AGH DRILLING, OIL, GAS • Vol. 30 • No. 1 • 2013

http://dx.doi.org/10.7494/drill.2013.30.1.97

Maciej Kaliski*, Marcin Krupa, Andrzej P. Sikora**, Adam Szurlej***

SELECTED ELEMENTS OF UNCONVENTIONAL NATURAL GAS ECONOMICS ON THE EXAMPLE OF NORTH AMERICAN ENERGY MARKET EXPERIENCE

1. INTRODUCTION

When presenting the North American market experience in exploiting unconventional shale gas plays allowance should be made for the fact that we are dealing with the 'mature' industry being developed over large areas of the United States and Canada. Shale gas exploitation in North America dates back to several years (first wells drilled for shale gas production were completed in 1996), and nowadays tens of thousands of wells are drilled annually. Also the area of exploration and mining works covers a large part of Canada and the US; there are Marcellus, Barnett and Fayetteville Shale plays in the US and large areas in western Canada, but there are also several smaller shale gas plays within practically the entire continent (Fig. 1).

A description of experience gathered in North American market helps assess the current situation in Polish shale gas sector, and outline possible scenarios of future recovery of this gas in Poland. However, it should be borne in mind that the results of American hydrocarbon industry development are not simply replicable in the Polish market.

2. STRUCTURE AND ORGANISATION OF THE NORTH AMERICAN HYDROCARBON EXPLORATION AND PRODUCTION MARKET

The structure of North American hydrocarbon exploration and production market has been evolving for over 150 years already (the first well to produce oil was drilled in Pennsylvania in 1859).

* AGH University of Science and Technology
** The Energy Studies Institute Ltd. Warsaw

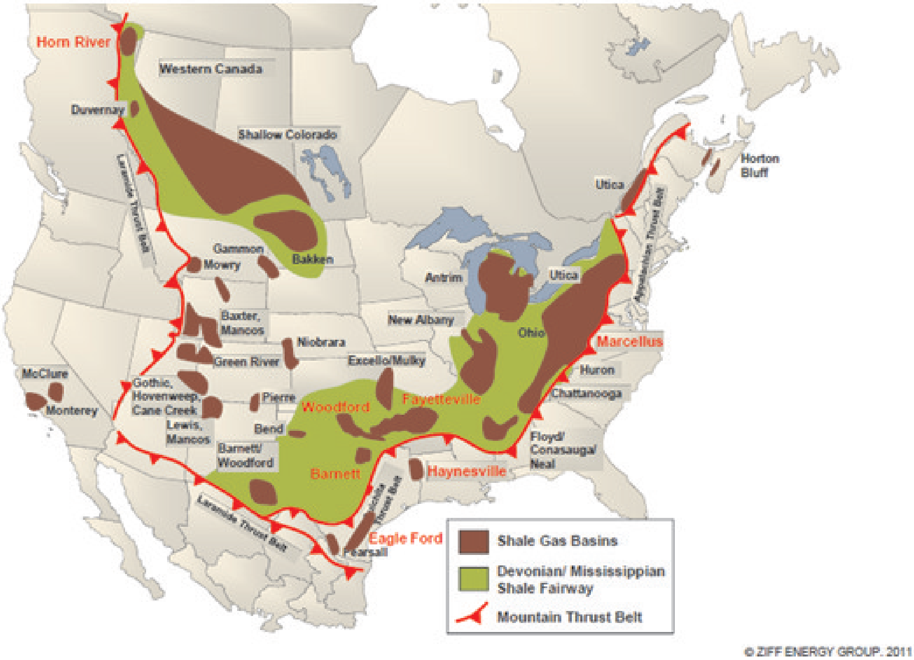

Fig. 1. North American Shale Gas Plays [9] Map source: ZIFF Energy Group, 2011

Initially, the exploration and production work was carried out by dozens, hundreds and eventually thousands of small ‘operators’, usually owners of individual oil wells. Despite the subsequent expansion of Standard Oil ‘descendants’ in hydrocarbon exploration and production area in all global markets, and the creation of numerous new vertically integrated undertakings, a very large number of US oil and gas production operators still exist, often relatively small, and very common are capital transactions intended to merge entities, split or sell/exchange shares [19].

