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Theme

CHARACTERIZATION OF SHALE GAS RESERVOIRS BY LOGGING AND MINERALOGICAL STUDIES

Approved By Supervising Committee:

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Thème

CARACTERISATION DU SHALE GAZ RESERVOIRS PAR LOGGING ET ETUDES MINERALOGIQUE

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ROBEI

ملخص : طوال السنوات الأربعين الماضية، تطورت صناعة النفط من مكامن الغاز التقليدية، إلى مكامن الغاز غير التقليدية ضيقة النفاذية إلى النفاذية شديدة الضيقة ، حيث لكل نوع تحدياته الفريدة. من خلال هذا العمل قمنا بشرح المفاهيم الأساسية لمكامن الغاز الصخري، ودراسة منهجية وكذا الوسائل اللازمة لتقييم هذا النوع من المصادر غير التقليدية وذلك من أجل تحديد الطرق الأمثل لاستغلال مخازن الغاز الصخري في الجزائر مع عرض خطة أولية والتي ستقوم بها الشركة الوطنية سونطراك للتحري عن المخزون الفعلي لحوض احنات بتيميمون والإمكانيات التقنية لاستخراج الغاز الصخري منه من خلال البيانات المتاحة .

الكلمات الدالة : النفاذية ،الغاز الصخري،المكامن التقليدية وغير التقليدية،النفط،استخراج الغاز، سونطراك

RÉSUMÉ : Tout au long des 40 dernières années, l'industrie pétrolière a progressé de réservoirs du gaz conventionnels, aux non conventionnelles, du tight gaz de réservoirs de faible perméabilité, à ultra-faible perméabilité réservoirs de gaz de shale, dans lequel chaque type de réservoir a présenté ses propres défis. Le but ultime de ce travail est d'aider à comprendre les concepts de base des réservoirs de gaz de shale, la méthodologie des évaluations de ce type de source non conventionnelle et à caractériser le potentiel des bassins de shale de l'Algérie avec le premier plan à partir du Sonatrach pour l'exploration de la base Ahnet sur les données disponibles.

MOTS-CLÉS : gaz de shale, l’industrie pétrolière, réservoir non conventionnel, perméabilité, tight gaz, Sonatrach

ABSTRACT: Throughout the last 40 years, the petroleum industry has progressed from conventional gas reservoirs, to tight gas reservoirs, to ultra-low permeability unconventional shale gas reservoirs, wherein each type of reservoir has presented its own unique challenges. The ultimate purpose of this work is to help understanding the basic concepts of shale gas reservoirs, evaluations methodology for this type of unconventional source and to characterize the potential of Algeria’s shale basins with the first plan for exploration the Ahnet (Timimoun); basis on the available data .

KEYWORDS : petroleum industry, tight gas,conventional,unconventional,exploration,shale gas

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Acronyms List

Bcf	Billion Cubic Feet
BI	Brittleness index
CBW	Clay Bound Water
DGMK	The Germen Society for Petroleum and Technology
E	Young Modulus
FID	flame ionization detector
GIP/GIIP	Gas in Place/Gas Initially in Place
GR	Gamma Ray
HC	Hydrocarbons
K	Permeability
LWD	Logging While Drilling
mD	Millidarcies
MCBW	Mobile and Capillary Bound Water
NMR	Nuclear Magnetic Resonance
PGC	Potential gas commitee
Ą **(phi)**	Porosity
PPy	Programmed Pyrolysis Instrument
Scf	Standard Cubic feet
SEM	Scanning Electron Microscopy
SRV	Stimulated reservoir volume
Tcf	Trillion Cubic feet
TCM	Trillion Cubic Meter
TOC	Total Organic content
UNCON	Unconventional reservoir
USEIA	Energy Information Administration
Wt% TOC	% TOC weight
XRD	X-Ray diffraction

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General Introduction

General Introduction

Shale gas is a kind of natural gas which mainly exists in dark mud shale and silty mudstone stratum in forms of adsorption, dissociation or dissolution.

The extraction of natural gas from organic rich shales is challenging and complicated. The most prominent property of shale gas reservoirs is low permeability, and this is one of the reasons why shales are some of the last major sources of natural gas to be developed. However, shale can store enormous amounts of gas and may, by the use of modern recovery techniques, be very profitable.

These stones are generally tight, interbed or interlayer, thus facilitating the coexistence of dissociated natural gas and absorbed natural gas, with the important characteristics of introduction of absorption mechanism and intrinsic essence of nearby (local) concentration. The shale gas is continuously formed biochemical gas or thermal gas or the mixture of both. With universal stratum saturation, unknown concentration mechanism, various lithologic sealing and relative short transportation distance, the shale gas can dissociate in natural crack and pore, absorb on kerogen or surface of clay particle and even dissolve in kerogen and bituminous matter.

The exploration and development of shale gas was started in United States. The first industrial shale gas well was drilled in 1921 in United States. Since then, many gas reservoirs have been found successively in United States. In 1970s, United States government invested a lot in geological and geochemical research of shale gas and made great breakthrough in shale gas absorption mechanism research, thus greatly improving the output of shale gas of United States by 7 times from 1979 to 1999.

The huge success of shale gas exploration and exploitation in United States greatly stimulates the enthusiasm of different countries all over the world in searching natural gas resource in shale sequence. In recent years, some scholars have started to pay attention to the shale gas resource of Algeria. However, the research hasn't been made systematically.

The ultimate purpose of this work is to help understanding the basic concepts of shale gas reservoirs, evaluations methodology for this type of unconventional source and to characterize the potential of Algeria's shale basins with the first plan for exploration the Ahnet basis on the available data .

This thesis is organized as follows:

→ The first chapter is a literature review on unconventional then in special shale reservoir, why shale plays study by determining of its principal elements to make it productive and commercial;

.

→ For the chapter two presents the aim methods and tools to identification of a potential gas shale reservoir ;

→ In chapter three, the technique keys (completion and stimulation) ;

→ Chapter four presents Algeria's shale basins characteristics, the choice of the Ahnet basin and ways for Preliminary estimates ;

→ Chapter five describes environmental footprint of shale gas extraction ;

Chapter I

Literature Review and General Information on Shale Gas Reservoirs

Introduction

Throughout the last 40 years, the petroleum industry has progressed from conventional gas reservoirs, to tight gas reservoirs, to ultra-low permeability unconventional shale gas reservoirs, wherein each type of reservoir has presented its own unique challenges.

I.1.Definition Of Unconventional Gas Reservoirs

Conventional natural gas comes from permeable reservoirs, typically composed of sandstone or limestone, where extraction is relatively straight forward because the gas generally flows freely. In contrast, unconventional gas is situated in rocks with extremely low permeability, which makes extracting it much more difficult at economic flow rates nor in economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, or special processes and technologies. An unconventional gas reservoir can be deep or shallow; high pressure or low pressure; high temperature or low temperature; blanket or lenticular; homogeneous or naturally fractured; and containing a single layer or multiple layers.

Once the well is drilled , completion realized then perforated , the hydrocarbons can flow in all directions converge towards the wellbore, under the effect of a pressure difference and permeability (Figure .I.1) . This flow covers a surface called drain surface and which is bounded by a radius of drain or barriers .Elsewhere in the unconventional field (Shale), the reservoir is a rock with organic- rich matter , slightly porous and has a permeability extremely low (nanoDarcy) .

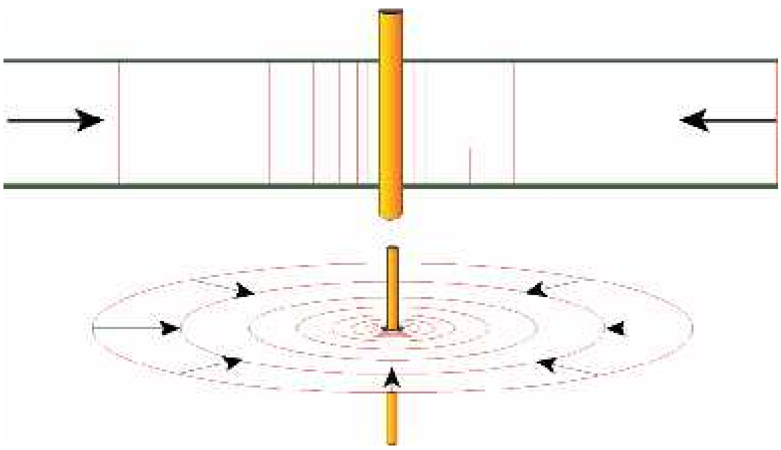


Figure .I.1. Drainage area in a conventional reservoir

On the well scale , the drain surface is in the limited volume of the fractured rock called SRV, which cannot be extracted as trapped in the hydrocarbons volume (SRV), unlike the volume of trapped outside SRV hydrocarbons do not contribute to the production, Due to the low permeability of these reservoirs (Figure.I.2) , which consolidates the idea of the large number of hydraulically fractured horizontal wells .

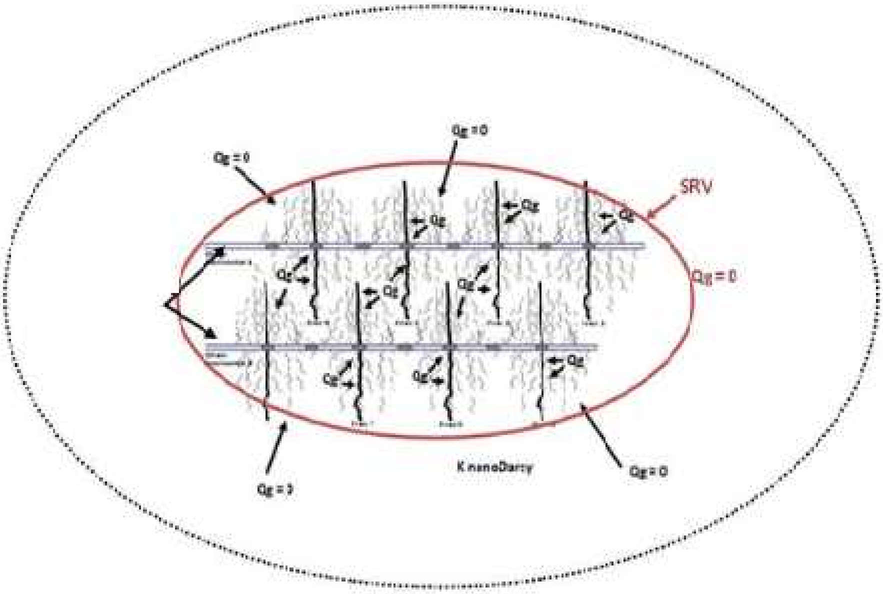


Figure .I.2. Above view of Drainage area in an unconventional reservoir

The unconventional gas reserves chiefly include : tight gas, coal bed methane, hydrate gas and shale gas.

I.1.1.Tight Gas

Tight gas lacks a formal definition, and usage of the term varies considerably. Law and Curtis (2002) defined low-permeability (tight) reservoirs as having permeability's less than 0.1mD.Therefore, the term "Tight Gas Reservoir" has been coined for reservoirs of natural gas with an average permeability of less than 0.1 mD (1 x 10 m^2). The DGMK announced a new definition for tight gas reservoirs elaborated by the German petroleum industry, which includes reservoirs with an average effective gas permeability less than 0.6 mD.

Tight gas Reservoir is often defined as a gas bearing sandstone or carbonate matrix (which may or may not contain natural fractures) which exhibits an in-situ permeability to gas of less than 0.10 mD. Many 'ultra tight' gas reservoirs may have in-situ permeability down to 0.001 mD.

Tight gas includes all the gas resources occurring as free gas in the pores of clastic and carbonate reservoirs in regionally pervasive continuous gas accumulations.

I.1.2.Coalbed Methane (CBM)

Coal, another fossil fuel, is formed underground under similar geologic conditions as natural gas and oil. These coal deposits are commonly found as seams that run underground, and are mined by digging into the seam and removing the coal. Many coal seams also contain natural gas, either within the seam itself or the surrounding rock. This coalbed methane is trapped underground, and is generally not released into the atmosphere until coal mining activities unleash it. Historically, coalbed methane has been considered a nuisance in the coal mining industry. Once a mine is built, and coal is extracted, the methane contained in the seam usually leaks out into the coal mine itself. This poses a safety threat, as too high a concentration of methane in the well creates dangerous conditions for coal miners. In the past, the methane that accumulated in a coal mine was intentionally vented into the atmosphere. Today, however, coalbed methane has become a popular unconventional form of natural gas. This methane can be extracted and injected into natural gas pipelines for resale, used as an industrial feedstock, or used for heating and electricity generation. In June 2009, the PGC estimated that 163 Tcf of technically recoverable coalbed methane existed in the US, which made up 7.8 percent of the total natural gas resource base.

I.1.3.Hydrate Gas

Hydrates gas or methane Hydrates are the most recent form of unconventional natural gas to be discovered and researched. These interesting formations are made up of a lattice of frozen water, which forms a sort of 'cage' around molecules of methane. These hydrates look like melting snow and were first discovered in permafrost regions of the Arctic. However, research into methane hydrates has revealed that they may be much more plentiful than first expected. Estimates range anywhere from 7,000 Tcf to over 73,000 Tcf. In fact, the USGS estimates that methane hydrates may contain more organic carbon than the world's coal, oil, and conventional natural gas - combined. However, research into methane hydrates is still in its infancy. It is not known what kind of effects the extraction of methane hydrates may have on the natural carbon cycle or on the environment.

I.1.4.Shale Gas

Natural gas can also exist in shale deposits, which were formed 350 million of years ago. Shale is a very fine-grained sedimentary rock, which is easily breakable into thin, parallel layers. It is a very soft rock, but it does not disintegrate when it becomes wet. These shales can contain natural gas, usually when too thick, black shale deposits ‘sandwich’ a thinner area of shale. Because of some of the properties of these shales, the extraction of natural gas from shale formations is more difficult and perhaps more expensive than conventional natural gas.

Conventional Gas	Shale Gas
Requires Structural or Stratighraphic traps	Does not requires trapping mechanism
Requires source, reservoir and seal lithologies	Gas stored in natural fractures or adsorbed on mineral surfaces; self-sourcing, self-sealing .
Consider burial history/thermal maturity/TOC of source .	Consider burial history/thermal maturity/TOC of shale itself .
Fractured reservoirs account for only ~20% of conventional HC production .	Gas shale must be fracture stimulated to produce commercially :artificial reservoir .
Sedimontology and facies mapping can be important indicators for reservoir quality .	Stress regime analysis ,rock Brittleness tend to more important due to the need to fracture the reservoir –but local facies variations can affect production .

Table.I.1.Outline Differences Between Conventional And Shale Gas

I.2.The Resource Triangle

The concept of the resource triangle was used by Masters and Grey to find a large gas field and build a company in the 1970s. The concept is that all natural resources are distributed log-normally in nature. If you are prospecting for gold, silver, iron, zinc, oil, natural gas, or any resource, you will find that the best or highest-grade deposits are small and, once found, are easy to extract. The hard part is finding these pure veins of gold or high-permeability gas fields. Once you find the high-grade deposit, producing the resource is rather easy and straightforward(Figure.I.3) illustrates the principle of the resource triangle.

As you go deeper into the resource triangle, the reservoirs are lower grade, which usually means the reservoir permeability is decreasing. These low permeability reservoirs, however, are usually much larger than the higher quality reservoirs. As with other natural resources, low quality deposits of natural gas require improved technology and adequate gas prices before they can be developed and produced economically. However, the size of the deposits can be very large, when compared to conventional or high-quality reservoirs. The concept of the resource triangle applies to every hydrocarbon-producing basin in the world. We can estimate the volumes of oil and gas trapped in low quality reservoirs in a specific basin by knowing the volumes of oil and gas that exist in the higher-quality reservoirs.

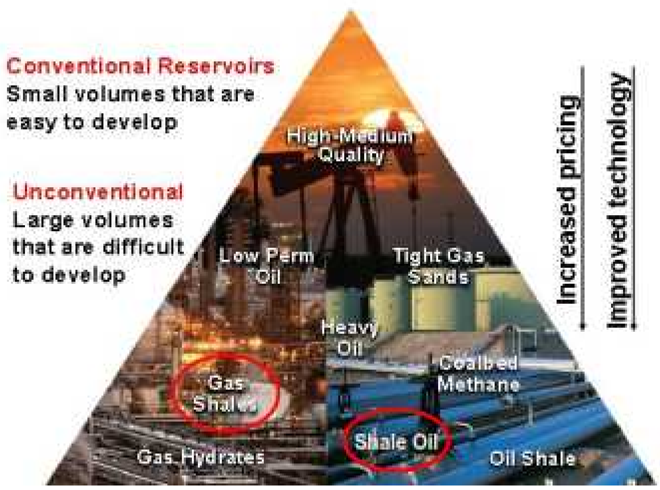


Figure .I.3. The resource triangle for oil and gas (Hoditch,JPT Nov.2003)

I.3.Worldwide Shale Gas Resources

Although there is significant uncertainty in assessing its recoverability, unconventional shale gas is expected to raise World technically recoverable gas resources by over 40% (USEIA, 2011). The initial estimate of technically recoverable shale gas resources in the 32 countries examined in the EIA's "World Shale Gas Resources" study is 5,760 trillion cubic feet (see Figure.I.4.)

Shale gas resources are thought to be plentiful in the European Union (Poland and France), North America, China, Australia, Africa (South Africa, Libya, and Algeria), and South America (Argentina and Brazil) (USEIA, 2011).

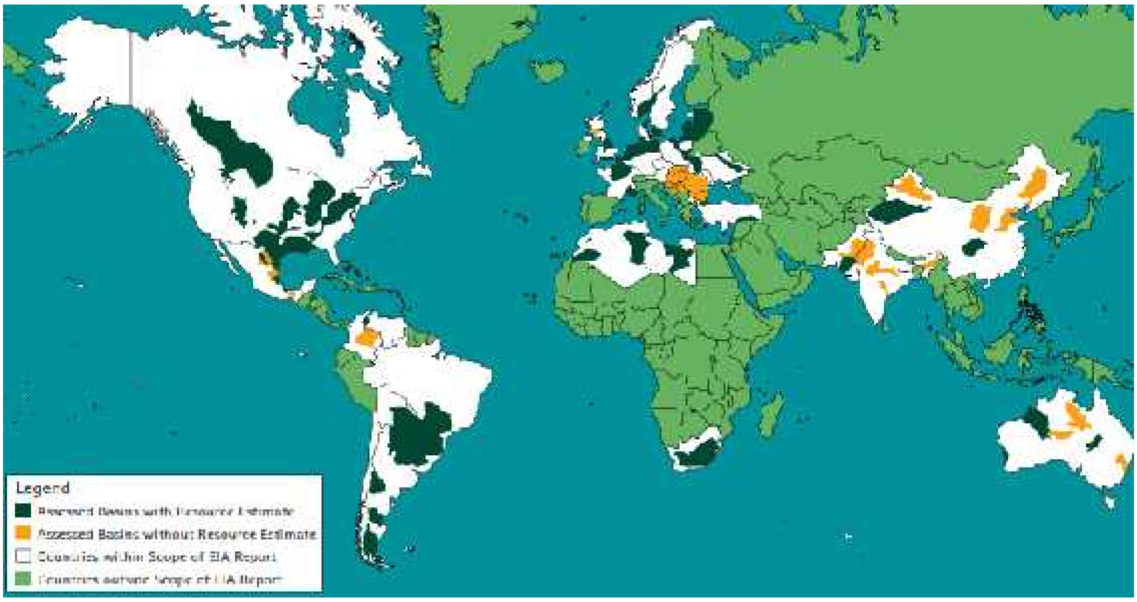


Figure.I.4.Map of 48 major shale gas basins in 32 countries (EIA,2011).

Importantly, much of this shale gas resource exists in countries with limited conventional gas supplies or where the conventional gas resource has largely been depleted, such as in China, South Africa and Europe.

The regional level tabulations of the risked in-place and technically recoverable shale gas resource are provided in Table.I.2. A more detailed tabulation of shale gas resources (risked gas in-place and risked technically recoverable), at the country-level, is provided in Table A-1 (Appendix A).Additional information on the size of the shale gas resource, at a detailed basin- and formation-level, is provided in Table A-2 (Appendix A).

Continent	Risked Gas In-Place (Tcf)	Risked Technically Recoverable (Tcf)
North America	3,856	1,069
South America	4,569	1,225
Europe	2,587	624
Africa	3,962	1,042
Asia	5,661	1,404
Australia	1,381	396
Total	22,016	5,760

Table.I.2. Risked Gas In-Place and Technically Recoverable Shale Gas Resources ;Six Continents,EIA 2013

I.3.1.Shale Gas In US

The current estimate of the shale gas resource for the continental US is about 862 Tcf. This estimate doubled from 2010 to 2011 and is expected to continue to grow with additional resource information. Annual shale gas production in the US increased almost five fold, from 1.0 to4.8 Tcf between 2006 and 2010.

The percentage of contribution to the Total, natural gas supply grew to 23% in 2010;it is expected to increase to 46% by 2035. With these dramatic increases in resource estimates and production rates, shale gas is widely considered a "game changer" in the energy picture for US.

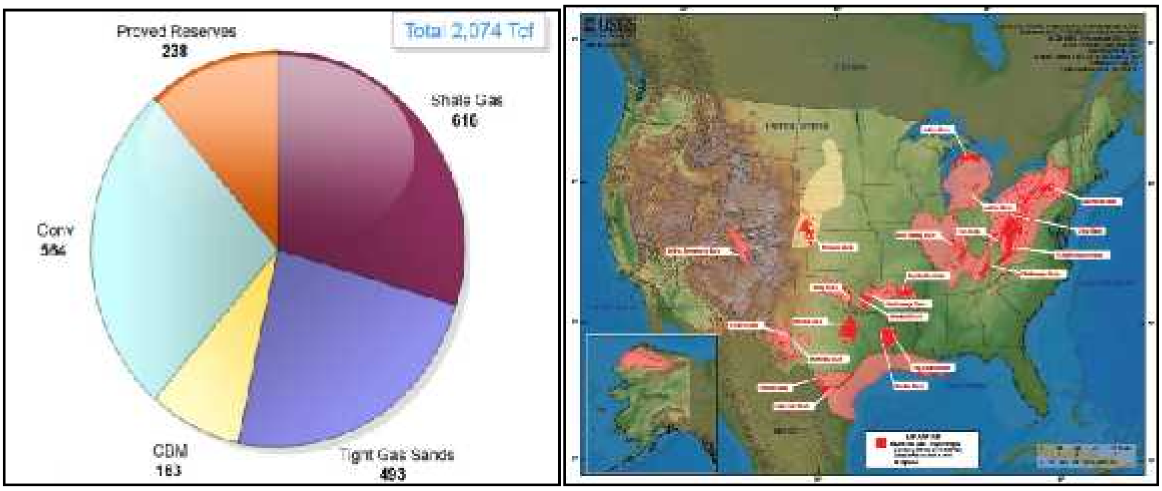


Figure.I.5.In the left Technically recoverable gas in US from PGC,2009,and in the right the map of assessed shale gas in US,2012

I.3.2.Shale Gas In Europe

The current state of shale gas exploration and appraisal in Europe merits some additional discussion.Although much has been made of shale gas potential in Europe, relatively little exploration activity is taking place outside of Poland.Licences for shale gas exploration were first granted in Poland in 2008-2009,although,legally and contractually,no distinction is made between shale gas and conventional gas in Poland (unlike coal-bed methane).Most of the activity has centred on the Lower Palaeozoic shales of the Baltic,Podlasie and Lublin basins,with operators tending to drill vertical exploration wells and later sidetracking or drilling horizontal wells.Since early 2010,some sixteen shale gas exploration and appraisal wells have been spudded,of which five are,or have been designed to be horizontal wells.Both the European Commission and the IEA believe these and other basins could be depositoies of significant resources with estimated total recoverable reserves in Europe that fall between 33 to 38 TCM, of which 12TCM are tight gas, 15 TCM shale gas, and 8 TCM coalbed methane. Such sizable resources have the potential to radically reshape the picture of Europeans gas supply and shale gas could thus play a key balancing role in gas markets on a regional basis.

Continent	Region	Country	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
Europe	VI. Eastern Europe	Poland	792	187
		Lithuania	17	4
		Kaliningrad	76	19
		Ukraine	197	42
			1,082	*252*
	VII. Western Europe	France	720	180
		Germany	33	8
		Netherlands	66	17
		Sweden	164	41
		Norway	333	83
		Denmark	92	23
		U.K.	97	20
		Subtotal	*1,505*	*372*
	Total		**2,587**	**624**

Table.I.3. Risked Gas In-Place and Technically Recoverable Shale Gas Resources in Europe;EIA 2013

I.3.3.Shale Gas In Algeria

The principal matrix likely to be the source of hydrocarbons highlighted in the various reservoirs of the sedimentary cover are:

* Lower Silurian

* Lower Frasnian

* The Cenomanian-Tournaisian passing.

The first two levels characterizing the Saharan platform while the third horizon is related to North of Algeria and to a lesser extent on the furrow of Melghir (more detailed informations in Chapter IV).

I.4.General Information On Shale Gas Reservoirs

Shale gas is both created and stored within the shale bed. Natural gas (methane) is generated from the organic matter that is deposited with and present in the shale matrix.

Shales have very low matrix permeability's requiring either natural fractures and/or hydraulic fracture stimulation to produce the gas at economic rates. Shales have diverse reservoir properties and a wide array of drilling, completion, and development practices are being applied to exploit them. As a result, the process of estimating resources and reserves in shales needs to consider many different factors and remain flexible as our understanding evolves.

I.4.1.Different Types Of Shale

The term "shale" suggests a laminar and fissile structure present in certain rocks (Figure.I.6) On the other hand, it is also used to refer to fine-grained,detrital rocks, composed of silts and clays. Mudrocks are also considered shale and ,hereafter, will indiscriminately be referred to as silty argillites or shale. They are fine –grained rocks, although they can also be mud masses or mudstones, which do not have any fissile properties.

Figure.I.6.Evidence of fissility in shale outcrops in the left, and Core in laminated shale in the right (Quuesterre Energy 2009 and Repsol YPF)

There are mainly two types of shales on the basis of organic matter:

Oil Shale

Sedimentary rocks containing up to 50% organic matter along with a considerable amount of oil, can be processed to produce oil and other chemicals and minerals. Oil shale contains significant amounts of petroleum like oil and refined products like gasoline, fuel oil and many other products due to the presence of organic material like kerogen (Ketris and Yudovich, 2009). Oil shales include organic rich shales, marls, and clayey limestones and dolomites with varying contents of organic matter as high as 50% in some very high grade deposits. In most cases the organic matter varies between 5 and 25%. Organic matter is present in combination with high contents of oil and other volatile components with no free hydrocarbons which indicated that oil shales are immature sources of oil (Dyni, 2006).

Black Shale

The black shale is the most important type of shale reservoir that fall under the gas shale umbrella beside there are others shale gas plays type like gray shale (Mowry, Steele, Baxter, Hilliard, Lewis, Montney) and biogenic gas shale (Antrim).These shales contain relatively lower amounts of organic material than the oil shale. Its black color is due to organic matter of algae, bacteria and other life forms that lived in the sea at that time. It can be considered as discarded ore used for building purposes for the manufacturing of cement, fertilizer and as a plant stimulant (Zhao et al., 2009). The black shale ores vary from others in mineralogical as well as chemical properties and in recovery of metals. These are mainly portrayed by copper contents not more than 5.5% and other metals like silver (0.01%).

Roughly 3 to10 time greater metals contents are present in bituminous shale ore than carbonate and sandstone forms (Luszczkiewicz, 2000). The former is therefore considered as a natural polymetallic concentrate. Some metals in the shale ore are present as bituminous organometallic compounds, like porphyrins in shales, and hence it reduces the metal recovery by using classical methods of ore enrichment. Affinity between metal ions and organic substances like kerogen could also fix metals in to black shale sediments (Hai et al., 2005; Steiner et al., 2001). Black shale is sometimes known as alum shale, which is mainly composed of clay minerals such as illite and montmorillonite, smectite and chlorite in combination with fine particles of quartz and mica (Bustin, 2005). On a global scale, there are widespread occurrence of black shales and interbedded charts.

I.4.2.Shale Gas Characteristics (Sweet-Spot)

In order for a shale to have economic quantities of gas it must be a capable source rock. The potential of a shale formation to contain economic quantities of gas can be evaluated by identifying specific source rock characteristics such as total organic carbon (TOC), thermal maturity, and kerogen analysis. Together, these factors can be used to predict the likelihood of the prospective shale to produce economically viable volumes of natural gas. A number of wells may need to be analyzed in order to sufficiently characterize the potential of a shale formation, particularly if the geologic basin is large and there are variations in the target shale zone.

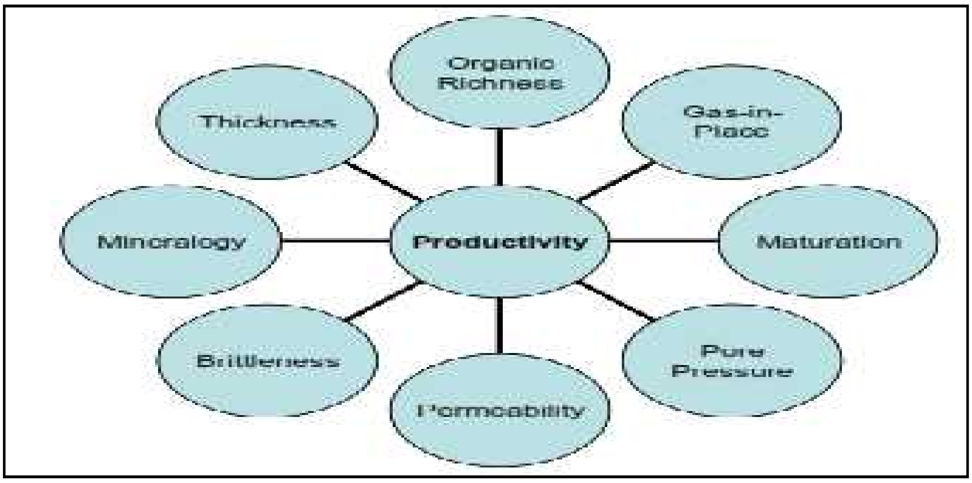


Figure.I.7.Elements necessary to make productive, commercial shale gas play (Hill et al.2008)

The purpose of this study is to define the Sweet-Spot that is by the following criteria**:**

- ✓ High TOC (thermally mature)
- ✓ Low clay volume (clay volume < 30%),
- ✓ High porosity (free gas and adsorbed) and permeability,
- ✓ High concentration of natural fractures,
- ✓ Low minimum horizontal stress (Stress Closure)
- ✓ Grand Brittleness

I.4.2.1.Porosity

The general definition of porosity of a porous medium is given the symbol of Ą and is defined as the ratio of void space, or pore volume, to the total bulk volume of the rock. This ratio is expressed either as a fraction or in percent. When using a value of porosity in an equation it is nearly always expressed as a fraction.

In the shale rocks the porosity, natural fractures aside , is composed of :

a) The porosity of the non-clay matrix
b) Clay porosity
c) Kerogen porosity; Porosity in organic matter can be five times higher than that in the nonorganic matrix (Javadpour, et al., 2007)

For an shale is considered a potential if it must include a porosity more than 2%

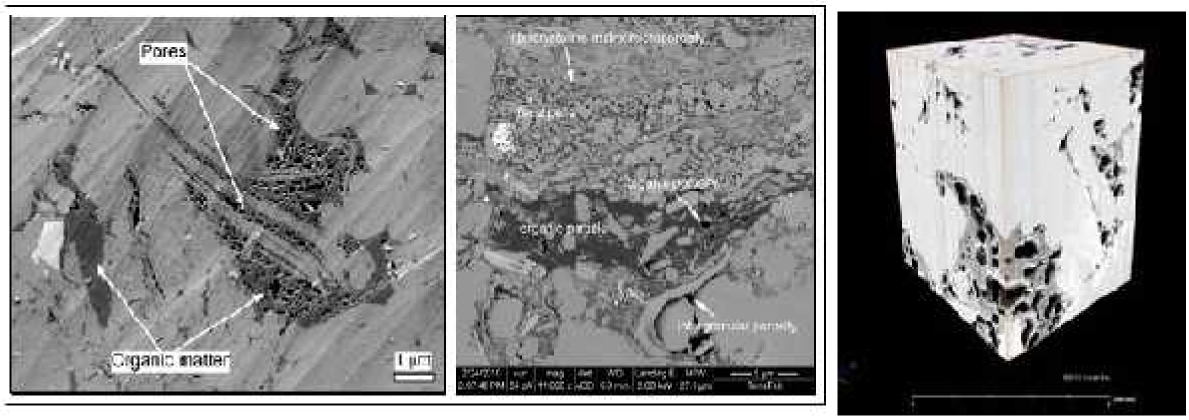


Figure.I.8.SEM showing kerogen porosity, inorganic matrix and pores in organic matter (Reed,R,BEG 2008)

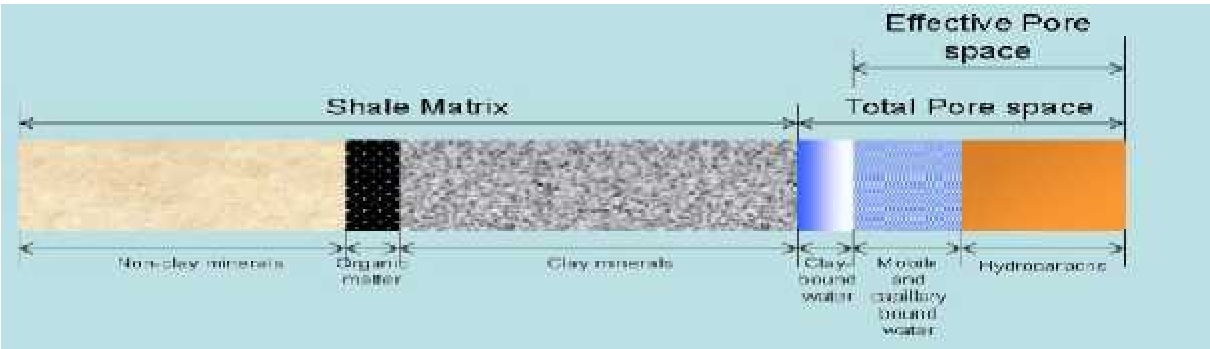


Figure.I.9. System porosity in shales,(Eslinger and Pevear,1998)

In shales, the total porosity is the sum of three porosities:

- Hydrocarbons Porosity (free and adsorbed: matrix and kerogen) :

$$\emptyset = \frac{V_{hc}}{V_T}$$

- Porosity of Mobile and Capillary Bound Water:

$$\emptyset_{MCBW} = \frac{V_{mcb}}{V_T}$$

- Porosity of Clay Bound Water:

$$\emptyset_{CBW} = \frac{V_{cbw}}{V_T}$$

So for the total porosity : $\emptyset_T = \underbrace{\emptyset_{hc} + \emptyset_{MCBW}}_{\text{Effective porosity}} + \emptyset_{CBW}$

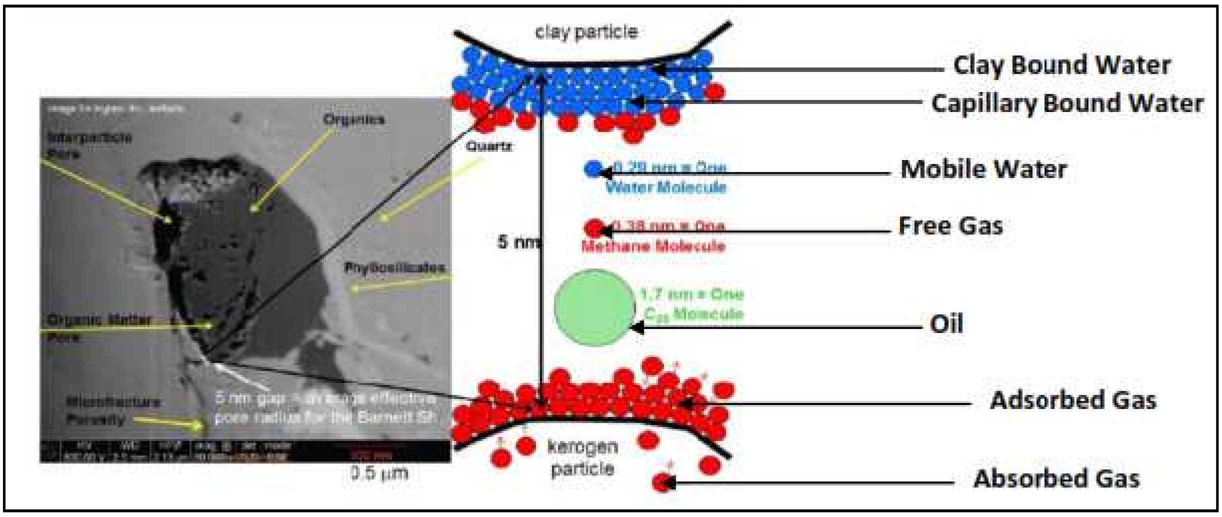


Figure.I.10.Distribution Of The Fluids In The Shales

I.4.2.2.Permeability

Permeability is a property of the porous medium and it is a measure of capacity of the medium to transmit fluids. Permeability is a tensor that in general is a function of pressure. Usually, the pressure dependence is neglected in reservoir calculations, but the variation with position can be pronounced. Very often the permeability varies by several magnitudes, and such heterogeneity will of course influence any Petroleum recovery. Beside, the permeability in shales is a key factor in stimulation design and production prediction.

Two permeability need to be considered: matrix and system.

