Assessment of technical and economic risks of unconventional gas production in Ukraine

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Abstract

Development of unconventional gas requires specific technical and technological means and is accompanied by diverse high risks. The lack of practical experience and therefore reliable data on the conditions of exploration and production requires a comprehensive technical and economic approach to assess risks of development of unconventional resources, including shale gas in Ukraine. Wide experience in production of unconventional gas, mainly shale gas in the U.S., can be extrapolated and quantifies the risks in Ukraine, considering its geological and technological conditions, economic factors and fiscal systems.

Stochastic simulation by Monte Carlo method showed that the geological part of the risks associated with the volume of gas recoverable reserves were estimated at 22–25%, technical risks associated with the initial production rate of wells – at 2–17%. Financial and economic risks associated with the cost of drilling, caused primarily by their depth, were estimated at 23–25%. Up to 45% of risks are determined by the price of gas. Quantitative risks are ranked for determining the priority areas of improvement the degree of projects commercialization.

Key words: *Monte Carlo method, production, risks, shale gas, stochastic modeling.*

Unconventional gas deposits and resources include gas deposits in tight gas reservoirs (low-permeability reservoirs), coalbed methane and shale gas. Gas hydrates are usually also included into this category. Development of unconventional gas deposits requires specific technical and technological facilities and is accompanied by versatile substandard risks.

The main problems connected with production of gas from tight reservoirs, coalbed methane and shale gas are very much alike and are caused by low density of reserves in deposits and critically low reservoir porosity and permeability characteristics. To a considerable extent the same problems are encountered in the course of production of traditional natural gas from small deposits which are buried at great depths. Thus, the main task while geological exploration of subsurface resources sites is maximum localization of prime zones (by different criteria) which ensure commercialization of discovered gas resources and their profitable production with the use of heavy development systems. Fundamental technological solutions concerning commercial development of traditional and unconventional deposits and resources of gas are nowadays alike because the usage of horizontal, multi bottomhole, multilateral wells and technologies of heavy (multi stage) hydraulic fracturing is carried out everywhere but depends on volume of reserves being produced, mining and geological conditions.

World reserves and resources of shale gas are estimated at 16,000 Tcf (450 trillion m^3), which is equal to estimated volumes of gas in coal beds and gas in tight reservoirs [1]. They are more than twice as large as the reserves and resources of conventional gas (208 trillion m^3 [2]).

In 2011 the total resources of shale gas in Ukraine were estimated by the Energy Information Agency (EIA) at 5.6 trillion m^3; 1.2 trillion m^3 of them were considered as recoverable [3]. In the review of 2013 they were increased to 16.2 and 3.6 trillion m^3 respectively [4]. They are associated with deposits of Viseu in the Dnieper-Donetsk depression (DDD) with a total area of 18,000 km^2, low coalfield oil and gas complex, with the depth of 3,000 to 5,000 m and the thickness of 8–70 m [5]. The prospects for the development of unconventional gas in Ukraine are aimed at two primary sites of the Western and Eastern oil and gas regions, namely: Oleska (Lviv region) and Yuzivska (Kharkiv and Donetsk regions) licensed areas. The area of Oleska Basin is more than 6 thousand km^2 and Yuzivska – about 8 thousand km^2. The National Service of Geology and Mineral Resources of Ukraine assesses resources of conventional and unconventional gas in the basins at 7 trillion m^3 [6, 7].

In general, the resources of shale gas in Ukraine can be compared with the unique areas of the Barnett Shale in North Texas; its bearing strata spread to 17 thousand km^2. They lie at a depth of 1,200–1,500 m, their thickness is of 15 to 270 m and their technically recoverable reserves are estimated at 1.2 trillion m^3. The

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resources of shale gas in Ukraine are several times less than the above mentioned reserves of Marcellus Shale with reserves of 11.6 trillion m^3, which extends to 245 thousand km^2 [8].