In 2011 the US capital market have noted [10]:

– 14 vertically integrated undertakings engaged in oil and gas exploration, logistics and processing, as well as in the trading of oil and gas derivatives (more than one of the domains mentioned, not necessary all). These are the largest companies, and their market capitalisation reaches 50% of the total oil and gas market capitalisation.
– 103 non-integrated companies, operating in one of the above areas. Their market capitalisation reaches 28% of the total sector market value.
– 56 oil and gas services companies, engaged in manufacturing equipment and facilities, conducting seismic studies, drilling etc. This segment’s share in the capitalisation of hydrocarbon sector amounts to 22%.

To better understand the size of the US hydrocarbon sector it should be added that the whole capitalisation of companies mentioned above reached $1,370 billion in mid-2011, and the market capitalisation of the largest one – ExxonMobil – reached as much as $356 billion (in the case of the smallest one – $2 million). It must be stressed that Oil & Gas companies have been highly ranked among the world's biggest companies by *Fortune Global 500* for 2012 (the top 500 corporations worldwide as measured by revenue) and in the top ten are as much as seven oil companies. Also, taking as criterion the profit, companies from oil and gas sector are predominant (2012): 1.Gazprom – 44,4 billion of US dollars, 2.ExxonMobil – 41,6 billion of US dollars and 4. Royal Dutch Shell – 30,9 billion of US dollars.

The shareholders of hydrocarbon companies are also relatively highly distributed (Fig. 2).

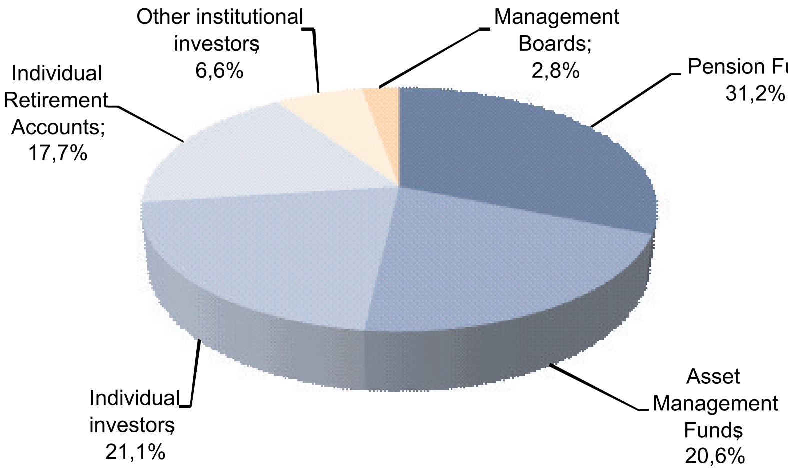

Fig. 2. Shareholding Structure in companies in Oil & Gas sector, based in the US in 2011 [10]

As can be seen from Figure 2, the majority of shares in the oil sector are in the hands of pension and investment funds (and they have greatest impact on the boards of these companies, with the ability to delegate their representatives to the supervisory authorities and – indirectly – to the management of these companies), but nearly 40% of the shares belong to individual investors (investment accounts and individual retirement accounts). Just over 5% is in the hands of other institutional investors, and the companies' managers operating in this sector have only ca. 3% of the shares. A very large part of the US population has the opportunity to directly 'participate' in the profits generated by this sector. Breaking down the aggregated data from Figure 2 in a more precise manner there may be stated [19]:

- In the hands of individual investors are 42% of shares of vertically integrated hydrocarbon companies (which are the biggest market players); 47% are owned by Asset Management.
- In non-integrated companies (dealing with a single area of activity) individual investors account for 18% of shareholders; a dominant role is played by Asset Management funds – 76% of shares.

– A similar structure prevails in oil and gas services companies: Asset Management funds own 63% of shares, and individual investors – 23%.
– Nearly 50 million US households own these companies' shares through individual retirement accounts. Over 60 million households pool funds in different pension funds investing in stocks of sector companies.

