Distinctive Features of Shale Hydrocarbons Development in the United States

(on the example of formations Bakken, Eagle Ford, Barnett, Haynesville, Fayetteville, Marcellus)

M.P. Yurova
Oil and Gas Research Institute of the Russian Academy of Sciences, Moscow, Russia

Abstract. The article provides a brief description of the major shale hydrocarbon formations in the US. The methods are shown to develop shale fields: multiple vertical horizontal drilling, multi-stage hydraulic fracturing using inflating packers. The influence of shale development on the environment is considered. The article emphasizes importance of the hydraulic fracturing drainage volume and density of reserves distribution. By means of production decline curves the authors define hydrocarbon reserves both extracted and remaining in the deposits. The 'productivity of wells' parameter determines the required number of additional wells to extract the remaining reserves. Average cost of drilling and development of wells is given.

Keywords: major formations, methods of development, well price for multiple vertical horizontal drilling and completion of wells, production curves, well productivity, technically recoverable reserves
DOI: 10.18599/grs.18.1.7

For citation: Yurova M.P. Distinctive Features of Shale Hydrocarbons Development in the United States (on the example of formations Bakken, Eagle Ford, Barnett, Haynesville, Fayetteville, Marcellus). *Georesursy* [Georesources]. 2016. V. 18. No. 1. Pp. 38-45. DOI: 10.18599/grs.18.1.7

The main tasks for the further development of shale hydrocarbons in the US are improving the quality of cost-demanding horizontal drilling and multi-stage hydraulic fracturing, and methods of environmental protection. Solution to these problems will increase areas previously inaccessible for drilling.

Currently, well drilling and testing for shale hydrocarbons (HC) includes both vertical and horizontal wells. Both types of wells provide fixing and cementing to isolate aquifers during fracturing of shale formations (Fig. 1). According to specialists, when extracting shale hydrocarbons, amount of water will be 0.1% of the total amount of water used for domestic purposes in the area of drilling (Modern Shale Gas, 2009).

In order to minimize the amount of water injected in fracturing, it is purified and injected again.

Horizontal drilling promotes greater formation disclosure than vertical one. The main difference between the modern development of shale hydrocarbons from conventional oil and gas production is in the extensive use of horizontal drilling and hydraulic fracturing. Cluster drilling of multiple horizontal shafts from one vertical well reduces the impact on groundwater and the terrestrial environment, reduces the number of driveways and roads, easier arrangement of the territory and transportation of raw materials. In order to prevent leakage of fluid from the well into the soil and groundwater, methods such as multicolumn wells and heavy-duty materials during cementation are applied during fracturing.

In multistage fracturing proppant fills the induced fractures, consisting of 99.5% water and sand, and 0.5% of various chemical additives, which increase the efficiency of operations to create fractures (Fig. 2).

An effective mean is environmental monitoring, including thermal, gamma spectrometry, gas and aerosol survey and radiation control (Modern Shale Gas, 2009).

In spite of the vast reserves of natural gas in the United States, the rate of its consumption is significantly increased. That is why unconventional resources (shale hydrocarbons) can significantly replenish reserves.

Another feature of shale is high density of reserves per area unit, which can reach 36 million tons/km^2 (Bunger, Growford, 2004).

Analysts say that in recent years the growth of reserves from 50 to 60% is associated with unconventional gas (Fig. 3). Total recoverable gas resources from four shale fields ('plays'): Haynesville, Fayetteville, Marcellus, Wood Ford may be 15.7 trillion m^3 (Modern Shale Gas, 2009).

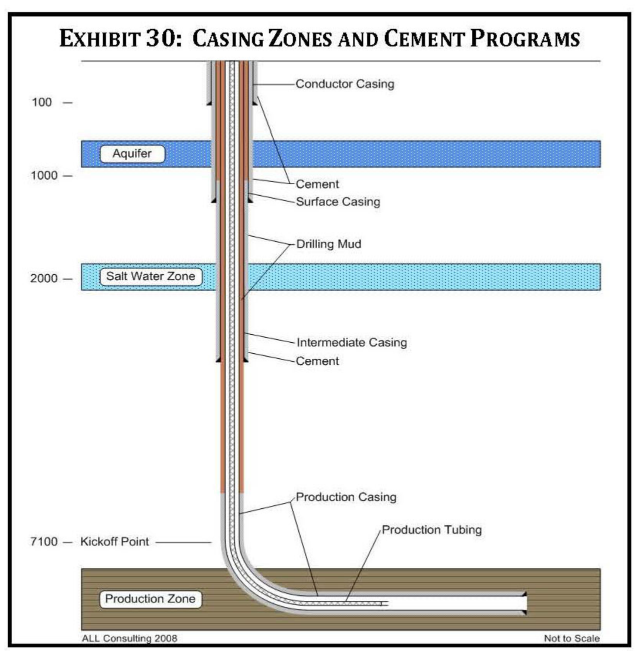

Fig. 1. Areas of well casing and cementing (Source: Ground Water Protection Council and ALL Consulting 2009).