The presence of huge shale gas areas explains the optimistic predictions about its role in the energy balance of the United States. In 2000, the United States produced 11 billion m^3 of shale gas, or about 2% of the total production of natural gas, after 10 years its share in the annual production was 23% (141.6 billion m^3). In 2035 its share is projected to increase to 49% [7].

Geological risks of shale gas extracting in new areas are rather high. Despite a good geological survey of the Dnieper-Donetsk depression (DDD) and age-old experience of natural gas extraction, the geological success of shale gas develop-ment in DDD is predicted to be low – at 16–20%. In inverse categories of risk it takes into account 50–60% risks associated with insufficient research of shale rocks formations, initial geological exploration of prospective shale gas deposits and a 60% probability of limiting a perspective area during its research [3, 4]. Reliable estimation of recoverable shale gas reserves is possible only after prolonged wells exploitation. For example, in a review in 2012 the EIA lowered the estimation of recoverable reserves of shale gas in the United States to 13.6 trillion m^3, as compared with 23.4 trillion m^3 – the estimation made in 2011. In particular, the assessment of extraction reserves of the Marcellus decreased from 11.6 to 4.0 trillion m^3 [9], although the industrial development of the area began in 1973.

Technical and technological risks associated with the development of shale gas are obviously low. During extraction from unconventional sources, particularly from tight reservoirs and shale gas, compared with conventional natural gas extraction, technical and as a result economic risks are associated with initial low production rate of wells. However, the development of construction technologies of horizontal wells and multiple (multi-stage) hydraulic fracturing immediately after reservoir opening minimizes the problem.

Since 1980, horizontal wells have become an accepted technology of gas resources development, especially unconventional ones. In most cases, the productivity of wells increases 3–10 times compared with vertical wells, and the cost of horizontal wells increases less than twice [10].

The well, which exploitates shale gas deposits as a result of the small drainage area, is characterized by the rapid decrease in flow rate compared to the development of conventional natural gas. Thus, the average “life” span of wells in the Barnet Shale is 7.5 years. Their productivity reduced by 80% in the first three years and thereafter decreases by 8% per year [11]. Antrim wells during their "life" produce from 400 to 800 million m^3 of gas. During water-free production within 6 to 12 months their flow rate is from 125 to 200 thousand m^3 per day. The production peak lasts for two years followed by a falling rate of 8% per year. Wells production is about 20 years [12].

Reserves of shale gas in areas drained by one borehole are a little contradictory according to the experience of the USA. Thus, according to operators of core material analysis, they vary over a wide range from 2 to 10 Bcf (about 60 to 300 million m^3). However, according to calculations based on the actual dynamics of wells discharge, they are twice less and not more than 4 Bcf (85 million m^3) [13]. The authors of the paper [14] emphasize a good descriptive ability of the exponential decline curve with the actual data. Yet the paper [15], which also deals with the analysis of decline curves of well discharge of the same formations, shows that the annual rate of decline decreases in length of time; it is a warning to use exponential curves for predicting recoverable gas reserves. Limited opportunities of the decline analysis for predicting ultimate recoverable reserves are also associated with the difference of results obtained from the decline curves for individual wells discharge or after their grouping and the dependence of results on the approximation method [12].

According to the given data [6] there are about 29 million m^3 of remaining recoverable reserves of shale gas per well in the United States. The authors [16] consider this assessment as a low "minimum." According to their estimations, there are between 45 and 150 million m^3 for one well. These estimations for major shale areas allow us to suggest that there are on an average 100 million m^3 of gas per one well with a standard error of 30%.

We can evaluate the initial well flow rate based on the data [17] obtained for about 4,000 wells. The initial production rate of wells in shale gas areas can be described by a normal distribution with a standard deviation, which is approximately half of the mathematical expectation. The rate can be, in its turn, 115 thousand m^3 per day.