3. CHANGES IN TERMS OF DRILLING EFFICIENCY FOR UNCONVENTIONAL DEPOSITS IN THE US AND CANADA

How has drilling efficiency changed in subsequent years on the example of Canadian and US shale plays? The Fayetteville Shale play is located in the Arkansas and covers the area of about 25,000 square kilometres. In terms of gas volumes produced it is the second largest shale play in the United States (the first is the Barnett Shale). Industrial-scale shale gas production commenced here in 2005, and due to a very rapid growth reached ca. 14 Bcm in 2009, 21 Bcm in 2010, and 26 Bcm in 2011. It was due to a number of new wells drilled in the Fayetteville Shale, which has been decreasing since 2010 only because of the drop in shale gas prices in the North American market (Tab. 1).

Table 1

New wells completed in the Fayetteville Shale [5]

Year	Number
until 2004	2
2004	14
2005	46
2006	132
2007	456
2008	730
2009	892
2010	745
Total	**3017**

A significant number of new production wells allows a reliable statistical analysis of their changing productivity depending on when the drilling was completed. Data showing gas volumes produced during the first 12 months starting from the launching of extraction, for wells completed in subsequent years are presented in Table 2.

Table 2

Average natural gas volumes produced during the first 12 months from a single well, for wells completed in the Fayette Shale over the period 2005–2010 [4]

Start of production	Volumes produced (Mmcf/d)	Volumes produced (mm^3/d)	Volumes produced (mmm^3/y)
2005–2006*	0.71	19.9	7.3
2006–2007	0.80	22.4	8.2
2007–2008	1.08	30.3	11.0
2008–2009	1.27	35.6	13.0
2009–2010	1.57	44.0	16.1

* data collected for the period from October to September of the following year

As can be seen from Table 2, the average size of production has more than doubled over five years. This is due to the use of technologies which are better and more adapted to the local conditions, and to general development of knowledge (focusing on the most promising areas), and the technique (it mainly regards hydraulic fracturing). It is also important to bear in mind that the above production figures relate to all completed wells, also to those where the production did not start due to gas absence or mining inefficiency. According to information cited by the data source, the number of 'misguided' drilling reaches ca. 20–30% and decreases with time. Another example concerning the changing productivity of wells refers to the Montney Shale Natural Gas Field, located in British Columbia (Canada). Figure 3 shows that over 12 years the average size of production from a single well (during the first 30 days) increased from about 700 Mcf/d (ca. 20 Mcm/d) to ca. 4 Mmcf/d (ca. 110 Mcm/d, which totals ca. 40 Mmcm/y), which is about five- or sixfold.

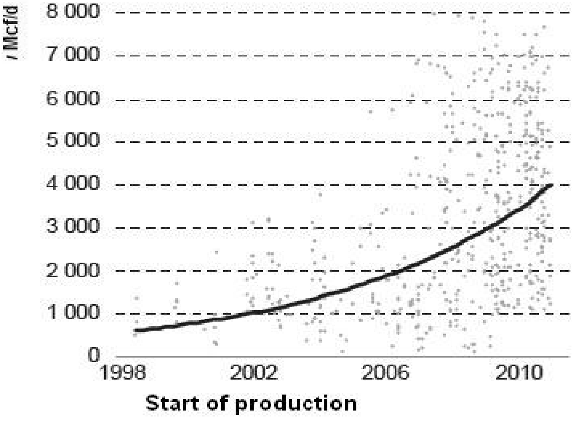

Fig. 3. The average volume of gas production during the first 30 days from a single well, for wells completed in the Montney Shale Play over the period 1998–2010 [3]

4. CHANGES IN INVESTMENT AND OPERATING COSTS RELATED TO THE EXPLOITATION OF MRQ DEPOSITS

In the hydrocarbon sector the capital and operating costs related to mining operations depend on a number of factors, which are both objective and independent of man, but also consciously shaped by policy-makers and the market of a given country or territory (taxes and other charges, equipment and infrastructure availability, or conditions prevailing in the labour market). The basic cost elements include: acquiring ownership rights to the land (or in any other manner the possibility to use land for mining operations), drilling and finishing work along with hydraulic fracturing (usually by contracting service companies), infrastructure construction (gas refining, collective pipelines) and finally the operational costs related to daily operation, gas treatment and compression.

A large number of purely local factors (i.e. taxes, labour costs, regulations) hinder the comparison of absolute values of costs in different markets; however, it is possible to determine the cost trends for the areas with the longest history of shale gas exploitation. This applies, as usual, to Canada et United States territories. The most important conclusion resulting from the analysis of information provided by companies extracting North American shale gas is a continuous fall in investment costs.

