The issues related to Shale Gas: from the estimation of reserves to the methods of development and production

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Abstract

The shale gas revolution in the United States which produced vast quantities of gas has triggered a strong interest elsewhere in the world, with many countries trying to replicate this success. Various institutions have developed several studies reporting significant volumes of gas reserves throughout the world. However, despite the significantly appreciable amounts, they usually exhibit a low recovery factor. The exploration and production of unconventional resources, such as shale gas, is much more complex compared to methods used for conventional resources, and as such, a deep knowledge is needed in various disciplines, so as to obtain an accurate understanding of a shale gas basin and the formations, in order to achieve success.

Determining the potential of a shale gas basin entails an exhaustive process of estimating the volume of technically recoverable gas. It is understood that the recoverable gas volume has two components – a free gas component and an absorbed gas component. Accuracy in the estimation process is essential to success of the play.

In the presence of positive indicators from the estimation of gas, it is necessary to define the parameters of horizontal drilling and hydraulic fracturing, which are two crucial processes for the production of gas in an economically viable way. Despite the great potential, due to several questions related to environmental, political and technological factors, it will take some time for the development of shale gas reserves in Europe to make exploitation possible and feasible.

1. Introduction

The continuous and increasing demand for low cost energy, and the availability of fossil fuels makes hydrocarbons an important non-renewable source for energy in the world energy matrix, for the future decades of the 21st century.

The advances in technology have increased the horizons of this industry and have allowed for the achievement of new targets. The efficiency of this technology has made it possible to exploit these unconventional resources.
There are several types of unconventional resource, such as, heavy oil, tight oil, shale oil, gas hydrates, tight gas sands, coalbed methane and shale gas. The last of these will be explored in detail in this report.

In recent years, several shale gas reserves containing appreciable quantities of gas have been discovered in the United States by small/medium American companies. It is increasingly claimed that the world is entering a ‘golden age of gas’, with the exploitation of unconventional resources expected to transform gas markets around the world. But the future development of these resources is subject to multiple uncertainties, particularly with regard to the size and the recovery factor of the resource (McGlade, 2013a). Natural gas may have an important role to play in the future. As well as being the least polluting of all hydrocarbons, it is very versatile and has diverse applications, such as, production of electricity, thermal energy and the production of energy for transport systems.

The shale gas revolution in the United States, where annual production has been increasing, has triggered a lot of interest elsewhere in the world. However, the exploration and production of unconventional resources is much more complex compared to the conventional resources. A deep knowledge of several areas of expertise is needed to understand the petroleum system sufficiently. Many companies have tried to exploit shale gas in Europe, but it hasn’t been easy to replicate the American experience.

Shale is a clay-rich formation typically derived from very fine grains deposited in a lacustrine environment and which has been buried for thousands of years. This formation has a very low permeability matrix, which makes it difficult for the gas to flow from the formation to the wellbore, once drilled. Production technology plays a crucial role in overcoming the limitations in the shale formation. Normally, it uses a combination of two techniques, horizontal drilling and hydraulic fracturing. Horizontal drilling enables the wellbore to have a large contact surface along the formation and the hydraulic fracturing (injecting water and some chemical additives under pressure into the well) cracks the rock thereby creating a network of fractures. Once the fractures have been created they allow the gas to flow from the formation to the well and on to production.

This report encompasses methods of estimation; identifies critical factors; and covers the methods of production and development of unconventional reservoirs, specifically those of shale gas, through exhaustive research of the information available.

2. Reserves and Resources

The resource estimates show the amount of gas that is present in the formation, however it is not possible to extract all the gas estimated. The reserve estimates are a description of the amount of gas it is possible to extract, taking into account the technology available and economic factors, among other things. The recovery factor is the estimate of the total gas portion that can be extracted, normally represented as a percentage.