The dynamics of gas well production, including those that exploit shale gas, mainly depends on the reserves that are drained and the productivity (productivity index), and to a lesser extent on the depth of the productive horizons, the initial reservoir pressure, restrictions that may be imposed on the well production rate and operating pressure. In general, the well flow rate is determined by the joint operation of the reservoir and gas lifting system:

$$q_{pl}\left[p_{pl}(t), p_{bh}(t), Ind_{pr}\right] = \\ = q_{lift}\left[p_{bh}(t), p_{wh}(t), L, d, \rho\right], \quad (1)$$

where q_{pl} is the flow from the reservoir, $p_{pl}(t)$ is reservoir pressure, $p_{bh}(t)$ is downhole pressure, Ind_{pr} is productivity index of the well, q_{lift} is output rate of the lift, $p_{wh}(t)$ is wellhead backpressure, L is the length of lifting pipes, d is the diameter of lifting pipes, ρ is gas properties, t is time.

The condition for the joint operation of a reservoir and a gas lift includes the well-known system of equations and is closed by the bond of reservoir pressure in the deposit with accumulated withdrawal.

Current gas reserves $Z(t)$ are associated with the initial reserves Z_0 and accumulated production by a simple correlation

$$Z(t) = Z_0 - \int_0^t q(t)dt\,. \qquad (2)$$

Accordingly, the current reservoir pressure $P_{pl}(t)$ is associated with an initial reservoir pressure and is given by the following correlation

$$P_{pl}(t) = \frac{Z(t)z_0}{Z_0 z_t} P_{pl0}\,, \qquad (3)$$

where z_0, z_t are the coefficients of gas compressibility under the initial reservoir conditions and at time *t*, respectively.

Low reliability of priori geological and engineering information necessary for forecasting the well production, often complete its lack and only approximate calculations require a sensitivity analysis of the forecasting results to the output parameters.

An effective method of evaluating the results of forecasting and risk assessment is a method of statistical tests, which is often called as Monte Carlo method. The method analyzes the statistical characteristics of the process obtained as a result of a large number of attempts with output parameters that vary because of the accuracy of their determination [18].

In case of application of equations, the parameters, which can posteriori significantly differ from the priori ones and, therefore, lead to significant difference between the forecasted and actual results, are the following: estimated gas reserves, the expected depth of the reservoir, the expected reservoir pressure, which is conveniently set by the ratio of anomality with respect to the hydrostatic pressure, and well productivity, which in its turn is expediently calculated according to the initial flow rate at a known buffer pressure at the wellhead.

Based on statistical estimations of the initial wells production rate and reserves attributable to one well, received based on the experience in shale gas development in the United States, we performed stochastic simulation of individual well by Monte Carlo method, the depth of which with probability of 80% is between 3,000 and 5,000 m and the anomaly coefficient of formation pressure with the same probability is between 1.0 and 1.8.

Fig. 1 shows the results of stochastic modeling of individual well production rate and accumulated gas from it. The results should be interpreted as follows: with the probability of 90% the values are not lower than the level of P10 and with the same probability they do not exceed the level of P90. So, for example, it is expected that the accumulated production from one well is approximately within 50–130 million m^3 with probability of 80%.

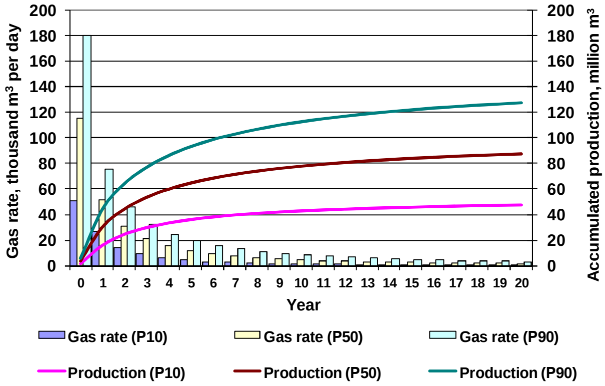

Figure 1 – Dynamics of the average monthly daily output of a well and the accumulated gas production based on the stochastic modeling