Figure 4 shows that within five years, between 2007 and 2011, time needed for completing a single horizontal well was more than twice reduced, and this despite the increased length of the hole by ca. 70% (from ca. 900 m to 1.500 m) . Interestingly, it could be completed along with drilling cost kept at (roughly) the same level. However, the biggest decline was noticed in gas exploration and production development costs (Finding & Development), which fell in this period almost two and a half fold (calculated per volume of gas produced unit).

A similar cost evolution can be seen in other gas exploration and production companies. Over the period 2005–2009 GMX Resources (the Haynesville Shale) reduced the cost of drilling of ca. $9 million in 2005 to $6.5 million in 2009 per well; Continental Resources (the Bakken Formation) reduced the average drilling time from 45 to 28 days between 2008 and 2009; Ultra Petroleum (the Pinedale Field) reduced the drilling time from 61 days in 2006 to 21 days in 2009, with drilling costs decreased from 7 to 5.25 million (Fig. 4) [2].

Due to the most commonly used practice of hiring oil and gas services companies, which in turn lease out necessary drilling and fracturing equipment, the cost of these works usually remains in an almost linear relationship with drilling/fracturing time, as shown in Figures 5 and 6.

Cheasepeake Energy Company obtained a 40% time reduction and 60% reduction in the average cost of vertical wells in 2006–2008. At the same time the total cost of drilling decreased by 37% in 2008–2009. As regards operating costs related to gas extraction, its purification, transmission by pipelines, they appear to be at the level similar to gas production from conventional fields.

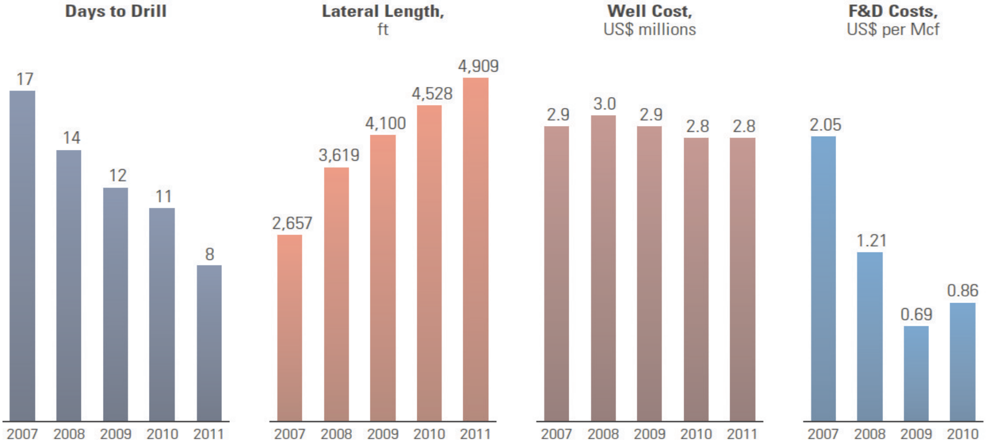

Fig. 4. Change in investment costs for wells completed in the Fayetteville Shale Play by Southwestern Energy Company [16]

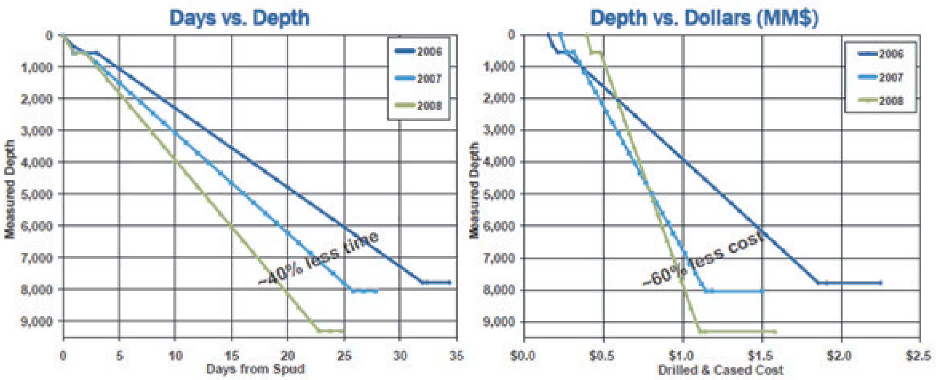

Fig. 5. Drilling time, depth and cost for wells completed by Cheasepeake Energy Co. in the Fayetteville Shale Play over the period 2006–2008 [11]