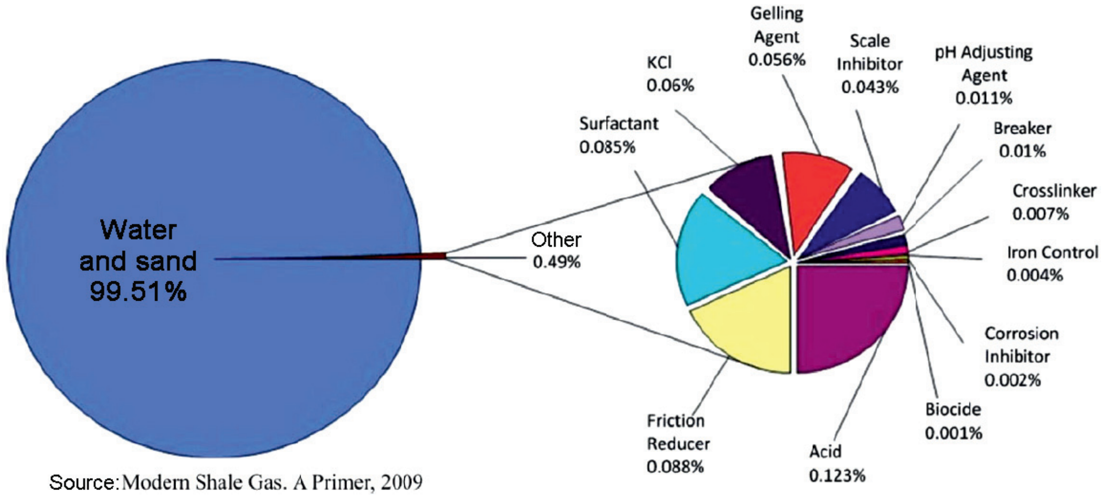

Fig. 2. Volumetric composition of the fluid in hydraulic fracturing.

These areas are provided with infrastructure of natural gas, and this simplifies the task of delivering raw materials to the consumer. However, in general, only 5-20 % of shale hydrocarbon can be extracted from the reservoir, unlike 50-90 % of conventional oil and gas. With the aim of improving economically and environmentally efficient production, new technologies of horizontal drilling and completion (testing) of wells have been developed, such as staged and multiple fracturing.

Thus, in the Barnett formation at the stage of completing in the newly created (induced) fracture 3% HCl is added to create a matrix fracture, which increases the inflow. In addition, it is common to conduct re-fracturing, which can significantly increase the recoverable gas reserves.

Shales are thin sheets of rock and often connected through natural fractures with higher and lower layers, and lateral hydraulic fracturing does not always reveal the full reservoir thickness. Therefore, it is required to apply such techniques that would define porosity, water saturation, and relative permeability in each layer in order to assess the possible production costs.

Microseismic logging survey is innovative technology that determines the nature of induced fracture. It allows us to determine the nature and distribution of the reservoir drainage after fracturing. Microseismic monitoring is a method for monitoring of hydraulic fracture as it moves laterally to formation. Thin layers do not serve only as the storage of oil and gas but also transport hydrocarbons from oil shale to a well. Determination of drainage area (after fracturing) in the fields of shale hydrocarbons is one of the most important aspects of the studied ‘plays’ and shale resources. Parameter of drainage area for one well will determine the number of wells. Experience in the Barnett shale shows that drainage area after fracturing is only 1/4 of the intended spread scope of the induced fractures (Bunger, Growford, 2004).

Fluid drainage depends on the permeability of shale, the presence and distribution of highly permeable aleuropelitic layers and efficiency of induced cracking. Drainage area when drilling vertical wells for shale gas is usually less than when drilling horizontal wells. Thus, the drainage area of shale in Fayetteville, Arkansas is close to Barnett shale and for vertical wells is 2-8 ha, and for horizontal wells is from 7.2 to 24.8 ha. At the same time, with a small area of productive strata distribution in the Antrim formation it is more and is 16-32 hectares (Bunger, Growford, 2004). Therefore, improvement of drilling and well completion methods may generally increase the fluid extraction per well at the same drainage area.

In the US there are 13 shale formations developed. Six of them (the Bakken, Eagle Ford, Barnett, Haynesville, Fayetteville, Marcellus) are the main suppliers of shale oil and gas in the total production volume in the United States (Fig. 4).

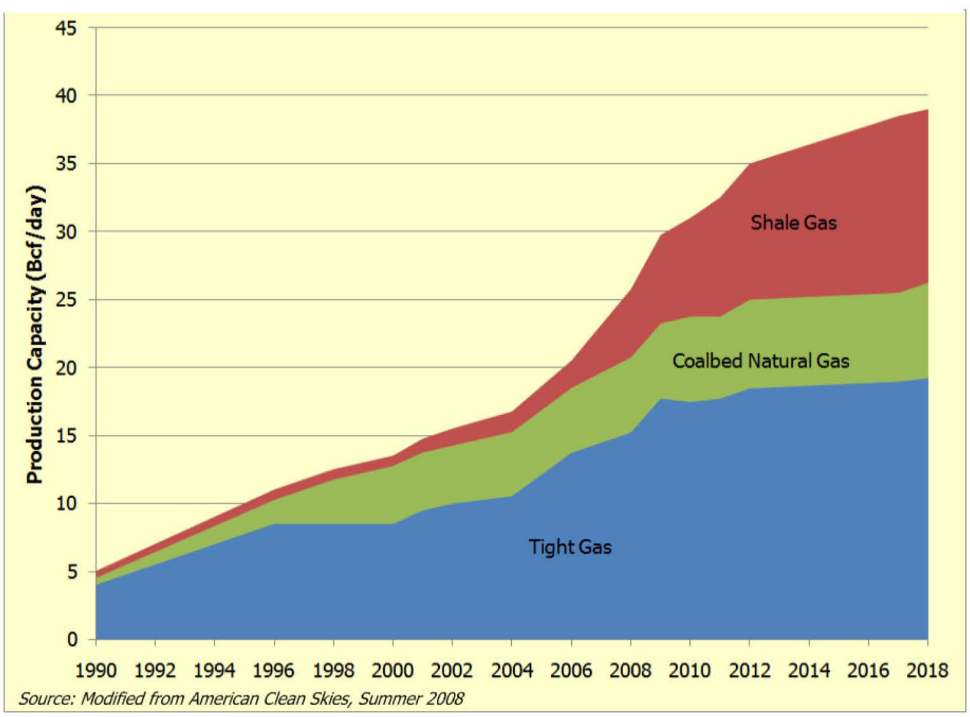

Fig. 3. The composition of unconventional gas in the United States.