An essential part of the technological risks of shale gas production is a large amount of water required for drilling and hydraulic fracturing. The volumes of processing fluids comprise from 7.5 to 20 thousand m^3 of processing water necessary for hydraulic fracturing in the same horizontal well [19]. In overall there are consumed about from 1 to 2 m^3 of water for production of 1000 m^3 of shale gas [20]. Thus, in 2000 there was used about 13.6 million m^3 of water or 1.3 m^3 – for 1000 m^3 of extracted gas in Marcellus area [21]. Such volumes of water usage require relevant sources, means of their preparation, reuse and recycling. In monetary terms, if a gallon costs 12 cents, the processing and recycling of water for hydraulic fracturing cost approximately 360,000 USD per hole [22]. Low reserves of one well during unconventional gas extraction, are explained by the rapid drop in well flow rate over time (Table 1).

Financial risks are the most important for making decisions about investing in the development of unconventional gas reserves, including shale gas. They are directly related to the level of gas production, capital costs for drilling and equipping them, and the current costs of production and the selling price of gas.

Assessment of financial risks is carried out in terms of the probability of obtaining beneficial discounted payback period (DPP) and internal rate of return (IRR) using the method of discounting of future cash flows and calculating key indicators of economic efficiency of drilling and gas production from an averaged well. The level of probability of any rate is calculated using a stochastic simulation by the Monte Carlo method.

Table 1 – The annual fall of the flow rate (%) at the beginning of the year relatively to the previous year

Probability	Year							
	1	2	3	4	5	10	15	20
P10	58.0	45.9	38.9	33.1	29.1	17.0	12.2	9.4
P50	55.7	40.1	32.1	26.9	23.3	14.1	10.2	8.1
P90	47.7	38.5	29.7	25.1	21.1	12.9	9.6	7.5

To calculate the cash flows there is used a dynamics in gas production from a well (Fig. 2) and it is obtained by stochastic modeling.

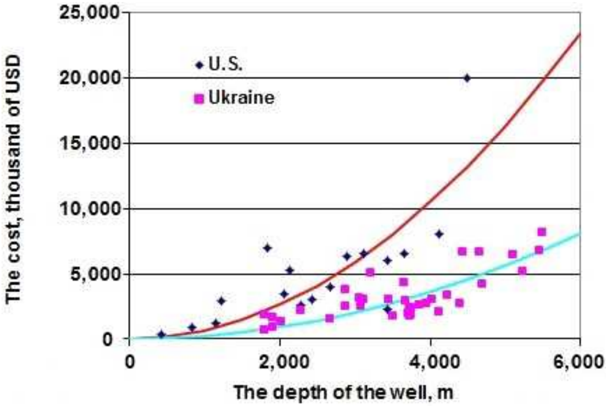

Figure 2 – The change of wells cost with their depth

Capital costs for gas production, including unconventional gas, can be divided into costs associated with the construction of a well, its equipment, intra-industrial arrangement for the preparation and transportation of gas to consumers.

The cost of wells primarily depends on their depth. Fig. 2 shows the data on the average cost of shale gas wells in the United States [23] and some gas wells in Ukraine. For estimation of wells cost we can use a regression formula:

$$WellCost = CostCoeff \cdot Depth^2 \quad (4)$$

where *WellCost* is the cost of well construction, thousand UAH, *CostCoeff* is a coefficient of wells cost, thousand UAH/m^2, *Depth* is the depth of a well, m.

In the USA terms the cost coefficient is estimated as $6.53 \cdot 10^{-3}$, and in Ukraine terms – $2.25 \cdot 10^{-3}$ thousand UAH/m^2. Taking into account the constant tendency of price rising of wells and their approaching to the world level we assume in the projected calculations of wells cost that the upper 80% limit factor for Ukraine is $3.5 \cdot 10^{-3}$ thousand UAH/m^2 with a standard deviation of $3.5 \cdot 10^{-4}$ thousand UAH/m^2.

The cost of the well equipment and well intra-industry arrangement are significantly lower than the costs for drilling and similarly to conventional gas production they may be summarily assessed in the range of 750–950 thousand UAH.