The estimation process is determined by the phase of play development, whether in the exploration or production phase. It can be called as gas in place (GIP); original gas in place
(OGiP) or initial gas in place (IGiP) depending on the phase of development. This concept is known to be a way of quantifying the amount of gas that exists, through the technically recoverable resources (TRR) that the US Geological Survey use to estimate the quantities it may be possible to extract. This methodology has been modified for coalbed methane and shale gas in order to use well production data to achieve better estimates compared to the recovery factor obtained through the conventional method used in oil and gas. The TRR shale gas and tight oil estimates, from US Energy Information Administration (EIA), have changed significantly in the last few years, and now include the performance data from new wells and the resources evaluation by the USGS guidelines (USEIA, 2012). However, a huge variety of resource estimate methods and potential reserves have been used by other institutions, these being described by Pearson et al. (2012), together with factors that determine the development viability.

According to the nomenclature of the SPE – Petroleum Resource Management System, the total amount of oil initially in place (total petroleum initially-in-place), is defined as the quantity of oil existing naturally in accumulations. This quantity is made up of the amount of oil estimated to be present in known accumulations from a given date, plus the oil quantities in undiscovered accumulations. This can then be described as a contingent resource due to certain conditions that avoid it becoming commercialized, at least that be clarified and proved to be viable (Figure 1).

3. Figure 1 - Resources Classification Framework (SPE, 2008).

Shale gas

Shale gas is produced from shale formations which are both source rock and reservoir rock. This gas is typically dry gas, composed essentially of methane (60-95% v/v), although it may be present in formations containing wet gas.

Shale is a sedimentary rock composed of a consolidation of clay-sized fine grains. These formations are deposited as slurry in low-energy environments, such as lakes and deep water basins, where the particles leave the suspension and are buried.

During this process, very fine sediments are deposited together with organic matter like algae, plants and animal debris creating composite layering which results in sedimentary rock with a
limited horizontal permeability matrix and an extremely limited vertical permeability matrix. The low permeability makes the gas present in the rock remain static or difficult to move, unless it is exposed to a geological event occurring over time (millions of years). The gas in shale formations can appear as free gas and absorbed gas, where the free gas is located in the pore formation and the absorbed gas is within the organic-rich formation. Hydraulic fracturing is needed to overcome the low permeability, inducing fractures that allow the gas to be produced in commercial quantities.

The model of conventional accumulation encompasses the source rock, reservoir rock, cap rock, trap and path migration. However, in the unconventional accumulations there is neither trap nor path migration. This signifies that the migration process doesn’t happen, making the source rock a reservoir rock (Table 1).

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<th>Table 1 – Conventional reservoir Vs. unconventional; Elements and processes.</th>
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<td><strong>Conventional</strong></td>
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<td><strong>Elements</strong></td>
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Shale formations have a different morphology from conventional resources and have a very low permeability matrix, roughly around 10-100nD ($10^{-6}$mD). They have elongated structures along the basin creating a greater subarea to explore. As such, horizontal wells are needed to allow the wellbore much more contact surface with the formation and this makes the cost of drilling higher.

According to “World Shale Gas and Shale Oil Resource Assessment” (EIA/ARI, 2013) a more appropriate methodology to estimate recoverable resources of shale gas is shown in the following 5 topics:

1. **Conducting preliminary geological and reservoir characterization of shale basins and formation(s).**

Preliminary geological and reservoir data is assembled for each major shale basin and formation, including following the depositional environment of shale (marine vs non-marine); depth (from top to base of shale interval); structure, including major faults; the gross shale interval; organically-rich gross and net shale thickness; total organic content (TOC, by wt.); thermal maturity (Ro).

2. **Establishing the areal extent of major shale gas formations.**

Having identified the major shale gas formations, the next step is to undertake a more intensive study to define the areal extent for each of these formations. For this, the study team
researches the technical literature for regional as well as detailed local cross-sections identifying the shale gas formations of interest.

3. **Defining the prospective area for each shale gas formation.**

An important step is to establish the portions of the basin that are deemed to be prospective for the development of shale gas. The criteria used for establishing the prospective area include: depositional environment; depth; total organic content (TOC); thermal maturity and geographic location.

4. **Estimating the shale gas in-place.**

A series of engineering calculations are used to estimate the volume of associated gas in-place. The calculation of total gas in-place is given in Equation 1.