- ☑ Matrix permeability of the shale rock is typically 10^{-4} to 10^{-8} mD.Matrix permeability can be accurately measured with core analysis, or it may be estimated via log evaluation if a local calibration can be developed.
- ☑ System permeability is equivalent to matrix permeability plus the contribution of open fractures. Conventional logs are insensitive to fractures and cannot be used to estimate system permeability.

I.4.2.3.Organic Richness

Total organic carbon (TOC), is the amount of carbon bound in organic compounds of the rock; it is the remnant of organic life preserved in sedimentary rocks subjected to chemical and bacterial degradation that have later been modified by heat and pressure over time. This final stage, maturity ,is a result of long periods of burial and proximity to heat sources. Chemical relations resulting from maturity of organic matter are responsible for producing gas ,oil ,bitumen ,pyrobitumen and coal that to gather contribute to total carbon content.

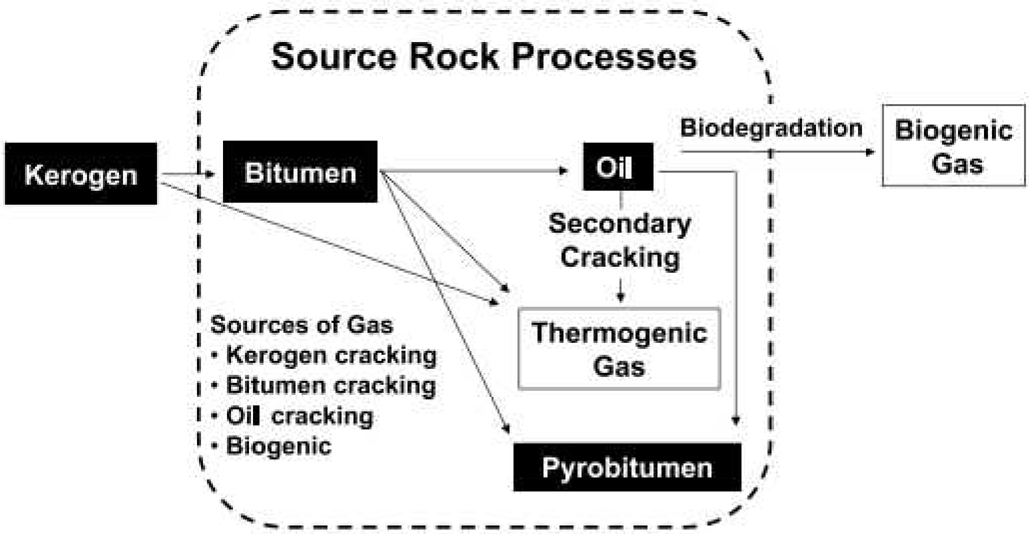


Figure.I.11.Processes In Source Rock,(Jarvie et al.2007)

Total Organic Carbon(weight %)	Resource Potential
<0.5	Very Poor
0.5 – 1	Poor
1 -2	Fair
2 – 4	Good
4 – 10	Very Good
>10	immature

Table.I.4.TOC and Shale Gas Resource Potential Relationship

I.4.2.4.Thikness

The thickness of the matrix is an essential parameter in the evaluation of shale gas potential , viewpoint of storage of the organic matter and for the success of stimulation by fracking. The minimal thickness for a potential gas shale is > 30 m

I.4.2.5.Maturity

Thermal maturity measures the conversion of the organic carbon contained in the shale to hydrocarbons. An ideal shale gas play can be identified by finding a proper combination of the TOC content and thermal maturity (Gault, et al., 2007).

A kerogen is a solid, waxy mixture of chemical compounds that is transformed into hydrocarbons with sufficient temperature and pressure. Kerogen is insoluble in organic solvents due to its high molecular weight.

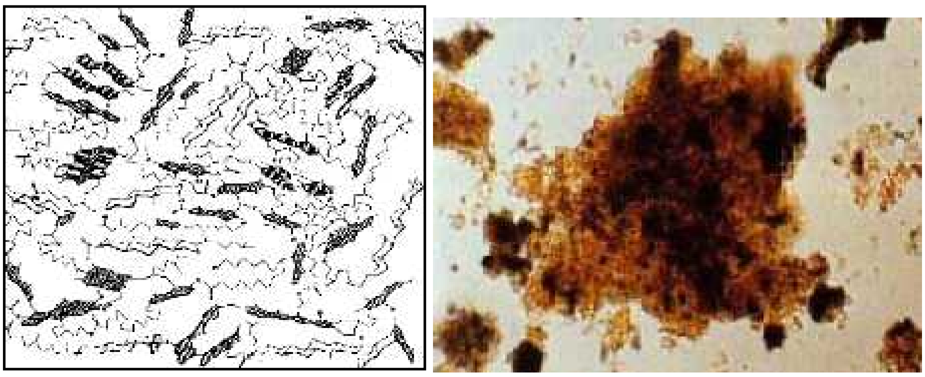


Figure.I.12.Kerogen Under The Microscope In The Left, And Molecular Structure Of Kerogen In The Right

Basic Types of Kerogen :

Type I: Derived primarily from algae in anoxic lakes; rich liquid HC source.

<u>Type II:</u> Derived from marine algae and transported terrestrial plant material; mixed oil and gas source.

***<u>Type IIS</u>**:* Similar to Type II, high in sulfur.

<u>Type III:</u> Principally coal--derived from terrestrial woody plants, gas source.

<u>Type IV:</u> Decomposed organic matter (does not produce hydrocarbons).

The process of burial, conversion of organic matter and generation of hydrocarbons can be summarized in three steps:

– Diagenesis: It is characterized by low-temperature alteration of organic matter below 50oC (122oF)gradually converted to kerogen.

– Catagenesis: generally occurs as further burial causes more pressure, thereby increasing heat in the range approx 50 to 150 °C (122 to 302 °F) causing chemical bounds to break down within the shale and the kerogen.

– Metagenesis: is the last stage in which heat and chemical changes result in almost transformation of kerogen to carbon. During this stage, late methane, or dry gas evolved, along with non-hydrocarbon gases such as C02, N2 and H2S. Temperature range from about 150°C to 200°C (302 to 392°F).

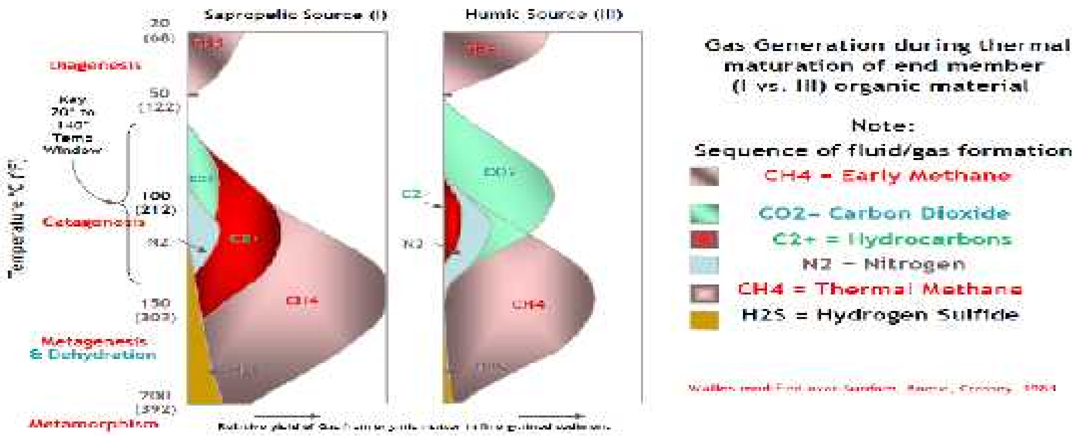


Figure.I.13.Kerogen type affects volume and timing of gas generation (Surdan et al 1984)

I.4.2.6.Mineralogy

Shale gas reservoirs show a complex and highly variable mineralogy with theoretical end points of :

i) A perfect shale in a petrophysical sense (100 % clay minerals with only electrochemically-bound water in the pore space and thence a zero effective porosity)

ii) A porous, lithologically-clean sandstone/limestone.

In reality, the mineralogy includes quartzitic or calcareous silts and clays; clay minerals such as chlorite, illite, smectite and kaolinite; and larger detritus that can include pyrite and siderite. Microscopic studies have suggested that the textural and mineralogical complexity of shales may not always be readily apparent (Aplin & Macquaker 2011). The inorganic minerals co-exist with solid organic matter in the form of kerogen.

Mineral	Chemical Formula	Identifying Elements
Quartz	S_iO_2	Silicon
Calcite	$CaCO_3$	Calcium
Dolomite	$CaMgCO_3$	Calcium+Magnesium
Anhydrite	$CaSO_4$	Calcium+Sulfur
Pyrite	FeS_2	Iron+Sulfur
Ankerite	$CaSO_3(Mg.Fe.Mn)\ CO_3$	Calcium+Sulfur+Iron+ Magnesium+Manganese
Limenite	$Fe\ TiO_3$	Iron+Titanium
Orthoclase	$KALSi_3O_6$	Potassium+Aluminium+Silicon
Gadolinium(III) oxide	Gd_2O_3	Gadolinium

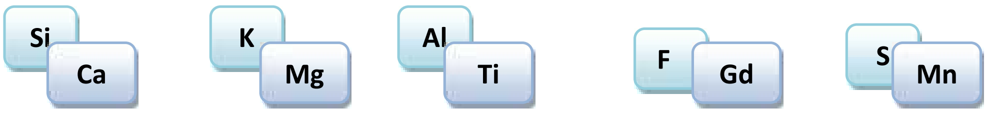
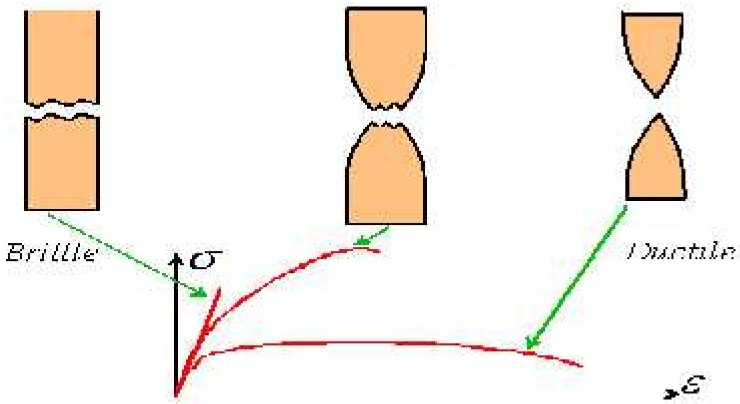


Table.I.5. The Main Minerals Of Shales

I.4.2.7.Brittleness

A material is brittle if, when subjected to stress, it breaks along discrete surfaces without little or no internal deformation between the surfaces. The relative brittleness of rock refers to its tendency to fail (fracture) along such surfaces when an external force is applied, such as the fluid pressure during hydraulic fracturing.

Conversely, the relative ductility of a rock refers to its tendency to fail by bulk internal strain rather than discrete fractures. The brittleness of zones within shale reservoirs is of critical importance to initiating fracture networks during frac, completions and for maintaining open fractures that do not suffer from excessive proppant embedment.



Brittle mineral content is the critical factor affecting matrix porosity, micro-fractures, gas content, and fracturing pattern (Li Xinjing et,al.2007; Sondergeld et,al.2010; Zou Caineng et,al.2010). The capacity of induced fractures in shale with abundant quartz or feldspar is strong. Brittle mineral content is generally higher than 40%, and clay mineral content is less than 30% for shale that can be commercially exploited.

I.4.2.8.Gas Content

The Gas in shale gas reservoirs is stored in :

- Adsorbed gas in the kerogen material
- Free gas trapped in nonorganic inter-particle (matrix) porosities
- Free gas trapped in micro fracture porosity
- Free gas stored in hydraulic fractures created during the stimulation of the shale reservoir
- Free gas trapped in a pore network developed within the organic matter or kerogen. (Rahmanian, et al., 2010)

I.4.3.Mecanisme Of Gas Shale Formation

In general the principal conditions and stages of formation of shale gas are the same like the conventional natural gas.

Clays can settle in various sedimentary mediums (lagoons, deltas, fluviatile plain, sea-beds or continental shelf).Their high content in organic matter depends not only on the medium of deposit but also on the climate, the hydrodynamism, the continental contributions but also on the biological production.

Its conservation requires however: an environment anoxic, hyper-saline and a fast sedimentation but at low rate. The difference between the shale gas formation and the conventional gas, is in:

- The absence of migration, shale gas is formed and stored in the same formation.
- The trapping of shale gas is related to the low permeability of shale formations, then the shale gas cannot mobilize to accumulate in the conventional systems.

In thermogenic shale gas reservoirs (like the Barnett Shale), the organic matter has been sufficiently cooked to generate gas which is held in the pore space and sorbed to the organic matter.

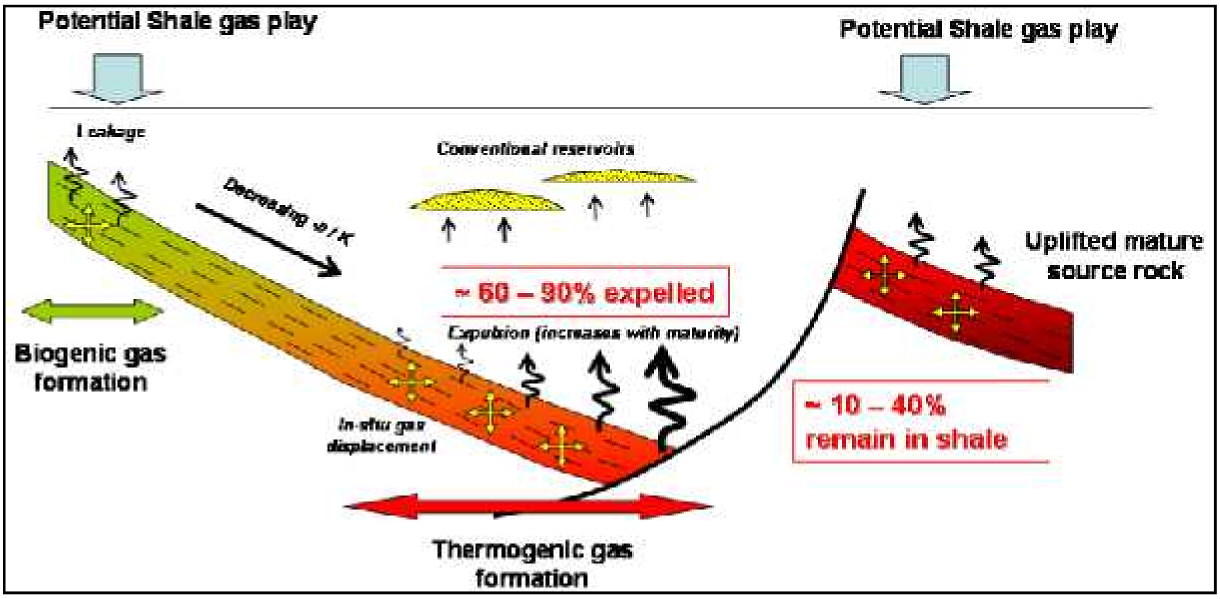


Figure.I.14. Mechanism of Gas Shale Formation,(Kaced-Sonatrach 2012)

In biogenic shale gas reservoirs (like the Antrim Shale) the organic matter has not been buried deep enough to generate hydrocarbons. Instead, bacteria which has been carried into the rock by water has generated biogenic gas that is sorbed to the organics.A common feature of productive thermogenic shale gas plays is brittle reservoir rock containing significant amounts of silica or carbonate and "healed" natural fractures. Relative to more clay rich-rock, it shatters when hydraulically fracture stimulated, which maximizes the contact area. Thermogenic shales are often referred to as "fracturable" shales instead of "fractured shales". In contrast, biogenic shales are commonly less brittle and rely, in large part, on the existence of open natural fractures to provide conduits for water and gas production.

I.4.4.Classification Of Shale Gas Resources And Reserves

Shales are composed of a mixture of silt-sized quartz and feldspar grains and much smaller clay mineral grains. Depending of the relative proportion, as well as bedding features, they may be classified as siltstones, mudstones, claystones, or shales.

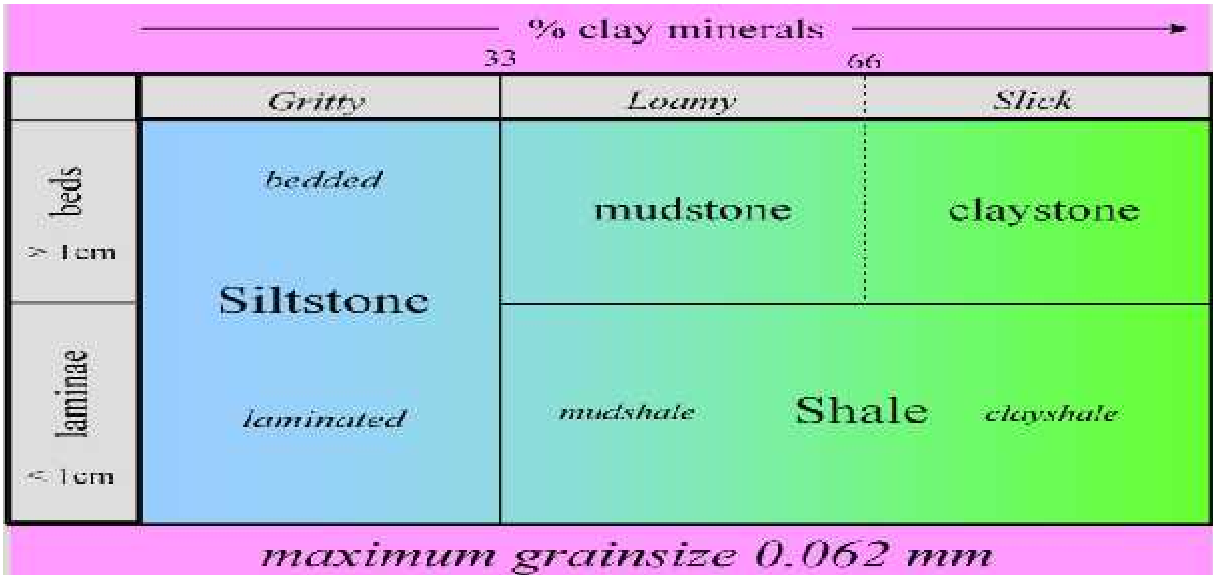


Figure.I.15.Basic shale classification,(Jeffrey Levine,2011)

The host rocks of shale gas accumulations act as source, seal and reservoir. They are characterized by complex pore systems with ultra-low to low interparticle permeability and low to moderate porosity. The word 'shale' is used in the sense of a geological formation rather than a lithology, so shale gas reservoirs can show marked variations in rock type from claystones, marlstones and mudstones to sandstone and carbonate lithological 'sweet spots'. The pore space includes both intergranular and intrakerogen porosity. The density of natural fractures varies markedly, and pore throat connectivity is relatively ineffective. Moreover, in-situ gas pore volume has to take account of both free and adsorbed gas, an evaluation exercise that is complicated by pronounced variations in water salinity. All these characteristics present major challenges to the process of petrophysical evaluation. The petrophysical responses to these issues are several fold.

Reservoir characteristics, including logs and mechanical properties, are strongly influenced by three parameters:

– Depositional mineralogy: intergranular porosity and permeability increase with increasing grain size.

– Organic content: based on abundance, source and thermal history .

– Matrix composition: material less than 4 microns (clay).

Shale gas resources and reserves may be estimated deterministically or probabilistically, with best practice being to use both methods.

Prior to discovery, these techniques can be used to generate low, best, and high estimates of prospective gas resources. The difference between the low and high estimates will likely be very large, reflecting the uncertainty in both gas-in-place volumes and recovery factors. Data available for this task could include 2-D seismic data and information such as logs, cuttings, mud logs, or cores from wells that passed through the shale on the way to deeper horizons. Prospective resources can become contingent resources once a well is drilled that demonstrates a significant quantity of potentially moveable gas. The most definitive evidence for this is a well test that produces gas to the surface, but this may not be possible if the well is damaged during drilling and requires fracture stimulation to flow. In this case, a suite of other data including laboratory desorption of the cores, gas kicks from the mud logs, evidence of thick organic-rich shales from the logs, and indications that the shale has produced gas in nearby leases or fields will be needed to assign contingent resources.

Initially, contingent resources should be placed in the "economic status undetermined" category while wells are drilled to evaluate the commercial potential of the play. During this time, contingencies that impede production (such as low permeability) and/or contingencies that impede development (such as the lack of a financial commitment) may be recognized. If it is clear that these cannot be overcome, the resources need to be assigned to the "unrecoverable" or" not viable" subclass.

After a sufficient number of wells have been drilled to demonstrate that the project is technically feasible and a development plan has been generated, economics can be run to determine whether the project should be placed in the marginal or submarginal contingent resources category. Because projects at this stage have a chance of failure, they are assigned risk factors in portfolio analyses. Once the gas has been shown to be commercially recoverable under defined conditions for a given project, and there is a commitment to proceed with development, shale gas contingent resources can be classified as reserves.

Shale gas reserves can be statistically aggregated up to the field, property, or project level. Some operators are using this technique to quantify proved reserves. Operators should be cautious in relying on such aggregations if they are supported only by type curve approaches to forecasting individual wells.

So there are two recognized methodologies for estimating reserves;

- Deterministic: A single best estimate of reserves is made based on known best estimates of geological, engineering and economic data
- Probabilistic: Estimated distributions of geological, engineering, and economic data are used to generate a range of reserves estimates and their associated probabilities.

I.4.5.Extraction Technology Of Shale Gas

I.4.5.1. Horizontal Drilling

Vertical drilling is typically used in the initial or pilot-testing phases of an emerging shale play, given the lower cost of coring and drilling vertically. However, once a shale play is deemed to be commercially viable based on early testing, almost without exception wide-scale development is undertaken using horizontal drilling. In a horizontal well, a vertical well is deviated to drill laterally, so as to expose the wellbore to the maximum amount of the shale formation as possible. Also, in many instances the naturally-occurring fractures in the shale are oriented vertically, so a horizontal well effectively intersects these pre-existing fractures, increasing potential production rates.

Well Pad is a series of horizontal wells in the same place, this technique is applied in the shales (see figure below).Within given the characteristics of shales, even using drilling horizontal and hydraulic fracturing, the volume of the gas which is drained remains limited. Communication between fractures remains weak as soon as one moves away from the horizontal wellbore. So the profitable development of shale requires a network of Well Pads covering up this formation. It is possible to drill several horizontal wells from a single location, which reduces the footprint area by grouping all wells.

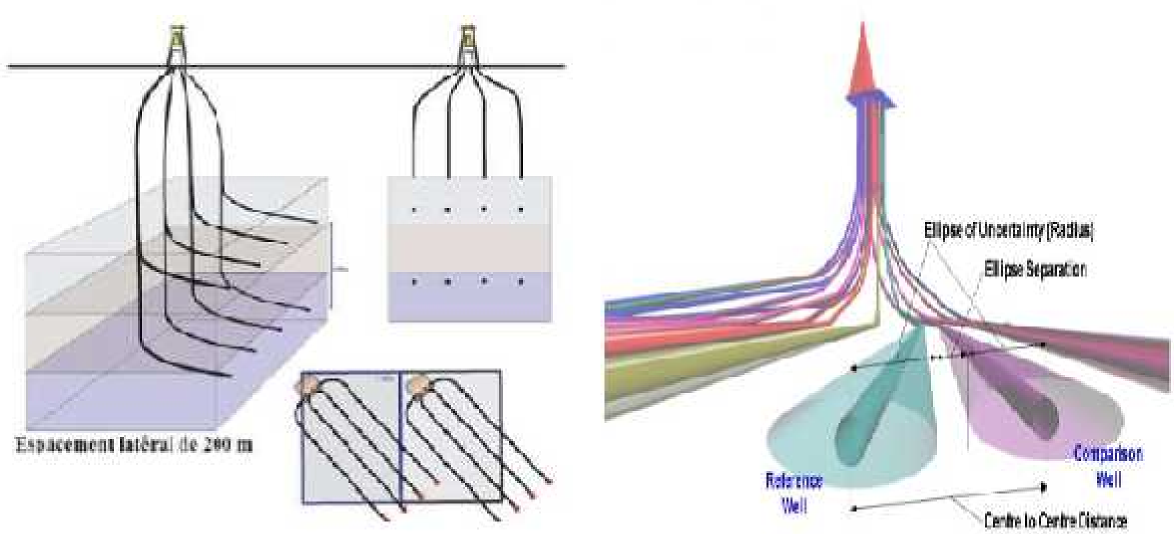


Figure.I.16.Well Pad (Schlumberger)

The mineralogical characteristics and compositions (type and percentage of clay) of shale play a very important role in choosing the type of drilling fluid. Experience has shown that the origin of some drilling problems derived from the properties of clays contained in the shales tend to swell. The drilling fluid must ensure both the flow of cuttings to the surface, the cleaning and lubrication of the drill bit, maintaining the stability of the walls, and stability of clays.

The problem with swelling clays during drilling in formations shale appears to be closely linked to the phenomena of clay and fluid interactions which is composed of a large quantity of water (between 4000 and 6000 m^3)and chemical additives. The instability of formations varies depending on the nature of these fluids drilling and their physical state.

To remedy this and increase drilling efficiency, today a new generation used for drilling fluid designed for shale, whose the environmental impacts are reduced. A new system of drilling fluid based water and based oil is used to deal with problems of clays in the formations shale.This innovation was a huge development in recent years using this new generation of drilling fluid adapted to shale formations.

For example, some drilling fluids used by Halliburton are cited in shale formations:

- **SHALEDRILL F : Fayetteville Shale**
- **SHALEDRILL H : Haynesville Shale**
- **SHALEDRILL B : Barnett Shale**

I.4.5.2. Hydraulic Fracturing

In addition to horizontal drilling, the other technology key to facilitating economical recovery of natural gas from shale is hydraulic fracturing. Hydraulic fracturing is a formation stimulation practice used in the industry to create additional permeability in a producing formation to allow gas to flow more easily toward the wellbore for purposes of production. Hydraulic fracturing can be used to overcome natural barriers to the flow of fluids to the wellbore. Barriers may include naturally low permeability common in shale formations or reduced permeability resulting from near wellbore damage during drilling activities. While aspects of hydraulic fracturing have been changing (mostly changes in the additives and propping agents) and maturing, this technology is utilized by the industry to increase the necessary production to support an ever increasing demand for energy. Hydraulic fracture treatments are not a haphazard process but are designed to specific conditions of the target formation (thickness of shale, rock fracturing characteristics, etc.) to optimize the development of a network of fractures. Understanding the in-situ conditions present in the reservoir and their dynamics is critical to successful stimulations. Initial hydraulic fracture treatments for new plays are designed based on past experience and data collected on the specific character of the formation to be fractured. Engineers and Geologists evaluate data from geophysical logs and core samples and correlate data from other wells and other formations which may have similar characteristics. Data are often incorporated into one of the many computer models the natural gas industry has specifically developed for analysis and design of hydraulic fracturing.

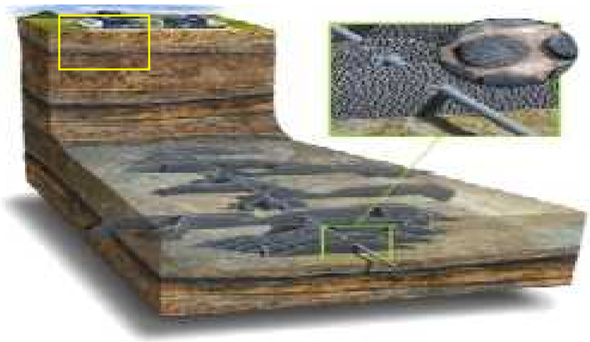


Figure.I.17. Horizontal Drilling And Fracking Method (HIWAY Schlumberger)

I.4.5.Overview Of Shale Gas Life Cycle Activities

Civil/site prep

Forest clearing, excavation, building of access routes, constructing and installing wells pads and preparing site for drilling activities.

Drilling

Natural gas will not readily flow to vertical wells because of the low permeability of shales. This can be overcome by drilling horizontal wells where the drill bit is steered from its downward trajectory to follow a horizontal trajectory for one to two kilometers, thereby exposing the wellbore to as much of the reservoir as possible.

Completion/fracking:

As drilling is completed, multiple layers of metal casing and cement are placed around the wellbore. After the well is completed, a fluid composed of water, sand and chemicals is injected under high pressure to crack the shale, increasing the permeability of the rock and easing the flow of natural gas.

Flowback

A portion of the fracturing fluid will return through the well to the surface due to the subsurface pressures. The volume of fluid will steadily reduce and be replaced by natural gas production.

Production

The fissures created in the fracking process are held open by the sand particles so that natural gas from within the shale can flow up through the well. Once released through the well, the natural gas is captured, stored and transported away for processing.

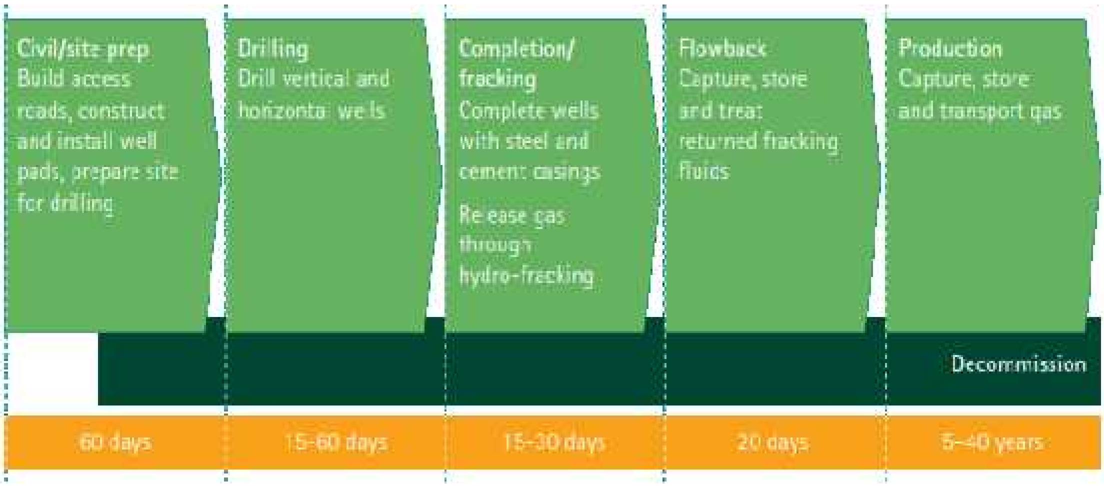


Figure.I.18.Shale Gas Lifecycle (Source Accenture,2012)

Conclusion

This section provides a general understanding of unconventional hydrocarbons reservoirs and passing through the shale gas reservoir specially by take on the necessary its elements for studying and get the ways to make this kind of reservoirs productive at the economic scale.

Chapter II

Potential Evaluation Methods of Shale Gas Reservoir

Introduction

Shale is the most common sedimentary rock and with the potential to be an economic gas reservoir, in contrast, is relatively rare. Due to their low permeability, gas shales are self-sourced. They must have the requisite volume and type of organic matter and proper thermal history to generate hydrocarbons, especially gas. The first step in any evaluation is the identification of a potential gas shale reservoir. So some knowledge of methods and tools are needed to specific fully characterize shale gas reservoirs.

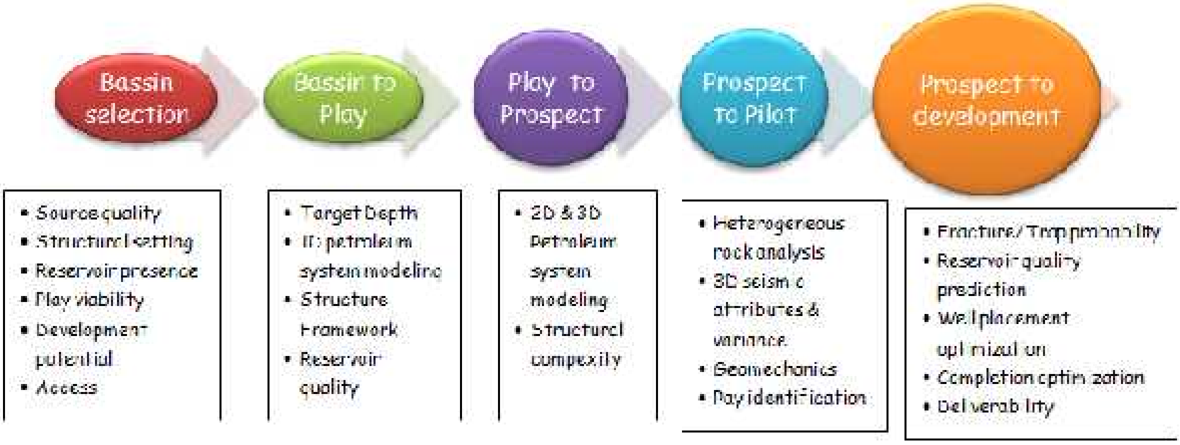
II.1.Shale Gas Reservoir Project Evaluation

The industry companies describe five stages of development of a shale gas project covering exploration (stages 1 to 4) and commercial production (stage 5):

1. Identification of the gas reservoir and during this stage the interested company performs initial geophysical and geochemical surveys in a number of regions. Seismic and drilling location permits are secured.

2. Early evaluation drilling. At this stage, the extent of gas bearing formation(s) is/are measured via seismic surveys. Geological features such as faults or discontinuities which may impact the potential reservoir are investigated. Initial vertical drilling starts to evaluate shale gas reservoir properties**.** Core samples are often collected.

3. Pilot project drilling. Initial horizontal well(s) are drilled to determine reservoir properties and completion techniques. This includes some multi-stage hydraulic fracturing, which may comprise high volume hydraulic fracturing. The drilling of vertical wells continues in additional regions of shale gas potential. The interested company executes initial production tests.



4. Pilot production testing. Multiple horizontal wells from a single pad are drilled, as part of a full size pilot project. Well completion techniques are optimized, including drilling and multistage hydraulic fracturing and micro seismic surveys. Pilot production testing starts. The company initiates the planning and acquisition of rights of way for pipeline developments.

5. Commercial development. Provided the results of pilot drilling and testing are favorable, the company takes the commercial decision to proceed with the development of the field. The developer carries out design of well pads, wells, pipelines, roads, storage facilities and other infrastructure. The well pads and infrastructure are developed and constructed, leading to the production of natural gas over a period of years or decades. As gas wells reach the point where they are no longer commercially viable, they are sealed and abandoned. During this process, well pad sites are restored and returned to other use .

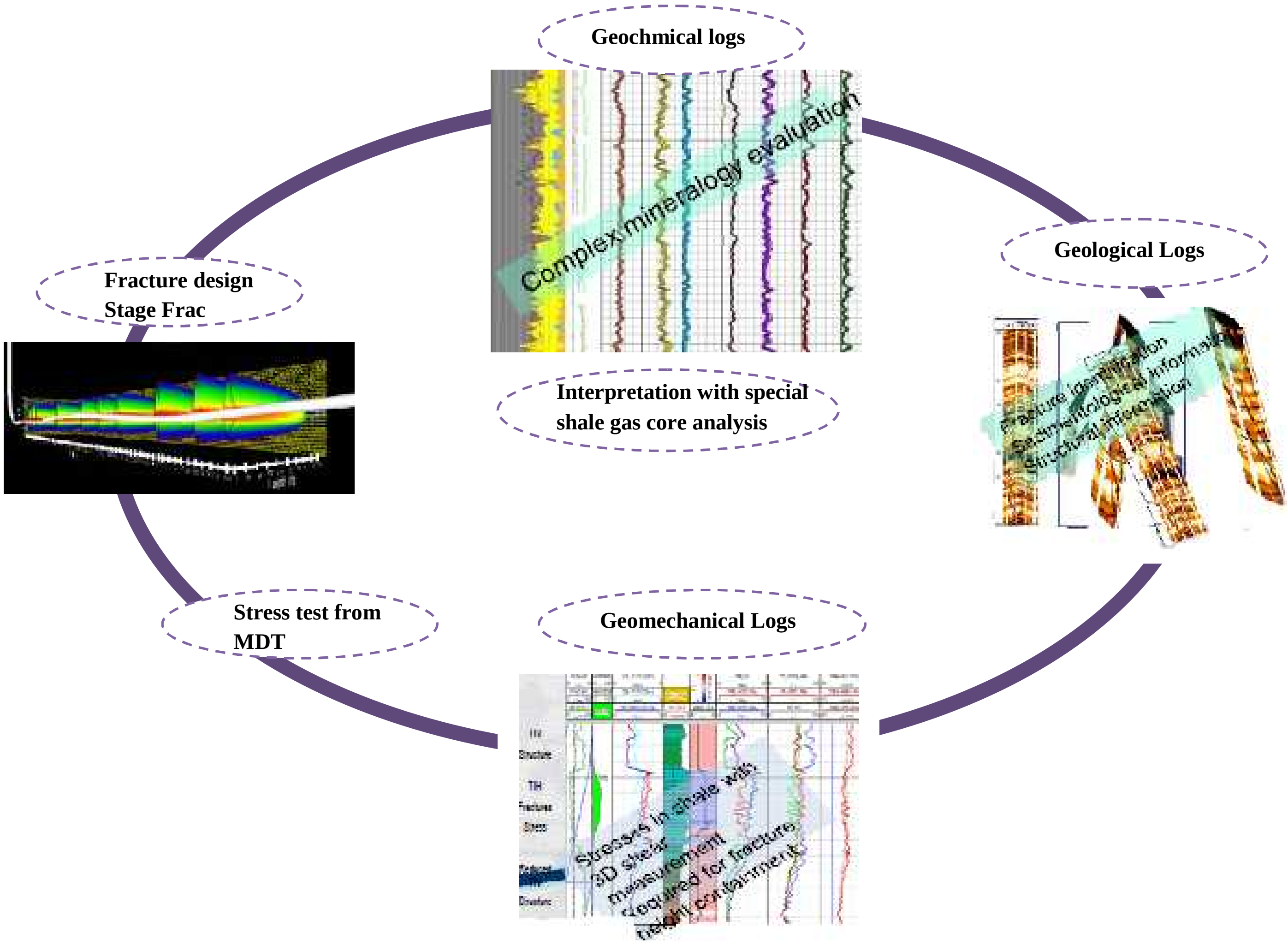


Figure.II.1.The Main Key Technologies For Shale Characterization

II.2. Critical Data Used To Appraise Shale Gas Reservoirs

1)Gas content:

- Provides volumes of desorbed gas (from core samples placed in canisters),residual gas(from crashed core),and lost gas (calculated).The sum of these is in-situ gas content.