An additional and essential component of investment in shale gas production is the cost of hydraulic fracturing to intensify the flow. These costs vary widely depending on the conditions. Thus, when the total costs of wells in the Barnett area are in the range of 750–950 thousand USD, the costs for intensification are 350–450 thousand USD [24]. For the Bakken area the total cost of wells is from 8 to 10 million USD, including 1.5 to 2.5 million USD – the cost of hydraulic fracturing [25]. It was projected in 2012, that there would be spent more than $ 7 billion USD on hydraulic fracturing in 1770 new wells [26], or almost 4 million USD per a well. Further for the stochastic simulation we assumed that the costs on intensification of inflow with 80% probability were within 12–20 million UAH[1].

Operating expenses for shale gas production, according to multiple operators, are estimated on average at 1.50 $/net Mscf (340 UAH per 1,000 m^3) and their semi-variable component is $ 0.75/net Mscf (170 UAH per 1,000 m^3) [23], which is about two times higher than during natural gas production in Ukraine.

The mathematical expectation of the conditional and constant component of operating costs during the stochastic simulation is taken as 175 thousand UAH per well per year, and the conditional variable – 65 UAH for extraction of 1000 m^3 of gas, with a standard deviation of 10% mathexpectation and normal distribution.

There is adopted a normal distribution with a mathematical expectation as a discount rate of the National Bank of Ukraine in 2012 of 7.5% with a standard error of 0.5% for the discount rate.

Depreciation, regulations and rates of the required taxes in mining on the territory of Ukraine are in accordance with the Tax Code of Ukraine [27].

The most significant risk factor in the system of economic assessments is the unpredictability of gas prices in the long run. On the one hand the high price for natural gas is an incentive for wide operations of unconventional gas extraction, on the other hand the large volumes of gas from new sources change the conjucture of prices of other energy sources. So it is believed that the rapid growth of shale gas in the United States led to a collapse in market prices of the same gas. The peak price for natural gas in 2005 at the Henry Hub at the intersection of nine interstate pipelines and four national in southern Louisiana was about $14 per thousand cubic feet, and in 2011 fell to $ 3.88, in 2013 – $ 3.50 per thousand cubic feet (respectively, $ 494, $ 137 and $ 125 per thousand cubic meters) [28].

Fig. 3 shows the comparative dynamics of some natural gas prices. In particular, the dynamics of the average export price from the Russian Federation [31], the CIF price in the European Union, the United Kingdom on a virtual gas hub (NBP Code) [32], the price of Russian gas at the German border [33], the price for industrial companies in Ukraine, as well as the Baker Tilly forecasting (2012) of the Russian gas price for Ukraine by two scenarios [32].

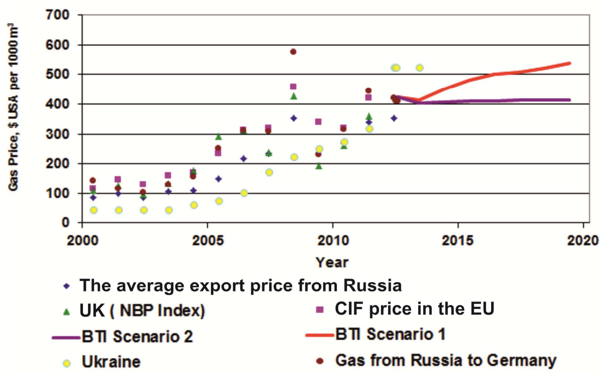

Figure 3 – Dynamics of natural gas prices in Europe and Ukraine

[1] Here and below we use the exchange rations 1 USD = 8 UAH

Overall, despite significant downward fluctuation of prices related to the financial crisis of 2008, there is a steady rising trend in wholesale prices for natural gas in the European market.

In Ukraine, despite the general trend of world gas markets, gas price remains high and there are no trends to decrease. In addition, the legislative obligations of public companies, which account for over 80% of domestic production and sell household gas at regulated tariffs, inhibit the rate of development of promising new projects. Consequently, the prices of gas in Ukraine can decrease for a short period, and in the long run based on actual dynamics we can expect their increase.