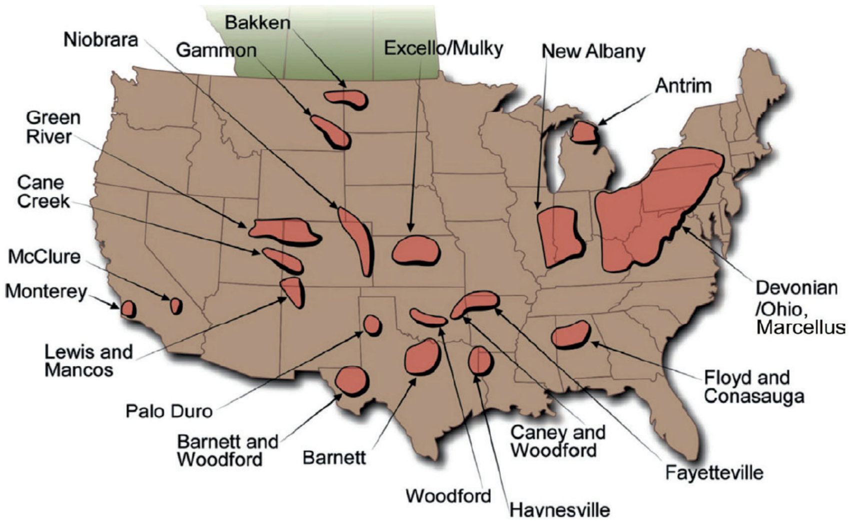

Fig. 4. The US shale formations (Collins, 2008, with amendments).

Formations Bakken and Eagle Ford account for 75% of shale oil produced in the country. 83% of shale gas is extracted from four formations: Barnett, Fayetteville, Haynesville and Marcellus. The Marcellus formation includes the biggest gas reserves. In 2013, 95.9 billion m^3 of gas was produced from this formation, and production continues to grow (Sandrea, Sandrea 2015).

Let us briefly discuss the main parameters of each favorite shale oil and gas.

Oil shale formations

1. Bakken Formation (Fig. 5) was discovered at the border of the United States and Canada. In the US, this formation is spread over an area of 300 km^2 (the states of South and North Dakota). Formation age: Upper Devonian – Lower Carboniferous.

It consists of three packs:

- Upper Bakken – black marine shale, thickness of 7 m;
- Central Bakken – interbedded dolomite, limestone, mudstone and aleuropelites, thickness of 26 m;
- Lower Bakken – black marine shale, thickness of 15.2 m.

The first drilling in the Bakken formation began in 1953 in the field Antelope. In 2000 hydraulic fracturing was used. In 2010, on an area of Elm Coulee 6.5 million tons of oil and 0.7 billion m^3 of gas were produced from 400 horizontal wells. In North Dakota, oil production is carried out from the Central Bakken. In 2011, North Dakota peak production was 144 bbl / day (3275 wells), in 2013 836 bbl / day was produced (6824 wells). To maintain production by 2020, 11208 well are required.

Hydraulic fracturing (up to 40 stages) is performed using continuously inflating packers. For the purpose to enhance oil recovery from shale formations an experiment is conducted on injecting carbon dioxide and water vapor into formation. In 2011, the company Slawson realized fracturing of 40 stages over two days (Paula Dittrick, 2011).

Bakken Shale is the discoverer of oil shale and ground to prove the effectiveness of the multi-stage fracturing.

In 2008, the US Geological Survey has estimated resources of the Bakken formation at 580 billion tones of oil, 53 billion m^3 of gas and 23.5 billion tons of condensate (Modem Shale Gas, 2009).

Judging by the statistics of the North Dakota, oil production has continuously increased from 4.4 million tons in 2008 to 8.0 million tons in 2009 and 13.6 million tons in 2010. According to the company JHS, for two years oil production has increased to 20 thousand tons/day or 7.3 million tons/year (Nick Snow, 2011).

2. Eagle Ford Formation (Fig. 6) was discovered in 2008 on the coast of the Gulf of Mexico. Reserves of the formation according to the company JHS are estimated at 0.32-1.43 billion tons of oil and condensate and 1.14 trillion m^3 of gas (EOG sees Eagle Ford Shale ..., 2010).

Eagle Ford Shale lie at a depth of 3500 m and have a high temperature. Thickness of shale is 30-100 m, 76 m in

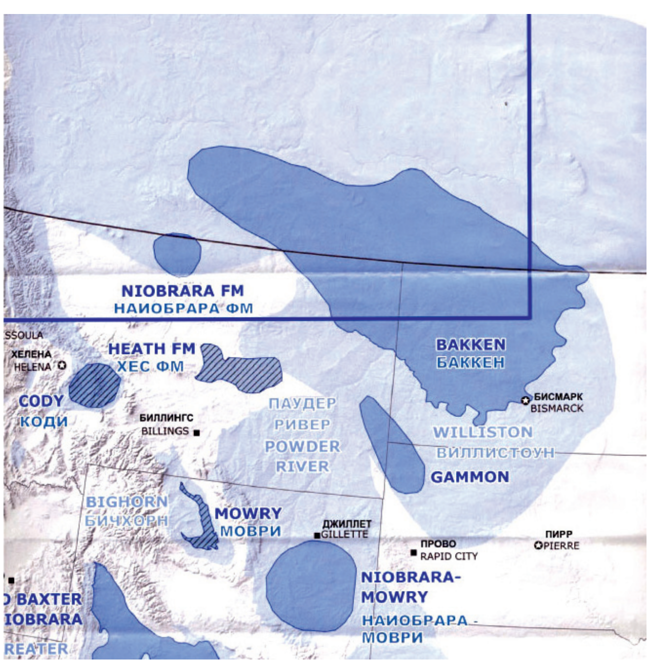

Fig. 5. Bakken Formation (Oil and Gas Journal, Sept. 5, 2011).