Equation 1:

\[ GIP_T = GIP_I + GIP_a \ (bcf/mi^2) \]

The free gas in-place for a given areal extent (acre, square mile) is governed, to a large extent, by four characteristics of the shale formation - pressure, temperature, gas-filled porosity and net organically-rich shale thickness. The calculation of free gas in-place \( (GIP_I) \) uses the following standard reservoir engineering equation:

Equation 2:

\[ GIP_I = \frac{43560 \times A \times h \times \phi \times (S_g)}{B_g} \ (bcf/mi^2) \]

\( A \) is area, in acres (with the conversion factors of 43,560 square feet per acre and 640 acres per square mile).

\( h \) is net organically-rich shale thickness, in feet.

\( \phi \) is porosity, a dimensionless fraction.

\( (S_g) \) is the fraction of the porosity filled by gas \((S_g)\).

\( P \) is pressure, in psi.

\( T \) is temperature, in degrees Rankin (temperature data is obtained from well test information published in the literature or from regional temperature versus depth gradients; the factor 460 oF is added to the reservoir temperature (in oF) to provide the input value for the gas volume factor \((B_g)\) equation).

\( B_g \) is the gas volume factor, in cubic feet per standard cubic feet and includes the gas deviation factor \((z)\), a dimensionless fraction.

In addition to free gas, shale can hold significant quantities of absorbed gas \((GIP_a)\) on the surface of the organics (and clays) in the shale formation. A Langmuir isotherm is established for the prospective area of the basin using available data on TOC and on thermal maturity to establish the Langmuir volume \((VL)\) and the Langmuir pressure \((PL)\) (Figure 2, on left). Absorbed gas in-place is then calculated using the formula below (where \( P \) is original reservoir pressure).
Equation 3:

\[ G_c = \frac{V_L \times P}{P + P_L} \text{ (scf/tonUS)} \]

Figure 2 - Langmuir isotherm curve (on left). Combining free and adsorbed gas for total gas in-place (on right) (Alexander, 2011).

The above gas content (GC) (typically measured as cubic feet of gas per ton of net shale) is converted to gas concentration (absorbed GIP per square mile) using actual or typical values for shale density (typical density \( \approx 2.65 \text{ gm/cc} \)).

The free gas in-place \( (GIP_f) \) and absorbed \( GIP_a \) are combined to estimate the resource concentration \( (\text{Bcf/mi}^2) \) for the prospective area of the shale gas basin (Figure 2, on right).

5. Calculating the technically recoverable shale gas resource.

The technically recoverable resource is established by multiplying the risked gas in-place (GIP) by a shale oil and gas recovery efficiency factor, which incorporates a number of geological inputs and analogs appropriate to each shale gas and shale oil basin and formation. The recovery efficiency factor relies on the mineralogy of the shale (favorability for applying hydraulic fracturing to “shatter” the shale matrix); presence of favorable micro-scale natural fractures; the absence of unfavorable deep cutting faults; the state of stress (compressibility) for the shale formations in the prospective area; and the extent of reservoir overpressure as well as the pressure differential between the original reservoir rock pressure and the reservoir bubble point pressure.

There are three basic shale gas recovery efficiency factors, incorporating shale mineralogy, reservoir properties and geologic complexity: favorable gas recovery (6% recovery efficiency factor); average gas recovery (4% to 5% recovery efficiency factor); less favorable gas recovery (3% recovery efficiency factor).

6. Production Technology

Shale gas can be extracted using two techniques: horizontal drilling and hydraulic fracturing. The horizontal drilling begins as a vertical well and at a certain point turns along the orientation of the formation target. In this way, it can achieve surface contact of several thousand meters.

As these formations are of elongated shape and have very low permeability, this technique increases the contact surface with the wellbore.
The horizontal drilling allows for the creation of wells with diverse shapes. In shale gas it is common to use a drilling pad to cover a large area, where with this technology it is possible to drill up to eight wells over a small area. From a single vertical well it is possible to drill various horizontal wells at different depths but in the orientation, they are referred to as ‘stacked’. Multilateral drilling is used to drill a formation at the same depth but with different orientations (azimuth).