In the first phase there is evaluated the sensitivity of techno-economic model to the input parameters. This assume that the selling price of gas, as a random variable, is normally distributed with expectation of 3,500 UAH per 1,000 m^3 with a standard error of 700 UAH per 1,000 m^3. This is equivalent to the expectation that the price of gas will be in the range of 2,200 to 4,800 UAH per 1,000 m^3 with the 80% probability.

Based on the example of the payback period and internal rate of return Fig. 4 shows the values of correlation coefficients and the share of the results to the overall variation for the most important factors of techno-economic model. These figures can be interpreted as differentiation of technical and economic risks according to the individual factors. Correspondingly, in descending order the main risks are associated with: the selling price of gas, natural gas reserves attributable to a well, depth of deposits, which mainly determines the cost of wells and the initial production rate of wells. They account for 97–98% of risks.

Further, considering the impossibility of forecasting the future dynamics of gas prices with a specified precision, measurement of financial risks of shale gas development is made based on the average selling price of gas in the coming period.

The results of the stochastic simulation by Monte Carlo method of evaluation of financial risks of shale gas development based on accepted technical and economic assumptions are shown in Fig. 5 as a relation of probability of obtaining certain levels of internal rate of return (IRR) and payback period (PBP) with an average price of gas in the coming period.

If we assume that the internal rate of return greater than 20% can be considered as favorable for the project, then receiving it with high probability (Fig. 6) is possible in the future while maintaining the current natural gas prices for industry – more than 4,000 UAH per 1,000 m^3. A similar conclusion may be reached by the results of calculating the payback period of a well (Fig. 7). At this price the probability of acceptable payback period of less than 5 years is estimated at more than 80%. For payback period of 1–3 years, as a strong indicator of economic efficiency of the project [33], the probability higher than 50% is in the range of prices greater than 3,500 UAH per 1,000 m^3.

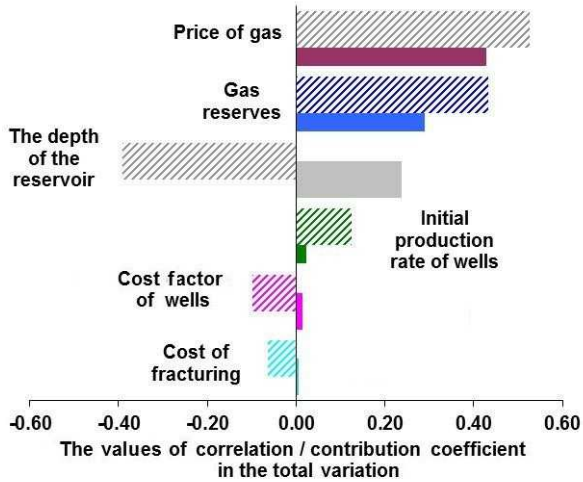

Figure 4 – The tornado diagram of IRR values sensitivity to major risk factors (primed bars - correlation coefficient, solid fill – the contribution to the total variation)

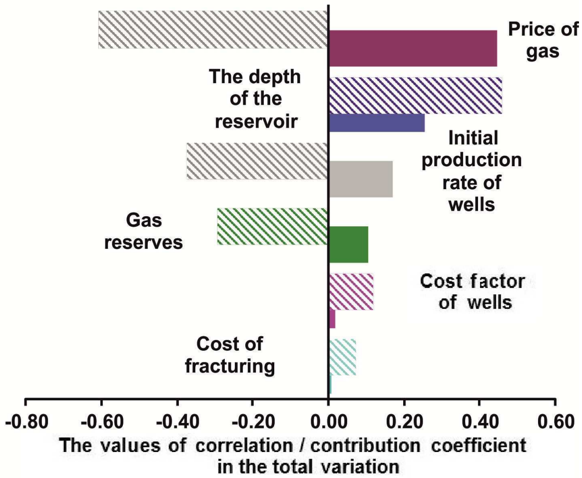

Figure 5 – The tornado diagram of sensitivity of discounted payback period to the major risk factors (primed bars – correlation coefficient, solid fill – the contribution to the total variation)

Conclusions

Thus, the presence of promising gas-bearing objects with significant unconventional gas resources requires a complex, multifactorial and systematic study during preparation and exploration work. The practice of study of unconventional gas resources in the United States and Europe showed that preliminary estimates were not confirmed by the actual data and technical and economic feasibility of extraction.