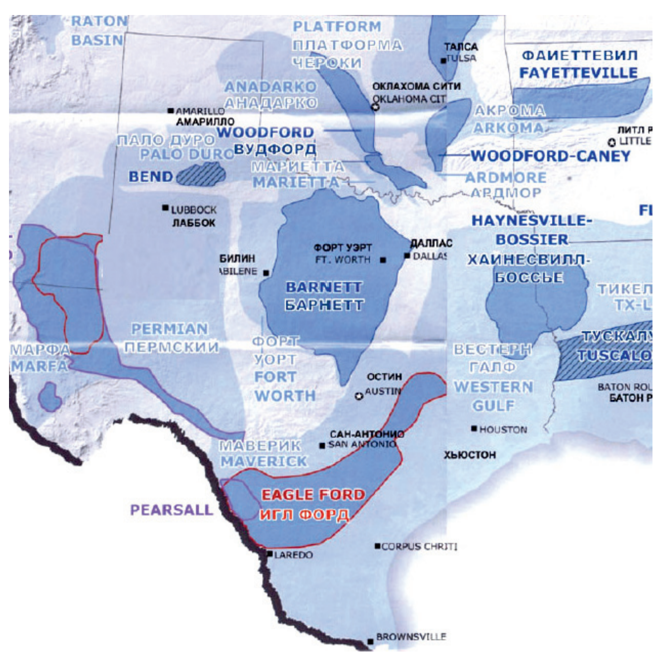

Fig. 6. Eagle Ford Formation (Oil and Gas Journal, Sept. 5, 2011).

average. The porosity is of 9%. Depth of deposit is 3200.4 m. The pressure in the reservoir is 514.5 atm (Ursula Hammes et al., 2011).

Exploration of the formation began with the development of a well Briscoe G-1H. The depth of 2875 m, horizontal wellbore of 986 m, testing 7 days, 10 stages of hydraulic fracturing, the well cost of $ 5.2 million (drilling, coring, logging and microseismic monitoring of fracturing) (Ursula Hammes et al., 2011).

Gas shale formations

1. **Barnett Formation** (Fig. 7)

Operation is carried out from 1981 by vertical wells. The first horizontal well was drilled in 2002. The name of formation is associated with the Barnett River, where in the XX century black shale, rich in organic matter, which age was defined as Upper Mississippian (Upper Permian), have been described. The peculiarity of the formation is in increased fragility, partly due to the high content of aleuropelitic and silt layers. The depth is of 1980 to 2590 m. The Barnett Shale is black with increased radioactivity.

The thickness is of 60-90 m (the most enriched in organic matter are 15-30 m). Content of organic carbon is 1.0-4.5 %, the porosity of 1-6%. The adsorbed gas is about 20%. Recoverable reserves are estimated at 570 billion m^3 (Sandrea, Sandrea 2015). In 2008, 7170 wells were drilled on the Barnett shale. By 2010, the number rose to 11800 wells. Coverage by fracturing is from 32 to 64 hectares. Reservoir pressure is increased. The cost of drilling and completing a well is $10 million. (Modern Shale Gas, 2009).

The main shale gas extraction technology is cluster drilling of vertical and horizontal wells with multistage fracturing using inflating packers, allowing to push the equipment along the stratum.

2. **Haynesville Formation** (Fig. 8)

Black shale of Haynesville is distributed in the states of Texas, Louisiana and Arkansas. Some wells penetrate formation Haynesville together with the overlying shale Bossier. Shale was formed in the Late Jurassic (Late Cimmerian). Higher resistance and higher radioactivity distinguish it From Bossier shale. Reserves comprise 7.17-8.50 trillion m^3 (the largest in the US and fourth in the world) (Modern Shale Gas, 2009). Distribution area is 23.3 thousand km^2. The depth is of 3200-4115 m. Reservoir pressure is abnormal - 1400 atm. The thickness of the gas-bearing black shale is 44-122 meters. Content of organic carbon is 3-5%. It is characterized by a high initial production rate of 286-571 thousand m^3/day. The maximum production rate was 857 m^3/day (Tsvetkov, Tsvetkova, 2012). The first well was drilled in 2005, and the first significant inflow of gas was received in 2008. In 2010, 1798 drilling units had been already operating. Cost of one well is $7-10 million. Due to the cluster drilling costs decreased from $15.6 to 9.0 million. One hydraulic fracturing covers an area of 32 hectares. Usually up to 11 stages of fracturing are applied (the company En Cana).

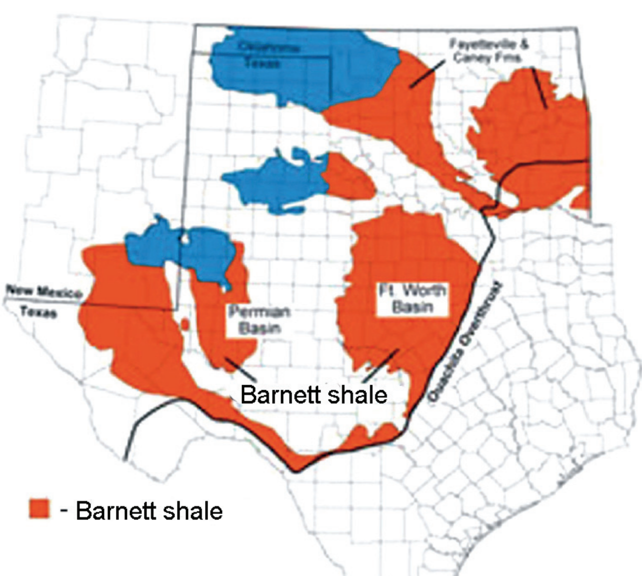

Fig. 7. Distribution of Barnett shale in Texas (United States Geological Survey, 2010).