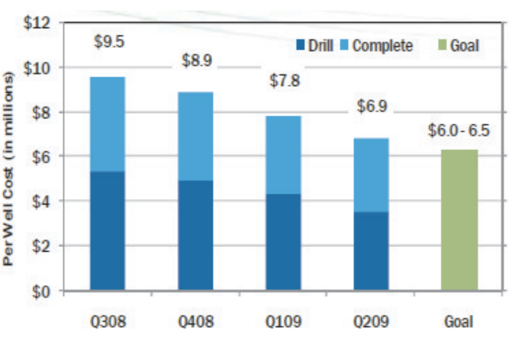

Fig. 6. The average drilling cost carried out by Cheasepeake Energy Co. in the Fayetteville Shale Play over the period 2008–2009 [6]

5. FISCAL POLICY AND ITS IMPACT ON THE ECONOMICS OF SHALE GAS PRODUCTION

The impact of any taxes on the economics of gas production can be seen from two points of view at least. The first is the position of governments (or local authorities, i.e. state authorities in the case of United States), which have the right to impose taxes and determine their amount. The second is the point of view of sector companies for which any tax increases costs and contributes to reducing the economic viability of production from wells in the given area, and sometimes to even ceasing production from a number of wells. In the United States, in addition to 'normal' taxes imposed on economic operators, individual states have the right to impose taxes on production volumes (primary severance tax burden), before the deduction of any expenses. The size of the burden is surprisingly different for each state (Tab. 3).

Table 3

The amount of taxes imposed locally on natural gas production in selected US states (in %) [17]

Alaska	25%	Michigan	5%
Alabama	10%	Arkansas	5%
Montana	12.2%	Louisiana	4.9%
New Mexico	7.9%	Colorado	4%
Texas	7.5%	North Dakota	2.5%
Oklahoma	7.1%	Ohio	0.4%
Wyoming	6.1%	California	0.13%

Very significant are differences in the approach of individual administrations. Furthermore, examples can be found how new projects are supported or how wells with high production costs are treated. In Texas, for example, it is now of common use to impose, for selected wells, zero tax rate for the first 120 months of extraction, or until the 'recovery' of 50% of investment costs. This is largely due to a significant fall in natural gas prices in North America[1]. Such an approach is justified by a very large impact of the sector on the economy of these states where hydrocarbons are extracted. For example, the number of jobs created by companies engaged in the extraction of shale gas in the United States in 2010 reached 600.000, of which directly employed in the sector were approximately 150.000 people. The remaining 450.000 are employed in jobs created owing to shale gas production. Therefore, a greater effort is made in the United States to develop domestic production [18].

[1] From 11,32 USD/Mcf in July 2008 to 2,92 in September 2009 and 4,22 in August 2010

In Texas, where nominally the amount of the present tax rate is 7.5%, this rate is only applied in the case of low-cost production wells. For high-cost gas wells which now make up the majority of wells operating in Texas, and which mainly produce shale gas, this rate is not applied in practice as shown in Figure 7.

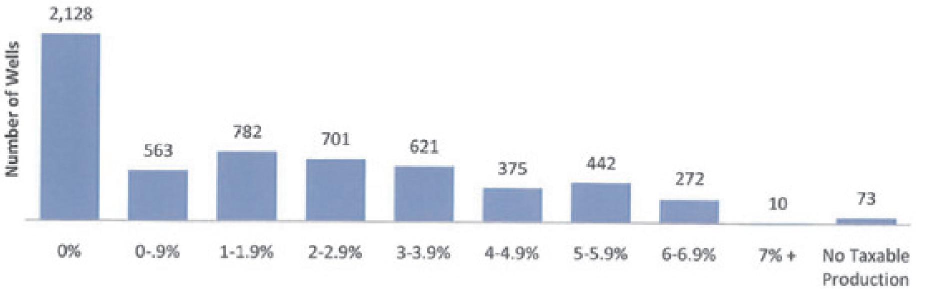

Fig. 7. The amount of effective tax rate depending on production volume for high-cost gas wells within Texas (2009) [14]

The analysis of a direct relationship between the amount of taxes, and the cost-effectiveness of natural gas production is beyond the scope of this article. In the available literature studies and models can be found that attempt to describe these dependencies for individual shale plays in North America. A research conducted by the state of Pennsylvania in the Fayetteville shale play area showed, for example, that a potential rise in the tax rate on production volume from 0.3% to 5% would result in 13% decline in investment activity within this shale play [15].