Certainly, geological risks are the most important and the least predictable because it is not possible to confirm or refute the assessment of unconventional gas resources without making exploration work, as opposed to technical, technological and financial indicators.

Technologies of seismic studies are of a special importance for the reduction of the impact of geological risks. These technologies can detect and locate the most promising areas of gas generation and accumulation

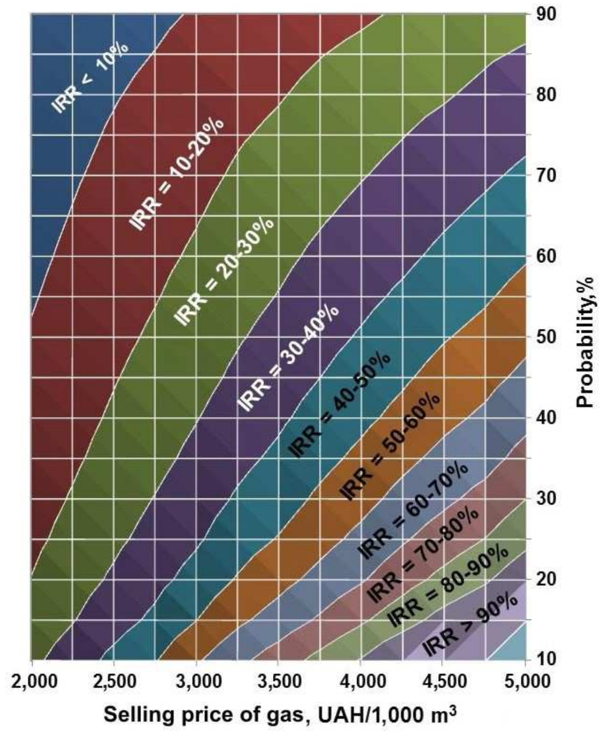

Figure 6 – The probability of recipience of a given internal rate of return according to the selling price of gas

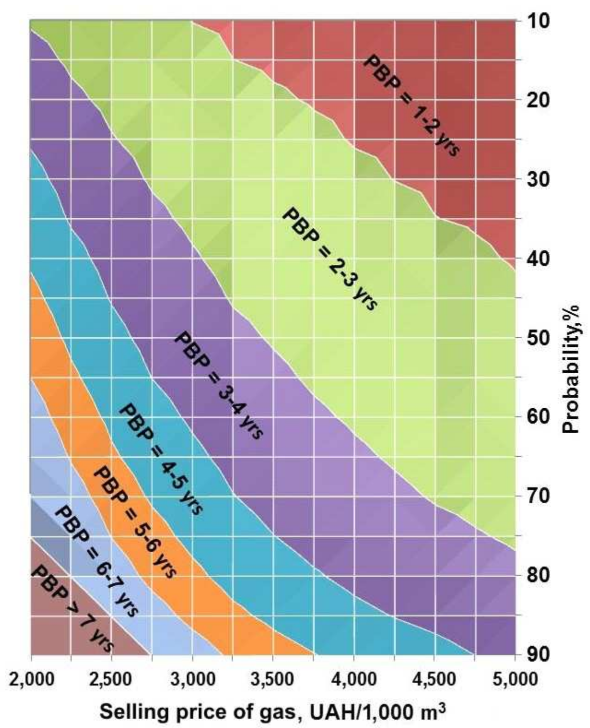

Figure 7 – The probability of recipience of a given payback period according to the selling price of gas

both by structural conditions and characteristics of shale gas and the surrounding rocks thinning. Therefore, further evaluations and calculations of technical and technological, financial and economic indicators and risks are possible based on the localized zones of gas accumulation.