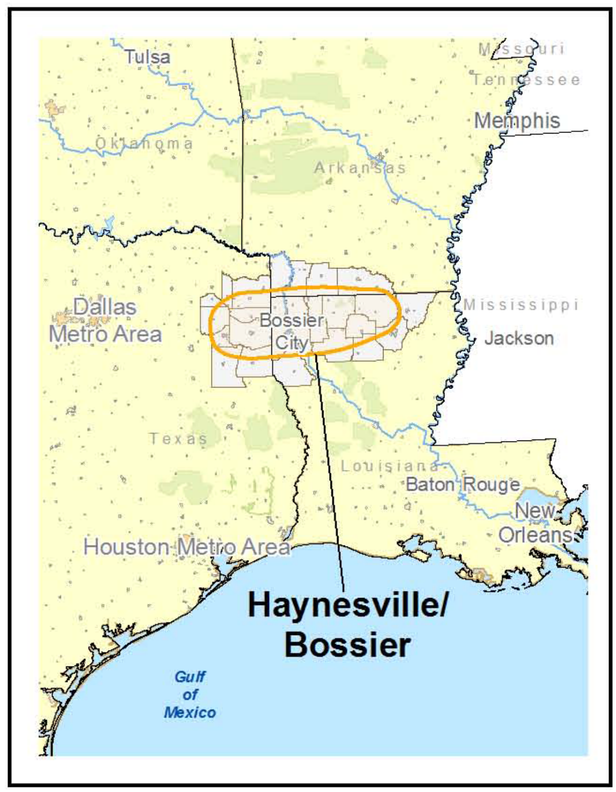

Fig. 8. Haynesville Shale Formation in Texas and Louisiana.

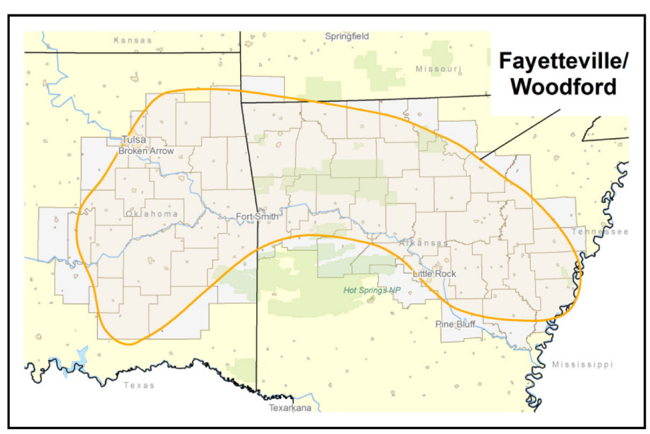

Fig. 9. Fayetteville Shale Formation in the Arkoma basin.

 Georesursy [Georesources]. 2016. V. 18. No. 1. Pp. 38-45

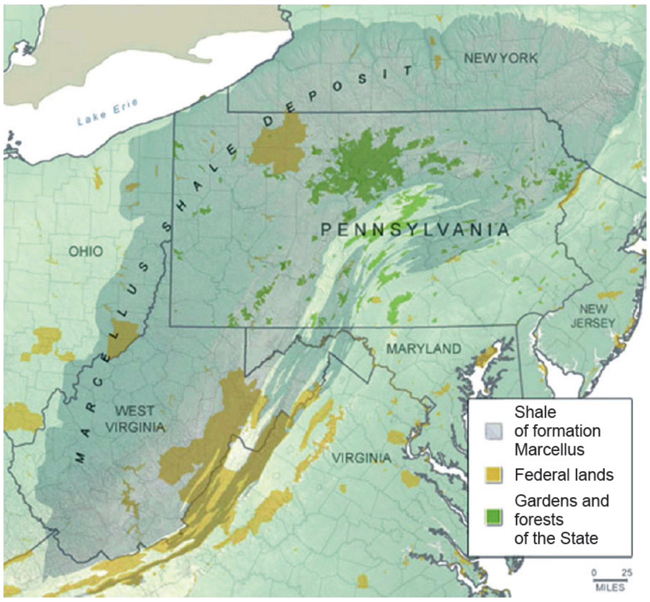

Fig. 10. Distribution of Marcellus Shale Formation (National Geographic, 2010).

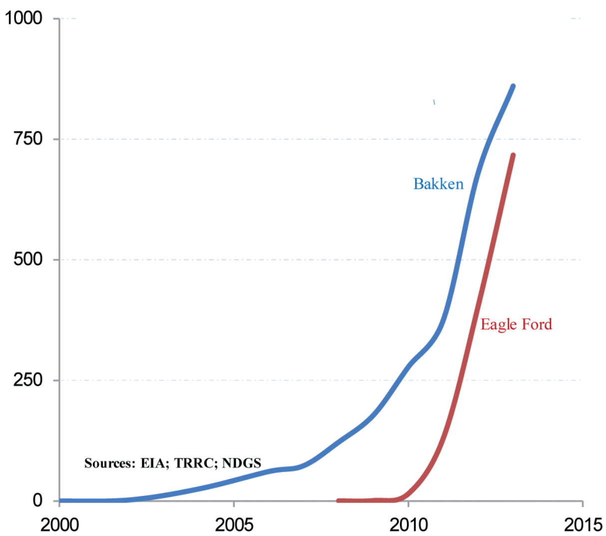

Fig. 11. Production of shale oil in the US major formations.