2)Rock Evaluation Pyrolysis:

- Assesses the petroleum-generative potential and thermal maturity of organic matter in a sample.
- Determines the fraction of organic matter already transformed to hydrocarbons and the total amount of hydrocarbons that could be generated by complete thermal conversion.

3)Total Organic Carbon (TOC) :

- Determines the total amount of carbon on the rock including the amount of carbon present in free hydrocarbons and the amount of kerogen.

4)Gas Composition:

- Determines the percentage of methane, carbon dioxide, nitrogen and ethane in the desorbed gas.
- Used to determine gas purity and to build composite desorption isotherms.

5)Core Description:

- Visually captures shale brightness, banding, cleat spacing, mineralogy, pay thikness and other factors.
- Provides insights about the composition,permeability,and heterogeneity of the shale.

6)Sorption Isotherm:

- A relationship, at constant temperature, describing the volume of gas that can be sorbed to a surface as a function of pressure
- Describes how much gas a shales in capable of storing and how quickly this gas will be liberated.

7)Proximate Analysis :

- Provides the percentage of organic matter. Used to determine the maturity of shales.

8)Mineralogical Analysis :

- Determines bulk mineralogy using petrography and/or X-ray diffraction, and clay mineralogy using X-ray diffraction and/or scanning electron microscopy.

9)Vitrinite Reflectance :

- A value indicating the amount of incident light reflected by the vitrinite maceral. This technique is a fast and inexpensive means of determining s maturity in higher-rank shales.

10)Calorific Value :

- The heat produced by combustion of a shales sample. Used to determine shales maturity in lower-rank shales.

11)Maceral Analysis :

- Captures the types, abundance, and spatial relationships of various maceral types.These differences can be related to differences in gas-sorption capacity and brittleness, which affect gas content and permeability.

12)Bulk Density :

- Relationships between bulk density and other parameters (such as gas content) can be used to establish a bulk-density cutoff for counting shale thicknesses using a bulk-density log.

13)Conventional Logs :

- Self-potential, gamma ray, shallow and deep resistivity, micro-log, caliper, density, neutron, and sonic logs.
- Used to identify shales, and to determine porosity and saturation values in shales.

14)Special Logs :

- Image logs to resolve fractures and wireline spectrometry logs to determine in-situ gas content.

15)Pressure Transient Tests :

- Pressure buildup or injection fall-off tests to determine reservoir pressure, permeability, skin factor, and to detect fractured-reservoir behavior.

16)3D Seismic :

- Used to determine fault locations, reservoir depths, variations in thickness and lateral continuity and shale properties.

II.3.Potential Evaluation Shale Gas Reservoir Techniques

II.3.1.Geochemical Measurements

The most Important Geochemical Parameters for a Shale Gas Reservoir are :

- Organic richness (> 2% TOC)
- S2 pyrolysis yield (> 5 mg HC / gram of rock)
- Volumetric extent (controlled by thickness)
- Extent of kerogen conversion
  - Temperatures must exceed 140°C
  - Vitrinite reflectance more than 1.0% and less than 2.1%
  - Transformation ratio > 0.8

- ❖ T_{max} > 455°C

And for the Data that should be gathered from the Shale Gas Well we can mentioned to:

- ➢ Mud gas samples (every 50 feet)
  - ❖ Gas composition and carbon isotopes
- ➢ Bottled cuttings samples (every 10-30 feet)
  - ❖ Gas composition and carbon isotopes
- ➢ TOC on cuttings and cores (every 10-30 feet)
- ➢ Rock-Eval pyrolysis on cuttings or core (every 10-30 feet)
- ➢ Vitrinite reflectance measurements
- ➢ Thermal alteration index (TAI) measurements
- ➢ Visual kerogen (type of organic matter that is present)
- ➢ Gas chromatographic fingerprinting for light HC's
- ➢ Mineralogy (including clay minerals)
- ➢ Gas yields on conventional cores

II.3.1.1.Shale Gas Organic Geochemistry

a)TOC measurement

Rocks present in shale gas reservoirs can generate and store hydrocarbons as they contain kerogen. To establish the type of kerogen present in the rock and its hydrocarbons generation potential, laboratory analysis of present formation samples is required; this process focuses on method of combustion pyrolysis, chemical degradation, spectral fluorescence or petrography. Based on this type of analysis ,the type of kerogen, its thermal maturity and the TOC content of the rock can be determined. These are all necessary elements in assessing unconventional reservoirs such as shale gas reservoirs.

To evaluate the current adsorbed gas content of the rock, it is essential to first establish the current TOC content(TOC_{pd}).This can be obtained from the % of kerogen, as outlined above (chapterI), or can be measured in laboratory by employing the same measuring techniques employed in geochemistry (Fig.II.2.B). Given that samples available for analysis are limited, there are many studies of correlation between TOC measured in laboratory and other parameters also measured in laboratory, such as the current rock density (ρ_b). Then using the ρ_b of density logs, they have obtained a regression that assists in establishing log TOC (Fig.II.2.A.).

Once of this calibration has been completed, adjustments must be performed to compensate that TOC and ρ_b are measured in laboratory using a dry and fluid-free sample, whereas log ρ_b includes gas and water adsorbed in clay. Therefore, some techniques use the ρ_{ma} (matrix density) correlation as a basis. The advantage of achieving such a correlation stems from the fact that logging is performed in the majority of wells, whereas core samples are obtained with less frequency.

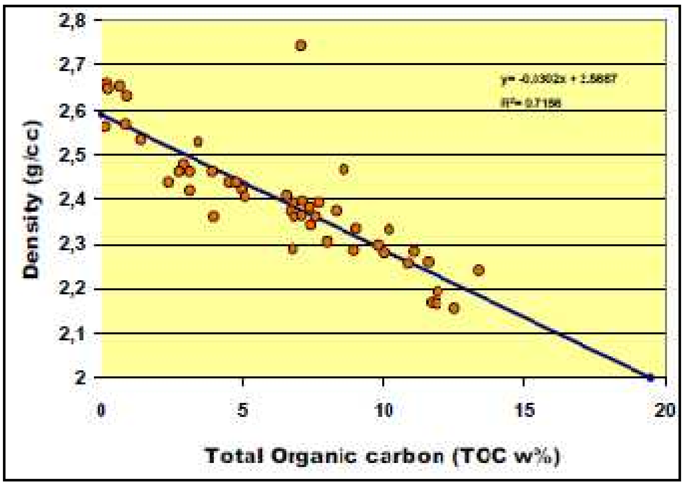


Figure.II.2.(a).Kerogen reduces rock density so that a connection between TOC content(w%).(jarvie,D.2011)

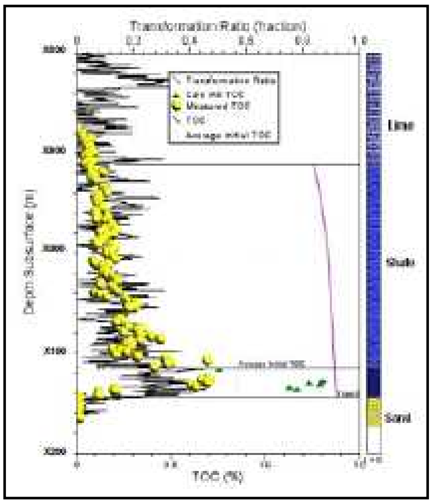


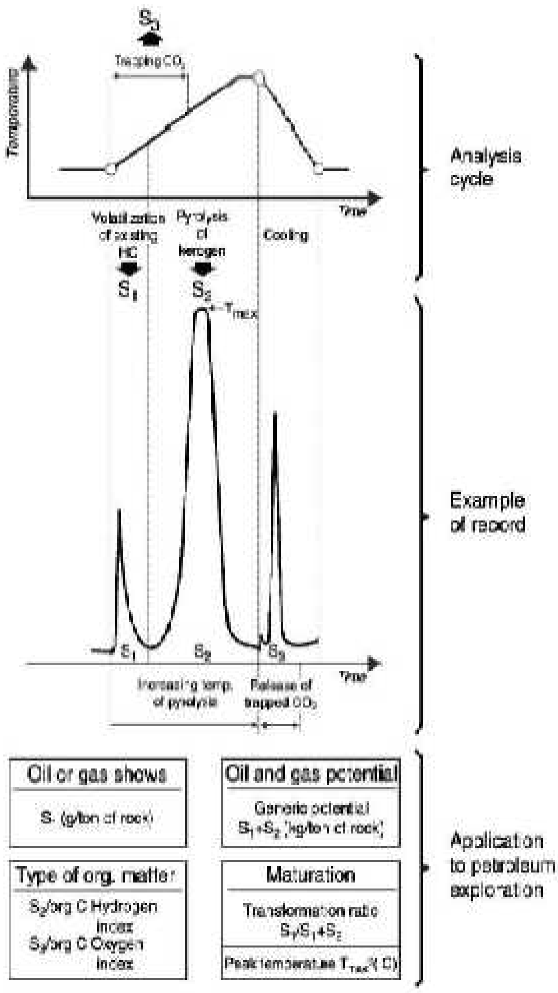
Figure.II.2.(b).Plot that shows increase in measured TOC's content with depth(source Repsol YPF)

TOC can be measured by too many tools like LECO CS230 carbon/sulfur Analyser, ShaleXpert software and can also be derived from correlations performed with other kinds of logs, such as GR, U(uranium) from NGT(natural gamma ray tool) and sonic travel time (Δt) logging, to name just a few examples, Strong correlation between Δt and TOC have been registered in the Neuquén basin; later particular technique, ΔLogR the technique was first utilized by the industry some years ago and it also utilizes travel time, in this case combined with resistivity.

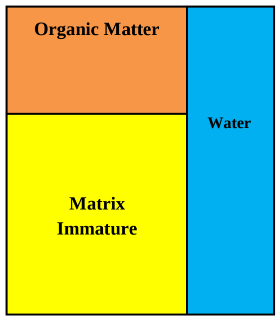
b) Rock Evaluation Pyrolysis

ROCK-EVAL is a method of pyrolysis in an open environment and it is a direct measurement of TOC is accomplished at well site by the PPy instrument, and data is available within about 30 minutes of sample collection. During pyrolysis, the sample is progressively heated to a temperature of 600°C, while a FID measures the derived hydrocarbons. The instrument uses powdered drill cuttings or other crushed rock samples to evaluate residual oil content (S1), remaining hydrocarbon generation potential (S2), thermal maturity (Tmax) and TOC. So it was designed to provide both a single cycle and information on:

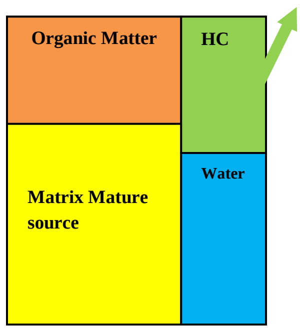
- The petroleum potential of the rock,
- The amount of free hydrocarbons,
- The type of organic matter and its evolution state.



Source rock quality	Pyrolysis S_2, mg hydrocarbons/g rock
None	< 2
Poor	2 to 3
Fair	3 to5
Good	5 to 10
Very Good	>10



Immature source rock (R_0 <0.5)



mature source rock (R_0 =1.0)

Product type	Hydrogen Index
Gas	50 to 200
Gas and OIL	200 to 300
OIL	>300

Figure.II.3. The Rock-Eval Pyrolysis Interpretation

The Peaks S1 and S2 provide the maturity of the rock, and the Tmax. This window allows to know the oil, and the boundary with the gas.

(a)

(b)

Figure.II.4.(a) Combustion Elemental Analyzer,(b) Rock-Eval Pyrolysis

c) Vitrinite Reflectance (R_0)

It is an optical method and the most way used for source rock maturity. The vitrinite is one of three common maceral (vitrinite, liptinite, inertinite).

The sample containing the vitrinite macerals is polished then submerged beneath an oil of a specified refractive index. A vertical beam of incident light of specified wave light is cast on the sample and the amount of reflected light is determined with a microscope.

The value of **R_0** can be ranged from 0.1 to > 4.0 .

In the case of the marine sediments as clays of Silurian we notice the scarcity of this component and consequently this technique is not useful in the Algerian desert evaluation.

Critical Vitrinite Reflectance (Ro) Values		
Poor risk for gas	Good risk for gas	CO_2 risk
• 0.60 % R_0 (onset of oil generation) • 0.90% R_0 (peak oil generation) • 1.00% R_0 (wet gas generation window)	• 1.40% R_0 (dry gas generation window) • 2.10% R_0 (dry gas only zone)	• 2.10 % R_0 (reservoir destruction)

TableII.1.Critical Vitrinite Reflectance Values

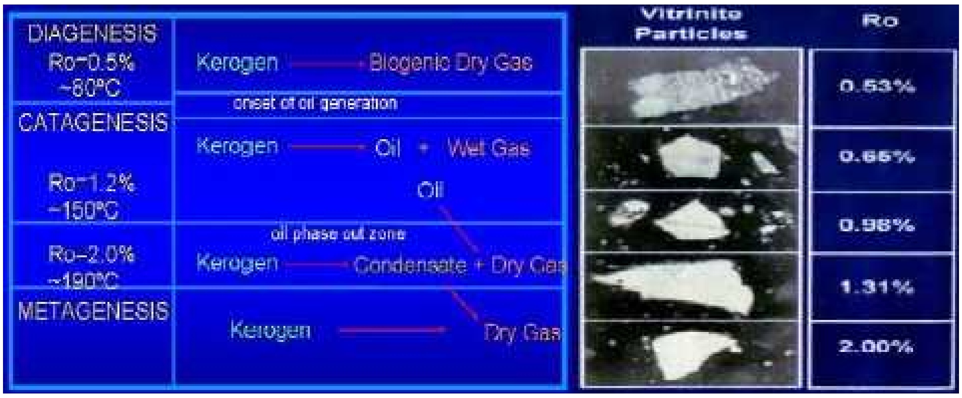


Figure.II.5.Kerogen/R_0 Relationship

II.3.1.2. Shale Gas Meniral Geochemical

a) The Diffraction Analysis (XRD / XRF) Rays

This analysis also provides access to the crystalline structure of the components, which can determine the nature of the phases, for example recognize the various forms of crystallization of the silica or whether the calcium is present as CaO or CaCO3 . The X-ray diffraction also allows the identification of minerals and their percentage (%).

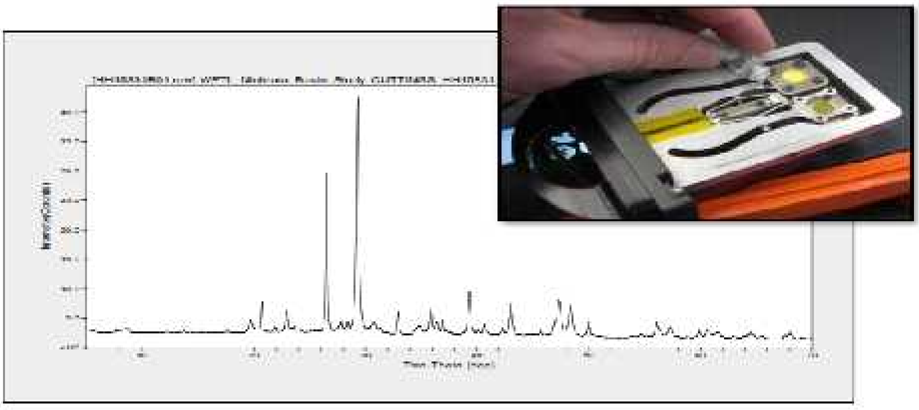


Figure.II.6.Procedures developed from laboratory bulk XRD analysis (weatherford)

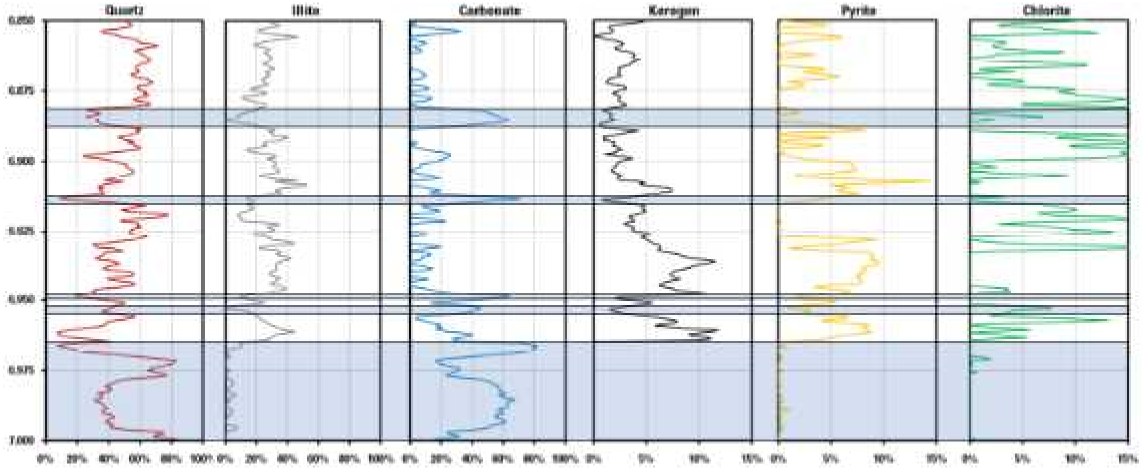


Figure.II.7.Mineral composition % by X-ray difraction

Among the minerals that fracturability (Brittleness see I.4.2.7) Shale was quartz,carbonates, feldspars. The higher the brittleness, the higher the brittle rock is therefore adapted to be breakable.

b) The Petrography (micrograph)

This method is based on the preparation of a thin section of rock, then the observation thereof with an optical microscope, including polarized light.

FIBSEM: Focused Ion Beam (FIB) and Scanning Electron Microscope (SEM) microscopes are generally used to allow 3D observation of pores between the particles and the matrix kerogen and their sizes, as can also be observed: The size, arrangement of grains or their classification and type of cement.

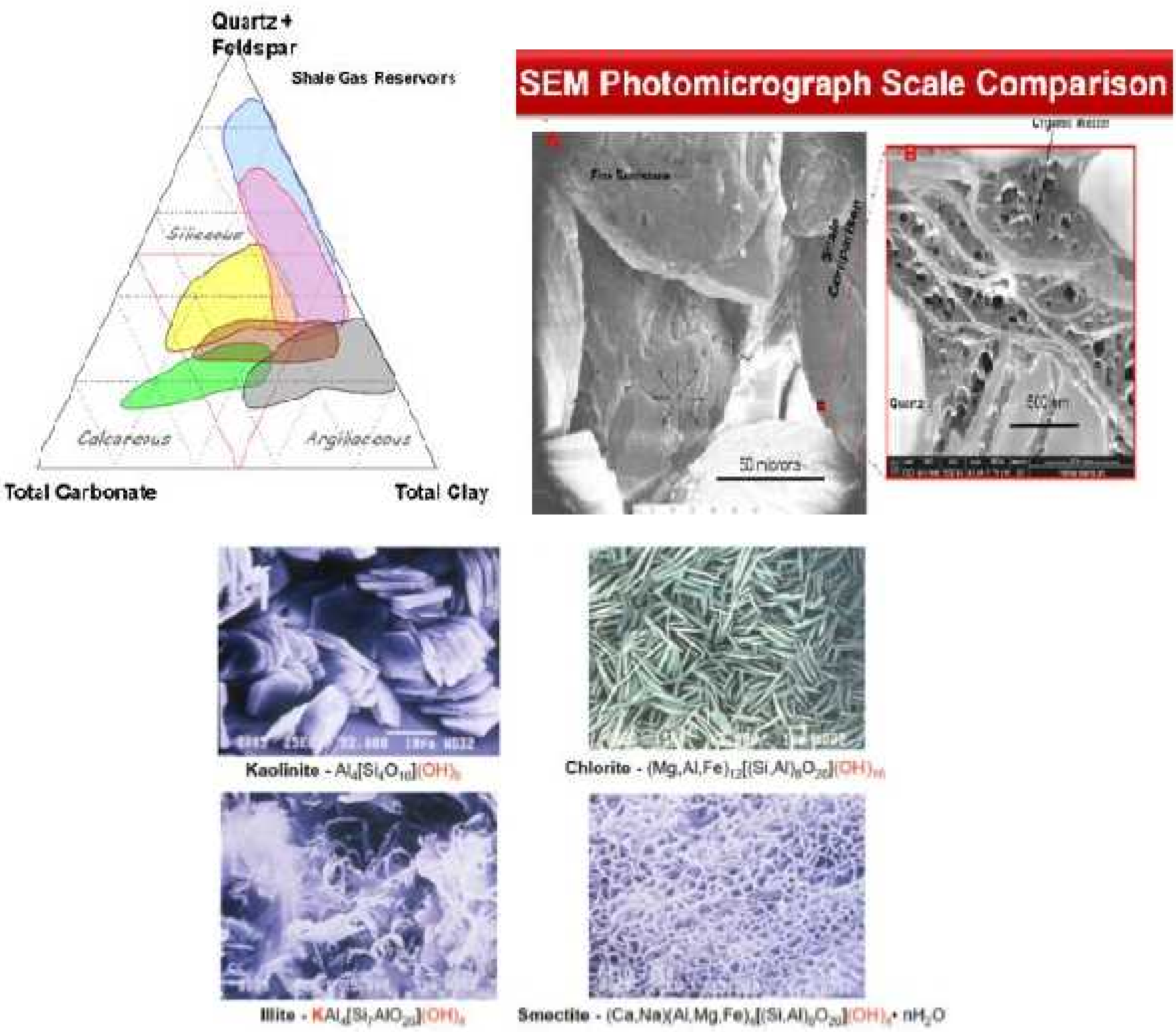


Figure.II.8. Observation of Shales at the Microscopic Scale,(Passey et al.2010)

We can also estimate the mineralogy by logging : GEM tool, or the analyzer cuttings: LaserStrat / Xepos-XFR .

II.3.2.The Chromatography

Chromatography is a separation technique of chemicals (gaseous or liquid homogeneous mixture) and according to this technique, caused by the separation of mobile phase components, or the result of their adsorption and subsequent desorption of them on the stationary phase, or of their different solubility in each phase.

This method is primarily used to identify components of a mixture (qualitative analysis) and their concentration (quantitative analysis). The samples used for chromatography are samples of fluid background and / or surface and data Geological Survey (Mud Logging) to create a chromatogram.

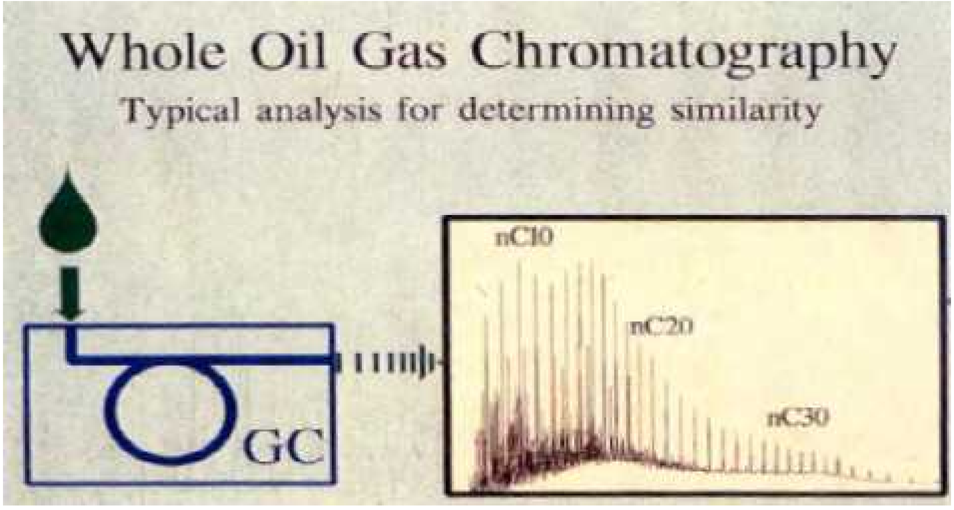


Figure.II.9.Chromatography Technique,(Spangenberg et al.2010)

II.3.3. Methods Of Gas Content Measurement

The best method for establishing gas content in these reservoirs stems from decline curve analysis in productive wells.

However, the development of this resource is relatively new in many areas and there is not sufficient information to establish a reliable performance trend. Volumetric analysis is one alternative method and is better when it is supplemented by the best extent of analogy established with the behavior of more mature wells from nearby geographic areas. within volumetric calculations, those that, in part, directly or indirectly measure the gas content of rocks and minerals(coals) are increasingly accepted by the industry as suitable methodology for shale gas. Direct and indirect methods of measuring gas content in formation samples are described below.

Adsorbed Gas-indirect method

The industry uses the Langmuir isotherm to measure adsorbed gas content in the form methane gas adsorbed by the surface of kerogen.Adsorption is a phenomenon that occurs when gas accumulates in the walls of solid, resulting in the creation of a molecular or atomic films. This must not be confused with absorption, when substance spreads in a liquid, resulting in the creation of a solution, or it is trapped within a solid .The term desorption is used in both cases to refer to the inverse process,or expulsion of gas.

The general expression of the Langmuir isotherm :

$$g_C = \frac{V_1 \times p}{(p + P_1)}$$

Where: g_C = adsorbed gas content (scf/ton)

p = reservoir pressure (psia)

V_1 = Langmuir volume (scf/ton)

P_1 = Langmuir pressure(psia)

The shape of the curve for a given temperature or TOC level depend on Langmuir pressure (P_1;pressure where one-half of the gas at infinite pressure has been desorbed) .The curve (Figure.II.10) defines the equilibrium between adsorbed and free gas as a function of reservoir pressure at the isotherm temperature. It must be stressed that this ratio has been developed for methane gas, and the presence of other gases may impact on the method's reliability; to this end ,measuring techniques to compensate for the effect of different gases have been developed (Hartman et.al.,2011).

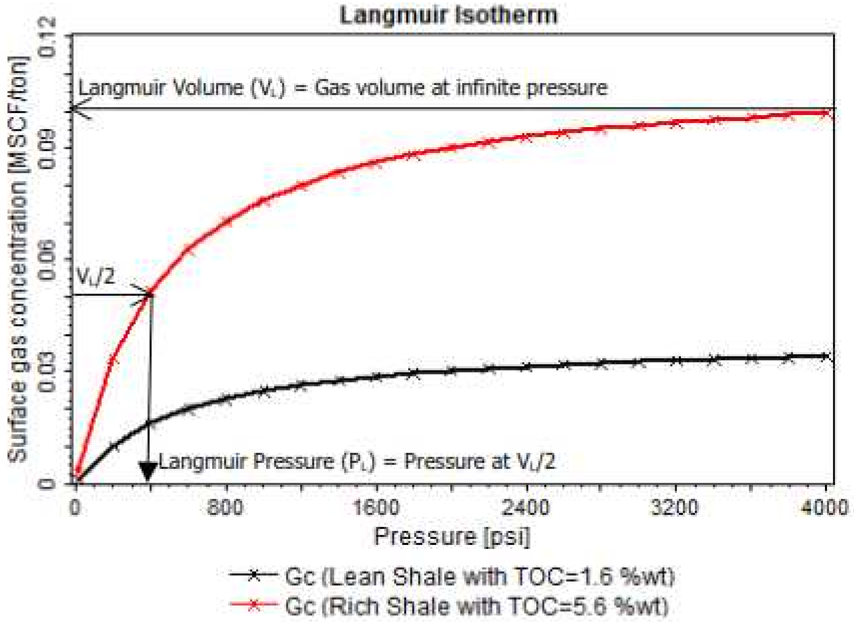


Figure.II.10.Langmuir Isotherm Curve for gas adsorption,(Mirzaei et all 2012)

For estimating adsorbed gas initially in- place ($GIIP_{ad}$) with Langmuir isotherms:

$$GIIP_{ad} = g_c * Den * Area * \square * C$$

Where :

$GIIP_{ad}$ = adsorbed gas initially in-place(Bcf)

g_c = adsorbed gas content (scf/ton)

Den = average formation density in h;ρ_b average (g/cc)

$Area$ = area(acres)

⍰ = average usable depth(ft)

C = units conversion factor;1.3597* 10^{-6}

Total gas content and estimating total gas initially in-place($GIIP_{tot}$)-direct method

The results of applying the Langmuir isotherm may be complemented by measuring desorbed gas in formation samples(cores, sidewall cores).This type was designed primarily to measure the gas content in coal samples can be referred to as either the direct method, or canister desorption analysis.

Full diameter samples are placed in sealed recipient, ‘‘canister’’ in (fig.II.7.A) and are sent from the well to the laboratory, where the timeline of gas desorption is measured as the sample is heated to the reservoir temperature. The experiment continues by also measuring the volume of gas desorbed in crushed samples.Afterwards,a correction is made to estimate lost gas ,gas lost between the time 0 (t_0) prior to isolating the sample and sealing it in the canister. t_0 is the moment at which the sample starts to desorbed gas to imbalances with hydrostatic pressure during its tripping ot of the hole and up to the surface after it was cut and removed from bottom hole..It is difficult to correct lost gas precisely, although this factor is less important when dealing with shale as opposed to coal; proportionately,however,it can represent an important percentage of gas content estimated by this method. Lost gas can be significant if the rock has natural open fractures that were the gas saturated, or if gas is widely spread in the matrix (moderate permeability);further more, certain measures must be applied to avoid expansion and shrinkage issues produced by heat and pressure together with a risk of oxidation of part of organic matter. The test provides data on total gas basis and it cannot account for the adsorbed gas percentage on the total gas content. total gas content and TOC have been correlated, thereby establishing a direct correlation (Fig.II.11.B)

Therefore, the formularies presenting total gas content is :

$$G_C = 32.0368 \times \frac{V_l + V_m + V_c}{m_{ad}}$$

Where:

G_C = total gas content (scf/ton)

V_l = volume lost gas,(cm^3)

V_m = volume of measured gas,(cm^3)

V_c = volume of crushed gas,(cm^3)

m_{ad} = air-dry gas volume (g)

Figure.II.11.(a).Canister apparatus used to hold core sample(weatherford laboratories)

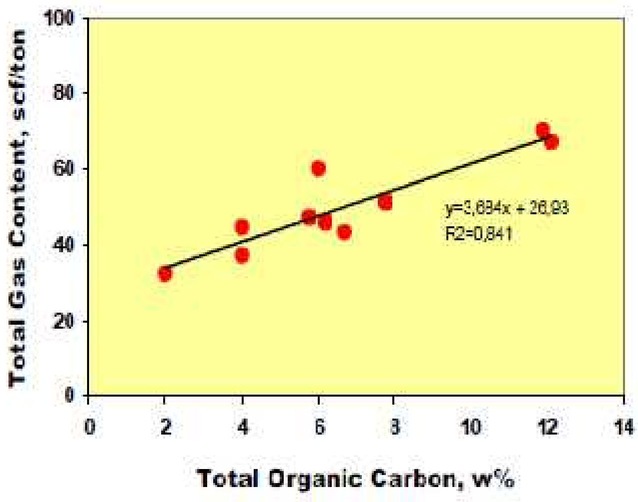


Figure II.11.(b).Correlation between total gas content and TOC (Luffel,D.,et al)

We have three categories of gas from Samples

• Desorbed Gas: Measured after sealing the sample in the canister and allowing it to desorb at reservoir temperature and pressure.

• Residual Gas: Gas left after desorption has reached a very low rate and determined by grinding the sample into small particles and measuring the released gas.

• Lost Gas: Gas lost during sample retrieval and handling on the surface. A calculation is done to estimate the amount of lost gas.

The addition of these three yields the total gas content.

II.3.4.Petrophysical Measurements

Petrophysics is critical for

– Estimating production potential

– Selecting completion intervals and designs

– Identifying poor performers

– Quantifying non-shale reservoirs, stimulation barriers, and water-bearing intervals

The main petrophysical characteristics of rocks are: porosity (ϕ), permeability (K),the water saturation (S_w) and grain density.

a)Porosity

In laboratory measurements, pore space is as follows:

Total ϕ → connected and unconnected of a crushed sample

Effective ϕ → connected of a whole core or plug sample under humidity control(if samples are adequately dried under controlled humidity, water adsorbed in the clay and clay hydration water will be preserved. On the other hand, if the drying process is not controlled and is completed at very high temperature, the measurement of porosity will include said pore space.)

As received(AR) ϕ → Measured by helium expansion in preserved sample

Gas Filled ϕ → Measured in two separate pieces of the sample; the gas is measured in an unwashed and un-dried sample by injecting mercury, this is know as "gas filled ϕ";liquids are measured in the other piece by distillation, also known as "summation of fluids";"gas-filled ϕ" is also found as a gas saturation (S_g),derived from helium expansion porosity and Dean stark extraction in an AR sample.In shale gas,it does not include adsorbed gas.

In electric and radioactive logging, pore space is as follows:

Total ϕ → Connected and unconnected matrix porosity, added to the shale porosity

Effective ϕ → total ϕ minus shale porosity

Shale ϕ → Estimated on shale volume basis

Clay bound water ϕ → occupied by water adsorbed in clay and clay hydratation water

Capillary bound water ϕ → occupied by capillary trapped water(water-wet rocks) in the non-clay matrix.

Free fluid ϕ → occupied by mobile fluids ($\phi_{FF} = \phi_{total}$ – clay bound water ϕ – capillary bound water ϕ);free gas would occupy this pore space when S_O~0%

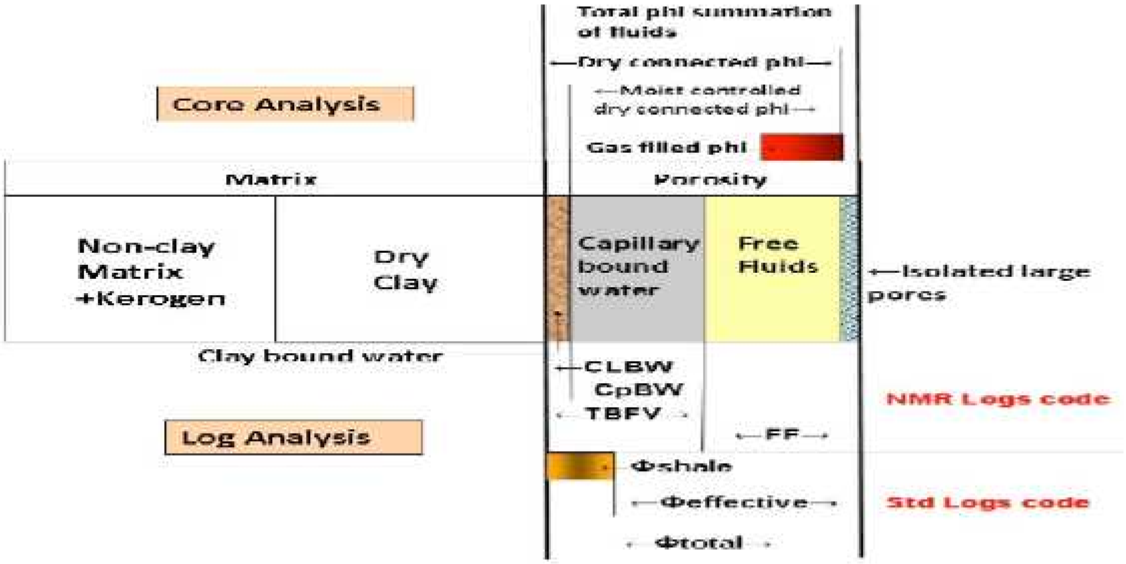


Figure.II.12.Types of porosity measures in laboratory and with logging (from API –RP-40- Recommended Practices From Core Analysis)

The porosity of rocks is obtained from:

- Measures in the laboratory as Crushed Rock Injection: GRI or Mercury injection
- The logs (NMR: Nuclear Magnetic Resonance giving the porosity of each fluid (MRIL, Halliburton)).

b)Permeability

The flow in the shale plans are as follows:

- Natural Fractures: Darcy flow, On the surface
- kerogen: desorption,
- In the kerogen: Diffusion (it takes time to start desorption)

Permeability of shales is measured by:

- Laboratory testing as Crushed Rock Injection or Mercury Injection Method,
- Well tests (FIT Diagnostic Fracture Injection Test)
- The logging (Logging: NMR (MRIL, Halliburton)).

c)Water Saturation

The technique used by GRI to measure water saturation (S_w) is Dean Stark on crushed samples. S_w can also be established by the retort method in laboratory. As is the case in conventional reservoirs, water salinity in the rock has a significant impact on these analyses and can often result in high levels of inaccuracy. Gas saturation is then estimated by difference. There are no great variants in regards to standard procedure, except the use of crushed sample and the unconventional characteristic of the rock. Differences between the results of different laboratories have been reported.

d)Grain Density

This is a very important parameter in the petrophysical assessment of such reservoirs, since kerogen has a strong influence on grain density (GD or ρ_{ma}) .Kerogen decreases grain density in shale when compared with other similar, kerogen-free shale. This parameter is useful to calibrate log interpretation results;however,as will be discussed below this is complicated given the difficulties experienced when estimating accurate kerogen volume and density in formations by using logs. But the problem that there are differences in comparative measurements from different laboratories (Sondergel,et al.,2010;Passey,et al.,2010);in lare part they have been attributed to the procedures followed for sampling and sample preparation(crushing,sieving,washing and drying).Grain density can also be estimated by correctly interpreting mineralogical analysis,sch as XRD,XRF or FT-IR.