6. INITIAL AND CURRENT BREAK-EVEN POINT FOR UNCONVENTIONAL HYDROCARBON DEPOSITS IN NORTH AMERICAN MARKET

The ‘break-even price’, which is the level of natural gas prices where cost or expenses are equal, is closely related to the very location of gas extraction and depends on geological features, external service costs, fiscal policy, technologies (i.e. EURO value), etc. An analogy can be seen to investment costs, but when calculating the break-even point there is another issue that arises of extracted gas components – depending on the market situation the presence of heavier hydrocarbons can significantly improve the efficiency of operations (such a situation is being observed in the North American market nowadays).

Therefore, this parameter can vary considerably, not only among countries, but also for individual fields within a single country. Furthermore, due to observed variability (mainly) of operating costs, but also fiscal policy, the break-even parameter fluctuates, which may significantly affect the production level – fields for which the market price is lower than the break-even ceiling are not economical to develop and thus the gas extraction will not be developed within these fields (although it can be carried out from existing wells, if it covers at least operating costs). Let us have a look at how the break-even parameter develops for the largest deposits in the United States and how it evolves over time (Fig. 8).

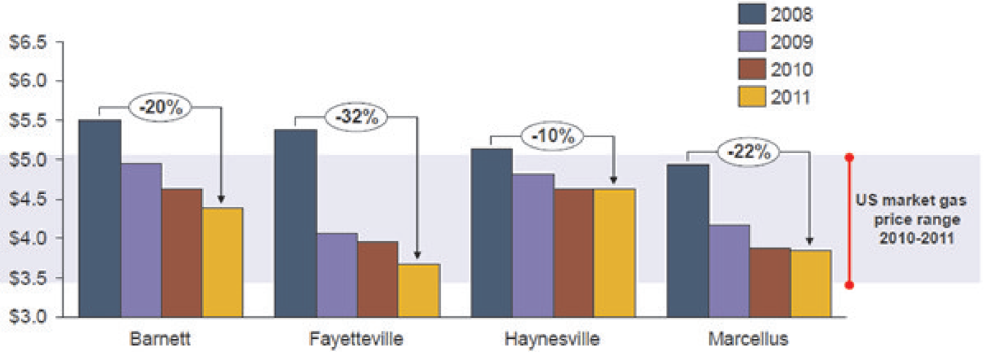

Fig. 8. The break-even parameter values for the largest natural gas plays in U.S., for wells run over the period 2008–2011 (US$/mcf) [12]

It is interesting to show the time development of break-even price for the total of shale gas plays owned by a single company. In this case it is Talisman Energy, and the break-even parameter only refers to investment costs.

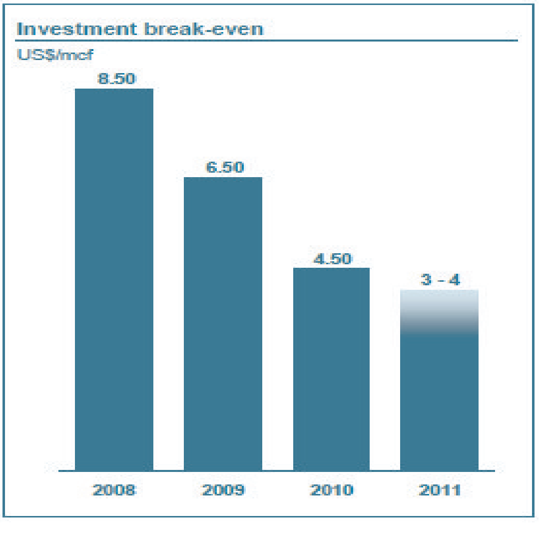

Fig. 9. The development of break-even price for shale gas plays owned by Talisman Energy for wells run in 2008–2011 [13]

As can be seen from the above figures the price balancing the cost of gas production over the last four years has fallen significantly – depending on the given deposit from 10 to over 30%, which is related on the one hand to technology advances, the use of economies of scale and greater efficiency of wells (rise in EURO value) and on the other hand – to increasingly better well „hitting" (better understanding of geology). However, it should be noted that the current price of gas in the North American market, amounting to ca. 4 USD/MBtu, does not guarantee the economic viability of total shale gas production, even despite the presence of heavier hydrocarbons (in particular oil shale) improving efficiency of the gas extracted.