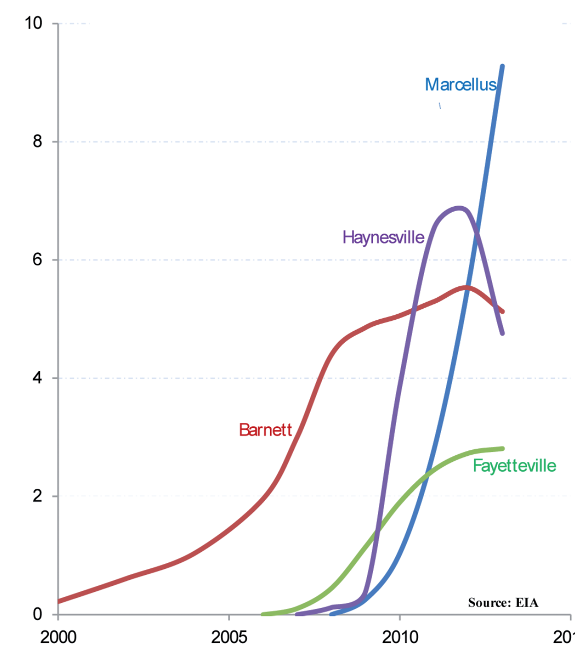

Fig. 12. Production of shale gas in the US major formations.

Recently it was revealed that Haynesville shale in Louisiana might have the recovery ratio of 30% (Sandrea, Sandrea 2015).

3. **Fayetteville Shale** (Fig. 9)

It is distributed in the Arkoma basin in the North Arkansas and eastern Oklahoma. The depth is of 305-2135 meters. Age of deposits is Lower Carboniferous. Development began in the 2000s. The experience was used of the development of Barnett shale. Distribution area of Fayetteville shale is 9 thousand m^2 (twice more than the Barnett shale). The gas content is 1.7-6.3 m^3/t, less than the Barnett shale (8.57-10.00 m^3/t). From 2005 to 2014 the number of wells drilled increased from 49 to 761 wells. The reserves of shale gas in Fayetteville according to the University of Texas assumed at 330 million m^3/km^2 (Modern Shale Gas, 2009). In August 2014 they estimate was 250 billion m^3 (Sandrea, Sandrea 2015).

4. **Marcellus Formation** (Fig.10)

The biggest object of exploration for shale gas (Modern Shale Gas, 2009). Lithologically it is an alternation of gray and black shale. The total content of organic carbon in gray shale is less than in black. Fracturing of black shale is higher than the gray. The depth of the productive rocks varies from 10 to 1524 m. Thickness is 150-170 m. The total porosity is of 2-5 %. The adsorbed gas is up to 50%. The experience of developing shale Barnett in Texas is used. Drilling began in 2005, and the first shale gas was received. Total organic carbon content is of 4.7%, which reflects its maturity. Predictive estimate of gas reserves was made in 2008. It equals to 143 trillion m^3. This amount could provide gas supplies to the US for 2 years (Modern Shale Gas, 2009). During development it was found that the productivity of gray shale is 3.5 higher than of black shale due to increased collection area (16-64 ha). Now Marcellus shale reached the first place in production in the United States. In 2013, 95.9 billion m^3 of gas was produced (according to EJA). Production is growing. At the end of 2014 the number of production wells was 10369. Estimated ultimate recovery (cumulative production and reserves that can be produced for the entire period of operation) at the end of 2014 is 3.964 trillion m^3 (Sandrea, Sandrea, 2015).

Despite the fact that 'shale boom' brought the United States into first place in the world in production of natural gas, and oil production since 2008 increased from 250 to 400 million tons/year, investments in the energy sector over the past 10 years were not high enough. According to the Oxford Institute, published at the end of 2014, investments decreased by 15% (Sandrea, Sandrea, 2015). When investing in shale, investors receive profit only after 3-4 years of the well operation. However, investors want to know the probable reserves of the formation at an early stage of development, and it is difficult to implement on a single well. Therefore, data on the production decrease of shale formations help to clarify the remaining period of operation. Productivity curves help to determine the number of additional wells at a late stage of development.

Fig. 11 and 12 show the curves of shale oil and gas production from six major formations of the US at the end of 2014. The largest reserves of shale gas, as mentioned above, include the formation Marcellus. In 2013, 95.9 billion m^3 of gas was produced from it (Sandrea, Sandrea 2015). Shale gas production in the Marcellus formation is growing steadily and

Plays	**Barnett**	**Fayetteville**	**Haynesville**	**Marcellus**
Gas-in-place[1], bcf/sq. mile	50	30	77	18
Year-end Output, bcfd	5.31	2.87	3.87	10.90
Cumulative Production, tcf	14.7	4.2	8.5	6.7
Reserves(EUR)[2], tcf	20	9	12	140
Recovery Factor, %	6.1	11.2	1.7	9.3
Production Potential[3], bcfd	5.64(2011)	2.88(2012)	7.0(2011)	24
Peak Well-Productivity, Mcfd/well	438 (2008)	833 (2010)	3,382 (2010)	
Present.Well-Productivity, Mcfd/well	303	610	1,195	1,050
Year-end Producing Wells	17,494	4,704	3,238	10,369
Current 180-day Well IPs, MMcfd	1.9	2.1	9.5	4.9
Well-Productivity Decline Rate, %/year	7	10	35	
Well EUR, bcf/well	2.2	3.0	3.5	1.6
Well-Productivity by 2020, Mcfd/well	190	306	102	
Depth, feet	5,000-8,000	1,000-7,000	9,600-13,500	2,000-8,500
Pore Pressure Gradient, psi/ft	0.49-0.54	0.44	0.75-0.85	0.40-0.58

Notes: Mcfd=thousand (standard) cubic feet per day; MMcfd=million cubic feet per day; bcfd=billion cubic feet per day; tcf=trillion cubic feet; psi=pounds per square inch; GIP=gas-in-place; EUR=estimated ultimate reserves. (1)GIP values reported in EIA/AEO2012, except for the Fayetteville which is based on a University of Texas study, OGJ/Jan., 2014; the Marcellus has an exceptionally low gas content of 80 cf/ton (USGS) – one quarter that of the Barnett – which accounts for its low GIP value of 18 bcf/sq mile. (2) obtained using logistic decline analysis, except for the Marcellus' EIA/AEO2012 estimate. (3) field values and date of occurrence except for Marcellus which is algorithm estimated (Sandrea et al, OGJ, Aug. 2014).