Some of these analysis like XRD,are unable to detect kerogen;however,a separate TOC w% measurement can be integrated to the XRD analysis to estimate GD.If sample frequency is high, curve continuity obtained in laboratory will also be high and this will facilitate core-to-log correlations.

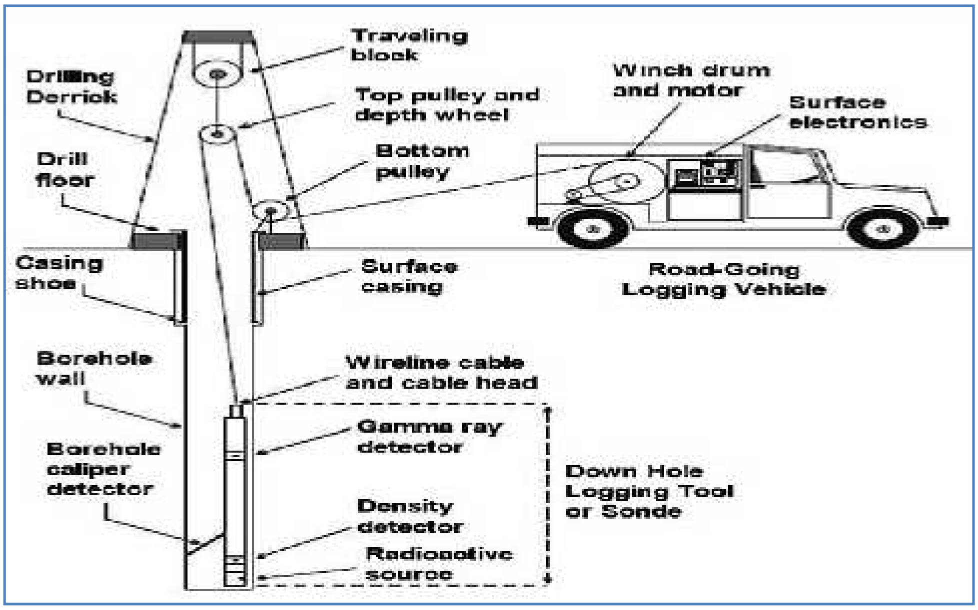
II.3.5.Geomechanical Measurements

Mechanical parameters of the rock are very important phases of drilling, completion and stimulation (hydraulic fracturing) of the well, the main mechanical parameters are: the sterss in place (σ_{vert}, σ_{max}, σ_{min}), Young's modulus (E), Poisson's ratio (v) and Brittleness (Br).

II.4.Logging

A wireline log is a continuous record of measurements made in a borehole by a probeable to respond to variations in some physical property of the rocks through which the borehole is drilled. Logs are traditionally displayed on gridded paper - Figure II.13.

Today, however, the primary record is likely to be a digital representation, paper logs being used primarily to help summarise results, and as a secondary archive medium.



. Figure.II.13. A typical logging system with main components. (Source: Reference [65]).

Immediately after a well is drilled, the formations are exposed to the wellbore. This is an opportune time to determine the properties of the rocks using OPENHOLE logging tools. In some cases, particularly in well with complex trajectories, companies include logging tools as part of the drilling tool assembly. This approach is referred to as logging while drilling or LWD.

The first objective of logging in an exploration area is to locate hydrocarbons in a well. Next ,the operating company want to determine if enough resource is present to economically justify completing and producing the well. Logging indicates the basic parameters of porosity (fluid-filled portion of the rock);the water, oil and gas saturations and vertical extent of a productive hydrocarbon zone, or net pay.Logging tools are calibrated to properly determine this and other quantities from the reservoir so companies can calculate accurate reserve values.

There are over 100 different logging tests that can be used to monitor the drilling process and to make decision if the drilling should be continued.

III.4.1. Well Log Response In Shale-Gas Rocks

Many of the well log techniques developed for mature oil-prone organic-rich rocks are readily applicable to the “overmature”shale-gas formations. The main differences relate to the fluid type (gas instead of oil), distribution of porosity (occurrence of pores within the organic matter in addition to intergranular matrix porosity), and bulk rock composition (the presence or absence of brittle minerals in the rock matrix).

The presence of kerogen and hydrocarbons can result in alterations in the responses of resistivity,density,sonic,neutron,spectral and natural gamma ray logging and micro-resistive imaging in comparison to responses from intervals in which there is no significant kerogen presence.

Resistivity Log

The resistivity of a rock is directly related to those components that are electrically conductive. In conventional reservoirs, formation water is the primary conductor of electricity, at least when the formation waters are brackish to saline, allowing for ionic conduction. Low resistivity is observed when the amount of saline water-filled porosity is high – the larger the volume of formation water (Bulk Volume Water), the lower the resistivity of the fluid-filled rock. Hydrocarbon fluids (oil or gas) are non-conductive, and when they are present in sufficient quantities, they displace the amount of water in a given formation, resulting in resistivity values higher than the same rock fully filled with electrically conducting formation water .

There are many variants to the interpretation of resistivity in conventional reservoirs (e.g., clay conductivity and shaly sand analysis; thin-bed effects due to interbeded shales; Waxman-Smits, 1968; Worthington, 1985; Passey et al., 2006) but these are beyond the scope of the current paper, yet may play second-order roles in the quantitative interpretation of shale-gas reservoirs.

Many shale-gas reservoirs contain relatively minor amounts of clay (20-30 wt%), whereas others may contain as much as 70 wt%clay. The importance of additional clay conductivity on the interpretation of fluid saturation depends on the relative conductivity of the clay to that of the formation water; in general, if the salinity of the formation water is greater than the salinity of sea water(e.g., 35 kppm NaCl equivalent), then the relative impact of excess conductivity due to clay minerals is small. Moreover, the amount of water-filled porosity (i.e., bulk volume water or BVW) plays a role on the impact of clay conductivity, because with decreasing amount of conductive formation water (i.e., low porosity), the relative impact of clay conductivity to that of the formation water will increase.

Other minerals (organic and inorganic) also play a role in the overall conductivity of the rock . Pyrite is commonly present in organic-rich intervals of shale-gas formations and may play a role in decreased resistivity response if the volume is sufficient, In general, most organic-rich intervals contain some pyrite, but overall, the resistivity remains relatively high in the TOC-rich intervals. As with organic matter, the matrix density of the rock components must be factored in when determining the volume percent occupied by that component. Due to the high density of pyrite, a rock containing 10 wt% pyrite may contain only 7 vol%, whereas with low density organic matter, 10 wt% TOC may correspond to about 20 vol% kerogen.

Finally, in some shale-gas reservoirs that are at very high maturities (Ro>>3), the overall rock resistivity can be 1-2 orders of magnitude less than is observed in the same formation at lower thermal maturities (Ro between 1 and 3). It was thought that perhaps the carbon in the organic matter is recrystalizing to the mineral graphite, which is electrically conductive, but preliminary studies indicate that pure mineral graphite (as indicated by XRD) is not present in abundance at these thermal maturities.. Thus, it is likely that a precursor to graphite is forming, and further studies are warranted. It is sufficient to state that in extremely high maturity organic-rich rocks (Ro>3), the rock may be much more electrically conductive due to other mineral phases being present rather than solely formation water, clay, and pyrite (as usually considered).

Gamma-ray and Spectral Gamma-ray

For most fine-grained rock evaluation the gamma-ray is a critical well log to help differentiate shales (seals or source rocks) from conventional reservoir lithologies,such as sandstone or carbonate. For shale-gas plays, the source, seal, and reservoir are often contained completely within the fine-grained rock lithofacies and the gamma-ray curve may or may not be as useful as in conventional reservoirs. If the shale-gas of interest is deposited under marine conditions (primarily Type II kerogen), the uranium content continues to be useful given its association with organic matter, and the uranium component can be a good indicator of organic richness. In lacustrine (or lake) settings, there is generally a paucity of uranium in these systems, and more often than not there is no relation between uranium and TOC (Bohacs and Miskell-Gerhardt, 1989; Bohacs, 1998); in these cases, the total gamma-ray curve remains a fairly good indicator of overall clay content in the rock but may not indicative of high TOC or the reservoir facies of interest. Figure 14 shows how the base of a parasequence is organic rich (decreasing upward), and this same observation can be seen in the total gamma-ray response.

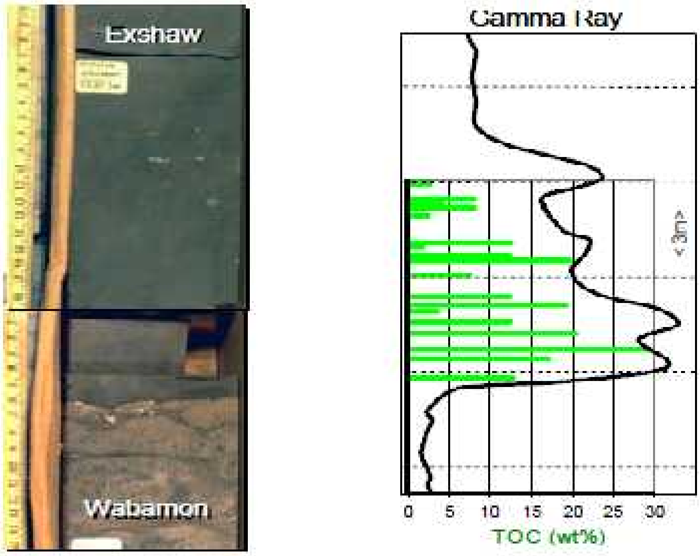


Figure.II.14.Core photograph of Exshaw flooding surface; corresponding GR and measured TOC profile. Gamma ray scale is 0 to 150 GAPI,(Passey et al.2010)

Density and photoelectric factor

Kerogen and gas are low density(ρ_b) and low photoelectric factor(P_{ef});as a result, high levels of the aforementioned components reduce the density and photoelectric factor of the rock.Also,kerogen matrix density ((ρ_{ma}) is very low, similar to the density of water; it is for those reasons that if the kerogen volume is not estimated accurately, the subsequent calculation of porosity will be incorrect, providing values higher than the actual ones. On the other hand, correlations between ρ_b and TOC have been made by exploiting this characteristic, reporting satisfactory results in deriving TOC from rock density as measured in laboratory, the application of which could be extended to log interpretation. The borehole diameter and the good shape of the wellbore walls are critical for this type of logs;the mud filtrate invasion depth and the type of invading fluid must be know in order to use this technique, although in this type of rock, changes in formation near to the borehole walls may be due to other factors rather than mud filtrate invasion.

Sonic

Similar to the density log response, the P-wave log can be calibrated to TOC content due to the low P-wave velocity (high transit time) of organic matter, given the previous caveats about no significant local variations (such as changes in porosity or mineralogy) that can affect sonic response. Most work to date has focused on the compressional (P) wave, but there is also a likely impact on the shear (S) wave response (Zhu et al., 2010). In general, the use of the sonic log for determining TOC is enhanced when combined with other logs.

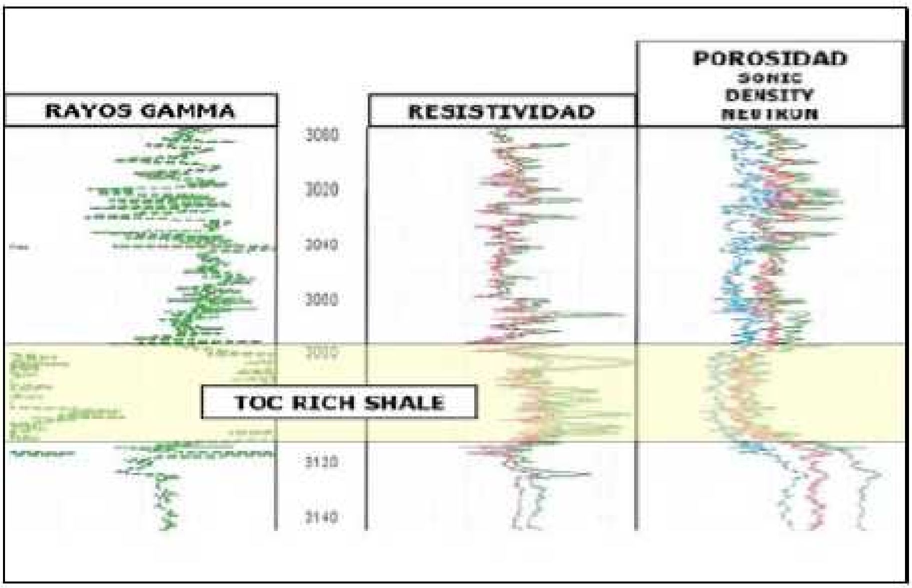


Figure.II.15.Log responses of some regions, in shale gas reservoirs with high level of mature kerogen. (Passey et al. 2010)

Neutron

General observations are that the neutron log is a poor indicator of organic matter as a single stand-alone tool. This tool is affected not only by the hydrogen in the organic matter, but also by the hydrogen in the hydroxyl (OH-) in the clay minerals, as well as by the hydrogen in the formation water and any liquid or gaseous hydrocarbons present. For some silica-rich shale-gas formations, the use of the standard neutron/density overlay has proven useful for recognition of intervals that contain higher gas volumes; this technique has limited application when the formation is not clay rich, due to the increase in hydroxyl (OH-) ions resulting in a larger neutron/density separation that may mask the "gas crossover".

NMR

Published applications of use of NMR logs for unconventional reservoirs evaluation are limited .In water-saturated low TOC shale-gas intervals, there is good agreement between total NMR porosity and total porosity measurements of core (using crushed rock methods). Further work is warranted to fully understand the response in organic-rich, and presumably, gas-bearing intervals.

Micro-resistive Imaging

In water-base mud, the colors in micro-resistive image of an area with high kerogen content tend to be clear, whereas in adjacent shaly areas of low or nil kerogen content the colors are darker. Personal communications have highlighted the use of micro-resistive imaging to corroborate the detection and quantification of kerogen with Rt(high) and P_{ef} highly resistant mineral concretions. It has been reported that in oil-based mud, this imaging technique is still reliable, provided that the mud does not disturb or deeply invade the formation, and there are no natural open fractures that could make the interpretation process more difficult. The borehole diameter and the good shape of the wellbore walls are critical for this type of logs; the mud filtrate invasion depth and the type of invading fluid must be know in order to use this technique, although in this type of rock, changes in formation near to the borehole walls may be due to other factors rather than mud filtrate invasion.

II.4.2.Log interpretation

Use of core, logging and special testing information to study reservoir properties and take operational and management decisions regarding the resources are another aspect that want to be considered.Hereon,we will discuss the interpretation of logs .

Calibration of Logs to Total Organic Carbon Content

As has been shown for Type II (oil-prone) source rocks in the oil-maturity window (Ro=0.5-1.1), the presence of the organic matter and the presence of generated hydrocarbon fluids can have a large response on the resistivity log . At the time that work was done, the focus was entirely on the oil-mature window and limited data existed for over mature shale-gas rocks (i.e., Ro>1.1). Active exploration of shale-gas plays has allowed acquisition of the data required to calibrate the logs to many of the critical controls for successful shale-gas plays.

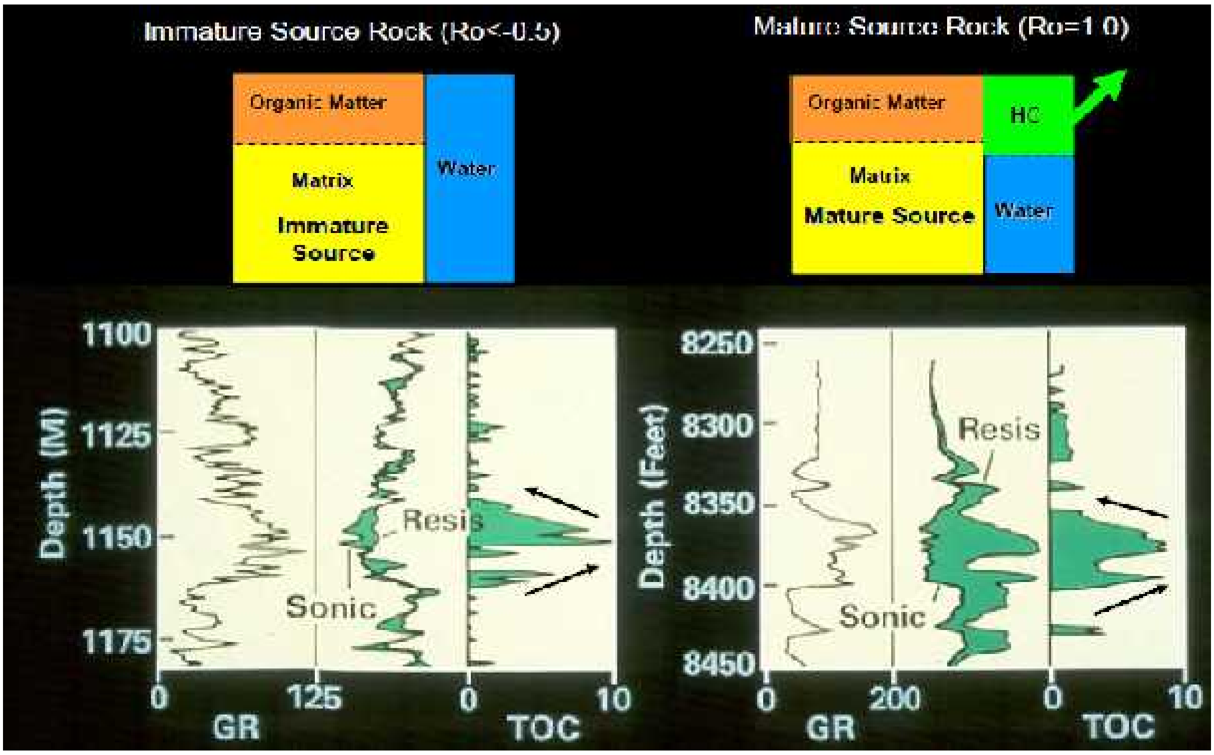


Figure.II.16.Well log response (ΔlogR and GR) response for immature (Ro=0.5) and mature (Ro-1.0) Devonian age Duverney formation in Canada. Note that the parasequence-set scale packages are identifiable in the TOC profiles (black arrows) (Passey et al.1990)

Combined porosity/resistivity methods (e.g., ΔlogR method)

As described in the Passey et al.(1990), the original calibration of the ΔlogR technique (using either sonic-resistivity or density-resistivity combinations) was for source rocks in the oil maturity window (Ro = 0.5–0.9 or LOM 6-10.5). No rock calibration was available at that time to included rocks in the overmature or "gas" window (Ro > 1.0; see Fig.II.13). As previously published, a parametric fit was made for TOC from ΔlogR separation as a function of LOM (maturity); the lines for maturities greater than LOM=10.5 (Ro>0.9) were numerical extrapolations of the lower maturity calibration lines. Recently acquired TOC data from shale-gas formations worldwide indicate that for overmature intervals (LOM>10.5 or Ro>0.9) the calibration to TOC is the blue line (Figure.II.17). Use of the original Passey et al., (1990) "calibration"lines for rocks with maturity values LOM>10.5 (or Ro>0.9) will result in underestimation of the actual TOC. Sondergeld et al.(2010b) propose using a correction multiplier to obtain accurate log-derived TOC using the ΔlogR technique for overmature shale gas formations, which is approximately equivalent to using the blue calibration line shown in Figure.II.17.

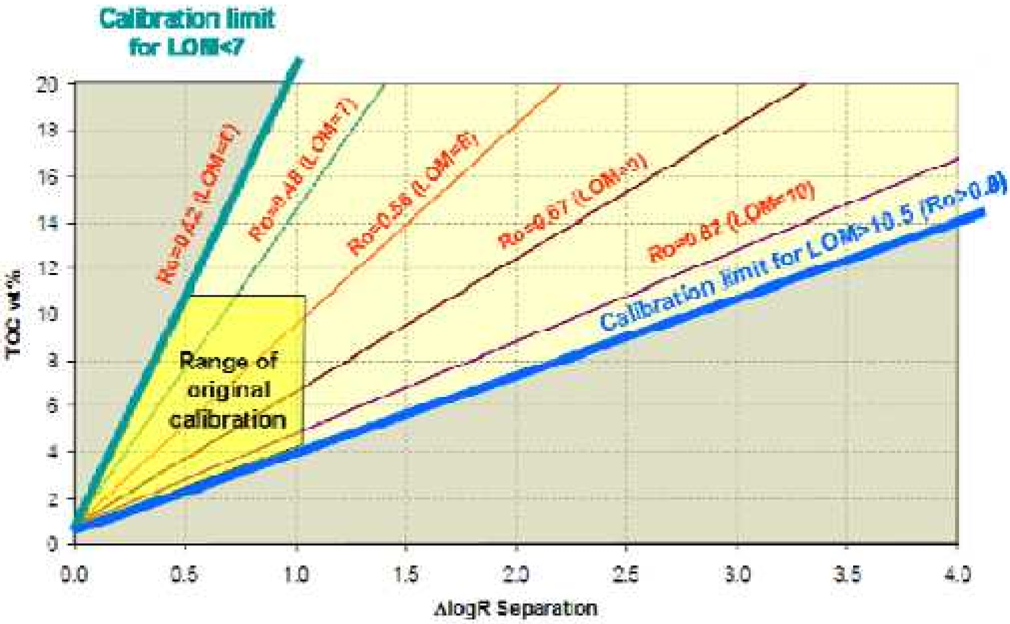


Figure.II.17. Revised relation of ΔlogR to TOC indicating possible upper limit for rocks with LOM> 10.5 (Ro>0.9),(Passey et al.1990)

A comparison of ΔlogR-derived TOC with high-frequency measured TOC is shown in Figure 19a; the green shading represents the TOC from standard ΔlogR (sonic/resistivity) using the blue calibration line illustrated in Figure 17; the cyan curve in Figure 18a is TOC from the ΔlogR density/resistivity pair, and the orange line is from high-resolution density/resistivity logs, providing more detailed vertical variability of TOC, and comparable with the borehole electrical image log (Figure.II.17).

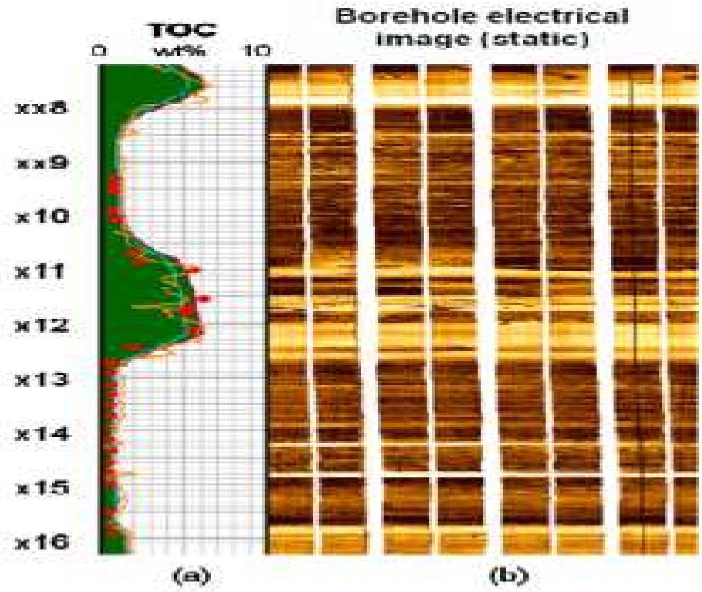


Figure .II.18.(a) Lod derived TOC using the ΔlogR showing comparison with high frequency TOC core measurements,and (b) Static borehole electrical image log for the same interval as(a),(Passey et al.2010).

Elemental and Mineralogic Logs

These logs can determine reasonable values for total clay, carbonate, and quartz (at least within 5-10 wt%), but none of these parameters are directly related to organic richness of shale gas reservoirs. But, the total silica or total carbonate content is likely related to geotechnical properties of the rock. Moreover, these logs appear to be useful in identifying pyrite and/or siderite intervals, and these intervals are commonly associated with sequence-stratigraphic surfaces in distal environments where clastic input is minimized . Further analysis is warranted in using these logs for recognition of significant stratigraphic surfaces.

Borehole image logs

High-resolution borehole electrical images are useful for identifying closely spaced vertical variations in resistivity, which can be tied to variations in organic richness (possibly due to higher gas saturation in these intervals (Figure.II.18.b).From this image, individual parasequences are readily identified -- high TOC and resistive (bright) at the base, and low TOC and conductive (darker) upward. Care must be used when interpreting borehole electrical images because tight (low porosity) carbonate or siliciclastic beds and siderite concretions appear resistive (bright).

The use of water-base mud is required for standard high resolution electrical images. It may be possible to identify similar features using oil-base imaging logs, but the vertical resolution is likely to be coarser than for water-base-mud electrical imaging wireline logs.

II.5.ShaleXpert WorkFlow

ShaleXpert is one of the most powerful software developed by the company Halliburton in the field of shale, a new integrated solution based on modules rated for shale gathers all analyzes exploration of shale basins. Petrophysical solutions are discussed in each of these modules independently workflow: estimation of TOC (maturity), evaluation of fluids and minerals, modeling Advanced saturation (NMR and dielectric volume), the mechanical properties, 3D constraints and their orientations, and the permeability of the pay analysis area.

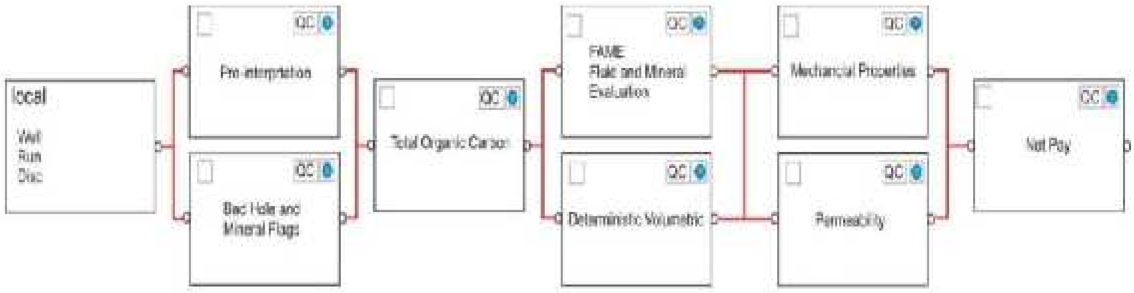


Figure. II.19. ShaleXpert Modules,(Halliburton)

The final composited ShaleXpert analysis brings together all the different workflow modules in a display that aids in primary sweet-spot identification, in-place reserve estimates, and delivers everything required for an optimized fracture stimulation design. Along the way, it can also generate individual quality-control plots and logs from any of its workflow components, so all processes are transparent to the end user.

Conclusion

The development of shale gas reservoirs is different from that of conventional, so there are a specific method for measurement for each characteristics, that’s why we have limits data acquisition testing wells, analyzes laboratories and logs.

Chapter III

Completions Consideration and Hydraulic Fracturing

Introduction

As mentioned early that shale reservoirs requires specialized technologies or treatments in order to be produced economically. On this chapter we try to explain the techniques and key elements of completion / stimulation as applied wells (horizontal wells), their benefits and how they meet the objectives of horizontal wells.

III.1.Completion Intervention And Diagnostic Techniques

Completion of unconventional horizontal wells requires optimization studies of the physical quantities such as the number of fractures (stages), the inter-distance fractures, the fracture length, the conductivity of the fracture, volume of fracturing fluid, the injection time, the required power surface, the selective production and the specific zonal treatment, while putting in Obviously the side length of the horizontal drain.

These required parameters and Sweet Spot-will be used for the selection of completion as cemented or cased hole and open techniques perforation and stimulation. These optimization studies will provide an optimal solution to the completion and stimulation in order to have positive and lasting effects necessary for unconventional reservoir profitability. The choice of the completion and stimulation relieves of the following steps:

- The development objectives and economic performance of the well, highlighting additional benefits of various completions and strategies stimulation.
- Establish selection criteria based on the objectives and performance economic.
- Integrate the objectives of the reservoir and geomechanic limitations in well completion and stimulation strategy.
- Identify and completing the well stimulation technique suitable, in based on the sweet-spot and the architecture of the well.

The technology provided by Halliburton for completion and horizontal well stimulation comprises the following four techniques:

- Plug-n-Perf,
- Ball Drop Frac Sleeve,
- Coiled Tubing,
- Intelligent Completion,

III.1.1.Plug-n-Perf

This technique is most commonly used in hydraulic fracturing, it has technical and economic benefits such as unlimited number of fracturing stages with flexible restrictions and less expensive. It can be applied with the completion cemented Casing or cemented Liner, by anchor plug to isolate the area (stage) which will already fractured perforation and fracturing a new zone (Figure.III.1).

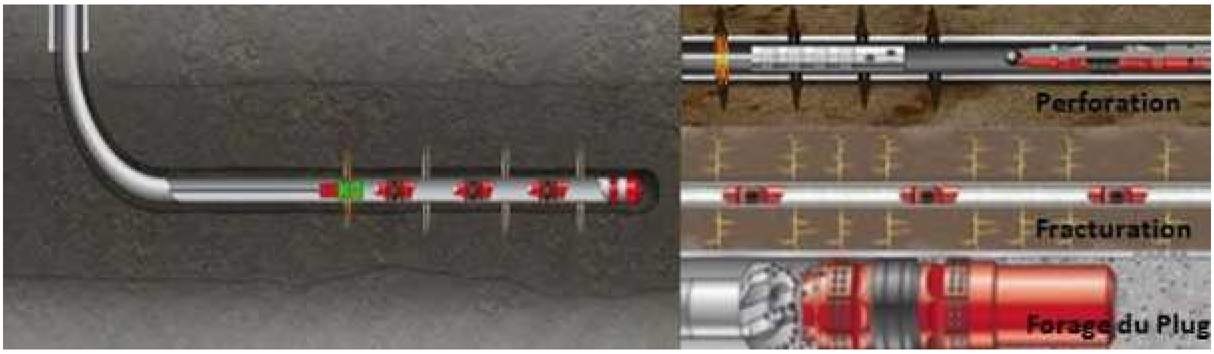


Figure. III.1. Plug-n-Perf Fracturing technique, (Halliburton)

III.1.2.Ball Drop Frac Sleeves (Multi-Stage Frac Sleeves)

This technique adapts for the Open Hole configuration, is equipped with Packers to isolate areas (stages) and a system to open the passage Sleeves perforations and provide access to the area to fracture. The opening of perforations is through the Sleeves by sending from the surface of a ball which slides thereof and open the passage of the perforation holes (Figure III.2).

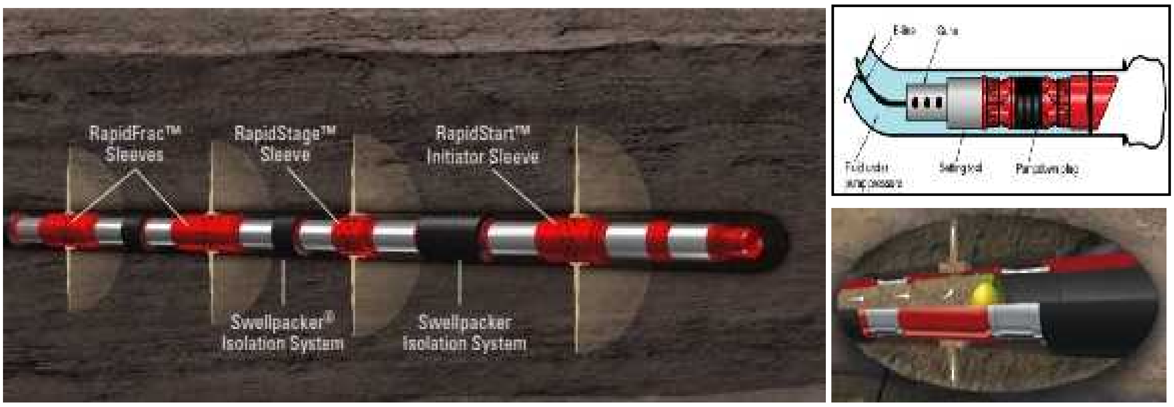


Figure. III.2. Ball Drop Frac Sleeves Fracturing technique, (Halliburton)

Ball Drop Frac Sleeves is characterized by its efficiency (keep time) compared with Plug-n-Perf Among its advantages include the operation need not perforation and plug for insulation fractures, pumping continuously, a limitation of number of fracturing stages and provides the selectivity of multiple hydraulic fracturing.

Five (5) types of Sleeves are used for this technique:

- Initiator Sleeve RapidStart used except for the first stage fracturing
- RapidFrac Sleeve, up to 20 stages fracturing
- RapidStage Sleeve, up to 41 stages fracturing

- RapidShift Mechanical Shift Sleeve, up to 41 stages fracturing
- RapidShift Ball Drop Sleeve, up to 41 stages fracturing.

III.1.3.Coiled Tubing (PinPoint stimulation)

This fracturing technique is based on the injection of the fracturing fluid through the tubing and the annular Coild (Coild Tubing completion), the injection method is to pump a fluid containing proppants in the Coiled Tubing, in parallel non-abrasive fluid is injected with a high velocity in the annular space, these two fluids mix at the bottom of the well initiate and accelerate the propagation of fractures (Figure.III.3).

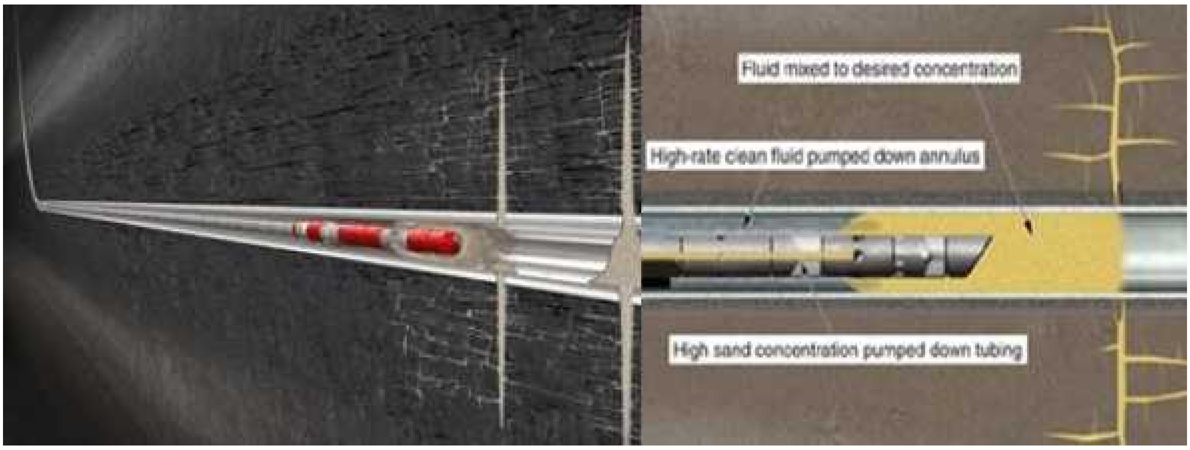


Figure. III.3. Coiled Tubing Fracturing Technique, (Halliburton)

This technique has several advantages such as no need for plug isolation, less risk, fast and flexible placement of fracturing with precision (fluid and proppant), reduced power (number of pump HHP) and clutter up the required volume of water is reduced by compared to the method Plug-n-Perf.

PinPoint provides a range of five (5) techniques for CoiledTubing fracturing:

• SurgiFrac : Ductile Rock,

• CobraMax DM: Moderately Brittle Rock,

• CobraMax H: Ductile Rock

• Cobra Max HJA: Ductile rock

• CobraMax ASF: Brittle Rock

III.1.4.SmartCompletion, Multi-stages Frac Valve

Smartcompletion is applied to the Open Hole configuration. This is with a control system selective and flexible electro-hydraulic (SmartPlex) for opening and closing of the valves from the bottom surface any order (Figure .III.4).

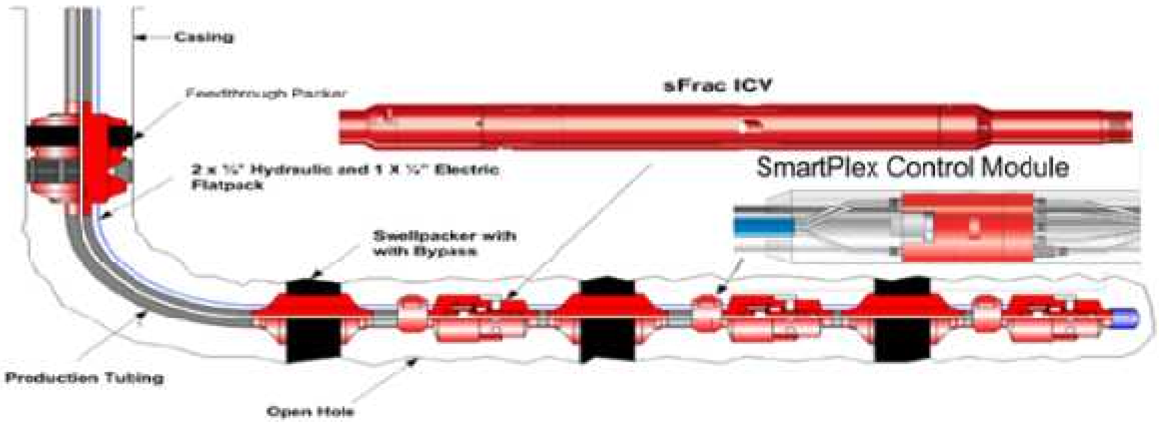


Figure. III.4. SmartCompletion, (Halliburton)

This valve system is used during fracturing, and when cleaning and production process (selective areas or fluids to produce re-fracturing).