Due to the presence of large perspective gas-bearing objects with inferred resources of unconventional gas in the Eastern and Western oil and gas regions of Ukraine it is necessary to prepare them for exploration work at the initial stage of their geological study. First of all, it is required to make geological and geophysical, geological and industrial database based on the available material on previously drilled wells (parametric, search, etc.). This will help to identify at this stage the most promising oil and gas complexes and their distribution within the oil and gas regions and examine the technical and technological aspects and problems associated with the development of unconventional gas resources.

In order to further effective development of unconventional gas resources it is advisable to examine the technical and technological risks, because well productivity is one of the most important factors of commercialization of such a project. If financial risks can be managed and minimized during implementation of the project, productivity of a well will depend on filtration-capacitive reservoir characteristics, depth and technical and technological implementation possibilities of technologies that provide high flow rates for a long period of its operation. In this aspect, one needs to make laboratory and industrial researches in similar geological conditions, as domestic companies are engaged in the development of gas fields with clay collectors, such as East Poltava and Zaluzhanske fields.

In addition, the technological risks also include provision with water resources the manufacturing operations, carried out in the initial stage according to the intensive graphics. It is advisable to study the options for the use of technical waters of liquidated mines in areas where such facilities are near.

As we can see from the simulation results the financial risks are determined by two factors: the selling price of gas and fiscal system in the sphere of extraction of hydrocarbon resources.

According to the first factor the most favorable condition for the development of gas resources in Ukraine is one of the highest gas prices in the world. Taking into account the current pricing trends and projections in Europe, gas price will not reduce significantly in the next 10 years according to the current balance of transport capacities. In case of modifying the imported gas flows to Europe and increase of its volumes by the United States, there will be a redistribution of growth in the share of gas consumption in the Asian sector, where the economies of China, India, Malaysia and other countries grow.

The second important factor is the fiscal system that needs optimization and transition to global principles of taxation and return of capital expenditures to investor. In this case, reimbursement of capital in the form of depreciation slows the return of current financial resources by increasing the tax burden on investors and reducing the profitability of the project.

To improve the efficiency of resource projects in Ukraine it is necessary to change the tax and fiscal policies in order to increase working capital of the oil and gas companies for reinvestment in oil and gas development as well as development of flexible pricing mechanisms for hydrocarbon resources for avoiding their sharp fall.

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Оцінка техніко-економічних ризиків видобутку з нетрадиційних покладів газу в Україні

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Розроблення покладів нетрадиційного газу вимагає особливих техніко-технологічних засобів і супроводжується різноплановими підвищеними ризиками. Відсутність практичного досвіду і, відповідно, надійних даних про умови розвідування і видобування вимагає комплексного техніко-економічного підходу до оцінки ступеня ризиків освоєння ресурсів нетрадиційного, зокрема сланцевого, газу в Україні. Широкий досвід видобутку газу з нетрадиційних джерел, в основному сланцевого газу, надбаний у США, може бути екстрапольований і в кількісну оцінку відповідних ризиків в Україні, з урахуванням її геолого-технологічних умов, економічних чинників і фіскальної системи.

Стохастичне моделювання із застосуванням методу Монте-Карло показало, що геологічна частка ризиків, пов’язана з обсягами видобувними запасами газу, оцінюється в 22–25%, технічні ризики, пов’язані з початковим дебітом свердловин, складають 2–17%. Фінансові і економічні ризики, пов’язані з вартістю буріння свердловин, зумовлених у першу чергу їх глибиною, оцінені 23–25%. До 45% ризиків визначаються ціною реалізації газу. Кількісне ранжування ризиків дає можливість визначити пріоритетність напрямків із підвищення ступеня комерціалізації проектів видобутку газу з нетрадиційних джерел, зокрема зі сланцевих покладів.

Ключові слова: *видобуток, метод Монте-Карло, ризики, сланцевий газ, стохастичне моделювання.*