Sources: EIA/AEO2012, USGS2011, TRRC.

Table 1. Shale gas in the United States. Indicators of major formations (Sandrea, Sandrea, 2014).

has not yet reached the point of fall, as well as the extraction of shale oil in the United States as a whole.

By analyzing production decline curves, the updated estimates of total forecasted technically recoverable reserves (EUR – cumulative production + remaining reserves that can be produced for the entire operation life) were obtained for the major oil and gas shale formations of the US (Table 1,2).

As can be seen from Table 1, for the Barnett and Fayetteville formations EUR is 556 and 255 billion m^3. For the formation Haynesville estimated reserves in 2012 amounted to 1.87 trillion m^3, and in 2014 they fell to 340 billion m^3 according to the decline curve. Production from shale Marcellus was started in 2008 and in December 2013 it reached 309 million m3. Cumulative production is small – only 190 billion m^3, while forecast technically recoverable reserves according to the EIA (US Energy Information Administration) are 3.96 billion m^3. The short history of the development makes it impossible to use the extraction curves for the revaluation of EUR of the given formation. According to the EIA, recovery factor is assumed at 9.3%.

After revaluation of inferred resources the following recovery ratios were obtained: 1.7% for Haynesville to 6.1% for Barnett and 11.2% for Fayetteville (Table 1). Gradient of pore pressure (17-19.2 kPa/m) played the main role in the productivity of Haynesville, which is almost 2 times more than normal pressure (9.7 kPa/m). Due to the high pressure, the initial flow rate was 270 m^3/day, which is several times (~ 5 times) greater than the flow rate of Barnett formation. However, the rate of pressure drop in the wells of Haynesville formation was 86% per year, and production fell sharply, due to which the recovery ratio was the lowest (1.7%) compared with other formations, which have large reserves. Based on EIA estimates (Table 1), technical recoverable reserves (3.96 trillion m^3) for the Marcellus shale should amount to 9.3%, which is 58% higher than the average recovery ratio values for the three formations (Sandrea, Sandrea, 2015).

After reaching peak values, production begins to fall or retain its values for some time, so this parameter does not always clearly define the next period of development.

Parameter that more accurately determines the peak production – is the total flow rate of the formation related to the number of wells that provide product. It is called ‘productivity of wells’ (Sandrea, Sandrea, 2015). This option must be distinguished from ‘the well productivity ratio’, which means the ratio of flow rate of the well to depression. Productivity parameter includes wells completed during the year and does not include wells with discontinued operation.

Thus, the study of well productivity graphs is a simple and reliable way to determine the number of wells to be drilled to maintain production at the required level. Fig. 13 shows the curves of falling productivity for major oil and gas shale ‘plays’. Peak values of productivity 144 th bbl/day/well in the Bakken formation were achieved in 2011. However, production continued to grow and reached in 2013 836 th bbl/day/well. Currently drilling activity (6824 wells) ensures the growth of total production (Fig. 11). To maintain production at the 2013 level, it is necessary to increase the number of producing wells to 11208, which is almost 2 times more than now.

In the Eagle Ford Shale production in 2013 rose to 717 th bbl/day/well with a steady drop of productivity from 270 bbl/day/well in 2011 to 130 bbl/day/well at the moment. Production growth was due to drilling a large number of producing wells from 480 in 2011 to 5493 wells in 2013.

Plays	Bakken	Eagle Ford
Oil-in-place[1], mb/sq. mile	63	94
Yearend Crude Output, kb/d	863	838
Cumulative Production, mbo	970	590
Reserves(EUR)[1], Bbo	7.4	5
Recovery Factor, %	1.8	1.7
Production Potential[2], kb/d	1,075	838
PeakWell-Productivity, b/d/well	144 (2011)	270 (2011)
PresentWell-Productivity, b/d/well	126	130
Yearend Producing Wells	6,824	5,493
Present 30-day Well IPs, b/d	565	812
Well-Productivity Decline Rate, %/year	6.7	36
Well EUR, kb	750	274
Well-Productivity by 2020, b/d/well	77	11
Depth, feet	3,100-11,000	2,500-15,000
Pore Pressure Gradient, psi/.ft	0.50	0.65
Notes: kb/d= 1000 b/d; mb=million barrels oil; Bbo=billion barrels oil. Well-productivity and number of producing wells for the Bakken refer to North Dakota. Eagle Ford's data refer to crude oil. (1) EIA/AEO2012 reported values. (2) algorithm estimate (Sandrea,OGJ. Dec. 2012.		
Sources: EIA, USGS, NDGS, TRRC		

Table 2. Shale oil in the United States. Indicators of major formations (Sandrea, Sandrea, 2014).