III.2.Methods of perforation

The purpose of perforing is to have access to the reservoir after the introduction of the completion, it applies to both types of completions following:

- cased hole cemented
- Liner cemented

In the Petroleum industry, there are two methods of perforation, which are:

- Perforation with explosive
- Perforation with Coiled Tubing,

III.2.1.Perforation with explosive

In this method, a punching tool (Perf-Gun) is used comprising detonators with explosives, it is used to perforate the casing before hydraulic fracturing. The perforating device is connected to an electric cable for allow the explosion of the charges from the surface (Figure.III. 5).

In horizontal wells, four techniques are used to get down and push the perforating (Perf-Gun) through the horizontal part:

- Jointed Tubing
- Coiled Tubing,
- Wireline Tractors,
- Pumped Down Wire Line

III.2.2.Coiled Tubing Perforating (Surji-Jet)

The Surji-Jet tool came down with the Coiled Tubing. This method is based on effect of the high pressure jet and erosion by the sand to pass through the casing, the cementing and penetrate the formation (Figure.III. 6).

Figure. III.5. Perf-Gun, (Halliburton)

Figure.III.6. Surji-Jet, (Halliburton)

III.3.Methods Fracturing

Today, stimulation treatments in shale often focus operational efficiency and velocity to pump the Fracjob for moving forward. So with the new techniques of Coiled Tubing in fracturing unconventional reservoirs, fracturing fluids are simply pumped, and no changes are made to the original design, which aims is to maximize the volume of the fractured reservoir (SRV, see I.1.2) to provide improved by minimizing the anisotropy of connectivity stresses that govern bedrock to create a network of the most complex fractures as possible.

III.3.1. Texas 2 Step

In this method, we divide the horizontal drain with a multitude of fractures transverse, starting with the furthest end of the drain until the top (Figure.III. 7).

This technique consists of fracture between two points, then add a fracture intermediary to be around the sresses that govern the rock.

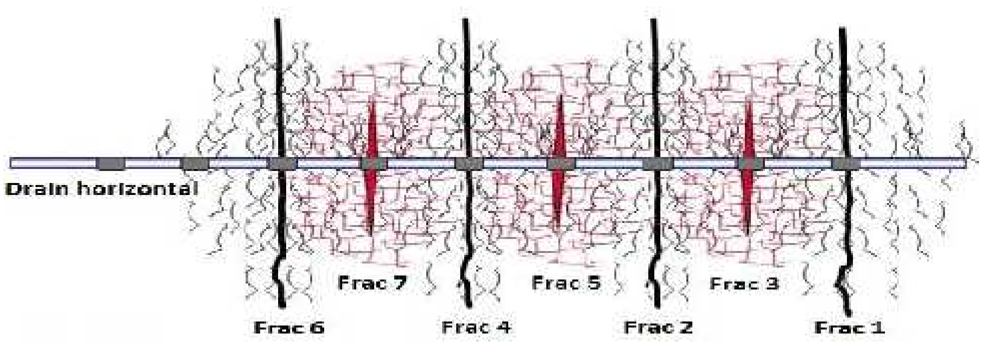


Figure. II.7.Texas 2 Step

III.3.2. Zipper Frac

This method is applied for fracturing WellPads which include several horizontal drains,the principle is to create equidistant fractures following ascending order along the supposed parallel drains, so that these fractures respect alignment fractures first drain (Figure .III.8).

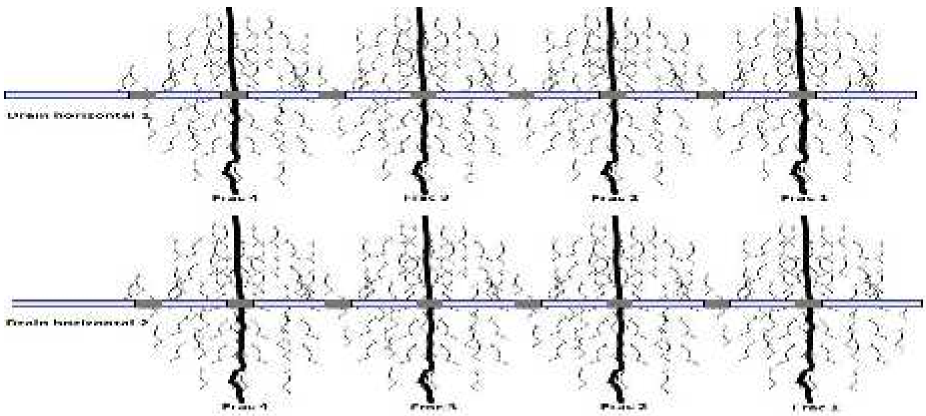


Figure.III.8.Zipper Frac

III.3.3.Modifier Zipper Frac

The principle of this method is the same as Frac Zipper except that fractures two parallel and successive drains are nested to maximize the volume fractured reservoir and create more complexity in the rock, as illustrated in the following figure.

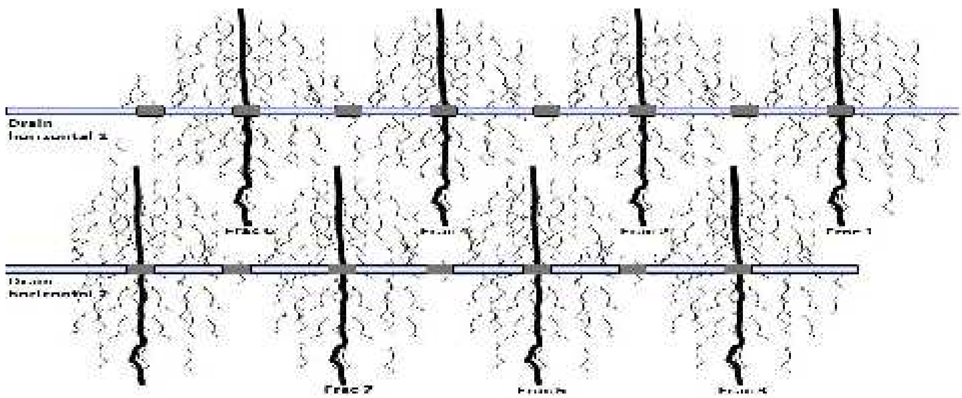


Figure. III.9.Modifier zipper Frac

III.4.Fracturing of shale gas well

Hydraulic fracturing consists of injecting a fluid more or less viscous at high pressure in a rock formation to open fractures on the well bore.

Fracture opens only if the pressure applied fluid exceeds a certain threshold. This pressure called initiation pressure, which depends on:

- petrophysical and mechanical properties of the rock,
- The rheology of injected fluids,
- The infiltration or not injected fluids.

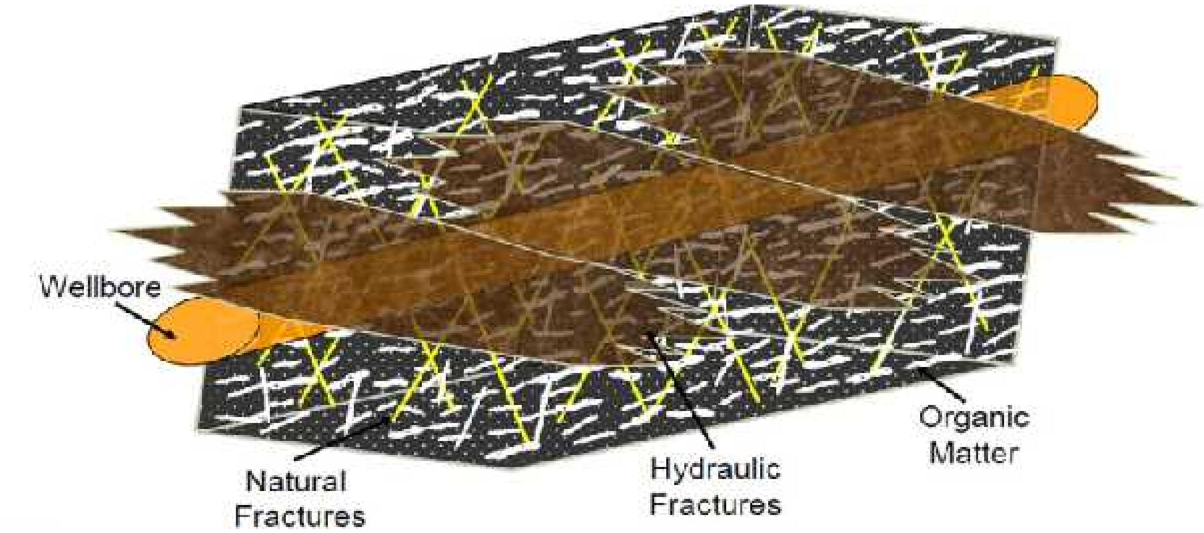


Figure. III.10. Hydraulic fracturing and production fairway relationship,(Wang et,al;2009)

III.4.1.Mechanical Properties Of The Rock

The main mechanical parameters involved in fracturing are: The in-situ stress, Young's modulus, Poisson's ratio and Brittleness.

III.4.1.1.Stresses In-situ

During the past decade Geomechanics has emerged as an important discipline in Geoscience with regard to conventional and unconventional reservoirs.

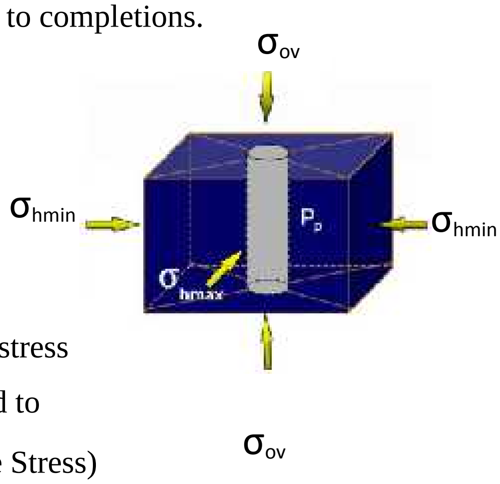
For shale reservoirs Geomechanics is generally applied in two areas :

-Helping to anticipate and prevent wellbore failure. This is very important consideration since shale reservoirs are developed using very long horizontal boreholes.

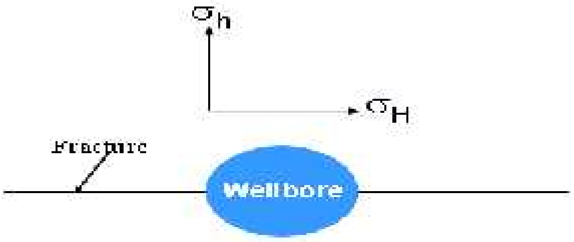
-Helping to determine optimum borehole orientation with respect to completions.

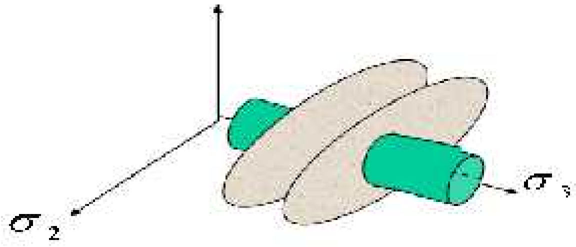
The three main stresses governing the rock burden are:

- Overburden pressure: $\boldsymbol{\sigma_V}$
- Maximum horizontal stress: $\boldsymbol{\sigma_H}$
- Minimum horizontal stress : $\boldsymbol{\sigma_h}$



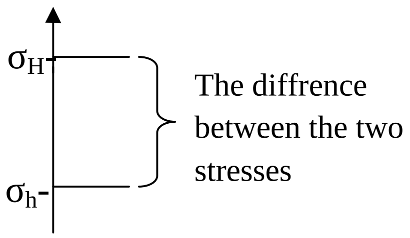
Fractures develop and propagate in the direction of Maximum stress perpendicular to the minimum horizontal stress (pressure required to open a fracture $\sigma_{min} = \sigma_c$ Closure Stress), this constraint (Closure Stress) is the minimum pressure to open a fracture.



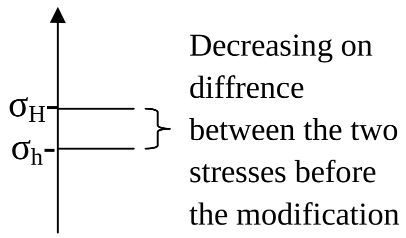


Each layer has its own minimum horizontal stress, and from the most in a small perforated wells, the fracture initiates and grows uniformly in all directions in a circular fashion, it will tend to have two wings tending to develop. After fracturing, there will be an modification in-situ stress in proximity of the well along the interval covered by the layer height fracture.

Note: The modification on stresses is made of reducing the difference between the minimum horizontal stress σ_h And the maximum horizontal stress σ_H .



After Fracturing



Before Fracturing

Minimum Stresses

The effective stress is the difference between the total stress and pore pressure fraction (The law of Terzaghi effective stress).

Total stress σ_t = Effective Stress σ'+ α Pore Pressure P_p

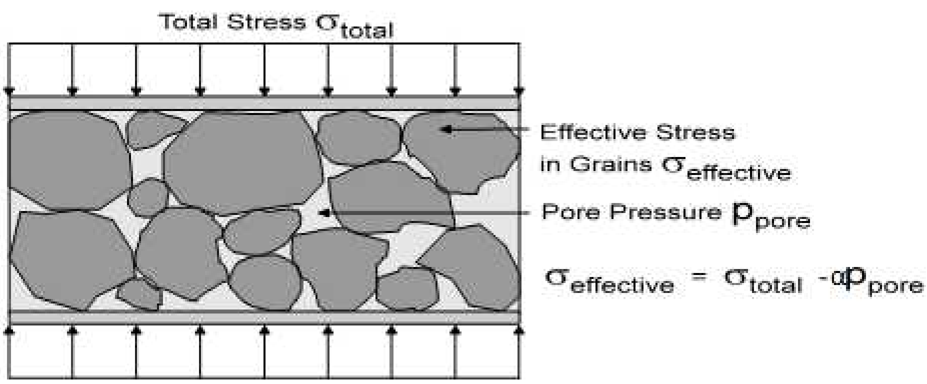


Figure. III.11. Stresses In-situ

Where :

σ_t : Total vertical stress (Overburden pressure) which depends on the density layers and depth

σ' : effective stress (stress supported by the solid part (grains rock)

P_p : pore pressure (fluid of the pores pressure),

With reference to the law of Terzaghi, the minimum stress is defined as:

$$\sigma_{h,min} = \frac{V}{1-V}\ \sigma_V - \alpha P_p\ + \alpha P_p$$

α : Biot's constant (constant effective stress, poroelastic,0< α <1).

This stress (σ_{hmin}) Represents the pressure required to open a fracture, and which the operators optimize fluid injection pressure fracturing (see **I.4.2.7**).

Once the fracture is initiated, the extension depends on the applied stress (pressure and

Anisotropic Rock Proprieties

Anistropy is the variation of a property with the direction in which it is measured. The Anisotropic effects in shale has two implications :

1.Determining Young's Modulus and Poisson's ratio
2.Estimation of in situ horizontal stress

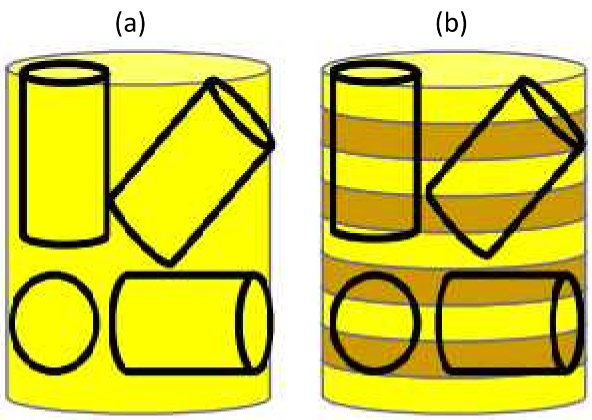
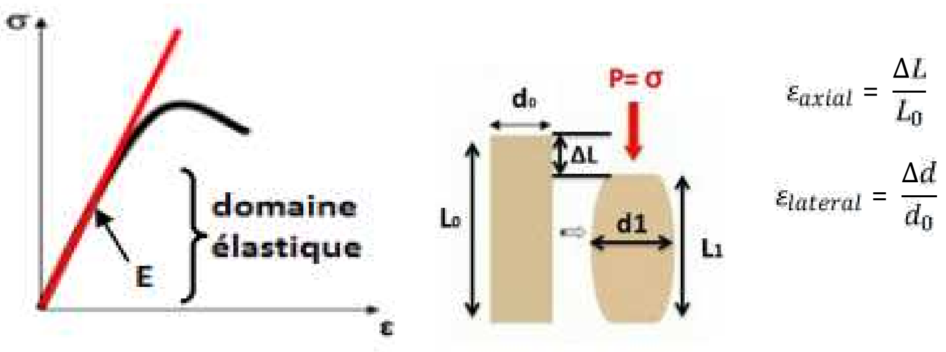


Figure. III.12.(a) isotropic and (b) anisotropic rock proprieties,(Fjaer et al.2008)

III.4.1.2.Young's Modulus

Young's modulus (E) is expressed in a well-defined field (elastic) as ratio of the tensile (axial) stress on the tensile strain : $E = \frac{\sigma_{axial}}{\varepsilon_{axial}}$



higher the Young's modulus, the more resistant to the medium to deform when subject to normal stress. Generally shales have a Young's modulus higher than that sandstones.

III.4.1.3.Poisson Ratio

The Poisson ratio (v) is the ratio of lateral strain on axial strain preceded by a negative sign (-), this ratio is the portion of the stress (or strain) vertical transmitted horizontally.

$$\nu = -\frac{\varepsilon_{lateral}}{\varepsilon_{axial}}$$

lateral

- For rocks: 0.1 <v <0.4 .
- A high Poisson ratio mean a ductile rock (soft) on the other side a small ratio means a hard and breakable rock (brittle).

Young's Modulus and Poisson's ratio are usually obtained from rock mechanics experiments on core plugs .

III.4.1.4.Brittlness

Shale is a function complex lithology, mechanical parameters, TOC, temperature, porosity and compaction.

Shales have a high Brittleness, which makes them easily breakable as sandstone (see I-2-3-1-7). This setting increases the chances of having natural and the success of hydraulic fracturing fractures.

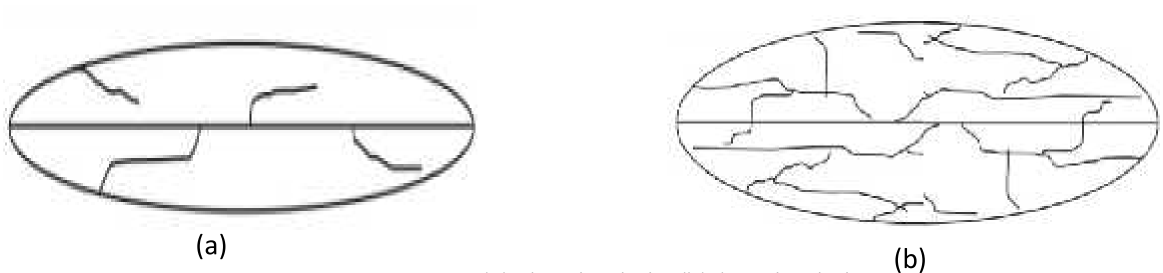


Figure. III.13.(a) ductile shale,(b) brittle shale

There is not a standardized universal concept for the brittleness or the method for measuring, which it could be directly controlled by mineralogy and the fabric/texture of the mineral components, also can be derived from properly-calibrated well site XRD and XRF data.

In fact each company has its own method and generally these methods are based on data logging (sonic). the method developed by Halliburton is as follows:

1) **The Young's modulus contributor Brittleness**

$$YM - C = \frac{8000000 - X}{8000000 - 1000000}$$

8000000 Psi: the maximum value of Young's modulus for rocks,
1000000 Psi: the minimum value of Young's modulus for rocks,
X (Psi): the value of Young's modulus measured by the Logging (sonic) to given depth.

2) **Poisson's ratio contributor Brittleness**

$$PR - C = \frac{0.1 - Y}{0.1 - 0.4}$$

0.1: the minimum value of Poisson's ratio for rocks,

0.4: the maximum value of Poisson's ratio for rocks,

Y: the value of Poisson's ratio measured at a depth Logging given.

3) **Brittleness :**

$$Brittleness\ Factor = \frac{YM - C + PR - C}{2}$$

The following figure shows the variation of Brittleness based on Mechanical rock properties (Young's modulus YMS, Poisson's ratio PR).

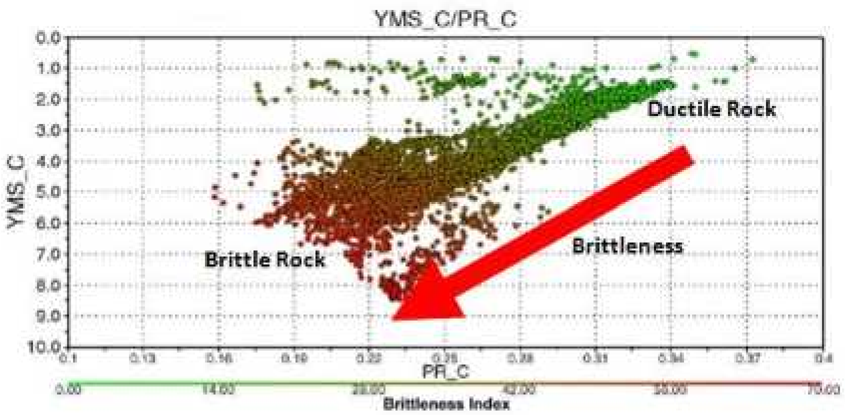


Figure.III.14.Brittlenes Index,(Rickman et al.2008)

III.4.2.Petrphysical Properties Of The Rock

The porosity and permeability are two parameters that influence directly on the infiltration or not of fracturing fluid in the target rock, thus the opening and closing of fractures (see II.3.4).

Note:

The mechanical and petrophysical parameters mentioned above are obtained by laboratory testing, logging and Well testing.

III.4.3. Fracturing Fluids

The objective of a fracturing operation is to artificially create a permeability with the injection means under very high pressure (greater than the pressure fracturing) fluid to a micro - crack and fracture the rock .

The fracturing of the rock is based on the combination of two elements essential , the pressure generated by the surface equipment and fluids fracturing.

Fracturing fluids used to:

- Convey the pressure generated by the equipment surface to the bottom well ,
- Create fractures pressure rise and develop its extension,
- Maintain the fracture opened by the transport and deposition proppants .

The fluids used must have several properties (viscosity , temperature,filtration , PH , friction , ... concentration) to ensure a good performance during and after fracturing . The preparation system and is designed for injection fluid is suitable for courses that will meet , and it changes properties and function and as it moves from the surface towards the end of the fractured zones and for cleaning and drainage of the fractured zone .

III.4.4.Composition Of Fracturing Fluids (Unconventional)

Fracturing fluids are a mixture of water, chemicals and propants including their percentage (variable) per unit volume is as follows:

- 95% water which is of the order of 10 000 to 15 000 m^3,this volume depends on dimensions wells and geological conditions.
- 4.5% of supports agents (fine sand proppants).
- 0.5% chemical additives.

During fracturing job, the volume of water injected must be controlled continuously by a permanant system to eliminate bacteria (CleanStream, Halliburton), and the periodic monitoring of PH (PH 6 <PH < 8), the density, chemical and mineralogical composition.

III.4.5. Proppants

Generally clean quartz sand of fairly uniform granularity is used (sand, resin coated sand) and in the case of deep and strong constraints, it makes use of proppants based ceramic or bauxite.

III.5. Stages Of Hydraulic Fracturing

During the process of hydraulic fracturing, it is essential to see the modeling, monitor and control processing operations.

In reservoirs shale, most wells are drilled horizontally in a direction parallel to the minimum constraint to maximize the extension of fractures and carry several regularly spaced fractures along the well, with a variable number of fractured sections, starting with the furthest point remote from the horizontal portion.

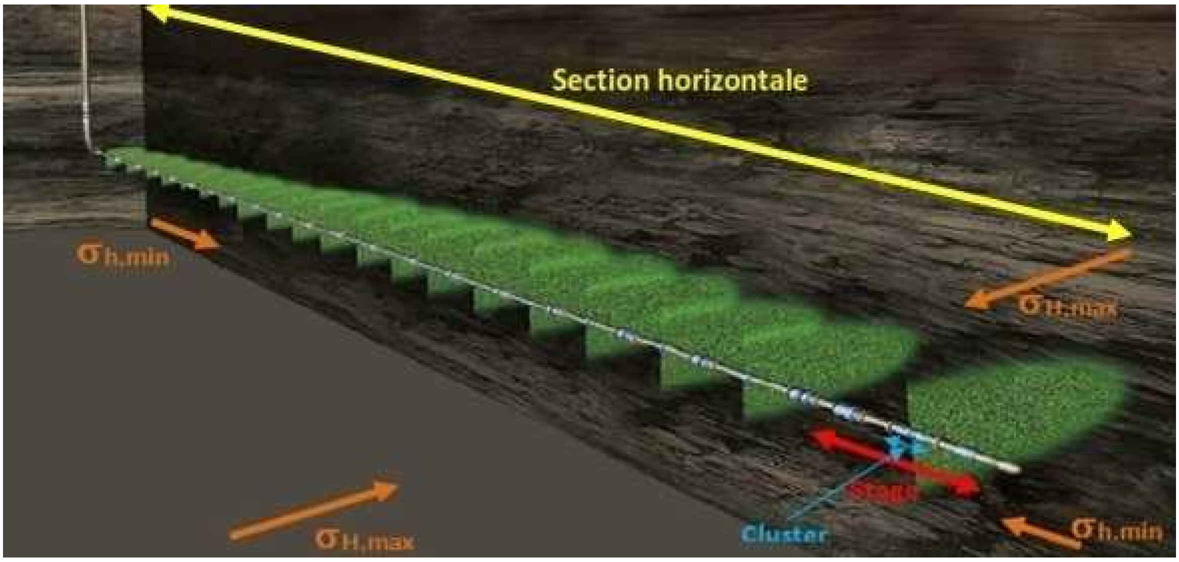


Figure.III.15. Technical fracturing in shale (Multi Frac Stages)

After the establishment of the completion, each perforated section and then fractured by injecting a fracturing fluid (water, sand and chemical additives) under high pressure that causes fracturing.

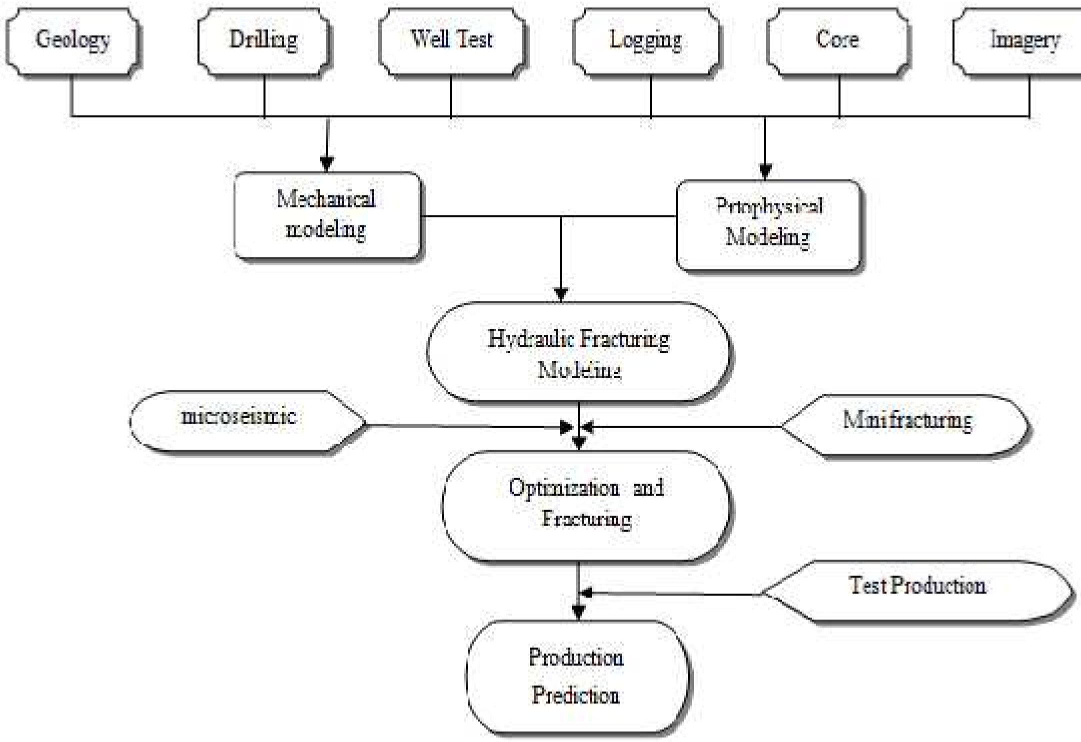
This process (hydraulic fracturing) is currency in four (4) main stages:
a) Modeling,
b) Step-Up and Step-Down test,

c) Mini fracturing

d) Fracturing (Main Frac).

III.5.1.Hydraulic Fracture Modeling

Hydraulic fracturing is a technique that must be controlled by a system IT throughout its implementation. Software (FracPro and Gohfer, Halliburton) are used to model the structure of shale (the same for conventional reservoirs), the evolution of layers with depth and mechanical and petrophysical properties, all based on the data drilling, logging , completion, well testing and laboratory.



The purpose of these computer models is to optimize a model of fracturing depending on the characteristics of the medium, clearly delineate fracture zone targeted optimize conditions for fracturing properties of the fracturing fluid and proppant .

The fracturing model answers many questions that arise before fracture the rock, such as:

a) The operating conditions

- Type fluid to be injected,
- The optimum injection rate (slow, rapid, pulsed), the injection pressure and the power needed surface.
- The type of proppants
- The value of water with friction reducer and additives chemical,
- The transport and distribution of proppant in the fracture network,

b) Quantitative evaluation of the operation

- Characterization of treated areas (σ_{hmin}, Brittleness, permeability, etc ...) and their peripherals
- The prediction of secondary fractures,
- Taking into account heterogeneities.

III.5.1.1.Optimization Fracturing Fluid

Fracturing is initiated by a low viscosity fluid (not to lose too much pressure by the friction forces), then injecting viscous fluids (gels) containers proppants to prevent the closure of the network fractures. To choose the type of fracturing fluid to be injected, we refer to table below :

Brittleness	Fluid System	Proppant Concentration	Fluid Volume	Proppant Volume
70%	Slick Water	Low	High	Low
60%	Slick Water			
50%	Hybrid			
40%	Linear			
30%	Foam			
20%	X-Linked			
10%	X-Linked	High	Low	High

Table.III.1. Brittleness Guide using for fracturing ,(Rickman et al.2008)

Note that the choice of the type of fracturing fluid is based on the last Brittleness influence on the volume of fluid injected and the volume concentration and proppants , but the selection of chemical additives depends on the mineralogical composition rock and operating conditions.

Once the fracturing fluid is optimized (the type of fluid and additives concentration), expert opinion and laboratory tests are recommended before each fracturing job (testing viscosity, gels, interruptions, clays stability, compatibility formation fluid and rock ...).

III.5.1.2.Optimization Proppants

Optimizing the type of proppant injected with the fracturing fluid has to ensure the opening of the fracture as long as possible in the life of the wells.

The type of proppants depends on:

- The stress closure (closure pressure, $\sigma_{h,min}$)
- minimum pore pressure .
- Net Pressure, P_{Net} (pressure required to keep the fracture open)
- The diameter of the perforations,
- The price of proppant (economic aspect).

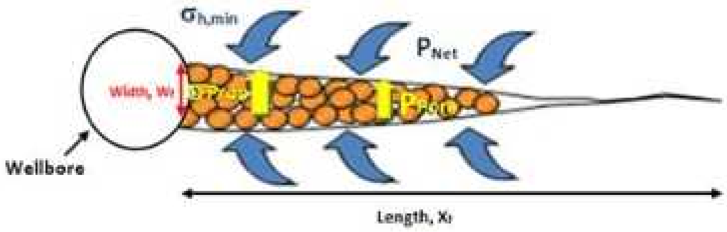


Figure. III.16. The various stresses governing the proppant (Halliburton)

Pressure to close the divide: $\sigma_{h,min} + P_{Net}$

The pressure to keep the fracture open: $\sigma_{prop} + P_{pore}$

The constraint of proppant (σ_{prop}) Needed to keep the fracture open:

$$\boldsymbol{\sigma_{prop} + P_{pore} = \sigma_{h,min} + P_{Net} \Longrightarrow \sigma_{prop} = \sigma_{h,min} + P_{Net} - P_{pore}}$$

For safety, this constraint would be increased by 34%.

Once this constraint is determined, select the type of proppant by Use the following chart:

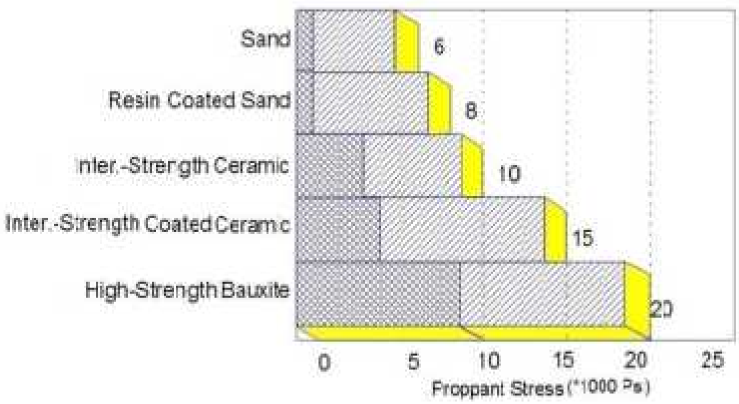


Figure. III.17.Chart of type proppant selection (Halliburton)

Each type of proppant has several sizes (mesh size) to optimize adequately sized software (Material library, Halliburton) are used.

The best size of proppant is one that gives a conductivity (KW) Stable with increasing stress over time and thus meets the following condition:

$$\frac{\emptyset_{perf}}{\emptyset_{prop}} > 6$$

with:

ϕperf: Diameter of perforation,

ϕprop: Diameter of proppant,

Maximum Proppant Concentration LB/Gal	Proppant Mesh Size 8/12	12/20	16/30	20/40	40/60
	Minimum Allowable Perforation Diameter, inch				
1	0.27	0.19	0.13	0.09	0.05
2	0.37	0.26	0.18	0.13	0.06
3	0.44	0.31	0.22	0.15	0.08
4	0.49	0.34	0.24	0.17	0.09
5	0.52	0.36	0.26	0.18	0.09
6	0.53	0.38	0.27	0.19	0.09
7	0.54	0.38	0.27	0.19	0.10
8	0.55	0.39	0.27	0.19	0.10
9	0.56	0.39	0.28	0.20	0.10
10 or more	0.56	0.40	0.28	0.20	0.10

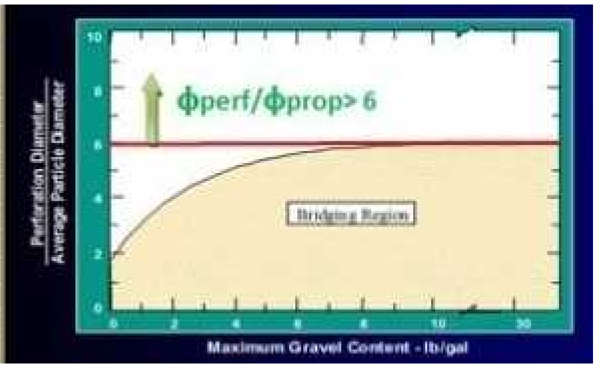


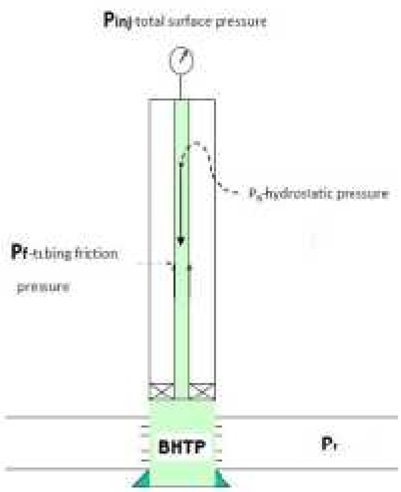
Figure. III.18.Select of proppant size,(Halliburton)

III.5.1.3.Flow Injection, Injection Pressure And The Number Of Pumps

During hydraulic fracturing, the injection velocity and pressure dependent and the state of completion of the mechanical parameters of the rock.

III.5.1.3.1.The Injection Rate

The injection rate is obtained from Step-Up test.



III.5.1.3.2.Injection Pressure

The injection pressure by the following formula is obtained:

$$BHTP = P_{inj} + P_H - P_f$$

Avec :

P_{inj} : Injection pressure ,
$BHTP$: Bottom Hole Treating Pressure ,
P_H : pression hydrostatique de fluide à injecter,
P_f : Friction pressure.

