.

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