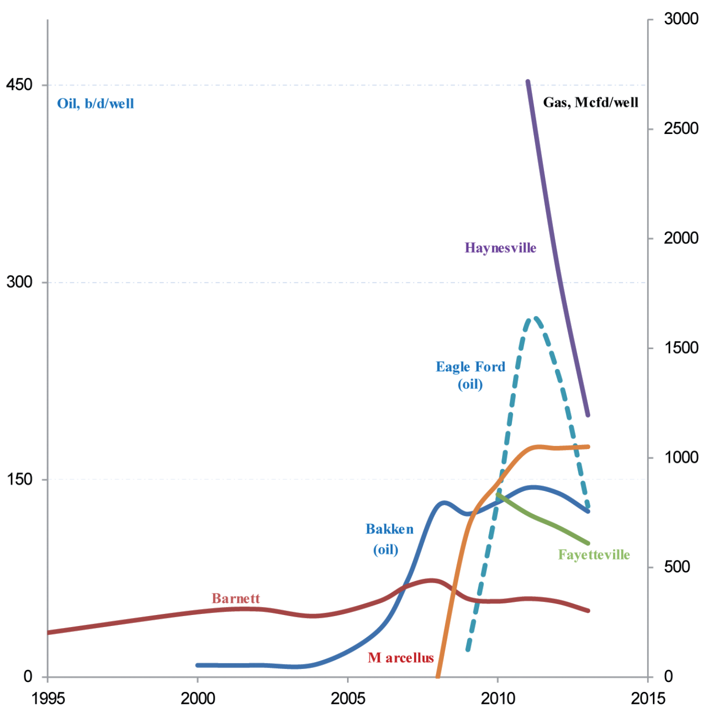

Fig. 13. The productivity of wells from major oil- and gas-bearing shale formations (Sandrea, Sandrea, 2014).

The average cost of a well drilled in the shale Eagle Ford is $4.0-6.5 million, in the Bakken shale – $5.5-8.5 million. Too short history of operation of both formations does not allow using production decline curves for further reserves update. The last reserves assessment of the Bakken formation (7.4 billion barrels) was made by the United States Geological Survey (USGS), by analogy with the surrounding Three Forks or Sanish formations. Railway Company of Texas (Texas Railroad Commission) has estimated reserves of oil shale in Eagle Ford at 5 billion barrels (Table 2).

Preliminary estimates for these two formations are to be confirmed or denied only after accumulation of a sufficient amount of data for the extraction and productivity decline that characterize the main criteria for evaluating the reserves of formations.

Conclusions

The main method of shale hydrocarbons development in the United States is vertical-horizontal (cluster) drilling and multi-stage hydraulic fracturing using inflating packers. Multi-column construction of wells and heavy-duty materials in the cementing process are used in order to isolate water-bearing layers.

Environmental monitoring is an effective mean, which includes heat, gamma spectrometry, gas and aerosol survey and radiation control.

Microseismic monitoring is used in order to clarify the nature of the induced fracturing distribution. Injection of 3% HCl (Barnett formation) in the induced cracks formed in hydraulic fracturing, helps to create a matrix fracturing of the formation. The use of secondary fracturing (Barnett formation) in order to increase inflows contributes to an additional influx of hydrocarbons.

In order to increase oil recovery in shale formations, experiments are carried out on the injection of carbon dioxide and water vapor (Bakken formation). The drainage area after fracturing is only 1/4 of the impact volume (Barnett formation). Area of the vertical drainage on shale gas is much less than for horizontal one (2-8 ha for vertical wells and 7.2-24.8 ha for horizontal wells).

By increasing the number of fracturing stages, costs increase. Therefore the drilling companies are trying to reduce the cost of work by reducing drilling time and completion (testing) of wells.

To determine the technically recoverable shale formations, curves of production and productivity of wells are used. Production curves determine updated estimates of total inferred recoverable reserves (EUR), equal to the sum of cumulative production + remaining reserves that are available for the entire period of operation. The 'productivity of wells' parameter, which characterizes all fields, helps to determine the number of wells to be drilled in order to maintain production at the required level, as well as to clarify the total estimated recoverable reserves per well.

Oil and gas production from shale hydrocarbons is increased by down-spacing of wells. The average life of wells in the Barnett formation is 7.5 years (due to the production decline speed and complex well completion methods in shale formations). The average value of vertical-horizontal wells in shale oil amounts to $4.0-8.5 million, for shale gas – $ 6.0 million.

References

Bunger J.M, Growford P.M. Is oil shale America's answer to peak-oil challenge? *Oil & Gas Journal*. Aug. 9. 2004. Pp. 16-24.

EOG sees Eagle Ford Shale as major US oil discovery. *Oil & Gas Journal*. Apr. 19. 2010. P. 35.

Modern Shale Gas. Development in the United States: A Primer. 2009.

Nick Snow. USGS to update Bakken formation assessment, Salazar Saus. *Oil & Gas Journal*. June 6. 2011. Pp. 35-38.

Paula Dittrick. Slading-sleeve fracs unlock more ND Bakken oil. *Oil & Gas Journal*. June 6. 2011. Pp. 35-38.

Rokosh C.D., Pawlowicz J.G., Berhane H., Anderson S.D. and Beaton A.P. What is shale gas? An introduction to shale-gas geology in Alberta. *Energy Resources Conservation Board. Alberta Geological Survey*. 2009. Pp. 34-41.

Sandrea R., Sandrea I. New data about the potential of shale formations in the United States. *Oil & Gas Journal*. 2015. No. 7. Pp. 46-52.

Sandrea R., Sandrea I. New Well-Productivity Data Provides US Shale Potential Insights. *Oil & Gas Journal*. 2014. Vol. 112.11. November 3.

Tsvetkov L.D., Tsvetkova N.L. Slantsevye uglevodorody [Shale hydrocarbons]. Yaroslavl. 2012.

Ursula Hammes, H.Skott Hammlin, Tomas E. Ewing. Geologie and analysis of the Upper Jurassic Haynesville Shale in east Texas and west Louisiana. *AAPG Bulletin*. V. 95. No. 10 (October 2011). Pp. 1643-1666.

Information about author

Margarita P. Yurova – PhD, Leading Researcher, Oil and Gas Research Institute of the Russian Academy of Sciences. Russia, 119333, Moscow, Gubkin str. 3

Phone: +7(499)135-71-81, e-mail: mpyurova@mail.ru

Received January 20, 2016