III.5.1.3.3. Number Of Pumps

The number of pumps necessary for a fracturing operation is obtained from the total hydraulic power (Hydraulic HorsePower) required surface area, the latter is defined by the following formula:

$$HHP = \frac{P \times Q}{40.8}$$

HHP: Hydraulic Horse Power (power)

P : Injection Pressure (Psi)

Q : injection rate (bbl / min),

$$Nomber\ of\ Pumps = \frac{Total\ Hydraulic\ \ Power\ (HHP)}{HHP\ issued\ by\ a\ single\ pump}$$

III.5.2.Step-Up And Step- Down Test

III.5.2.1. Step-Up Test

The idea behind this test is to inject a fluid under different levels of viscous flow until the opening of the fracture. This test for purposes of determining the pressure propagation (Extension pressure) fracture and the injection rate to keep the fracture open .

III.5.2.2. Step- Down Test

This test involves injecting a fluid at high speed and Once the flow has stabilized , the reduction is carried out thereof by bearing to determine the possible presence of friction problems near the well (due the tortuosity of fracture or damage at the perforations)

III.5.3.Mini Frac (Shadow Frac Or Data Frac)

In this step , we proceed to the injection of a viscous fracturing fluid to propagate the fracture. Once the fracture is open and spread , using control system and software (FrcaPro , Halliburton), we obtain the parameters Key fracturing :

- **FE** : Fluid Efficiency , this parameter represents the ratio of the volume of fluid fracture in the total volume pumped .
- The volume of fracturing fluid injection (PAD) obtained from several methods based on **FE** .
- Closure Stress: the minimum horizontal stress of the fractured zone ,obtained by interpreting the pressure curves (FracPro , Halliburton)
- **ISIP** : Instantaneous Shut-In Pressure is the pressure after stopping pumping .
  $ISIP\ =\ \sigma_{h,min} + P_{Net}$
- P_{Net}: Net Pressure , represents the pressure necessary to keep the fracture opened.

These parameters are used to calibrate (matching) model fracturing previously prepared in the first step (modeling) .

III.5.4.Fracturing (Frac Main)

This is the last step in the process of fracturing involves injecting a volume of fracturing fluid (PAD) responsible for proppants that role for keep the fractures open .

III.6.Techniques For Analyze The Location Of The Fractures Created

Fracture diagnostics are the techniques used to analyze the created fractures and involve analyzing data before (prefrac),during (realtime)and after (post-frac) hydraulic fracture treatment.

Analysis is done to determine the dimensions of the created and also the effectively propped fracture.Fracture Diagnostic techniques are divided into several groups.

III.6.1. Direct Far Field Techniques

These comprise tiltmeter and microseismic fracture mapping techniques which require delicate instrumentation to be placed in boreholes surrounding and near the well to be fracture treated.Microseismic fracture mapping typically relies on using a downhole receiver array of accelerometers,or geophones, to locate “micro-earthquakes’’ that are triggered by shear slippage in natural fractures surrounding the hydraulic fracture. As with all monitoring and data collection techniques, however, the economics of UNCON means that typically they are considered marginal wells and the expense is often not justified until the resource has been proved. If the technology is used at the beginning of the development of a field, however, the data and knowledge gained have been shown to be cost effective in the long run once development of the shale play begins in earnest.

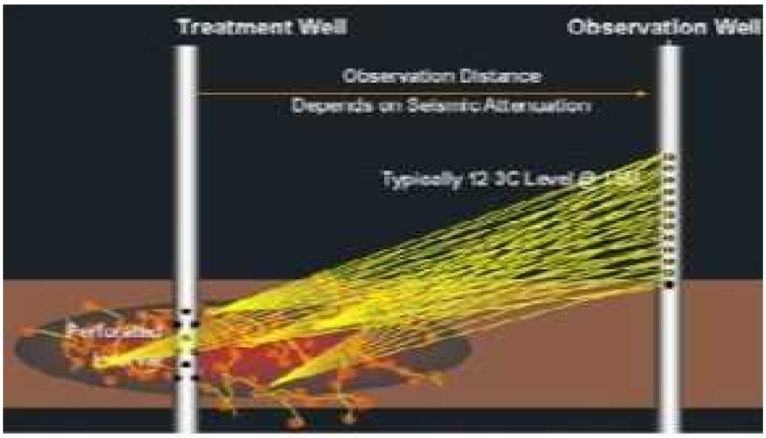


Figure. III.19.microseismic principle (Halliburton)

The introduction of micro- seismic monitoring in fracturing operations allows you to:

- Observe fracturing operations in real time,
- A possible intervention or modification of treatment,
- Estimate the volume of fractured rock (SRV)

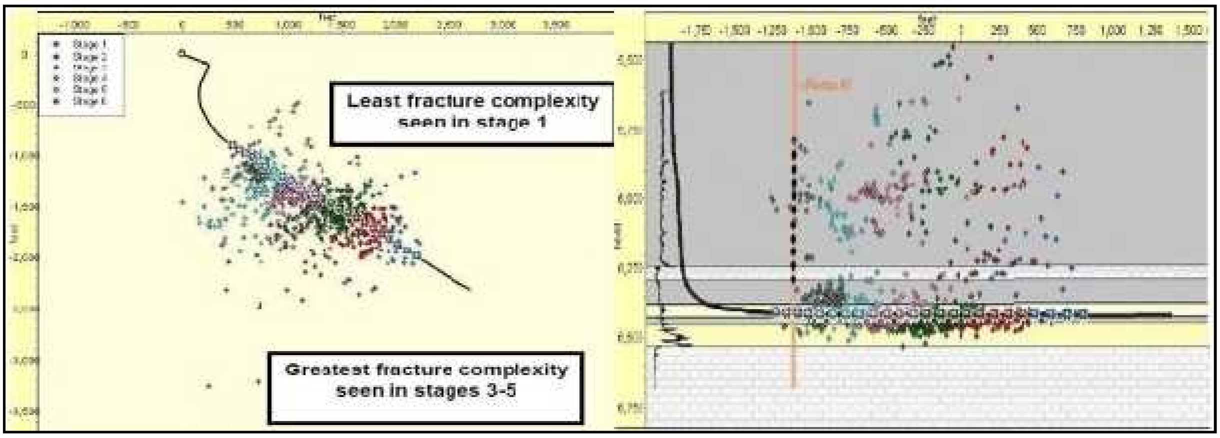


Figure. III.20.3D micro-seismic monitoring example of a fractured horizontal well

III.6.2. Direct Near-Wellbore Techniques

These techniques are run in the well that is being fractured to locate the portion of fracture that is very near wellbore and consist of tracer logs, temperature logging, production logging, borehole image logging, downhole video logging, and caliper logging. In Shale gas plays, where multiple fractures are likely to exist, the reliability of these direct near-wellbore techniques can often be poor.

As such, very few of these direct near-wellbore techniques are used on a routine basis to evaluate hydraulic fracture and if deployed they are used in conjunction with other techniques.

III.6.3. Indirect Fracture Techniques

This consists of hydraulic fracture modeling (see Figure.III.21) and matching of the net surface treating pressures (see Figure.III.22), together with subsequent pressure transient test analyses and production data analyses. As fracture treatment data and the post-fracture production data are normally available on every well, indirect fracture diagnostic techniques are the most widely used methods to determine the shape and dimensions of both the created and the propped hydraulicfracture.

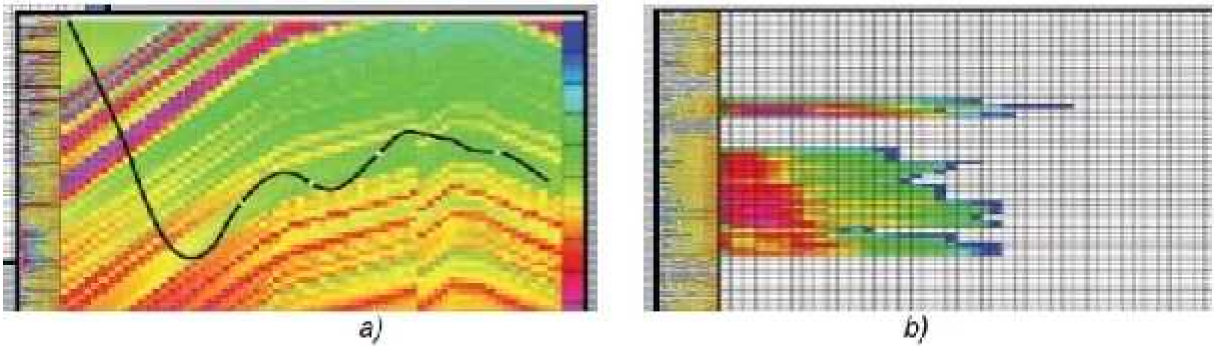


Figure. III.21.(a) 3D frac simulator grid model and (b) frac outputs(Source:Reference [19])

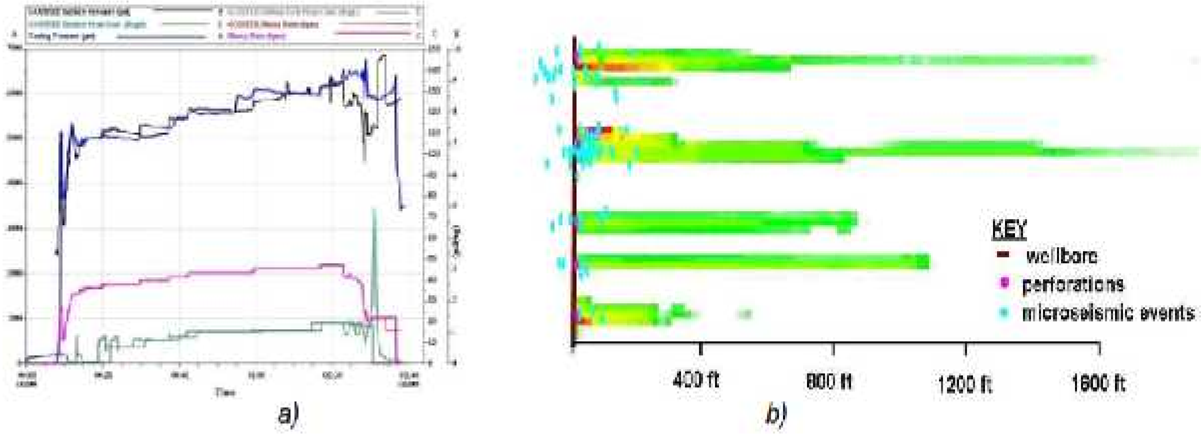


Figure. III.22.(a) pressure and (b) simulator output/microseismic matching,(Source:Reference [19])

Conclusion

As a result of the improved horizontal drilling with completions consideration and hydraulic fracturing technologies, significant progresses are being made towards commercial gas production from such reservoirs, as demonstrated in the US.

Chapter IV

Shale Gas Extraction in Algeria

Introduction

According to the USEIA,Algeria holds the third largest recoverable shale gas reserves after China and Argentina, that what was made the petroleum industry (SONATRACH) is very closely interested in this unconventional resource type.

This chapter is organized in two parts: The first one is all about Algeria's geological presentation of shale basins and the second part is about the plan that made it for the exploitation and the choice of the Ahnet basin and it characteristics .

IV.1. Geologic setting of Algeria Shale Basins

Algeria's hydrocarbon basins hold two significant shale gas formations, the Silurian Tannezuft shale and the Devonian Frasnian shale. The geological studies examines seven of these shale gas basins: the Ghadames (Berkine) and Illizi basins in eastern Algeria; the Timimoun,Ahnet and Mouydir basins in central Algeria, and the Reggane and Tindouf basins in southwestern Algeria.

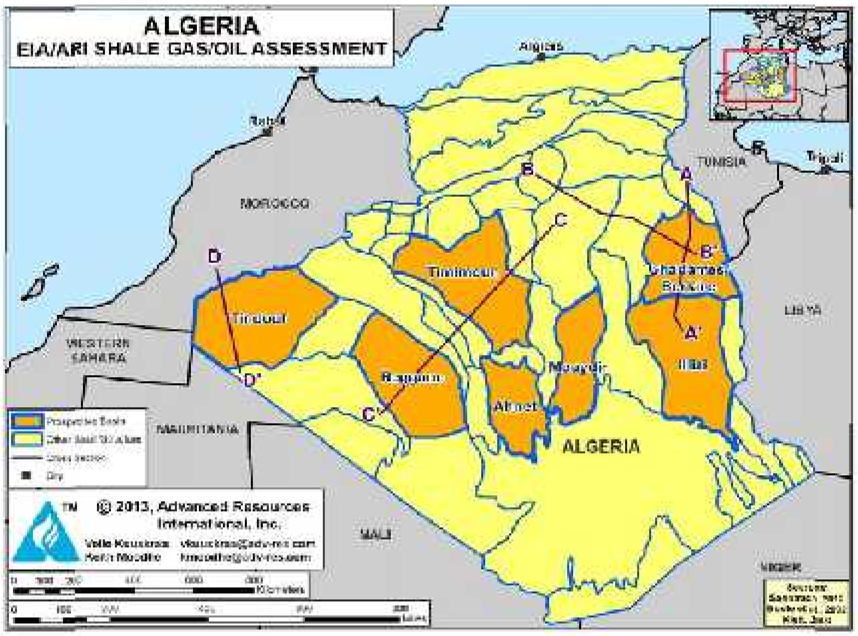


Figure.IV.1.Algeria's shale gas and shale oil basins(ARI 2013)

IV.1.1.Ghadames(Berkine) Basin

The Ghadames (Berkine) basin is a large intracratonic basin underlying eastern Algeria, southern Tunisia and Western Libya. The basin contains a series of reserves faults, providing structural gas traps sourced from Devonian and Silurian age shales.

The Ghadames Basin and its two significant shale formation, the Silurian Tannezuft and the Upper Devonian Frasnian, are located in the eastern portion of Algeria.

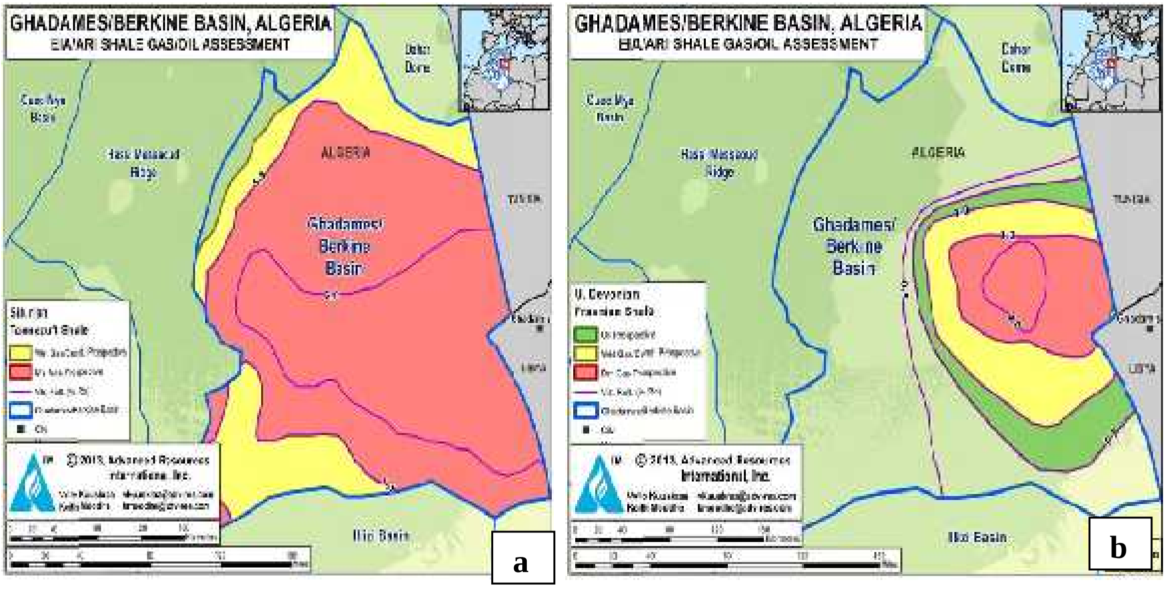


Figure.IV.2. Ghadames basin;(a) Silurian Tannezuft and (b) basin Upper Devonian Frasnian shale outline and thermal maturity ,(ARI 2013)

In Algeria's portion of the Ghadames Basin, in Silurian Tannezuft formation contains an organic-rich marine shale that increases in maturity toward the basin center. It have been mapped 28,130 mi^2 with higher quality prospective area for the Tannezuft Shale in this basin. The western and northern boundaries of the Tannezuft Shale prospective area are defined by the erosional limits of the Silurian and by minimal thermal maturity.

The central, dry gas portion of the Tannezuft Shale prospective area in Ghadames basin, covering 21420 mi^2 ,has thermal maturity (R_0) of 1.3% to over 2%.The remaining portion of the prospective area of 6710 mi^2 has an R_0 between 1.0%,placing this area in the wet gas and condensate window.

Deposited above the Tannezuft is the already more limited and thermally less mature Upper Devonian Frasnian shale. The prospective area for Frasnian shale with a high quality is mapped about 10040 mi^2 in the Ghadames basin of Algeria.

The western, northern and southern boundaries of the Frasnian shale prospective area are set by the minimum thermal maturity criterion of 0.7% R_0 .

The eastern boundary of the prospective area is the Tunisia and Algeria border.

The northern, eastern and southern outer ring of the Frasnian shale prospective area in the Ghadames basin ,encompassing an area of 2720 mi^2,is oil window with R_0 between 0.7% and 1.0%. The dry gas window is in the central 5010 mi^2 portion of the Frasnian shale prospective area, with R_0 of 1.3% to over 2% and the wet gas and condensate window is 2310 mi^2 in between for the Frasnian, with R_0 between 1.0% and 1.3%.

IV.1.2.Illizi Basin

The Illizi basin is located south of the Ghadames basin, separated by hinge line in the slope of the basement rocks. this hinge line controls much of differing petroleum generation, migration and accumulation histories of this two basins. The Illizi basin is bounded on the east by Tihembokz(Garoaf) Arch, in the south by the Hoggar Massif,and on the west by the Amguir-Hassi Touareg structural axis which separates the Illizi basin from the Mouydir basin (Figure.IV.4).The Illizi basin is located on basement high and thus its shale formations are shallower than in the Berkine basin. it's mapped an overall shale gas and oil prospective area of 26600 mi^2 for the Illizi basin.

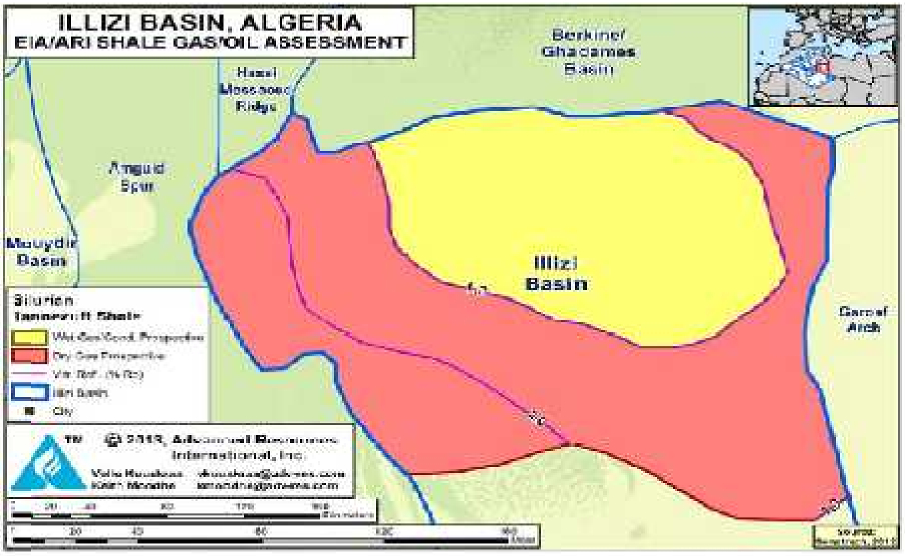


Figure.IV.3.Illizi Silurian Tannezuft shale, outline and thermal maturity (ARI 2013)

IV.1.3.Timimoun Basin

The Timimoun basin, located in central Algeria, is bounded on the north and east by structural uplifts, on the west by the Beni Abbes Saddle, and on the south by the Djoua Saddle that separates the Timimoun basin from the Ahnet basin. The depth and deposition of the Timimoun basin varies greatly due to erosion along the structural highs during the Hercynian.

The Paleozoic section is thickest in the center of the Timimoun basin, thinning to the north and east. The major shale source rocks in this basin are Silurian Tannezuft shale and the Upper Devonian Frasnian shale.

It is mapped a 41670 mi^2 dry gas prospective area for the Tannezuft shale that covers essentially all of the Timimoun basin, excluding a small area along the north-western portion of the basin where the Silurian is absent.

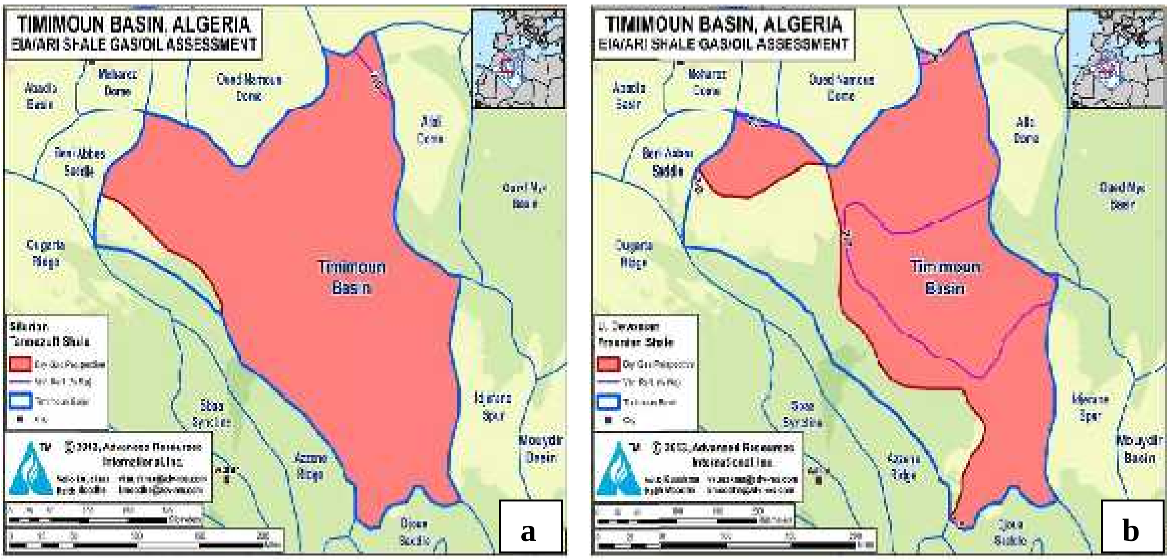


Figure.IV.4. Timimoun basin; (a) Silurian Tannezuft and (b) Upper Devonian Frasnian shale,(outline and thermal maturity),(ARI 2013)

In addition,it was mapped a 32040 mi^2 Frasnian shale dry gas prospective area that covers the eastern two-thirds of the basin,excluding the low (<2%)TOC area along the western portion of the basin.

IV.1.4.Ahnet Basin

The Ahnet basin is located in the Sahara desert platform, south of the large Timimoun basin, west of the Mouydir basin, and north of the Hoggar shield. The Ahnet basin is a north-south trending basin that contains thick (over 3000 ft) of Paleozoic sediments including organic rich Silurian and Devonian shales.the structures in the basin take the form of large ,elongate anticlines and domes formed as a result of tectonic compression, as shown on the north to south cross section (Figure.IV.6)

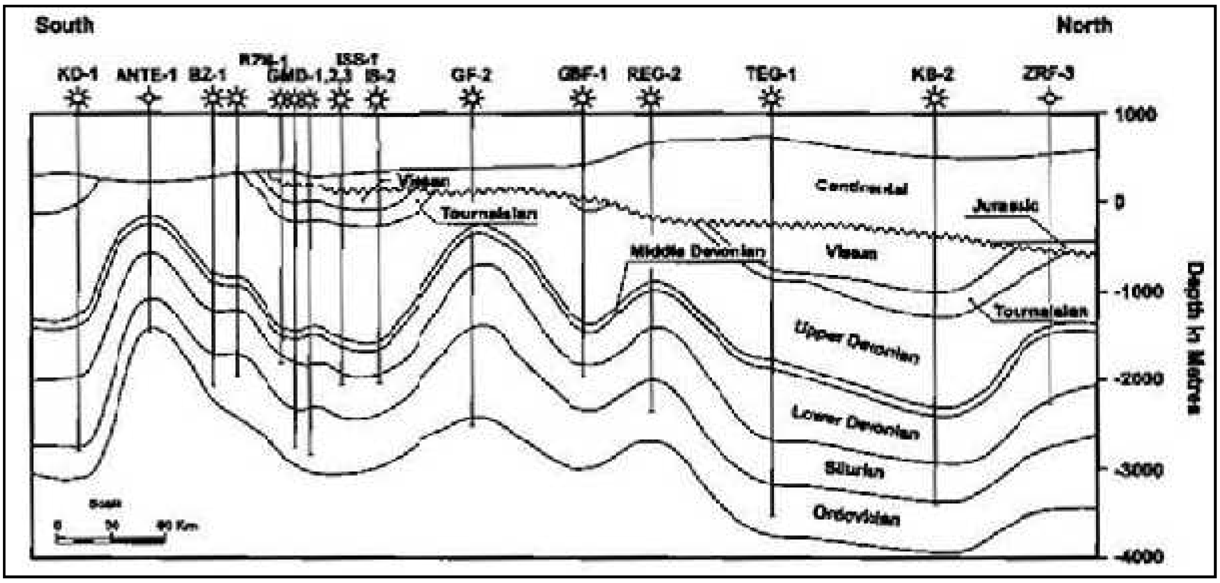


Figure.IV.5.Schematic cross section of the Ahnet basin (Logan et al,1998)

The Ahnet basin contains the Silurian Tannezuft and Upper Devonian Frasnian formations and their organic rich shale intervals. In some portions of the basin, the Paleozoic section was eroded during Hercynian deformation.However,up to 4km of Paleozoic deposits remain intact in the center of the basin. We have defined prospective areas of 11730 mi^2 for the Silurian Tannezuft shale and 7390 mi^2 for the Devonian Frasnian shale in the Ahnet basin.

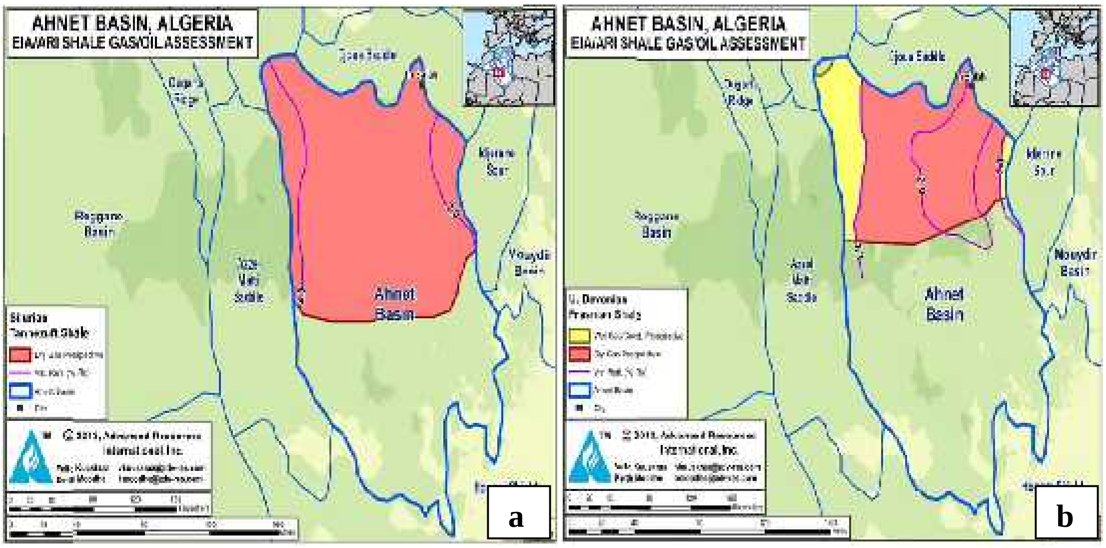


Figure.IV.6. Ahnet basin,(a) Silurian Tannezuft and (b) Upper Devonian Frasnian shale, outline and thermal maturity (ARI 2013)

IV.1.5.Mouydir Basin

The Mouydir basin is located in the central Algeria, west of the Illizi basin and east of the Timimoun and Ahnet basins. A variety of upthrusted structural ridges separated these basins.

The Paleozoic Silurian and Devonian sediments, which include the important Silurian Tannezuft shale and the upper Devonian Frasnian shale, are deepest in the northern portion of the basin and crop out in the southern portion of the basin.

It was mapped a prospective area of 12840 mi^2 in the northern portion of the basin, limited on the south by the depth of the shale (figure.IV.7).

Figure.IV.7.Mouydir Silurian Tannezuft shale, outline and thermal maturity (ARI 2013)

IV.1.6.Reggane Basin

The Reggane basin located in the Sahara desert portion of central Algeria, is separated from Timimoun basin by the Ougarta Ridge. The basin is an asymmetric syncline, bounded on the north by a series of reserve faults and on the south by shallowing outcrops (FigureIV.8.).This basin may contain over 800 m of Silurian section, although well control in the deep northern portion of the basin is limited. The basin also contains the Upper Devonian Frasnian formation which is reported to reach maximum thickness of 400m.

It was mapped prospective area of 34750 mi^2 for Silurian Tannezuft shale and 4680 mi^2 for the Upper Devonian Frasnian shale in the eastern portions of the Reggane basin(Figure.IV.8).

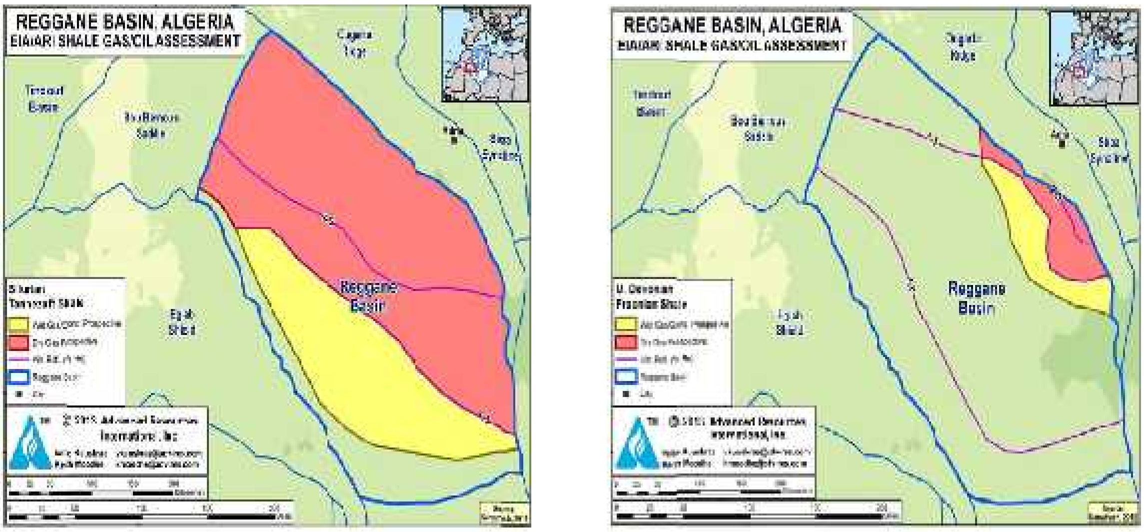


Figure.IV.8. Reggane basin;(a) Silurian Tannezuft (b) Upper Devonian Frasnian shale (outline and thermal maturity)

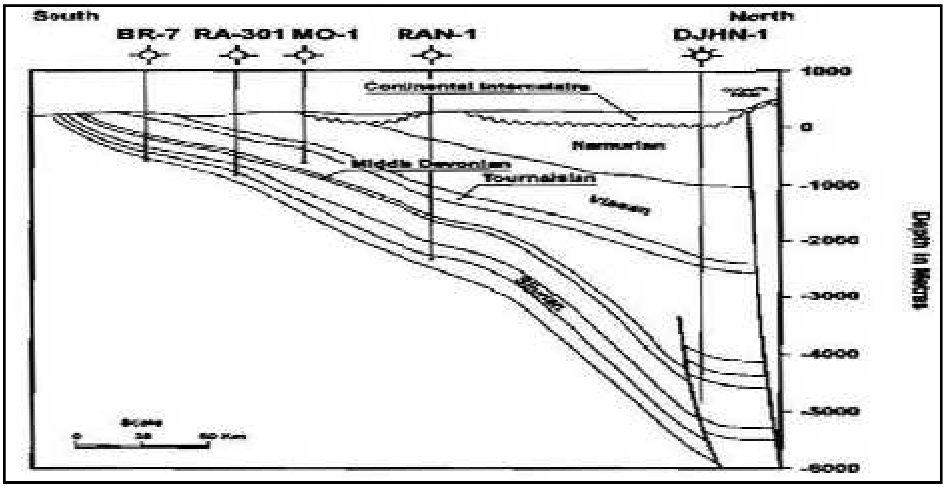


Figure.IV.9.Schematic cross Section of the Reggane basin (Logan et al,1998)

IV.1.7.Tindouf Basin

The Tindouf basin is located in the far southwestern portion of Algeria, bordered on the west by Morocco and the south by Mauritania. This large basin, the least explored basin in the sahara derst platform, covers an area of over 45000 mi^2 just within the Algeria.

Because of limited well penetrations, considerable uncertainty surrounds the shale gas and oil potential of the Tindouf basin. Based on recent data from Sonatrach,the Devonian Frasnian shale is relatively thin (average 10 m) with a TOC of only about 1%.As such ,this shale unit has been excluded from further quantitative assessement.However,the Silurian Tannezuft shale appears to be more promising. It is had established a dry and wet gas prospective area of

29140 mi^2 for the Silurian Tannezuft shale in the northern portion of the Tindouf basin where the TOC is 2% or higher(Figure.10).

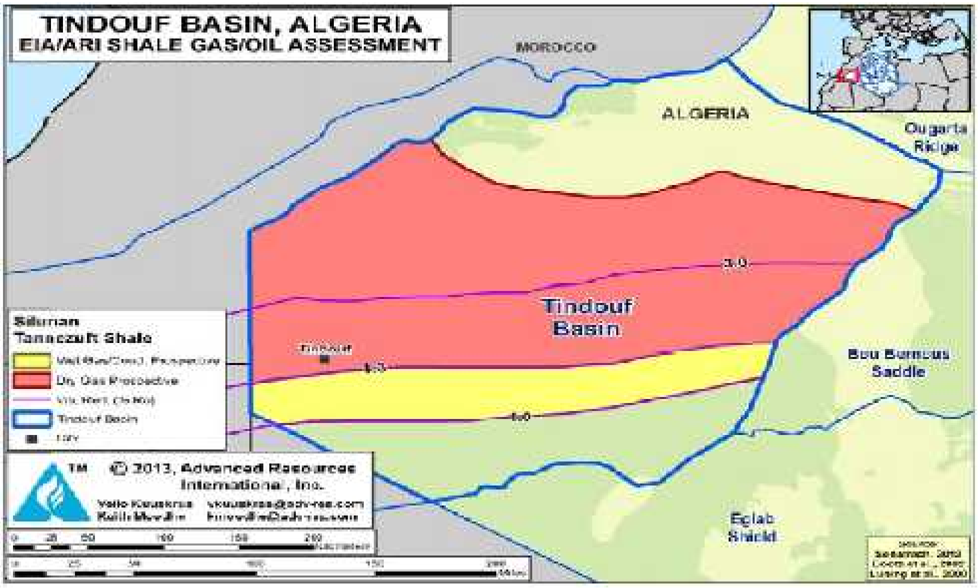


Figure.IV.10.Tindouf Silurian Tannezuft shale,outline and thermal maturity (ARI 2013)

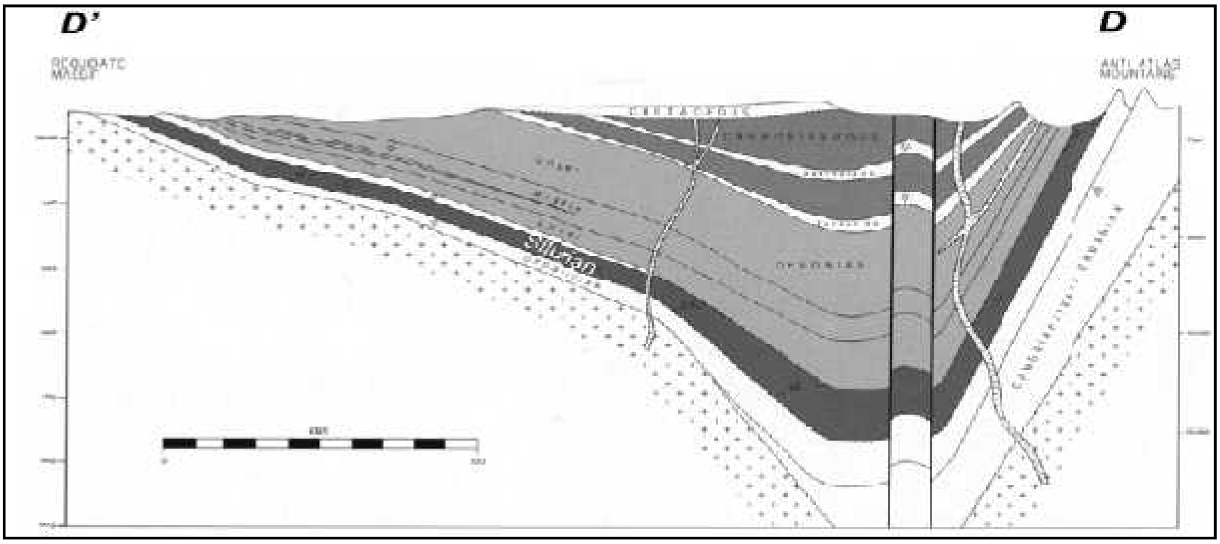


Figure.IV.11. Tindouf basin Cross Section,(Boote,1998)

IV.2.Potential Shale Gas Of Silurian And Frasnian Hot Shales

The Silurian and Frasnian hot shales having a very high TOC and wide extension are classified as a first class source rocks.