7. Hydraulic Fracturing

Hydraulic fracturing, which is an injection of water mixed with sand (99.5%) and some chemical additives (0.5%) under pressure into the shale formation. This is used in order to induce permeability within the formation making the gas flow from the formation to the wellbore. To achieve success with fracturing is necessary to understand the lithology across the horizontal well and select segments with similar lithology. These segments are divided by stages in order to break down and initiate fractures at more or less the same pressure.

As the field development continues more data becomes available and this is used to update the propagation fracture model and production model.

There are two classes of material injected during fracturing treatments — fracturing fluid to carry the material to keep the created fracture open, and the solid proppant to keep the created “fissure” open. The main environmental concerns relate to the additives used in the frac carrier fluid, as detailed below:

**Fracturing Fluid:** The fracturing fluid should have a number of properties which are optimised for each formation. These are: to be compatible with the formation rock, compatible with the formation fluid, generate sufficient pressure drop down the fracture to create a wide enough fracture, have lower viscosity sufficient enough to allow clean-up after the treatment, and be cost effective. Water-based fluids are commonly used and “Slickwater” is the most common fluid used for shale gas fracturing, where the major chemical added is a surfactant polymer which reduces the surface tension or friction so that water can be pumped at lower treating pressures. Other fluids that have been used are oil-based fluids, energised fluids, foams and emulsions.

**Fracture Fluid Additives:** Possible additives for fracturing fluids are listed below, but it should be noted that not all chemicals are added for every job and in general as few additives as possible are added to avoid potential problems with the reservoir and to maximise production:

- Polymers – allow for an increase in the viscosity of the fluid, together with crosslinkers.
- Crosslinkers – increase the viscosity of the linear polymer base gel.
- Breakers – are used to break the polymers and crosslink sites at formation temperature for better clean-up.
- Biocides – used to kill bacteria in the mix water.
• Buffers – used to control the pH.
• Fluid loss additives – used to control excessive fluid leak-off into the formation.
• Stabilizers – used to keep the fluid viscous at higher temperature.

8. Development of shale gas field

A shale gas field has different developments when compared to the conventional gas field. The cash flow profile between them is different. Conventional gas has a high level of investment initially but it will produce a significant profit over the “short” term. On the contrary, shale requires less investment initially but in turn produces lower profits over the period of exploration but with a longer period of exploration. The duration of licenses required for shale gas are longer than the licenses required for conventional gas otherwise it is not viable.

Shale gas could be of great importance in Europe. However, it is not possible to replicate the American experience. In the United States, the laws are less restrictive, providing an opportunity for the owners of the land to decide if they permit the companies to explore their properties or not. This also gives the property owner an opportunity to make a profit from any production resulting from the exploration. The United States also has a vast distribution network to deliver the gas throughout the country.

In Europe, the laws are different in that the property owners are not able to gain profit from anything produced from under their land e.g. oil, gas, or gold. Furthermore, there is no infrastructure able to receive the gas produced. The population is not well-informed about hydraulic fracturing, and this poses a potential problem in the event of any environmental damage that may occur from the process. At present there are no controls in place in Europe that will work to mitigate any potential problems arising.

9. Conclusion

Based on the research done on the estimate reserves of shale, it is possible to conclude that there is a huge discrepancy of nomenclature used by the institutions involved in the estimation of shale gas resources. There is an evident lack of a standard nomenclature and method to estimate the shale gas resources.

Although there is a level of uncertainty about the estimations of shale gas, in the United States, there is a huge production from it.

Many countries in Europe have tried to replicate the American experience but they have been unsuccessful. Europe is not prepared to accommodate the exploration of shale gas and at the moment, there is no the infrastructure able to receive the gas produced, there is no expert knowledge about this subject, and the laws are very restrictive. In Europe, shale gas, has the potential to be a huge asset, however it will take more time until it is a viable resource.
10. References


http://www.slb.com/~/media/Files/resources/oilfield_review/ors98/win98/key.pdf