7. SUMMARY

There are fundamental differences between the structure of mining markets in North America, and Poland. These differences mainly arise from the scale of hydrocarbon production, the history and the depth of the capital market. As a result, the current Polish energy policy, but also the structure of the market in Poland is not conducive to the rapid development of shale exploitation [7]. Interestingly, the amount of funds necessary for the extraction of shale gas is so high that – according to available sources – the combined resources of companies based in Poland (and especially those dependent on the State Treasury of Poland), are far from satisfactory for large-scale gas production.

It should also be noted that Polish and North American shale geology differ significantly. As a result, we are somehow „fated" to welcome a large share of international companies in the exploitation of Polish shale gas deposits. It is to be hoped that the performance of mining companies will prove to be positive enough to be able to meet the expectations awakened in Poland.

REFERENCES

[1] Borkowski D., Jasiński A.W., Kaliski M., Sikora A.P., Stefanowicz J.: *Wyzwania regulacyjne związane z możliwością poszukiwania, rozpoznania i wydobycia węglowodorów ze złóż niekonwencjonalnych w Polsce*. Rynek Energii nr 4, 2012, 71–78.

[2] *Drilling And Completion Costs Continue to Fall In Shale Plays*. October 02, 2009, www.investopedia.com

[3] Gouvernement du Québec "A Fair and Competitive Royalty System For Responsible Shale Gas Production", March 2011 (IHS Production Data).

[4] James E. Mason: *Well Production Profiles for the Fayetteville Shale Gas Play*. Oil and Gas Journal, April 4, 2011.

[5] John A. Veil: *Water Management Practices Used by Fayetteville Shale Gas Producers*. Oil & Natural Gas Technology, June 2011.

[6] John Webster: *Haynesville Shale*. 2010, AADE* Fluids Technical Conference and Exhibition, Houston, kwiecień 2010, * – AADE – American Association of Drilling Engineers.

[7] Ministerstwo Gospodarki, 2009: Polityka energetyczna Polski do 2030 roku.
[8] Kaliski M., Szurlej A., Grudziński Z.: *Węgiel i gaz ziemny w produkcji energii elektrycznej Polski i UE*. Polityka Energetyczna, t. 15, z. 4, 2012, 57–69.
[9] Lev Virine: *Western Canadian Gas Production: What to Expect in Next Three – Ten Years*. ZIFF Energy Group, October 2011.
[10] Robert J. Shapiro, Nam D. Pham: *Who Owns America's Oil and Natural Gas Companies*. October 2011.
[11] Scott Sachs: *Fayetteville Shale Overview*. 2008 Investors & Analysts Meeting Chesapeake Energy.
[12] Panos E. Cavoulacos (Schlumberger): *Shale Gas: Unlocking the Potential in Asia*. Shale Gas Summit, Beijing, 23 April 2012.
[13] Talisman Energy Corporate Presentation, April 2011.
[14] Texas State Legislative Budget Board, " Overview of Natural Gas Tax Structures", April 2012.
[15] The Center for Business and Economic Research. (March 2008), "Projecting the Economic Impact of the Fayetteville Shale Play for 2008–2012".
[16] Tom Alexander, Southwestern Energy Company, „Shale gas revolution", Oilfield Review, 23 no. 3, Autumn 2011.
[17] Tompkins County Council of Governments, Gas Drilling Task Force, "White Paper on Taxation Issues Related to Gas Drilling", February 2011.
[18] IHS Global Insight, „The Economic and Employment Contribution of Shale Gas in United States", December 2011.
[19] Yergin D.: *Nafta, władza, pieniądze*. Philip Wilson, Warsaw 2006.