The TOC values of Hot Shale Ahnet are generally comparable to other shales examined (Table.IV.1). This feature is an advantage for Ahnet to be a good potential taking into account the importance of this parameter in the evaluation of shale gas.

Basin	Source Rock	Depth	thickness	Maturity	TOC
Ahnet	**Frasnian Hot Shale**	**< 3000 m**	**50 – 200 m**	**1.7 – 3 %**	**1.5 – 4 %**
	Silurian Hot Shale	**< 3000 m**	**20 – 180 m**	**1.7 – 4 %**	**1 – 3 %**
Illizi	**Silurian Hot Shale**	**< 3000 m**	**10 – 60 m**	**1.30 %**	**6 – 10 %**
Reggane	**Frasnian Hot Shale**	**< 3000 m**	**30 – 200 m**	**1.7 – 2 %**	**1 – 3 %**
	Silurian Hot Shale	**> 3000 m**	/	/	/
Tindouf	**Frasnian Hot Shale**	**< 3000 m**	**10 m**	**1.7 – 2 %**	**1 – 2 %**
	Silurian Hot Shale	**> 3000 m**	/	/	/
Berkine	**Frasnian Hot Shale**	**> 3000 m**	/	/	/
	Silurian Hot Shale	**> 3000 m**	/	/	/
Timimoun	**Frasnian Hot Shale**	**< 2000 m**	**40 – 250 m**	**1.4 – 4 %**	**2 – 5 %**
	Silurian Hot Shale	**< 3000 m**	**20 – 140 m**	**1.7 – 4 %**	**1 – 4 %**
Mouydir	**Frasnian Hot Shale**	**< 500 m**	**50 – 200 m**	**1.3 – 1.7 %**	**2 – 4 %**
	Silurian Hot Shale	**< 3000 m**	**05 – 35 m**	**1.5 – 4 %**	**2 – 10 %**

Table IV.1.Characteristics of some Algeria's shale basins (Sonatrach)

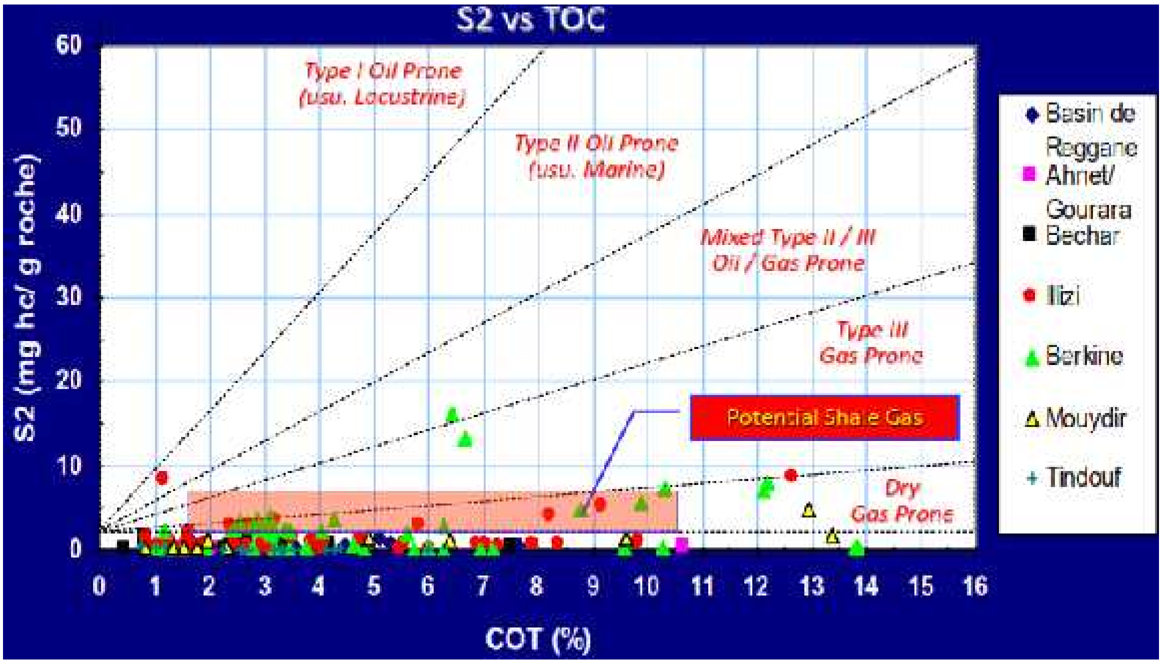


Figure.IV.12(a).S2 vs TOC for Silurian hot shale (Sonatrach)

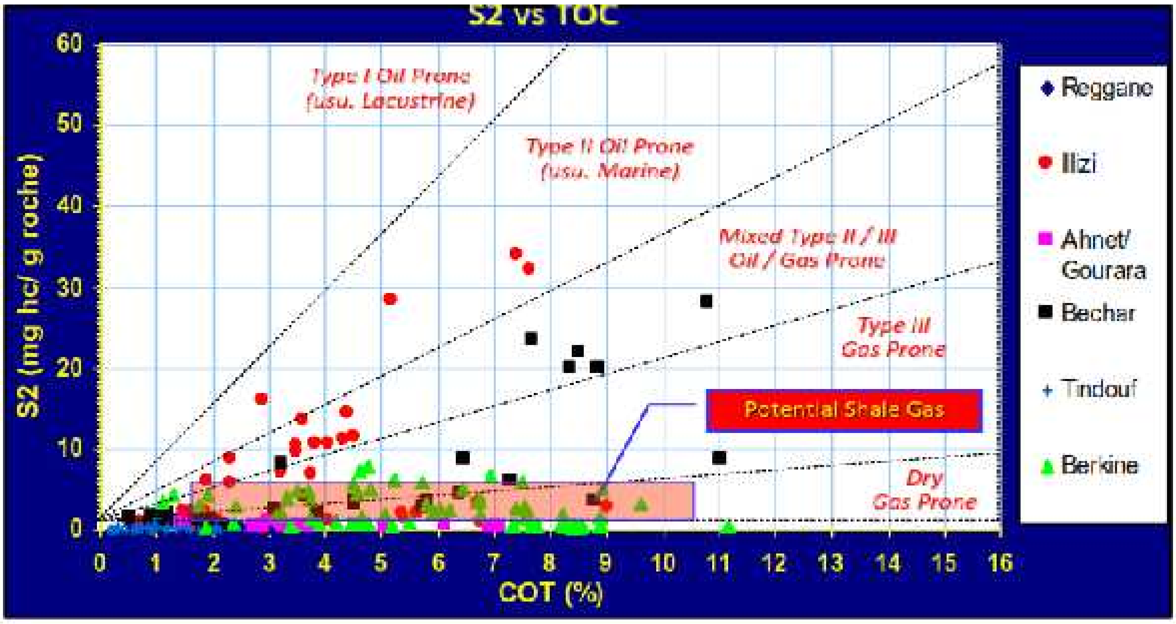


Figure.IV.12(b).S2 vs TOC for Frasnian hot shale (Sonatrach)

The Figure.IV.12 (a) and Figure.IV.12 (b) compares the relationship between S2 and TOC values for the various fields.From the last figure we can wrap up that the potential shale gas is from type III gas prone and dry gas prone and little bit from mixed type II/III oil/gas prone and the Ahnet basin belong to the dry gas prone window.

IV.3. The Algeria's Plan For Shale Gas

Algeria's natural gas company,Sonatrach,has undertaken a comprehensive effort to define the size and quality of its shale gas resources. To date, the company has established a data base of older cores, logs and other data and complemented this with information from new shale well logs in the main shale basins of Algeria. Next in the plan is to drill a series of pilot wells to test the productivity of the high priority basins, targeting shale formations with high TOC(>2%) and thick pay (>20m) at moderate depths (<3000 m). The outline of exploitation of shale gas can be summarized :

1)Definition of the play "shale gas": make a regional evaluation by exploiting the data available (cores, logging, seismic catrography,drilling index and others).

2)Consolidation of the data base: gathering complementary data in various basins cores and specific logs (ECS, APS, CMR, Sonic Scanner, Resistivity, EMS, the FMI…).

3) Confirmation of the concept:

→ Prove the concept on 2 or 3 pilot wells by the main operations:

- Formation productivity, design of the test and other measurements.
- drillability of horizontal drain .
- Stimulation type of fracs(transverse, longitudinal).

→ Estimate the resources and to make the economic evaluation in Algerian context .

- How much is the volume of gas in place?
- Is it producible?
- What would be the production in the short and long term?
- Is it economic?

4) Phase of development: this phase requires very expensive investments, compared to the volume of work to be realized, and a established expertise.

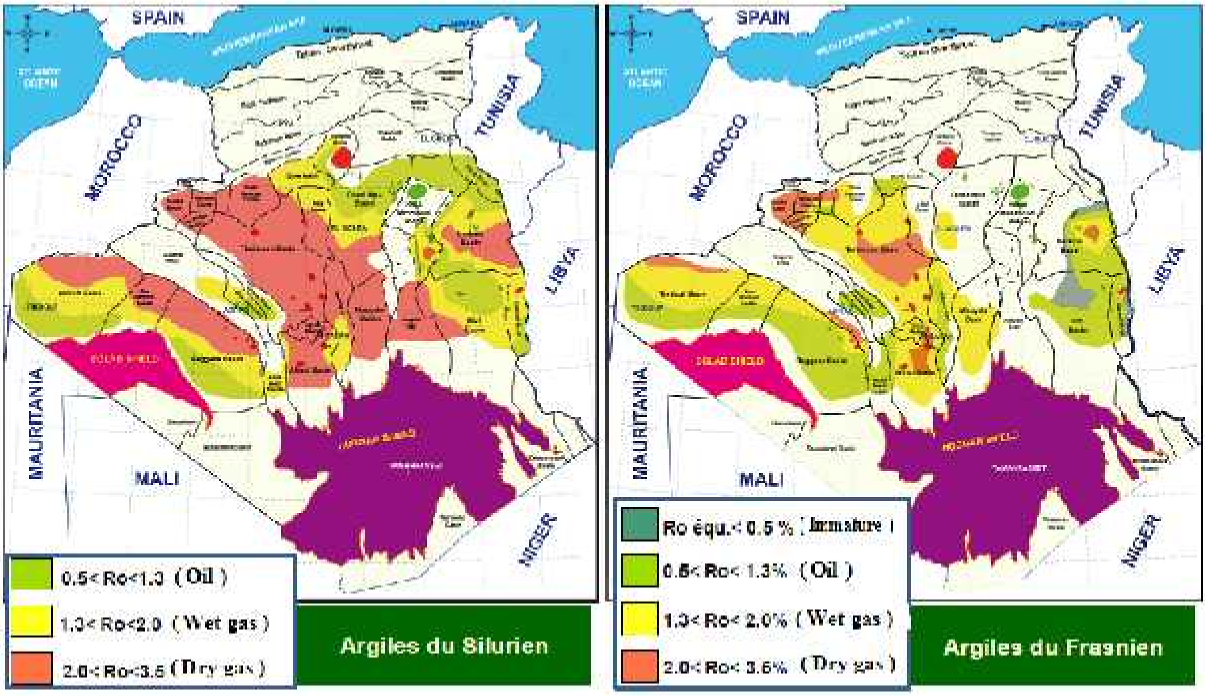


Figure. IV.13.Charts of thermal maturity of the levels "hot shales" Silurian and Frasnian of Saharan platform Kaced,2013).

The initial development can consist of 20 vertical wells, whose the half can be cored and 500 to 1000 horizontal wells, which:

- The vertical wells are pilot wells used for the observation and the coring.
- The horizontal wells are used for the production.

The first pilot well within this comprehensive shale resource assessment program is scheduled for the Berkine (Ghadames) basin, followed by test wells in the Illizi, Timimoun,Ahnet and Mouydir basins. International energy companies, Statoil and Repsol,have also undertaken geological and reservoir characterization studies of Algeria’s shales.

Over the past two years, Algeria has passed amendments to its federal legislation covering the hydrocarbons sector improving investment climate in anticipation of an expanded hydrocarbon licensing round due in 2013.However,the position of its stated owned company Sonatrach is expected to remain dominant in this sector.

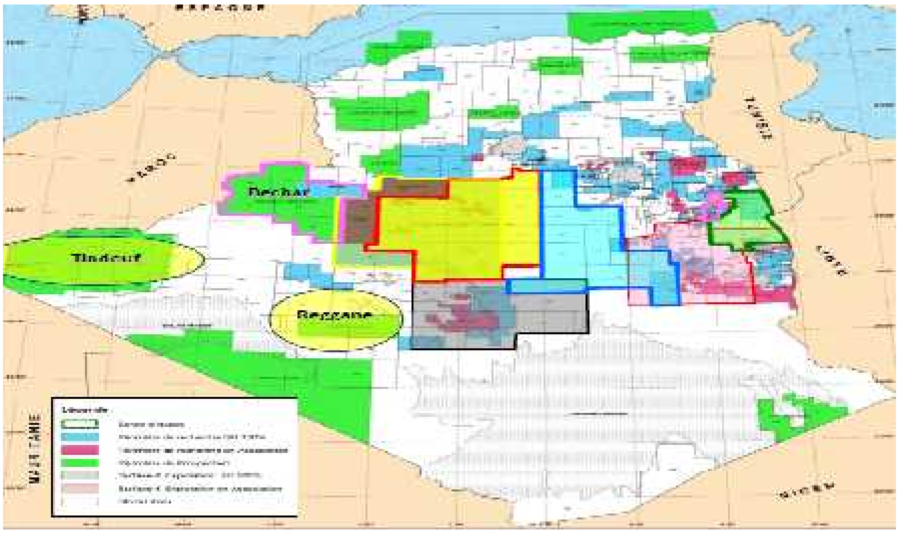


Figure.IV.14.Plan of the "shale gas" studies zones situation (Reggane and Tindouf are future areas in the study,Kaced 2012)

IV.4.Shale Gas Resource Potential And The Choice The Basin

Evaluation of the Silurian and Frasnian shale gas formations from Ahnet and Gourara basins wells indicate a good reservoir quality over large area can be made a great comparison with US shale gas plays.

The choice of the Ahnet basin was made after an initial study based on the comparison of following elements: depth, net thickness, maturity (dry gas window) and TOC, in some sedimentary basins of the Algerian Saharan platform. The results are represented on Table IV.1.It is notable that the Ahnet basin has good general characteristics for the two formation rocks.

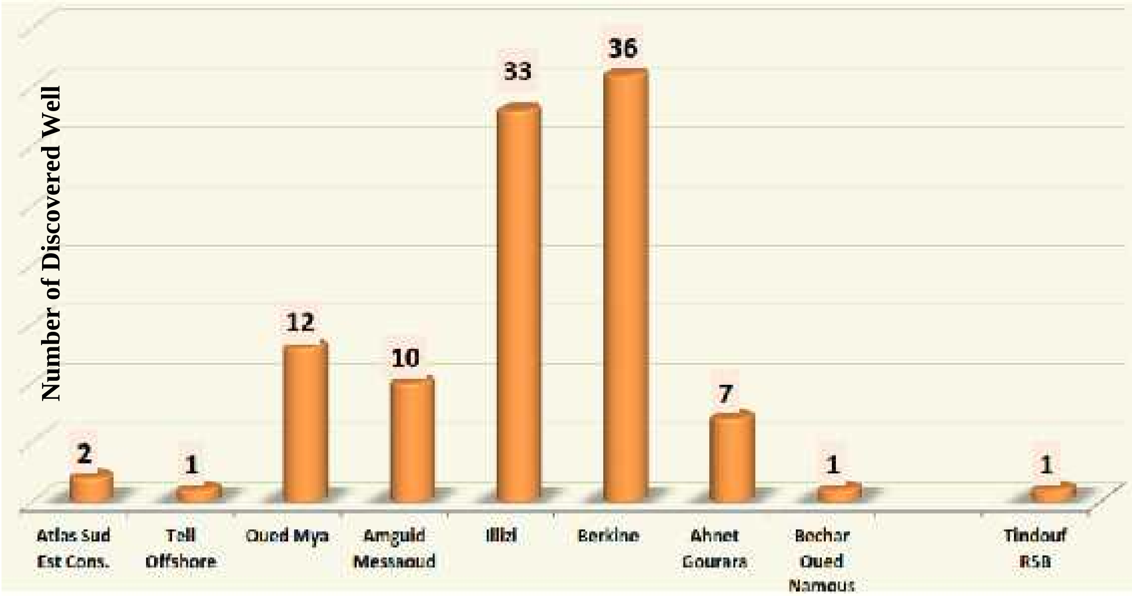


Figure. IV.15. Number of discovered by basins (2005-2012),(Sonatrach)

IV.4.1.Evaluation Of The Potential Shale Gas In Ahnet Basin

The principal results summarize as follows:

- the characteristics tanks and the quality of the Frasnian rocks are of first world class in terms: of richness of the organic matter, of maturity (dry gas window with wet gas), high porosity and permeability (effective porosity attain an average 9.5% and permeability > 100 nanoDarcies) and low water saturation of the reservoir (< 25).

- The thicknesses of the Frasnien objective are judged importantes.Il can reach 230 m;two on three levels of adits are necessary to drain all the vertical extent of the formation.
- the clay contents are generally high (> 60% higher than the majority of the analogues), but there remains weak in the zones of high TOC.
- the first conclusions of the geomechanical study indicate that there is not much difference compared to other productive clays.

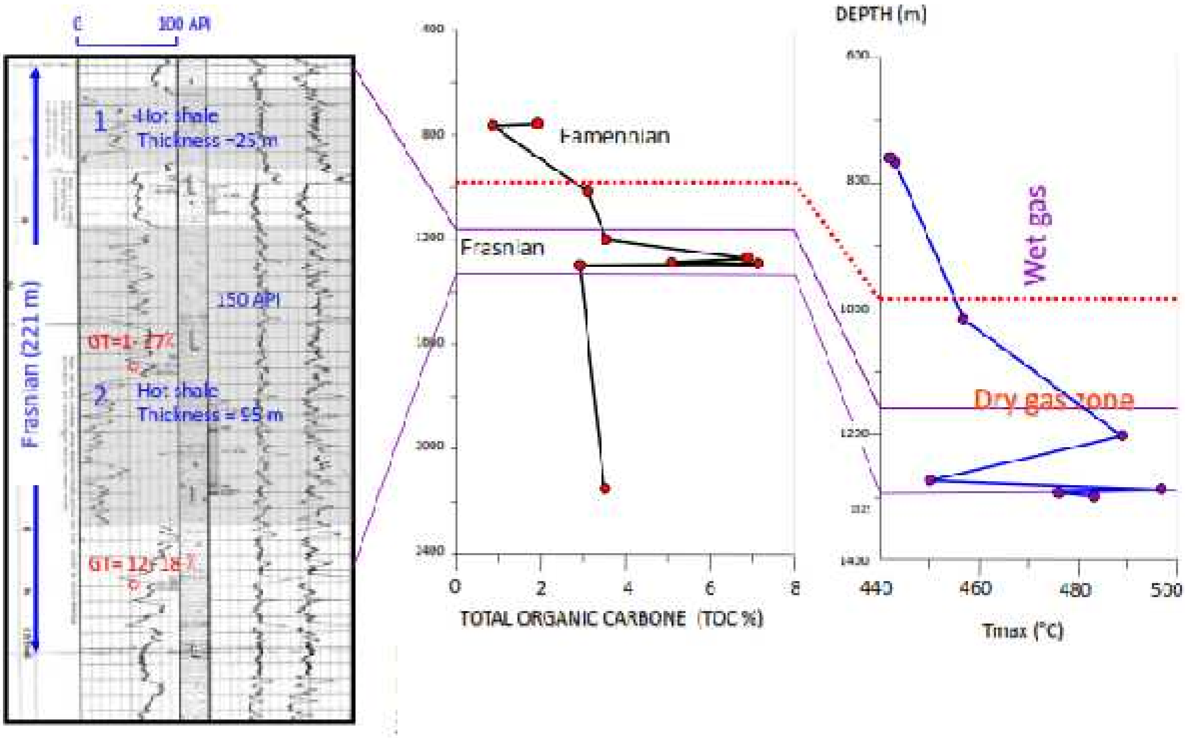


Figure.IV.16.Frasnian source rock of Ahnet basin (Sonatrach)

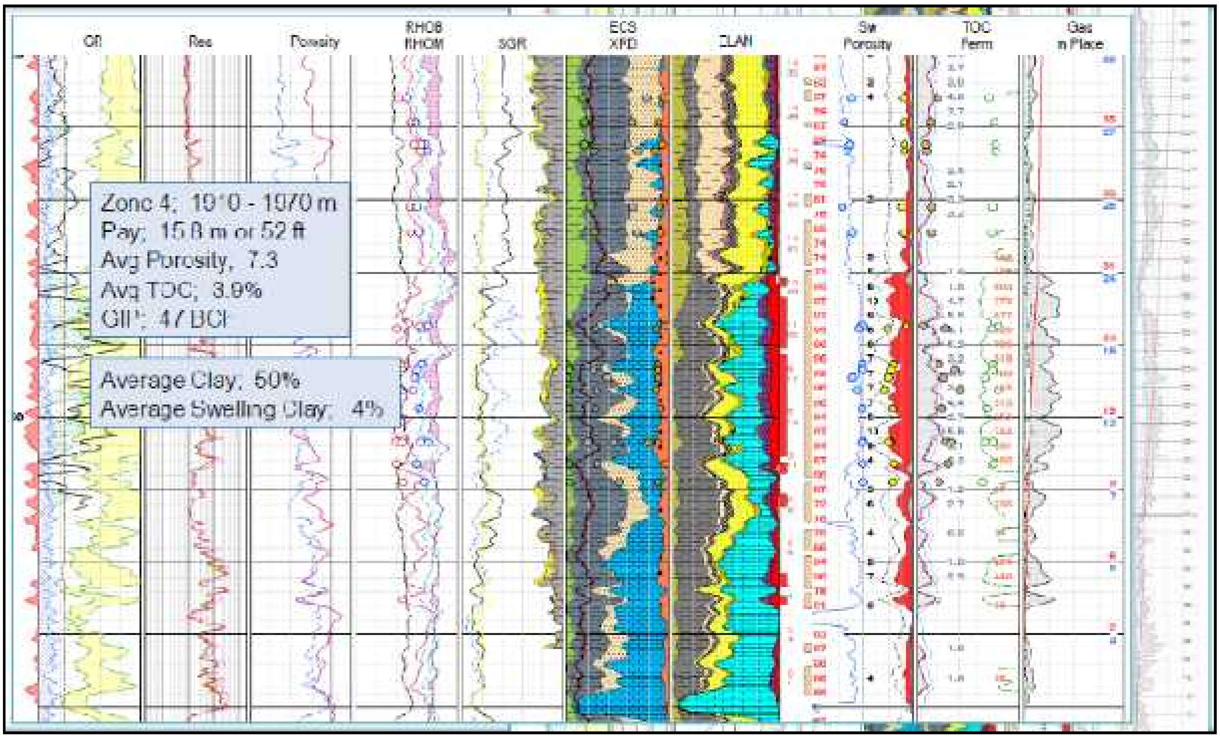


Figure.IV.17. Preliminary results Frasnian basin of Ahnet (Sonatrach)

IV.4.2. Petrophysic evaluation of radioactive Frasnian shales

In order to assess reservoir quality, specific open hole logs have been acquired in shale gas sections of wells drilled for conventional objectives in sandstone reservoirs, the evaluation tools comprise: Elemental device (spectroscopy),array induction, Magnetic Resonance, Sonic with anisotropic determination,GR,Sonic,Resistivity,Image log et Neutron density.

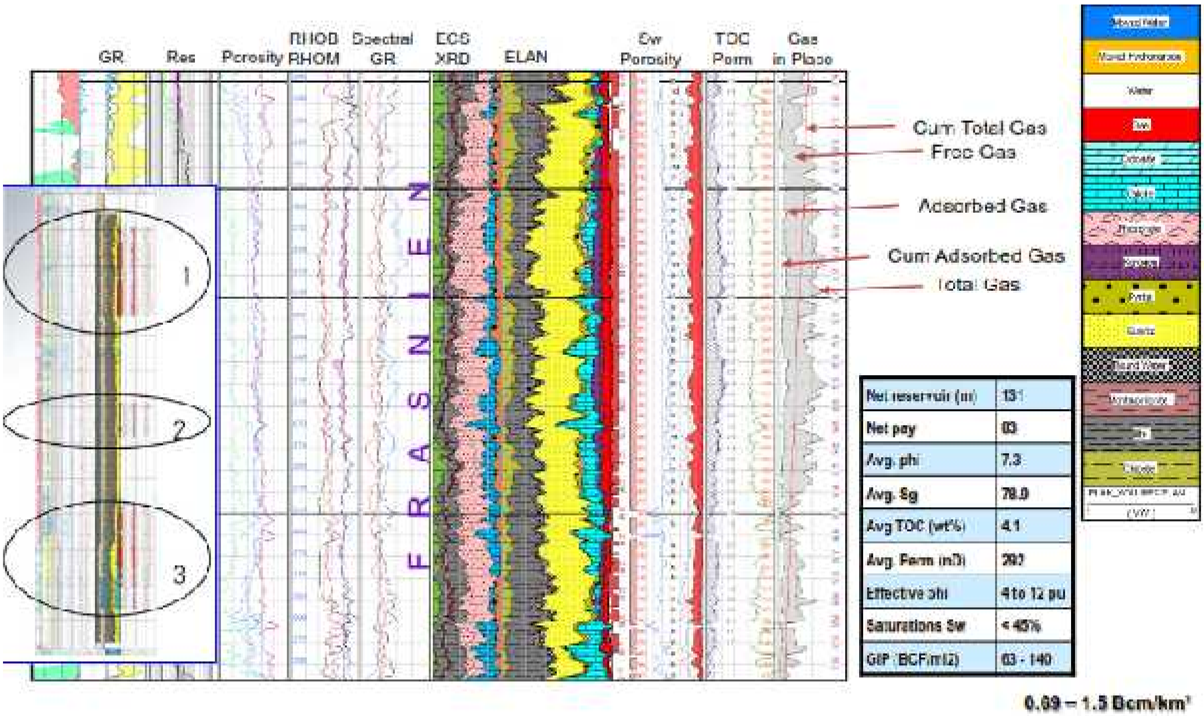


Figure.IV.18.Petrophysical acquisition data (Sonatrach)

IV.4.3. Evaluation of well in Ahnet Frasnian interval

Higher radioatives clays have excellent petrophysic properties :the effective porosity, K_{gas} and S_{weff} are so good.

Very weak S_{weff} suggests that the pores almostl are entirely associated with the kerogen.The amount of pores inter/interparticules is low enough.

The average value of TOC for organic clays is high.The formation is probably deposited in an anoxic medium(gone up per much pyrite)

All radioactive clays have very high clay contents with in particular much of kaolinite, chlorite and smectite.la average of the clay contents is ~ 60%.

high rate of smectite(5.1% in Hot Shale Sup) suggests that the compatibility of the fluid of frac must be evaluated.

Kerogen is completely transformé: production of dry gas.

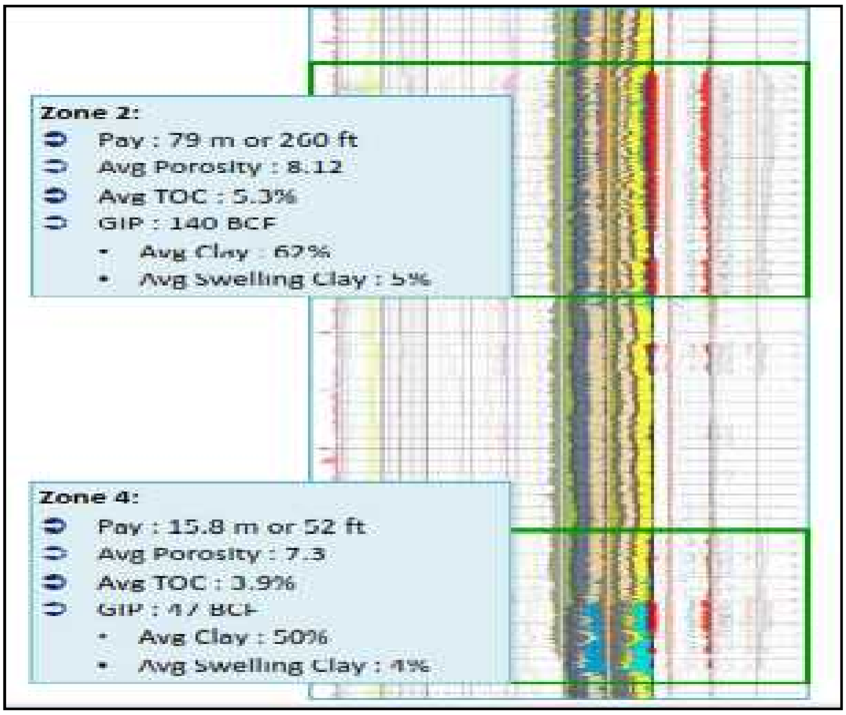


Figure.IV.19. Evaluation of well in Ahnet Frasnian interval (pay zone) (Sonatrach)

IV.4.4.Plays of Shale Gas: Mineralogy Variation

The mineralogical composition of shales is an essential criterion for the evaluation of potential shale gas, from this criterion can judge on the formation fractuability, and this criterion is evaluated based on the ternary diagram of mineralogy (Figure IV .19), which gives the percentage distribution of: Clay, carbonate and quartz-feldspar-mica,

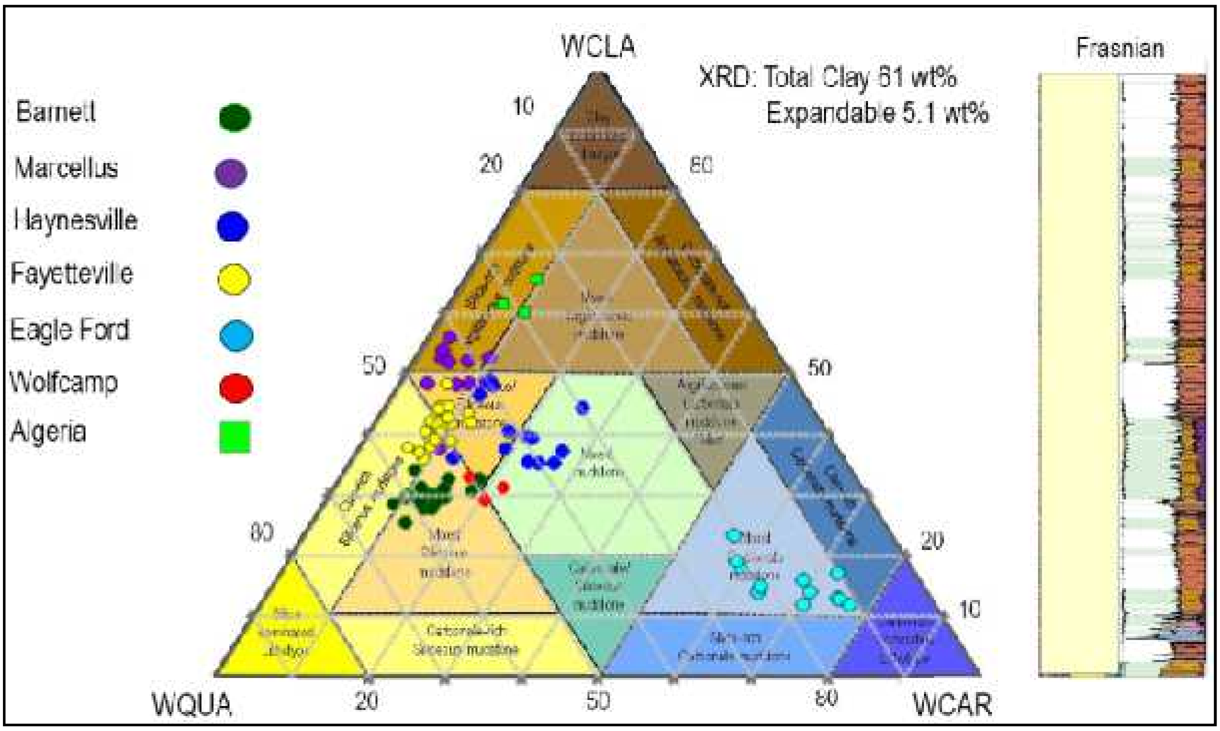


Figure.IV.20.Mineralogy Variation of Algeria's shale basins (Sonatrach)

Richness in QFM is favorable given the brittle nature of its minerals, on the other hand rich clay is unfavorable given the nature of the plastic clays. For the study area, there is not enough study on the mineralogical composition of hot shale Ahnet. A limited study in advanced logs indicated a clay volume of between 20-60%.

IV.4.5. Comparison of the Ahnet Frasnian gas shale (Algeria) with the US main Gas Shales (Preliminary results)

The analysis are about the six principal basins containing North American shale gas (see table.IV.2).

The Studies on its shales were examined to establish certain similarities with the radioactive shale basin Ahnet.

Formation	Net Ft. Pay	Avg. Eff. Phi (%)	Avg. TOC (wt%)	Avg. Sw (%)	Avg. K (nD)	Total GIP (Bcf/mi²)
Marcellus Shale (Wash Co)	76	8.1	3.6	19	567	59
Barnett Shale (Core)	133	8	3.3	24.5	299	139
Woodford Shale (Arkoma)	66	6.8	6	26.4	285	59
Atoka Shale	21	9.6	2.6	48	191	55
Fayetteville Shale	84	7.2	3.6	29.1	288	53
Haynesville Shale	112	8.4	2.2	39	270	129
Eagle Ford Shale	105	6.6	2.7	23	284.5	90
Algeria (area A)	108	7.0	2.7	18	350	65
Algeria (area B)	250	8.6	4.1	23.2	360	122
Algeria (area C)	248	9.0	4.0	22	354	122

Table.IV.2. Comparison of the Ahnet Frasnian gas shale with US main gas shales (Sonatrach)

IV.4.6.The Beginning of Exploration and The First Pilot Wells of Ahnet

Sonatrach started the exploration phase in shale gas reservoir by drilling the two pilot wells AHT-1 and AHT-2 in Ahnet basin and they recovered :

1) Canisters Sampling (about 50 samples) from AHT-1
2) 12 cores (11 from Frasnian ,01 Framennian) from AHT-1
3) TD=2000 m at couvinian formation for AHT-1,and TD=2625 m(±50 m) at Top Ordivician formation for AHT-2.

Figure.IV.22.Situation Of AHT-2 Pilot Well (Sonatrach)

Conclusion

Although some basins like Illizi and Berkine have best qualities interms of the generation potential, but this last depends on the relations between maturity of gas and depth. The Western Saharan basins have just an average potential, they have relatively low to medium generation potential. The best zones (basins) for the exploration of shale gas plays in the Saharan platform are the western part of Illizi, the Ahnet-Gourara and Bechar basins.

In the Illizi Basin, there are some prospects which are in a favorable environment for Silurian shale gas, but none for Frasnian shale gas which is in the oil window at present. The interesting zones for Silurian shale gas are located in a narrow western Northen band.

In the Berkine basin, some prospects are located in potential zones for both Frasnian and Silurian shale gas,in the same time ;however ,the depth of the objectives is too high. Silurian hot shales are well developed in the central part of the basin where values of R_0 going up to 1.6% were recorded.

In the Ahnet and Gourara basin, there are zones interesting for both Silurian and Frasnian basin with respect to the maturity and the depth of the objectives. Preliminary estimates of total GIP in the Frasnian hot shales of one well from the Ahnet basin indicate a potential of 65 Bcf/mi^2 .Resource estimates from geochemical modeling for both Silurian and Frasnian shale gas plays in the Saharan basins is 2650 Tcf.

In terms of choice of source rocks, Frasnian of the Ahnet basin having already shown strong gas concentrations in mud during drilling, also in the Gourara and Berkine basins are considered as the best candidate to prove the concept with performance indicators(drilling and stimulation feasibility, minimum tested gas,…).For the Silurian shale gas, the interesting zones are identified in the Ahnet and Gourara basins and to lesser degree in the Illizi basin.

As far as the development of shale reservoir is concerned in the view of the expertise needs and the costs involved it's necessary to go take the US experiences for having weel established knowledge.

Chapter V

Environmental Impacts of Shale Gas Extraction

Introduction

Shale gas was welcomed at first by environmentalists as a lower-carbon alternative to coal. However, as it became apparent that shale gas was a competitive threat to renewable energy as well as to coal, the green movement has turned against shale.

Producing unconventional gas is an intensive industrial process, generally imposing a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use and water resources. Serious hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse-gas emissions must be minimized both at the point of production and throughout the entire natural gas supply chain. Improperly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources.

V.1.General Risk Causes

In general, the main causes of risks and impacts from high-volume hydraulic fracturing identified in the course of this study are as follows:

- The use of more significant volumes of water and chemicals compared to conventional gas extraction .
- The lower yield of unconventional gas wells compared to conventional gas wells means that the impacts of HVHF(high volume hydraulic fracturing) processes can be greater than the impacts of conventional gas exploration and production processes per unit of gas extracted.
- The challenge of ensuring the integrity of wells and other equipment throughout the development, operational and post-abandonment lifetime of the plant (well pad) so as to avoid the risk of surface and/or groundwater contamination .
- The challenge of ensuring that spillages of chemicals and waste waters with potential environmental consequences are avoided during the development and operational lifetime of the plant (well pad) .
- The challenge of ensuring a correct identification and selection of geological sites, based on a risk assessment of specific geological features and of potential uncertainties associated with the long-term presence of hydraulic fracturing fluid in the underground .

- The potential toxicity of chemical additives and the challenge to develop greener alternatives.
- The unavoidable requirement for transportation of equipment, materials and wastes to and from the site, resulting in traffic impacts that can be mitigated but not entirely avoided.
- The potential for development over a wider area than is typical of conventional gas fields .
- The unavoidable requirement for use of plant and equipment during well construction and hydraulic fracturing, leading to emissions to air and noise impacts.

V.2.Environnemental Pressures

V.2.1.Land-Take

The American experience shows there is a significant risk of impacts due to the amount of land used in shale gas extraction. The land use requirement is greatest during the actual hydraulic fracturing stage (i.e. stage 3), and lower during the production stage (stage 5).

Surface installations require an area of approximately 3.6 hectares per pad for high volume hydraulic fracturing during the fracturing and completion phases, compared to 1.9 hectares per pad for conventional drilling. Land-take by shale gas developments would be higher if the comparison is made per unit of energy extracted. Although this cannot be quantified, it is estimated that approximately 50 shale gas wells might be needed to give a similar gas yield as one North Sea gas well. Additional land is also required during re-fracturing operations (each well can typically be re-fractured up to four times during a 40 years well lifetime).

Consequently, approximately 1.4% of the land above a productive shale gas well may need to be used to exploit the reservoir fully. This compares to 4% of land in Europe currently occupied by uses such as housing, industry and transportation. This is considered to be of potentially major significance for shale gas development over a wide area and/or in the case of densely populated European regions.

The evidence suggests that it may not be possible fully to restore sites in sensitive areas following well completion or abandonment, particularly in areas of high agricultural, natural or cultural value. Over a wider area, with multiple installations, this could result in a significant loss or fragmentation of amenities or recreational facilities, valuable farmland or natural habitats.

V.2.2.Releases To Air

Emissions from numerous well developments in a local area or wider region could have a potentially significant effect on air quality. Emissions from wide scale development of a shale gas reservoir could have a significant effect on ozone levels. Exposure to ozone could have an adverse effect on respiratory health and this is considered to be a risk of potentially high significance.

The technical hydraulic fracturing stage also raises concerns about potential air quality effects. These typically include diesel fumes from fracturing liquid pumps and emissions of hazardous pollutants, ozone precursors and odours due to gas leakage during completion(e.g. from pumps, valves, pressure relief valves, flanges, agitators, and compressors).

There is also concern about the risk posed by emissions of hazardous pollutants from gases and hydraulic fracturing fluids dissolved in waste water during well completion or recompletion. Fugitive emissions of methane (which is linked to the formation of photochemical ozone as well as climate impacts) and potentially hazardous trace gases may take place during routeing gas via small diameter pipelines to the main pipeline or gas treatment plant.

On-going fugitive losses of methane and other trace hydrocarbons are also likely to occur during the production phase. These may contribute to local and regional air pollution with the potential for adverse impacts on health. With multiple installations the risk could potentially be high, especially if re-fracturing operations are carried out.

Well or site abandonment may also have some impacts on air quality if the well is inadequately sealed, therefore allowing fugitive emissions of pollutants. This could be the case in older wells, but the risk is considered low in those appropriately designed and constructed. Little evidence exists of the risks posed by movements of airborne pollutants to the surface in the long-term, but experience in dealing with these can be drawn from the management of conventional wells.

V.2.3.Noise Pollution

Noise from excavation, earth moving, plant and vehicle transport during site preparation has a potential impact on both residents and local wildlife, particularly in sensitive areas. The site preparation phase would typically last up to four weeks but is not considered to differ greatly in nature from other comparable large-scale construction activity.

Noise levels vary during the different stages in the preparation and production cycle. Well drilling and the hydraulic fracturing process itself are the most significant sources of noise.

Flaring of gas can also be noisy. For an individual well the time span of the drilling phase will be quite short (around four weeks in duration) but will be continuous 24 hours a day. The effect of noise on local residents and wildlife will be significantly higher where multiple wells are drilled in a single pad, which typically lasts over a five-month period. Noise during hydraulic fracturing also has the potential to temporarily disrupt and disturb local residents and wildlife. Effective noise abatement measures will reduce the impact in most cases, although the risk is considered moderate in locations where proximity to residential areas or wildlife habitats is a consideration.

It is estimated that each well-pad (assuming 10 wells per pad) would require 800 to 2,500 days of noisy activity during pre-production, covering ground works and road construction as well as the hydraulic fracturing process. These noise levels would need to be carefully controlled to avoid risks to health for members of the public.

V.2.4.Surface And Groundwater Contamination

The study found that there is a high risk of surface and groundwater contamination at various stages of the well-pad construction, hydraulic fracturing and gas production processes, and during well abandonment. Cumulative developments could further increase this risk.

Runoff and erosion during early site construction, particularly from storm water, may lead to silt accumulation in surface waters and contaminants entering water bodies, streams and groundwater. This is a problem common to all large-scale mining and extraction activities.

However, unconventional gas extraction carries a higher risk because it requires high-volume processes per installation and the risks increase with multiple installations. Shale gas installations are likely to generate greater storm water runoff, which could affect natural habitats through stream erosion, sediment build-up, water degradation and flooding.

Mitigation measures, such as managed drainage and controls on certain contaminants, are well understood. Therefore the hazard is considered minor for individual installations with a low risk ranking and moderate hazard for cumulative effects with a moderate risk ranking.Road accidents involving vehicles carrying hazardous materials could also result in impacts on surface water.

The study considered the water contamination risks of sequential as well as simultaneous (i) well-drilling and (ii) hydraulic fracturing.

i. Poor well design or construction can lead to subsurface groundwater contamination arising from aquifer penetration by the well, the flow of fluids into, or from rock formations, or the migration of combustible natural gas to water supplies. In a properly constructed well, where there is a large distance between drinking water

sources and the gas producing zone and geological conditions are adequate, the risks are considered low for both single and multiple installations. Natural gas well drilling operations use compressed air or muds as the drilling fluid. During the drilling stage, contamination can arise as a result of a failure to maintain storm water controls, ineffective site management, inadequate surface and subsurface containment, poor casing construction, well blowout or component failure. If engineering controls are insufficient, the risk of accidental release increases with multiple shale gas wells. Cuttings produced from wells also need to be properly handled to avoid for instance the risk of radioactive contamination. Exposure to these could pose a small risk to health, but the study concluded that this would only happen in the event of a major failure of established control systems. No evidence was found that spillage of drilling muds could have a significant effect on surface waters.

However, in view of the potential significance of spillages on sensitive water resources, the risks for surface waters were considered to be of moderate significance.

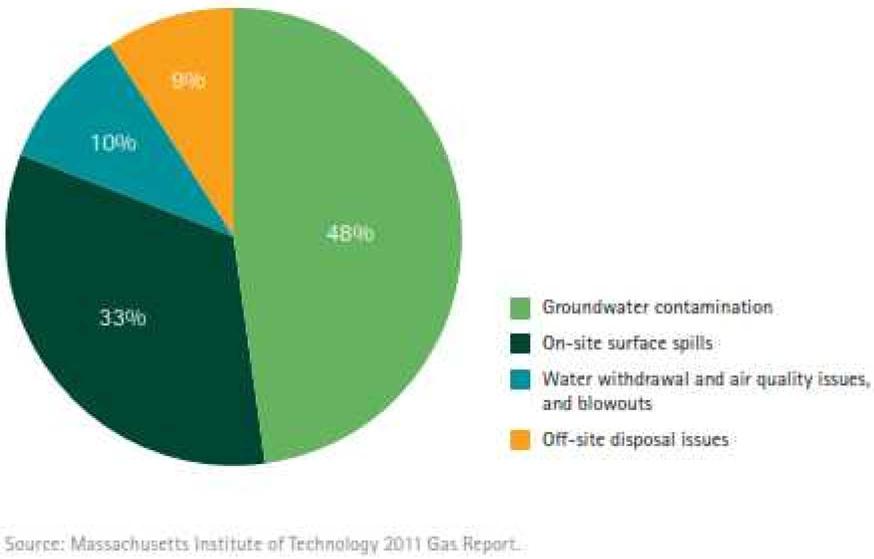


Figure.IV.1.Chart of Water Contamination Incidents Related to Gas Well Drilling

ii.The risks of surface water and groundwater contamination during the technical hydraulic fracturing stage are considered moderate to high. The likelihood of properly injected fracturing liquid reaching underground sources of drinking water through fractures is remote where there is more than 600 m separation between the drinking water sources and the producing zone. However, the potential of natural and manmade geological features to increase hydraulic connectivity between deep strata and more shallow formations and to constitute a risk of migration or seepage needs to be duly considered. Where there is no such large depth separation, the risks are greater. If wastewater is used to make up fracturing fluid, this would reduce the water requirement, but increase the risk of introducing naturally occurring chemical contaminants and radioactive materials into aquifers in the event of well failure or of fractures extending out of the production zone. The potential wearing effects of repeated fracturing on well construction components such as casings and cement are not sufficiently understood and more research is needed.

In the production phase, there are a number of potential effects on groundwater associated however with the inadequate design or failure of well casing, leading to potential aquifer contamination. Substances of potential concern include naturally occurring heavy metals, natural gas, naturally occurring radioactive material and technologically enhanced radioactive material from drilling operations. The risks to groundwater are considered to be moderate high for individual sites, and high for development of multiple sites.

Figure.IV.2. Flowback water samples from select Shale Gas Plays, (Kerstin,2010)

Inadequate sealing of a well after abandonment could potentially lead to both groundwater and surface water contamination, although there is currently insufficient information available on the risks posed by the movement of hydraulic fracturing fluid to the surface over the long term to allow these risks to be characterized. The presence of high-salinity fluids in shale gas formations indicates that there is usually no pathway for release of fluids to other formations under the geological conditions typically prevailing in these formations, although recently published research indicates that pathways may potentially exist in certain geological areas such as those encountered in parts of Pennsylvania, emphasizing the need for a high standard of characterization of these conditions.

V.2.5.Water Resources

The hydraulic fracturing process is water-intensive and therefore the risk of significant effects due to water abstraction could be high where there are multiple installations. A proportion of the water used is not recovered. If water usage is excessive, this can result in a decrease in the availability of public water supply; adverse effects on aquatic habitats and ecosystems from water degradation, reduced water quantity and quality; changes to water temperature; and erosion. Areas already experiencing water scarcity may be affected especially if the longer term climate change impacts of water supply and demand are taken into account. Reduced water levels may also lead to chemical changes in the water aquifer resulting in bacterial growth causing taste and odour problems with drinking water. The underlying geology may also become destabilised due to upwelling of lower quality water or other substances. Water withdrawal licences for hydraulic fracturing have recently been suspended in some areas of the United States.

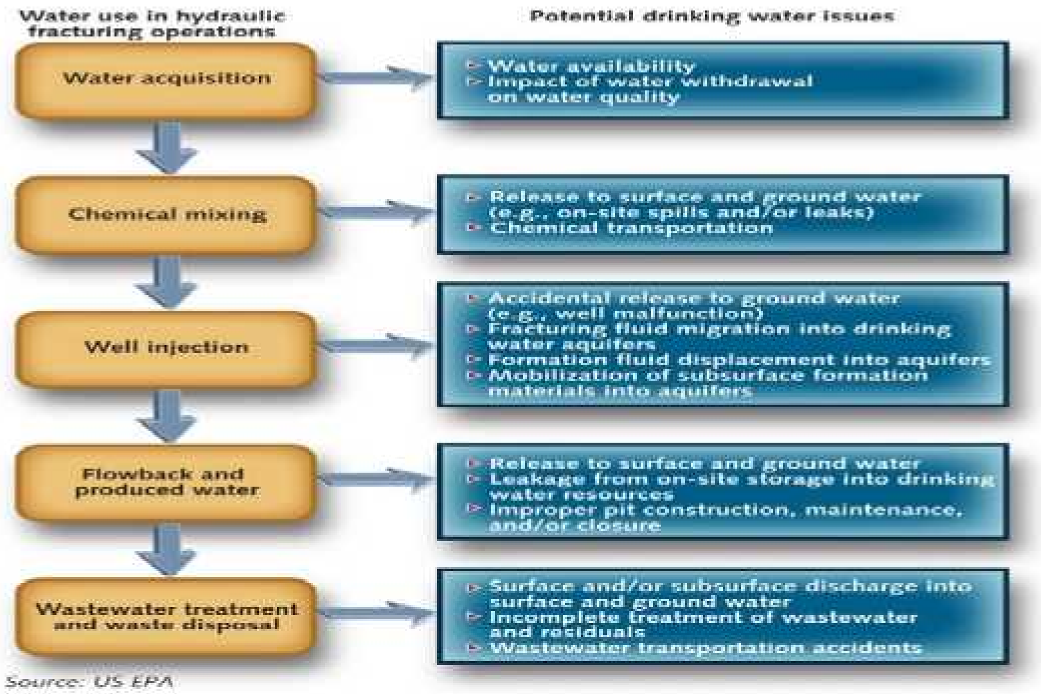


Figure.IV.3.Water Use in Hydraulic Fracturing Operations

Fracking Fluid

The first problem came about because of the industry‘s initial refusal to reveal the ingredients of the slick water used in hydraulic fracking. Pressed by regulators, shale gas companies are now becoming more transparent about the chemicals in fracking fluid.Typically, what goes down the well is 94.62% water, 5.24% sand, 0.05% friction reducer,0.05% antimicrobial, 0.03% hydrochloric acid and 0.01% scale inhibitor. The actual chemicals are used in many industrial and even domestic applications: polyacrylamide as a friction reducer, bromine, methanol and naphthalene as antimicrobials, hydrochloric acid and ethylene glycol as scale inhibitors, and butanol and ethylene glycol monobutyl ether as surfactants. At high dilution these are unlikely to pose a risk to human health in the event they reach groundwater.Any toxicity of the components, such as acid, is greatly reduced by dilution in the pumped fluid and by the reaction of the acid with the rock in the subsurface that converts the acid into inert salts (Arthur, et al., 2009).

The well pipe running down through the aquifer is encased in alternating layers of concrete and steel and is generally triple-encased down to the depth of aquifers (less than 500 feet). For the well to produce gas it is vital that there are no leaks of either gas or fracking fluids into the aquifer or any other strata, so it is not in the company‘s interest to allow this.

However, on rare occasions wells may fail through the loss of the drilling bit and have to be abandoned. In such cases, the well must be sealed with cement but it is possible that this can be unsuccessful or that contamination can occur before it takes effect.

The industry contends that ground water contamination occurs much more frequently as a result of pollution unrelated to the shale-gas industry: agricultural run-off, oil spills from the transport industry, run-off from abandoned coal mines, and so forth. Wherever well water has been tested before and after gas drilling, no evidence has been found of groundwater contamination by fracking fluids.

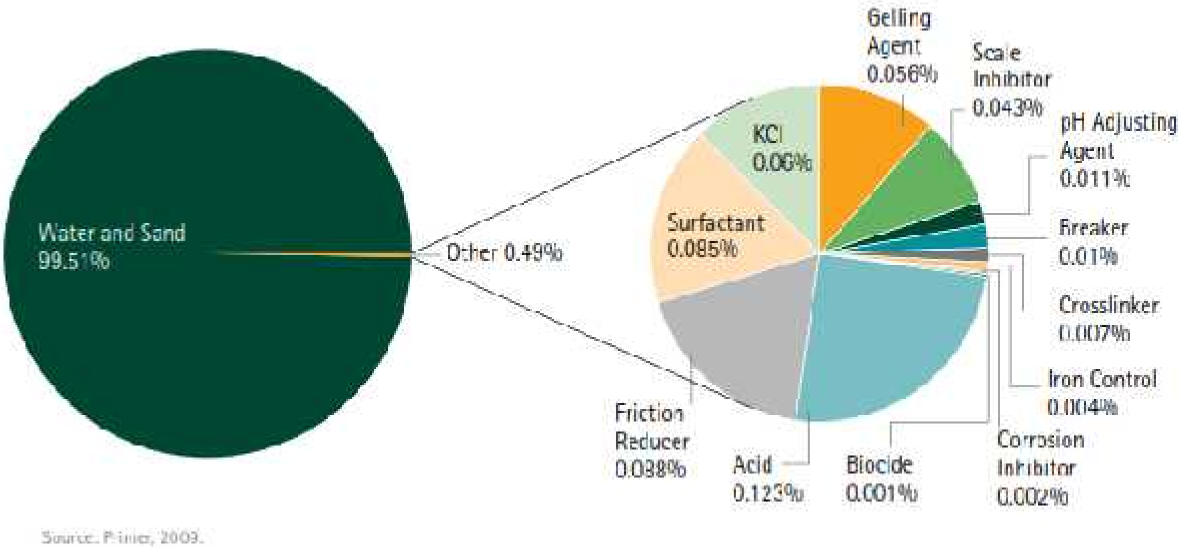


Figure.IV.3.Example of composition of fracturing fluid,(Primer2009)

Shale gas operations in the United States are heavily regulated and closely monitored. State regulators from Alaska, Colorado, Indiana, Louisiana, Michigan, Oklahoma, Pennsylvania, South Dakota, Texas and Wyoming have all asserted in writing that there have been no verified or documented cases of groundwater contamination as a result of hydraulic fracking

Flaming Faucets

Again, the industry has no interest in allowing that gas can escape into aquifers to happen because it would reduce the productivity of a well, so the casing of the well pipe is in everybody‘s interest. There are cases in Colorado, highlighted by a flaming tap in Fort Lupton in the film Gasland, where gas in domestic drinking water from an aquifer can be ignited.Natural gas in well water is a phenomenon that was known for many decades beforeshale-gas drilling began. (A similar phenomenon allows journalists to film scientists igniting methane that escapes through holes made in ice on Arctic lakes – again this has always happened as a result of organic decay on the lake bed.)

In April 2010 Cabot Oil and Gas Corporation paid a fine to the state of Pennsylvania after contamination of the drinking water of 14 homes in Dimock following a water well explosion possibly caused by gas escaping from an incompletely cased well. cabot maintains that it was not the cause of gas contamination

Waste Water

Approximately one-third of the water pumped down the well for fracking returns eventually to the surface together with gas during production. In the Marcellus Shale this water is saline, because the shale rock was formed on the bed of an ancient sea. The water is extracted from the gas, collected in pools doubly lined with heavy-duty polythene, and either re-used for fracking in other wells or desalinated, treated and disposed of as waste. This is no different from the treatment of waste water in any other industrial process. Pollution incidents involving such ‘produced water‘ are rare. A gas well operated by EOG Resources blew out in Clearfield County, Pennsylvania, in June 2010, spilling 35,000 gallons of slick water. The water was contained by berms and linings, and there were no injuries or significant damage to the environment.

The returning water is also slightly more radioactive than surface water because of naturally occurring isotopes within the rocks. However, this radioactivity drops when the salt is removed and before the water is disposed of in the sewage system. In any case many granite rocks have higher natural radioactivity, so exposure to waste water from gas drilling is likely to be no more hazardous than exposure to some other kinds of rock. There is no evidence that either gets close to being hazardous. Indeed the Pennsylvania Department of Environmental Protection has tested the water in seven rivers to which treated waste water from gas wells is discharged and found not only no elevation in radioactivity but: “All samples were at or below background levels of radioactivity; and all samples showed levels below the federal drinking water standard for Radium 226 and 228”.

All technologies have environmental risks. Press coverage that talks about ‘toxic‘,carcinogenic‘ and ‘radioactive‘ ‘chemicals‘ is meaningless

Water Depletion

The shale gas industry uses water: 1-5 million gallons per well. However, its needs are not great in comparison with those of other industries, such as the power generation industry, or even the quantity used in domestic appliances. Gas drilling in Pennsylvania uses less than 60 million gallons per day, compared with 1,550 used in public water systems, 1,680 used in industry and 5,930 used in power generation in the state (US Geological Survey). A single shale gas well uses in total about the same amount of water as a golf course uses in three weeks.

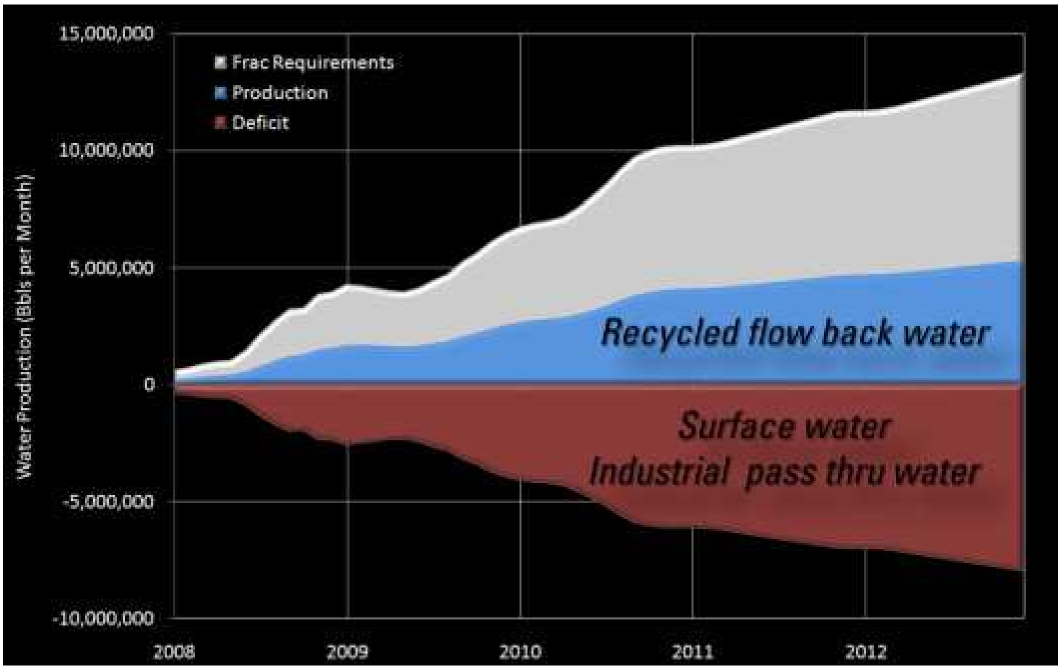


Figure.IV.4.Water Deplition by Frac requirements,(US Geological Survey).

V.2.6.Seismicity

There are two types of induced seismic events associated with hydraulic fracturing. The hydraulic fracturing process itself can under some circumstances give rise to minor earth tremors up to a magnitude of 3 on the Richter Scale, which would not be detectable by the public. An effective monitoring program can be used to manage the potential for these events and identify any damage to the wellbore itself. The risk of significant induced seismic activity was considered to be low.

The second type of event results from the injection of waste water reaching existing geological faults. This could lead to more significant underground movements, which can potentially be felt by humans at ground level. This would not take place at the shale gas extraction site.

According to the Ohio Department of Natural Resources, these events have been “almost certainly” caused by the use of underground wells to dispose of waste water produced by fracking. The wastewater is thought to lubricate fault lines, causing them to slip.

In April and May 2011, Cuadrilla Resources, the company carrying out fracking at Preese Hall, Lancashire, suspended exploration following two earthquakes with magnitudes of 1.5 and 2.3. Experts investigating the quakes stated that they may have occurred as a result of the fracking process. An independent scientific report commissioned by the British government confirmed that “the earthquake activity was caused by direct fluid injection” during the fracking process and conceded that it was not possible “to categorically reject the possibility of further quakes”.

However it concluded that operators could resume fracking operations, as long as they were effectively regulated, despite the obvious understatement of the risks generated by the earthquakes (such as the impacts on wells’ integrity, deformation of well casings, likely to create leakages).

Conclusion

Also environmental considerations should be focused on, like water management for fracturing and surface installations (well spacing, field development), to be successful within a shale gas project (Handler, 2010).

As documented recently in this chapter ,fracking is a high-risk carbon-intensive activity that impacts human health and the wider environment. Evidence –including from inside the industry – shows that the extraction process is prone to accidents, and that these pose a serious threat to the environment and to water supplies. Leaks of methane and highly toxic, carcinogenic chemicals from the process are almost unavoidable, directly impacting the quality of the air, water and soil, posing a serious risk to human health.

Many of these effects are not only local or just temporary. They can be felt regionally and even globally and over generations in the case of water contamination or air pollution. People around the world are increasingly aware of the potential impacts of shale gas development, and started to resist project in countries such as South Africa, Bulgaria, France, the US, Argentina and Czech Republic. Affected communities should be included in a full debate about impacts of shale gas, with the option to say ‘no’ to any project. Many governments have started to realize that and moratoriums have been installed in a number of places.

Conclusion

The challenges facing shale gas have been examined from the standpoints of gas in place and producibility.In this thesis we tried to explain the major aspects of shale gas production and describe the main methods of evaluation this type of unconventional reservoirs. Based on this study, a several conclusions can be showed ;

Firstly , Shale is a rapidly emerging natural gas reservoir in the United States where the development has begun in a broad range of sedimentary basins, beside that the almost of shale reservoirs researches and development were done in the US until being economic recoverable, then it was been exported to all over world where there is significant of assessing shale gas resources technically recoverable . The literature review presented that Complex shale reservoirs are not identical and each reservoir has its own characteristics and key parameters (Sweet Spot) must turn around it for the selection of the location of drilling sites, the types of completion and the location of the fractures,beside the The use of Muli-Stage Frac and Multi-Lateral WellPad techniques for the extraction of this type at the economics scale .

After that, to fully characterizing of shale gas reservoirs, a specific tools and methods are needed matching between logs and laboratory analysis. the development progress to producing economically; it will be important to effectively employ drilling, completion and hydraulic fracturing methods with sensitive and unique ways.

In Algeria, a several basins presents an important shale gas potential ,we have focused in this thesis at the Ahnet basin like the first exploration of shale gas basin in Algeria based on the therm of rock source , Frasnian of the Ahnet basin having already shown strong gas concentrations,and also after an initial study the main elements of shale reservoir : depth, net thickness, maturity (dry gas window) and TOC, in some sedimentary basins of the Algerian Saharan platform; for that the two first pilot well were drilling in this basin to continue of the investment gas shale.

The last topic discussed in this thesis is the environmental impact point of view concerning a shale gas reservoir extraction passing by air pollution, water depletion, surface ,groundwater contamination and other footprint, this impacts is not localized for nature of the gas shale but because of the extraction techniques particularly the hydraulic fracturing. This impact can be avoided if we take a respect to the security accordance rules.

As mentioned above, each shale play is unique. As a consequence, the exploration, prospection and production of shale gas are non-standardized processes. The unique characteristics of each shale play mean that it can take a number of years for a producer to find the best way to exploit an area, resulting in only small volumes of gas being drilled at the start of the project. Next to this, it may take years for exploitation activities to cover the entirety of the authorized area. In other words, some projects may start on a small scale basis but, in case of positive results, may become large scale. Moreover, the unique characteristics of each shale area also lead to a different proportion of fracturing fluid additives. This proportion is usually kept proprietary/secret.

This thesis is globally a literature review with an updates, but it is necessary associated with other experimental applications, unfortunately; we have attention that the access to the information data and to laboratory of petroleum companies for treating the subject of this thesis is still impossible under the confidentiality.

At the last we hope that this situation will be changed and we could access on source data, having the permission and collaboration with these petroleum industries for developing several aspects in the axis of subject thesis .

General Conclusion

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Appendix

Appendix A

Table A-1.Detailed Tabulation of shale Gas resources :48 Major Basins and 69 Formations (EIA 2013)

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
North America	I. Canada	Appalachian Fold Belt	Utica	155	31
		Windsor Basin	Horton Bluff	9	2
		Horn River	Muskwa/Otter Park	378	132
			Evie/Klua	110	33
		Cordova	Muskwa/Otter Park	83	29
		Liard	Lower Besa River	125	31
		Deep Basin	Montney Shale	141	49
			Doig Phosphate	81	20
		Colorado Group	2WS & Fish Scales	408	61
		Sub-Total		*1,490*	*388*
	II. Mexico	Burgos Basin	Eagle Ford Shale	1,514	454
			Tithonian Shales	272	82
		Sabinas Basin	Eagle Ford Shale	218	44
			Tithonian La Casita	56	11
		Tampico Basin	Pimienta	215	65
		Tuxpan Platform	Tamaulipas	25	8
			Pimienta	28	8
		Veracruz Basin	U. K Maltrata	38	9
		Sub-Total		*2,366*	*681*
	Total			**3,856**	**1,069**
South America	III. Northern South America	Maracaibo Basin	La Luna	42	11
		Catatumbo Sub-Basin	La Luna	29	7
			Capacho	49	12
		Sub-Total		*120*	*30*
	IV. Southern South America	Neuquen Basin	Los Molles	478	167
			Vaca Muerta	687	240
		San Jorge Basin	Aguaca Bandera	250	50
			Pozo D-129	180	45
		Austral-Magallanes Basin	L. Inoceramus	420	84
			Magnas Verdes	351	88
		Parana-Chaco Basin	San Alfredo	2,083	521
		Sub-Total		*4,449*	*1,195*
	Total			**4,569**	**1,225**

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
Europe	V. Poland	Baltic Basin	Silurian Shales	514	129
		Lublin Basin	Silurian Shales	222	44
		Podlasie Depression	Silurian Shales	56	14
		Sub-Total		*792*	*187*
	VI. Eastern Europe	Baltic Basin	Silurian Shales	93	23
		Drieper-Donets Basin	Visean Shales	48	12
		Lublin Basin	Silurian Shales	149	30
		Sub-Total		*290*	*65*
	VII. Western Europe	North Sea-German Basin	Posidonia Shale	26	7
			Namurian Shale	64	16
			Wealden Shale	9	2
		Paris Basin	Permo-Carboniferous Shale	303	76
		Scandinavia Region	Alum Shale	589	147
		South-East French Basin	Terres Niores	112	28
			Liassic Shale	305	76
		N. U.K. Petroleum System	Bowland Shale	95	19
		S. U.K. Petroleum System	Liassic Shale	2	1
		Sub-Total		*1,505*	*372*
	Total			**2,587**	**624**
Africa	VIII. Central North Africa	Ghadames Basin	Tannezuft Formation	520	156
			Frasnian Formation	251	75
		Sirt Basin	Sirt-Rachmat Formation	647	162
			Etel Formation	443	111
		Sub-Total		*1,861*	*504*
	IX. Morocco	Tindouf Basin	Silurian Shales	251	50
		Tadla Basin	Silurian Shales	16	3
		Sub-Total		*267*	*53*
	X. South Africa	Karoo Basin	Prince Albert	453	91
			Whitehill	995	298
			Collingham	386	96
		Sub-Total		*1,834*	*485*
	Total			**3,962**	**1,042**

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
Asia	XI. China	Sichuan Basin	Longmaxi	1,373	343
			Qiongzhusi	1,394	349
		Tarim Basin	O1/O2/O3 Shales	897	224
			Cambrian Shales	1,437	359
		Sub-Total		5,101	1,275
	XII. India/Pakistan	Cambay Basin	Cambay Shale	78	20
		Damodar Valley Basin	Barren Measure	33	7
		Krishna-Godavari Basin	Kommugudem Shale	136	27
		Cauvery Basin	Andimadam Formation	43	9
		Southern Indus Basin	Sembar Formation	80	20
			Ranikot Formation	126	31
		Sub-Total		496	114
	XIII. Turkey	Thrace Basin	Hamitabat	14	4
			Mezardere	7	2
		SE Anatolian Basin	Dadas Shale	43	9
		Sub-Total		64	15
	Total			5,661	1,404
Australia	XIV. Australia	Cooper Basin	Roseneath-Epsilon-Murteree	342	85
		Maryborough Basin	Goodwood/Cherwell Mudstone	77	23
		Perth Basin	Carynginia Shale	98	29
			Kockatea Fm	100	30
		Canning Basin	Goldwyer Fm	764	229
	Total			1,381	396
Grand Total				22,016	5,760

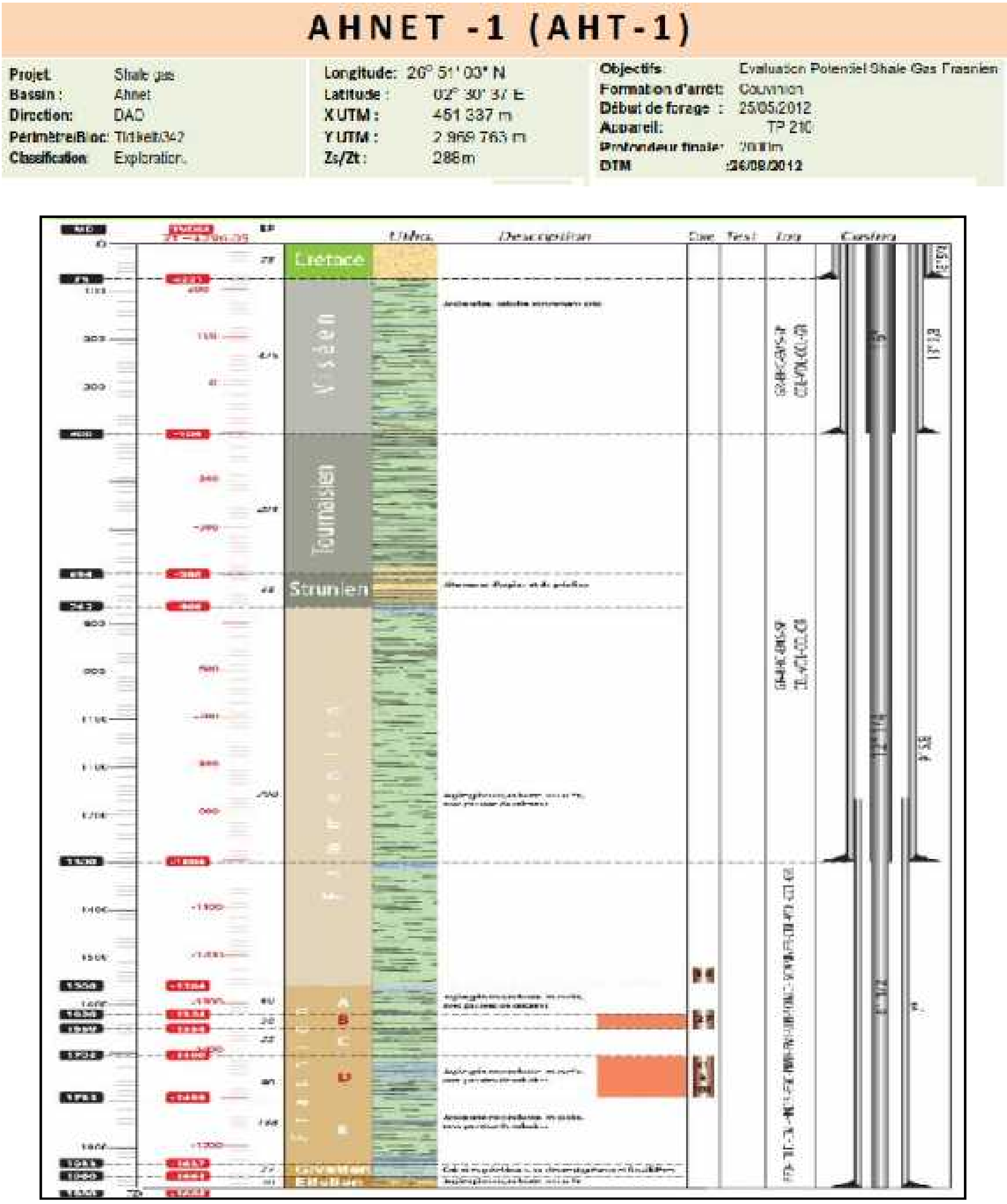
Table A-2.Risked Gas in-Place and Technically Recoverable Shale Gas Resources:32 Countries

Continent	Region	Country	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
North America	I. Canada		1,490	388
	II. Mexico		2,366	681
	Total		**3,856**	**1,069**
South America	III. Northern South America	Columbia	78	19
		Venezuela	42	11
		Subtotal	*120*	*30*
	IV. Southern South America	Argentina	2,732	774
		Bolivia	192	48
		Brazil	906	226
		Chile	287	64
		Paraguay	249	62
		Uruguay	83	21
		Subtotal	*4,449*	*1,195*
	Total		**4,569**	**1,225**
Europe	VI. Eastern Europe	Poland	792	187
		Lithuania	17	4
		Kaliningrad	76	19
		Ukraine	197	42
			1,082	*252*
	VII. Western Europe	France	720	180
		Germany	33	8
		Netherlands	66	17
		Sweden	164	41
		Norway	333	83
		Denmark	92	23
		U.K.	97	20
		Subtotal	*1,505*	*372*
	Total		**2,587**	**624**
Africa	VIII. Central North Africa	Algeria	812	230
		Libya	1,147	290
		Tunisia	61	18
		Morroco*	108	18
		Subtotal	*2,128*	*557*
	X. South Africa		1,834	485
	Total		**3,962**	**1,042**
Asia	XI. China		5,101	1,275
	XII. India/Pakistan	India	290	63
		Pakistan	206	51
	XIII. Turkey		64	15
	Total		**5,661**	**1,404**
Australia	XIV. Australia		**1,381**	**396**
Grand Total			**22,016**	**5,760**

* Includes Western Sahara & Mauritania

Appendix B

B-1- Drilling program and lithology prediction for AHT-1(SONATRACH)



B-2- Drilling program and lithology prediction for AHT-2 (SONATRACH)